A Petroleum Resource Assessment Of The Huron Domain Area, Southern Ontario

NWMO-TR-2019-20 December 2019

Zhuoheng Chen[1], Peter Hannigan[1], Terry Carter[2], Xiaojun Liu[1], Richard Crowe[3], Mark Obermajer[1]

[1]Geological Survey of Canada, Calgary
[2]Carter Geologic
[3]Nuclear Waste Management Organization

NUCLEAR WASTE MANAGEMENT ORGANIZATION
SOCIÉTÉ DE GESTION DES DÉCHETS NUCLÉAIRES

Nuclear Waste Management Organization
22 St. Clair Avenue East, 4th Floor
Toronto, Ontario
M4T 2S3
Canada

Tel: 416-934-9814
Web: www.nwmo.ca

A Petroleum Resource Assessment Of The Huron Domain Area, Southern Ontario

NWMO-TR-2019-20

December 2019

Zhuoheng Chen[1], Peter Hannigan[1], Terry Carter[2], Xiaojun Liu[1], Richard Crowe[3], Mark Obermajer[1]

[1]Geological Survey of Canada, Calgary
[2]Carter Geologic
[3]Nuclear Waste Management Organization

Document History

Title:	A Petroleum Assessment of the Huron Domain area, Southern Ontario		
Report Number:	NWMO-TR-2019-20		
Revision:	R000	Date:	December 2019
Author Company(s)			
Authored by:	Zhuoheng Chen, Peter Hannigan, Terry Carter, Xiaojun Liu, Richard Crowe and Mark Obermajer		
Verified by:	Edward Little, Head,Energy Geoscience Subdivision Program Manager, Geoscience for New Energy Supply Geological Survey of Canada–Calgary		
Approved by:	Edward Little, Head,Energy Geoscience Subdivision Program Manager, Geoscience for New Energy Supply Geological Survey of Canada–Calgary		
Nuclear Waste Management Organization			
Reviewed by:	Monique Hobbs		
Reviewed by:	Sarah Hirschorn		
Accepted by:	Paul Gierszewski		

Revision Summary		
Revision Number	**Date**	**Description of Changes/Improvements**
R000	2021-08	Initial issue

ABSTRACT

Title: **A Petroleum Resource Assessment of the Huron Domain Area, Southern Ontario**
Report No: **NWMO-TR-2019-20**
Author(s): Zhuoheng Chen[1], Peter Hannigan[1], Terry Carter[2], Xiaojun Liu[1], Richard Crowe[3], Mark Obermajer[1]
Company: [1]Geological Survey of Canada, Calgary
[2]Carter Geologic
[3]Nuclear Waste Management Organization
Date: December 2019

Abstract

The Geological Survey of Canada has quantitatively assessed oil and gas resources in self-sourced and self-retained fine-grained clastic (shale) reservoirs within the Upper Ordovician Collingwood and Rouge River members, as well as the undiscovered potential oil and gas resources in Paleozoic conventional reservoirs, incorporating data from a site formerly proposed for a Low and Intermediate deep geologic repository and regional data from southern Ontario. If these two Upper Ordovician shale units are treated as separate resource plays, both fail to meet the minimum criteria set out by the United States Geological Survey (USGS) that define a hydrocarbon resource play. When combined however, the two units can be treated as a continuous sedimentary package and, therefore, can be treated as a single resource play.

In this report, only the technically recoverable resources are reported. Technically recoverable resources are defined as the volume of oil and gas that could be produced with technology available at the time of the present report, regardless of commodity price, production cost and the cost of bringing the products to markets.

The cut-off for the volumetric calculation is 0.5 meters of cumulative hydrocarbon-saturated rock column, which is calculated from hydrocarbon saturated porosity times gross thickness of the combined Collingwood and Rouge River shale units. The 0.5 meter cut-off is equivalent to a hydrocarbon saturated porosity >2.5% and combined gross thickness >20 meters. The cut-off is in general consistent with the geological criteria for defining the shale play boundary as described by the USGS and mentioned above. The total area defined by the reservoir cut-off is smaller than the area within the shale play boundary and is regarded as the risked prospective area by reservoir criterion.

The geographic distribution of the predicted hydrocarbon resources of the Upper Ordovician Collingwood and Rouge River shale units indicates that a large volume of the potential hydrocarbon resources of these two shale units occur in the Appalachian Basin portion of southern Ontario. Only a small quantity of the reservoir-risked resource is predicted to occur in the southeastern part of the study area.

Among the undiscovered technically recoverable unconventional resources within the study area, the mean totals are 11.7 million barrels of shale oil (MMBO), with a fractile (F95–F05, respectively) range from 6.4–19.2 MMBO and 8.0 billion cubic feet of continuous gas (Bcf), with a fractile range from 4.6–12.7 Bcf. Regarding conventional resource, mean totals of 6.5 million barrels of conventional oil and 51.5 Bcf of conventional gas are estimated to occur in the study area, although subjectively this estimate is considered to be optimistic.

The ranges of resource estimates reflect the geologic uncertainty of the source-reservoir rock systems and spatial extrapolation of resource mapping from sparse well controls. Much of the uncertainty is related to models constructed to estimate the quantity of oil remaining in the source rocks following migration and the quality of oil and gas stored in conventional reservoirs. Only a small portion of the potential resource lies within the study area (Huron Domain). The bulk of the potential hydrocarbons that are estimated to be trapped within the lithostratigraphic members is considered to be exceptionally low in the study area due to a combination of low permeability, contrasting lithologies, low formation pressures, low degrees of thermal maturation, high oil viscosity impeding hydrocarbon fluid flow and poor oil show index (S1/TOC <1).

TABLE OF CONTENTS

LIST OF TABLES

Page

LIST OF FIGURES

Page

1. INTRODUCTION

The purpose of this study is to conduct a quantitative assessment of the hydrocarbon resources in the study area outlined in Figure1.

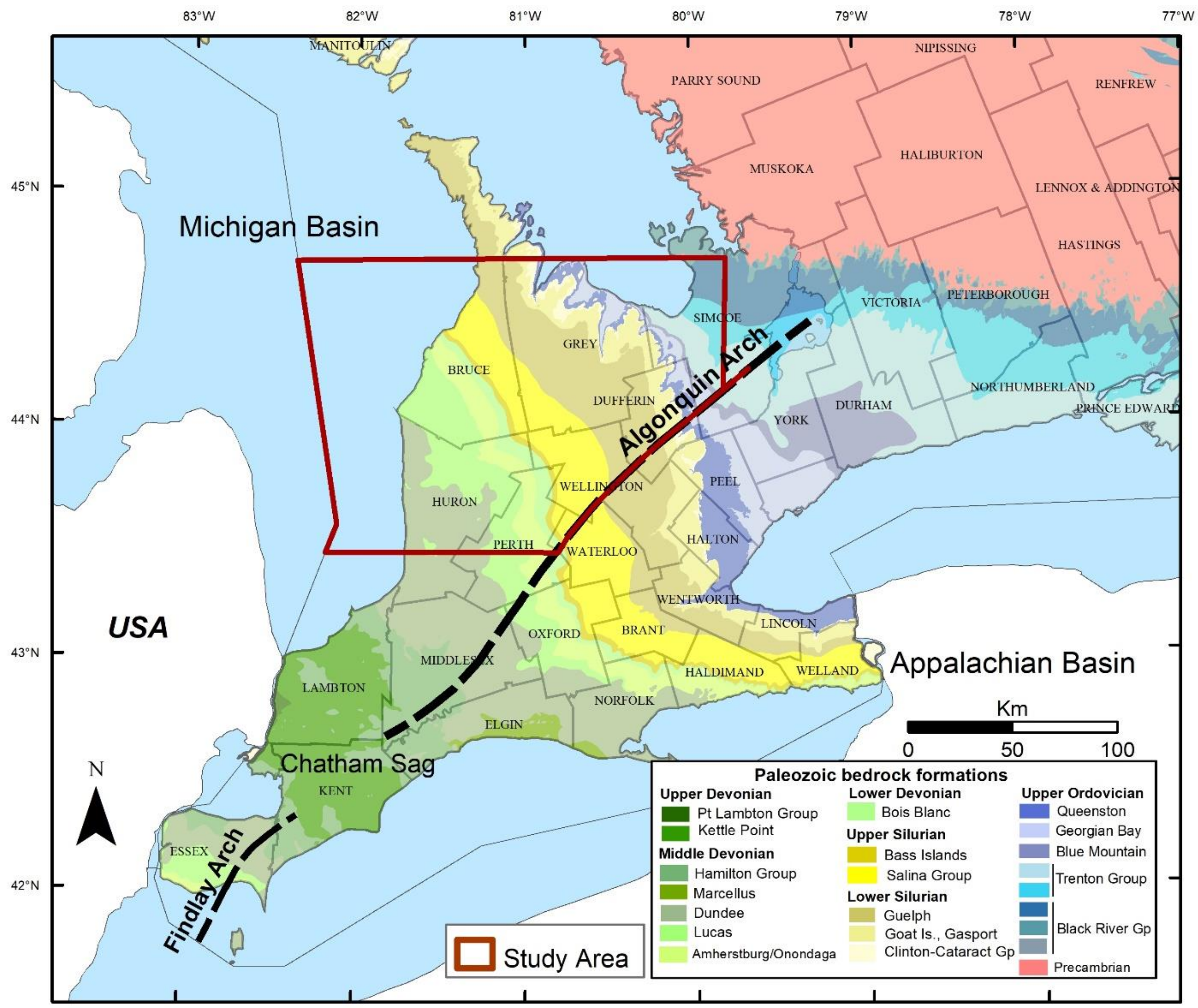

Figure 1: Map showing regional geological setting, county boundaries and location of the study area. The study area is largely confined within the boundaries of the Huron lithotectonic domain in the underlying Precambrian basement (Easton and Carter 1995). Geological map adapted from Armstrong and Dodge (2007).

This petroleum resource assessment of the hydrocarbon potential of the study area in southern Ontario (area outlined in red in Figure1) consists of two major tasks: a) an unconventional resource assessment of two potential source rock units within the Upper Ordovician succession; and b) a resource assessment of petroleum resources in conventional reservoirs in established plays in southern Ontario that also are located in the study area.

2. UNCONVENTIONAL RESOURCES

An accidental discovery of crude oil in outcropping bedrock at Craigleith on the southern shore of Georgian Bay in 1859 resulted in the first production of unconventional oil in Canada occurring from 1859 to 1863. The oil was contained in black organic-rich limestone of the Upper Ordovician Collingwood Member. The oil was produced by means of quarrying the limestone and subsequently heating it in iron distillation retorts, which produced 250 to 1000 gallons of lamp and lubricating oil per day (Dabbs, 2007). After closure of the works due to poor economics, there has been no subsequent shale oil production in Ontario.

The only comprehensive assessment of the unconventional oil and gas potential of the Paleozoic strata of southern Ontario was completed by the Ontario Geological Survey as part of the Hydrocarbon Energy Resources Program (HERP), a five-year program initiated in 1981. HERP was funded by the Ontario Ministry of Treasury and Economics in response to a government policy decision to endeavour to raise the level of energy self-sufficiency of the province. The Ontario Geological Survey (OGS) was responsible for conducting inventories and evaluations of peat, lignite and oil shale resources. The Ministry of Natural Resources (MNR) was responsible for assessing the province's conventional resources of oil and natural gas. The four shale intervals investigated by OGS included the Upper Ordovician Collingwood Member of the Cobourg (Lindsay) Formation, the Middle Devonian Marcellus Formation and the Upper Devonian Kettle Point Formation in southern Ontario as well as the Upper Devonian Long Rapids Formation in northern Ontario (Churcher et al, 1991; Johnson et al, 1989; Johnson, 1983, 1985; Johnson et al, 1983a, 1983b, 1983c, 1989; Barker, 1985; Barker et al, 1983). The economic aspect of this work was based on the potential recovery of crude oil using oil mining technology. No assessment of natural gas potential was attempted. High-volume hydrofracturing technology had not been developed at that time.

Commercial high-volume hydrofracturing technology for the recovery of natural gas from shales was developed in the United States in the late 1990's, and became prevalent in the mid-2000's. In response, the Geological Survey of Canada (GSC) completed a literature appraisal of organic-rich shales in Canada that might be suitable candidates for hydrocarbon recovery with the use of this technology (Hamblin, 2006). A similar overview for Ontario shales was completed by the Ontario Ministry of Natural Resources and the Ontario Geological Survey (Carter et al, 2008). From 2009 to 2015, the Ontario Geological Survey completed geological studies of the Upper Devonian Kettle Point Formation and the Upper Ordovician organic-rich shales and shaly limestone of the Collingwood Member of the Cobourg (Lindsay) Formation and the Rouge River Member of the Blue Mountain Formation (Béland-Otis, 2009, 2010, 2012, 2013a, 2013b, 2015). Allostratigraphic analysis of the Rouge River Member and isopach maps relevant to resource analysis were prepared by Sweeney (2014). In 2014 and 2016 geological reviews of the resource potential, including oil, were completed by Phillips (2014, 2016) and Phillips et al. (2016).

Two potential petroleum source rock units documented within the Upper Ordovician succession underlying most of southern Ontario include the Collingwood Member of the Lindsay Formation and the Rouge River Member of the Blue Mountain Formation. Each of these intervals shows distinct bulk geochemical characteristics and petroleum generation potential (Obermajer et al., 1999). As part of the North America shale gas and oil revolution, both source rock units have become recently a focus of studies evaluating their potential as shale oil and gas resources (Béland-Otis, 2012a, 2012b, 2015a; Béland-Otis et al., 2010), since several stratigraphically equivalent strata in the United States have been shown to be commercial hydrocarbon-producing shales. The organic geochemistry and paleo-depositional environments of the Upper Ordovician source rocks have been studied by Obermajer et al., (1999, 2005). More recently, a study examining their geological potential as shale oil reservoirs by Béland-Otis (2015a, 2015b) resulted in a release of a comprehensive scientific report and data compilation. However, the quantitative petroleum resource potential in the Upper Ordovician strata is still unknown.

3. CONVENTIONAL RESOURCES

In 1858 the first commercial oil well in North America was completed by James Miller Williams on the site of an oil seep in the swamps near the hamlet of Oil Springs in southern Ontario. The larger Petrolia oil field was discovered soon after in 1862. The first commercial gas wells in Ontario were completed by Eugene Coste in Essex County and in the Niagara Peninsula, both in 1889 (Carter et al, 2016a). Today oil is still produced from the Oil Springs and Petrolia shallow Devonian fields, but most of the current oil and gas production in Ontario is from deeper Silurian and Ordovician pools discovered more recently. The crude oils produced from different stratigraphic intervals appear to be genetically distinct and originated from different source rocks (Powell at al., 1984; Obermajer et al., 1998). There are currently 1200 producing oil wells and 1200 producing gas wells in southern Ontario. Gas is also produced from 550 “private gas wells” for non-commercial use by land-owners.

There have been four quantitative assessments of conventional oil and gas potential in Ontario: Bailey Geological Services Ltd. and Cochrane, R.O. (1984a, 1984b, 1985, 1986, 1990); Osadetz et al. (1996); Golder Associates (2005); and the Canadian Gas Potential Committee (2006). Based on these assessments, remaining hydrocarbons to be produced or still undiscovered in southern Ontario at the end of 2014 was estimated to be 190 million barrels of oil (MMBO) (81% beneath the Great Lakes) and 1.45 trillion cubic feet of natural gas (TCFG) (62% beneath the Great Lakes) (Carter et al, 2016b).

Provisional quantitative estimates of potential oil and gas resources in Ontario were included in regional studies of resources in all of Canada by Hutt et al. (1973) and Proctor et al. (1983). No rigorous analysis of individual pools or plays was attempted in Ontario as no commercially significant discoveries of oil or natural gas had been made in any other part of Ontario by that time.

4. GEOLOGICAL BACKGROUND

Southern Ontario is underlain by a relatively thin succession of largely undeformed, marine sedimentary rocks ranging in age from late Cambrian to late Devonian. These Paleozoic strata are comprised of an interlayered succession of sandstone, siltstone, shale, evaporites and carbonates, deposited and preserved in two major sedimentary basins, the Appalachian Basin to the southeast and the Michigan Basin to the west. A maximum thickness of approximately 1400 metres of sedimentary rocks are preserved in the Chatham Sag, thinning northeasterly into the subcrop belt and pinching out at the edge of the Canadian Shield (Figures 1 and 2), with the entire study area lying within the Michigan Basin. The Paleozoic formations are deposited unconformably on the Precambrian basement complex of deformed igneous and metamorphic rocks which are the buried equivalents of the Canadian Shield rocks exposed to the northeast (Armstrong and Carter, 2010).

Structural ridges known as the Algonquin Arch and the Findlay Arch trend southwesterly along the length of southern Ontario. Regional dips along the crest of the arches average 3-6 m/km into the Chatham Sag and 3.5 to 12 m/km into the Michigan and the Appalachian basins, respectively. The arches and basins are the result of several episodes of uplift and subsidence in response to regional tectonic events. Strata thin, pinch-out and exhibit changes of the sedimentary facies over the crests of the arches.

The Paleozoic bedrock formations form northwest to southeast-trending belts of subcrop and local outcrop beneath a thin veneer of unconsolidated sediments of largely glacial origin. The sediments average a few tens of metres in thickness in most of southern Ontario, reaching a maximum of 200 metres. The contact between the sediments and the bedrock is an angular unconformity representing an extended period of exposure and erosion of the bedrock, with localized karst development on subcropping carbonate and evaporite strata.

Regionally, siliciclastic units are thickest and coarsest in the Appalachian Basin, thinning to the northwest away from highland source areas to the southeast, and pinching out on the crest of the Algonquin Arch. The Michigan Basin is dominated by carbonate strata, including reefal and non-reefal facies, with thick beds of halite and anhydrite preserved in the Upper Silurian Salina Group. Silurian reefs form important traps for conventional accumulations of oil and natural gas. There has been selective post-depositional dissolution of halite beds over millions of years near faults, over reefs and on the up-dip margins of the salt layers. Subsequent collapse of overlying strata over dissolution cavities has resulted in subsidence, fracturing and brecciation of overlying strata, or thickening, depending on the timing of salt dissolution in relation to deposition of overlying strata. This has major implications for trapping of hydrocarbons and for groundwater movement.

Several studies (Obermajer, et al., 1999, 2005; Béland Otis, 2015a) suggest that the Upper Ordovician shale units - the Collingwood Member of the Lindsay Formation and the Rouge River Member of the Blue Mountain Formation, contain sufficient oil-prone organic matter (predominantly Type II kerogen of marine origin) to be considered as potential petroleum source rocks in southern Ontario. Although stratigraphically the Collingwood Member is in direct contact with the Rouge River Member, geological and geochemical characteristics of the two units suggest they were formed in different depositional environments. The Collingwood Member of the Cobourg/Lindsay Formation is described as black, organic-rich and very shaly limestone (Armstrong and Carter, 2010). The deposition of the Collingwood Member occurred at the peak of a marine transgression prior to the deposition of the overlying Ordovician clastic shales (Melchin et al*.,* 1994), forming the youngest foreland shelf unit of the Trenton – Black River carbonate platform. Sedimentation occurred in a largely anoxic environment, controlled by rapid tectonic foundering of the foreland shelf (Hamblin, 2006), which resulted in the accumulation of calcareous mudstone with abundant bioclastic-rich layers at the base of the unit, rapidly grading upward into unfossiliferous black shale.

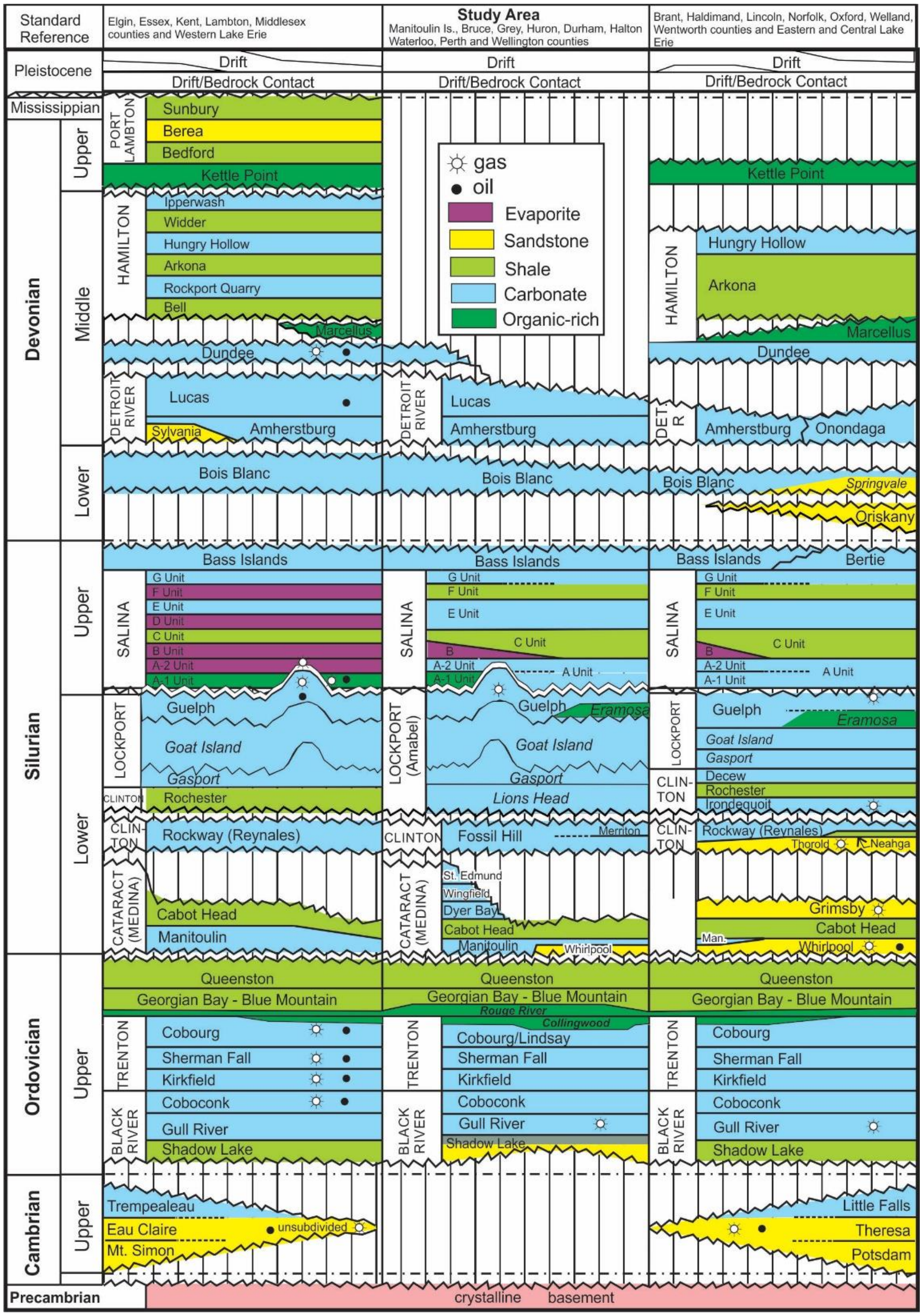

Figure 2: Lithostratigraphy of the study area, showing organic-rich shales and shaly limestones and principal intervals of (conventional) oil and gas resources. Modified from Armstrong and Carter (2010).

The Rouge River Member is the lower member of the Blue Mountain Formation that gradationally overlies the Collingwood Member of the Cobourg/Lindsay Formation, or sharply overlies the lower member of the Lindsay unit where the Collingwood unit is absent (Figure 2) (Armstrong and Carter, 2010). The overlying Blue Mountain Formation is a distinctly noncalcareous and clay-dominated shale sequence, deposited in an open deep shelf environment resulting from westward inundation of marine clastic sediments associated with the initial phase of the Taconic Orogeny. The formation thins northwestward over the Algonquin Arch and further west into the Michigan Basin. Only the lower part of the Blue Mountain Formation - the Rouge River Member - contains elevated amounts of organic matter and can be qualified as a petroleum source rock while the upper part is an organic-lean shale unit.

The present-day maximum burial depth of the Upper Ordovician Collingwood and Rouge River strata is only slightly greater than 1100 metres (in the Chatham Sag south of the study area), although extensive erosion is inferred to have occurred during their geological history (Legall, et al., 1981; Coniglio and Williams-Jones, 1992). Figure 3 illustrates the present day burial depth to the base of Collingwood Member constructed from well log interpretations of subsurface data (Béland Otis, 2015b).

4.1 BURIAL DEPTH

As these strata have only been subjected to moderate thermal maturation (early mature to "oil window") and are found at shallow depths (<1000 m) at present (Figure 2), suitable hydrocarbon generation kinetic models are essential for hydrocarbon resource estimation and basin thermal history reconstruction.

