Petrophysical and geochemical characterization of Midale carbonates from the Weyburn oilfield using synchrotron X-ray computed microtomography

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ABSTRACT

Understanding the controls on fluid migration in reservoir rocks is becoming evermore important within the petroleum industry as significant hydrocarbon discoveries become less frequent and more emphasis is placed on enhanced oil recovery methods. To fully understand the factors controlling fluid migration in the subsurface, pore scale information is necessary. In this study, synchrotron-based X-ray computed microtomography (CMT) is being utilized to extract physically realistic images of carbonate rock cores for the evaluation of porosity and mineralogy in the Mississippian Midale beds of the Weyburn Oilfield in southeastern Saskatchewan. Non-destructive in-situ imaging by CMT is unique as it provides a detailed and novel approach for the description of pore space geometry, while preserving connectivity and spatial variation of pore-body and pore-throat sizes. Here, three-dimensional micron to sub-micron (0.3µm-100µm) resolution of CMT is coupled with, and compared against, conventional laboratory-based methods (liquid and gas permeametry, mercury injection porosimetry, electrical resistivity, backscattered electron (BSE) from electron probe micro-analysis (EPMA) and transmitted light microscopy). Petrophysical and mineralogical information obtained from both CMT and conventional methods will have direct implications for understanding the petrophysical mechanisms that control fluid movement in the subsurface of the Weyburn Oilfield.

At Weyburn, CO$_2$ gas is being injected into producing horizons to enhance oil recovery and permanently sequester CO$_2$ gas. Fundamental questions exist regarding: (1) The significance of pore geometry and connectivity to the movement of CO$_2$ and other fluids in the subsurface, (2) the nature of the interactions between CO$_2$ and pore lining minerals and their impact on petrophysical properties, and (3) the distribution and mineralogy of finely disseminated silicate and carbonate minerals adjacent to pore spaces as interaction among these phases and CO$_2$ may result in permanent sequestration of CO$_2$.

The two producing horizons within the Weyburn Reservoir, the Midale Marly and Midale Vuggy units, have variable porosities and permeabilities. Porosity in the Marly unit ranges from 16% to 38% while permeability ranges from 1mD to greater than 150 mD across the field. For the Vuggy unit, porosity ranges from 8% to 21% with permeability ranging from 0.3mD to 500mD. Using CMT, pore space is critically examined to highlight the controlling factors on permeability. Digital processing of CMT data indicates that pore space in the Marly unit is dominated by intercrystalline pores having diameters of approximately 4 µm. From here, it is noted that the pore-throat radii are approximately ½ the radii of the pore-bodies, having profound implications to current oil recovery methods. Tortuosity values from CMT are also observed to have similar values in three orthogonal directions indicating an isotropic pore space distribution within the Marly unit. Alternatively, the Vuggy unit is found to possess greater pore-body and pore-throat sizes that are heterogeneous in distribution. Based on this, permeability in the Vuggy unit is strongly dependant on pore-length scales that vary drastically between localities.
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TABLE OF CONTENTS

PERMISSION TO USE AND DISCLAIMER STATEMENT ..............................................i
ABSTRACT .............................................................................................................. ii
ACKNOWLEDGEMENTS ....................................................................................... iii
TABLE OF CONTENTS ........................................................................................ iv
LIST OF TABLES ..................................................................................................... vi
LIST OF FIGURES ................................................................................................. vii

1. HISTORY AND GEOLOGY OF THE WEYBURN OILFIELD
   AND CARBONATE PETROPHYSICS ................................................................. 1
   1.1 Introduction ............................................................................................... 1
   1.2 Geographical Setting ................................................................................ 2
   1.3 History of the Weyburn Oilfield ............................................................... 3
   1.4 Regional Geology .................................................................................... 4
   1.5 Geology of the Midale Beds in the Weyburn Oilfield ............................ 6
   1.6 Pore Space Classification of Carbonate Systems .................................. 9

2. METHODS AND MATERIALS ........................................................................... 15
   2.1 Midale Carbonate Core Samples ............................................................. 15
   2.2 Analytical Techniques ............................................................................ 17
       2.2.1 Thin-Sections ................................................................................... 17
       2.2.2 Transmitted Light Microscopy ......................................................... 17
       2.2.3 Electron Probe Micro-Analysis ....................................................... 18
       2.2.4 X-rays and X-ray Computed Microtomography .............................. 18
           2.2.4.1 X-rays .................................................................................... 18
           2.2.4.2 X-ray Computed Microtomography ....................................... 21
       2.2.5 Water Saturation Porosity ............................................................... 27
       2.2.6 Electrical Resistivity ...................................................................... 29
       2.2.7 Gas Permeability ........................................................................... 31
       2.2.8 Liquid Permeability ....................................................................... 32
       2.2.9 Mercury Injection Porosimetry ...................................................... 33

3. RESULTS ............................................................................................................ 36
   3.1 Minerals and Pore Space ........................................................................ 36
       3.1.1 Mineral and Pore Space Distribution based on BSE and
              Transmitted Light Microscopy .................................................... 36
       3.1.2 Mineral and Pore Space Distribution Based on CMT .................... 40
       3.1.3 Integration of BSE and CMT to Determine Mineralogy .............. 43
       3.1.4 Digital Voxel Reconstruction of Minerals and Pore Space ......... 47
           3.1.4.1 Mineral Visualization ............................................................. 47
           3.1.4.2 Pore Space Visualization ....................................................... 48
       3.1.5 Mercury Injection Porosimetry ....................................................... 64
   3.2 Petrophysics .............................................................................................. 56
       3.1.1 Gas Permeability ............................................................................ 56
       3.1.2 Liquid Permeability ....................................................................... 58
       3.1.3 Water Saturation Porosity ............................................................. 59
       3.1.4 Electrical Resistivity ..................................................................... 60
       3.1.5 Mercury Injection Porosimetry ....................................................... 64
4. COMPARISON BETWEEN CONVENTIONAL PETROPHYSICS AND CMT ANALYSES

4.1 Previous Studies

4.2 Integration between Conventional Petrophysics and CMT from the Midale Carbonates

4.2.1 Porosity and CMT

4.2.2 Mercury Injection Porosimetry and CMT

4.2.3 Comparison of Laboratory Permeability with Theoretically Determined Values from CMT Data

4.3 Implications of CMT for the Weyburn Oilfield

5. SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

5.1 Summary and Conclusions

5.2 Recommendations

6. REFERENCES

APPENDIX A Gas Permeability Plots
APPENDIX B Mercury Injection Porosimetry Results
APPENDIX C CMT Voxel Reconstruction Results
LIST OF TABLES

Table 1.1. Porosity and permeability in the Weyburn Oilfield...........................8
Table 2.1. Midale Carbonate core sample information.................................16
Table 2.2. Theoretically determined mass attenuation coefficients (MAC) for common sulphate, sulfide, carbonate and silicate minerals...........25
Table 3.1. Chemical formulae, backscatter coefficients, effective atomic numbers and observed grey-levels of major mineral phases in the Midale Carbonates.................................................................38
Table 3.2. Distribution of observed LAC values in CMT data from the Midale Vuggy and Marly units............................................................42
Table 3.3. Empirically and theoretically calculated backscatter coefficients, effective atomic number, MAC, LAC and observed grey-levels from both CMT and BSE.................................................................45
Table 3.4. Corrected gas permeabilities for the Midale Carbonate core samples….57
Table 3.5. Measured liquid and gas permeabilities for the Midale Carbonate core samples............................................................59
Table 3.6. Dry and saturated masses for all Midale Carbonate core samples used in effective porosity determination by water saturation...........60
Table 3.7. Electrical resistivity results for the Midale Carbonate cores............61
Table 3.8. Calculated petrophysical parameters for the Midale Carbonate samples from electrical resistivity results..............................64
Table 4.1. Petrophysical parameters derived from conventional laboratory and CMT measurements.................................................73
Table 4.2. Measured porosity and permeability are compared with theoretical permeabilities calculated from mercury injection porosimetry and CMT data using the Katz-Thompson relationship for the three sections of Midale Carbonate core.......................80
| Figure 1.1. | Williston Sedimentary Basin and location of the Weyburn Oilfield | 3 |
| Figure 1.2. | Mississippian stratigraphy of southern Saskatchewan | 5 |
| Figure 1.3. | Geological diagram of the Midale Carbonates of the Weyburn Reservoir | 9 |
| Figure 1.4. | Common carbonate pore space classification systems | 10 |
| Figure 2.1. | Midale Carbonate core samples | 17 |
| Figure 2.2. | The electromagnetic spectrum | 19 |
| Figure 2.3. | Experimental arrangement of synchrotron CMT analyses | 22 |
| Figure 2.4. | Beam hardening in CMT images | 26 |
| Figure 2.5. | Ring artifacts in CMT images | 27 |
| Figure 2.6. | Vacuum cell apparatus for water saturation | 28 |
| Figure 2.7. | Midale reservoir brine chemical composition and PHREEQC modeling results | 29 |
| Figure 2.8. | Geometrical arrangement of the two-point method for electrical resistivity measurements | 30 |
| Figure 2.9. | Ruska gas permeameter | 32 |
| Figure 2.10. | Ruska liquid permeameter | 33 |
| Figure 2.11. | Ruska mercury injection porosimeter | 35 |
| Figure 3.1. | TLM and BSE comparison of the Midale Carbonate core samples | 37 |
| Figure 3.2. | BSE and CMT mineral identification and correlation plots | 39 |
| Figure 3.3. | Two-dimensional CMT slices for all Midale Carbonate core samples | 41 |
| Figure 3.4. | Two-dimensional CMT slices from the Midale Vuggy (V4) and Midale Marly (M0) samples | 42 |
| Figure 3.5. | Comparison of the Midale Vuggy (V2) with TLM and CMT | 44 |
| Figure 3.6. | Three-dimensional voxel reconstructions of mineral phases present in the Midale Vuggy (V4) sample | 46 |
| Figure 3.7. | Three-dimensional voxel reconstruction of pore space in the Midale Vuggy and Midale Marly units | 49 |
| Figure 3.8. | Comparison of two-dimensional tomographic slices of the Midale Marly (M0) sample collected at 10 µm and 0.78 µm | 51 |
| Figure 3.9. | Three-dimensional voxel reconstruction of pore space in the Midale Marly (M0) sample at 10 µm and 0.78 µm | 51 |
| Figure 3.10. | Three-dimensional voxel reconstruction of pore space and corresponding pore network skeleton of the Midale Marly (M0) | 52 |
| Figure 3.11. | A tortuous pathway through closely packed spheres | 53 |
Figure 3.12. Tortuosity computation and visualization in the Midale Marly (M0) sample...............................................................54
Figure 3.13. Pore statistics plots from the Midale Marly (M0) sample..........................................................55
Figure 3.14. Gas permeability plot and Klinkenberg correction for the Midale Vuggy (V2).................................................................57
Figure 3.15. Log-log plot of formation resistivity factor versus porosity for determining the cementation exponent........................................63
Figure 3.16. Apparent pore diameters in the Midale Vuggy (V2) sample from mercury injection porosimetry........................................67
Figure 3.17. Apparent pore diameters in the Midale Vuggy (V4) sample from mercury injection porosimetry........................................68
Figure 3.18. Apparent pore diameters in the Midale Marly (M0) sample from mercury injection porosimetry........................................69
Figure 4.1. Visual comparison between apparent pore diameters from mercury injection porosimetry in the Midale Vuggy (V4) sample and the corresponding CMT image.................................................................75
Figure 4.2. Determination of the critical pore diameter from mercury injection porosimetry..............................................................78
Figure 4.3. Comparison of apparent pore diameters from mercury injection porosimetry and with pore diameters from CMT on the Midale Carbonate samples.................................................................79
Figure 4.4. Paleoenvironmental model of the Weyburn Reservoir.............83
Figure 4.5. Pore lining minerals in the Midale Vuggy...............................86
Figure 4.6. Paragenetic sequence of diagenetic events in the Midale Carbonates of the Weyburn Oilfield................................................87
Figure 4.7. Flow chart of methods used in this study.....................................88
Figure 4.8. Concept of scale in geology and petrophysics...........................90
1. History and Geology of the Weyburn Oilfield and Carbonate Petrophysics

1.1 Introduction

In southeastern Saskatchewan, the Mississippian Midale beds of the Charles Formation host significant hydrocarbon fields within the Williston Sedimentary Basin (WSB). Many prolific oilfields in Saskatchewan situated along the Midale-Steelman Oilfield trend produce from the Midale beds, thus it is imperative to understand porosity and permeability within these rocks.

The focus of this study is to evaluate and develop techniques which can improve the physical characterization of pore space in the Midale beds within the Weyburn Oilfield, site of EnCana Corporation’s CO$_2$-miscible enhanced oil recovery (EOR) and greenhouse gas (GHG) storage project. At Weyburn, the Midale beds are separated into two reservoir lithologies, a marly dolomite unit and a vuggy limestone unit. Both units together create a complex and compartmentalized reservoir with variable porosities and permeabilities.

Conventional petrophysical laboratory methods such as gas and liquid permeability, electrical resistivity and mercury injection porosimetry along with mineralogical techniques, transmitted light microscopy, electron probe micro-analysis and scanning electron microscopy, have been the benchmark for evaluation of petrophysical and mineralogical parameters in geological materials for many years. However, with advances in medical radiology, geoscientists are able to observe the internal structure of reservoir quality rocks obtaining crucial information about pore space and the minerals that line them. Here, a novel radiological imaging approach, X-ray computed microtomography (CMT) using brilliant and coherent synchrotron light, is being applied to answer fundamental questions regarding the spatial distribution of pore space and minerals within the Midale beds of the Weyburn Oilfield. The non-destructive imaging of reservoir rock by synchrotron-based X-ray computed microtomography
yields physically realistic, three-dimensional digital images of pore space and rock matrix at micron to sub-micron resolution. Visual and quantitative information obtained from CMT is later compared directly with conventional petrophysical and mineralogical laboratory techniques to evaluate the reliability and accuracy of applying synchrotron-based CMT to formation evaluation problems.

1.2 Geographical Setting

Samples used in this research were obtained from the Weyburn Oilfield located in southeastern Saskatchewan approximately 12 km south of the city of Weyburn in townships 5 to 7 and ranges 12 to 14 W2M (Figure 1.1).
Figure 1.1. (A) The WSB is situated in southeastern Saskatchewan and northern United States hosting (B) the Weyburn Oilfield (study site) and other oilfields that together form the prolific Midale-Steelman oilfield trend. (C) Sample locations are shown in proximity to the phase 1A CO$_2$ injection pilot project (after Smith, 1980).

1.3 History of the Weyburn Oilfield

First discovered in 1954, the Weyburn Oilfield is situated near the northeastern flank of the WSB occupying 180 square kilometers and hosting approximately 1.4 billion barrels of medium gravity (22-35º API) sour crude (Churcher and Edmunds, 1994; Wilson and Monea, 2004) (Figure 1.1). Hydrocarbon production within the Weyburn Oilfield, along with many other fields in the surrounding area, is from the Midale beds of the Mississippian-aged Charles Formation. Up until 2000, the Weyburn
Oilfield produced approximately 370 MMBbls of the original oil in place (OOIP) through both primary and secondary oil recovery methods. In 2000, EnCana Corporation (operator and formerly PanCanadian Petroleum Limited) commenced Phase 1A of a CO₂ EOR and GHG storage project using supercritical CO₂ to increase oil recovery by an additional 5-10% or 130 MMBbls while potentially sequestering 20 million tonnes of CO₂ over the next 25 years. CO₂ gas (approximately 96% pure) is a purchased byproduct from the Great Plains Synfuel coal gasification plant located in Beulah, North Dakota. The CO₂ gas is transported 320 km by pipeline to the Weyburn Oilfield where it is injected into the producing zone at approximately 5000 tonnes/day (Wilson and Monea, 2004).

1.4 Regional Geology

Mississippian rocks in southern Saskatchewan are rich in hydrocarbons, accounting for approximately 75% of proven oil reserves and have been the focus of much petroleum exploration since the early 1950’s (Kent, 1984). To date, much of the petroleum exploration and exploitation in Saskatchewan has occurred within the WSB, a sub-basin of the greater Elk Point Basin, that occupies an area approximately 256,000 km² with its structural centre located near the town of Williston, North Dakota (Figure 1.1). Of interest to this research is the relationship between porosity and permeability in carbonate rocks belonging to the Mississippian Madison Group, particularly the Midale beds of the Charles Formation (Figure 1.2).
In southeastern Saskatchewan rocks of the Mississippian Madison Group gently dip approximately 1.9 to 10.5 m/km south-southeast from the basin margins towards the basin centre where it reaches a maximum thickness of 580 m in Saskatchewan (Fuller, 1956; Fuzesy, 1960). Along the northern flanks of the WSB the Madison Group carbonates are truncated by a post-Mississippian to pre-Middle Jurassic erosional event that created a stratigraphic wedge which acts as a trap for numerous hydrocarbon fields.
situated along the prolific Midale-Steelman oilfield trend (Figure 1.1). The Madison Group carbonates are indicative of cyclic transgressive-regressive pulses that reflect an overall progradation and shallowing-upward trend within the WSB during the Mississippian (Smith, 1980; Kent, 1984; Wegelin, 1984; Van de Reep, 1987).

1.5 Geology of the Midale Beds in the Weyburn Oilfield

At Weyburn, the rock unit of interest is the Mississippian Charles Formation which contain the hydrocarbon-bearing Midale beds that were given the name after oil was first discovered in the Midale area in 1953 (Fuzesy, 1960). The Midale beds range in thickness from 20 to 40 m in the Weyburn Oilfield and are a classic example of a shallowing-upward succession of peritidal and subtidal carbonates and evaporites deposited on a regionally extensive marine to marginal marine, shallow-water, wave-swept carbonate ramp. In southern Saskatchewan the Midale beds are divided into the Frobisher Evaporite and Midale Carbonate (Figure 1.2). In the Weyburn area, the Midale Carbonate is further subdivided into two distinct lithostratigraphic units based on electrical well-log response and lithology into an upper dolostone layer (Midale Marly dolomite) and a lower limestone layer (Midale Vuggy limestone) (Fuzesy, 1960; Wegelin, 1984). The terms Marly unit and Vuggy unit will be used here forward when referring to the Midale Marly dolomite and Midale Vuggy limestone, respectively.

The Midale beds conformably underlie the Ratcliffe beds and overlie the Frobisher-Alida beds (Figure 1.2) (Fuzesy, 1960). In the Weyburn Oilfield, the Midale beds are separated into an upper Marly unit and lower Vuggy unit. The upper Marly unit constitutes the upper half of the Midale Carbonate and is a productive reservoir horizon. It is predominately a chalky, microcrystalline (20-30 μm) dolostone with minor interbedded, tight vuggy limestone beds. Deposition of the Marly unit is interpreted to have occurred in restricted marine carbonate ramp settings consisting of mainly lagoonal wackestones, lime mudstones and minor intertidal lime mudstones. These restricted lagoonal mudstones and wackestones were later pervasively dolomitized producing a 0.1 m to 9.8 m thick (total net pay), relatively homogeneous, microcrystalline dolostone with variable porosities ranging from 16% to 38% and permeabilities ranging from 1 mD to greater than 150 mD (Table 1.1) (Churcher and Edmunds, 1994).
The Vuggy unit, situated directly below the Marly unit, is composed of six lithologic types as identified by Wegelin (1984): 1) argillaceous lime mudstone-wackestone, 2) wavy laminated mudstone-wackestone, 3) bioturbated mudstone-wackestone, 4) skeletal packstone, 5) peloidal and mixed peloidal-skeletal packstone and 6) peloidal packstone-grainstone. Based on these six lithologic types two zones, shoal and intershoal, each of which have their own unique lithological and petrophysical characteristics, can be defined within the Weyburn Oilfield.

