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Geological Characteristics and Petroleum Resource Assessment of Utica Shale, Quebec, Canada

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Introduction

The Upper Ordovician Utica Shale has been, since the early days of hydrocarbon exploration in southern Quebec, considered as an excellent hydrocarbon source rocks for conventional hydrocarbon systems (Lavoie et al., 2009; Dietrich et al., 2011). The paradigm shift towards its significance for resource play started in mid-2000 with initial drilling and testing of the Utica in 2006 (Lavoie et al., 2008). Since, 18 vertical and 11 horizontal wells have been drilled for evaluation and testing of the shale gas resource with 18 of them being fracked until 2010 (Lavoie et al., 2014).

No regional in-place resource evaluation is available for the Utica Shale. Various operators in southern Quebec have, over the years, released independent evaluation of the in-place and recoverable gas resource on their acreage, with mention of local liquids in-place without quantitative estimates. As part of a recent Quebec Government strategic environmental evaluation of the Utica Shale in southern Quebec, a report synthesizing and integrating numbers released by the industry came out with the conclusions that the Utica Shale hosts between 100 to 300 Tcf with an estimated recoverable resource between 22.4 and 47.4 Tcf (Duchaine et al., 2012).

For many years, the Geological Survey of Canada has carried out quantitative hydrocarbon resource evaluations for both mature and frontier sedimentary basins. However, as the industry moved towards appraisal and development of shale resource plays, an independent in-house methodology for quantitative evaluation of shale plays was not available within the GSC and this issue was identified as a critical technical gap to be rapidly addressed (Lavoie et al., 2012a). The new methodology had to be flexible enough to be applied for both gaz and liquid-rich plays and in both mature and frontier basins.

This report presents the methodology developed to evaluate hybrid shale gas play with hydrocarbon filled matrix and organic porosities. The dual-porosity methodology presented here allows for quantitative evaluation of in-place liquids and gaz resources in the Utica Shale of the St. Lawrence Platform that can be, from the density and quality of hydrocarbon exploration data, be considered as a frontier sedimentary basin.

Geological Setting of the St. Lawrence Platform

Regional setting

Rocks ranging in age from the Neoproterozoic to the Late Mesozoic are found onshore eastern Canada. The major Paleozoic tectonic events documented in the Appalachians are related to the obduction of ophiolites (oceanic crust) and progressive accretion of volcanic arcs, microcontinents and ultimately continents to the paleo-craton Laurentia (van Staal, 2005). The main compressive deformation phases climaxed during the Ordovician (Taconian Orogeny), the Devonian (Acadian Orogeny) and in Late Carboniferous–Permian (Alleghenian Orogeny).

In southern Quebec, the Cambrian – Late Ordovician sedimentary rocks preserved in the St. Lawrence Platform (Figure 1) recorded the Neoproterozoic rifting of Rodinia (Allen et al., 2009), to the development of a Cambrian – Early Ordovician passive margin (Lavoie et al., 2012b) and of a Middle – Late Ordovician foreland basin (Lavoie, 2008).