Geographically, the Collingwood Member is thickest in the north-central part of southern Ontario and within the study area and it thins to the north, south and east, with a gradual transition from calcareous shale to carbonate in these directions. In contrast, the Rouge River Member thickens southwards indicating greater sedimentation rates in the Appalachian Basin (Figure 4).

Fission-track ages, vitrinite reflectance and conodont alteration indices from the Michigan Basin suggested that maximum burial in the basin occurred during Late Carboniferous to Early Permian (Wang et al., 1994; Coniglio et al., 1992; Legall, et al., 1981), and the inferred additional burial depth varies from less than 1 km in the basin center to more than 2 km near the adjacent arches (Wang et al., 1994).

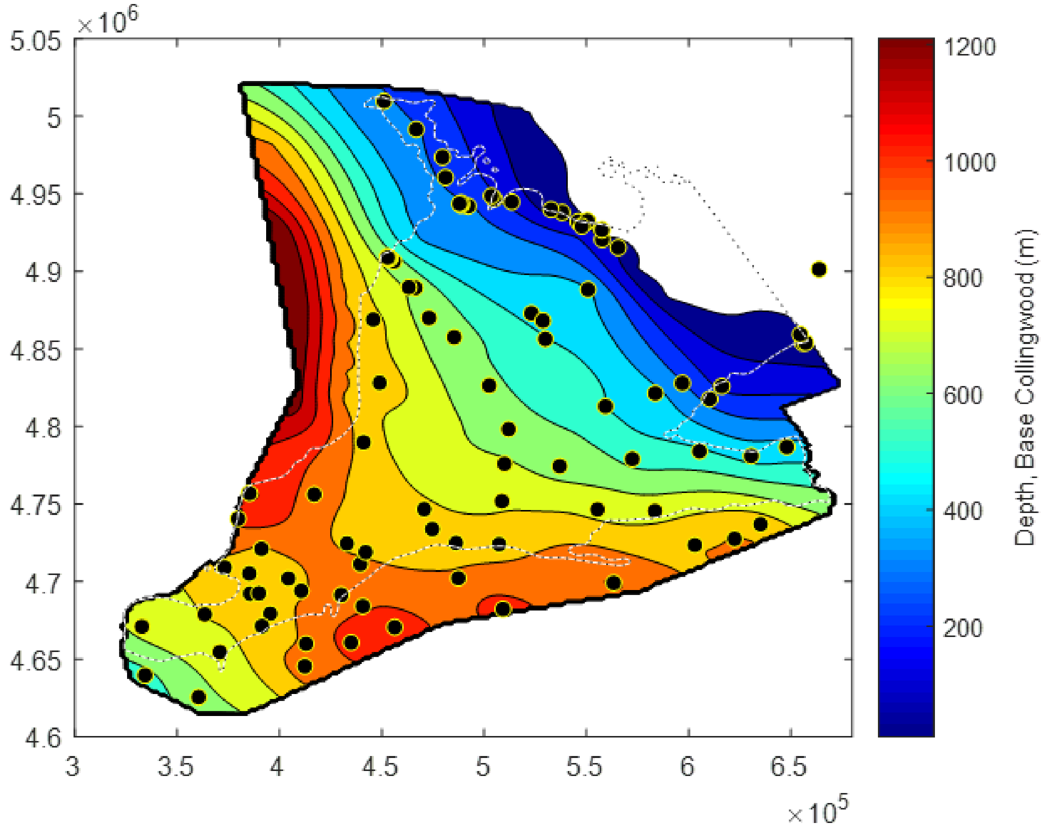

Figure 3: Present day burial depth to the base of the Collingwood Member. Data source: MRD 326 Metadata (Béland Otis, 2015b).

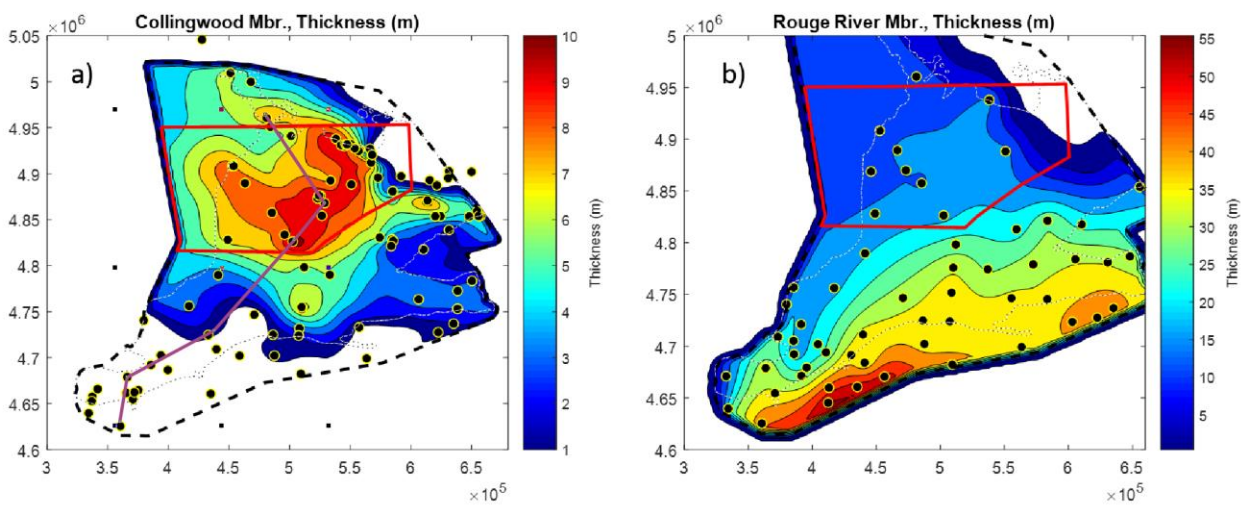

Figure 4: Isopachs of the Upper Ordovician shale units (Collingwood and Rouge River members) showing geographic variations in thickness of the shale units in a relation to the study area (red polygon). Thick dashed black line indicates mapping boundary (also international Canada/USA border in the south and west) and thin grey dotted line indicates the shorelines of southern Ontario. Purple thick line shows the location of the cross section in Fig. 5.

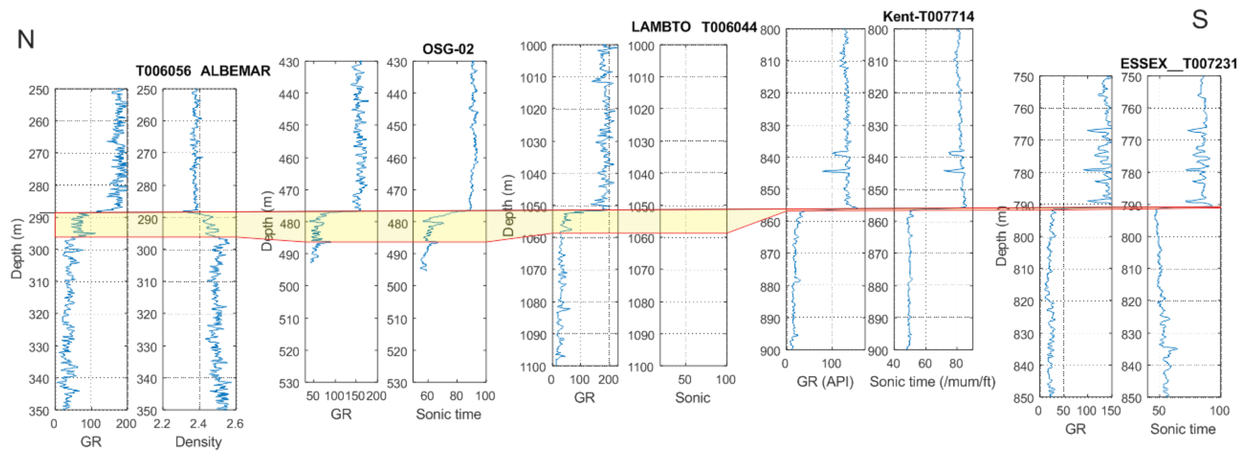

Figure 5: Cross-section showing the picked tops and bases of the Collingwood Member across the study area. See Fig. 4a for location of the cross-section.

4.2 DATA AVAILABLE FOR THIS STUDY

The petroleum resource assessment of fine-grained shale formations is based on a regional geological understanding derived from organic geochemistry data and reservoir characteristics taken from limited laboratory tests and applied to a regional stratigraphic framework. The data are partly compiled from publicly available sources, but also include data from the Geological Survey of Canada unpublished in-house databases and internal technical reports.

4.3 STRATIGRAPHIC DATA

The stratigraphic framework is based on the Armstrong and Carter (2010) technical report. The thicknesses for the Collingwood Member are based on a compilation and revision of formation top data from Armstrong and Carter (2010), Churcher et al. (1991), and Beland-Otis (2015b), supplemented with new formation top interpretations made by Carter Geologic using geophysical well logs, drill core and drill cuttings stored at the Oil, Gas and Salt Resource Library (OGSR Library, London, Ontario). The revised formation thicknesses for the Collingwood Member are listed in Appendix A. The thicknesses for the Rouge River Member are from original MRD 326 Metadata (Béland Otis, 2015b) with additional data points from DGR wells at the Bruce nuclear site available in a technical report TR-11-06 (Sterling, 2011).

4.4 GEOCHEMICAL DATA

The primary organic geochemical dataset utilized in the study are results of Rock-Eval pyrolysis from a Geological Survey of Canada corporate database, consisting of all archival records of analyses performed in the geochemistry laboratory of the Geological Survey of Canada in Calgary (GSC-C) using Rock-Eval 6 instrument. The analyzed samples included well cores and cuttings collected during several internal studies and cost-recovery services for non-GSC customers during the 2005-2015 period. A complete set of all derivative parameters, such as TOC, S1, S2, HI, Tmax and MinC, as well as the original hydrocarbon pyrogram data from the experiments are available and have been used. There are 104 samples in the dataset, providing good spatial coverage of southern Ontario. The primary outputs derived from this dataset are three-fold: a) estimates of the generation potential from the Collingwood and the Rouge River members, b) establishment of thermal maturity models for the two units and c) calculation of organic porosity for the two units for resource estimation.

4.5 WELL LOGS AND RESERVOIR PARAMETERS

Geophysical well logs in LAS format from more than two hundred wells were collected from the petroleum well database maintained by the OGSR Library in London, Ontario. These old oil exploration and production wells are geographically distributed in the southernmost part of southern Ontario's major oil & gas producing region and contain only basic logs, such as gamma ray, density and sonic logs. Among the wells, only two have resistivity logs. In addition to old industry wells, a LAS file for the OSG11-02 well was collected from MRD 326 Metadata (Béland Otis, 2015b) and LAS files from DGR 3 and 4 wells (e.g. Geofirma, 2011) were also made available for this study. Well log curves in LAS format of 20 wells in the study area and close vicinities were purchased from OGSR library to ensure more representative spatial coverage. Laboratory test results of shale reservoir porosity, water saturation and gas adsorption properties are collected from Béland-Otis (2015b) and well history reports of the DGR wells (Jackson, 2009).

4.6 CONVENTIONAL OIL AND GAS DISCOVERIES

The data for oil and gas resource assessment in conventional reservoirs consist of a list of discovered oil and gas pools, their pool size and discovery date, the areal extents of the Paleozoic potential reservoirs for established oil and gas plays (play boundaries) and the discovery sequence of oil and gas pools in each petroleum play. A discovery sequence is a time series of pool sizes according to their order of discovery in a play.

An exploration play is defined as a family of pools or prospects that share a common history of hydrocarbon generation, migration, reservoir development and trap configuration. These pools and prospects form a single population that is limited to a specific area. Usually, a play is defined by common reservoir type, source rock system and trapping mechanism. For this study, only established plays (i.e. the plays that have been verified by at least one commercial petroleum accumulation) were examined.

The play boundaries and discovery sequences in each play were compiled from data provided by the OGSR Library. For each of the plays, the details of the play boundary and the discovery sequence in the form of creaming curve are discussed in Section 5.2 of this report.

5. METHODS

Occurrence and storage characteristics of oil and gas resources in a fine-grained shale reservoir system differ significantly from those in conventional reservoirs. Lamination and alternation in lithology both vertically and laterally (source rock heterogeneity at a micro-scale) are common and unique features in shale, making co-occurrence of hydrocarbon generation, storage and entrapment possible to scales of hand specimen size. An unconventional resource play is a self-sourced and self-retained oil and gas system that requires no trap mechanism or top seal (Engelder, 2011). Thus, methods for assessing oil and gas resource in a fine-grained shale unit must consider these unique features of a shale reservoir. Therefore, the methods for assessing unconventional and conventional resource are discussed separately in the following sections.

5.1 ASSESSMENT METHODS FOR HYDROCARBON RESOURCE IN FINE-GRAINED SHALE RESERVOIRS

The method used for estimating petroleum resource potential in fine-grained shale reservoirs utilizes a reservoir volumetric approach combined with a dual-porosity model that quantifies the reservoir storage capacity for oil and gas. The method is suitable for self-sourced resource plays where both, matrix porosity and organic porosity, provide effective storage. The assessment method consists of the following components: a) geological and reservoir risk evaluations, b) reservoir volumetric calculations of hydrocarbon pore space and subsequently oil and gas in-place and c) technically recoverable resource calculations.

The geological risk evaluation examines the adequacy of geological conditions that lead to meaningful oil and gas accumulation in a shale unit, which are defined by geological variables or their proxies. Regardless of the economic significance, the reservoir risk examines the basic conditions for establishment of technically recoverable resource which represents resources that can be at least partially extracted using currently available techniques. The reservoir risk is determined by various reservoir parameters. The two risk evaluations are also based on analogues of producing shale oil and gas plays in North America. The geological risk evaluation is equivalent to finding a site or area where all geological requirements are satisfied and adequate, which defines the shale resource play area; while the reservoir risk evaluation is equivalent to applying an economic and technological cut-off of reservoir criteria to further eliminate part of the areal extent of the shale resource play to delineate the so-called ‘sweet spots’ containing technically recoverable oil and gas resources.

Figure 6a illustrates the different components that have been incorporated to derive the volumetric equations for the calculation of oil and gas volumes in shale reservoirs. The dual-porosity model takes into account three different storage mechanisms (Figure 6a) in a self-sourced shale reservoir system: a) matrix pores (including natural fracture) with free hydrocarbons as well as free and bound water; b) organic pores with free hydrocarbons; and c) organic pores with adsorbed hydrocarbons. This method has been applied to estimate shale gas and oil resources in stratigraphically equivalent Upper Ordovician Utica Shale and Macasty Formation in Quebec (Chen et al., 2016; 2017)

The organic porosity created by hydrocarbon generation from organic matter is a function of the abundance of organic matter, type of kerogen and level of thermal maturity of the source rock and can be estimated using organic geochemical data along with a thermal maturity model (Figure 6b). Chen and Jiang (2016) proposed methods for estimating organic porosity. Appendix B provides full details of the mathematical formulation for the method.

Well logs were used for calculation of matrix porosity and water saturation. All log models were calibrated by laboratory measurements prior to its use in the volumetric parameter evaluation. The calculation of hydrocarbon volume is based on individual exploration wells for which adequate well log data is available (Figure 6b). Oil and natural gas (free, associated and adsorbed gases) were assessed at each such well. A spatial geostatistical model (semivariograms) derived from the collected data was used to infer the spatial variation of resources and capture the uncertainty where data were extrapolated spatially. The uncertainties in spatial extrapolation and interpolation for each component (oil, associated and adsorbed gases) were expressed in variance maps.

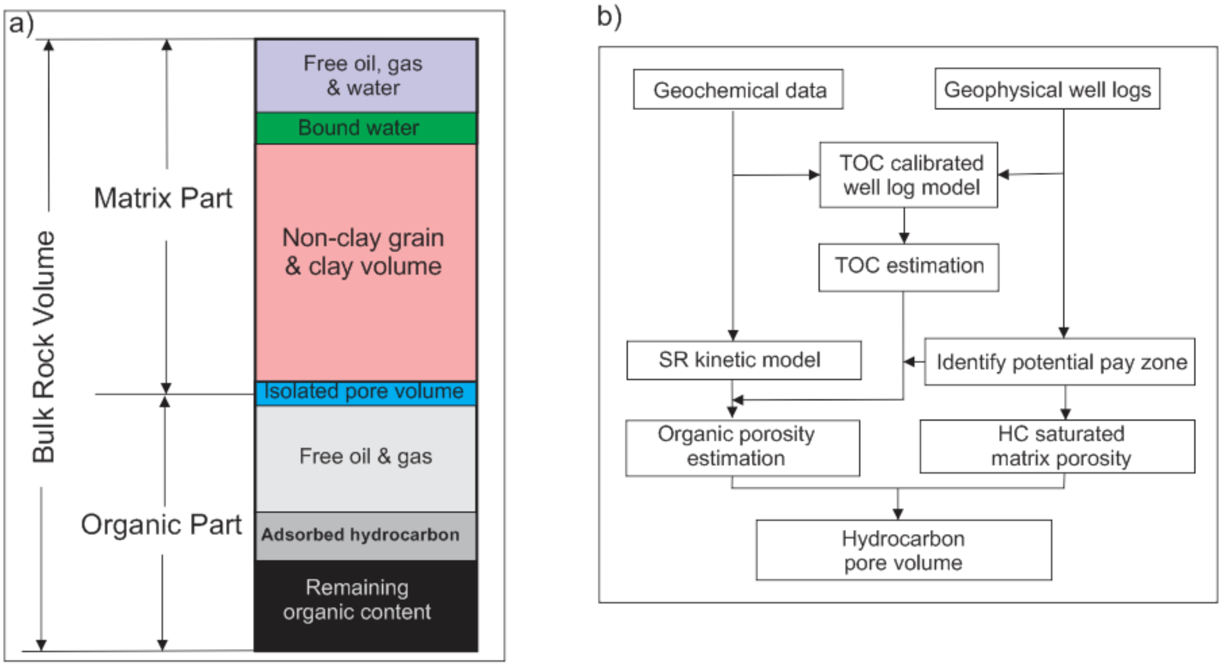

Figure 6: A petrophysical model of a self-sourced shale play where both matrix and organic porosities contribute to the storage of oil and gas. (a). The percentage of the various components forming the bulk of the rock volume is schematic and does not represent a specific case study. b) A work-flow chart showing the components and procedures in hydrocarbon pore volume evaluation using geochemical and well log data under the dual-porosity model. SR: Source Rock; HC: Hydrocarbon; TOC: Total Organic Carbon (wt%) (Figures from Chen et al., 2017).

Monte Carlo methods were employed to aggregate the hydrocarbon resources of each cell in the study area to form probabilistic distributions. The ranges of probabilistic distributions of oil and gas resources represent the uncertainties in the assessment. Appendix B provides mathematical details for estimating various portion of hydrocarbons. Details of the volumetric estimation of petroleum resource potentials in different forms (oil, dissolved and adsorbed gases) are also presented in Appendix B.

The determination of technically recoverable resources involves calculating the portion of oil and gas in-place that can be extracted by means of the current technology, regardless of economic conditions. The recovery factor for the shale oil was derived by an analogue from North American producing shale plays, summarized by the Energy Information Administration (EIA, 2013). A distribution, instead of a single value, was used to reflect the uncertainty for the recovery factor associated with the oil and gas resources in the Upper Ordovician shale units of Ontario.

5.2 ASSESSMENT METHODS FOR PETROLEUM RESOURCE IN CONVENTIONAL RESERVOIR

The discovery process model developed by the Geological Survey of Canada (GSC) was used to estimate the petroleum resource potential of conventional reservoirs for this study. The principles, mathematic formulation and application examples are available from Lee and Wang

(1985). The data on the oil or gas accumulations already discovered in the play and their order of discovery are treated as a statistical sample used by the discovery process model. In general, the discovery sequence shows a decline of pool size over time. This trend indicates that the exploration process produces a biased sample in a statistical sense; that is, larger pools are discovered relatively early in the exploration history of a petroleum play.

The biased sample causes a statistical problem because normal statistical procedure assumes a random sample. One must, therefore, create a statistical model which can handle biased samples in order to estimate the pool populations. The biased sample does contain information that can be extracted and used for estimating undiscovered resources.

The GSC discovery process model adopts the following statistical assumptions: 1) hydrocarbon discovery is modelled as sampling from statistical population without replacement and 2) the probability of discovering a petroleum pool is proportional to the magnitude of the specific pool raised a power to a coefficient β, called the exploration efficiency coefficient. The larger the exploration efficiency, the greater the impact pool size played on the order of discovery. These two assumptions are verified by observing discovery sequences from various plays in sedimentary basins around the world. Because of the biased nature of the sample contained in the discovery sequence, these sequences contain vital information for resource evaluation, i.e., the number of pools that might exist in a play and the corresponding pool size probability distribution. The mathematical treatment of this discovery sequence for inferring parameters for an unbiased parent population is called the discovery process model (Lee, 1993; Lee and Wang, 1985, 1986, 1990). These estimated parameters allow for a reconstruction of the parent population that is used to calculate the total resource and all individual pool sizes.

Depending on the assumption on the shape of the parent population of pool size, two types of discovery process model have been adopted in GSC's petroleum assessment program. One type assumes a lognormal distribution of the parent population while the other, called nonparametric, makes no assumption on the probability distribution of the pool sizes. In this study, both models were executed for each hydrocarbon play.

The discovery process models (lognormal and nonparametric) generate estimates of the mean, μ, variance, σ^2, and total number of pools, N, in the underlying pool population or play. After estimating the N value, various combinations of μ and σ^2 were tested to determine the best match to the pool size data. The 'best match' μ and σ^2 were then used to generate the pool size distribution of the play.

Both discovery process models contain an unknown variable, the exploration efficiency coefficient, β, which is estimated from the discovery sequence. The discovery process is proportional to the magnitude of the pool size, as well as other factors (e.g., commercial objectives, land availability, pool depth, and exploration techniques). The use of a single parameter, β, to account for all these factors may seem oversimplified. Nevertheless, the example presented by Lee and Singer (1994) demonstrates that a simple but logical approach can approximate reality, at least for the purposes of resource assessment.

The models also predict sizes of individual undiscovered pools. These pool sizes are represented in a graphical form by bars indicating the range of possible sizes from largest to smallest (see section 7). The pool-size-by-rank graph plots the individual pool size against the pool rank.

After the individual pool sizes have been estimated, discovered pool sizes are matched to these estimated size range intervals (dots in pool-size-by-rank plots). The sizes of the undiscovered pools are further constrained by the fact that their size ranges cannot exceed or be less than any discovered pools that are ranked greater or lesser than the unmatched pool (i.e., undiscovered pool sizes smaller than the smallest discovery are not plotted).

A play resource distribution can be estimated from the N value and the pool size distribution (either lognormal or nonparametric distribution) (Lee and Wang, 1983). Furthermore, a play potential distribution (see section 6) can be derived from the play resource distribution, given that the sum of all discoveries of the play is used as a condition.

The discovery process model of GSC is proven to be a cost effective method for established petroleum plays in maturely explored basins and has been applied to many established hydrocarbon plays in the Western Canada Sedimentary Basin (e.g., Barclay, et al., 1997; Bird et al., 1994a, 1994b; Hamblin and Lee,1997; Lee and Singer,1994; Olsen-Heise et al., 1995; Podruski et al., 1988; Reinson and Lee,1993; Reinson et al., 1993 and Warters et al., 1997) as well as in other maturely explored basins world-wide. The GSC lognormal discovery process model is similar in principle to the truncated lognormal discovery model (TDPM) by Logan (2005) that was used for assessing the petroleum resources in the same area by Golder Associates Ltd. (2005). The TDPM was developed by TC Energy Corporation (formally TransCanada Pipelines) as a support for the company strategic business decisions on natural gas pipelines. Three important differences exist between these two discovery models: a) although both assuming a lognormal size distribution, TDPM applies truncations to both sides in a lognormal distribution; b) GSC lognormal discovery model assumes a continuous distribution for the lognormal population (a super population) and pools in a play is a realization of natural process of the super population, while the TDPM uses a finite population; c) the GSC model uses a likelihood function for parameter estimation; in contrast, the TDPM employs a least square curve fitting methodology for parameter estimation. The advantages of using TDPM include: a) no limitation on inputting the number of pools and b) it uses Microsoft Excel as the operation platform. In contrast, the GSC discovery process model has a limitation on the number of pools (<1000 pools) for input and uses the DOS operating system. However, the GSC's discovery process model has several advantages over the TDPM including: a) rigorous mathematic algorithms for model parameter estimation; b) options on both lognormality or nonparametric for the pool sizes in case the discovered pools cannot be fitted into a lognormal distribution; c) the provision of rank by size data to facilitate an easy reality check.