The lower portion of the Vuggy unit consists of thinly-bedded (10 cm - 2 m) mudstone-wackestone facies that are interbedded with higher energy open-marine, subtidal porous bioclastic and peloidal packstone-grainstone facies influenced by storm and wave-reeaking. This lower “shoal” portion of the Vuggy unit is a productive zone in the Weyburn Oilfield having a variable net pay thickness ranging from 0.1 m to 18.6 m and patchy aereal distribution, making reservoir prediction difficult. Porosity within the Vuggy shoal horizon is a combination of fenestral, intercrystalline, intracrystalline and vuggy pore types and typically has high values (8% to 21%, averaging 15%). Measured matrix gas permeabilities on sections of Vuggy core range from 0.3 mD to greater than 500 mD, with 50 mD being the mean permeability across the field (Table 1.1).

Situated above the coarser shoal deposits are lower energy muddy sediments, known as the intershoal, that were formed in response to sea-level rise subsequently infilling the channels and blanketing the partially eroded lower shoal deposits. These deposits, predominately bioclastic lime wackestones, are low in porosity (ranging from 2% to 15%, averaging 10%) and permeability (ranging from less than 0.01 mD to 20 mD, averaging 3 mD) and are non-productive horizon within the Weyburn Oilfield.

In addition to the dominant depositional and diagenetic pore types, abundant northeast and southwest trending fractures are readily observed throughout the Midale beds in the Weyburn Oilfield with the Vuggy unit being more fractured. Fracture development within the intershoal deposits is more pronounced than those in the shoal deposits, possibly acting as fluid conduits for oil migration from shoal to shoal (Pendrigh, 2004). These fractures are deemed to control a majority of the movement of fluids within the Midale beds of the Weyburn Oilfield (Churcher and Edmunds, 1994; Whittaker et al., 2004).
Table 1.1. Porosity and permeability in the Weyburn Oilfield (from Churcher and Edmunds, 1994).

<table>
<thead>
<tr>
<th>Rock Texture</th>
<th>Marly Dolostones</th>
<th>Vuggy Shoal</th>
<th>Vuggy Intershoal</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mudstone - Wackestone</td>
<td></td>
<td>Vuggy Mollic</td>
<td></td>
</tr>
<tr>
<td>Porosity Types</td>
<td></td>
<td>Vuggy Moldic Intercrystalline Fenestral</td>
<td>Vuggy Intercrystalline</td>
</tr>
<tr>
<td>% Porosity (Average)</td>
<td>16-38 (26)</td>
<td>8-21 (15)</td>
<td>2-15 (10)</td>
</tr>
<tr>
<td>Permeability (mD) (Average)</td>
<td>1-150 (10)</td>
<td>0.3-500 (50)</td>
<td>0.01-20 (3)</td>
</tr>
<tr>
<td>Thickness (m) (Average)</td>
<td>0.1-9.8 (4.3)</td>
<td>0.1-18.6 (6)</td>
<td></td>
</tr>
</tbody>
</table>

The top and bottom seals in the Weyburn Oilfield for the shallow, southeast dipping porous Midale Carbonate beds are provided by the overlying Midale Evaporite and underlying Frobisher Evaporite, both of which represent supratidal conditions within the WSB during the Mississippian (Smith, 1980). In northeastern regions of the Weyburn Oilfield, the Midale beds are truncated by a regional erosional surface that juxtaposes marine shales of the Triassic Watrous Formation against the porous Midale Carbonates providing the up-dip seal (Figure 1.3). This regional erosional surface is termed the Sub-Mesozoic Unconformity (Whittaker et al., 2004).
Figure 1.3. Geological cartoon of the Weyburn Midale beds (courtesy of Geoff Burrowes, EnCana Corporation). The bulk of CO$_2$ injection and enhanced oil recovery takes place in the dolomitic Marly flow units (M0, M1, M3). Midale Vuggy flow units are labeled V1 through V4 and V6. Solid lines separate flow units and red lines depict erosional surfaces.

1.6 Pore Space Classification of Carbonate Systems

Carbonate rocks are significant hydrocarbon reservoirs, hosting approximately 60% of the world’s hydrocarbons; thus it is imperative for the petroleum industry to understand pore space development, distribution and influence on fluid transport (Vissapragada et al., 2000; Arns et al., 2005). Unlike siliciclastic sediments, pore systems in carbonate rocks are complex both genetically and geometrically (Choquette and Pray, 1970). At the reservoir scale, pore space distribution in carbonates is notoriously heterogeneous due to both syn-depositional and post-depositional (diagenetic) processes that result in drastic changes in pore shape, size, connectivity and distribution, making accurate estimations of hydrocarbon reserves difficult (Vissapragada et al., 2000; Lønøy, 2006).

Nearly as common as the classification and description of carbonate depositional fabrics is the classification and terminology of pore space in carbonate rocks. Due to the complexity of carbonate pore systems in comparison with its siliciclastic counterparts, extensive research into the relationship between carbonate rock fabrics, pore geometry and petrophysical properties has been completed (Archie, 1952; Murray, 1960;
Although numerous carbonate pore classification systems exist, carbonate petrographers and geologists commonly adopt the pore space nomenclature and classification scheme created by Choquette and Pray (1970) as it readily makes use of sedimentological and diagenetic information. On the other hand, pore classification schemes created by Archie (1952) and Lucia (1983; 1995; 1999) are more widely used by petrophysicists and reservoir engineers as a greater emphasis is placed on pore geometry and its influence on fluid transport (Lønøy, 2006) (Figure 1.4).

**Figure 1.4.** Common carbonate pore classification systems (after Lucia, 1999).
Archie (1952) was first to note that not all pore space is easily recognized using a petrographic microscope and therefore, created a scheme for estimating porosity based on rock fabric. Archie’s 1952 classification scheme separated porosity into two categories, visible and non-visible. For non-visible porosity, Archie used the rock surface texture to reflect the amount of matrix porosity present. Carbonate rocks having chalky texture are considered to possess approximately 15% porosity, a sucrosic texture indicates about 7% and a compact texture suggests about 2%. Furthermore, Archie (1952) constructed a four class (A, B, C and D) classification scheme for visible porosity with each class representing a distinct pore size range, with all pore space ranging in size from less than 0.01 mm to greater than cutting size (Figure 1.4). Although, Archie’s (1952) method for estimating porosity in carbonate rocks still remains useful today for understanding a suite of petrophysical parameters, his method does not provide any useful information pertaining to porosity formed by depositional and diagenetic events (Lucia, 1999).

Subsequent research by Murray (1960) and Choquette and Pray (1970) took Archie’s (1952) pore size classification system a step further by incorporating carbonate depositional and diagenetic textures, upon which porosity evolution is dependant. According to Murray (1960), porosity in carbonate rocks can be grouped into three general categories: 1) primary, 2) sucrosic dolomite and 3) secondary vug porosity (Figure 1.4). Primary porosity is any pore space created syn-depositionally while remaining relatively unchanged during burial and lithification. Sucrosic dolomite is applied to carbonate rocks dominated by euhedral to subhedral dolomite crystals that together form a tight interlocking texture while the creation of pore space in relation to post-depositional modification of the original rock matrix, producing larger pores than typically expected with interlocking crystals, is given the term secondary vug porosity.

Choquette and Pray (1970) further expanded on Murray’s (1960) classification scheme by rigorously devising a comprehensive nomenclature and systematic classification scheme for all pore types commonly encountered in carbonate rocks. In addition, their proposed pore classification and nomenclature system provided insight into pore space evolution (creation and modification) and its relation to different
carbonate depositional fabrics. According to Choquette and Pray (1970), pore types in carbonate rocks can be grouped into two distinct categories, fabric selective and non-fabric selective (Figure 1.4). Fabric selective porosity is defined as porosity directly related to depositional features, typically identified by configuration of the pores relative to fabric elements. Pore types falling under the fabric selective category are intercrystalline, interparticle, moldic, shelter, fenestral and growth-framework. Non-fabric selective porosity is commonly observed in rocks that have undergone post-depositional (diagenetic) processes resulting in the non-selective dissolution of original rock material (i.e., vuggy porosity), fractures or other features (Choquette and Pray, 1970).

Although the above pore space classification systems relate pore space formation to geological processes, their petrophysical implications remained unaddressed. Lucia (1983; 1995; 1999) was the first to devise a classification scheme by incorporating Choquette and Pray’s (1970) sedimentologically-based carbonate pore classification system while introducing petrophysical relationships, namely permeability, for both limestones and dolostones. From here, Lucia (1983) was able to showcase the effects of both crystal size and pore type in relation to permeability. The pore space classification system created by Lucia (1983) demonstrates that pore space existing between grains (intergrain) and between crystals (intercrystalline) are comparable petrophysically and thus, can be grouped together under the interparticle category (Figure 1.4). Moldic porosity was determined to have a different effect on permeability than intercrystalline porosity and is separated into the separate vug category along with intraparticle and vuggy pore types (Figure 1.4). Separate vug pore space is typically fabric selective and interconnected only through the interparticle pores. Any pore space observed to be significantly larger than the particle size while forming an interconnected pore system, defines the touching vug pore system. Touching vugs are typically non-fabric selective in origin (Figure 1.4) Lucia (1999).

From the above rock fabric relationships, Lucia (1995) compared the interparticle pore type with permeability at varying grain sizes from which three distinct rock-fabric/petrophysical classes could be recognized. Rock-fabric/petrophysical class 1 is defined as the greater than 100 mD permeability field and is represented by lime- and
dolo-grainstones, large crystalline (average 150 µm) grain-dominated dolo-packstones and mud-dominated dolostones. For the 20-100 mD permeability field, grain-dominated packstones, fine (average 15 µm) to medium (average 50 µm) crystalline grain-dominated dolo-packstones and medium crystalline mud-dominated dolostones define the rock-fabric/petrophysical class 2. The less than 20 mD permeability field is characterized by mud-dominated limestones and fine (average 15 µm) crystalline mud-dominated dolostones and is defined as rock-fabric/petrophysical class 3. Using the above rock fabric descriptions and their petrophysical relationships permits estimation of permeability. Vuggy pore types, both separate and touching, were not incorporated into Lucia’s (1995) classification system because of their petrophysical variability and subsequently, do not conform to the conditions defining each class.

Lønøy (2006) aimed to improve on previous petrophysical work on carbonate rocks by Lucia (1983; 1995; 1999) by devising a new pore classification system relating porosity and permeability with major carbonate pore types. To do this, Lønøy (2006) subdivided all major pore types into two broad subclasses, uniform and patchy (Figure 1.4). Uniform porosity is defined as the equal distribution of a particular pore type across the entire rock core while patchy porosity represents anisotropy in the distribution of the pore type throughout the rock core. According to Lønøy (2006), patchy porosity is found to yield higher permeabilities than a uniform porosity distribution when comparing two rocks with similar porosity values. This phenomenon is explained by individual pores having a closer proximity to one another leading to a greater degree of connectivity. Lønøy (2006) also suggests that patchy porosity is typically related to secondary dissolution, further enhancing the connectivity between individual pores. It is important to note that the vuggy pore type is absent in Lønøy’s (2006) classification system as vuggy porosity is extremely heterogeneous and difficult to classify petrophysically.

Although, the classification systems proposed by Lucia (1983; 1995; 1999) and Lønøy (2006) have created a better understanding of different carbonate pore types and their relation with permeability, many questions still remain. The work done in this thesis research represents an attempt to further develop the relation between porosity and permeability in carbonate rocks from the Weyburn Oilfield. Using conventional
petrophysical laboratory approaches coupled with synchrotron-based CMT, visualization and quantification of pore types and their petrophysical parameters within the Midale beds can be accomplished. As evidenced from the previous studies mentioned above, a major setback with all current pore classification systems is their inability to observe petrophysical features of carbonate rocks in a spatial domain, particularly in vuggy rocks (Archie, 1952; Choquette and Pray, 1970; Lucia, 1983; Lucia, 1995; Lucia, 1999; Lønøy, 2006). Both Archie (1952) and Lønøy (2006) argued the importance of being able to directly observe and quantify the spatial distribution of pore space within carbonate rock cores as it will ultimately improve current reservoir characterization methods.
2. Methods and Materials

2.1 Midale Carbonate Core Samples

Six sections of Midale Carbonate core were extracted from drill core (five wells) previously recovered from Weyburn Oilfield and currently housed in the Saskatchewan Industry and Resources Subsurface Laboratory in Regina, Saskatchewan (Table 2.1). Of the six core samples recovered, three samples were taken from the Marly unit and three from the Vuggy unit. From this, six samples were cored for CMT analyses and four for conventional petrophysical laboratory methods (Figure 2.1). The CMT core samples, measuring 10 mm in diameter and 20-30 mm in length, were imaged at the European Synchrotron Radiation Facility (ESRF) in Grenoble, France using beamline ID-19 (high resolution topography and microtomography) which has a tunable photon range from 6 keV to 120 keV. CMT measurements on the six Midale Carbonate cores were collected at spatial resolutions of 7.46 µm and 10 µm with one sample (KD-03-18) being re-imaged later at 0.78 µm. CMT analysis was undertaken using parallel beam geometry and a monochromatic X-ray energy of 35 keV ($\lambda = 3.54 \times 10^{-11}$ m). Incident X-rays were made monochromatic using a Si (111) double crystal monochromator. Transmitted X-rays were recorded with a 2048 x 2048 pixilated charge coupled device (CCD) camera having readout times of less than 0.1 second permitting collection of up to 8 gigabytes (GB) of data in approximately 1 hour. Reconstructed digital images were recorded in sections to reduce file size (files range in size from 20 MB to 1.2 GB) and later manipulated using visualization software programs (AMIRA® and 3DMA Rock) for digital petrophysical and mineralogical analyses.

For conventional laboratory petrophysical methods, larger sections of Midale Carbonate core were extracted in close proximity to the CMT core locations to minimize any petrophysical differences existing between the core samples. The larger sections of carbonate core measured 25.1 mm in diameter and 21-31 mm in length. All rock cores, both CMT and permeability cores, were soaked in toluene for a period of 14 days and
the toluene was periodically replaced for samples that were saturated with oil. Once the
colour of the toluene solution appeared to remain unchanged, the cores were removed
and dried in an oven at 80°C for 7 days and weighed occasionally. Once the weight of
the rock core stabilized, the core sample was assumed to be dry and suitable for
conventional petrophysical laboratory analyses.

From the six samples recovered from both the Marly and Vuggy units, three
samples (Midale Vuggy (V2) (ID-02-40), Midale Vuggy (V4) (KD-03-23), and Midale
Marly (M0) (KD-03-18)) were studied in detail using both conventional petrophysical
and mineralogical analyses and CMT imaging. These three samples are discussed in
detail and will be presented from here forward. The Midale Marly (M0) sample is a
pervasively dolomitized lagoonal lime-mudstone having a sucrosic (20-30 µm)
microtexture. The two samples from the Vuggy unit vary from a tight-looking peloidal
packstone (Midale Vuggy (V4)) to a lime-wackestone (Midale Vuggy (V2)) having
abundant visible vuggy porosity (Figure 2.1B).

Table 2.1. Core samples used in this research and their respective lithological unit, well
location, sample depth within the Weyburn Oilfield and the CMT resolution used.

<table>
<thead>
<tr>
<th>Sample</th>
<th>Unit</th>
<th>UWI</th>
<th>Depth (m)</th>
<th>CMT Resolution(µm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ID-02-40</td>
<td>Vuggy (V2)</td>
<td>14-11-6-14W2</td>
<td>1426</td>
<td>10</td>
</tr>
<tr>
<td>KD-03-23</td>
<td>Vuggy (V4)</td>
<td>12-19-6-13W2</td>
<td>1408</td>
<td>10</td>
</tr>
<tr>
<td>ID-02-19</td>
<td>Vuggy (N/A)</td>
<td>12-26-6-14W2</td>
<td>N/A</td>
<td>7.46</td>
</tr>
<tr>
<td>KD-03-11</td>
<td>Marly (M3)</td>
<td>8-20-6-13W2</td>
<td>1394</td>
<td>7.46</td>
</tr>
<tr>
<td>KD-03-18</td>
<td>Marly (M0)</td>
<td>12-19-6-13W2</td>
<td>1391</td>
<td>10 and 0.78</td>
</tr>
<tr>
<td>MD</td>
<td>Marly (N/A)</td>
<td>6-8-6-13W2</td>
<td>1446</td>
<td>7.46</td>
</tr>
</tbody>
</table>

Remarks:
N/A – Information not available
Figure 2.1. (A) All six Midale Carbonate cores used in CMT analyses and (B) larger diameter cores used in conventional petrophysical laboratory measurements. The KD-03-18, KD-03-23 and ID-02-40 samples were studied in detail by both CMT and conventional petrophysical and mineralogical analyses.

2.2 Analytical Techniques

2.2.1 Thin-Sections

Three thin-sections were taken from small-diameter Midale Carbonate cores that have been previously imaged with CMT. The thin-sections were examined by transmitted light microscopy (TLM) to resolve the mineralogical composition and morphological characteristics of each rock core. Thin-sections were prepared in the Thin Section Preparation Laboratory in the Department of Geological Sciences, University of Saskatchewan. Thin slices, approximately 1 mm thick, were cut from three CMT cores, Midale Marly (MD), Midale Marly (M3) and Midale Vuggy (V2), and mounted on a glass slide with epoxy resin and polished to a thickness of 30 µm.

2.2.2 Transmitted Light Microscopy

TLM was done using a Nikon® polarizing petrographic binocular microscope to examine the textural and mineralogical characteristics of the three thin-sections cut from
previously imaged CMT rock cores. Photomicrographs of each thin-section were captured using a Pentax® camera mounted on the Nikon® petrographic microscope using a 1x objective lens. Images collected by TLM were then compared with tomographic images from the same carbonate core sample to determine the resolution capabilities of CMT for resolving mineralogy and textural features in carbonate rocks.

2.2.3 Electron Probe Micro-Analysis

Electron Probe Micro-Analysis (EPMA) was completed using a Jeol JXA-8600 Superprobe currently housed in the Department of Geological Sciences, University of Saskatchewan. Prior to EPMA analyses, the thin-sections were carbon coated under vacuum to reduce any charging effects encountered during the analyses. The EPMA was operated at 15 kV and 10 nA using Wavelength Dispersive Spectrometry (WDS) for semi-quantitative analyses on the three carbonate thin-sections. Backscattered Electron imaging (BSE) was also employed to semi-quantitatively resolve the mineralogical composition and textural features of the rock matrix. Images obtained from BSE provide visual and semi-quantitative comparison with photomicrographs from transmitted light microscopy and CMT data. Grey-level values obtained from BSE are used as a calibration for minerals and are directly compared with X-ray attenuation values from CMT.