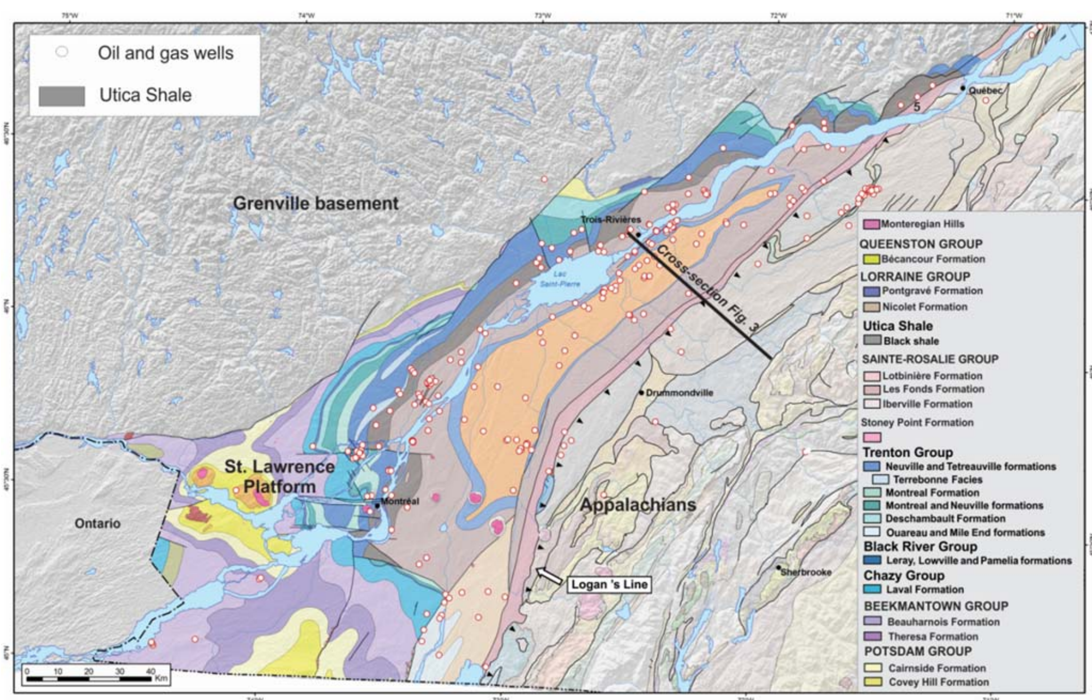

Figure 1: Simplified geological map of southern Quebec with the Cambrian-Ordovician St. Lawrence Platform between the Precambrian Grenville basement and the Cambrian-Devonian Appalachians. Logan's line marks the limit between the platform and the Appalachians whereas the platform is either in fault contact or unconformably overlying the Grenvillian basement. The map shows the location of oil and gas wells drilled in southern Quebec. The cross-section is on Figure 3. Stratigraphic legend is for St. Lawrence Platform units. Modified from Thériault (2012a).

Stratigraphy and structure of the St. Lawrence Platform

Stratigraphy

In southern Quebec, the St. Lawrence Platform corresponds to a Cambrian – Lower Ordovician siliciclastic and carbonate platform having a maximum thickness of ca. 1200 m, overlain by Middle – Upper Ordovician foreland carbonate-clastic depositsthat reach a minimum thickness of ca 1800 m locally (Figure 2) (Lavoie, 2008).

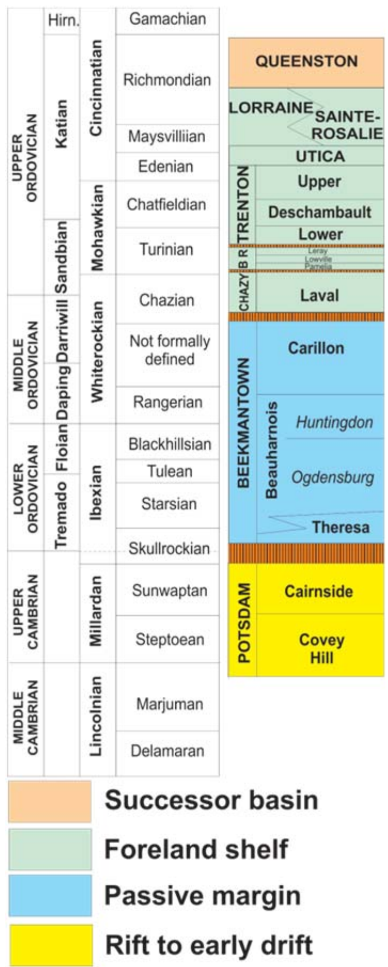

Figure 2: Stratigraphic framework of the St. Lawrence Platform in southern Quebec. Upper Cambrian to Upper Ordovician clastics and carbonates were deposited under evolving tectonic scenarios. The Upper Ordovician Utica Shale was deposited during the Taconian foreland shelf episode. No vertical scale. Modified from Lavoie (2008).

The base of the platform succession consists of the Upper Cambrian Potsdam Group, which unconformably overlies the Precambrian basement. The base of the Potsdam Group is dominated by a rift to early-drift fluvial to shallow marine succession of conglomeratic arkose and subarkose gradually passing upward to nearshore shallow marine quartz arenite (Lavoie, 2008).