To visualize play-level reserve growth and examine exploration efficiency, creaming curve analysis was used along with discovery process modeling. A creaming curve is a plot of cumulative reserves of every discovery versus the order of historical discoveries, which can reveal: a) the impact of pool size on the order of discovery; b) the maturity of a petroleum play; c) the future trend of discovery. Fitting the historical discoveries and extrapolating their pool size trend into the future provides a general picture of remaining potential and a cross-check for comparison with results from the discovery process model. The creaming curve analysis was proposed by Meisner and Demirmen (1981) and has been used by industry in conventional oil exploration (e.g., Snedden et al., 2003; Bohorquez, 2014).

5.3 OIL AND GAS RESOURCES IN SELF-SOURCED FINE-GRAINED SHALE RESERVOIRS

Although organic-rich shales have been traditionally regarded as the hydrocarbon source rock in a conventional petroleum system (Tissot and Welte, 1984), some of these rock intervals are now considered to be a self-sourced and self-retained economically viable reservoir from which hydrocarbons are or can be produced by means of long range horizontal drilling coupled with multi-stage, high volume hydraulic fracturing.

Abundance/thickness, type of organic matter and level of thermal maturity of the organic-rich shale are the three major factors controlling petroleum resource potential in the self-sourced and self-retained reservoirs of the Upper Ordovician source rock units of southern Ontario. Organic geochemical data were analysed and mapped to study general characteristics and spatial variations within these rocks prior to assessment of their resource potential in the study area in southern Ontario.

5.4 GENERAL GEOCHEMICAL CHARACTERISTICS OF THE UPPER ORDOVICIAN SHALE UNITS

Rock-Eval pyrolysis has been widely accepted by the petroleum industry as a useful tool for efficient and cost-effective generation of analytical data applicable to source rock evaluation and shale oil/gas resource appraisal (Peters, 1986; Jarvie, 2012a, 2017b; Modica and Lapierre, 2012; Chen and Jiang, 2016; Chen et al., 2016a, 2016b, 2017a, 2017b, 2017c). Preliminary data analysis of available Rock-Eval samples indicates that the total organic carbon (TOC) content in Upper Ordovician shales of southern Ontario vary from less than 1% to more than 12% (Figure 7a). The remaining hydrocarbon generation potential is indicated by hydrogen index (HI) values that range from less than 200 to close to 700 mg HC/g TOC (Figure 7c), showing variable generation potentials. The bitumen equivalent index S1/TOCx100 (Espitalié et al., 1987) or the oil saturation index (Jarvie, 2012b) is less than 100 mg HC/g TOC (Figure 7a) suggesting that there is not much free hydrocarbons present in the samples. Tmax values from most analysed samples are lower than 440°C with their production indices less than 0.1, indicating that the Upper Ordovician source rocks are marginally mature and in the early “oil window”. The interpretation of Rock-Eval data is consistent with the results derived from molecular organic geochemical data reported by Obermajer et al. (1999).

Another remarkable feature of this dataset is the large variation in MinC value (Figure 7d), an indicator of carbonate mineral content in source rock from Rock-Eval 6 analysis (Behar, 2001; Pillot et al., 2014), ranging from less than 1% to close to 12 %. A study by Jiang et al. (2017) suggests 1.0% MinC is equivalent to about 8.0% of carbonate minerals in the sample, which means that the sample carbonate mineral contents in the dataset could vary from less than 10% to about 96%. The transition of the paleo-depositional setting from a dominant carbonate platform to an open marine clastic environment during the Late Ordovician supports this sharp contrast in carbonate mineral composition.

Rock-Eval data analysis suggests that the organic matter in the two shale units differ considerably in hydrocarbon generation potential and thermal decomposition behaviour. The Collingwood Member strata are organic-rich calcareous shales with TOC values up to 12% (mean of 4.15%), a higher hydrocarbon generation potential (an average HI of 541) and restored initial HI of up to 700 mg HC/g TOC (Figures 7a and c), suggesting Type II kerogen as the dominant organic component in this source rock. This unit has an average MinC value of 7.3%. If Jiang et al. (2017) factor of 8.0 is applied to MinC, the average carbonate content in the Collingwood Member is 58.4%. In contrast, the Rouge River shale unit shows average present day TOC of about 1.6% and HI of 325 mg HC/g TOC (Figures 7a and 7c). Although these data also suggest a marine Type II kerogen source rock, the average MinC is only 1.2%, which is equivalent to about 10% of carbonate minerals in the samples. The Rouge River Member is described as an argillaceous shale deposited in an open marine system.

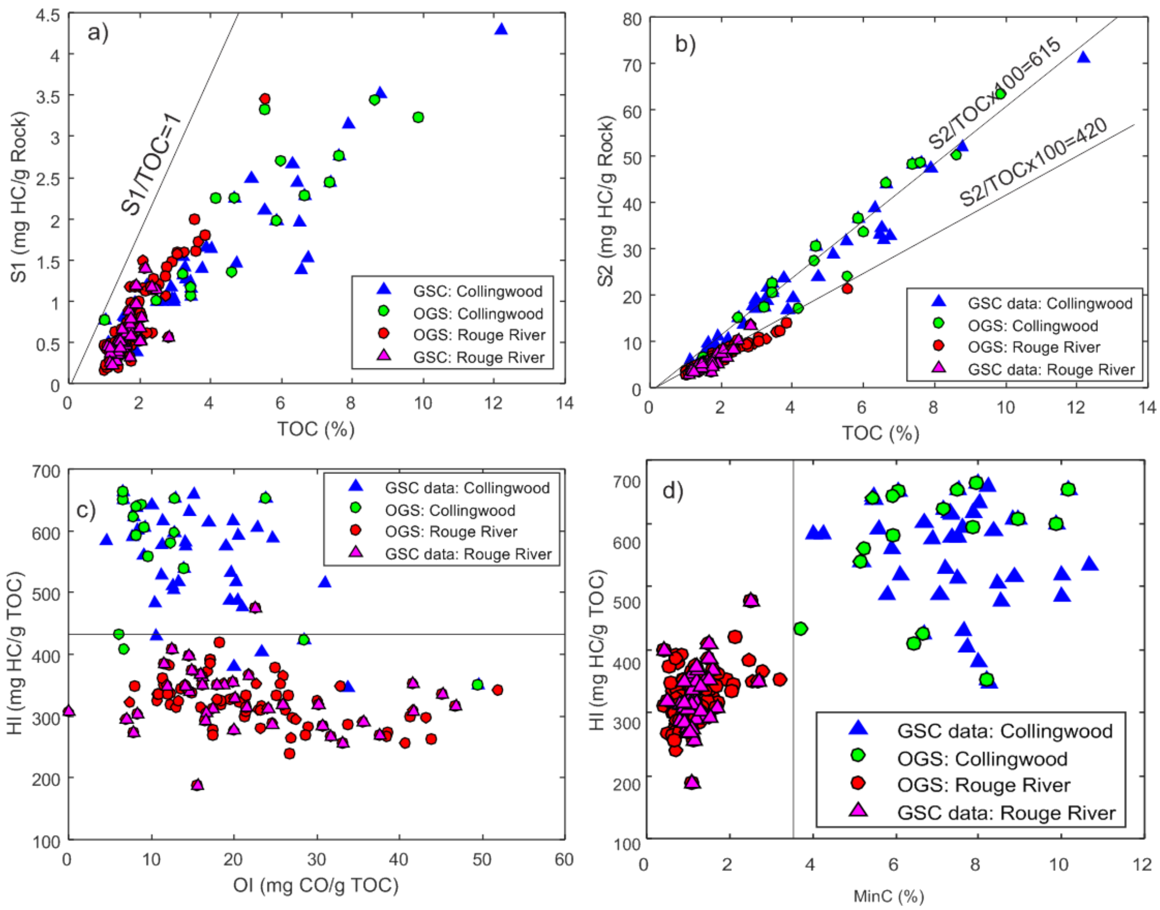

Figure 7: General characteristics of organic geochemistry of the Collingwood and the Rouge River shale units in southern Ontario.

5.4.1 Source rock maturity

A technique of kinetics forward modeling (Chen et al. 2017a, 2017b) was employed to calculate Tmax-HI synthetic data pairs from the hydrocarbon pyrograms to constrain the thermal degradation path for high maturity regimes. Figure 8 shows the constructed thermal decomposition trajectories and estimated transformation ratios for the two source rock units. The models suggest that these two source rock units have entered “oil window” as indicated by maximum transformation ratios up to 0.7 and 0.4 for the Collingwood and the Rouge River shales, respectively. These models are consistent with the findings of source rock maturity from molecular geochemistry data analyses by Obermajer et al. (1999), supported by bulk geochemical data (Figure 9, S1/TOC vs depth) and the observed oil stains from fresh core in a recently completed shale and groundwater research well (Figure 9). At depth below 450 meters, free hydrocarbons indicated by S1 values display rapid increases with depth, suggesting the occurrence of onset of hydrocarbon generation in the two shale units. This is coincident with the occurrence of oil stains in the Collingwood Member at the depth of about 478 meters in the OGS-SG11-02 well (Béland Otis, 2015b). Studies (Wang et al., 1994; Coniglio et al., 1992; Legall, et al., 1981) suggesting the maximum burial during the Late Carboniferous to Early Permian in Michigan Basin and inferred additional burial depths varying from less than 1 km in the basin center to more than 2 km near the adjacent arches could explain the thermal maturity of corresponding to early “oil window” in these Ordovician shales.

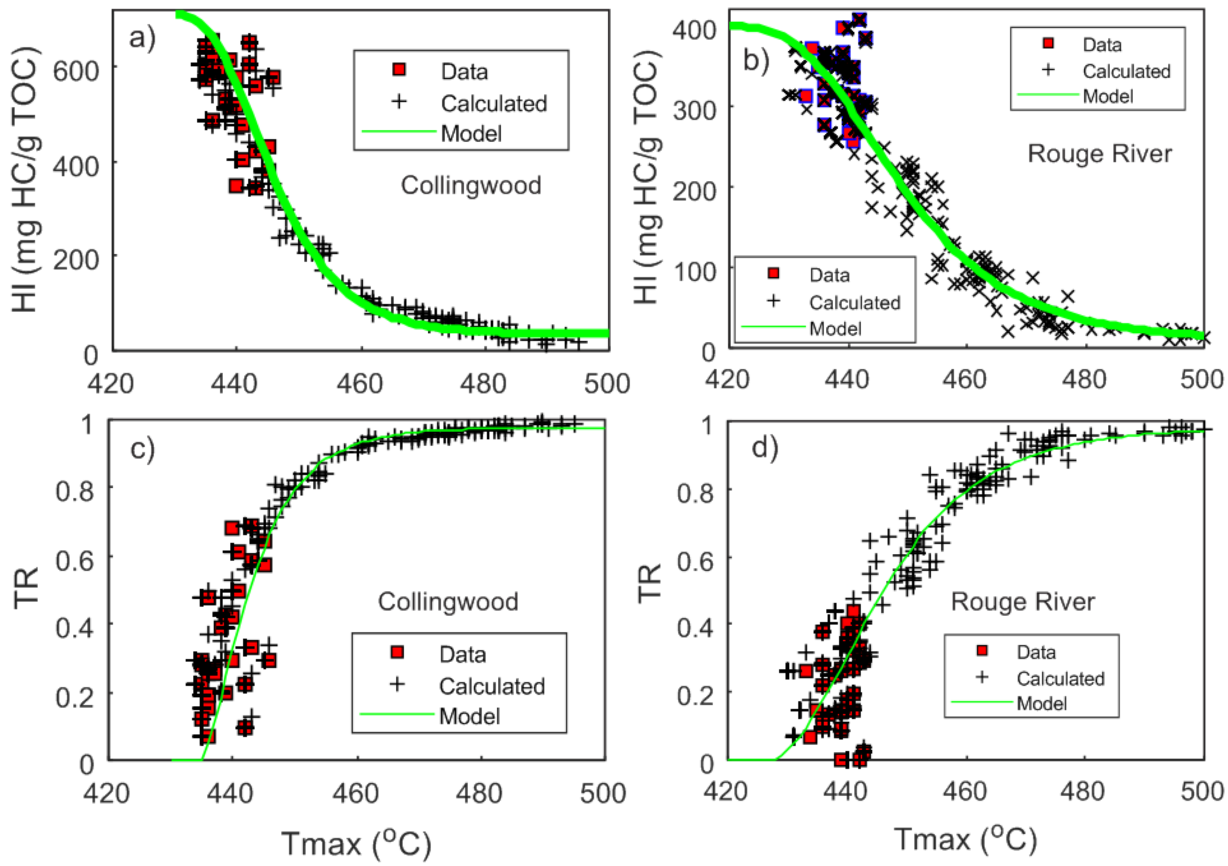

Figure 8. **Diagrams showing empirical models for thermal decomposition trajectories (a & b) and transformation ratios (c & d) for the Collingwood and the Rouge River members.**

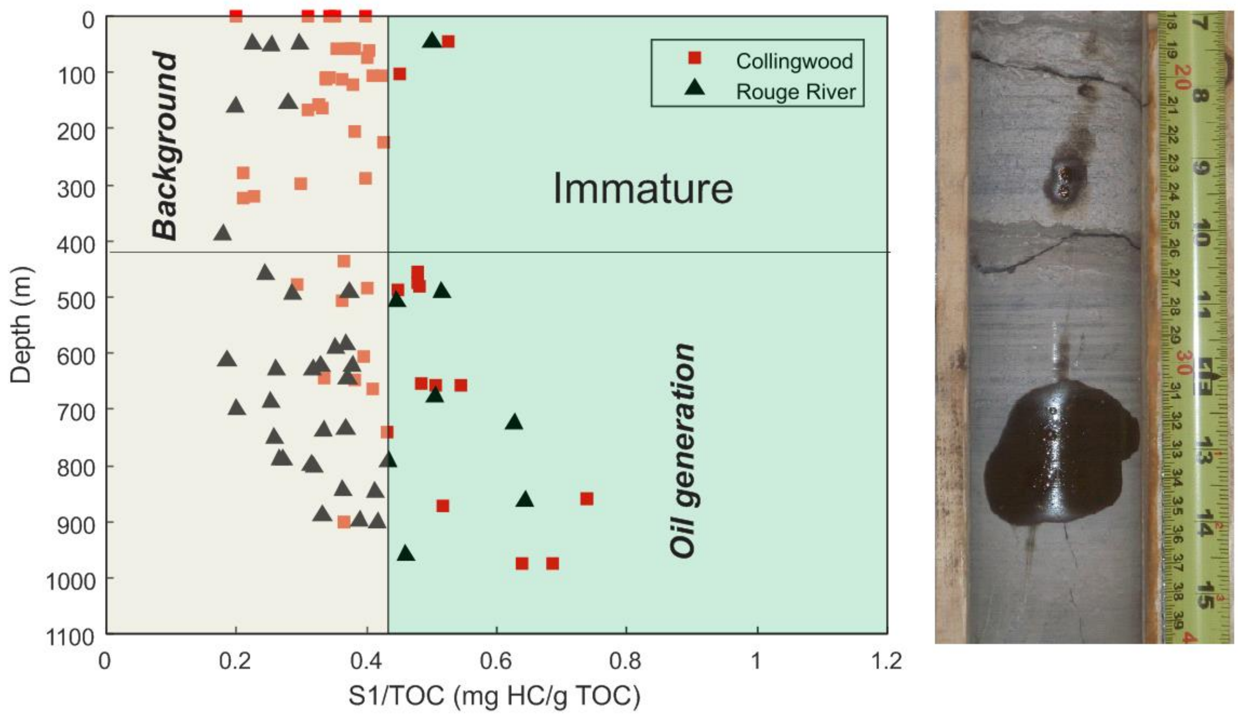

Figure 9: Geochemical data (left) and oil stain (right) suggesting the Collingwood and the Rouge River members are within the oil generation window. Core photo: around 478.8m, Collingwood Member, OGS-SG11-02 well (Photo from Béland Otis, 2015, OGS OFR 6312).

Except for a few outliers, Tmax measurements in the Collingwood Member display a general increasing trend with greater depth (Figure 10a), suggesting that present burial depth can be used as a proxy for mapping thermal maturity for the two source rock units. Thermal maturity varies greatly across the study area depending on burial depth (Figure 10b). Spatial variation of the maturity is depth-converted employing the generalized relationship between present day burial depth and Tmax and is shown in Figure 10. The data scatter in Figure 10a is related to variations in kerogen composition, exogenous hydrocarbon contaminations (Li et al. 2018; Snowdon, 1995) and laboratory random errors. Chen et al. (2017) demonstrated that the standard deviation of Tmax for the GSC Calgary laboratory standard sample 9702 is 1°C, which means that there is 99% chance that the variation of Tmax from the standard sample 9702 can be up to 4°C. Figure 10b is a thermal maturity map of depth-converted Tmax variation within the Collingwood strata across southern Ontario.

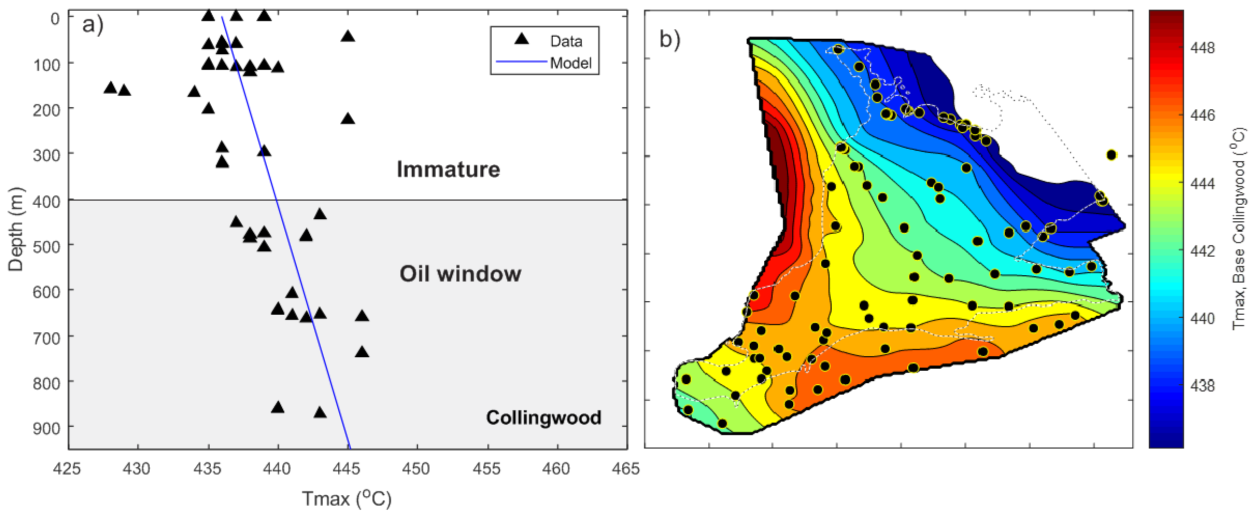

Figure 10: A cross-plot of Tmax and present day burial depth showing a general trend of thermal maturity with depth for the Collingwood Member (a) and a depth converted Tmax map (b).

5.4.2 Abundance of Organic Matter

Although spatial coverage of the samples analyzed using Rock-Eval 6 instrument is fairly widespread (Figures 3 and 10b), vertical sample representation for characteristics of the organic matter within the two organic-rich shale units is poor as many wells contain only one sample from each of the two units. Thus, geophysical well log data were used to estimate TOC (total organic carbon) content to capture the vertical variation of organic matter within individual shale units where data was available. There are several determining factors affecting this model for TOC prediction using well logs. A major factor is that the majority of the exploration and production wells in the study area do not have resistivity logs. Thus, the ΔlogR method by Passey et al. (1995) to determine TOC cannot be applied. In addition, the two shales have their own distinct lithology and show contrasting petrophysical properties; therefore using a single model for the two shales seems inappropriate.

Available data show a fair to good correlation between the total organic carbon (TOC) content and common log curves in the two shale units (Figures 11 and 12). However, the intrinsic geological controls on organic matter in the two shale members are quite different as shown by the cross-plots of geophysical log curves and measured TOC. The gamma ray (GR) shows a positive correlation with TOC for the Collingwood Member, while a negative correlation between the two variables is evident for the Rouge River Member (Figures 11 and 12). Also, the TOC and two porosity logs (density and sonic transit time) show opposite trends in the two shales, indicating different geological controls on the organic matter enrichment processes, consistent with the regional geological settings and organic geochemical data. Thus, with respect to TOC prediction using well logs, two separate models were developed. Figure 13 shows the empirical models for calculating TOC using well logs. Correlation coefficients between measured Rock-Eval TOC results and predicted TOCs from well logs in both shale units are high, indicating both models are valid. Because most log curves are correlated, a linear combination of multiple well log curves increases the correlation coefficient only marginally.

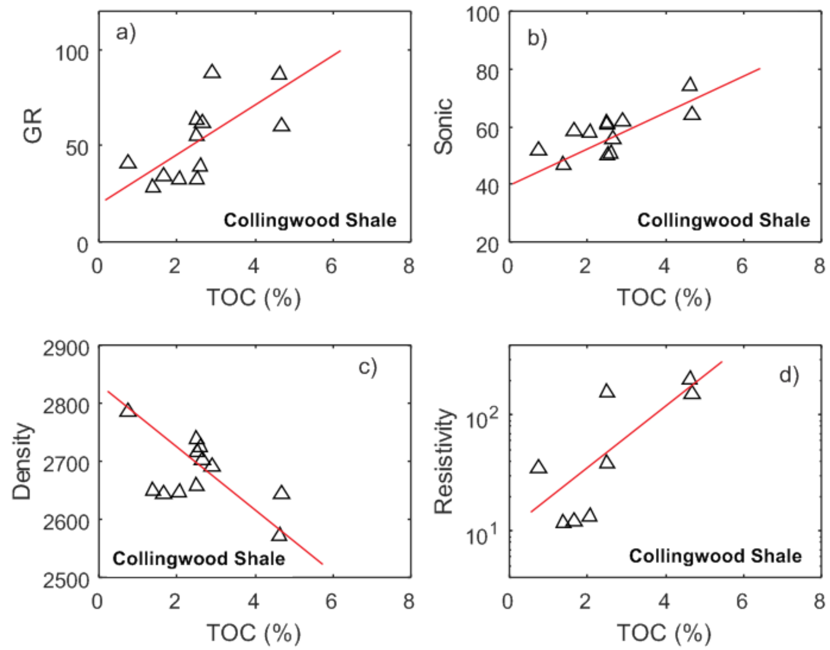

Figure 11: Cross-plots demonstrating the correlations between TOC and various well log curves in the Collingwood Member. (a) TOC vs. gamma ray; (b) TOC vs. sonic transient time; (c) TOC vs bulk density; and (d) TOC vs. resistivity.

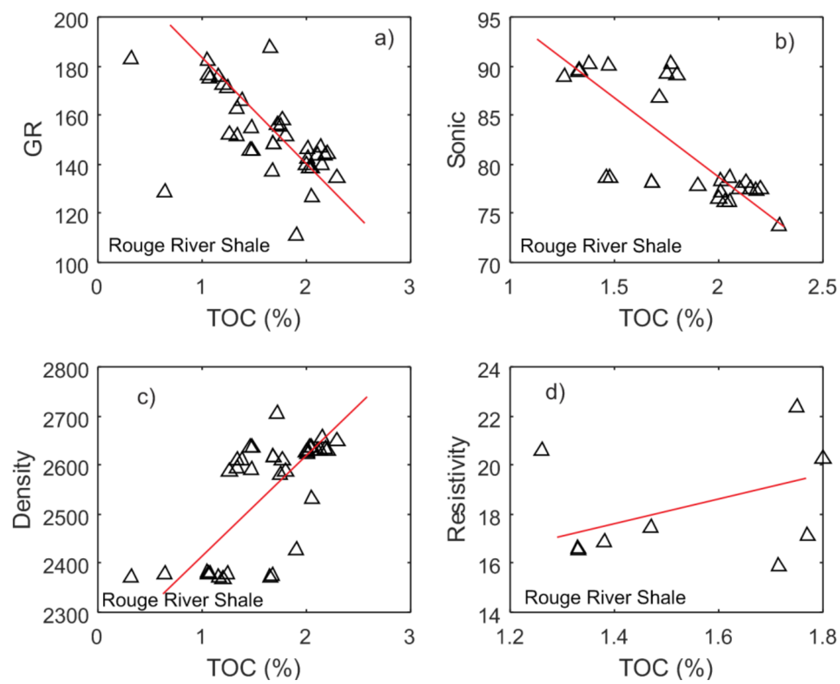

Figure 12: Cross-plots demonstrating the correlations between TOC and various well log curves in the Rouge River Member. (a) TOC vs. gamma ray; (b) TOC vs. sonic transient time; (c) TOC vs bulk density; and (d) TOC vs. resistivity.