2.2.4 X-rays and X-ray Computed Microtomography

2.2.4.1 X-rays

Since the discovery of X-rays in 1895 by Wilhelm Röntgen, their application in medicine, primarily for imaging, has led to profound medical discoveries and treatments. Today, X-rays are vital for examining the internal properties and structural arrangement of biological, chemical, industrial and geological materials. X-rays are part of the electromagnetic spectrum having a short wavelength and high frequency that allow for the penetration of dense materials (Figure 2.2). For many years the only way to produce X-rays was by applying a high voltage between two electrodes composed of high atomic weight materials (i.e., tungsten or platinum) in an evacuated glass tube. The applied voltage results in electrons being emitted from the cathode and, due to electrostatic
attraction, accelerate towards the anode. The collision of electrons with anode nuclei produce X-rays simultaneously in two ways; first, collision of electrons with the anode reduces the electron velocity resulting in the emission of X-rays termed bremsstrahlung X-rays. The second method of X-ray production occurs when high speed electrons collide with the anode nuclei resulting in the ejection of an inner K-shell electron, promoting the anode nuclei to a higher energy state. As the nuclei decline back to a lower, stable energy state an X-ray is produced with a wavelength characteristic of the anode material. Together, the two processes produce a polychromatic continuum of X-rays possessing a range of frequencies ($10^{16}$ to $10^{20}$ Hz or $10^{-8}$ to $10^{-11}$ m) and energies (200 to 100000 electron volts (eV)) (Bonse and Busch, 1996).

![Figure 2.2. The electromagnetic spectrum.](image)

In 1947, a discovery by physicists in the General Electric Research Laboratory in Schenectady, N.Y. changed the way scientists could view the world by being the first to create and observe synchrotron light (Baldwin, 1975; Pollock, 1983). They noticed that accelerating charged particles (electrons or positrons) to nearly the speed of light ($2.99 \times 10^8$ m/s) in a circular magnetic field resulted in the development of asymmetry in the electromagnetic emission pattern around the particle, or more specifically, the emission pattern became folded sharply in a forward direction. This relativistic effect produces an intense and highly collimated beam of electromagnetic radiation being emitted tangentially to the particle path. Electromagnetic radiation produced in this way is known today as synchrotron radiation.

Synchrotron sources produce broad spectrum (polychromatic) electromagnetic radiation consisting of infrared light, visible light, ultraviolet light and X-rays. The major benefit of synchrotron radiation compared against conventional X-ray sources is...
the intense brilliance and parallel beam geometry can be made monochromatic (single wavelength) while still retaining sufficient photon flux for tomography and spectroscopic techniques (Wildenschild et al., 2002).

To fully understand the importance of synchrotron radiation for scientists conducting a wide range of experiments some simple, fundamental equations must be applied. Firstly, synchrotron X-rays are highly collimated due to the electron relativistic effect. A synchrotron’s beam divergence is vital to micro-beam and spectroscopic techniques as the beam width at the end of a beamline varies with electron beam energy:

\[ \gamma = \frac{E}{m_e c^2} \]  

where, \( \gamma \), is the relativistic gamma for X-rays, \( E \), is the electron energy, in GeV, \( m_e \) is the rest mass of the electron and \( c \) is the speed of light. Using the relativistic gamma, the angular distribution or divergence \( (\theta; \text{ in radians}) \) of synchrotron radiation can be calculated from:

\[ \Delta \theta = \frac{1}{\gamma} \]  

From equations 2.1 and 2.2 it is easy to see that the beam divergence decreases with increasing electron energy (Bonse and Busch, 1996). In the case of tomography, beam divergence is important as a highly collimated, parallel X-ray beam simplifies the tomographic image reconstruction process and increases the X-ray source to sample distance. This increase in the source to sample distance allows subtle differences in X-ray attenuation to be enhanced, improving image quality. Imaging by this technique is known as phase-contrast imaging.

Another advantage of utilizing X-rays generated from synchrotron is the intense brilliance that is tunable over a wide range of X-ray energies. Brilliance is expressed as the number of photons emitted per second per unit source area over a unit angle of emission and unit energy (photons/s/mrad²/mm²/0.1% radiation bandwidth). The brilliance of synchrotron X-rays is many orders of magnitude (~4 to 12) greater than characteristic X-ray lines produced by conventional X-ray sources that are commonly used in medical and industrial CT scanners. Furthermore, the intense X-ray beam produced from a synchrotron can be made monochromatic while retaining sufficient
brilliance which decreases imaging time and most importantly, increases image resolution (micron to sub-micron) and quality (Bonse and Busch, 1996).

2.2.4.2 X-ray Computed Microtomography

In 1972, a British engineer by the name of Godfrey Newbold Hounsfield revolutionized medical diagnostics by developing X-ray computed tomography (CT) which permitted the internal investigation of a patient without requiring invasive surgical procedures. Soon after the development of CT, the petroleum industry began experimenting with reservoir rocks in hopes of gaining considerable information about their internal microstructure (Vinegar, 1986). Non-destructive imaging of rock cores by CT provides visual and quantitative information that can be manipulated and integrated with laboratory results and electrical log data, adding crucial insight into exploration procedures, reservoir characterization methods and recovery calculations (Kayser et al, 2006). By the late 1980’s, X-ray computed microtomography (CMT) was implemented at the National Synchrotron Light Source (NSLS) in Brookhaven, N.Y., providing nearly 100 times better spatial resolution and enhanced image quality (i.e., large signal-to-noise ratio) when compared with conventional medical and industrial CT scanners (Flannery et al., 1987; Spanne and Rivers, 1987; Prodanović et al., 2007). The parallel and intense, monochromatic nature of synchrotron X-rays reduces image artifacts and simplifies image reconstruction at micron to sub-micron scale resolution (0.3 µm to 100 µm). Non-destructive imaging by synchrotron-based CMT is a unique and attractive method for rapidly collecting both qualitative and quantitative information of minerals and pore space geometry while preserving the connectivity and spatial variation, providing a novel approach for petrophysical evaluation of porous hydrocarbon-bearing rocks (Wellington and Vinegar, 1987; Spanne et al., 1994; Lindquist and Lee, 1996; Klobes et al., 1997; Coles et al., 1998a; Coles et al., 1998b; Lindquist and Venkatarangan, 1999; Lindquist et al., 2000; Appoloni et al., 2002; Arns et al., 2002; Wildenschild et al., 2002; Arns et al., 2003; Arns et al., 2004a; Arns, 2004b; Nakashima et al., 2004; Turner et al., 2004; Bauget et al., 2005; Bernard, 2005; Al-Raoush and Willson, 2005; Kayser et al., 2006; Jones et al., 2007; Prodanović et al., 2007).
CMT works by passing X-rays towards an opposed detector that simultaneously records the intensities of X-rays transmitted through an object which is being translated and rotated perpendicular to a highly collimated and parallel X-ray beam. The detector records a series of many closely spaced radiographs at multiple angles that are then later reconstructed to produce a three-dimensional image of the object in digital format. Before the detector can record an image, the transmitted X-rays must be converted to visible light by a scintillation plate. A scintillation plate works by the photoelectric effect whereby a transmitted X-ray is absorbed by high atomic weight compounds (e.g., Yttrium-Aluminum-Garnet, CdWO\(_4\) or Gd\(_2\)O\(_5\)S) that result in the production of a new secondary photon within the visible light range (Figure 2.2). This visible light is collimated by a microscope objective lens (5x-20x) onto a single pixel (picture element) of a charge coupled device (CCD) camera (Figure 2.3). Stimulation of a pixel by light produces an electrical signal that is recorded and converted by a computer to a digital signal. Typically, each pixel is coded on eight bits (\(2^8\) bits or 256 grey-levels) where each bit represents a different shade of grey, ranging from 0 (black) to 255 (white). The charge recorded by the pixel directly corresponds to the intensity of the X-rays striking the scintillation plate. CCD cameras used in synchrotron CMT measurements usually consist of either 1024\(^2\) or 2048\(^2\) pixels.

**Figure 2.3.** Experimental arrangement for synchrotron CMT analyses. Three-dimensional CMT images are reconstructed from a series of 2D projections recorded by the CCD camera (after Bernard, 2005).
To fully understand the underlying principle of CMT, consider a homogeneous material placed in the path of an incident monochromatic X-ray beam. X-rays entering the sample are absorbed, producing secondary X-rays. These secondary X-rays, typically lower in energy, exit the sample and are measured to determine the absorption potential (or X-ray attenuation; \( \mu \)) of the material. The absorptivity of a sample can be calculated from Beer’s Law simply by knowing the amount of incident X-rays entering, \( I_0 \), and exiting, \( I \), a sample of thickness \( x \) [L] (Wildenschild et al., 2002):

\[
I = I_0 e^{(-\mu x)}.
\]  

(2.3)

In geology, however, we are typically concerned with heterogeneous samples and must account for how an incident photon is attenuated along its path through the material. For this, the integral of \( \mu \) must be applied along the path length (thickness) of the sample to account for changes occurring in \( \mu \) along the X-ray path:

\[
I = I_0 e^{-\int_{x}^{x+dx} \mu(x) dx}.
\]  

(2.4)

The X-ray attenuation or Linear Attenuation Coefficient (LAC), \( \mu \), as defined by Wellington and Vinegar (1987) and Homem et al. (2000) is a measure of the transmissivity or absorptivity of a sample to the incident X-rays and is largely a function of both electron density, \( \rho_e \), and effective atomic number, \( Z_e \).

Since LAC depends on the incident photon energy from a synchrotron X-ray beam, \( E \), the electron density of the material being imaged, \( \rho_e \), the effective atomic number of the material, \( Z_e \), the Klein-Nishina coefficient, \( a \), which is dependant on the X-ray beam used, and a constant, \( b \) (9.8x10^{-24}), the following formula can be applied to determine the characteristic \( \mu \) value for a material of interest:

\[
\mu = \rho_e \left( a + \frac{bZ_e^{3.8}}{E^{3.2}} \right).
\]  

(2.5)

The Klein-Nishina coefficient in equation 2.5 represents Compton or incoherent X-ray scattering which is important at X-ray energies of 5-10 MeV. The second part of equation 2.5 applies to lower energy X-rays (50-100 keV) whereby their interaction with a material is mainly by photoelectric absorption which is strongly dependant on atomic number and is most important when using synchrotron sources (Wildenschild et al,
In this study, X-ray energies between 25 keV and 50 keV were used, thus the effect of the Klein-Nishina coefficient on $\mu$ is significantly reduced.

When imaging heterogeneous geological media with CMT, a mixture of atomic species and their overall photoelectric absorption effect must be accounted for by determining the effective atomic number:

$$Z_e = \left( \sum_i f_i Z_i^{3.8} \right)^{\frac{1}{3.8}}$$

(2.6)

where, $f_i$, is the fraction of electrons on the $i$-th element and, $Z_i$, is the atomic number of the $i$-th element (Wellington and Vinegar, 1987). The $Z_e$ value is characteristic for each mineral, and as such, must be computed for each mineral phase being imaged to determine its corresponding LAC value.

The electron density, $\rho_e$, of the material being imaged is also important and must be computed for each material present in the heterogeneous mixture. The electron density depends on the sample bulk density, $\rho$, the atomic number, $Z$, atomic weight, $A$, and Avogadro’s number, $N_{AV}$ (Wildenschild et al, 2002):

$$\rho_e = \rho \left( \frac{Z}{A} \right) N_{AV}.$$  

(2.7)

It must be noted, however, from equations 2.6 and 2.7 that two minerals with different electron densities and atomic compositions can have similar LAC values if a difference in electron density in one mineral is compensated by a similar difference in atomic composition in another mineral (Wildenschild et al, 2002).

Aside from direct measurement of LAC values, as is done in CMT, they can also be calculated theoretically simply by knowing the chemical compositions of all minerals present in the sample and the incident X-ray energy used. Equation 2.8 states that LAC is represented by the sample bulk density, $\rho$, the weight fraction, $w_i$, of the $i$-th element, the mass attenuation coefficient (MAC), $\tau_i$, of the $i$-th element measured at the incident photon energy (Tsuchiyama et al., 2005):

$$\mu = \rho \sum_i w_i \tau_i.$$  

(2.8)

The MAC value describes changes in LAC as a function of density and is independent of the physical or chemical state of the absorbing specie while accounting
for both coherent and incoherent X-ray scattering (Table 2.2). Tabulated MAC values determined by Hubbell and Seltzer (1996) are applied in this study for calculating theoretical LAC values for all major mineral phases present within the Midale Carbonate core samples.

**Table 2.2.** Theoretically determined MAC values for some common sulphate, sulphide, silicate and carbonate minerals. MAC values are dependant on the both the atomic mass of an element and the photon interactions occurring within the same element at a given monochromatic X-ray energy, providing no absorption edges are crossed.

<table>
<thead>
<tr>
<th>Mineral</th>
<th>Density (g/cm³)</th>
<th>MAC (cm²/g)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gypsum</td>
<td>2.30</td>
<td>1.92</td>
</tr>
<tr>
<td>Anhydrite</td>
<td>2.95</td>
<td>1.88</td>
</tr>
<tr>
<td>Celestine</td>
<td>3.96</td>
<td>10.79</td>
</tr>
<tr>
<td>Quartz</td>
<td>2.65</td>
<td>0.87</td>
</tr>
<tr>
<td>Illite</td>
<td>2.60</td>
<td>0.94</td>
</tr>
<tr>
<td>Orthoclase</td>
<td>2.55</td>
<td>1.20</td>
</tr>
<tr>
<td>Calcite</td>
<td>2.72</td>
<td>1.85</td>
</tr>
<tr>
<td>Dolomite</td>
<td>2.86</td>
<td>1.24</td>
</tr>
<tr>
<td>Pyrite</td>
<td>4.95</td>
<td>4.94</td>
</tr>
</tbody>
</table>

Although, CMT provides valuable visual information about rock microstructures, image artifacts can affect data quality. A common problem encountered when imaging dense materials, including geological samples, with conventional CT is a phenomenon known as beam hardening. Beam hardening arises from the preferential absorption of lower energy X-rays over higher energy X-rays in dense materials, resulting in image degradation (Figure 2.4). Conventional CT scanners are especially prone to beam hardening effects because of the polychromatic continuum of X-rays they produce. The only way to completely remove beam hardening effects is by utilizing monochromatic radiation, such as that produced by a synchrotron. Correction of beam hardening by mathematical means is nearly impossible due its dependency on both material composition and sample thickness (Bonse and Busch, 1996).
Figure 2.4. 2D tomographic slices of Midale Vuggy (ID-02-19) core imaged with (A) synchrotron CMT and (B) conventional CT. Conventional CT measurements were completed by XRADIA Inc. in Concord, California, USA, at a spatial resolution of 3 µm using an X-ray voltage of 130 kV. Beam hardening effects can be seen by the ‘snowy’ appearance and by the white regions along the boundaries of the conventional CT image (B). Field of view in (A) is 10 mm and in (B) is 3 mm.

Additional image artifacts, such as rings, can also appear in tomographic data. Ring artifacts are independent of the type of CT scanning used, although more frequent when using synchrotron sources, and are typically encountered at high X-ray fluxes. Ring artifacts are the result of detector saturation arising from numerous X-rays stimulating the detector at a single moment in time causing the detector to ‘freeze’. This is commonly known as a detector dead-time effect. The rings can often be corrected, minimizing their effect on a tomographic image, but in some cases the image is discarded (Figure 2.5) (Raven, 1998). To minimize detector saturation effects and their associated image artifacts during tomography experiments, a beam chopper and slit is placed in the path of the incident X-ray beam effectively reducing the number of X-rays entering the sample and stimulating the detector.
Figure 2.5. Ring artifacts are the result of detector dead-time effects. Field of view is 10 mm.

2.2.5 Water Saturation Porosity

Water saturation was used to determine total effective porosity on both previously imaged CMT cores and permeability cores. Initially, all cores were weighed dry and then immersed in water and placed under vacuum to ensure complete saturation. Once saturated, the cores were removed from vacuum and weighed to determine the total effective porosity:

\[
\phi = \frac{(M_{\text{wet}} - M_{\text{dry}})}{\rho_{\text{H}_2\text{O}} \times V_{\text{sample}}}
\]

where, \( \phi \), is the fractional porosity, \( M_{\text{wet}} \), is the mass of the water saturated core in grams, \( M_{\text{dry}} \), is the mass of the core when completely dry, \( \rho_{\text{H}_2\text{O}} \), is the density of pore water in grams per cm\(^3\) and \( V_{\text{sample}} \) is the bulk sample volume in cm\(^3\).

Small-diameter CMT cores were saturated using distilled water under vacuum in a glass vacuum apparatus for a period of 7 days (Figure 2.6). Once saturated, the samples were removed from vacuum and weighed to determine total effective porosity.
For the large-diameter permeability cores, synthetic brine was used to simulate Midale Reservoir brine to preserve any mineral phases susceptible to dissolution. The chemical composition of the synthetic brine was determined using published Midale Reservoir brine data from Rostron et al. (2005). To ensure the synthetic brine was comparable with measured reservoir brine data, the water modeling software PHREEQC® was utilized to determine saturation indices for all mineral phases present in the rock cores determined from both EPMA and TLM (Figure 2.7).

Figure 2.6. Vacuum cell apparatus used to saturate the Midale Carbonate core samples.
2.2.6 Electrical Resistivity

Electrical resistivity measurements are frequently used by petrophysicists to indirectly evaluate porosity, cementation, permeability and saturation within porous reservoir rocks. Electrical resistivity measurements were completed on three sections (Midale Vuggy (V2) (ID-02-40), Midale Vuggy (V4) (KD-03-23), and Midale Marly (M0) (KD-03-18)) of brine-saturated, large diameter Midale Carbonate core samples (Figure 2.1). Prior to electrical resistivity measurements, all large diameter cores were saturated in synthetic brine. Electrical conductivity was measured for the synthetic brine using an ion-probe conductivity meter. The samples were placed under vacuum for a period of 7 days to ensure complete saturation. Once saturated, the cores were removed from the vacuum cell apparatus for electrical resistivity measurements. Electrical resistivity was completed using a two-point method set up in a Wenner array (AB/3) for shallow induction on water-saturated core (Figure 2.8). The two-point method consists of using a vice equipped with two metal plate electrodes between which a section of Midale Carbonate core was situated. On either end of the core, conductive pads saturated with copper sulfate (CuSO₄) were placed to reduce the effects of contact resistance.

**Figure 2.7.** Chemical composition of Midale Reservoir brine taken from the 91-9-14-5-13W2 well within the Weyburn Oilfield (left). Saturation indices for common mineral phases were calculated for both synthetic and reservoir brine using the PHREEQC® modeling software (right).
between the metal plate electrodes and the rock core (\( R_{c1} \) and \( R_{c2} \)). Potential leaching of \( \text{CuSO}_4 \) from the saturated pads into the rock core may result in small junction potentials which occur from the contact between \( \text{CuSO}_4 \) and synthetic brine. These junction potentials were likely to occur at both ends of the core with opposing amplitude and thus, were neglected. From here, an electrical voltage (50 V) was applied using a four cycle, 1 second pulsed current pattern to cancel any effects related to electrode polarization. Voltage and current measurements were obtained by recording the current and voltage drop across a core sample (\( R_{\text{rock}} \)) placed between two metal plate electrodes (Figure 2.8). Voltage and current measurements were recorded three times for each core sample to ensure repeatability between measurements. From the recorded voltage and current measurements, electrical resistance of the brine-saturated Midale Carbonate core samples were calculated from the relation between electrical resistance, \( R \) (ohms), current, \( I \) (amps), and voltage, \( V \) (volts), as stated by Ohm’s law:

\[
R = \frac{V}{I}.
\]  

(2.10)

The resistance of the carbonate core was calculated for each run and then averaged to determine the average resistance. Using the calculated average resistance from equation 2.10 and knowing the core dimensions, permits determination of electrical resistivity:

\[
R_o = R \times \left( \frac{A}{L} \right)
\]  

(2.11)

where \( R_o \) is the resistivity of the rock core in \( \Omega \cdot \text{m} \), \( R \) is the resistance in \( \Omega \), \( A \) is the cross-sectional area of the core sample in \( \text{m}^2 \) and \( L \) is the length of the core sample in m.