A significant unconformity developed at the Cambrian – Ordovician boundary and was followed, in Early Ordovician times, by a eustatic sea level rise leading to the formation of a continental-wide passive margin (Lavoie et al., 2012b). In southern Quebec, the passive margin succession is recorded by the Beekmantown Group, which is dominated by intertidal to shallow subtidal limestones and dolostones deposited in response to high-frequency sea level fluctuations (Salad Hersi, 2012). The Lower Ordovician Beekmantown Group is truncated by an unconformity, which is recognized in many parts of North America (Lavoie et al., 2012b).

Along the active foreland margin, the Lower Ordovician carbonate platform succession was covered by an initially slow to ultimately rapid deepening-upward succession of limestone to argillaceous limestone to black organic-rich mudstone and capped by shallowing-upward flysch and post-orogenic molasse (Lavoie, 2008). The succession of foreland basin limestone and argillaceous limestone comprises the Chazy, Black River and Trenton groups.

The Trenton Group is overlain by the calcareous black mudstone of the Utica Shale. The Utica Shale is a diachronous unit, older approaching the Appalachian front, as in the Quebec City vicinity (*Corynoides americanus-Orthogratus ruedemanni* to the *Climacograptus spiniferus* graptolite Zones) and younger to the southwest on the Laurentian platform, as in the Montreal region (*Climacograptus pygmaeus* graptolite Zone). Diachronous east to west progression of subsidence was coincident with the progressive westward change from carbonate to siliciclastic sedimentation within the foreland basin, also documented elsewhere along the Appalachian Orogen (Ettensohn, 2008). The thickness of the Utica Shale ranges between 30 and 300 m, while the facies- and time-equivalent Stony Point Formation in southernmost Quebec can be as thick as 750 m. The Utica Shale unit is distinguished from younger siliciclastic facies by its higher calcite content, fine-grained limestone beds and lack of siltstone and sandstone suggesting that it was deposited prior to the influx of coarser sediments coming from the erosion of the advancing Appalachian thrust sheets.

The uppermost preserved succession consists of Upper Ordovician sediments that accumulated during and after the overthrusting of the external Taconian thrust sheets. The flysch unit is dominated by thick successions of mudstones with subordinate alternating sandstone and siltstone of the Lorraine Group that consists of two formations: the Pontgravé Formation is coarser grained and more calcareous compared to the underlying Nicolet Formation. The Lorraine Group is the thickest (up to 3800 m; Globensky et al., 1993) and the most exposed unit of the St. Lawrence Platform. The Lorraine Group lies conformably over the Utica Shale (Globensky, 1987). The Queenston Group is found at the top of the preserved sedimentary pile. It comprises one formation (Bécancour Formation) that consists of post-orogenic shale, sandstone and conglomerate (Globensky, 1987). The only occurrence of post-Ordovician sediments deposited on the St. Lawrence Platform is found in the Montréal area where a small outcrop of a diatreme breccia exposes fragments of the entire Cambrian-Ordovician succession with the addition of Middle Devonian limestones (Globensky, 1987). Finally, in Cretaceous times, silica-depleted – nepheline-rich plutons and lamprophyre dykes intruded the St. Lawrence Platform (Globensky, 1987; Rocher et al., 2003). These intrusions have a clear morphological signature and form the Monteregian Hills of southern Quebec.

Structural framework

In southern Quebec, most exposed strata of the St. Lawrence Platform are sub-horizontal, but are locally affected by mesoscopic open folding or locally by drag folds neighbouring faults. Major structural features include regional low angle thrust faults as well as normal faults bounding half grabens, and broad open folds related to the Chambly-Fortierville Syncline (Figure 1). Reprocessing and reinterpretation of regional deep seismic lines in southern Quebec have documented compressive deformation features, including triangle zones and blind thrusts, west of the previously assumed Appalachian structural front (Logan's Line; Castonguay et al., 2006, 2010). Other recent studies also advocate for a more complex structural evolution than previously thought, including: 1) Middle Ordovician normal faulting that results in the formation of sags affecting the foreland basin carbonates prior to the deposition of the fine-grained, organic-rich Utica Shale on top of the foundering carbonate platform (Thériault, 2007); 2) Late Ordovician compressive deformation associated with the Taconian Orogeny; 3) post-Ordovician (probably 'Acadian') folding (Pinet et al., 2008) and faulting (Sasseville et al., 2008).