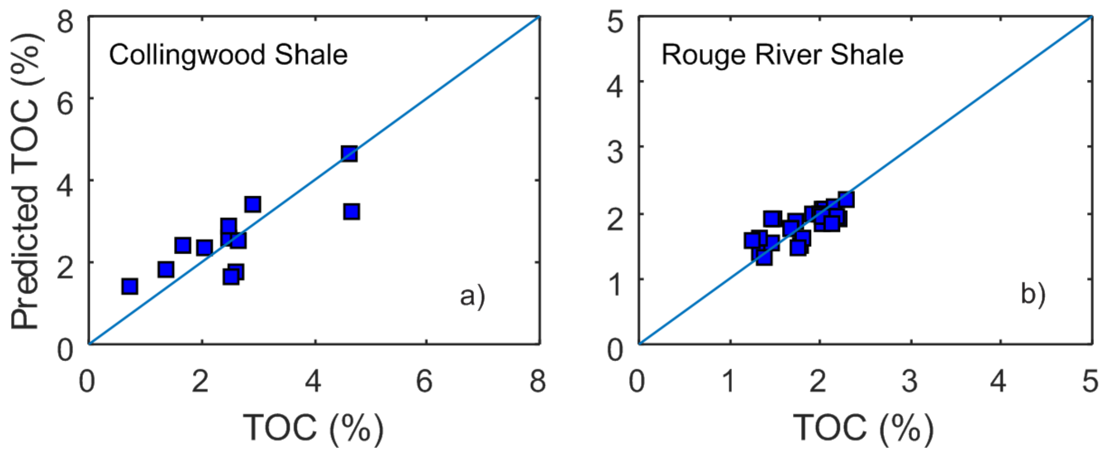

Figure 13: Comparison of observed Rock-Eval TOC data and predicted TOC values from well logs for the Collingwood and the Rouge River members. a) the Collingwood shale with a correlation coefficient of 0.80; and b) the Rouge River shale with a correlation coefficient of 0.75.

The mean TOC values estimated from wells with log data were calculated using established empirical relationships as conditional data for present day TOC mapping. The measured TOC and estimated mean values of TOC from logs were then contoured to represent the spatial variation of the quality of present day organic matter in the two Upper Ordovician shale units. Figure 14 shows the contoured organic richness (TOC) for the two organic-rich shale units in the study area. Similar to the isopach maps of the two units, the TOC contents in the two shale units exhibit distinctly different spatial patterns. The most organic-rich strata of the Collingwood Member are limited to the northwest of the Algonquin Arch in the Michigan Basin, while the most organic-rich part of the Rouge River shale unit occurs southeast of the Algonquin Arch in the Appalachian Basin, demonstrating widely different regional geological controls on the distribution, thickness and TOC contents of the two shale units.

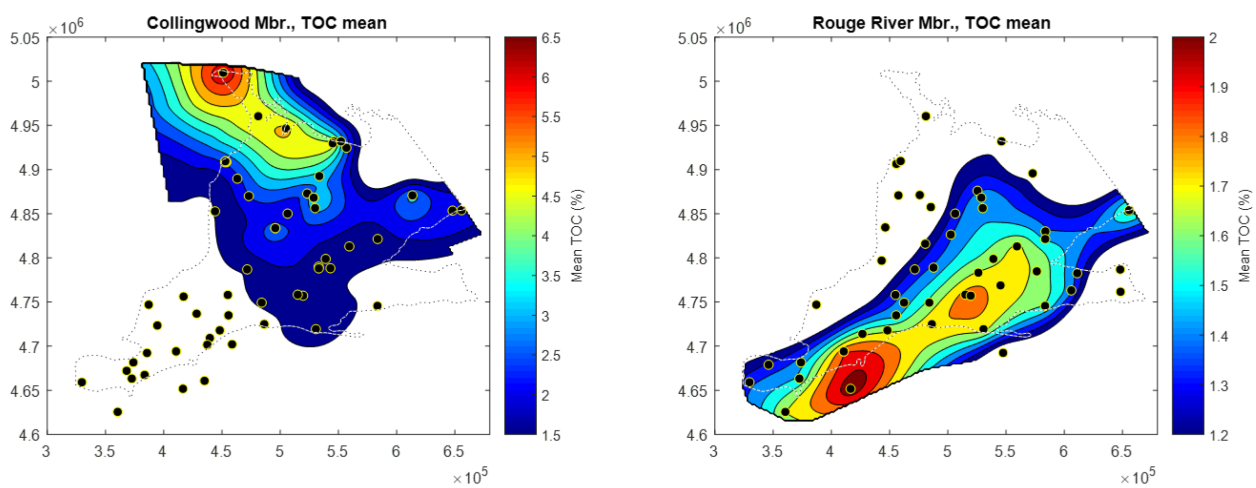

Figure 14: Maps showing the spatial variation of present day TOC for the Collingwood Member (a) and the Rouge River Member (b).

5.5 RESERVOIR PARAMETERS

Figure 15 depicts a plot of laboratory test results showing the relationship between porosity and water saturation in the two shale units in southern Ontario. Samples can be subdivided into two clusters that behave differently. The low porosity group (on the left) appears to be self-sourced with a negative correlation between water saturation and effective porosity, a characteristic of a self-sourced system (Jarvie, 2012a; Chen et al., 2017c) while the other group shows a trend of increasing hydrocarbon saturation with porosity, which is a typical reservoir behaviour (Jarvie, 2012a; Chen et al., 2017c). The samples showing characteristics of a self-sourced and self-retained system come from the Collingwood Member of the Cobourg Formation except for one Rouge River sample, and samples showing characteristics of a tight reservoir are primarily from the Rouge River Member of the Blue Mountain Formation.

Available data (Figure 16) show that samples from the Collingwood Member show high hydrocarbon saturation regardless of TOC values and this is in contrast to samples from the Rouge River shale where a trend of increasing hydrocarbon saturation with TOC content is observed. This positive trend suggests increasing contribution from organic matter as TOC increases. Other samples in Figure 16 display a wide range of water saturation from 20% to more than 90%, suggesting that a variety of other factors which may control hydrocarbon saturation in organic-lean rock samples have to be considered.

The oil industry commonly utilizes resistivity logs to calculate water saturation using the Archie equation. However, there are only three wells with resistivity logs available in the study set (DGR-3 and 4, and OGS-11-02 wells). This poor spatial coverage presents a challenge in the resource estimation. To overcome this obstacle, an innovative approach was used for estimating water saturation. Passey et al. (1990) proposed a method for estimating TOC based on Archie’s equation involving resistivity and porosity logs. As we can estimate TOC directly from a combination of porosity logs and gamma ray logs, a pseudo-resistivity log can be generated from Passey’s equation. The back-calculated resistivity (pseudo-resistivity) log is then used to calculate water saturation using Archie’s equation. The estimated water saturations derived from well log data confirm the general trend of the relationship between water saturation and TOC as depicted by laboratory tests (Figures 16, 17) for the Collingwood and the Rouge River members. A comparison of the original and calculated resistivity log is presented in Figure 18. Comparisons between laboratory-tested reservoir properties and estimated well log curves are also provided in Figure 18 for the OGS-11-02 well.

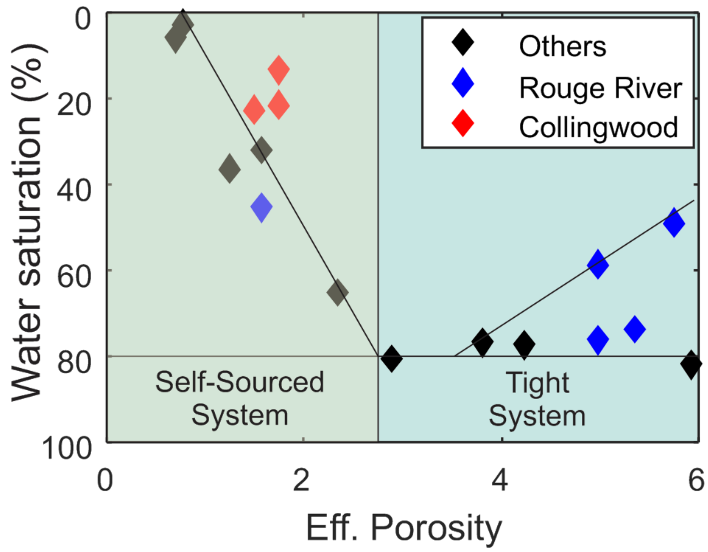

Figure 15: A cross-plot showing relationship between effective porosity and water saturation. Data collected from laboratory test results from two DGR wells and OGS 11-02 well. “Others” indicate non-source rock quality samples. (Eff. Porosity: effective porosity).

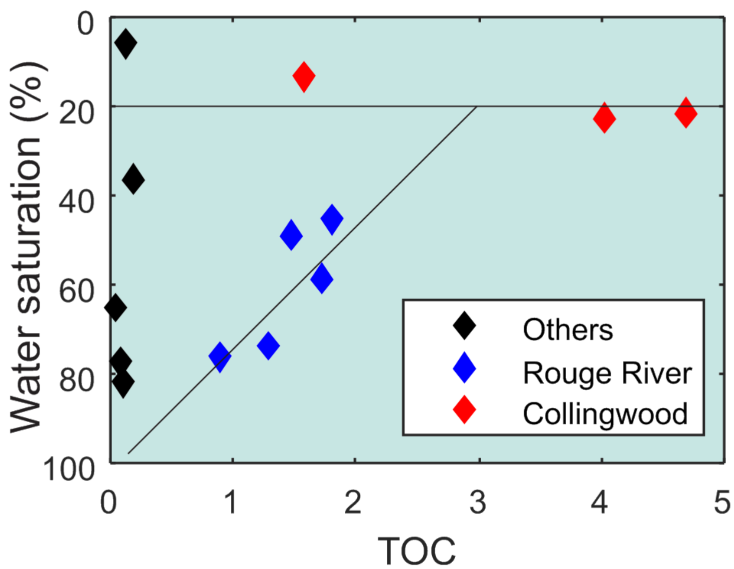

Figure 16: Cross plot of TOC content with water saturation showing relationship between organic content and water saturation in the same rock groups as shown of Fig. 15. “Others” indicate non-source rock quality samples.

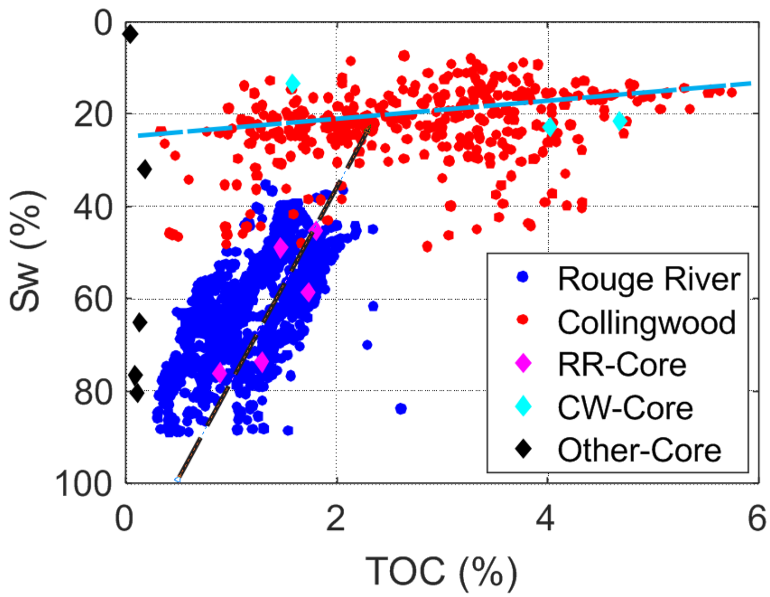

Figure 17: Cross-plot of TOC and water saturation (Sw) for wells where pseudo-resistivity logs were calculated.

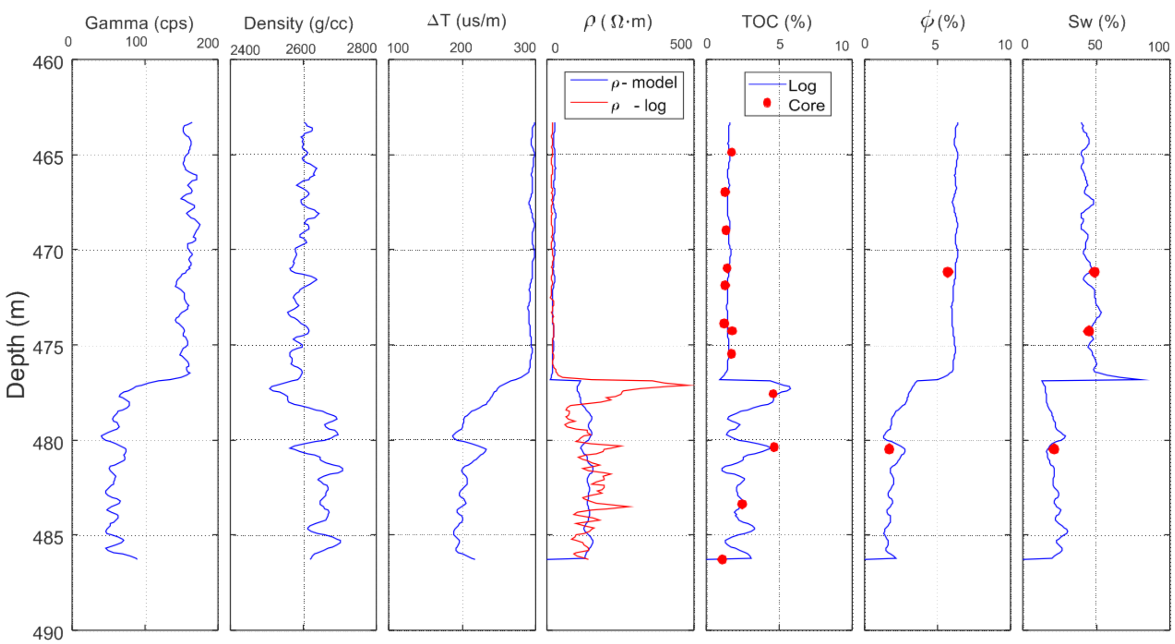

Figure 18: Composite plot showing well logs and comparison with estimated resistivity logs (4th column) and comparison of laboratory tested reservoir properties with estimated well log curves in the OGS-11-02 well.

6. PETROLEUM RESOURCE ASSESSMENT

6.1 GEOLOGICAL RISK ANALYSIS AND SHALE RESOURCE PLAY DEFINITION

Occurrence of petroleum resources in self-sourced and self-retained reservoirs in fine-grained shale strata is pervasive with spatially varying resource abundance and reservoir quality. However, only certain portions of the shale strata contain abundant resources and show adequate physical properties that meet favorable conditions for hydrocarbon extraction. Similar to conventional resource assessment, it is important to eliminate the intervals within the shale strata where extraction of hydrocarbon fluid is deemed impossible using currently available technology. By screening appropriate geological criteria, the geological risk analysis defines the resource play as the areal extent of the targeted shale strata where the quantity of oil and gas in the unit meets the criteria of a potential extractable resource. Regarding petroleum resource appraisal of unconventional (continuous) resource plays, the USGS suggested the following geological criteria for determining the potential areal extent of a shale gas formation (Charpentier and Cook, 2011, 2012); a) present day burial depth is greater than 1500 m; b) there is abundant organic matter (TOC>2%) with proper type (kerogen Type II and II/III) and thermal maturity (Ro>1.1%); c) target shale gas formation shows sufficient volume (thickness >20 m); d) the formation is over-pressured. By comparison, in their worldwide oil and gas resource assessments of shale formation, the EIA (2013) excluded shale formations where the TOC is less than 2% and vertical depth is less than 1000 meters or greater than 5000 meters.

Based on our analysis of the available data, if the two Upper Ordovician shale units are treated as separate resource plays, neither of the two could be qualified by the criteria set out by either the USGS (Charpentier and Cook, 2011, 2012) or the EIA (2013). However, the two units represent a continuous sedimentary package deposited in a transitional geological settings ranging from a carbonate platform to an open marine clastic offshore environments and, therefore, can be treated as a single resource play. Since, the two source rock units have distinctly different characteristics associated with the hydrocarbon generation potential and the kinetics of that process, these characteristics need to be addressed separately in the assessment.

In the geological risk evaluation, the following criteria were used: TOC >2% for the Collingwood and 1.5% for the Rouge River shale; present day burial depth >400 m; combined thickness of the Collingwood and Rouge River shale units >20m. The stratigraphic extent of the combined shale units that meet all the conditions is defined as a resource play. Figure 19 shows the areal extent of potential petroleum resources for the two shale units in southern Ontario.

A depth of 400 m was chosen because the S1 values indicating presence of free oil increase rapidly as a sign of enhanced hydrocarbon generation at this depth (Figure 9). Also, it corresponds to an average Tmax of 440°C (Figure 10), consistent with the kinetic models of transformation ratio of 0.3 for both the Collingwood and the Rouge River members (Figure 8). Production test results from the St.-Augustin #1 well in Quebec penetrating the Utica shale show flow rates of 47 barrels oil/day and 457 MCF (thousand cubic feet) gas/day from a depth interval of 436.5-473.5 meters (Chen et al., 2014), suggesting that extractable oil can be recovered from relatively shallow depths. Different TOC thresholds for the two members are reasonable because the Collingwood unit serves as the primary source rock that requires high TOC content to ensure sufficient generation; while data analysis indicates that the Rouge River shale may serve as both a source rock and reservoir (Figures 15 and 16).

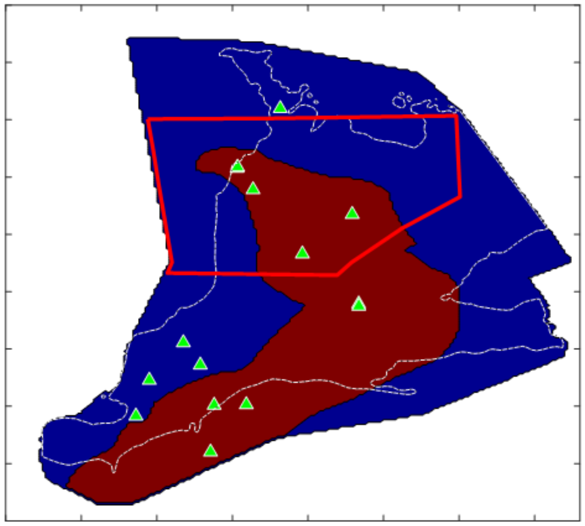

Figure 19: Map showing the study area (red polygon), areal extent of potential petroleum resources in the Collingwood and the Rouge River members (reddish brown colored area). Green triangular symbols indicate well locations with log data used in this study. The blue colored area is in Canada and dashed broken line is the shoreline.

6.1.1 Reservoir Risk Evaluation and Hydrocarbon Volumetric Calculation

Reservoir risk analysis ensures that the anticipated resource under consideration falls into the category of technically recoverable and is evaluated as such using reservoir cut-offs based on analogues from producing shale plays in North America. The cut-off for the volumetric calculation is 0.5 meters of cumulative hydrocarbon-saturated rock column, which is calculated from hydrocarbon saturated porosity times gross thickness of the combined Collingwood and Rouge River shale units. The 0.5 meter cut-off is equivalent to a hydrocarbon saturated porosity >2.5% and combined gross thickness >20 meters. The cut-off is, in general, consistent with the geological criteria for defining the shale play boundary discussed in the previous section. The total area defined by the reservoir cut-off is much smaller than the area within the shale play boundary and is regarded as the risked prospective area by a reservoir criterion.

Hydrocarbon resource at a specific location is estimated by the product of hydrocarbon saturated porosity and thickness, which gives a hydrocarbon pore volume (HCPV) under subsurface conditions. HCPV can be then converted to hydrocarbon volumes under standard surface conditions by applying formation volume factors. The estimated hydrocarbon volume at well control points are extrapolated to cover the entire southern Ontario region by kriging. The hydrocarbon resources of oil and gas are then aggregated into probability distributions to reflect the uncertainty in data and spatial extrapolation.

Figure 20 displays geographic distribution of hydrocarbon pore volume (HCPV) (a) and oil in-place (b) in the anticipated hydrocarbon resources of the Upper Ordovician Collingwood and Rouge River shale units, showing a large proportion of hydrocarbon resource of these two shale units occurring in the Appalachian Basin portion of southern Ontario. Only a small portion of the reservoir-risked resource occurs in the southeastern part of the study area. Figure 21 presents the statistical distributions of the aggregated oil in-place. Thermal maturity level has not reached the gas generation window and the natural gas resources include gas dissolved in oil and gas adsorbed in organic matter. Figure 22 shows the dissolved and adsorbed gas in-place estimates and their spatial distributions, respectively, in the southern Ontario area. Figure 23 shows statistical distribution of combined dissolved and adsorbed gases to capture the uncertainties in the resource assessment.

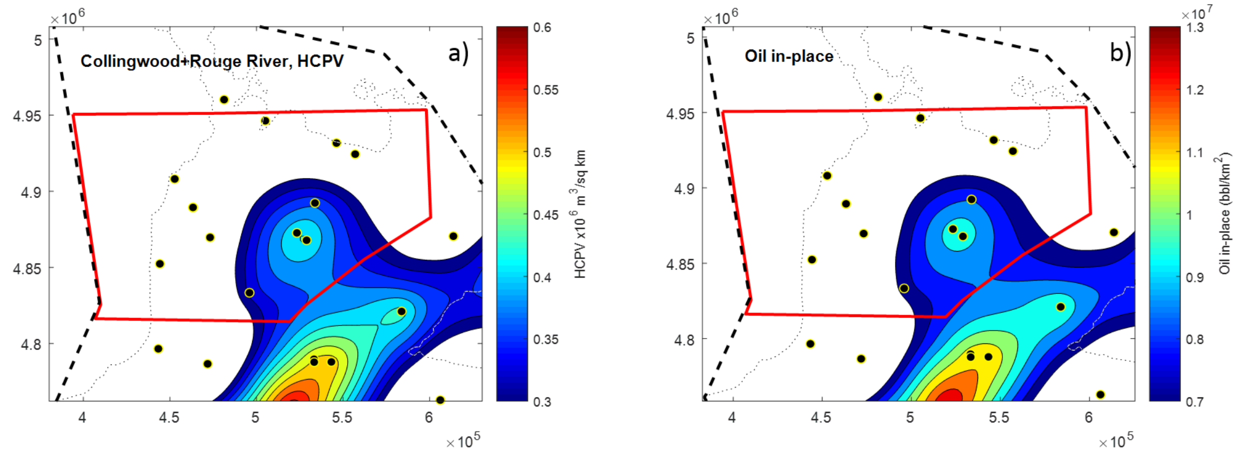

Figure 20: Resource maps of hydrocarbon pore volume (HCPV) (left) and oil in place (right) showing the geographic variation in resource abundance in the Upper Ordovician Collingwood and Rouge River shale units. Black dots: well control point; Red polygon: study area; Black dashed line: mapping area, dotted line: Ontario shoreline.

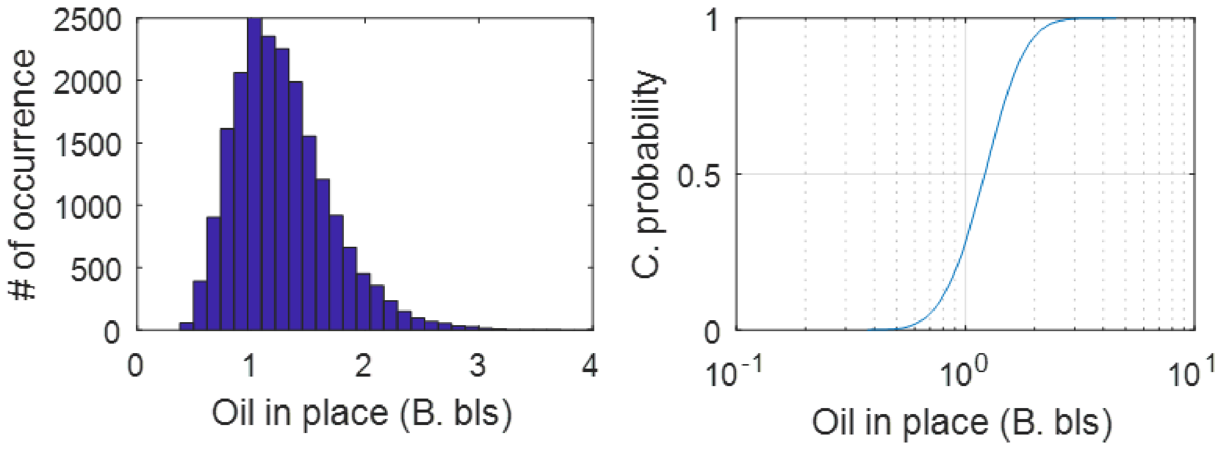

Figure 21: Statistical distribution of estimated oil in-place in the study area. Histogram of the estimated oil in-place in billion barrels (bbls) (left), and cumulative probabilistic distribution of the oil in-place in billion barrels (bbls) (right).