![Figure 2.8](image)

**Figure 2.8.** Geometrical arrangement of the two-point method for determining electrical resistivity properties of reservoir rock cores.
2.2.7 Gas Permeability

Permeability, which is a measure of the transmissivity of a rock core to fluid flow, was measured using a Ruska gas permeameter located in the Rock Mechanics Laboratory, operated by the Department of Civil and Geological Engineering, University of Saskatchewan (Figure 2.9). Permeability measurements were completed on three sections (Midale Vuggy (V2) (ID-02-40), Midale Vuggy (V4) (KD-03-23), and Midale Marly (M0) (KD-03-18)) of Midale Carbonate core recovered from the Weyburn Oilfield to determine their apparent permeability ($k_a$). Gas permeability can be calculated for a rock core of known dimensions using the following relationship:

$$k = \left( \frac{\mu Q L}{A P} \right)$$

(2.12)

where $\mu$ is the viscosity of the test fluid in Pa·s, $Q$ is the average flow rate at the mean pressure in m$^3$/s, $L$ is the length of the sample in m, $A$ is the cross-sectional area of the sample in m$^2$, $P$ is the pressure drop in Pa and $k$ is the permeability measured in m$^2$.

Permeability, as widely used in the oil and gas industry, has units of darcies (D) with 1 darcie $\approx 10^{-12}$ m$^2$. Gas permeability was determined for three, large-diameter Midale Carbonate core samples measuring 25.1 mm in diameter and ranging in length from 21 mm to 31 mm. Each core sample, cylindrical in shape, was placed into a rubber sleeve that ensures all gas enters the rock core. Both the carbonate core and rubber sleeve were then inserted into a metal coreholder and placed into the permeameter. From here, compressed nitrogen gas ($N_2$(g)) was injected into the coreholder to determine the gas permeability for the rock core at a given pressure. Gas flow rates were determined by flow meters of known diameter attached to the permeameter. Using conversion charts provided by the manufacturer, the gas flow rate, corrected to the mean gas pressure within the sample in m$^3$/s, can be determined.

Permeability was calculated at three different pressure drops (0.25, 0.5 and 1.0 atm) to account for gas slippage effects that result in artificially high permeabilities. To correct for this, the permeability measurements taken at three different pressures were cross-plotted and regressed to the y-intercept to achieve a corrected permeability. This method is known as the Klinkenberg correction (Klinkenberg, 1941). Each carbonate core sample was tested at the same three pressure intervals, cross-plotted on an x-y
graph and regressed to the y-axis to obtain the Klinkenberg-corrected apparent permeability. This process was repeated three times for each core sample while rotating the sample between each experiment. The corrected apparent permeabilities from each experiment were then averaged to obtain the average apparent gas permeability for each core sample.

![Ruska gas permeameter](image)

**Figure 2.9.** Ruska gas permeameter.

### 2.2.8 Liquid Permeability

Liquid permeability measurement was performed using a Ruska Liquid Permeameter housed in the Rock Mechanics Laboratory, operated by the Department of Civil and Geological Engineering (Figure 2.10). The three same large-diameter Midale Carbonate core samples used in the gas permeability measurements were used in the liquid permeability tests. Prior to liquid permeability measurements the carbonate cores were saturated to eliminate the presence of air-water interfaces within the sample, as these tend to reduce the effective permeability to water. Water saturation was completed using the vacuum cell apparatus (Figure 2.6) with synthetic brine for 7 days to ensure complete saturation. Once each core was fully saturated, it was fit snugly into a rubber sleeve and placed into a metal coreholder. Synthetic brine was added to the permeameter as the testing fluid and held in a 5 ml burette prior to delivery into the rock core. External pressure above atmospheric was applied to the fluid filled burette using compressed N$_2$(g) (2 atm or 202.65 kPa) to drive the fluid into the rock core. The time
required to deliver the fluid volume of the burette to the rock core was recorded (in seconds). Knowing the viscosity, \( \mu \), of the brine at room temperature in Pa·s, the applied external pressure, \( P \), in Pa, the length, \( L \), of the core sample in cm, the cross-sectional area, \( A \), of the core in cm\(^2\) and the volume, \( V \), of test fluid used in cm\(^3\) permits calculation of liquid permeability for the rock core using equation 2.13:

\[
k = \frac{\mu VL}{APt}.
\]  

(2.13)

Figure 2.10. Ruska liquid permeameter.

**2.2.9 Mercury Injection Porosimetry**

In order to directly compare pore size distribution and identify the amount of pore space existing below the 10 µm resolution limit of the CMT data, mercury injection porosimetry was employed. Measurement of pore aperture size and pore aperture size distribution within rock cores by mercury injection porosimetry has been used by geologists and reservoir engineers to estimate permeability and evaluate cap-rock and reservoir properties (Thompson et al., 1987 and Pittman, 1992). Pore aperture size directly influences fluid transport and recovery in oil reservoirs and as such their measurement and spatial distribution can prove crucial. In siliciclastic rocks, mercury intrusion measurements can provide reasonably accurate information about the true pore aperture size distribution while in carbonate rocks pore space is much more complex due
to the large variation in pore types and sizes (Wardlaw, 1976; Van Brakel et al., 1981; Kent, 1984; Pittman, 1992).

Mercury injection porosimetry was completed using a Ruska Mercury Injection Porosimeter to determine the pore-throat size distribution in the Midale Carbonate core samples from the Weyburn Oilfield. The Ruska Mercury Injection Porosimeter is housed in the Rock Mechanics Laboratory, operated by the Department of Civil and Geological Engineering, University of Saskatchewan (Figure 2.11). Mercury injection porosimetry works on the principle of injecting mercury, assumed to be an ideal non-wetting fluid, into evacuated pore space (see Van Brakel et al., 1981 for capillary theory). The external pressure required to penetrate any given pore-throat (i.e., the capillary pressure, $P_c$) is related to the pore-throat diameter, $d$, the air-mercury interfacial tension, $\gamma$, and the mercury wettability (as parameterized by the contact angle), $\theta$. The relationship between these parameters can be stated by the Laplace law (Wardlaw, 1976; Van Brakel et al., 1981; Thompson et al., 1987; ASTM, 2004) as follows:

$$d = -\frac{4\gamma \cos \theta}{P_c}.$$  \hspace{1cm} (2.14)

Three sections of Midale Carbonate core previously characterized with gas and liquid permeability and electrical resistivity measurements were used in mercury injection porosimetry. Prior to mercury injection tests, a calibration test was performed to assess the compressibility of the chamber and mercury at each pressure step during the test. This was done by observing the change in mercury level at each pressure step with the chamber filled only with mercury (i.e., no sample present). Any volume change was recorded and later used to correct the volume changes recorded for the Midale Carbonate core at the same pressure intervals. Prior to mercury injection porosimetry, the samples were dried in an oven at 80°C to ensure all residual water was removed. Once dry, the core sample was placed into the porosimeter and immersed in mercury. The chamber was sealed and measurements were taken to determine the volume of mercury surrounding the core. From here, the sample chamber was evacuated using a vacuum pump for 2-4 days prior to testing to remove as much air as possible from the chamber and sample (Figure 2.11). Once the vacuum chamber stabilized at $1.32 \times 10^{-5}$ atm ($1.33$ Pa) the mercury level was adjusted to the reference level for the porosimeter and the
vacuum pump turned off. Successive mercury volume readings were recorded at
designated pressures until the chamber was in equilibrium with atmospheric pressure.
From here, compressed \( N_2(g) \) was applied externally in increments up to 100 atm or
\( 1.01 \times 10^7 \) Pa. At each pressure step the mercury level was adjusted to the reference level
and allowed to stabilize for approximately 1 minute to account for drainage and
adiabatic effects. After this, the volume of mercury invading the rock core was recorded.

Figure 2.11. Ruska mercury injection porosimeter.
3. Results

3.1 Minerals and Pore Space

3.1.1 Mineral and Pore Space Distribution Based on BSE and Transmitted Light Microscopy

Backscattered electron (BSE) images from EPMA offer a semi-quantitative method for mineral identification and pore space characterization in greater resolution and detail than that provided by TLM. Furthermore, BSE images can be directly compared with photomicrographs from TLM allowing for quantitative analysis of mineral composition and distribution. Three Midale Carbonate core samples (Midale Vuggy (V2) (ID-02-40), Midale Vuggy (V4) (KD-03-23), and Midale Marly (M0) (KD-03-18)) were examined using both techniques to determine mineralogy of the Marly and Vuggy units. From TLM, the Vuggy samples consist of abundant bioclasts and matrix minerals of micritic calcite, minor euhedral to subhedral dolomite, and large crystals of pore-filling anhydrite. The Marly sample is pervasively dolomitized consisting of fine grained (sucrosic – 20-30 µm) euhedral to subhedral dolomite, minor quartz, celestine and pore filling calcite. Porosity development in both the Marly and Vuggy units is predominately intercrystalline and vuggy, respectively. Minor fracture and moldic porosity is also observed in some sections. It must be noted, however, that textural features occurring in the same mineral phase observed in TLM are commonly obscured in BSE images due to their similar chemical composition (Figure 3.1). BSE images, unlike TLM, are coded in grey scale. Previous work by Hall and Lloyd (1981) and Dilks and Graham (1985) have shown that grey-level in a BSE image directly corresponds to mineralogy, or more specifically, the effective atomic-number of elements composing the mineral. Based on this principle, minerals can be easily identified in BSE images due to their assigned grey-level values which are characteristic of the electron absorption and electron density for a given mineral.
Figure 3.1. Comparison of images from thin-sections of Midale Vuggy and Marly carbonate core obtained from TLM (left) and BSE (right). Minerals identified are calcite (cc), dolomite (dol), anhydrite (anh) and quartz (qtz). Photomicrograph and corresponding BSE image of the Midale Vuggy (V4) sample is taken from Durocher et al., (2005).

According to Dilks and Graham (1985), assigned grey-level values in a BSE image are directly governed by the backscatter coefficient, $\eta_i$, which is defined as the ratio of the BSE current to the initial beam current. Based on BSE dependence on atomic number for a given mineral phase, the following empirical expression (Equation 3.1) can
be applied to determine the backscatter coefficient for a single chemical element in a mineral phase:

\[ \eta_i = -0.0254 + 0.016Z_i - 1.86 \times 10^{-4}Z_i^2 + 8.3 \times 10^{-7}Z_i^3 \]  

(3.1)

where, \( Z_i \), is the atomic number of the i-th element. Considering that minerals are composed of numerous chemical elements it is more useful to use a weighted mean backscatter coefficient, \( \eta \):

\[ \eta = \sum w_i \eta_i \]  

(3.2)

where, \( w_i \), is the weight fraction of the i-th element in a mineral phase and, \( \eta_i \), is the backscatter coefficient for the i-th element in the same mineral phase. Applying equations 3.1 and 3.2, a relationship between grey-level and backscatter coefficient can be established for major minerals encountered in the Midale Carbonates (Figure 3.2A and Table 3.1).

To further support the correlation between atomic number and grey-level in a BSE image, the effective atomic number can be determined for a particular mineral phase from equation 2.6. The effective atomic number is directly proportional to the amount of photoelectric absorption occurring and indicates that higher atomic numbers are more heavily favoured in a BSE image. For example, the effective atomic number of quartz is 11.85 which is determined from the chemical formula for quartz that has two oxygen atoms (\( Z = 8 \)) and one silicon atom (\( Z = 14 \)).

<table>
<thead>
<tr>
<th>Mineral</th>
<th>Chemical Formula</th>
<th>( \eta )</th>
<th>( Z_e )</th>
<th>Observed BSE Grey Level</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quartz</td>
<td>SiO(_2)</td>
<td>0.125</td>
<td>11.85</td>
<td>68 ± 13</td>
</tr>
<tr>
<td>Dolomite</td>
<td>CaMg(CO(_3))(_2)</td>
<td>0.134</td>
<td>13.94</td>
<td>78 ± 18</td>
</tr>
<tr>
<td>Calcite</td>
<td>CaCO(_3)</td>
<td>0.151</td>
<td>15.88</td>
<td>119 ± 12</td>
</tr>
<tr>
<td>Anhydrite</td>
<td>CaSO(_4)</td>
<td>0.154</td>
<td>15.81</td>
<td>162 ± 18</td>
</tr>
<tr>
<td>Celestine</td>
<td>SrSO(_4)</td>
<td>0.236</td>
<td>30.79</td>
<td>228 ± 8</td>
</tr>
</tbody>
</table>

Table 3.1. Chemical formulae, backscatter coefficients (\( \eta \)), effective atomic number (\( Z_e \)) and observed grey-level values for minerals encountered in the Midale Carbonates.
Figure 3.2. (A) Observed grey-level values from BSE are plotted against calculated backscatter coefficients from equation 3.2 with strong agreement. (B) Observed grey-level values from CMT are cross-plotted with theoretical LAC values determined from equation 2.9. (C) Calculated backscatter coefficients are compared with theoretically determined LAC values. (D) Comparison of observed grey-level values from BSE and CMT. Data shown here are from all major mineral phases from all of the Midale Carbonates core samples. $R^2$ values indicate a strong correlation between measured grey-level values for all mineral phases.
3.1.2 Mineral Distribution Based on CMT

Non-destructive imaging by CMT provides a novel approach for investigating the spatial distribution of the physical and chemical properties of materials in three dimensions. Based on density contrasts, CMT data is well suited for semi-quantitative identification of mineral phases within rock cores. Similar to BSE images (Section 3.1.1), CMT data is displayed in grey-level with each grey-level value directly proportional to X-ray attenuation (LAC) or mineral density (Figure 2.4B). Qualitative examination of LAC distribution in one digitized slice from each of the carbonate samples in this study (Figure 3.3A to F) indicate that: 1) there are a number of distinct density-related phases within the samples ranging from open pore space (black) to the highest density mineral phases (white) and 2) evaluation of the relative amounts of phases with different LAC values allows for qualification of pore space and mineral phases alike (Figure 3.4).

In principle, differences in LAC values are correlative with minerals present in the rock core samples as it is proportional to mineral density (Table 3.2). To effectively use LAC values for identifying different minerals in CMT data, a relationship between chemical or mineralogical composition and LAC must be established (Tsuchiyama et al., 2005). To date, limited research has been done on correlating between mineral phase and LAC in CMT images (Wellington and Vinegar, 1987; Amos et al., 1996; Watanabe, 1999; Homem et al., 2000; Duliu, 2003; Dowker et al., 2004; Lemelle et al., 2004; Midgley, 2004; Tsuchiyama et al., 2005).

In this study, equation 2.9 is used to determine the theoretical LAC value for a given mineral which can then be compared with its corresponding grey-level in a CMT image (Table 3.3 and Figure 3.2B).
Figure 3.3. CMT slices of the six Midale Carbonate core samples used in this thesis research. (A) ID-02-40, (B) KD-03-18, (C) ID-02-19, (D) KD-03-23, (E) KD-03-11 and (F) Marly Dolostone. Field of view for all samples is 10.13 mm having image resolutions of 7.45 µm (C and F) and 10 µm (A, B, D and E).
Figure 3.4. Two-dimensional CMT slice of the (A) Midale Vuggy (V4) and (B) Midale Marly (M0) showing differences in LAC as observed through variations in grey-levels, with black representing air space (porosity) and increasing brightness correlated with increasing mineral phase density. The lower histograms show the bimodal distribution of grey-levels (LAC) in a sample. Field of view is 10.13 mm. The black line indicates upper grey-level limit of detector noise.

Table 3.2. Distribution of observed LAC values in CMT data from both the Vuggy and Marly units.

<table>
<thead>
<tr>
<th>Sample Number</th>
<th>Unit</th>
<th>LAC Distribution</th>
<th>Porosity</th>
<th>Quartz</th>
<th>Dolomite</th>
<th>Calcite</th>
<th>Anhydrite</th>
<th>Celestine</th>
</tr>
</thead>
<tbody>
<tr>
<td>ID-02-40</td>
<td>Vuggy (V2)</td>
<td>Bimodal</td>
<td>0-85</td>
<td>N/A</td>
<td>118-130</td>
<td>146-186</td>
<td>214-233</td>
<td>N/A</td>
</tr>
<tr>
<td>KD-03-23</td>
<td>Vuggy (V4)</td>
<td>Trimodal</td>
<td>0-85</td>
<td>N/A</td>
<td>118-130</td>
<td>146-186</td>
<td>214-233</td>
<td>N/A</td>
</tr>
<tr>
<td>ID-02-19</td>
<td>Vuggy (N/A)</td>
<td>Bimodal</td>
<td>0-85</td>
<td>N/A</td>
<td>118 130</td>
<td>146-186</td>
<td>214-233</td>
<td>N/A</td>
</tr>
<tr>
<td>KD-03-18</td>
<td>Marly (M0)</td>
<td>Trimodal</td>
<td>0-85</td>
<td></td>
<td>92-112</td>
<td>130-170</td>
<td>179-204</td>
<td>223-255</td>
</tr>
<tr>
<td>KD-03-11</td>
<td>Marly (M3)</td>
<td>Trimodal</td>
<td>0-85</td>
<td></td>
<td>92-112</td>
<td>130-170</td>
<td>179-204</td>
<td>223-255</td>
</tr>
<tr>
<td>MD</td>
<td>Marly (N/A)</td>
<td>Trimodal</td>
<td>0-50</td>
<td>N/A</td>
<td>53-93</td>
<td>104-120</td>
<td>N/A</td>
<td>223-255</td>
</tr>
</tbody>
</table>
3.1.3 Integration of BSE and CMT to Determine Mineralogy

EPMA and TLM are commonly used for determining chemical composition of minerals and identifying rock microtextures in a variety of rock lithologies. Information obtained from EPMA, in the form of BSE images, provides visual and semi-quantitative information about minerals. The brightness of a BSE image has been shown to be directly related to the mean atomic number and electron density of chemical elements within the minerals being examined (Section 3.1.1). Using this principle, a grey-level value can be assigned to a particular mineral phase, thus permitting its identification throughout an image. Unlike BSE, the brightness of a CMT image is related to X-ray attenuation (LAC), which is directly proportional to mineral density as stated by equation 2.9. Knowing the relationship between these parameters allows for comparison between theoretical backscatter coefficient from EPMA and LAC for minerals present in the Midale Carbonate core samples (Figure 3.2C). Such a comparison allows interpretation of well established EPMA data for mineral identification with LAC values to positively identify mineral phases within a CMT image.

The strong correlation observed between BSE and LAC, and also TLM (Figure 3.5), suggests that CMT is well suited for delineating minerals in three-dimensional space.
Figure 3.5. Comparison between a thin-section of the Midale Vuggy (V2) observed under cross-polarized light (left) and its corresponding CMT image (right). Note enhanced porosity in the thin-section can be attributed to ‘plucking’ that occurred during the preparation process. Additionally, the coarser calcite (CC) located on the left side of photomicrograph and the endothyrid foraminifera test (shell) located at the center of the photomicrograph do not appear in the CMT image. This can be attributed to both the coarser calcite and endothyrid test being composed of similar density calcite to that of the matrix.