The Yamaska Fault is one of the many basin-parallel extensional faults that cuts through the basement – platform succession and, based on available seismic data, seems to die out in the overlying flysch (Castonguay et al., 2010; Séjourné et al., 2013). This fault was active in late

Middle Ordovician and played a critical role in the depositional basin morphology and sedimentary evolution. The thickness and depth of the Utica Shale increase significantly east of the Yamaska fault (Figure 3), and consequently current shale gas exploration fairways are defined on the presence of that structure (see further).

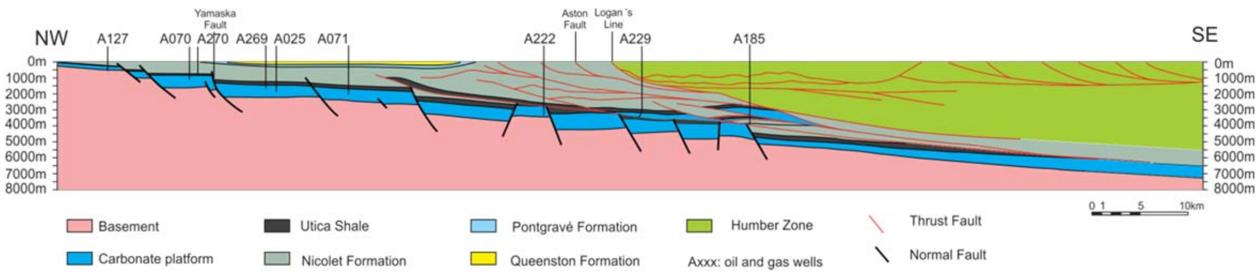

Figure 3: Structural cross-section based on limited field outcrops, oil and gas well data and MRN deep seismic line M-2002 (modified from Castonguay et al, 2006, 2010). The Utica Shale (in black) is progressively thicker and deeper from NW to SE and is also remobilized and imbricated in thrust stacks beneath the St. Lawrence Platform and the Appalachians. Location of cross-section on Figure 1. Cross-sections Modified from Séjourné et al. (2013).

Logan's Line delineates a series of thrust faults that mark the transition of the autochthonous (i.e. St. Lawrence Platform) and parautochthonous (i.e. imbricated thrust slices of the St. Lawrence Platform) domains with the allochthonous domain (Taconian thrust sheets; Figure 3). This line does not mark the structural front but the limit between *in situ* shallow and deep platform facies and coeval but tectonically transported deep marine slope and rise sediments. The thrust sheets comprise Proterozoic to Upper Ordovician rocks initially deposited on Laurentia continental slope and rise and transported over Laurentia continental margin (hence over the St. Lawrence Platform) during the Taconian accretion. The detailed stratigraphy of these deep marine facies can be found in Lavoie (2008).

<u>Current stress regime</u>

The maximum / minimum horizontal stress orientations were determined from borehole geomechanical studies of 17 wells of the St. Lawrence Platform by Konstantinovskaya et al. (2012). One of the major contributions of that study is that the present-day stress regime is of compressive strike-slip type between depths of 250 to 4 000 m. The average maximum horizontal stress orientation is estimated at N59°E±20°, varying along the Appalachian front. These results compare well with the regional NE–SW maximum horizontal stress orientation observed regionally in eastern Canada (Plumb and Cox, 1987). The proposed modern strike-slip regime is also compatible with the compressive features locally observed at surface (Wallach and Chagnon, 1990).