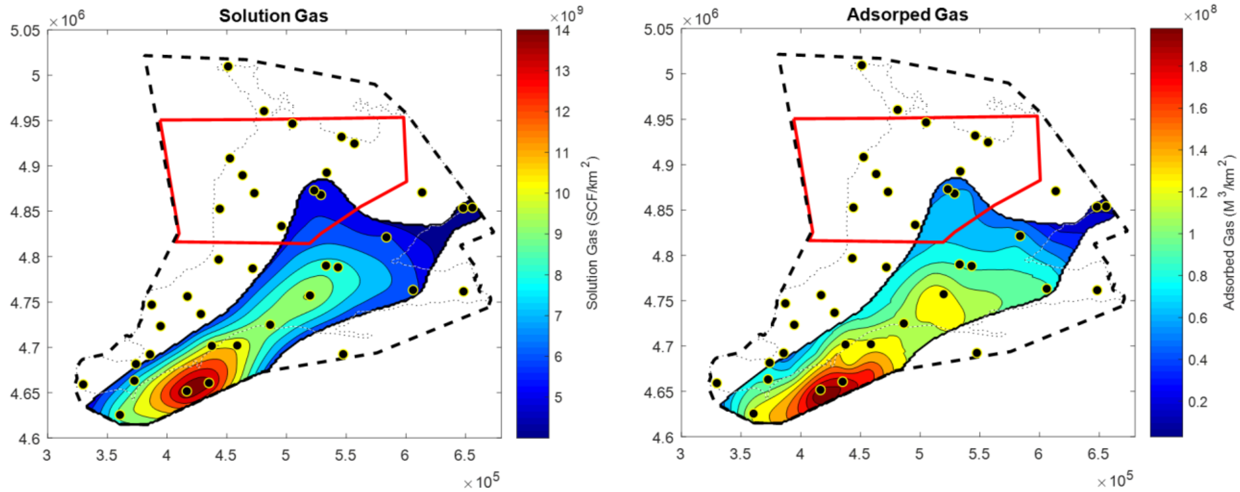

Figure 22: Maps showing spatial variations of the estimated dissolved or solution gas in-place (left) and adsorbed gas in organic matter (right) in the Upper Ordovician Collingwood and Rouge River shale units. Black dots: well control points; Red polygon: study area; Black dashed line: mapping area; Dotted line: Ontario shoreline.

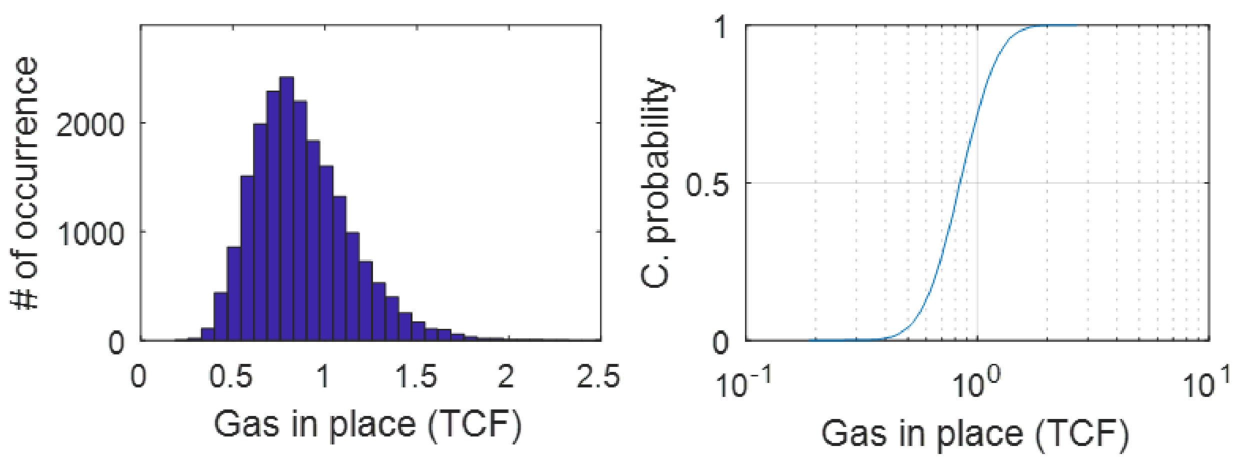

Figure 23: Statistical distribution of estimated gas in-place in the study area. The gas resources include natural gases dissolved in oil and adsorbed natural gases in organic matter. Histogram of the estimated gas in-place in trillion cubic feet (left), and cumulative probabilistic distribution of the gas in-place in trillion cubic feet (right).

The estimated oil and gas in-place resources in the Upper Ordovician shale units (the Collingwood and Rouge River shales combined) are summarized numerically in Table 1 as probabilistic distributions to reflect the uncertainties in the assessment and in Figures 21 and 23. The mean of in-place oil and gas resources are 1.273 billion barrels and 0.876 Tcf (trillion cubic feet), respectively with uncertainties in the fractile range (95% to 5%) from 0.694 to 2.071 billion barrels for oil and 0.51 to 1.357 Tcf for natural gas. The total oil equivalent resource estimate has a mean volume of 1.424 billion barrels with uncertainty ranging from 0.841 to 2.225 billion barrels in place.

Table 1: Summary table showing the estimated in-place resources in the study area (shown as red polygon in Figures 19 and 22). The estimated oil and gas resources are presented as probabilistic distributions to reflect the uncertainties in the resource assessment. (B. bbls: billion barrels; Tcf: trillion cubic feet; and BBOE: billion barrels of oil equivalent).

Probability distribution	95%	90%	75%	50%	25%	10%	5%	Mean
Oil in-place (B. bbls)	0.694	0.792	0.966	1.208	1.507	1.851	2.071	1.273
Gas in-place (Tcf)	0.51	0.569	0.688	0.841	1.027	1.223	1.357	0.876
Oil eq. in-place (BBOE)	0.841	0.935	1.118	1.356	1.659	2.001	2.225	1.424

6.2 RECOVERABLE RESOURCE CALCULATION

The EIA (2013) examined oil and natural gas recovery factors from producing shale formations in North America and provided numerous ranges of recovery factors, which can be used as reference values for the estimation of recoverable resource in this study. The recovery factors for shale oil are typically low, ranging from 3 percent to 7 percent with exceptional cases being as high as 10 percent or as low as 1 percent (EIA, 2013). Technically recoverable resources represent the estimated volumes of oil and natural gas that could be produced with currently available technology, regardless of oil and natural gas prices, production and infrastructure costs. Technically recoverable resources are determined by multiplying the risked in-place oil or natural gas by a recovery factor (EIA, 2013). Considering the low maturity of the source rock, low gas/oil ratio (GOR) and normal reservoir pressure, the oil recovery could be exceptionally low. A beta distribution of the recovery factor is assigned with a minimum of 0.0% and a maximum of 3%, and with a median at 0.75% (Figure 24) to reflect the reservoir conditions of the shale units and associated uncertainty with recovery. The recent studies suggested that a large part of the total oil yield from the source rock of early maturity and oil generation window resource plays are in the adsorption phase. Depending on the thermal maturity and the characteristics of source rock, adsorption can take up 75% of the total oil yield (e.g., Zink et al., 2016; Jiang et al., 2016; Li et al 2017). Heavy oil and bitumen in adsorbed phases do not flow easily, as the gases are either dissolved in oil or adsorbed onto the organic matter. Dissolved gas recovery depends on oil recovery and the contribution from the adsorbed gas component is insignificant.

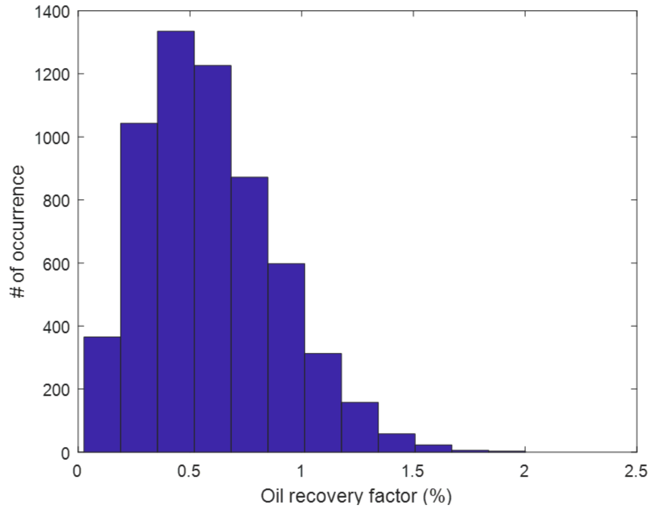

Figure 24: A beta distribution for oil recovery factor is assigned based on the reservoir conditions as compared with producing shale plays in North America.

The technically recoverable oil and gas resources are graphically shown in Figures 2, 25 and 26, and numerically in Table 2. The mean of recoverable oil resource potential is 11.7 million barrels with uncertainty in the fractile range (95% to 5%) ranging from 6.4 to 19.2 million barrels in the probabilistic distribution. The recoverable gas mean volume is 8.0 billion cubic feet ranging from 4.6 to 12.7 billion cubic feet. The total recoverable resource has a mean of 13.1 million barrels of oil equivalent with uncertainty in the fractile range from 7.7 to 20.6 million barrels of oil equivalent in the shale play.

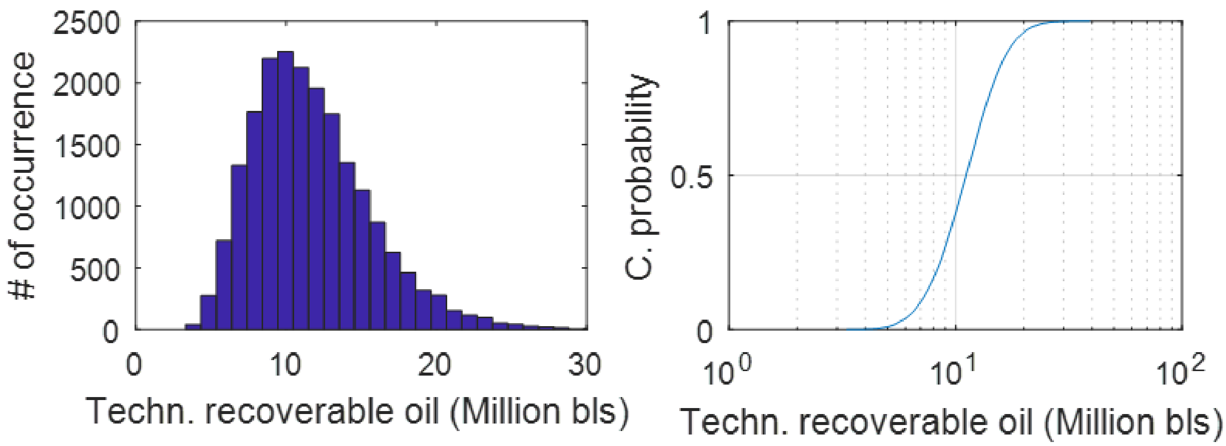

Figure 25: Probabilistic distribution of recoverable oil resource in the targeted Upper Ordovician shale units: Histogram (left) and cumulative distribution (right).

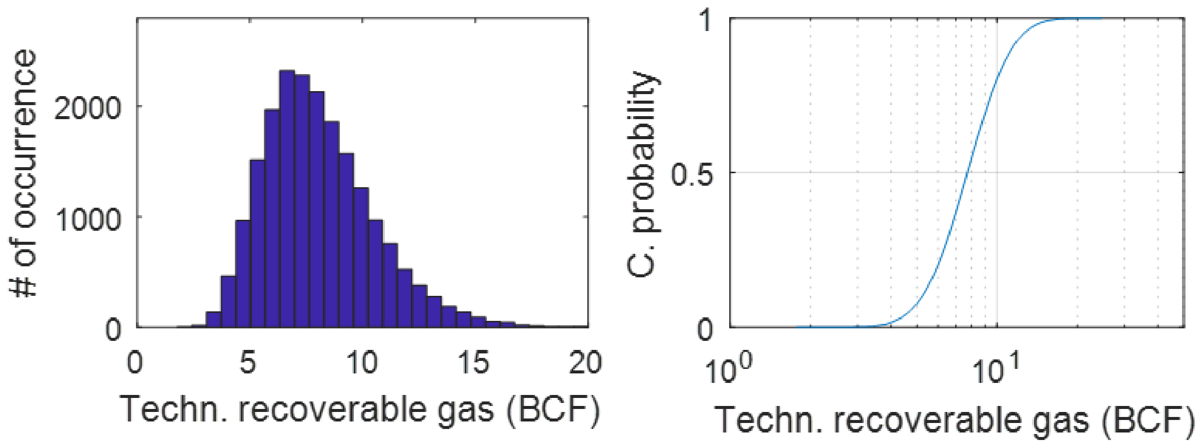

Figure 26: Probabilistic distribution of recoverable gas resource in the targeted Upper Ordovician shale units: Histogram (left) and cumulative distribution (right).

Table 2: Summary table showing the estimated technically recoverable resources in the study area (shown as red polygon in Figure 19). The estimated oil and gas resources are presented as probabilistic distributions to reflect the uncertainties in the resource assessment (M. bbls: million barrels; BCF: billion cubic feet; and M. BOE: million barrels of oil equivalent).

Probability distribution	95%	90%	75%	50%	25%	10%	5%	Mean
Oil T. rec. (M. bbls)	6.4	7.2	8.8	11.1	13.9	17.1	19.2	11.7
Gas T. rec. (BCF)	4.6	5.2	6.3	7.7	9.4	11.3	12.7	8.0
Oil eq. T. rec. (M. BOE)	7.7	8.5	10.2	12.5	15.4	18.5	20.6	13.1

7. OIL AND GAS RESOURCES IN CONVENTIONAL RESERVOIRS

Eight established exploration plays each with oil and gas discoveries have been defined in southern Ontario based on the nature of their stratigraphic location, types of reservoir, trap mechanism and geographical occurrence. Table 3 provides a summary of the basic information on the eight established oil plays and Table 4 of the eight established natural gas plays. Only those plays within the study area are subject to the petroleum resource assessment in this study and are the focus of data analysis and play descriptions.

Table 3: Summary table showing the basic information for oil plays in southern Ontario. Compiled from Bailey and Cochrane (1984a, 1984b, 1985, 1986, 1990), Canadian Gas Potential Committee (2006), Golder Associates (2005) and Oil Gas and Salt Resources Library (2016). Pools/discoveries with recoverable reserve <1,000 m^3 are not included in # of discoveries.

Play Name	# of discoveries	Cumulative production (10^6 m^3)	Original Reserve (10^6 m^3)	Play Area (km^2)	Overlap with study area (km^2)	Overalap Percentage
Devonian Structural	28	7.2	7.9	32702	0	0.00
Silurian carbonate structural	17	0.6	0.6	38614	0	0.00
Silurian carbonate pinnacle reefs	25	1.5	1.6	18515	11294	0.61
Silurian carbonate incipient reefs	33	0.2	0.2	18515	11294	0.61
Silurian carbonate platform reefs	9	0.2	0.2	34132	0	0.00
Lower Silurian sandstone stratigraphic	4	0.01	0.01	15448	0	0.00
Ordovician structural	50	4	4.4	84322	26348	0.31
Cambrian sandstone (structural & strat).	13	0.8	0.9	48874	0	0.00
Total	179	14.51	15.81			

Table 4: Summary table showing basic information for the natural gas plays in southern Ontario. Compiled from Bailey and Cochrane (1984a, 1984b, 1985, 1986, 1990), Canadian Gas Potential Committee (2006), Golder Associates (2005) and Oil Gas and Salt Resources Library (2016). Pools/discoveries with recoverable reserve <10,000 m^3 are not included in # of discoveries.

Play Name	# of discoveries	Cumulative production (10^6 m^3)	Original Reserve (10^6 m$^{3)}$	Play Area (km^2)	Overlap with study area (sq km)	Overalap Percentage
Devonian Structural	1	0.1	0.1	32702	0	0.00
Silurian carbonate structural	27	1716.7	1995.4	38614	0	0.00
Silurian carbonate pinnacle reefs	55	5737.1	7518.2	18515	11294	0.61
Silurian carbonate incipient reefs	40	413.9	502.6	18515	11294	0.61
Silurian carbonate platform reefs	19	12494.3	14205.1	34132	0	0.00
Lower Silurian sandstone stratigraphic	102	14339.7	14895.4	15448	0	0.00
Ordovician structural	36	1234.4	1409.6	84322	26348	0.31
Cambrian sandstone (structural & strat).	12	909.2	1004.8	48874	0	0.00

7.1 A BRIEF DESCRIPTION OF CONVENTIONAL OIL AND GAS PLAYS IN ONTARIO

All of Ontario's conventional oil and gas discoveries and production to date are found in the southern part of the province in the Paleozoic rocks that are similar to, and extensions of, plays occurring in the United States portions of the Michigan and the Appalachian basins. There have been no significant discoveries or production in other parts of Ontario. Oil and natural gas has been produced from reservoirs at several stratigraphic intervals in the Paleozoic bedrock of southern Ontario (Figure 2). These can be grouped into eight oil plays (Table 3) and eight gas plays (Table 4). The plays are described in more detail below and in recent articles published by the Canadian Society of Petroleum Geologists (Carter et al. 2016b; Dorland et al 2016).

As previously documented by Bailey and Cochrane (1984a, 1985), most of the remaining undiscovered oil and gas resources in both the Devonian and Cambrian plays are expected to occur beneath Lake Erie. In both plays, the Paleozoic sedimentary strata thicken and deepen to the southeast into the Appalachian Basin beneath the Lake Erie. Within the study area no undiscovered resources are assigned to either of these plays. For the Cambrian play, all of the discovered resources and significant oil and gas shows occur in the Appalachian Basin, while the study area lies entirely within the Michigan Basin. For the Devonian play, there are no discoveries within the study area, the potential reservoir strata occur at shallow depths (<200 metres), there are no cap rocks, and water well records indicate widespread occurrence of fresh water within the Devonian carbonate strata. Therefore, in the present study we only focus on those plays with resource potentials in the study area.

7.2 DATA ANALYSIS AND RESOURCE ESTIMATES FROM CREAMING CURVES

The discovery histories of the three oil plays that overlap with the study area (Silurian carbonate pinnacle reefs, Silurian carbonate incipient reefs, Ordovician structural) were examined to investigate the characteristics of the discovered pool sizes and their relation to the order of discovery. The creaming curve is an ideal tool for such an analysis.

Among the established oil plays, the Ordovician structural play is the second largest contributor to the oil resources (28% of the total). Some oil plays show that they have already reached their mature status as indicated by flattened reserve growth plateaus (Figure 27). However, in large parts of southern Ontario, the Ordovician play has not been drilled and it is reasonable to assume that large discoveries may be expected in the oil and gas plays associated with this stratigraphic interval.

A simple extrapolation of the creaming curve to forecast future oil discovery trend provides an approximation of the remaining resources to be discovered in each play that show overlap with the study area. Tables 5 and 6 provide a summary of the predicted oil resources remained to be discovered in each play. The total oil resources remaining to be discovered in the three plays is 5.2 million cubic meters (32.6 million barrels) in southern Ontario and 2.0 million cubic metres (12.7 million barrels) of recoverable oil within the study area.

Each of the three natural gas plays are assessed in the study area. Figure 28 illustrates creaming curves of the three natural gas plays. Except for the Silurian carbonate incipient reef play, the other two have shown plateaus with flat reserve growth. The Silurian carbonate pinnacle reef play appears to have the largest proportion of large individual pool sizes and cumulative original reserve while the Silurian carbonate incipient reef play shows the smallest individual pool size and cumulative play reserve.

The same extrapolation was also made to the three gas plays that show overlap with the study area. The largest remaining oil resource to be discovered is in the Ordovician Structural play with 2.9 billion cubic meters in all of southern Ontario; the Silurian carbonate pinnacle reef play appears to show the largest remaining gas resource (1.4 billion cubic metres) in the study area (Tables 7 and 8). The total remaining natural gas resources to be discovered in the three plays is 6.1 billion cubic metres (215 BCF) in all of southern Ontario, while within the study area, the remaining gas resource is 2.8 billion cubic metres (100.2 BCF). The simple extrapolation using the creaming curve does not provide an uncertainty range for each of the plays. The single valued resource number from the creaming method can, however, be regarded as the expectation (mean value) of the remaining oil and gas resources to be discovered and used as a reference for other values derived using different methods.

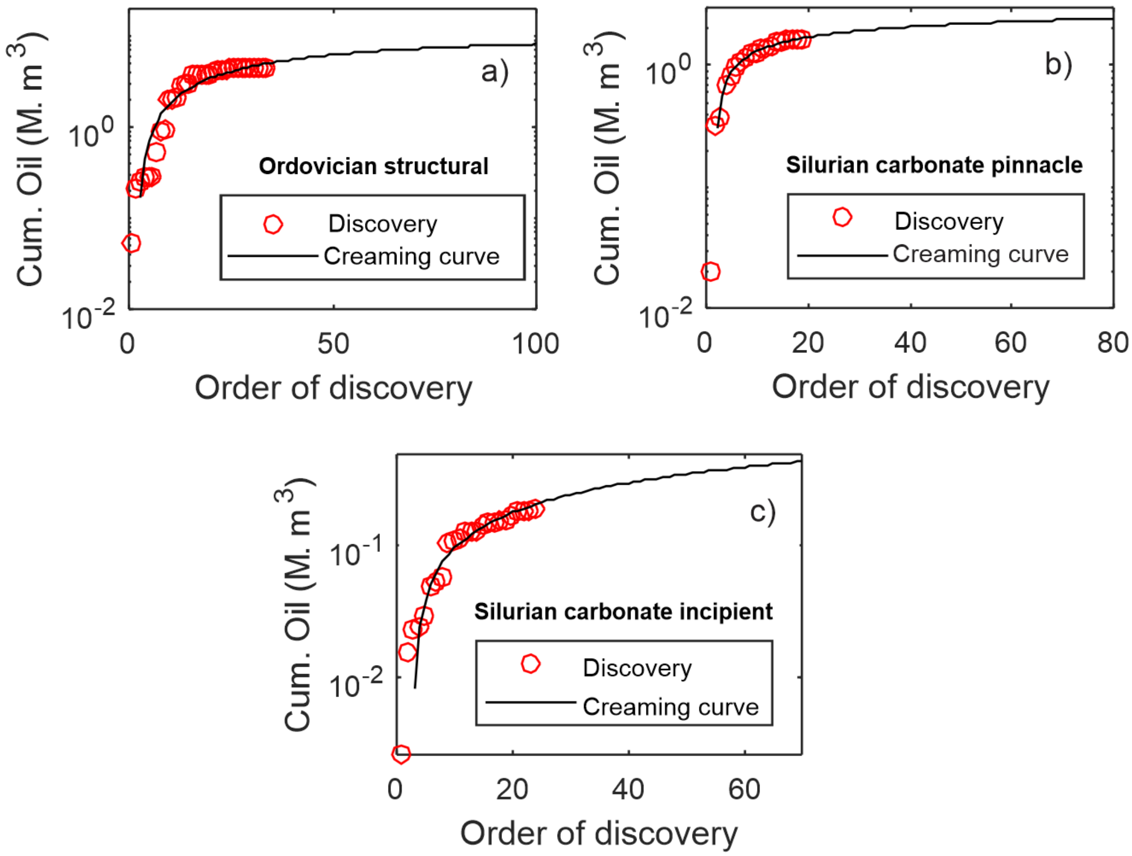

Figure 27: Creaming curves of the three established oil plays that overlap with the study area, showing general characteristics of the pool sizes in relation to their reserve growth for each oil play in southern Ontario.

Table 5: Resource estimation summary for oil plays with overlap in the study area in southern Ontario (SI units).

Method	Reserve (million m^3)		GSC lognormal discovery process model								Percentage	Creaming Curve Analysis		
Play Name	Initial recoverable	Discovered pools (#)	Total pools (#)	Propobability Distribution 0.95	0.75	0.50	0.25	0.05	Mean	Potential in the study	Overlap with the study area	Total recoverable (million m^3)	Remain to be discovered	Remain in the study area
Silurian carbonate pinnacle reefs	1.60	19	170	1.16	1.65	2.75	5.31	25.80	9.99	0.65	0.61	2.72	1.12	0.68
Silurian carbonate incipient reefs	0.20	24	60	0.25	0.26	0.28	0.32	0.44	0.31	0.07	0.61	0.44	0.24	0.15
Ordovician structural	4.40	34	100	2.08	3.67	5.01	8.35	15.79	6.09	0.30	0.31	8.23	3.83	1.19
Total	6.20	77	330							1.03		11.39	5.19	2.02

Table 6: Resource estimation summary for oil plays with overlap in the study area in southern Ontario (Imperial units).