From Figure 3.5, it must be noted that although the TLM and CMT images are strikingly similar, textural features occurring in the TLM image are obscured in the CMT data. This can be attributed to the fact that textures occurring in mineral phases having comparable densities will be essentially invisible to CMT (Table 3.4). Tsuchiyama et al. (2005) found CMT had the best contrast resolution, approximately 5%, for minerals having recorded LAC values between 10 cm\(^{-1}\) and 30 cm\(^{-1}\) while decreasing drastically at LAC values below 10 cm\(^{-1}\) (e.g., feldspars, quartz and carbonates). In this study, recorded LAC values for all major mineral phases are below 10cm\(^{-1}\) and are easily discriminated from one another (Table 3.3). This would decrease significantly if more mineral phases with LAC values below 10cm\(^{-1}\) were present in the Midale Carbonate core samples as solid-solution in carbonates, feldspars and silicates can result in similar LAC values. From the strong correlation between backscatter coefficients from BSE with LAC values from CMT in Figure 3.2C for the major mineral phases, an observed brightness comparison can be made with good agreement (Figure 3.2D). Using this, all minerals are plotted in three-dimensions for all carbonate samples.
examined with CMT to highlight the spatial distribution and their relation to pore space (Figure 3.6 and Appendix C).

**Table 3.3.** Empirically and theoretically calculated values for common minerals in the Midale Carbonates. Data is shown in Figure 3.2. Bulk density values were obtained from Deer et al. (1992). MAC values for elements used in theoretical LAC calculation, which include photoelectric absorption and coherent and incoherent scattering, are from Hubbell and Seltzer (1996).

<table>
<thead>
<tr>
<th>Mineral</th>
<th>Bulk Density (g/cm³)</th>
<th>MAC (cm²/g)</th>
<th>LAC (cm⁻¹)</th>
<th>η</th>
<th>Zₑ</th>
<th>Observed BSE (grey-level)</th>
<th>Observed CMT (grey-level)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quartz</td>
<td>2.65</td>
<td>0.87</td>
<td>2.31</td>
<td>0.125</td>
<td>11.85</td>
<td>68 ± 13</td>
<td>102 ± 10</td>
</tr>
<tr>
<td>Calcite</td>
<td>2.72</td>
<td>1.85</td>
<td>5.02</td>
<td>0.151</td>
<td>15.88</td>
<td>119 ± 12</td>
<td>177 ± 14</td>
</tr>
<tr>
<td>Dolomite</td>
<td>2.86</td>
<td>1.24</td>
<td>3.55</td>
<td>0.134</td>
<td>13.94</td>
<td>78 ± 18</td>
<td>141 ± 10</td>
</tr>
<tr>
<td>Anhydrite</td>
<td>2.95</td>
<td>1.88</td>
<td>5.54</td>
<td>0.154</td>
<td>15.81</td>
<td>162 ± 18</td>
<td>223 ± 13</td>
</tr>
<tr>
<td>Celestine</td>
<td>3.96</td>
<td>10.79</td>
<td>42.73</td>
<td>0.236</td>
<td>30.79</td>
<td>228 ± 8</td>
<td>239 ± 16</td>
</tr>
</tbody>
</table>

Remarks:
MAC – Mass Attenuation Coefficient is the ratio of X-ray attenuation at a given X-ray energy to atomic mass for the sum of atomic elements present in a mixture.
LAC – Linear Attenuation Coefficient is the amount of X-ray attenuation occurring within a mineral phase and is dependant on the X-ray energy used.
Figure 3.6. 3D visualization of mineral phases in the Midale Vuggy (V4) segmented according to BSE and LAC relationships established in Figure 3.2 and Table 3.3. A) Shows a portion of the total sample volume (306 mm$^3$), light grey and grey regions are the rock volume and black areas are porosity. B) Displays the 3D distribution of porosity (blue). C) 3D distribution of dolomite. D) 3D extent of the light gray (highest density) mineral phase, anhydrite. E) Metallic silver represents calcite which is gray in the CMT slices. Image F shows all mineral phases (calcite is transparent gray) and porosity plotted together.
3.1.4 Digital Voxel Reconstruction for Minerals and Porosity

3.1.4.1 Mineral Visualization

As previously discussed, the LAC values displayed in CMT images allows for spatial visualization of minerals and pore space as the CMT data is comprised of up to 1500 digital 2D scans, each of which has distinct variations in LAC values (Figures 3.3A to F). Combining all 1500 2D CMT slices provides for visualization of their properties in three-dimensions. Using the correlations between mineralogy and observed brightness from BSE and CMT data (Figure 3.2D and Table 3.3), a suite of minerals occurring within the Midale Carbonate core samples can be identified and displayed in 3D. Use of the voxel-based reconstruction software AMIRA®, along with the established grey-level values for each mineral phase in Table 3.3, permits visualization of mineral phases and pore space in 3D (Figure 3.6 and Appendix C).

Visual inspection of the images in Figure 3.6 reveals the three-dimensional distribution of minerals present in the Midale Vuggy (V4) as determined from the established relationship between LAC and BSE (Figure 3.2D). When mapped in 3D, the relation between each mineral phase and pore space is readily observed, providing insight into potential late-stage mineral formation resulting in newly formed pore-lining minerals that ultimately govern wettability and CO₂ sequestration. Furthermore, three-dimensional visualization of minerals allows for an improved interpretation of depositional and diagenetic events that may have resulted in pore space construction/ destruction and mineral distribution. From CMT data on the Midale Vuggy (V4) sample, it is observed that dolomite is located in close proximity to existing pore space suggesting that dolomitization occurred after porosity creation, but had only a minor effect on the rock. Additionally, the three-dimensional distribution of anhydrite, which is interpreted to be secondary pore-filling cement, provides insight into the extent of the original matrix vuggy porosity within the Midale Vuggy (V4) sample that is now in-filled. From this, CMT can add significant information about the paragenetic evolution and textural features of a rock sample, critical to understanding and characterizing reservoir development.
3.1.4.2 Pore Space Visualization

CMT data provides statistical and visual information of pore space on high resolution three-dimensional images which can be directly compared with traditional laboratory-based petrophysical methods. For this, voxel-based software has been employed to visualize and quantify pore space and permeability within the Midale Carbonate core samples from the Weyburn Oilfield (Figure 3.6 and Appendix C). Using the observed brightness values (i.e., LAC) for pore space presented in Table 3.2, pore space can be displayed in three-dimensions providing critical information about pore size, shape, connectivity and distribution within the Vuggy and Marly units.

Closer inspection of the spatial distribution of porosity in core samples of both the Vuggy and Marly units reveals some significant differences. In Figure 3.7A, the Vuggy (V4) sample is shown to consist of connected, large secondary dissolution vugs with minor, isolated pores, suggesting greater permeability. Conversely, pore space within the Marly (M0) sample is homogeneously distributed and consists of smaller, connected pores with reduced permeability (Figure 3.7B). It must be noted, however, that both images were collected at a spatial resolution of 10 µm and it is expected that a considerable amount of pore space exists below the image resolution of the 10 µm CMT data.
Figure 3.7. 3D reconstruction of CMT data highlighting porosity (gold) in the (A) Midale Vuggy (V4) and (B) Midale Marly (M0) samples. CMT porosity images of the Vuggy (V4) sample shows heterogeneously distributed, larger pores that are connected while the Marly (M0) sample displays a more uniform distribution of pore space, but less well connected than the Vuggy (V4).

An important aspect of this research is to critically evaluate the capabilities of the digitized three-dimensional data from CMT to provide quantitative petrophysical information about pore space in the Midale Marly and Vuggy units. This has been done
using voxel-based software specifically designed for quantification and statistical characterization of connected pore space within reservoir rocks and is applied to the CMT data collected from the Midale Carbonates of the Weyburn Oilfield (3DMA Rock; Lindquist, 1999). Statistical and quantitative information that can be obtained from CMT data allows for computation of pore-body volume, pore-body and pore-throat radii, principal pore-body and pore-throat diameters and tortuosity that can be used to characterize fluid dynamic properties of the Midale Carbonate core samples while providing a mode of direct comparison with conventional petrophysical laboratory methods.

As previously shown in Figure 3.7B, the CMT data collected on the Midale Marly (M0) at a resolution of 10 µm did not reveal any valuable information pertaining to connected pore space, suggesting a majority of the pore space exists below the 10 µm resolution. To investigate the possibility that a significant portion of pore space exists below the 10 µm resolution, the Midale Marly (M0) sample was re-imaged at a resolution of 0.78 µm, which produced a significantly different view. From a single 2D tomographic slice of the Midale Marly (M0) sample, the micro-sucrosic (20-30 µm) texture of the dolomite crystals and the intercrystalline pore space existing between them is readily observed (Figure 3.8B). Reconstruction of the 10 µm and the 0.78 µm tomographic data indicates the three-dimensional distribution and connectivity of all pore space present within the Midale Marly (M0) sample (Figure 3.9). From this it can be seen that the porosity is diffuse, poorly connected and low in value (0.26%) in the 10 µm CMT data while the 0.78 µm CMT data displays a highly porous (32.0%) rock with abundant connected pores (Figure 3.9B).
Figure 3.8. Comparison of tomographic slices from the Midale Marly (M0) (A) at 10 µm resolution (porosity shown in black) and (B) at 0.78 µm resolution (porosity shown in dark grey). The 0.78 µm CMT image is taken as a sub-section of the 10 µm CMT image. Field of view in (A) is 10 mm and in (B) is 1.43 mm. The histograms below depict the distribution of grey-levels in each image with the black line representing the upper limit of detector noise.

Figure 3.9. Three-dimensional voxel reconstruction of pore space in the Midale Marly (M0) sample (A) at 10 µm (0.26% pore space) and (B) at 0.78 µm (32.0% pore space).
Considering that calculated porosity for the 0.78 µm resolution CMT data is much greater in value and visually more well-connected than the 10 µm resolution data, physical assessment of the connected pore space in the Midale Marly (M0) sample can be completed. To quantitatively evaluate the pore space highlighted in Figure 3.10A, the CMT data is separated (i.e., binarized) into pore space and matrix. From here, an erosion algorithm is computed along the central axis for all connected pores to create a skeletonized image (Figure 3.10B). This skeletonized image of pore space in the 0.78 µm resolution CMT data represents total effective porosity and can be used further to quantitatively evaluate the physical pathways connecting each pore-body and pore-throat within the Midale Marly (M0) sample (Figure 3.10B).

**Figure 3.10.** (A) Three-dimensional distribution of pore surfaces (shown in gold) in the Midale Marly (M0) sample. (B) Corresponding skeletonized image of pore space in (A) highlighting the connectivity between individual pores. Rainbow colours depict pore size with purple representing the largest pores, smallest pores shown in red and intermediate pore size shown in green.

The skeletonized image in Figure 3.10B permits calculation of tortuosity for all connected pores existing in the Midale Marly (M0) sample. Tortuosity (τ) is an important petrophysical parameter as it directly influences the flow of fluids across a volume of rock and is a key factor in hydrocarbon recovery (Ehrenberg et al., 2006). Tortuosity is a dimensionless parameter ranging from 1 for a straight line to infinity for a circle. It is defined as the degree of curvature or twistedness of a fluid pathway through a
volume of rock. Tortuosity is mathematically expressed as the ratio between the length of a fluid flow path \( L_a \) and the total length between its ends \( L \) (Figure 3.11)

\[
\tau = \frac{L_a}{L}.
\] (3.3)

**Figure 3.11.** A tortuous pathway through closely packed spheres.

The three-dimensional nature of CMT permits tortuosity to be measured in three orthogonal directions, x, y and z, providing information about potential anisotropy in the distribution of pore space and fluid pathways within the Midale Marly (M0) (Figure 3.12 and Appendix C). For the Midale Marly (M0) sample, measured tortuosity for all three orthogonal directions ranges from 1.4 to 2.8, having an average value of 1.76, while the tortuosity of the shortest measured pathways range from 1.5 to 1.9, with an average value of 1.67.
Figure 3.12. (A) 0.78 µm CMT image of all connected fluid pathways in the Midale Marly (M0) sample extending from the right to left (x-direction). Measured tortuosity from CMT was found to have an average value of 1.75. (B) Visualization of the shortest paths across the section of Midale Marly (M0) core in the x-direction having an average tortuosity of 1.63.

Furthermore, reconstruction of the CMT data permits quantification of all connected pore space and yields petrophysical information regarding pore-body volume, pore-body and pore-throat radii, principal pore-body and pore-throat diameters and pore-throat/pore-body radii ratios as discussed by Prodanović et al. (2007) (Figure 3.13). Pore-body and pore-throat radii were directly obtained from calculation of pore-body volume and pore-throat surface area. It is assumed that the pore-bodies and pore-throats are spherical in shape for simplicity. However, from three-dimensional visualization of the CMT data, the pore-bodies and pore-throats are observed to be variable in shape (Figure 3.7A). To provide a more quantitative method for determining pore shape, pore-body and pore-throat diameters were calculated in three principal orthogonal directions for each pore based on its center-of-mass as determined from moment-of-inertia analysis. In Figure 3.13C and D, principal pore-body and pore-throat diameters are labeled $D_1$, $D_2$ and $D_3$ in decreasing length. Another vital piece of information that can be obtained from CMT data is the ratio between pore-throat and pore-body radii (Figure 3.13E). This ratio indicates that pore-throat radii are, on average, approximately $\frac{1}{2}$ the radii of the pore-bodies. This has far-reaching implications for understanding capillary forces and improving current EOR methods within the Midale Marly unit of the Weyburn Oilfield.
Figure 3.13. Statistical histograms of (A) pore-body radii, (B) pore-throat radii, (C) principal pore-body diameter, (D) principal pore-throat diameter and (E) pore-throat/pore-body radii ratio. All histograms were generated from the 0.78 µm CMT data of the Midale Marly (M0) sample.
3.2 Petrophysics

3.2.1 Gas Permeability

Using the Midale Vuggy (V2) sample as an example, gas permeability can be calculated from the following data using equation 2.12.

\[ k = \left( \frac{\mu Q L}{A P} \right). \]

Test parameters known prior to permeability measurement are:
- \( \mu = 1.75 \times 10^{-5} \) Pa·s
- \( L = 2.30 \times 10^{-2} \) m
- \( A = 4.99 \times 10^{-4} \) m²
- \( P = 2.53 \times 10^{4} \) Pa

Upon completion of the permeability test, a corrected flow rate can be determined by knowing the type of flow meter used and using the flow meter conversion charts provided in the Ruska permeameter manual. The corrected flow rate determined for the Midale Vuggy (V2) sample is:

\[ Q = 3.70 \times 10^{-6} \text{ m}^3/\text{s} \]

Substituting all of the above parameters into equation 2.12,

\[ k = \left( \frac{1.75 \times 10^{-5} \text{ Pa} \cdot \text{s} \times 3.70 \times 10^{-6} \text{ m}^3/\text{s} \times 2.30 \times 10^{-2} \text{ m}}{4.99 \times 10^{-4} \text{ m}^2 \times 2.53 \times 10^{4} \text{ Pa}} \right) \]

leaves

\[ k = 1.18 \times 10^{-13} \text{ m}^2 \]

or when converting to millidarcies,

\[ k = 119 \text{ mD}. \]

Figure 3.14 shows this data point, as well as the other two apparent permeabilities that were calculated for this sample at pressure drops of 5.07 \times 10^4 \text{ Pa} and 1.01 \times 10^5 \text{ Pa}. The Klinkenberg-corrected perm for this sample (i.e., the y-intercept of a trendline through all 3 data points) is 48.5 mD.
Figure 3.14. Gas permeability plot for the Midale Vuggy (V2). $k_{corr}$ value is corrected according to the Klinkenberg principle.

Table 3.4 summarizes Klinkenberg-corrected gas permeabilities for the three Midale Carbonate cores. Permeabilities are variable in the Vuggy unit as the Midale Vuggy (V2) sample displayed the highest permeability (49.2 mD) while Midale Vuggy (V4) sample had the lowest (11.0 mD) with the Midale Marly (M0) sample having an intermediate permeability value of 16.9 mD. Measured gas permeability values for the three sections of Midale Carbonate core agree with field averages presented by Churcher and Edmunds (1994) from the Weyburn Oilfield (Table 1.1).

Table 3.4. Corrected gas permeabilities for all three Midale carbonate cores.
3.2.2 Liquid Permeability

For the Midale Vuggy (V2), liquid permeability is calculated using equation 2.13:

\[ k = \left( \frac{\mu V L}{A P t} \right). \]

The test parameters known prior to measurement of liquid permeability are:

- \( \mu = 9.00 \times 10^{-4} \text{ Pa}\cdot\text{s} \)
- \( V = 5.00 \times 10^{-6} \text{ m}^3 \)
- \( L = 2.30 \times 10^{-2} \text{ m} \)
- \( A = 4.99 \times 10^{-4} \text{ m}^2 \)
- \( P = 1.01 \times 10^5 \text{ Pa} \)

The time taken for the entire fluid volume to flow through the sample was measured with a stop watch, with the following result being obtained:

\( t = 48.5 \text{ s.} \)

From this, permeability for the Midale Vuggy (V2) sample can be determined using equation 2.13 and parameters measured above:

\[
k = \left( \frac{9.00 \times 10^{-4} \text{ Pa} \cdot \text{s} \times 5.00 \times 10^{-6} \text{ m}^3}{4.99 \times 10^{-4} \text{ m}^2 \times 1.01 \times 10^5 \text{ Pa} \times 48.5 \text{ s}} \right)
\]

\[
k = \left( \frac{1.04 \times 10^{-10} \text{ Pa} \cdot \text{s} \cdot \text{m}^4}{2.44 \times 10^3 \text{ Pa} \cdot \text{s} \cdot \text{m}^2} \right)
\]

giving a permeability of:

\[ k = 4.26 \times 10^{-14} \text{ m}^2 \]

or converting to millidarcies:

\[ k = 42.8 \text{ mD}. \]

Measured liquid permeabilities for the three sections of Midale Carbonate core (Midale Vuggy (V2), Midale Vuggy (V4) and Midale Marly (M0)) returned slightly lower permeability values than those from gas. However, the same trend is observed with Midale Vuggy (V2) sample having the highest permeability value, Midale Marly (M0) sample with the intermediate value and the Midale Vuggy (V4) having the lowest value (Table 3.5). This trend is similar to gas permeability results and agrees with
measured values from the Weyburn Oilfield (Table 1.1). During liquid permeability tests, permeability was observed to decrease with each successive run. This phenomenon has been attributed to precipitates forming in the synthetic brine affecting the liquid permeability results. Alternatively, gas permeability measurements tended to produce repeatable results for each successive sample run. For this reason, gas permeabilities have been taken as the absolute permeability for the rock cores.

**Table 3.5.** Liquid and gas permeability results for the Midale Carbonate cores.

<table>
<thead>
<tr>
<th>Sample Number</th>
<th>Unit</th>
<th>Gas</th>
<th>Liquid</th>
</tr>
</thead>
<tbody>
<tr>
<td>ID-02-40</td>
<td>Vuggy (V2)</td>
<td>49.2</td>
<td>42.8</td>
</tr>
<tr>
<td>KD-03-23</td>
<td>Vuggy (V4)</td>
<td>11.0</td>
<td>4.2</td>
</tr>
<tr>
<td>KD-03-18</td>
<td>Marly (M0)</td>
<td>16.9</td>
<td>7.7</td>
</tr>
</tbody>
</table>

### 3.2.3 Water Saturation Porosity

Water saturation porosity was determined for all permeability and CMT cores in order to obtain the true effective porosity using equation 2.9 (Figure 3.6):

\[
\phi = \left( \frac{M_{\text{wet}} - M_{\text{dry}}}{\rho_{H_2O} \times V_{\text{sample}}} \right).
\]

Measured masses for wet and dry Midale Vuggy (V2) core were:

- \(M_{\text{wet}} = 27.12\) g
- \(M_{\text{dry}} = 24.90\) g
- \(\rho_{H_2O} = 1.00\) g/cm\(^3\)
- \(V_{\text{sample}} = 11.47\) cm\(^3\)

By substituting the above masses into equation 2.9 yields:

\[
\phi = \left( \frac{27.12 g - 24.90 g}{1.00 \frac{g}{cm^3} \times 11.47 cm^3} \right).
\]
\[ \phi = 0.194 \]
or expressed in percent:
\[ \phi = 19.4\% . \]

Table 3.6. Dry and saturated masses for all Midale Carbonate core samples used in effective porosity determination by water saturation.