Utica Shale

Facies and internal stratigraphy

New-York

The term Utica Shale was introduced by Emmons (1842) for a succession of late Middle Ordovician calcareous shales in the Mohawk Valley in central New York. The first geologists to map the St. Lawrence Platform in southern Quebec imported this nomenclature. The thickness of the Utica in New York, as in southern Quebec, increases towards the east, from *circa* 50 m to a maximum close to 1000 m with synsedimentary faults controlling thickness and to some extent the total organic carbon (TOC) richness of the unit (Smith, 2011). The Utica Group is locally unconformably overlying the Trenton Group and is conformably overlain by the Lorraine Group (Smith, 2011). In New York, the Utica Group consists of three formations: in ascending order, the Flat Creek, the Dolgeville and the Indian Castle. As in southern Quebec, the Utica Group in New York is time-transgressive to the west with the lower two formations being time-correlative with the Trenton Group (Baird and Brett, 2002; Smith, 2011). The tripartite division of the Utica in New York is based on the presence of a very distinctive shaly carbonate unit (Dolgeville Formation) that is underlain and overlain by calcareous shales. These various units can also be recognized on the basis of their TOC content; the Flat Creek Formation is characterized by TOC values that range from 1.5% to 3.0%, the ribbon limestone-dominated Dolgeville Formation yields TOC values between 1% and 1.5%, and the TOC content of members of the Indian Castle Formation is usually less than 1.0%. (Nyahay, 2008).

Quebec

Stratigraphy

In Quebec, the Utica Shale consists of limy mudstone; the high carbonate content and the absence of sandy layers being the physical elements used to distinguish the Utica Shale from the overlying shale-dominated Lorraine Group (Lavoie et al., 2008; Thériault, 2012a). However, this lithostratigraphic limit has not been strictly applied in the past and on number of geological maps in southern Quebec, non-calcareous shales (i.e. Lorraine Group) are mapped out as the Utica, in particular in the Montreal area of southernmost Quebec (Trempe, 1978). The contact between the Utica Shale and the overlying Nicolet Formation at the base of the Lorraine Group is sharp and possibly disconformable in the northwestern and western parts of the St. Lawrence Platform, usually on the north shore of the St. Lawrence River and west of the Yamaska Fault, whereas, based on well data, the contact is gradual towards the southeast and to the east of the Yamaska Fault (Thériault, 2012a; Séjourné et al., 2013).

The source of carbonate mud in the Utica Shale and its upsection abundance variation have been interpreted to be related to 5th order transgressive – regressive cycles with highstand shedding of mud from the carbonate platform which was backstepping on the Precambrian craton at that time (Lavoie, 2008; Lavoie et al., 2008). Centimeter-thick shaly limestone beds punctuate the Utica succession, but are clearly more abundant in the middle part of the succession. In well-exposed sections, these limestone intervals are almost invariably forming meter-thick thickening-upward cycles (Figure 4). Based on abundant graptolites fauna, the Utica is assumed to be Edenian to Maysvillian in age (Riva, 1969), a time interval supported by chitinozoan data (Lavoie and Asselin, 1998). Besides graptolites, brachiopods, trilobites and cephalopods are common, suggesting the lack of anoxic conditions in the depositional basin.

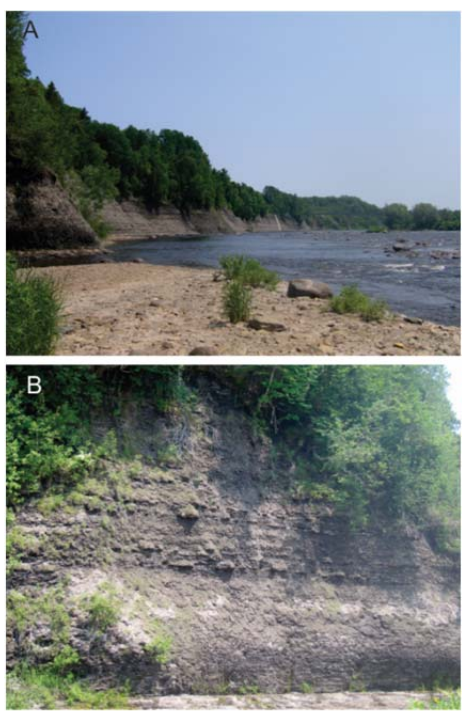

Figure 4: A) The Utica Shale along the Jacques Cartier River, 50 km southwest of Quebec City on the

north shore of the St. Lawrence River. B) Close-up view of the river cliff showing prominent limy mudstone beds forming a 3 m thick thickening upward interval. Exposed vertical view is 7 m.