Method	Reserve (million bls)		GSC lognormal discovery process model							Percentage		Creaming Curve Analysis		
Play Name	Initial recoverable	Discovered pools (#)	Total pools (#)	Propobability Distribution						Potential in the study	Overlap with the study	Total recoverable (million bls)	Remain to be discover	Remain in the study area
				0.95	0.75	0.50	0.25	0.05	Mean					
Silurian carbonate pinnacle reefs	10.1	19	170	7.30	10.38	16.10	33.40	162.30	62.84	4.10	0.61	17.11	7.04	4.28
Silurian carbonate incipient reefs	1.2	24	60	1.57	1.64	1.75	1.99	2.75	1.95	0.46	0.61	2.77	1.51	0.94
Ordovician structural	27.5	34	100	13.10	23.10	31.50	52.50	99.30	38.30	1.90	0.31	51.77	24.09	7.49
Total	38.8	77	330							6.46		71.64	32.65	12.71

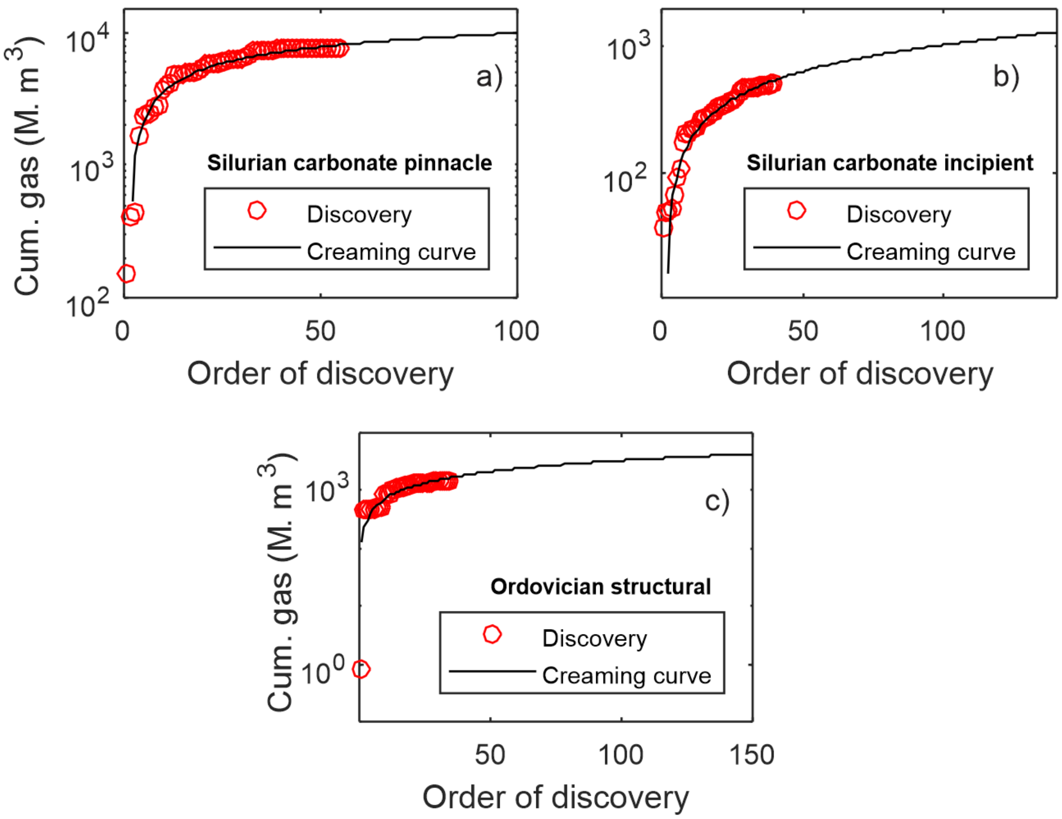

Figure 28: Creaming curves of the three mature natural gas plays that overlap with the study area, showing general characteristics of pool sizes in relation to reserve growths for each play in southern Ontario.

Table 7: Resource estimation summary for natural gas plays with overlap in the study area in southern Ontario (SI units).

Method	Reserve (million m^3)		GSC lognormal discovery process model								Percentage	Creaming Curve Analysis		
Play Name	Intitial recoverable	Discovered pools (#)	Total pools (#)	Propobability Distribution						Potential in the study area	Overlap with the study area	Total recoverable (million m^3)	Remain to be discovered	Remain in the study area
				0.95	0.75	0.50	0.25	0.05	Mean					
Silurian carbonate pinnacle reefs	7518.2	55	70	80.80	403.20	897.40	1581.20	3242.60	1154.40	976.92	0.61	9880.90	2362.70	1441.25
Silurian carbonate incipient reefs	502.6	40	160	319.30	329.20	348.20	386.80	532.40	378.40	145.09	0.61	1309.70	807.10	492.33
Ordovician structural	1409.6	35	360	1311.06	1458.00	1716.00	2464.00	6768.00	3058.00	336.97	0.31	4328.90	2919.30	904.98
Total	9430.4	130	590							1458.98		15519.50	6089.10	2838.56

Table 8: Resource estimation summary for natural gas plays with overlap in the study area in southern Ontario (Imperial units).

Method	Reserve (BCF)		GSC lognormal discovery process model								Percentage	Creaming Curve Analysis		
Play Name	Initial recoverable	Discovered pools (#)	Total pools (#)	Propobability Distribution						Potential in study area	Overlap with study area	Total recoverable (BCF)	Remain to be discovered	Remain in study area
				0.95	0.75	0.50	0.25	0.05	Mean					
Silurian carbonate pinnacle reefs	265.5	55	70	2.9	14.2	31.7	55.8	114.5	40.8	34.5	0.61	348.9	83.4	50.9
Silurian carbonate incipient reefs	17.7	40	160	11.3	11.6	12.3	13.7	18.8	13.4	5.4	0.61	46.3	28.5	17.4
Ordovician structural	49.8	35	360	46.3	51.5	60.6	87.0	239.0	108.0	11.9	0.31	152.9	103.1	32.0
Total	333.0	130	590							51.8		548.1	215.0	100.2

7.3 ASSESSMENT FROM GSC DISCOVERY MODEL PROCESS

The three oil plays and three natural gas plays assessed in this report partially occur within the study area and were subjected to the resource potential assessment to determine the proportion of resources in the study area using the GSC discovery process model.

Individual discovered pool sizes and their discovery date for all established conventional oil and gas plays in southern Ontario were compiled from data supplied by the OGSR Library in London, Ontario. Recoverable discovered reserves were used in this resource evaluation. In many cases, the cumulative production of individual pools exceeds or equals booked recoverable reserves. In these cases, it was considered prudent to increase the cumulative production volume by 10% for input purposes in order to take into account future reserve growth.

It also became apparent after initial assessment tests that modeling using input data as supplied did not yield reliable results. Remaining resource potential and individual undiscovered pool sizes were often exceedingly small. It was observed, especially in the oil plays, that many of the booked accumulation sizes were very small and most likely containing no commercial accumulations that can be classified as pools. The inclusion of these very small accumulations in the discovery sequence input data drastically affects the lognormal approximation of predicted pool sizes and ultimately the potential of the play. It was considered prudent to remove the smallest accumulations from the input data and perform revised assessment analyses. Oil accumulations of less than 1000 m^3 (6,290 barrels) and gas accumulations of less than 10,000 m^3 (353,000 cubic feet) were removed from the input data. Consequently, the number of discoveries for all oil plays in the study area were greatly reduced. Gas play discoveries were not significantly affected (reduction of one accumulation in each of the Ordovician and Cambrian plays). The reduced number of discoveries are displayed in Tables 3 and 4. Estimates of recoverable remaining resource potential and pool-size-by-rank plots are depicted in Figures 29 (oil) and 30 (natural gas). These plots are in Imperial measurements. Tables 5 & 6 and 7 & 8 display the resource estimates for the plays that also occur within the study area.

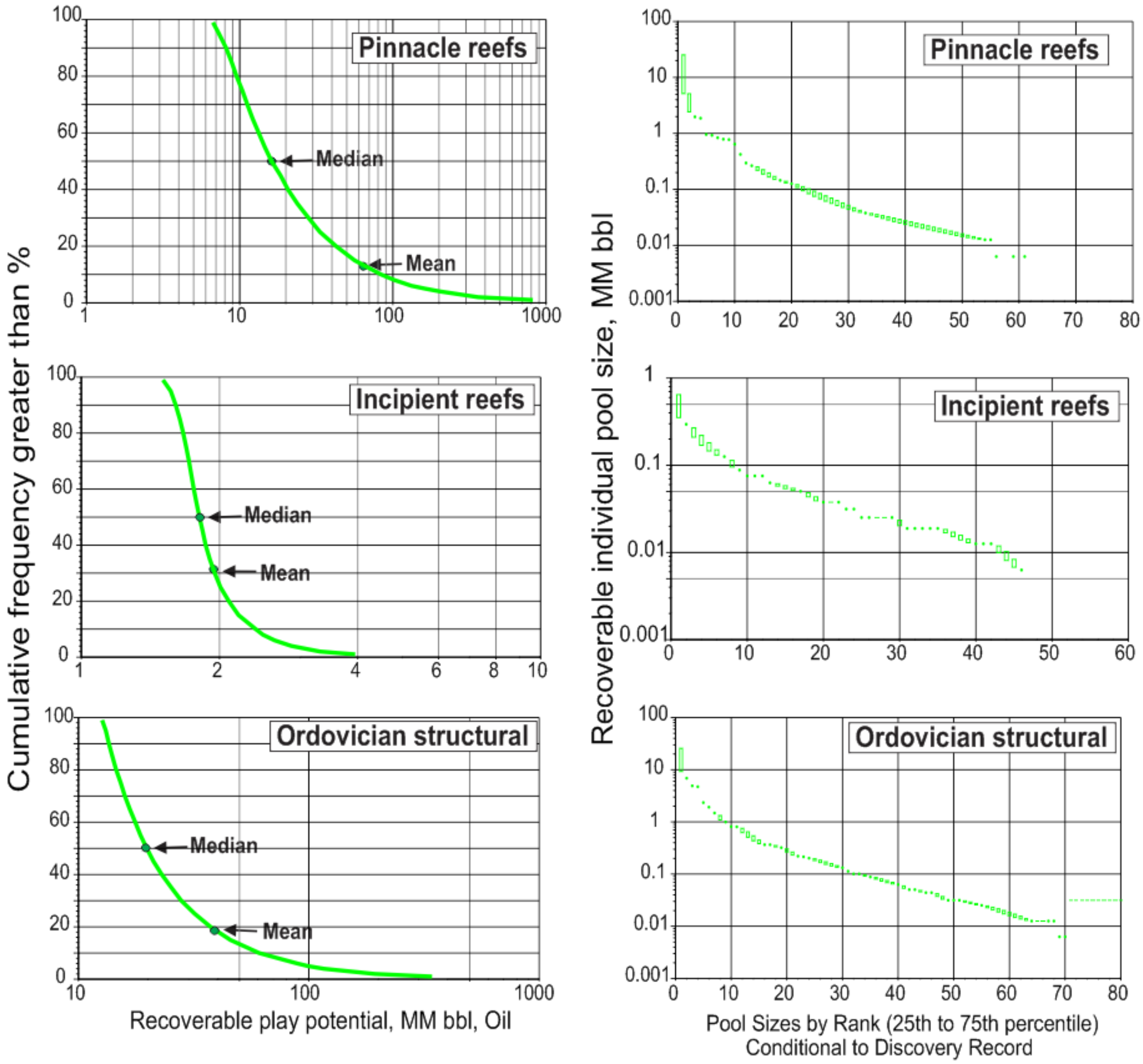

Figure 29: Estimates of recoverable remaining oil potential and pool-size by rank plots of conventional oil plays that partially occur in the study area.

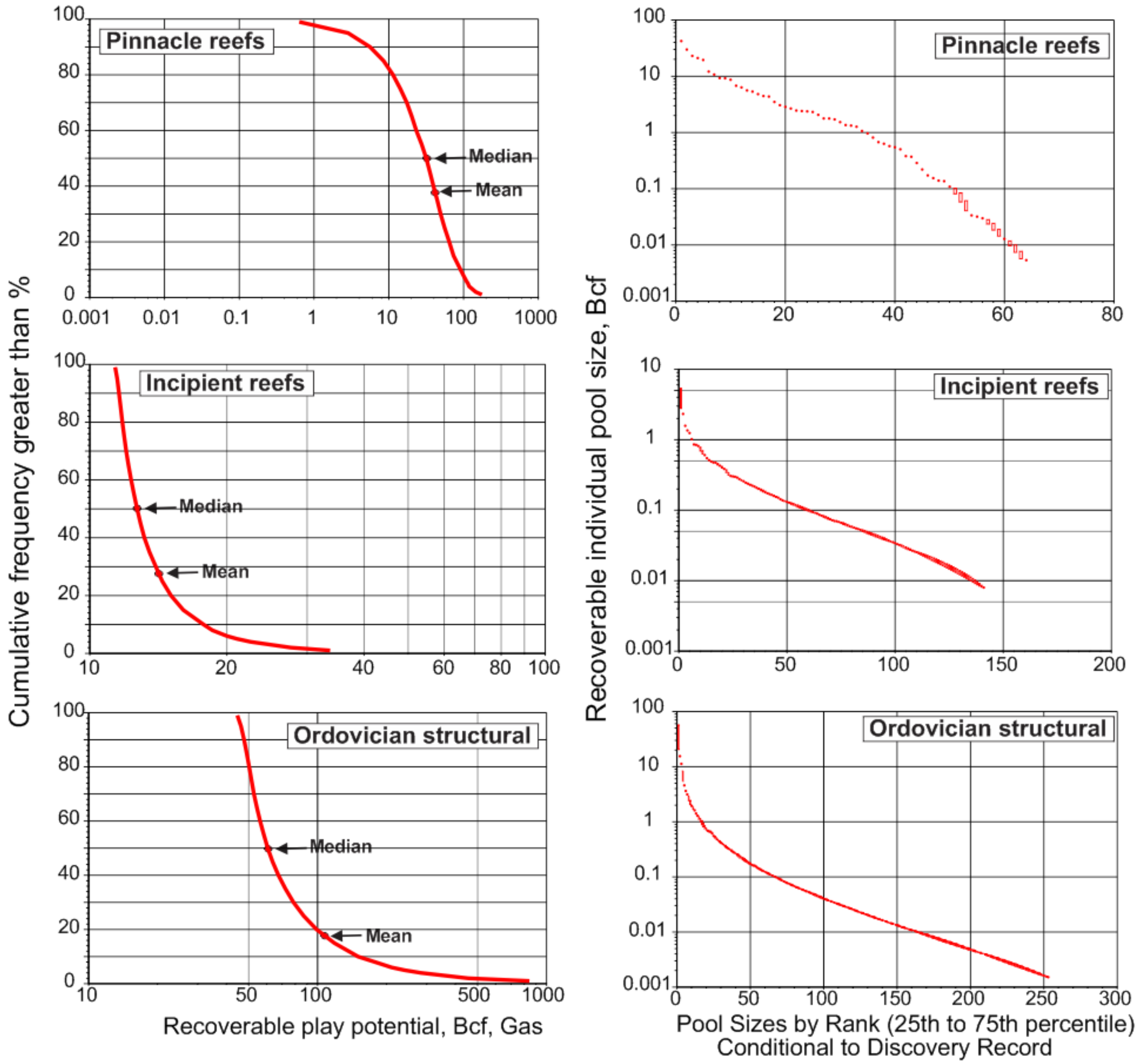

Figure 30: Estimates of recoverable remaining natural gas potential and pool-size by rank plots of conventional gas plays that partially occur in the study area.

Properly defined petroleum exploration plays are based solely on geology and it is inappropriate to define and statistically analyse plays based on arbitrary geographic limits such as study area borders. It is necessary, therefore, to perform statistical analyses on exploration plays over the full extent of their geologically defined limits and subsequently impose proper areal and volumetric proportions for play areas located within a study area. Probabilistic statistical analysis does not provide information on locations of individual hydrocarbon accumulations in a play. An assumption is made in this analysis that oil or gas resources in each exploration play are evenly distributed throughout the total play area. The percentage of the play area within the study area is used to derive an apportionment of resource potential from the total play resource. The assumption of an evenly distributed resource over a play area is not necessarily accurate as certain areas of an exploration play may have greater or lesser potential, depending on local geological factors. Nonetheless, the assumption of an even resource distribution provides an initial statistical framework for assessing resource potential in portions of regional exploration plays.

In most petroleum plays, a substantial volume of the total play potential is concentrated in the largest pool. Accordingly, the apportionment of resources within the study area is further modified by applying the assumption that the largest undiscovered pool in the play occurs outside the study area. This scenario is achieved by subtracting the mean of the largest undiscovered pool size from the mean remaining resource potential and multiplying the result by the play overlap percentage.

7.3.1 Silurian Carbonate Pinnacle Reefs Play

The Silurian carbonate pinnacle reef play involves all pools and prospects occurring in isolated pinnacle reefs on the margins of the Michigan Basin. Pinnacles have been subjected to several episodes of subaerial exposure, creating erosional discontinuities and extensive paleokarst horizons, which led Brintnell (2012) to describe pinnacles as “karst towers”, but the prevailing view is that the pinnacles are karsted reefs (see Carter et al 2016b). Pinnacles comprise carbonate reef buildups greater than 50 m in height and ranging up to 128 m within the Silurian Lockport Group carbonates, with principal reservoir development in the Guelph Formation and the overlying Salina A-1 Carbonate Unit. Sometimes, closely-spaced reefs form reef complexes with reservoir communication (Bailey and Cochrane, 1990). Most of these reefs have been extensively dolomitized and all are variably karsted, resulting in the formation of complex stratified reservoirs with widely varying porosity and permeability.

The first pinnacle reef discovery was a commercial gas accumulation completed in 1930 called the Dawn 47-49 Pool. Another gas discovery was established in the Dawn area in 1931, before the first oil and gas discovery was found in 1949 at Kimball-Colinville. In total, 44 gas, 8 oil and 11 oil and gas discoveries have been made in the play. The largest oil discovery was found at Seckerton-Seckerton North Pool and the largest gas accumulation occurred in the Kimball-Colinville Pool. Ten gas discoveries have been made in the study area (Ashfield 5-IX WD, Ashfield 7-1-III ED, Bayfield, Dungannon, Stanley 4-7-XI, Stephen 2-23-XVI, Tipperary South, Tuckersmith 30-III-SHR, West Wawanosh 1-25-XIII, West Wawanosh 26-X), as well as one oil and gas discovery at Tipperary. Reserve volumes in the study area are 0.01 million barrels of oil and 9.7 billion cubic feet of natural gas. In the entire play, recoverable reserve volumes for the 19 oil pools and the 55 gas accumulations are 10.1 million barrels of oil and 265.5 billion cubic feet of natural gas, respectively.

Analysis of the oil potential of the Silurian carbonate pinnacle reef play predicts 170 pools containing a mean volume of 62.8 million barrels (Figure 29, Table 6). The play potential ranges from 7.3 to 162.3 million barrels. Natural gas potential in the Silurian carbonate pinnacle reef play is predicted to occur in 70 pools (Figure 30, Table 7). The expected play potential ranges from 2.9 to 114.5 billion cubic feet. The mean play potential is predicted to be 40.8 billion cubic feet.

A large proportion of the pinnacle reef play area in Canada occurs within the study area (~ 61%). The apportionment of oil and gas resource in the study area gives about 4.1 million barrels and 34.5 billion cubic feet, respectively. These estimates are likely to be very optimistic, as all of the discovered pools within the study area are significantly underpressured and reservoir quality is significantly impacted by salt plugging in this area. Much of this potential may occur beneath the waters of Lake Huron.

7.3.2 Silurian Carbonate Incipient Reefs Play

Incipient reefs occur in the same area as the pinnacle reefs on the margins of the Michigan Basin. These reefal buildups are usually less than 30 m in height. Similar to pinnacle reefs, they are extensively dolomitized and form complex stratified reservoirs. Numerous oil and gas discoveries were made in these buildups.

This play became established in 1946 with the discovery of the Becher East gas pool. Two more gas discoveries were made in the play before the first oil discovery was found at Talford in 1959. In the play, a total of 32 gas discoveries, 16 oil and 8 oil and gas discoveries have been made to date. The largest oil discovery is found in the Dawn 28-II pool while the largest gas accumulation was found at Otter Creek. Although the play area is coincident with the pinnacle reef play, no discoveries have been made to date in the study area. Recoverable reserve volumes in the play are 1.2 million barrels oil and 17.7 billion cubic feet of natural gas.

The oil play has an estimated recoverable potential range of 1.57 to 2.75 million barrels with a mean volume of 1.95 million barrels (Figure 27, Table 6). The number of predicted pools is 60. The largest undiscovered pool, which is also the largest pool in the play is expected to contain 0.6 million barrels (mean value).

Potential for the Silurian carbonate incipient reef gas play ranges from 11.3 to 18.8 billion cubic feet with a mean volume of 13.4 billion cubic feet (Figure 28, Table 8). This estimate assumes a total pool population of 160 with the largest undiscovered pool, which is also ranked the largest in the play, having a recoverable mean volume of 5.1 billion cubic feet.

7.3.3 Ordovician Structural Play

The Ordovician structural play involves all pools and prospects in the Ordovician Trenton-Black River carbonate reservoirs that are structurally controlled by a regional fault and fracture network. This network provided sites for infiltration of hydrothermal dolomitizing fluids which created the reservoirs and provided heat and impetus for hydrocarbon maturation, migration and emplacement.

Oil seeps and significant oil shows were noted in the Ordovician carbonate strata on the Manitoulin Island in 1883. The first commercial gas discovery occurred at Hepworth pool in 1900. The initial oil and gas discovery that revealed a link to faulting and dolomitization in southern Ontario was at the Dover pool in 1917. Total discoveries in the play are 14 gas, 13 oil and 21 oil and gas accumulations. The largest oil accumulation in the play has a recoverable volume of 6.1 million barrels in the Goldsmith-Lakeshore pool. Dover is the largest gas pool found so far in the play in southern Ontario with a recoverable volume of 14 billion cubic feet. There are three hydrocarbon accumulations in Ordovician strata within the study area. The Hepworth gas pool on the Bruce Peninsula has a recoverable reserve volume of 0.025 billion cubic feet. The geology of the Arthur gas pool, with a recoverable reserve of 1.28 billion cubic feet, is poorly understood and the pool does not seem to produce from a typical Trenton-Black River reservoir. Instead, production seems to come principally from the clastic strata of the Shadow Lake Formation on top of the Algonquin Arch. The third Ordovician accumulation in the study area is Egremont which has no booked reserves. In the entire play area, recoverable reserves are 27.5 million barrels of oil and 49.8 billion cubic feet of natural gas.

Estimates of the undiscovered potential of the Ordovician structural oil play range from 13.1 to 99.3 million barrels with a mean recoverable volume of 38.3 million barrels (Figure 27, Table 7).

The total number of pools is predicted to be 100. The largest undiscovered pool, ranked as the largest, is predicted to contain 32.2 million barrels.

The Ordovician structural gas play predicts a total of 360 pools having a remaining play potential ranging from 46.3 to 239.0 billion cubic feet with a mean recoverable volume of 108.0 billion cubic feet (Figure 28, Table 8). The largest undiscovered pool, ranked as the largest in the play, is predicted to contain 74.4 billion cubic feet (mean value). Study area reserve estimations for the Ordovician structural play are 1.9 million barrels oil and 11.9 billion cubic feet of natural gas. Such estimates are considered optimistic.

7.4 TOTAL OIL AND GAS POTENTIAL IN THE STUDY AREA

The summation of individual areal apportionment results for each play produces a final prediction on conventional oil and gas potential in the study area. The potential reserves are expected to be 6.5 million barrels of oil and 51.5billion cubic feet of natural gas in the study area. The unconventional oil resources of the study area are considered to be extremely poor when compared to equivalent black shales in North America (Table 9).

Table 9: Comparison of total volume and resource density for unconventional oil in the Ordovician shale units within the study area, to other unconventional shale producing units in North America. Within the study area, the resource abundance is significantly lower when compared with other currently producing shale units in N. America. See Table 1 for estimates of the recoverable portion of the oil resource. CW: Collingwood Member; RR: Rouge River Member. QC: Quebec (Canada), BC: British Columbia (Canada), OH: Ohio (USA), PA: Pennsylvania (USA).