<table>
<thead>
<tr>
<th>Sample</th>
<th>Unit</th>
<th>Mass Dry (g)</th>
<th>Mass Saturated (g)</th>
<th>Water density (g/cm(^3))</th>
<th>Sample Volume (cm(^3))</th>
<th>Porosity (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ID-02-40</td>
<td>Vuggy</td>
<td>24.90</td>
<td>27.12</td>
<td>1.00</td>
<td>11.47</td>
<td>19.4</td>
</tr>
<tr>
<td>KD-03-23</td>
<td>Vuggy</td>
<td>36.89</td>
<td>38.69</td>
<td>1.00</td>
<td>15.65</td>
<td>11.5</td>
</tr>
<tr>
<td>KD-03-11</td>
<td>Marly</td>
<td>24.20</td>
<td>25.29</td>
<td>1.00</td>
<td>10.44</td>
<td>10.4</td>
</tr>
<tr>
<td>KD-03-18</td>
<td>Marly</td>
<td>28.11</td>
<td>32.90</td>
<td>1.00</td>
<td>15.09</td>
<td>31.7</td>
</tr>
</tbody>
</table>

3.2.4 Electrical Resistivity

The electrical resistance for the Midale Vuggy (V2) core sample can be calculated from Ohm’s Law as stated in equation 2.10:

\[ R = \frac{V}{I} . \]

Using electrical voltage and current measurements on the Midale Vuggy (V2), the electrical resistance can be determined from equation 2.10:

\[ R = \left( \frac{516mV}{310mA} \right) \times 100 . \]

Solving, gives:
\[ R = 166.73\Omega . \]

In order to determine electrical resistivity the cross-sectional area, \( A \), of the core sample is required. Since the core samples used in this study are cylindrical in shape, the cross-sectional area is easily obtained from the core radius using the equation:
\[ A = \pi r^2. \] \hspace{1cm} (3.4)

The measured diameter of the Midale Vuggy (V2) sample was 0.0251 m and using equation 3.3, the cross-sectional area is:

\[ A = \pi \left( \frac{0.0251m}{2} \right)^2 \]

\[ A = 4.99 \times 10^{-4} m^2. \]

Knowing the electrical resistance and cross-sectional area of the Midale Vuggy (V2) sample permits determination of electrical resistivity (equation 2.11):

\[ R_o = R \times \left( \frac{A}{L} \right). \]

Calculated and measured parameters for the Midale Vuggy (V2) sample were:

\[ R = 166.73 \Omega \]
\[ A = 4.99 \times 10^{-4} m^2 \]
\[ L = 2.30 \times 10^{-2} m \]

The electrical resistivity of the Midale Vuggy (V2) sample was:

\[ R_o = (166.73 \Omega) \times \left( \frac{4.99 \times 10^{-4} m^2}{2.30 \times 10^{-2} m} \right) \]

\[ R_o = 3.62 \Omega \cdot m. \]

**Table 3.7.** Electrical resistivity results for the Midale Carbonate cores.

<table>
<thead>
<tr>
<th>Sample Number</th>
<th>Unit</th>
<th>Vave (mV)</th>
<th>Iave (mA)</th>
<th>Rave ((\Omega))</th>
<th>Ro ((\Omega)-m)</th>
<th>Rw ((\Omega)-m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ID-02-40</td>
<td>Vuggy (V2)</td>
<td>516.00</td>
<td>309.60</td>
<td>166.73</td>
<td>3.62</td>
<td>0.07</td>
</tr>
<tr>
<td>KD-03-23</td>
<td>Vuggy (V4)</td>
<td>529.90</td>
<td>94.20</td>
<td>562.57</td>
<td>8.91</td>
<td>0.07</td>
</tr>
<tr>
<td>KD-03-18</td>
<td>Marly (M0)</td>
<td>401.04</td>
<td>833.42</td>
<td>48.12</td>
<td>0.78</td>
<td>0.07</td>
</tr>
</tbody>
</table>

In formation evaluation, electrical resistivity measurements are used along with established empirical relationships between rock resistivity and porosity to understand the physical properties of reservoir rocks. A common petrophysical property that is extracted from electrical resistivity measurements is the formation resistivity factor. The
formation resistivity factor, $F$, is simply expressed as the ratio of the resistivity of brine saturated rock core, $R_o$, to the resistivity of the brine, $R_w$, itself:

$$ F = \frac{R_o}{R_w} \quad (3.5) $$

For the Midale Vuggy (V2), the formation resistivity factor can be determined from measured electrical resistivity values for the rock core and brine, respectively:

$$ F = \frac{3.62\Omega \cdot m}{0.07\Omega \cdot m} $$

$$ F = 54.23. $$

The formation resistivity factor is taken to be solely dependant on the geometry of the brine-filled pores and independent of the brine itself, providing insight into the connectedness of the pores (Archie, 1942). From this, Winsauer et al. (1952) established a relationship between porosity ($\phi$) and the formation resistivity factor ($F$), known as the Humble formula, from which porosity can be obtained using electrical resistivity measurements:

$$ F = \frac{1}{\phi^m} \quad (3.6) $$

or rearranging for porosity:

$$ \phi = \left( \frac{1}{F} \right)^{\frac{1}{m}} $$

where, $m$, is the cementation exponent. The cementation exponent describes the distribution of pores and generally increases in value with increasing cementation. It is obtained by cross-plotting direct measurements of porosity against the formation resistivity factor, and typically lies within the range of 1.3-3.0. From a limited dataset, Figure 3.15 shows that the Midale Marly unit has a greater cementation exponent (1.87) than the Midale Vuggy unit (1.73) suggesting a more complex pore system. However, the determination of the cementation exponent is purely a statistical method and the values obtained in Figure 3.15 may not be representative of the true pore geometry.
Figure 3.15. Log-log cross-plot of formation resistivity factor and porosity used in the determination of the cementation exponent for the Midale Vuggy and Marly core samples.

For the Midale Vuggy (V2), porosity can be calculated from electrical resistivity using the Humble formula:

$$\phi = \left( \frac{1}{54.23} \right)^{1.73}$$

$$\phi = 0.0994$$

or

$$\phi = 9.94\% .$$

Within this study, porosity values determined using the Humble formula from electrical resistivity for Vuggy core samples tends to underestimate porosity while more accurate values of porosity are achieved for the Marly unit core samples when compared against porosity values determined by water saturation (Tables 3.6 and 3.8). This difference between measured and calculated porosity values for the Midale Vuggy samples can be explained by the fact that the Humble formula was derived from electrical resistivity results on coarse granular sands rather than carbonate rocks.
Another petrophysical parameter that can be obtained from electrical resistivity is tortuosity. Tortuosity directly influences permeability and can be estimated using the relationship between porosity (fractional) and the formation resistivity factor (Winsauer et al., 1952, Katsube and Williamson, 1994, Tiab and Donaldson, 2004 and Arns et al., 2005):

$$\tau = \sqrt{\phi \times F}.$$  \hspace{1cm} (3.7)

Using equation 3.7, tortuosity can be determined for the Midale Vuggy (V2) from total effective porosity information and the calculated formation resistivity factor:

$$\tau = \sqrt{0.194 \times 54.23}$$

$$\tau = 3.24.$$  

**Table 3.8.** Calculated petrophysical parameters for the Midale Carbonate samples from electrical resistivity results.

<table>
<thead>
<tr>
<th>Sample Number</th>
<th>Unit</th>
<th>A (m²)</th>
<th>L (m)</th>
<th>F</th>
<th>(\tau)</th>
<th>m</th>
<th>(\phi)(%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ID-02-40</td>
<td>Vuggy</td>
<td>4.99x10⁻⁴</td>
<td>2.30x10⁻²</td>
<td>54.23</td>
<td>3.24</td>
<td>1.73</td>
<td>9.94</td>
</tr>
<tr>
<td>KD-03-23</td>
<td>Vuggy</td>
<td>4.97x10⁻⁴</td>
<td>3.13x10⁻²</td>
<td>133.08</td>
<td>3.91</td>
<td>1.73</td>
<td>5.92</td>
</tr>
<tr>
<td>KD-03-18</td>
<td>Marly</td>
<td>4.95x10⁻⁴</td>
<td>3.05x10⁻²</td>
<td>11.71</td>
<td>1.93</td>
<td>1.87</td>
<td>26.83</td>
</tr>
</tbody>
</table>

Remarks:

- \(F\) – Formation resistivity factor \((F = R_o/R_w)\).
- \(\tau\) – Tortuosity (curvature or twistedness) of connected pore space \((\tau = \sqrt{\phi \times F})\).
- \(m\) – Cementation exponent defined by Archie (1942) for estimating the amount of cement filling pore space in a rock core.
- \(\phi\) – Porosity estimated from electrical resistivity using the Humble formula

\[
(\phi = \left(\frac{1}{F}\right)^\frac{1}{m}).
\]

**3.2.5 Mercury Injection Porosimetry**

The Laplace law, which assumes pore space is cylindrical in shape, is used to calculate apparent pore-throat diameters from mercury capillary pressure data and has the form (equation 2.14):
\[
d = \frac{-4\gamma \cos \theta}{P_c}.
\]

Mercury parameters obtained from literature are:

\[
\gamma = 0.484 \text{ N/m}
\]
\[
\theta = 141^\circ \text{ (calcite)}
\]

From mercury injection porosimetry measurements on the Midale Vuggy (V2), the incremental volume of mercury intruded into the sample was measured at a number of discrete pressure increments. At each pressure increment, the corresponding apparent diameter intruded pores was calculated. For example, consider an injection pressure of:

\[
P_c = 5.07 \times 10^4 \text{ Pa}.
\]

Substituting the above parameters into equation 2.14 yields a pore-throat diameter of,

\[
d = \frac{-4(0.484 N/m)(\cos(141))}{5.07 \times 10^4 \text{ Pa}}
\]

\[
d = 2.96 \times 10^{-5} \text{ m}
\]

or converting to micrometres

\[
d = 29.7 \mu \text{m}.
\]

Calculated mercury injection capillary pressure curves for sections of Midale Carbonate core display significant differences in pore-throat diameter distribution (Figures 3.16, 3.17 and 3.18). The distinct differences in mercury capillary pressure curves allow for characterization of pore-throat sizes between the Vuggy and Marly units within the Weyburn Oilfield. All three Midale Carbonate samples show evidence of larger surface pores filling early in the experiment; however, these peaks are more evident in the Vuggy unit (Figures 3.16A, 3.17A and 3.18A). Visually, the distribution of mercury intrusion peaks in all three samples can be separated into predominately unimodal for the Midale Vuggy (V2), tetramodal for the Midale Vuggy (V4) and bimodal for Midale Marly (M0). In the Midale Marly (M0) sample, the capillary pressure curve differs drastically from those belonging to the Vuggy (V2 and V4) unit by the appearance of a single large peak at 4.3 \mu m (peak B) with neighboring smaller peak at 0.8 \mu m (peak A) (Figure 3.18A). Larger pores, ranging from 61 \mu m to 16700 \mu m, are encountered in the Midale Marly (M0) sample; however, their influence in the overall capillary pressure curve is small (peak C) (Figure 3.18A).
For the Vuggy samples (V2 and V4), large surface vugs are more pronounced, ranging in size from 34 µm to 100000 µm (peaks C and H, respectively), and dominate the capillary pressure curve in the Midale Vuggy (V2) sample (Figure 3.16A and 3.17A). In the Midale Vuggy (V2) sample, smaller injection peaks at 7.6 µm and 17.5 µm (peaks A and B, respectively) are evident adjacent to the large surface vugs (peak C). The size distribution is nearly matched within the Midale Vuggy (V4) sample with two injection peaks occurring at 6.2 µm and 20 µm (peaks D and F, respectively), however, these peaks are more significant than in the Midale Vuggy (V2) sample. Large surface vugs are also observed in the Midale Vuggy (V4) sample, existing between 62 µm and 100000 µm (peak H), similar to that of the Midale Vuggy (V2) sample but of less importance (Figure 3.17A). A more in-depth discussion of these pore size distributions is given in the following chapter.
Figure 3.16. A) Mercury capillary pressure curves for the Midale Vuggy (V2). Data points are plotted in red and major intrusion peaks are labeled from A-C. B) Cumulative plot indicates a total intruded pore volume of 7.88%.
Figure 3.17. A) Mercury capillary pressure curves for the Midale Vuggy (V4). Data points are displayed in red and major intrusion peaks labeled A-H. B) Cumulative plot indicates a total intruded pore volume of 11.21%.
Figure 3.18. A) Mercury capillary pressure curves for the Midale Marly (M0). Data points are plotted in red and major intrusion peaks labeled A-C. B) Cumulative plot indicates a total intruded pore volume of 34.48%.
4. Comparison between Conventional Petrophysics and CMT Analyses

4.1 Previous Studies

The integration of rock, fluid, well-log, seismic and other pertinent reservoir data is essential for delineating reservoir performance in mature hydrocarbon basins where exploration and production are occurring (Castle and Byrnes, 2005). To fully understand reservoir properties and model the behaviour of fluids in the subsurface, a complete picture of pore space geometry is needed. This is especially challenging in sedimentary rocks, namely carbonate rocks, in which porosity and permeability occupy an extremely broad distribution of length scales (from nanometres to hundreds of micrometres) over a short distance (centimetres to metres) (Radlinski et al., 2004). Further adding to the frustration, many of the successful reservoir evaluation methods applied to sandstone reservoirs typically fail in carbonate reservoirs due to the large variability in pore type, size and distribution that directly affect hydrocarbon reserve estimates and permeability. In order to effectively characterize these complex reservoirs, a large number of physical properties and their controls on fluid transport within these rocks must be identified and simulated (Cerepi et al., 2003). As noted by Archie (1952) and Lønøy (2006), a method is required to investigate the spatial distribution of pore space in order to accurately estimate reserves in a wide variety of lithologies.

Since the early 1900’s, conventional petrophysical laboratory methods have been the benchmark for reservoir rock characterization, providing information that can be related to pore structure and permeability (Washburn, 1921; Kozeny, 1927). Many of these techniques, however, use simple assumptions in order to characterize pore space geometry that is inherently complex. These assumptions, although providing useful and relevant information, limit the complete understanding of pore space geometry and physical controls on fluid transport in the subsurface. As techniques in medical imaging advance, particularly in X-ray radiology, geoscientists are able to obtain high resolution
images of the internal features of reservoir rocks while preserving any spatial variation in pore space or matrix minerals. Visual information of this sort can be obtained through the medical imaging procedures of CT and Nuclear Magnetic Resonance Imaging (NMR). Information provided by CT and NMR, such as in-situ three-dimensional digital images of pore space, is impossible to obtain using current conventional petrophysical laboratory methods. Even though both CT and NMR provide non-destructive, three-dimensional images of materials, CT is best suited for obtaining high resolution images of both minerals and pore space while NMR is well-suited for understanding fluid distributions in dense geological materials (Vinegar, 1986; Wellington and Vinegar, 1987; Spanne and Rivers, 1987; Kayser et al., 2006; Padhy et al., 2007; Prodanović et al., 2007). With the advent of synchrotron radiation coupled with CT, micron to sub-micron scale images of the internal microstructure of porous geological materials can be acquired with extraordinary accuracy (Prodanović et al., 2007). This development significantly contributes to the qualitative understanding and quantitative evaluation of many petrophysical properties in reservoir quality rocks that previously have been difficult to assess. For instance, reservoir properties and characteristics that have be assessed through synchrotron-based CMT data for reservoir simulation include: 1) single and multiphase fluid flow, 2) capillary pressure, 3) permeability, 4) pore-body and pore-throat diameters and 5) pore-connectivity and tortuosity (Wellington and Vinegar, 1987; Spanne et al., 1994; Lindquist and Lee, 1996; Klobes et al., 1997; Coles et al., 1998a; Coles et al., 1998b; Lindquist and Venkatarangan, 1999; Lindquist et al., 2000; Appoloni et al., 2002; Arns et al., 2002; Wildenschild et al., 2002; Arns et al., 2003; Arns et al., 2004a; Arns, 2004b; Nakashima et al., 2004; Turner et al., 2004; Baud et al., 2005; Bernard, 2005; Al-Raoush and Willson, 2005; Kayser et al., 2006; Jones et al., 2007; Prodanović et al., 2007). Having the ability to quantify these micro-scale features in reservoir quality rocks is essential to understanding the micro- and macro-scale controls on fluid transport in the subsurface (Prodanović et al., 2007).
4.2. Integration of Conventional Petrophysics and CMT Data from the Midale Carbonates

4.2.1 Porosity and CMT

Within this study, integration and comparison of conventional petrophysical laboratory-based methods with synchrotron-based CMT imaging has been done to qualitatively and quantitatively describe the spatial distribution and connectivity of pore space within select carbonate rocks from the Weyburn Oilfield.

Data presented in Table 4.1 indicates the difference in porosity values obtained for the selected Midale Carbonate cores examined in this research. It is evident from Table 4.1 that porosity values extracted from CMT data are significantly lower than those determined by water saturation. This difference is attributed to the fact that the CMT data was originally collected at a resolution of 10 µm which is shown to be substantially greater than pore size distributions from mercury injection porosimetry (Figures 3.16, 3.17 and 3.18). Successive CMT imaging at a higher spatial resolution of 0.78 µm resolved this discrepancy between porosity values from water saturation and CMT in the Midale Marly (M0) sample which then has a measured porosity value of 32.0% from CMT and compares favorably with porosity values determined by water saturation and electrical resistivity (Table 4.1). This strong correlation in porosity values from CMT with those from water saturation and electrical resistivity further supports the reliability and accuracy of CMT in formation evaluation.

Of importance to the development of accurate reservoir flow models is how fluids move through rocks. The tortuosity, curvature or twistedness of a fluid pathway, can have a significant effect on permeability. As previously shown, tortuosity is traditionally calculated from the fractional porosity and the formation resistivity factor (Equation 3.7).

Using the high resolution (0.78 µm) CMT data of Midale Marly (M0) as an example, tortuosity of all potential fluid pathways in three orthogonal directions was determined to range between 1.5 and 2.9, with an average value of 1.76, while tortuosity of the shortest paths ranged from 1.4 to 2.4, with an average value of 1.67 (Figure 3.12 and Appendix C). This is similar with tortuosity calculated from electrical resistivity
(1.93) on a similar section of the Midale Marly (M0) sample (Table 4.1), however, the effects of scale may be responsible for the slight difference between the two methods.

Furthermore, additional physical parameters extracted from three-dimensional CMT data from the Midale Marly (M0) sample include pore-body volume, pore-body and pore-throat radii and principal pore-body and pore-throat diameters that can provide significant insight into the controlling factors on permeability and CO$_2$-miscèle EOR methods within these rocks (Figure 3.13).

**Table 4.1.** Petrophysical parameters derived from conventional laboratory measurements. * Values were measured on small diameter, CMT cores. CMT porosity values were measured on the 10 µm data while † represents values determined from the 0.78 µm CMT data.