Based on recent lithological, mineralogical and petrophysical data, Thériault (2012a, b) suggested the division of the Utica Shale into two informal (lower and upper) units. The lower Utica is characterized by a mineralogical composition close to that of the underlying Trenton Group, whereas the mineralogy of the upper Utica reflects a progressive transition with the overlying Lorraine Group. Even if the major mineralogical components are present in both informal units, there are some significant differences (see further). The thickness of these two units is fairly similar although the upper Utica is usually slightly thicker, particularly east of the Yamaska Fault (Thériault, 2012b).

Structural framework

There are few structural studies specific to the Utica Shale. From a detailed high resolution satellite (QuickBird) images and field surveys, Pinet (2011) documented a complex fracture framework along the low-tide north shore of the St. Lawrence River southwest of Quebec City. Two generations of folds, superimposed over the regional Chambly-Fortierville syncline, are recognized. Faults trend N100°-N120° or N30°-N60°; however their precise kinematic is unknown. Fracture orientations are fairly scattered, but NE and WNW sets dominate.

Mineralogy

The first systematic work on the mineralogical composition of the Utica Shale is from Thériault (2012b). Nearly 300 X-ray diffraction analyses were carried out on Trenton Group, Utica Shale and lower Lorraine Group cuttings from 18 wells.

The Utica Shale samples are rich in calcite whereas the Lorraine shales are calcite-poor, clay-rich with higher percentages of quartz and feldspar compared to the Utica Shale. Calcite content decreases from the Trenton Group to a minimum near the top of the lower Utica Shale, calcite content rapidly increases up to the middle part of the upper Utica Shale and then decreases significantly to minimal values at the base of the Lorraine Group. Clays as well as quartz and feldspars content trends inversely to that of the calcite (Fig. 5).

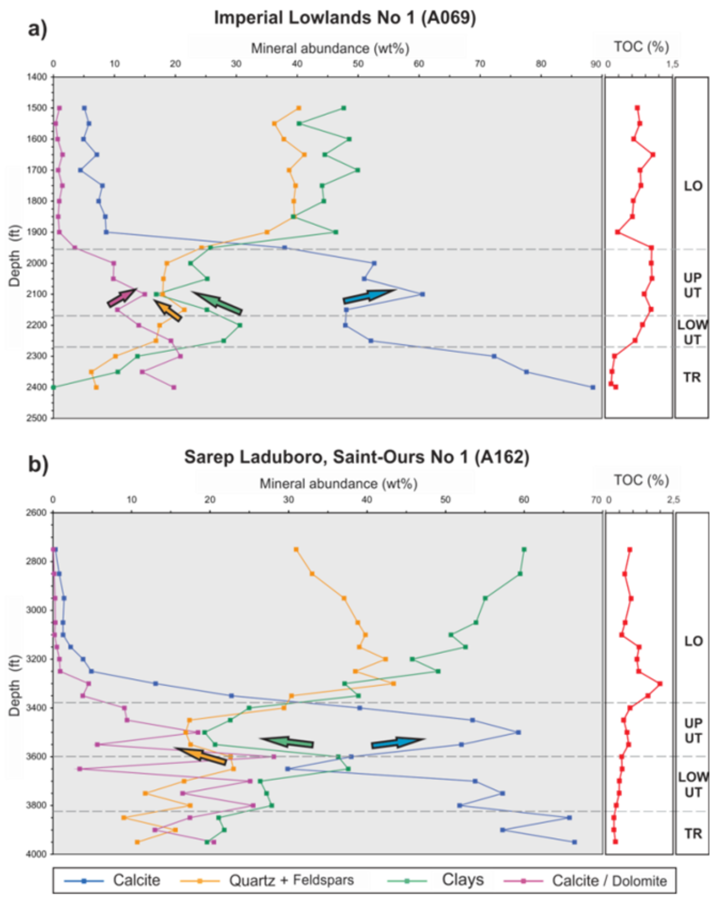

Figure 5: Detailed vertical mineral trends for the Trenton (TR) to the Lorraine (LO) groups for two wells. Calcite content decreases from the Trenton Group to a minimum near the top of the lower Utica Shale (LOW UT), calcite content rapidly increases up to the middle part of the upper Utica Shale (UP UT) and then decreases significantly to minimal values at the base of the Lorraine Group. Clays as well as quartz + feldspars content trends inversely to that of the calcite. Modified from Thériault (2012a).