Shale Unit	Stratigraphic Age	Resource (B. boe)	Area (km^2)	Density (M.boe/km^2)
CW+RR Combined (Study Area)	U. Ordovician	1.42	5296	0.27
Macasty, QC	Ordovician	42.1	7900	5.33
Utica, QC	Ordovician	31.2	10000	3.12
Horn River, BC	M. Devonian	74.7	8600	8.69
Utica, OH	Ordovician	162.3	58300	2.78
Marcellus, PA	Devonian	250	53750	4.65

8. DISCUSSION

The oil and gas resource assessments are based on the data available to this study and the understanding of the geological conditions controlling the occurrence of the resources. The spatial occurrences of the resources result from extrapolation of the resource estimates from well locations where geoscientific data and information were collected. Probabilistic distributions are used to characterize the uncertainties that are inherited from data interpretation, model quantification and spatial extrapolation in this assessment.

The assessment combines the Collingwood and Rouge River shale units in the Upper Ordovician succession into a single shale resource play based on the following considerations:

a) the two shale units, if treated separately, could not be justified by the criteria suggested by the USGS (Charpentier and Cook, 2012; EIA, 2013) as a continuous shale assessment unit; b) the two shale units are a continuous sedimentary package, and in fact, industry has often treated the two as a single shale unit in subsurface (e.g., Béland Otis , 2015a); c) although the two units vary in hydrocarbon generation potential and kerogen kinetics, the difference can be dealt with using different generation and kinetic models in the assessment; d) the mineral compositions differ in the two units and rock mechanical properties vary spatially. This can be treated as a problem of rock lithological heterogeneity common in many hydrocarbon producing shale plays in North America, which is an engineering problem for future technology to address.

In this report, the technically recoverable resources are reported. Technically recoverable resources represent the volume of oil and gas that could be produced with currently available technology regardless of commodity price, production cost and the cost of bringing the products to markets. The technical recovery factor used in this report is from analogues of the producing shale oil resource plays with extrapolation of shale well production over a long period in North America, as analyzed by the EIA (2013). The recovery factor varies typically from 3% to 7% of the in-place volumes, with exceptional low and high cases being 1% to 10% respectively (EIA, 2013). Because most shale oil and shale gas wells contain time-limited production data, large uncertainty is expected because real life spans of the production wells, ultimate recoveries from current technology, and additional recovery brought forward by future technology are all unknown.

Our judgement of the recovery factor for oil and gas in-place resource is exceptionally low for the following reasons:

- First of all, as revealed by laboratory tests (Béland Otis, 2015a; Jackson, 2009), the permeability of the two shale units is extremely low and recovery would have to rely on artificially-induced fractures caused by hydraulic fracturing.
- Secondly, the contrasting lithologies in the two units may cause additional difficulties for successful completions.
- Thirdly, North American experience indicates that shale oil is difficult to produce commercially and the most profitable part in an unconventional play is often defined by the combination of high reservoir pressure with the most appropriate gas-oil ratio (Cander, 2012). Recent studies suggest that large portion of total oil yield in source rocks of low maturity and early “oil window” stages is in a sorption phase and its mobility is limited (Jiang, 2016; Li et al., 2017; Zink et al., 2016). The maturity level for the two southern Ontario shale units with respect to hydrocarbon generation is marginal mature to early mature, gas-oil ratio and hydrocarbon saturation are low, and oil viscosity is high (Stoneburner, 2013), impeding hydrocarbon fluid flow.
- Fourthly, data shows that all current oil producing shales in North America have S1/TOC>1 (Jarvie, 2012b). Behar et al. (2002) regarded S1/TOC>1 as a favourable oil show index with respect to conventional oil exploration. There is no data point greater than 1 for S1/TOC in the dataset used in this study.
- Fifthly, in the volumetric calculation, a threshold of cumulative hydrocarbon column is used because there are not enough data to exclude those intervals with <2.0% hydrocarbon saturated porosity, which may include a large amount of hydrocarbon pore volume from poor quality reservoir in the shale units.

The conventional resource assessment is based on our current understanding of the occurrences of discovered oil and gas pools and their geological controls employing the following assumption: all potential oil and gas plays in southern Ontario are identified. No attempt was made to estimate the undiscovered petroleum resources in conceptual plays that might exist in the region. The GSC discovery process model along with creaming curve analysis were applied to estimate the remaining oil and gas potential in each of the identified plays. The only data used for the assessment for each of the plays are their discovery sequences. Most of the creaming curves of the identified oil and gas plays show that all plays have entered mature exploration status; thus no drastic increments in reserve would be expected and the sizes of future new pools are small for those plays. This may not be the case if the sizes of hydrocarbon accumulation in unexplored parts of the basin are governed by different geological factors and do not follow the same lognormal distributions depicted by the already discovered pools in the region.

A large part of southern Ontario containing the thickest accumulations of the Paleozoic sedimentary rocks lies beneath the waters of the Great Lakes. Exploration for and production of oil is not permitted on the Great Lakes and drilling for natural gas has only occurred on Lake Erie, consequently limiting the area tested by drilling. Previous studies (see Carter et al 2016a) have identified that most of the remaining undiscovered conventional oil and gas resources lie beneath the Great Lakes.

9. CONCLUSIONS

Amounts of the undiscovered technically recoverable resources within the study area (the mean totals) are: 11.7 million barrels of shale oil (MMBO), with a range from 6.4–19.2 MMBO fractile (F95–F05, respectively); 8.0 billion cubic feet of continuous gas (BCFG), with a fractile range from 4.6–12.7 BCFG; 6.85 MMBO of conventional oil and 51.5 BCFG of conventional gas. A creaming curve approximation provides larger oil and gas resource estimates than those from discovery process model, but not significantly. The ranges of resource estimates reflect the geologic uncertainty of the source-reservoir rock systems and spatial extrapolation of resource mapping from sparse well controls. Much of the uncertainty is related to models constructed to estimate the quantity of oil remaining in the source rocks following migration, and the quality of oil and gas stored in conventional reservoirs.

ACKNOWLEDGEMENTS

The authors thank our internal reviewers Dr. Chunqing Jiang and Christopher Lister of the GSC-Calgary, and Monique Hobbs of NWMO for their valuable suggestions and comments. This study benefited from a digital 3D stratigraphic model of the Paleozoic bedrock of southern Ontario currently developed as a component of Canada-in-3D groundwater work led by Dr. Hazen Russell, GSC-Ottawa. Christine Deblonde, GSC-Calgary, provided GIS support. Drs. Gary Sonnichsen and Edward (Ted) Little, managers of Geoscience for New Energy Supply Program of Geological Survey of Canada, are thanked for their continuous support of this study.

REFERENCES

Ambrose, R.J., Hartman, R.C., Diaz-Campos, M. Akkutlu I.Y. and Sondergeld, C. H., 2012. Shale gas-in place calculations Part I: New pore-scale considerations: SPE Journal, March, p. 219-229.

Armstrong, D.K., and Carter, T.R., 2010. The subsurface Paleozoic stratigraphy of southern Ontario: Ontario Geological Survey, Special Volume 7, 301p.

Armstrong, D.K., and Dodge, J.E.P., 2007. Paleozoic geology of southern Ontario: Ontario Geological Survey, Miscellaneous Release-Data 219.

Bailey Geological Services Ltd. and Cochrane, R.O., 1984a. Evaluation of the conventional and potential oil and gas reserves of the Cambrian of Ontario; Ontario Geological Survey, Open File Report 5499, 72p.

Bailey Geological Services Ltd. and Cochrane, R.O., 1984b. Evaluation of the conventional and potential oil and gas reserves of the Ordovician of Ontario; Ontario Geological Survey, Open File Report 5498, 77p.

Bailey Geological Services Ltd. and Cochrane, R.O., 1985. Evaluation of the conventional and potential oil and gas reserves of the Devonian of Ontario (Volume 1); Ontario Geological Survey, Open File Report 5555, 178p.

Bailey Geological Services Ltd. and Cochrane, R.O., 1986. Evaluation of the conventional and potential oil and gas reserves of the Silurian sandstone reservoirs of Ontario; Ontario Geological Survey, Open File Report 5578, 275p.

Bailey Geological Services Ltd. and Cochrane, R.O., 1990. Geology of selected oil and gas pools in the Silurian carbonates of southern Ontario; Ontario Geological Survey, Open File Report 5722, 50p.

Barclay, J.E., Holmstrom, G.D., Lee, P.J., Campbell, R.I., and Reinson, G.E., 1997. Carboniferous and Permian gas resources of the Western Canada Sedimentary Basin, Interior Plains, Part I: Geological play analysis and resource assessment; Geological Survey of Canada, Bulletin 515, p. 1-67.

Barker, J.F., 1985. Geochemical analysis of Ontario oil shales; Ontario Geological Survey, Open File Report 5568, 77p.

Barker, J., Russell, D.J., Johnson, M.D., and Telford, P.G., 1983. Oil shale assessment project, volume 3, organic geochemical results 1981-82; Ontario Geological Survey, Open File Report 5460, 36 p.

Béland-Otis, C. 2009. Shale gas assessment project, southern Ontario; in Summary of Field Work and Other Activities, 2009, Ontario Geological Survey, Open File Report 6240, p.30-1 to 30-4.

Béland Otis, C., 2010. Shale gas assessment project, southern Ontario: Preliminary results from the Kettle Point Formation; in Summary of Field Work and Other Activities, 2010, Ontario Geological Survey, Open File Report 6260, p.38-1 to 38-7.

Béland Otis, C., Carter, T.R., and Fortner, L., 2010. Preliminary Results of a Shale Gas Assessment Project in Ontario, Canada, Search and Discovery Article #50390 (2011), Posted March 14, 2011, Adapted from oral presentation at AAPG Eastern Section Meeting, Kalamazoo, Michigan, September 25-29, 2010.

Béland Otis, C., 2012a. Shale gas potential for the Ordovician shale succession of southern Ontario, Canada: American Association of Petroleum Geologists, Discovery Article #50730, Abstract.

Béland Otis, C., 2012b. Preliminary results: potential Ordovician shale gas units in southern Ontario; in Summary of Field Work and Other Activities 2012: Ontario Geological Survey, Open File Report 6280, p. 29-1 to 29-12.

Béland-Otis, C., 2013a. Gas Assessment of the Devonian Kettle Point Formation; Ontario Geological Survey Open File Report 6279, 63p.

Béland-Otis, C., 2013b. Geological, Geochemical and Geophysical Data from the Kettle Point Formation Drilling Program, Southern Ontario, Miscellaneous Release-Data 304.

Béland Otis, C., 2015a. Upper Ordovician Organic-Rich Mudstones of Southern Ontario: Drilling Project Results. Ontario Geological Survey, Open File Report 6312, 59 p.

Béland Otis, C., 2015b. Geological, Geochemical and Geophysical Data from the Ordovician Shales Drilling Program and the Regional Sampling Program, Southern Ontario, MRD 326 Metadata, http://www.geologyontario.mndm.gov.on.ca/mndmaccess/mndm_dir.asp?type=pub&id=MRD326.

Behar, F.V. Beaumont, H. L. Tenteado, B. De, 2001. Rock-Eval 6 technology: performances and developments: Oil Gas Sci. Technol. Rev. IFP 56, p. 111–134.

Bird, T.D., Barclay, J.E., Campbell, R.I., and Lee, P.J., 1994a. Triassic gas resources of the Western Canada Sedimentary Basin, Part I: Geological play analysis and resource assessment; Geological Survey of Canada, Bulletin 483, p 1-66.

Bird, T.D., Barclay, J.E., Campbell, R.I., and Lee, P.J., 1994b. Triassic gas potential seen high in western Canada plains region; Oil and Gas Journal, v. 92, December, 1994, p. 70-73.

Bohorquez, M.O. 2014. Hydrocarbon Discovery Potential in Colombian Basins: Creaming Curve Analysis, Search and Discovery Article #10613 (2014), Posted July 21, 2014. http://www.searchanddiscovery.com/pdfz/documents/2014/10613bohorquez/ndx_bohorquez.pdf.html

Brintnell, C. 2012. Architecture and stratigraphy of the Lower Silurian Guelph Formation, Lockport Group, southern Ontario and Michigan; University of Western Ontario, unpublished MSc thesis, 242 p.

Canadian Gas Potential Committee, 2006. Natural gas potential in Canada 2005; Canadian Gas Potential Committee, Volume 3: Frontier Basins, 103 p.

Cander, H. 2012. Sweet Spots in Shale Gas and Liquids Plays: Prediction of Fluid Composition and Reservoir Pressure; Search and Discovery Article #40936 (2012). Posted May 29, 2012 http://www.searchanddiscovery.com/pdfz/documents/2012/40936cander/ndx_cander.pdf.html

Carter, T.R., Clark, J., Colquhoun, I., Dorland, M., and Phillips, A., 2016a. Ontario Oil and Gas Plays 1. Exploration, production and geology; Canadian Society of Petroleum Geologists, Reservoir, volume 43, issue 8, p.19-24.

Carter, T.R., Hamilton, D., Phillips, A., Dorland, M., Colquhoun, I., Fortner, L., Clark, J., 2016b. Ontario Oil and Gas 3. Silurian and Devonian conventional plays; Canadian Society of Petroleum Geologists, Reservoir, Volume 43, issue 10, p.19-27.

Carter, T.R., Fortner, L., and Béland Otis, C., 2008. Shale gas opportunities in southern Ontario – an update. Oral Presentation at the 48th Annual OPI Conference and Trade Show, Sarnia, Ontario, Canada, November 11-13, 2008.

Charpentier, R.R. and Coke, T.A., 2011. USGS Methodology for Assessing Continuous Petroleum Resources, USGS, Open-File Report 2011–1167. https://pubs.usgs.gov/of/2011/1167/OF11-1167.pdf

Charpentier, R.R. and Coke, T.A., 2012. Improved USGS Methodology for Assessing Continuous Petroleum Resources, Data Series 547. https://pubs.usgs.gov/ds/547/downloads/DS547v2.pdf

Chen, Z., Lavoie, D. and Malo, M. 2014. Geological Characteristics and Petroleum Resource Assessment of Utica Shale, Quebec, Canada: Geological Survey of Canada, Open File 7606, 43 p. doi:10.4095/293793

Chen, Z., and Jiang, C. 2015, A data driven model for studying kerogen kinetics with application examples from Canadian sedimentary basins: Marine and Petroleum Geology, v. 67, p. 795-803.

Chen, Z., and Jiang, C. 2016. A revised method for organic porosity estimation using Rock-Eval pyrolysis data, example from Duvernay Shale in the Western Canada Sedimentary Basin: American Association of Petroleum Geologists, Bulletin, v. 100, no. 3, p. 405-422, DOI:10.1306/08261514173.

Chen, Z., Jiang, C., Lavoie, D., and Reyes, J., 2016a, Model-assisted Rock-Eval data interpretation for source rock evaluation: Examples from producing and potential shale gas resource plays: International Journal of Coal Geology, v. 165, p. 290–302, doi:10.1016/j.coal.2016.08.026.

Chen, Z., Lavoie, D., Jiang, C., Duchesne, M.J. andMalo, M., 2016b. Geological Characteristics and Petroleum Resource Assessment of the Macasty Formation, Anticosti Island, Quebec, Canada; Geological Survey of Canada, Open File 8018, 67 p., doi:10.4095/297865, http://geoscan.nrcan.gc.ca/starweb/geoscan/servlet.starweb?path=geoscan/downloade.web&search1=R=297865.

Chen, Z., Liu, X., and Jiang, C., 2017a. A Quick Evaluation of Source Rock Kerogen Kinetics Using Hydrocarbon Pyrograms from Regular Rock-Eval Analysis: Energy & Fuel. v. 31, no. 2, p. 1832–1841, http://dx.doi.org/10.1021/acs.energyfuels.6b01569.

Chen, Z., Liu, X. Guo, Q. Jiang, C. and Mort, A. 2017b. Inversion of source rock hydrocarbon generation kinetics from conventional Rock-Eval data: Fuel, v. 194, p. 91–101.

Chen, Z., Lavoie, D., Malo, M., Jiang, C., Sanei, H. and Haeri-Ardakani, O. 2017c. A dual-porosity model for evaluating petroleum resource potential in unconventional tight-shale plays with application to Utica Shale in Quebec, Canada: Marine and Petroleum Geology. v. 80, p. 333-348, http://dx.doi.org/10.1016/j.marpetgeo.2016.12.011.

Chen, Z., Liu, X., Jiang, C. and Mort, A. 2017. Source Rock Kerogen Kinetics Using Hydrocarbon Pyrograms from routine Rock-Eval Analysis. Geoconvention, Calgary, Canada, May 15-19, 2017.
http://www.geoconvention.com/archives/2017/277_GC2017_Source_Rock_Kerogen_Kinetics_Using_Hydrocarbon_Pyrograms.pdf

Churcher, R.L. Johnson, M.D. Telford R.G. and Barker, J.F., 1991. Stratigraphy and Oil Shale Resource Potential of the Upper Ordovician Collingwood Member, Lindsay Formation, Southwestern Ontario: Ontario Geological Survey, Open File Report 5817.

Coniglio, M., and A.E. Williams-Jones, 1992. Diagenesis of Ordovician carbonates from the north-east Michigan Basin, Manitoulin Island area, Ontario: evidence from petrography, stable isotopes and fluid inclusions: Sedimentology, v. 39, p. 813-836.

Churcher, P.L., Johnson, M.D., Telford, P.G., and Barker, J.F., 1991. Stratigraphy and oil shale resource potential of the Upper Ordovician Collingwood Member, Lindsay Formation, southwestern Ontario; Ontario Geological Survey, Open File Report 5817, 98 p

Dabbs, F., 2007. Craigleith Oil Shale Works, Ontario; Petroleum History Society Archives, Volume XVIII, Number 2.

Dorland, M., Colquhoun, I., Carter, T.R., Phillips, A., Fortner, L., Clark, J., and Hamilton, D., 2016. Ontario oil and gas 2. Cambrian and Ordovician conventional plays; Canadian Society of Petroleum Geologists, Reservoir, volume 43, issue 9, p.18-25.

Easton, R.M., and Carter, T.R., 1995. Geology of the Precambrian basement beneath the Paleozoic of southwestern Ontario; in Ojakangas, R.W., Dickas, A.B. and Green, J.C., eds., Basement Tectonics 10; Kluwer Academic Publishers, The Netherlands, p.221-264.

EIA, 2013. Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States.

Engelder, T. 2011. Analogue Study of Shale Cap Rock Barrier Integrity: Nuclear Waste Management Organization Report NWMO DGR-TR-2011-23 R000. Toronto, Canada.

Espitalié, J., Marquis, F., Sage, L., and Barsony, I., 1987. Géochimie organique du bassin de Paris: Revue de l'Institut Français du Pétrole, v. 42, p. 271–302.

Golder Associates Ltd., 2005. Hydrocarbon resource assessment of the Trenton-Black River hydrothermal dolomite play in Ontario; Ontario Oil, Gas and Salt Resources Library, 35 p.

Hamblin, A.P. 1999. Upper Ordovician Strata of Southwestern Ontario: Synthesis of Literature and Concepts: Geological Survey of Canada Open File 3729.

Hamblin, A.P. and Lee, P.J., 1997. Uppermost Cretaceous, post-Colorado Group gas resources of the Western Canada Sedimentary Basin, Interior Plains; Geological play analysis and resource assessment; Geological Survey of Canada, Bulletin 518, 88 p.

Hamblin, A.P. 2006. The “Shale Gas” Concept in Canada: a Preliminary Inventory of Possibilities: Geological Survey of Canada Open File 5384.

Hamblin, A.P. 2008. Hydrocarbon Potential of the Paleozoic Succession of Southwestern Ontario: Preliminary Conceptual Synthesis of Background Data: Geological Survey of Canada Open File 5730.

Hutt, R.B., MacDougal, T.A., and Sharp, D.A., 1973. Southern Ontario, in R.G. McCrossan, ed., The future petroleum provinces of Canada. Canadian Society of Petroleum Geologists, Memoir 1, p.411-442.

Jackson, R., 2009. Organic Geochemistry and Clay Mineralogy of DGR-3 and DGR-4 Core, Technical Report TR-08-29.

Jarvie, D.M., and Lundell., L.L., 2001. Kerogen type and thermal transformation of organic matter in the Miocene Monterey Formation, in Isaacs CM and Rullkötter J. eds., The Monterey Formation: From Rocks to Molecules: New York, Columbia University Press, p. 269–295.

Jarvie, D.M., 2012a. Shale resource systems for oil and gas: part 1—shale–gas resource systems. In: Breyer, J.A. (Ed.), Shale Reservoirs—Giant Resources for the 21st Century. AAPG Memoir 97, p. 69–87.

Jarvie, D.M., 2012b. Shale resource systems for oil and gas: part 2—shale–oil resource systems. In: Breyer, J.A. (Ed.), Shale Reservoirs—Giant Resources for the 21st Century: AAPG Memoir 97, p. 89–119.

Jiang, Q., Li, M., Qian, M., Li, Z., Li, Z., Huang, Z., Zhang, C., and Ma, Y., 2016. Quantitative characterization of shale oil in different occurrence state and its application: Pet. Geol. Exp. 38 (6), 843–848.
Jiang, C., Chen, Z., Lavoie, D., Percival, J.B., and Kabanov, P., 2017. Mineral carbon MinC (%) from Rock-Eval analysis as a reliable and cost-effective measurement of carbonate contents in shale source and reservoir rocks: Marine and Petroleum Geology, v. 83, p. 184-194, DOI: 10.1016/j.marpetgeo.2017.03.017.

Johnson, M.D., 1983. Oil shale assessment project – deep drilling results 1982/83 Toronto region; Ontario Geological Survey, Open File Report 5477, 17 p.

Johnson, M.D., 1985. Oil shale assessment project – shallow drilling results 1982/83 Kettle Point and Marcellus formations; Ontario Geological Survey, Open File Report 5531, 44 p.

Johnson, M.D., Russell, D.J., and Telford, P.G., 1983a. Oil shale assessment project Volume 1 – shallow drilling results 1981-1982; Ontario Geological Survey, Open File Report 5458, 36 p.

Johnson, M.D., Russell, D.J., and Telford, P.G., 1983b. Oil shale assessment project Volume 2 – drill holes for regional correlation; Ontario Geological Survey, Open File Report 5459, 20 p.

Johnson, M.D., Russell, D.J., and Telford, P.G., 1983c. Oil shale assessment project – drill holes for regional correlation 1983-1984; Ontario Geological Survey, Open File Report 5565, 49 p.

Johnson, M.D., Telford, P.G., Macauley, G., and Barker, J.F., 1989. Stratigraphy and oil shale resource potential of the Middle Devonian Marcellus Formation, southwestern Ontario; Ontario Geological Survey, Open File Report 5716, 149p.

Lazorek, M., and Carter, T.R., 2008. The oil and gas plays of Ontario: Ontario Petroleum Institute, Ontario Oil&Gas Magazine June 2008, June-Warren Publishing, p.18-27.

Lee, P.J., 2008. Statistical Methods for Estimating Petroleum Resources, Oxford University Press.

Lee, P.J., 1993. Two decades of Geological Survey of Canada petroleum resource assessments: Canadian Journal of Earth Sciences, v. 30, no. 2, p. 321-332.

Lee, P.J., and Singer, D.A., 1994. Using PETRIMES to estimate mercury deposits in California: Nonrenewable Resources; v. 3, no. 3, p. 191-199.

Lee, P.J. and Wang, P.C.C., 1983. Probabilistic formulation of a method for the evaluation of petroleum resources: Mathematical Geology, v. 15, no. 1, p. 163-181.

Lee, P.J. and Wang, P.C.C., 1985. Prediction of oil or gas pool sizes when discovery record is available: Mathematical Geology, v. 17, no. 2, p. 95-113.

Lee, P.J. and Wang, P.C.C., 1986. Evaluation of petroleum resources from pool size distribution: in, Oil and Gas Assessment Methods and Applications, D.D. Rice, ed.; American Association of Petroleum Geologists, Studies in Geology, no. 21, p. 33-42.

Lee, P.J. and Wang, P.C.C., 1990. An introduction to petroleum resource evaluation methods: Canadian Society of Petroleum Geologists, 1990 Convention on Basin Perspectives, Short Courses Program: SC-2 Petroleum Resource Evaluation, 108 p.

Legall, F. D., Barnes, C.R., and Macqueen, R.W., 1981. Thermal maturation, burial history and hotspot development, Paleozoic strata of southern Ontario - Quebec, from conodont and acritarch colour alteration studies: Bulletin of Canadian Petroleum Geology, v. 29, no. 4, p. 492-539.