<table>
<thead>
<tr>
<th>Sample</th>
<th>Midale Vuggy (V2)</th>
<th>Midale Vuggy (V4)</th>
<th>Midale Marly (M0)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CMT*</td>
<td>0.70</td>
<td>0.29</td>
<td>0.26 (32.0†)</td>
</tr>
<tr>
<td>Water Saturation*</td>
<td>4.2</td>
<td>1.2</td>
<td>39.4</td>
</tr>
<tr>
<td>Electrical Resistivity</td>
<td>9.9</td>
<td>5.9</td>
<td>26.8</td>
</tr>
<tr>
<td>Water Saturation</td>
<td>19.4</td>
<td>11.5</td>
<td>31.7</td>
</tr>
<tr>
<td>Mercury Porosimetry</td>
<td>7.9</td>
<td>11.2</td>
<td>34.5</td>
</tr>
</tbody>
</table>

| Permeability (mD) |
|-------------------|-------------------|
| Gas               | 49.2              | 11.0              | 16.9              |
| Liquid            | 42.8              | 4.2               | 7.7               |

<table>
<thead>
<tr>
<th>Electrical Resistivity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Formation Resistivity Factor (F)</td>
</tr>
<tr>
<td>Tortuosity (t)</td>
</tr>
<tr>
<td>Cementation Factor (m)</td>
</tr>
</tbody>
</table>

### 4.2.2. Mercury Injection Porosimetry and CMT

As discussed in Section 3.2.5, the many different pore types existing within the Midale Carbonates, especially within the Vuggy unit, result in capillary pressure curves that are difficult to describe and quantitatively assess (Figures 3.16, 3.17 and 3.18).
Using CMT, visualization of pore space aids significantly in the identification of pore space in three-dimensions while providing a quantitative and more realistic approach for measuring pore aperture sizes within the Midale Carbonates.

In this study, three-dimensional CMT information on pore space within the Midale Vuggy (V4) sample is compared with corresponding information from mercury injection porosimetry on the Midale Vuggy (V4) core (Figure 4.1). The low resolution of the 10 µm CMT data for this sample limits the visual connectivity between individual pores. However, it does provide significant insights into information gathered from the measured mercury intrusion peaks. Aside from direct measurement of pore aperture size, mercury injection porosimetry curves can be used to qualitatively explain pore types present in rock cores (Murray, 1960; Wardlaw, 1976; Kent et al., 1984; Pittman, 1992). For the Midale Vuggy (V4) sample, mercury injection porosimetry indicates that internal vuggy pore space is contributing to large peaks at 6.2 µm, 20 µm and ~100 µm while intercrystalline porosity connecting the individual vuggy pores is presumed to have a more-or-less log-normal response (peaks D, F and H, respectively; Figure 4.1A). This apparent pore aperture diameter distribution returns questionable results as larger pore-bodies existing adjacent to a smaller pore-throat will result in a more significant mercury injection peak which can be especially problematic in carbonate rocks due to the irregularities in pore shape and size. High-resolution (0.78 µm) CMT data collected from the Midale Marly (M0) sample indicates that the pore-throat radii are approximately ½ the radii of the pore-bodies (Figure 3.12E). Based on this, it is suggested that the results from mercury injection porosimetry may give erroneous pore aperture size distributions, leading to inaccurate estimations of hydrocarbon reserves and conclusions about the dominant pore apertures controlling fluid transport in carbonate rocks (Figure 4.1). This problem is addressed more quantitatively in Section 4.3.
Figure 4.1. Visual comparison between mercury porosimetry data and digital CMT data from the Midale Vuggy (V4) unit. (A) Calculation of pore diameters in mercury porosimetry. Fields A-H are referred to in text (Section 3.2.5). (B) Visual characterization of pore space and interconnectivity within the Midale Vuggy (V4) sample from 3D reconstruction of CMT data. Coloured regions and porosity types in A correspond with coloured regions in the 3D CMT data (B).
4.2.3. Comparison of Laboratory Permeability with Theoretically Determined Values from CMT Data

Permeability is a poorly understood physical property in complex pore networks, such as those encountered in sedimentary rocks, and has been the focus of petroleum and groundwater research for over 80 years (Katz and Thompson, 1986). As shown in Sections 3.2.1 and 3.2.2, permeability is typically assessed through laboratory measurements by flooding a core with a liquid or gas at a prescribed pressure drop to determine the fluid flow rate across the core. In some instances, core retrieval is difficult or impossible due to cost or other factors, thus making direct permeability measurements difficult and sparse. When this happens, permeability is often predicted from electrical well-logs, reservoir production data, knowledge of the rock lithology and use of established empirical formulas relating porosity and other petrophysical parameters with permeability (Kozeny, 1927; Timur, 1968; Carman, 1979; Katz and Thompson, 1986; Thompson et al., 1987). Although all of these empirical relationships do provide insight into the approximate permeability of a rock core, the theoretical determination of absolute permeability continues to elude geoscientists and reservoir engineers. In this study, the equation proposed by Thompson et al. (1987) will be used to simulate permeability within select Midale Carbonate core samples due to its reliability and robustness for a wide variety of lithologies and pore geometries. The Kozeny-Carman relation, although popular in its usage for the estimation of permeability in porous reservoir rocks, is insufficient for two reasons. Firstly, the Kozeny-Carman equation relates permeability with macroscopic features, such as porosity, and secondly does not recognize the significance of pore-length scales in fluid transport simulations (Katz and Thompson, 1986). Alternatively, the empirical formula established by Thompson et al. (1987), widely known as the Katz-Thompson relationship, makes use of methods derived in condensed-matter physics to understand and describe fluid percolation through porous geological media using the concept of a characteristic pore-length scale or critical pore diameter. The accuracy of the Katz-Thompson relation relies on the use of mercury intrusion porosimetry to determine a critical pore diameter that is deemed to control fluid migration throughout a rock core. The Katz-Thompson equation is defined as:
where, \( l_c \), is the critical pore diameter in micrometres obtained from mercury porosimetry, \( F \) is the formation resistivity factor from electrical resistivity, \( k \) is the permeability measured in \( \mu m^2 \) and \((1/226)\) is a constant dependant on the fractal nature of pore space within all sedimentary rocks. Applying this theory, Thompson et al. (1987) were able to estimate fluid percolation through a variety of porous sedimentary rocks to within a factor of 2 to 3 of measured permeability values. According to Thompson et al. (1987), \( l_c \) can be accurately determined from a mercury injection capillary pressure curve at the first sharp rise in mercury invasion when cross-plotting the fraction of pores (normalized against the total pore volume sampled) invaded with mercury against the applied pressure (Figure 4.2). Using the Laplace law (equation 2.14) and the determined inflection point for a given capillary pressure curve, Thompson et al. (1987) suggest that \( l_c \) is equal to the local pore diameter, \( d \), assumed to be responsible for dictating fluid percolation across the rock core.

In the case of CMT, pore-throat diameters were directly obtained from image analysis. For the 10 \( \mu m \) CMT data, pore volume was calculated for each individual pore, and the volumes for all pores were summed to determine the total pore volume of the sample. Next, pore diameters were calculated assuming spherically shaped pores. Each pore diameter was normalized against the total pore volume to determine the fraction that each pore diameter occupies in the sample. The pore diameters were then converted to theoretical capillary pressures using the Laplace law (equation 2.14), cross-plotted with the fraction of pores and compared directly against the corresponding capillary pressure curve from mercury injection (Figure 4.3A-C). Alternatively, the highly connected 0.78 \( \mu m \) CMT data of the Midale Marly (M0) sample permitted quantitative determination of pore-throat diameter (Figure 3.13D). These pore-throat diameters were normalized by the total pore volume to obtain the fraction of pore-throats. From here, the pore-throat diameters were used to theoretically determine capillary pressure from the Laplace law (equation 2.14) for each pore-throat diameter sampled by CMT. The CMT theoretical capillary pressure curve was then compared directly against the curve obtained from mercury injection porosimetry to determine the suitability and accuracy of
CMT for measuring pore-throat diameters. It can be seen in Figure 4.3D that capillary pressure curves calculated from CMT and mercury injection porosimetry are in strong agreement with one another. This indicates that both CMT and mercury injection porosimetry provide a quantitative method for determining the cumulative volume of pores having a specified pore-throat diameter and estimating permeability in porous geological materials (Table 4.2). However, volume effects associated with mercury infiltrating a pore-throat and subsequently filling the attached pore-body(s) in a mercury injection test can be removed by using CMT, hence allowing for more complete characterization of pore-throat and pore-body sizes and size distribution. This can have a significant impact on hydrocarbon reserve estimates and recovery techniques.

**Figure 4.2.** Determination of the critical pore diameter \( (l_c) \) from mercury injection porosimetry data is taken as the inflection point or first sharp increase in infiltration pressure.
Figure 4.3. Comparison between capillary pressure curves determined from mercury injection porosimetry and CMT data on the (A) Midale Vuggy (V2), (B) Midale Vuggy (V4), (C) Midale Marly (M0) and (D) Midale Marly (M0) at 0.78µm. Capillary pressure curves A-C were generated from the 10 µm resolution CMT data.
Table 4.2. Measured porosity and permeability were compared with theoretical permeabilities calculated from mercury injection porosimetry and CMT data using the Katz-Thompson relationship for the three sections of Midale Carbonate core. † Represents values determined from the 0.78 µm CMT data.

<table>
<thead>
<tr>
<th></th>
<th>V2</th>
<th>V4</th>
<th>M0</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total Porosity from Water Saturation</strong></td>
<td>Φ_{effective} (%)</td>
<td>2.05</td>
<td>1.20</td>
</tr>
<tr>
<td><strong>Total Porosity from CMT</strong></td>
<td>Φ_{total(&gt;10µm)} (%)</td>
<td>0.70</td>
<td>0.29</td>
</tr>
<tr>
<td><strong>Measured Permeability (mD)</strong></td>
<td>Gas</td>
<td>49.2</td>
<td>11.0</td>
</tr>
<tr>
<td></td>
<td>Liquid</td>
<td>42.8</td>
<td>4.2</td>
</tr>
<tr>
<td><strong>Simulated Katz-Thompson Permeability (mD)</strong></td>
<td>Predicted from CMT</td>
<td>491</td>
<td>11.2</td>
</tr>
<tr>
<td></td>
<td>Predicted from Mercury Injection</td>
<td>567</td>
<td>11.4</td>
</tr>
<tr>
<td><strong>Critical Pore Diameter (µm)</strong></td>
<td>CMT</td>
<td>77.6</td>
<td>18.3</td>
</tr>
<tr>
<td></td>
<td>Mercury Injection</td>
<td>83.3</td>
<td>18.6</td>
</tr>
</tbody>
</table>

Applying the Katz-Thompson relationship, permeabilities were calculated using pore diameter data from mercury injection porosimetry and CMT data for the three Midale Carbonate cores and directly compared with measured results obtained from gas and liquid permeametry on the same sections of core (Table 4.2). From Figure 4.3, the similarity between capillary pressure curves determined from both mercury injection and CMT is observed, indicating CMT is well suited for accurately measuring pore-throat diameters and predicting permeability in carbonate rock cores.

Tabulated results (Table 4.2) indicate a strong correlation between simulated permeabilities from CMT and mercury injection porosimetry and measured gas permeability. Overall, the determination of the critical pore diameter from mercury injection is more comprehensive as the total effective pore volume was sampled for each rock core, unlike the CMT method which only sampled pore diameters greater than 10 µm in all cases except one. The differences largely show up as dissimilarities in the total range of fractional pore diameters sampled, with CMT being more restricted than mercury injection porosimetry (Figure 4.3 A, B and C). Comparing measured gas permeability values and simulated permeability by the Katz-Thompson method, the 10 µm CMT data from the Midale Vuggy (V4) returned the most reliable value, agreeing
to within a factor of 1.1 (Table 4.2). Significant differences exist between measured and
simulated permeabilities for the Midale Vuggy (V2) and Midale Marly (M0) samples,
which differ from measured gas permeability by approximately a factor of 10 and 22,
respectively. A reason for this deviation is directly attributed to the 10 µm resolution
limit of the CMT data resulting in inflated permeability values. This has been shown
conclusively as the 0.78 µm CMT pore-throat data extracted from the Midale Marly
(M0) sample displays a strong resemblance with the capillary pressure data from
mercury injection (Figure 4.3D). From this, simulated permeability is within a factor of
2.2 of the measured gas permeability value and differs from the mercury injection
prediction by only 11% (Table 4.2). For the Midale Vuggy (V2) and Midale Vuggy (V4)
samples, the inflection points for the simulated CMT curves were close to the inflection
points observed by mercury injection even though the CMT only imaged a small fraction
of the pores. This looks promising, but it would require additional investigation to
determine if this was coincidental, or if there is some underlying physical explanation
that would make this a repeatable result.

4.3. Implications of CMT for the Weyburn Oilfield

As demonstrated by the data presented in this thesis and previous research
conducted on carbonate pore space, micro-scale features is vital for predicting macro-
scale fluid migration. For example, permeability is dependant on pore apertures, pore
type and pore network geometry (e.g., formation resistivity factor, $F$, and tortuosity, $\tau$),
rather than bulk rock porosity alone (Prodanović et al., 2007). In order to obtain
meaningful information from petrophysics it must be related back to geological
interpretations to create successful reservoir models. In this study, traditional
petrophysical laboratory methods have been compared against, and combined with,
synchrotron-based CMT to fully characterize the micro-scale features of a selected suite
of samples from the Midale Carbonates in the Weyburn Oilfield. The ability of CMT to
aid in the petrophysical characterization of carbonate rocks has been shown to be both
complimentary and, in some cases, superior to traditional petrophysical laboratory
approaches as it can provide both qualitative (visual) and quantitative information about


pore space geometry and mineral-pore relationships, while preserving the original rock microstructure, providing greater insight into the controlling factors on permeability.

As discussed in Sections 1.3 and 1.4, the Midale beds within the Weyburn Oilfield form a complex and compartmentalized reservoir based on porosity development and carbonate depositional models for the Marly and Vuggy units. Porosity development in the Midale Carbonates is dominated by both primary depositional and diagenetic processes that together have a significant influence on permeability (Churcher and Edmunds, 1994). The Marly unit consists mainly of restricted lagoonal limemudstones and wackestones that were later pervasively dolomitized producing microcrystalline (20-30 µm) dolostones with a chalky texture and abundant intercrystalline porosity and minor visible pin-point vuggy porosity (Figures 3.1, 3.8B and 4.4). Together, these two porosity types contribute to high porosity values (typically greater than 25%) and moderate to low permeabilities (Table 1.1). This reduction in permeability within the Marly unit, as evidenced from the Midale Marly (M0) sample, is directly related to pore aperture size connecting each individual pore (Figures 4.3 and Table 4.2). Lucia (1983; 1995; 1999) noticed this same phenomenon in sucrosic dolomites, suggesting permeability can be qualitatively predicted based on crystal size (Section 1.6).

In comparison, the Vuggy unit, consisting mainly of skeletal and peloidal limepackstones and grainstones that were deposited in an open-marine, shoal environment, having abundant secondary dissolution vuggy and intracrystalline porosity resulting in a higher permeability, on average, than the Marly unit within the Weyburn Oilfield (Table 1.1. and Figure 4.4). The increased permeability within the Vuggy unit can be attributed to a patchy distribution of pore space and greater pore apertures as observed from mercury injection porosimetry and CMT data (Figures 3.7, 3.16, 3.17, 4.1, 4.3 and Table 4.2). From mercury injection porosimetry, pore apertures within the Midale Marly (M0) sample occurs within the 1 µm to 10 µm range, with the peak centered at 4.3 µm while for the Vuggy core samples, pore apertures range from 6 µm to 20 µm for the interior vugs and 35 µm to greater than 1000 µm for the exterior surface vugs (Figures 3.16, 3.17 and 3.18). As shown in Figure 4.1, pore apertures and their distribution in the Vuggy unit are difficult to assess by conventional techniques alone. This problem can be more
adequately addressed using CMT which provides valuable information regarding the patchy and heterogeneous nature of the distributed pore space prevalent throughout the Vuggy unit (Figure 4.4).

**Figure 4.4.** Paleoenvironmental model of the Weyburn Reservoir. The two producing horizons are the Midale Marly and the Midale Vuggy (shoal). The Midale Marly unit was originally deposited in quiet, shallow water lagoons consisting of lime mudstones and wackestones that were later pervasively dolomitized producing a microcrystalline dolo-mudstone rock with abundant intercrystalline porosity. Alternatively, shoal deposits of the Midale Vuggy are mainly coarse skeletal and peloidal packstones and grainstones that, upon sea-level fall, contain abundant large secondary vuggy pores. Channel-fill deposits in the Vuggy unit, termed intershoal deposits, are low-porosity, non-reservoir quality rocks consisting of skeletal lime wackestones. The regional seal for the Weyburn Oilfield is provided by the Midale Evaporite which was formed in sabkha to tidal flat conditions. Corresponding three-dimensional CMT data highlighting porosity within the Midale Marly and Midale Vuggy units is shown in relation to depositional environments providing an improved understanding of reservoir properties (after Whittaker et al., 2004).

In this study, most of the CMT images were collected at resolutions (10 µm), above the critical pore diameters deemed to control fluid transport in the Midale Carbonates (~18 µm in the Vuggy and 4 µm in the Marly), however, significant insight
into the spatial distribution of minerals and pore space is still achieved (Figure 4.3 and Table 4.2). In light of this, it has been shown that by re-imaging the same (i.e. Midale Marly (M0)) sample at a much higher resolution (i.e. 0.78 µm) indicates that the highly connected intercrystalline pore network existing between 0.78 µm and 10 µm is generally much more complex than the corresponding mercury capillary pressure curve suggests (Figures 3.13 and 4.1 and Table 4.2).

From electrical resistivity measurements, pore space connectivity within the Midale Marly (M0) sample was observed to be high, as both the formation resistivity factor and tortuosity were low in value. Alternatively, the Vuggy unit, as evidenced from the Midale Vuggy (V2) and Midale Vuggy (V4) samples, is less well-connected, resulting in higher formation resistivity factors and tortuosity values (Table 4.1). From CMT, tortuosity values determined for the Midale Marly (M0) sample agree with calculated tortuosity values from electrical resistivity, suggesting CMT is well suited for constructing detailed fluid flow simulations to determine reservoir performance (Figure 3.12).

Comprehensive analysis of the three-dimensional digital CMT data shows that the physical characteristics of the Midale Marly (M0) sample at a resolution of 0.78 µm match closely with tortuosity values calculated from electrical resistivity, porosity values from water saturation and pore-throat diameters from mercury injection completed on larger sections of carbonate core (Figures 3.12, 3.13, 4.1 and 4.3 and Table 4.1). Given the strong agreement between all methods, the Midale Marly unit has been characterized from the Midale Marly (M0) sample investigated here as possessing abundant bulk rock porosity with constricted pore throats (~1-5 µm) connecting individual pores, ultimately reducing permeability to approximately less than 20 mD (Figure 4.3D and Table 4.2). Fluid pathways through the rock core are less tortuous than those encountered in the Vuggy unit and are similar in all directions thus, suggesting an isotropic pore space distribution (Figure 3.12, Table 4.1 and Appendix C). Furthermore, the pore-throat radii were found to be approximately ½ the radii of the pore-bodies, which may be restrictive to oil migration throughout the Marly unit and has implications to current oil recovery methods by CO₂ miscibility and water flooding within the Weyburn Oilfield. Alternatively, the Vuggy unit can be characterized from the Midale Vuggy (V2) and
(V4) samples by having larger pore-throats, likely resulting in higher permeabilities (Figure 4.3 and Table 4.2). Tortuosity and pore geometry are highly variable in each of the two samples, suggesting the importance of pore-length scales in accurately determining permeability within vuggy rocks, as is the case in the Midale Vuggy (V4) sample which has greater pore apertures than the Midale Marly (M0) sample, but lower permeability (Table 4.1).