Organic geochemistry

The Utica Shale has been considered as an excellent source rock for conventional hydrocarbon exploration in southern Quebec (Lavoie et al., 2009). Lavoie et al. (2011) and Thériault (2012b) have released over 2300 Rock-Eval (II and VI) analyses from 88 wells and few outcrops of Utica Shale and Lorraine Group. The data are presented on maps for the lower and upper informal units of the Utica Shale, as well as for the Lorraine Group in Thériault (2012b). Most pertinent information is presented below.

Thermal maturation

Various thermal maturation indicators (T_{max}, organic matter reflectance, transformation ratio or production index) indicate that the Utica Shale is a mature succession with a southwesterly maturation increase from oil window – condensate zone in the Quebec City area to the dry gas zone (Figure 6). A southeasterly trend is also documented with an increase of thermal conditions from condensate (northeast area) and dry gas (southwest area) north of the St. Lawrence River towards dry gas and overmature to the southeast.

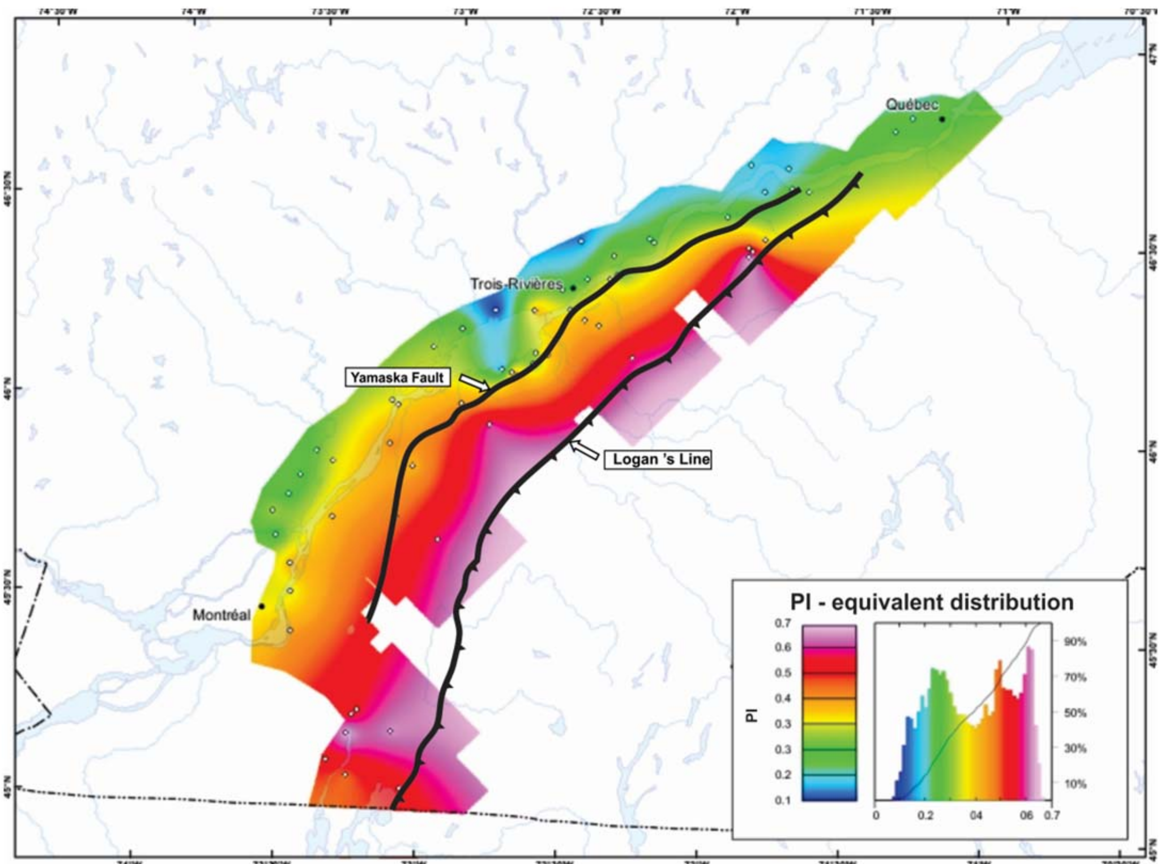

Figure 6: Map of the production index (PI) for the upper Utica Shale. Production index is a proxy for thermal maturation as it indicates the degree of transformation of organic matter into hydrocarbons. PI lower than 0.4 indicates liquids window. Increases of PI from NE to SW and from NW to SE are noted. The area west of the Yamaska Fault is the thermally least mature domain. The NW to SE increase is related to deeper burial of the Utica. Modified from Thériault (2012a).