Li, M., Z. Chen, T. Cao, X. Ma, X. Liu, Z. Li, Q. Jiang and S. Wu. 2018. Expelled oils and their impacts on Rock-Eval data interpretation, Eocene Qianjiang Formation in Jianghan Basin, China: International Journal of Coal Geology v. 191, April 2018, Pages 37-48.

Logan, K., 2005. The truncated discovery process model: Natural Resources Research, v. 14, No. 3, September 2005, DOI: 10.1007/s11053-005-8080-4

Meisner, J. and Demirmen, F., 1981, The creaming method: a bayesian procedure to forecast future oil and gas discoveries in mature exploration provinces: Journal of the Royal Statistical Society, v. 144, part A, p. 1-31.

Melchin, M.J., Brookfield, M.E., Armstrong, D.K. and M. Coniglio, M., 1994. Stratigraphy, sedimentology and biostratigraphy of the Ordovician rocks of the Lake Simcoe area, south-central Ontario: Geological Association of Canada–Mineralogical Association of Canada, Joint Annual Meeting, Waterloo, Ontario, Guidebook for Field Trip A4.

Modica, C.J., and Lapierre, S.G, 2012. Estimation of kerogen porosity in source rocks as a function of thermal transformation: Example from the Mowry Shale in the Powder River Basin of Wyoming: American Association of Petroleum Geologists Bulletin, v. 96, p. 87–108.

Obermajer, M., Fowler, M.G. and Snowdon, L.R. 1999. Depositional environment and oil generation in Ordovician source rocks from southwestern Ontario, Canada: Organic geochemical and petrological approach: American Association of Petroleum Geologists Bulletin, v. 83, no. 9, p. 1426-1453.

Obermajer M., Fowler, M.G., and Snowdon, L.R., 1998. A geochemical characterization and a biomarker re-appraisal of the oil families from southwestern Ontario: Bulletin of Canadian Petroleum Geology, v. 46, p. 350-378.

Obermajer, M., Fowler, M.G., and Snowdon, L.R. , 2005. Black shales of southern Ontario and their petroleum potential: American Association of Petroleum Geologists, Search&Discovery Article 90039, Abstract.

Olsen-Heise, K., Lee, P.J., and Reinson, G.E., 1995. Resource assessment of the Cadotte Plains and Deep Basin gas; in, Proceedings of the Oil and Gas Forum >95 - Energy from Sediments, J.S. Bell, T.D. Bird, T.L. Hillier, and P.L. Greener (eds.); Geological Survey of Canada, Open File 3058, p. 361.

Oil Gas and Salt Resources Library, 2016. Oil and gas pools and pipelines of southern Ontario, map 1:400 000 and pool production tables.

Osadetz, K.G., Hannigan, P.K, Carter, T.R. and Trevail, R., 1996. Reappraising petroleum potential in eastern Canada cratonic basins in light of new methods and data: A provisional assessment of the Michigan Basin in southwestern Ontario; in Proceedings, Ontario Petroleum Institute, 35th Annual Conference, Toronto, Ontario, v.35, Technical Paper 11, 19p.

Passey, Q.R., Creaney, S., Kulla, J. B., Moretti F. J. and Stroud, J. D., 1990. A practical model for organic richness from porosity and resistivity logs: American Association of Petroleum Geologists Bulletin, v. 74, p. 1777-1794.

Peters, K. E., 1986. Guidelines for evaluating petroleum source rock using programmed pyrolysis: American Association of Petroleum Geologists Bulletin 1986, v. 70, no. 3, p. 318–329.

Phillips, A.R., 2014. Devonian and Ordovician Shale correlations under Lake Erie, bridging the gap; Oral Presentation at the AAPG Eastern Section Meeting, London, Ontario, Canada, September 27-30, 2014.

Phillips, A.R., 2016. North America's first oil shale play, Ordovician Collingwood (Utica) Shale in Southwestern Ontario; Core Workshop, 54th Annual OPI Conference and Trade Show, London, Ontario, Canada, May 4, 2016, 47p.

Phillips, A.R., Carter, T.R., Fortner, L., Clark, J., Hamilton, D., Dorland, M., Colquhoun, I., 2016. Ontario Oil and Gas 4. Unconventional resource potential of Ontario. Canadian Society of Petroleum Geologists, v.43, issue 11, p.17-23.

Pillot, D., Deville, E., and Prinzhofer,A., 2014. Identification and quantification of carbonate species using Rock-Eval pyrolysis: Oil Gas Sci. Technol. – Rev. IFP 69, p. 341-349.

Podruski, J.A., Barclay, J.E., Hamblin, A. P., Lee, P.J., Osadetz, K. G., Procter, R. M., and Taylor, G. C., 1988. Conventional oil resources of Western Canada (light and medium), Part I: Resource endowment; Geological Survey of Canada, Paper 87-26, p. 1-125.

Powell, T.G.R., Macqueen, R.W., Barker, F.J., and Bree, D.G., 1984. Geochemical character and origin of Ontario oils: Bulletin of Canadian Petroleum Geology, v.32, p. 299-312.

Procter, R.M., Taylor, G.C., and Wade, J.A., 1984. Paleozoic basins-eastern Canada, in Oil and natural gas resources of Canada 1983. Geological Survey of Canada, Paper 83-31, p.42-43.

Reinson, G.E. and Lee, P.J., 1993. Study finds Devonian gas resources of western Canada attractive target; Oil and Gas Journal, v. 91, September 13, 1993, p. 80-85.

Reinson, G.E., Lee, P.J., Warters, W., Osadetz, K.G., Bell, L.L., Price, P.R., Trollope, F., Campbell, R. I., and Barclay, J. E., 1993. Devonian gas resources of the Western Canada Sedimentary Basin; Part I: Geological play analysis and resource assessment; Geological Survey of Canada, Bulletin 452, p. 1- 127.

Russell, D.J. and Telford, P.G., 1983. Revisions to the stratigraphy of the Upper Ordovician Collingwood Beds of Ontario – A potential oil shale; Canadian Journal of Earth Sciences, v.20, p.1780-1790.

Russell, D.J., 1985. Depositional analysis of a black shale using gamma-ray stratigraphy: The Upper Devonian Kettle Point Formation of Ontario; Bulletin of Canadian Petroleum Geology, v. 33, No. 2 (June, 1985), p. 236-253.

Sanford, B.V., 1961. Subsurface stratigraphy of Ordovician Rocks in southwestern Ontario; Geological Survey of Canada, Paper 60-26. 54p.

Snedden, J.W. Sarg, J.F. and Ying, X., 2003. Exploration Play Analysis from a Sequence Stratigraphic Perspective, AAPG Search and Discovery Article #40079 (2003) http://www.searchanddiscovery.com/pdfz/documents/snedden/images/snedden.pdf.html

Snowdon, L.R., 1984. A comparison of RockEval pyrolysis and solvent extract from the Collingwood and Kettle Point oil shales, Ontario: Bulletin of Canadian Petroleum Geology, v.32, p. 327-334.

Snowdon, L.R., 1995. Rock-Eval Tmax suppression: documentation and amelioration. American Association Petroleum Geologists Bulletin, v. 79, p. 1337–1348.

Sterling, S. 2011. Bedrock Formations in DGR-7 and DGR-8, technical report TR-11-06 to NMWO.

Sterling, S., 2011. Bedrock Formations in DGR-7 and DGR-8, Technical report TR-11-06 to NWMO.

Stoneburner, D., 2013. The Exploration, Appraisal and Development of Unconventional Reservoirs: A New Approach to Petroleum Geology, AAPG Distinguished Lecture. http://www.searchanddiscovery.com/documents/2015/110181stoneburner/ndx_stoneburner.pdf

Sweeney, S.N., 2014. Allostratigraphy of the Upper Ordovician Blue Mountain Formation, southwestern Ontario, Canada. MSc thesis, University of Western Ontario, electronic thesis and dissertation repository, Paper 2555, 301 p., http://ir.lib.uwo.ca/etd/2555/

Tissot, B. P., and D. H. Welte, 1984, Petroleum formation and occurrence: New York, Springer, 699 p.

USGS, 2016. The Importance of Reserve Growth to the Nation's Supply of Natural Gas, Fact Sheet FS-202-96. https://pubs.usgs.gov/fs/fs-202-96/

Wang, H.F., Crowley, K.D and Nadon, G.C., 1994. Thermal History of the Michigan Basin from Apatite Fission-Track Analysis and Vitrinite Reflectance. In basin Compartments and Seals P.J. Ortoleva,ed., AAPG Memoir 61. American Association of Petroleum Geologists. Tulsa, Oklahoma, USA.

Wang, J., Luo, H., Liu, H., Lin, J., Li, Lin, W., 2016a. Influences of adsorption/desorption of shale gas on the apparent properties of matrix pores. Petroleum Exploration and Development, 43 (1), p.158-165. http://www.sciencedirect.com/science/journal/18763804/43/1.

Warters, W.J., Cant, D.J., Tzeng, H.P., and Lee, P.J., 1997. Mannville gas resources of the Western Canada Sedimentary Basin; Geological Survey of Canada, Bulletin 517, 101 p.

Yu, W., Sepehmoori, K., and Patzek, T.W., 2015. Modeling gas adsorption in Marcellus Shale with Langmuir and BET isotherms, SPE 170801, SPE Journal, p.1-12.

Zhang, T, Ellis, G.S., Ruppel, S.C., Milliken K. and Yan, R. 2012. Effect of organic-matter type and thermal maturity on methane adsorption in shale-gas systems: Organic Geochemistry v. 47, p. 120–131.

Appendix A. Collingwood Member thickness data sheet

Licence	Township	Latitude	Longitude	Ground Elev. (m)	TVD (m)	Thicknesses (m)	QA	Source
H000015	Melancthon	44.1402158	-80.358622	503.3	611.5	10.8	2	SV7
T006311	Jocelyn	46.0962378	-83.927433	189.62	349.94	10.55	2	OFR 5817
N000257	Collingwood	44.51392	-80.426963	263.8	117.34	10.16	2	OFR 5817
N000264	Collingwood	44.5880164	-80.513346	218.76	80.85	10.06	2	OFR 5817
N000258	Collingwood	44.5342019	-80.35379	226.5	55.9	10.04	2	OFR 5817
T006332	Collingwood	44.5272722	-80.459723	219.3	95.7	9.7	2	OFR 5817
N000262	Collingwood	44.5339797	-80.414292	219.3	63.7	9.58	2	OFR 5817
T012100	Arthur	43.9599642	-80.635347	458.7	496.5	9.4	2	MRD326
N002887	King	43.9755558	-79.57825	317.5	250.2	9.44		OFR 5817
N002593	Nottawasaga	44.3541944	-80.151278	317	263.65	9.14	2	OFR 5817
F014217	Darlington	43.8691667	-78.755417	89	302.7	9	2	OFR 5817
T011811	Bruce	44.3214039	-81.588406	187.35	871.3	8.7	2	TR-11-06
T006056	Albemarle	44.7918558	-81.23235	196	446.5	8.4	2	SV7
T011812	Bruce	44.3304625	-81.584761	181.6	859.2	8.4	2	TR-11-06
T011583	Bruce	44.3212958	-81.574259	185.8	864.2	7.9	2	TR-11-06
T002306	Nottawasaga	44.4858075	-80.268958	218.8	NULL	7.62	2	OFR 5817
T001938	Dereham	42.9217142	-80.870968	274.3	1036	7.6	2	log interpretation
H000038	Proton	44.180045	-80.573381	475.49	701.95	7.6	2	OFR 5817
N000259	Collingwood	44.53446	-80.357299	183.8	32.08	7.42	2	OFR 5817
N000255	Collingwood	44.4674419	-80.27927	261.5	80.01	7.32	2	OFR 5817
T004767	Turnberry	43.8650989	-81.175928	342.3	865.94	8.8	2	log interpretation
T006883	Cockburn Island	45.8666944	-83.344806	192.43	521	6.7	2	OFR 5817
T001842	Niagara	43.1828356	-79.144788	98.75	726.9	3.1	2	log interpretation
T001924	Dereham	42.9415186	-80.872609	275.2	1014.98	7.62	2	OFR 5817
T011961	Bidwell	45.8619589	-81.968507	239.9	139.29	6.55	2	OFR 5817
N002129	Howland	45.9509353	-82.004627	195.07	38.1	6.45	2	OFR 5817
N000256	Collingwood	44.4940922	-80.318462	232.25	49.68	6.29	2	OFR 5817
N002555	Pickering	43.8647222	-79.070861	86.48	42.52	6.19	2	OFR 5817
T003552	Canborough	43.0107028	-79.69025	186.23	920.5	3.7	2	log interpretation
T002754	Maryborough	43.8355203	-80.664325	434.9	743.41	9.4	2	log interpretation
T002327	Assiginack	45.7627222	-81.843417	195.07	252.4	6.1	2	SV7
N002108	Cockburn Island	45.9187222	-83.320917	249.94	376.73	6.1	2	OFR 5817

H000141	Adjala	44.0691667	-79.930806	241	296.6	6.1	2	OFR 5817
H000033	Keppel	44.6164269	-80.979618	239.57	472.44	6.1	2	OFR 5817
F011963	Nassagaweya	43.6184444	-80.074111	334.41	643.7	6.1	2	OFR 5817
F012141	Amabel	44.7059478	-81.19436	208.5	501.4	6	2	OFR 5817
T004910	Kincardine	44.1538056	-81.454639	282.2	909	9.1	2	log interpretation
N002180	Sheguiandah	45.8562111	-81.818264	190.5	49.3	5.97	2	OFR 5817
F012012	Vaughan	43.8206125	-79.447026	203.51	345.9	5.79	2	OFR 5817
T008369	Blenheim	43.2565397	-80.586939	308.4	863	6	2	log interpretation
T011197	Vaughan	43.8205714	-79.502152	197.5	1414.3	4.88	2	OFR 5817
N002130	Howland	45.9510228	-82.038711	190.5	27.43	4.83	2	OFR 5817
N000261	Collingwood	44.5328631	-80.397559	223.7	57.63	4.8	2	OFR 5817
F014415	Robinson	45.851	-82.758333	NULL	762	4.78	2	OFR 5817
N002554	Pickering	43.8163486	-79.039476	76.47	32.61	4.7	2	OFR 5817
N002894	City of Toronto	43.8140889	-79.154003	86.33	56.01	4.65	2	OFR 5817
F012155	St. Edmunds	45.233	-81.616778	205.44	492.25	6.4	2	OFR 5817
T012473	Indian Reserve no. 26	45.5556558	-81.920761	181.1	376.43	4.57	2	OFR 5817
T004065	Mulmur	44.2052453	-80.082527	324.75	371.86	4.57	2	OFR 5817
F012153	Lindsay	45.1460278	-81.400167	222.5	438.3	4.57	2	OFR 5817
T004730	Elma	43.6500481	-81.046256	357.84	873.25	8.2	2	log interpretation
T004105	Stephen	43.2524861	-81.719833	191.1	1153.97	3.4	2	MRD326
T001714	Malahide	42.7340556	-80.896861	225.6	1144.2	3.4	2	log interpretation
T002627	Egremont	44.030755	-80.676017	449.58	679.7	9.7	2	OFR 5817
F011248	Pelham	43.0877619	-79.293687	114.3	750.4	3.05	2	OFR 5817
T004907	Wainfleet	42.9126278	-79.299292	176	1008.8	3.05	2	OFR 5817
T002613	Egremont	44.0036583	-80.704855	422.45	677.57	9.5	2	MRD326
T002284	Egremont	44.0340556	-80.692294	438.61	672.08	10.6	2	log interpretation
F011943	Esquesing	43.5999722	-79.950444	284.07	573.6	3.05	2	OFR 5817
F011913	Esquesing	43.58575	-79.936889	259.08	584	3.05	2	OFR 5817
T006305	Howland	45.9411822	-81.946845	281.9	222.92	9	2	MRD326
T006124	Pickering	43.8165164	-79.057891	88.16	251.5	4.7	2	log interpretation
T006120	Nassagaweya	43.5347914	-79.958576	304.8	637.64	2.1	2	log interpretation
T004985	Elma	43.5843536	-80.962754	363.6	875.1	11.5	2	log interpretation
T007511	Plympton	42.9479722	-82.011222	202.1	1269	3.5	2	log interpretation
H000143	Adjala	44.0698056	-79.933917	240	304.8	1.52	2	OFR 5817

N002895	City of Toronto	43.6857222	-79.364783	92.55	124.64	1.46	2	OFR 5817
T006044	Moore	42.8017603	-82.464298	190.8	1380.7	0	2	log interpretation
T006102	Toronto	43.4981125	-79.630054	94.4	429	3	2	MRD326
F005446	Charlotteville	42.7406389	-80.294944	214.6	1711.8	0.8	2	core
T006817	Lake Erie	42.4640928	-81.496396	174.7	1296	0	1.5	log interpretation
T006815	Lake Erie	42.0901969	-81.779723	174.7	1436	0	2	log interpretation
T008346	Dover	42.46175	-82.284861	179	1179	0	2	log interpretation
T010596	Raleigh	42.3194675	-82.212162	178.85	1173	0	2	log interpretation
T008203	Mersea	42.0886786	-82.621074	207.3	802	0	NULL	log interpretation
T007873	Colchester South	42.0492222	-82.960083	189	925	0	NULL	log interpretation
T007836	Aldborough	42.5268889	-81.729444	210.9	1269	0	2	log interpretation
T007821	Mersea	42.1184444	-82.504056	188.9	823	0	2	log interpretation
T008079	Pelee	41.7633792	-82.672899	174.3	926	0	2	log interpretation
T006539	Mersea	42.0269722	-82.554667	177	1062	0	2	log interpretation
T006127	Mersea	42.0968889	-82.542889	186	1080	0	2	OFR 5817
T002948	Rochester	42.24475	-82.61725	181.36	1074.42	0	2	OFR 5817
T002843	Lake Erie	41.8858758	-82.991589	173.74	936.04	0	2	OFR 5817
T000565	Colchester North	42.1239167	-82.909444	186.23	854.05	0	2	OFR 5817
T000187	Colchester South	42.0039167	-82.964333	177.39	749.81	0	2	OFR 5817
N002620	West Gwillimbury	44.1750556	-79.54875	252	256.03	0	2	OFR 5817
N002613	Nottawasaga	44.4876389	-80.161556	177.4	NULL	0	2	OFR 5817
N002599	Nottawasaga	44.4291111	-80.140083	228.6	125.88	0	2	OFR 5817
N002588	Essa	44.2164606	-79.844156	230	629.41	0	2	OFR 5817
H000186	North Gwillimbury	44.2598889	-79.349806	224.64	189.3	0	2	OFR 5817
H000180	East Gwillimbury	44.1229164	-79.476253	226.2	254.51	0	2	OFR 5817
H000179	East Gwillimbury	44.1920553	-79.359569	229.82	329.79	0	2	OFR 5817
H000121	Brock	44.2498283	-79.116113	271.58	349.3	0	2	OFR 5817
T007714	Dover	42.36825	-82.382917	175.1	1132	0	2	log interpretation

T008512	Lake Erie	42.2872989	-80.881942	174.4	1464.5	0	2	log interpretation
T005473	Lake Erie	42.4365711	-80.223639	174.6	1427	0	2	log interpretation
T006078	Yarmouth	42.6707683	-81.161395	211.4	1168.5	1.2	2	core
T006960	Mosa	42.6651542	-81.812501	212.1	1158.5	1.5	2	MRD326
T006818	Lake Erie	42.4667122	-81.146814	173.7	1269	2	2	MRD326
T010456	Malahide	42.6632344	-80.904139	204.1	1185	2	2	MRD326
T006364	Goderich	43.5986542	-81.626277	278.55	1134	7.5	2	MRD326
T002887A	Lake Erie	42.7670867	-79.342268	173.7	1250.9	1.8	2	MRD326
T004907	Wainfleet	42.9126278	-79.299292	176	1008.8	3.05	2	OFR 5817
T009793	South Easthope	43.331155	-80.846379	356.9	925.9	5.4	2	log interpretation
T001536	Delaware	42.8667942	-81.35232	242.6	1088.14	0	2	log interpretation
N002613	Nottawasaga	44.4876389	-80.161556	177.4	NULL	0	2	OFR 5817
N002599	Nottawasaga	44.4291111	-80.140083	228.6	125.88	0	2	OFR 5817
T010043	Lake Erie	42.6847667	-79.499233	174.4	1302	1.3	2	log interpretation

Appendix B. Hydrocarbon Volume Calculation in Self-Sourced Reservoir

Estimation of organic porosity

The organic porosity $\emptyset_{org}$ can be estimated from the following equation (Chen and Jiang, 2016):

$$\emptyset_{org} = \gamma[C_{toc}^{o}\alpha f T_R\left(1 - \frac{0.833C_{toc}}{100}\right)]\frac{\rho_b}{\rho_k} \qquad (B1)$$

where C_{toc} is the measured total organic carbon content (in weight fraction), α ($\alpha = H_i^o/1200$) is the percentage of petroleum convertible carbon in TOC (a function of kerogen type); f is an expulsion efficiency (fraction); T_R is transformation ratio that is a function of kerogen type and thermal maturity; $\rho_b\, and\, \rho_k$ are the rock bulk density and the density of the kerogen respectively; and γ represents the carbon equivalent mass of kerogen in hydrocarbon conversion (γ=1.200).

Adsorbed gas

Langmuir (monolayer) gas absorption in organic rich shales can be described by the following Langmuir equations (Yu et al., 2015; Zhang, 2012):

$$V_P = V_L\frac{P_{res}}{P_L + P_{res}} \qquad (B2)$$

where V_L is the Langmuir volume (maximum capacity of adsorption), V_P is a specific adsorption capacity at reservoir pressure P_{res} (kPa), P_L is the Langmuir pressure (kPa), at which one half of the Langmuir volume ($V_L/2$) can be adsorbed. The gas in adsorption state can be estimated from the following relationship:

$$Gas_{in-place}^{adsorbed} = V_{rock}\rho_b V_L\frac{P_{resv}}{P_L + P_{resv}} \qquad (B3)$$

where V_{rock} is the rock volume (m^3), ρ_b is bulk rock density (ton/m^3); P_{resv}: reservoir pressure (kPa); V_L: Langmuir volume (scf/ton), which can be approximated by a function of TOC content and is derived from the following relationship in this study:

$$V_L = \beta\, C_{toc} + C \qquad (B4)$$

where β is an unknown scale parameter, and C is a constant that relates to other contributions for the adsorbed methane in the reservoir. Both parameters can be determined from laboratory tests on rock examples, and Yu et al. (2015) provides a good example of obtaining such a relationship.

Ambrose et al. (2012) indicated that the adsorbed gas from Eq. (A3) occupies pore space that has to be removed from the volumetric calculation for free oil and gas. The over-estimation (in scf/ton) can be quantified by the following equation:

$$Gas_{ov}^{ad} = \frac{32.0368}{B_g}\{\frac{0.000001318\widehat{M}}{\rho_s} V_L \frac{P_{resv}}{P_L + P_{resv}}\} \quad \text{(B5)}$$

where $\widehat{M}$ is natural gas apparent molecular weight (16 lb/lb-mole), ρ_s is gas density in adsorbed-phase (0.34 g/cm^3) and *Bg* is gas formation volume factor. For details of the derivation of Eq. (A5) and application examples, readers are referred to Ambrose et al. (2012). Yu et al. (2015) presented a mathematical formulation for estimating adsorbed gas considering multi-layers adsorption based on the BET isotherm.

Hydrocarbon volumetric calculation

To capture the spatial variability of the resource potential in the target reservoir, the study area is divided into *N* equal sized cells with location index of *n*. The total hydrocarbon pore volume, V_{pHC}, in the reservoir can be estimated from the volumetric equation:

$$V_{pHC} = \sum_{n=1}^{N} A(n)T(n)\,\emptyset_{HC}(n) \quad \text{(B6)}$$

where *A(n)* is the cell size (m^2), *T(n)* is the net reservoir thickness (m), $\emptyset_{HC}$ *(n)* is hydrocarbon saturated reservoir porosity (in fraction).

The following equations are used to convert the in-place oil and gas pore volumes in reservoir condition to in-place oil and gas volumes in standard surface condition.

$$V_{oil} = f_{oil}V_{pHC}/F_{VF} \quad \text{(B7)}$$

$$V_{gas} = f_{gas}V_{pHC}/B_g \quad \text{(B8)}$$

$$V_{gas}^{sol} = V_{oil}G_{OR} \quad \text{(B9)}$$

where V_{gas}^{sol} is solution gas, F_{VF} is oil formation volume factor, *Bg* is gas formation volume factor and G_{OR} is gas to oil ratio. Methodology details and application examples are referred to Chen et al., 2017).