In this study, the suitability of CMT to determine the spatial distribution of minerals within a sample has been investigated, although not exhaustively. Within this, CMT has been shown to accurately delineate mineral relationships in three-dimensional space as the recorded X-ray attenuation coefficients, or LAC values, provide a mode for semi-quantitative identification of minerals in CMT data (Figure 3.2). With further refinement, this can have far-reaching implications regarding secondary porosity development and assessing fluid reactions and subsequent precipitation of new minerals as a result of CO₂ sequestration at the Weyburn CO₂ EOR and GHG pilot project. Analyses of the combined CMT data and BSE from EPMA collected on rock cores from both the Midale Marly and Vuggy units suggest that diagenetic features, such the secondary dissolution of limestone and subsequent precipitation of new calcite minerals along the pore walls and late-stage filling by anhydrite, may be evident within the Vuggy unit (Figure 4.5). For instance, newly formed euhedral calcite crystals can be seen in-filling existing pore space, which may suggest neo-formed carbonate minerals as a result of reactions between the CO₂ fluids and the rock matrix (Figure 4.5). However, more information, such as detailed chemical analyses, would be required to determine whether this calcite rhomb is of similar chemical composition as that seen in Figure 4.5B, which is observed to have formed prior to anhydrite cementation and subsequently CO₂ injection.
Figure 4.5. Diagenetic features in the Midale Vuggy (ID-02-19) sample. (A) Newly formed calcite rhomb in-filling pore space. (B) Early formed calcite rhomb formed prior to late stage anhydrite in-filling of pore space. Calcite, anhydrite and pore space is labeled in figure A.

From Figure 4.5 and previous research, diagenetic events related to porosity creation and destruction within the Midale Carbonates has been identified (Kendall and Walters, 1978; Churcher and Edmunds, 1994; Kent, 1999; Whittaker et al., 2004) (Figure 4.6). In the Vuggy unit, porosity creation is a combination of both primary depositional (fenestral and intercrystalline) and secondary dissolution (moldic and vuggy) events, with secondary porosity development being the most significant. The pore space was later filled by blocky calcite and anhydrite that reduced the original bulk rock porosity and associated permeability (Figure 3.6). Furthermore, extensive fracturing in the Vuggy unit created conduits for fluids to migrate through the shoal and intershoal portions of the Vuggy unit, creating an important secondary hydrocarbon horizon. Alternatively, porosity development within the Marly unit was controlled through the process of dolomitization that recrystallized the original lime mudstones and wackestones into microcrystalline dolostones having abundant intercrystalline porosity (Figure 3.10 and Table 4.2). With injection of CO$_2$ gas into the Midale Carbonates, porosity can be initially expected to increase in the near vicinity of the injection well. Dissolution of calcite by CO$_2$ is likely to be more pronounced in the Vuggy unit than in
the Marly unit due to the lower solubility of dolomite to CO$_2$ than calcite. Once the solubility for calcite is exceeded, precipitation of calcite along the pore-walls is possible (Figure 4.5A).

<table>
<thead>
<tr>
<th>Event</th>
<th>Shallow Burial</th>
<th>Deep Burial</th>
<th>CO$_2$ Injection</th>
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<tr>
<td></td>
<td>Syn-depositional</td>
<td>Early</td>
<td>Intermediate</td>
</tr>
<tr>
<td>Calcite Cementation</td>
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<td>Vuggy Unit</td>
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<tr>
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<td>Vuggy Unit</td>
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<tr>
<td>Dolomitization</td>
<td>Vuggy Unit</td>
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<td>Stylolization</td>
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**Figure 4.6.** Paragenetic sequence of diagenetic events for the Midale Carbonates within the Weyburn Oilfield. CO$_2$ injection may result in enhanced porosity while potentially being sequestered as new minerals (i.e., blocky calcite) along the pore walls (after Kent, 1999).

In this study, conventional petrophysical and mineralogical laboratory analyses have been compared with in-situ, three-dimensional analyses from CMT to show that the integration of these techniques can be combined to provide a detailed qualitative and quantitative evaluation of core properties. As shown in Figure 4.7, information pertaining to pore space geometry and minerals from CMT data can be directly integrated with petrophysical and mineralogical information of reservoir rock properties from traditional laboratory-based techniques. As previously discussed in Section 4.2, permeability can be directly simulated by combining pore geometrical information from both CMT and conventional methods with reasonable accuracy. The retention of three-dimensional pore space information from CMT data can be used in digital network flow simulations (e.g., Lattice Boltzmann or Finite Element) that can provide more realistic permeability simulations than those from empirical relationships (e.g., Katz-Thompson or Kozeey-Carman) (Prodanović et al., 2007). From the relationships built upon and
developed in this study between conventional petrophysical and mineralogical techniques and CMT, poorly understood relationships between minerals, porosity and permeability in carbonate rocks can be improved. Together, this data can be used to create more detailed core descriptions of petrophysical and mineralogical properties based on the preservation of three-dimensional features within rock cores.

Figure 4.7. Flow chart of petrophysical and mineralogical methods used in this thesis research. Three-dimensional qualitative and quantitative information of pore space and minerals from CMT provides a novel and powerful tool for characterization of rock core properties that improve the understanding of hydrocarbon reservoirs.

A common problem in reservoir engineering is scaling laboratory measurements to obtain meaningful information about a reservoir. To accomplish this, two-point correlation functions, fractals and other statistical approaches have been applied with reasonable success (Radlinski et al., 2004). The complex pore geometry and multiple pore-length scales that exist within sedimentary rocks make the correlation between field-scale and pore-scale techniques difficult. Although this is beyond the scope of this research, it is important to bear this in mind when studying the influence of pore geometry on fluid transport properties within sedimentary rocks. From Figure 4.8, most laboratory-based petrophysical and mineralogical measurements are taken at the pore- and core-scale. Using pore space information from core experiments, up-scaling of the
simulated core properties to electrical well-logs and geological descriptions is the next logical step. At this point, it is possible to suggest similarity in petrophysical features at multiple length scales. One major set-back of traditional petrophysical and mineralogical techniques is the inability to resolve pore space and minerals in three-dimensions. This problem can be easily overcome by utilizing high spatial resolution data from CMT that provides visualization and quantification of the internal pore geometry of porous reservoir rocks. Critical pore-scale (i.e., micron to sub-micron) information obtained from CMT can be accurately applied to core-scale petrophysical and mineralogical predictions, ultimately improving the understanding of the micro-scale features that directly influence fluid transport and field-scale hydrocarbon recovery.
Figure 4.8. Importance of scale in measurement and simulation of petrophysical parameters in geology (after Patzek, 2000).
5. Summary, Conclusions and Recommendations

5.1 Summary and Conclusions

Throughout this study, synchrotron-based CMT is shown to provide a valuable visual and quantitative tool for investigating the spatial distribution of pore space and minerals within rock cores. The application of advanced imaging by synchrotron-based CMT for the delineation of the porous microstructure and matrix materials with micrometre to sub-micrometre resolution in hydrocarbon-bearing rocks will ultimately lead to an improved understanding of fluid transport properties and fine-tune current enhanced oil recovery techniques. Petrophysical information obtained by conventional laboratory tests conducted on the select sections of Midale Carbonate core characterized a number of important rock properties; however, many limitations were revealed. These limitations include: 1) the inability to accurately describe the pore aperture size distribution within the carbonate rock cores, 2) the inability to visually investigate minerals and pores in the spatial domain and 3) test parameters assume simple pore space geometry for rocks with complex pore space geometry. All of these limitations can be addressed and easily assessed from three-dimensional information supplied by synchrotron-based CMT.

In the Weyburn Oilfield the Midale Carbonates form a complex and compartmentalized reservoir having variable porosities and permeabilities. Of particular importance is the influence of pore type and pore size on permeability, which is readily observed from the permeabilities which were found to be greater in the Midale Vuggy than in the Midale Marly. This difference in permeability is attributed to smaller intercrystalline pores in the Marly while larger vuggy pores prevail in the Vuggy unit, as evidenced from mercury injection porosimetry and CMT. The non-destructive imaging made available by CMT provides qualitative and quantitative information about pore space geometry (e.g., pore-body and pore-throat size, shape and connectivity) and minerals in three-dimensions, something that is not obtainable using conventional
petrophysical and mineralogical methods. Three-dimensional information from CMT can significantly aid in characterization and understanding of pore space geometry in complex reservoir rocks where pore-body and pore-throat sizes can have a significant impact on current recovery methods.

From the CMT data, porosity and permeability within the Marly and Vuggy units of the Weyburn Oilfield are significantly different, both visually and quantitatively. Pore space within the Marly unit is dominantly intercrystalline with minor vugs while the Vuggy unit is composed mainly of vuggy porosity connected by smaller vugs and intercrystalline pores. Furthermore, porosity within the Marly unit is typically higher in value and displays an isotropic distribution unlike the Vuggy unit which is lower in porosity and considerably more heterogeneous in distribution. This heterogeneous distribution in pore space and pore size results in highly variable permeabilities which makes simulation of reservoir performance in the Vuggy unit difficult. As noted from CMT, the importance of pore-length scales in permeability simulation is more profound within Vuggy rocks compared with those from the Marly unit. This is observed visually by the patchy distribution of pore space and pore size which varies drastically between the Midale Vuggy (V2) and Midale Vuggy (V4) samples. In comparison, pore space within Midale Marly (M0) sample is more isotropic in distribution having smaller pore-throats, ultimately resulting in lower measured permeabilities across the Weyburn Oilfield.

All of these observations from the CMT data are consistent with pore space information obtained from mercury injection porosimetry and measured gas and liquid permeabilities. To support this conclusion, the 0.78 µm resolution CMT data from the Midale Marly (M0) sample revealed a highly connected pore network that is nearly isotropic in three-dimensions. Furthermore, calculated pore-throat diameters from the CMT data strongly agree with capillary pressure data from mercury injection. From this, pore-throats that are approximately 4 µm in diameter are deemed to be dictating fluid movement within the Marly unit of the Weyburn Oilfield. Additionally, the ratio between pore-throat and pore-body radii has significant implications to current EOR methods.
5.2 Recommendations

From this study, the following recommendations can be made:

1) Selection of CMT core samples in carbonate rocks should be chosen with caution as pore space can vary significantly over very short length scales. When selecting an appropriate CMT resolution, the porosity type being examined should be determined prior to imaging. Rocks having dominantly vuggy porosity should be imaged using a large enough core sample to ensure a broad distribution of pore sizes is sampled. However, high resolution CMT data is often required to observe the spatial connectivity. In this study, an image resolution of approximately 5 µm (10 mm core) would have returned more accurate data pertaining to bulk rock porosity and connectivity. For rocks having dominantly intercrystalline porosity, it is important to note the pore sizes from thin-section. If visible using TLM, then a lower resolution (~10 µm) may be sufficient. If, however, porosity is nearly or completely invisible using TLM, significantly higher resolution (0.7-2 µm) CMT data is required.

2) When conducting conventional petrophysical measurements in conjunction with CMT analyses, large sections of rock should be sampled so that both large and small core samples can be obtained in close proximity, ensuring petrophysical and mineralogical uniformity between the samples.

3) Gas and liquid permeability measurements should be completed prior to CMT imaging with cores for CMT being sub-sampled from the large permeability core samples. This is important when constructing digital fluid flow models (e.g., Lattice Boltzmann or Finite Element) from CMT data. This will ensure similar fluid pathways are being sampled by both methods.

4) When attempting to tackle the problem of scaling pore-scale measurements to the field-scale, large core samples (i.e., cm to m in length) could be imaged at a lower spatial resolution (i.e., ~50-100 µm) and directly correlated with electrical
well-logs from the same well and depth interval. From here, smaller sections can be cut for high resolution (i.e., ~0.7-10 µm) CMT analyses.

5) CMT analysis can be completed at elevated temperatures and pressures, simulating reservoir conditions, providing critical information about matrix compressibility and influence of pressure on permeability and fracture aperture. This has implications for unconventional gas reservoirs (i.e., coal bed methane (CBM), shale gas and tight gas reservoirs) upon which the success is strongly dependant on fracture aperture at depth. However, this method can also be applied to porous geological samples to observe the effects of pressure and temperature on fluids within these rocks and its relation to permeability and hydrocarbon recovery.

6) Digital information of pore space and mineralogy from CMT can be used to construct both simple (i.e., single-phase) and complex (i.e., multi-phase) digital fluid percolation models that incorporate pore-lining minerals and pore space characteristics (i.e., shape, size, distribution and connectivity) to further understand permeability (absolute and relative), enhanced oil recovery and reservoir stimulation techniques.

7) Advanced CMT imaging techniques (i.e., phase contrast) can be used to image fluids residing in pores (i.e., oil and water) or observe fluid movement through a porous rock core in real time. This can be used to calculate absolute permeability and to directly compare with conventional laboratory permeameter results.

8) CMT is a cost effective alternative to conventional petrophysical and mineralogical laboratory techniques as both visual and quantitative information of pore space and minerals is obtained rapidly. The cost of a single full-core CMT scan is approximately $1000 CDN (independent of image resolution) and image acquisition time takes approximately 1 hour, although rapid CMT scanning is currently available allowing full-core CMT scans to be completed in
less than 15 minutes (complete with auto-sampler for rapid, multiple-sample CMT scanning). Data reduction time is considerably reduced as visual information of both minerals and pore space can be achieved shortly after data collection. Quantitative information, such as pore-body and pore-throat size and tortuosity, requires more time, but can be accomplished within a few (1-4) hours (depending on file size). This is a considerable advantage over conventional methods which can take several hours or days to complete a single test. Although individual conventional laboratory tests are typically inexpensive, in-order to retrieve the same amount of data as collected by CMT, multiple tests (both petrophysical and mineralogical) would need to be completed. Given this, the sum of all conventional laboratory costs and processing time required is greater than the cost of CMT. However, it should be noted that some conventional tests may be required in addition to CMT, especially since many relationships between CMT and conventional methods (i.e., mineralogy and permeability) are not well established.

9) Given the amount of valuable information that can be obtained from CMT, construction of a database incorporating a wide range of lithologies and their corresponding petrophysical properties should be created. This could prove to be an immensely powerful tool when attempting to establish new permeability and porosity relationships for scientific and industrial applications.
REFERENCES


Padhy, G.S., Lemaire, C., Amirtharaj, E.S., Ioannidis, M.A., 2007. Pore size distribution in multiscale porous media as revealed by DDIF-NMR, mercury porosimetry and

Patzek, T., 2000. Verification of a complete pore network simulator of drainage and imbibition. SPE Presentation 59312


Appendix A

Gas Permeability Plots
Midale Vuggy (V2) ID-02-40
RUN 1

Apparent Permeability ($k_a$) (mD)

$k_{corr} = 48.5$mD

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<th>$P$ (Pa)</th>
<th>$k_a$ (mD)</th>
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Reciprocal Mean Pressure (1/$P$)

Midale Vuggy (V2) ID-02-40
RUN 2

$K_{corr} = 50.0$mD

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Reciprocal Mean Pressure (1/$P$)
Midale Vuggy (V4) KD-03-23

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Midale Vuggy (V4) KD-03-23

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Appendix B

Mercury Injection Porosimetry Results
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<th>Corrected Vol. Injected per unit mass (cm³/g)</th>
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### Mercury Intrusion Porosimetry

**Sample Mass** 27.966 g  
**Porosity** 34.48%

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**KD-18 - Midale Marly**  
"NO SAMPLE IN CHAMBER"

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### Additional Data
- **Contact Angle (dolomite):** 140 deg
- **NO SAMPLE IN CHAMBER**
- **Corrected Mid-Point Corr. Vol:**
  - **Apparent Pore Diameter:**
  - **Injection Hg Vol:**
  - **Pump Reading:**
  - **Sample Mass:** 27.966 g
  - **Porosity:** 34.48%
  - **Sample Name:** KD-18 - Midale Marly (M0)
  - **Sample Tension:** 0.484 N/m

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B-6
Appendix C

CMT Voxel Reconstruction
Appendix C – 3D visualization of minerals and pore space in the Midale Vuggy (V2). A) Shows a portion of the total sample volume (213 mm$^3$), light grey and grey regions are the rock volume and black areas are porosity. B) Displays the 3-D distribution of porosity (blue). C) 3-D distribution of dolomite. D) 3-D extent of the light gray (highest density) mineral phase, anhydrite. E) Metallic silver represents calcite which is gray in the CMT slices. Image F shows all mineral phases (calcite is transparent gray) and porosity plotted together.
Appendix C – 3D visualization of minerals and pore space in the Midale Marly (M0). A) Shows a portion of the total sample volume (284 mm$^3$), white and grey regions are the rock volume and black areas are porosity. B) Displays the 3-D distribution of porosity. C) 3-D distribution of quartz. D) 3-D extent of the light gray mineral phase, calcite. E) White regions in the CMT slices are the high density mineral phase, celestine. F) Purple represents dolomite which is grey in the CMT slices. Image G shows all mineral phases (dolomite is transparent purple) and porosity plotted together.
Appendix C – 3D visualization of minerals and pore space in the Midale Vuggy (ID-02-19). A) Shows a portion of the total sample volume (45 mm³), light grey and grey regions are the rock volume and black areas are porosity. B) Displays the 3-D distribution of porosity. C) 3-D extent of the light gray (highest density) mineral phase, anhydrite. D) Metallic silver represents calcite which is gray in the CMT slices. Image E shows all mineral phases (calcite is transparent gray) and porosity plotted together.
Appendix C – 3D visualization of minerals and pore space in the Midale Marly (MD). A) Shows a portion of the total sample volume (38 mm$^3$), dark grey and white regions are the rock volume and black areas are porosity. B) Displays the 3D distribution of porosity. C) 3D distribution of calcite. D) 3D extent of the white (highest density) mineral phase, celestine. E) Purple volume represents the dominant mineral phase dolomite. Image F shows all mineral phases (dolomite is transparent purple) and porosity plotted together.
Appendix C – 3D visualization of minerals and pore space in the Midale Marly (M3). A) Shows a portion of the total sample volume (123 mm$^3$), light grey and grey regions are the rock volume and black areas are porosity. B) Displays the 3D distribution of porosity. C) 3D distribution of quartz. D) 3D extent of calcite. E) Highest density mineral phase, celestine. F) Purple volume represents the dominant mineral phase dolomite. Image F shows all mineral phases (dolomite is transparent purple) and porosity plotted together.
Appendix C – 3D visualization of pore space in the six Midale Carbonate core samples used in this study. A) ID-02-40, Midale Vuggy (V2), B) ID-02-19 Midale Vuggy, C) KD-03-23, Midale Vuggy (V4), D) KD-03-18, Midale Marly (M0), E) Marly Dolostone, Midale Marly and F) KD-03-11, Midale Marly (M3).
Appendix C – (A) 3D visualization of all connected pore space pathways in the y-direction (front to back) in the Midale Marly (M0) sample. Tortuosity ranges from 1.5 to 2.9 (average is 1.78). (B) Absolute shortest connected pore space pathways having tortuosities ranging from 1.5 to 2.4 (average is 1.74).

Appendix C – (A) 3D visualization of all connected pore space pathways in the z-direction (top to bottom) in the Midale Marly (M0) sample. Tortuosity ranges from 1.4 to 2.9 (average is 1.76). (B) Absolute shortest connected pore space pathways having tortuosities ranging from 1.4 to 2.2 (average is 1.64).