Total organic carbon (TOC)

Based on TOC values from Rock-Eval analyses, the two units of the Utica Shale may be recognized with the upper Utica having a general higher mean TOC value (Thériault, 2012b). However, for both units, the highest TOC values (about 1% and 2% for the lower and upper unit, respectively) are commonly located in the northeast area (vicinity of Quebec City) with some high values in the north-central zone (Trois-Rivières area) (Figure 7). This pattern is compatible with the thermal zonation of the Utica, with higher thermal conditions associated with lower residual organic matter in the rock. Higher TOC values (2.0%) are located west of the Yamaska fault and correlates with lower thermal maturation (Figure 6).

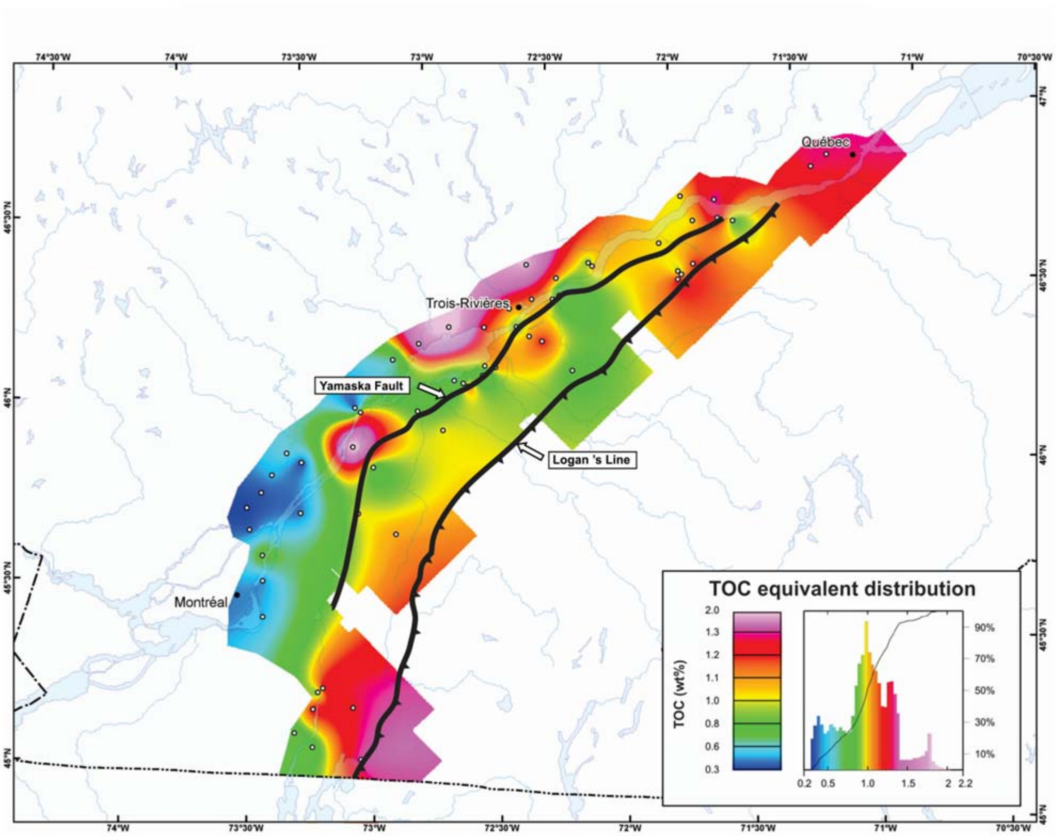

Figure 7: Map of the total organic carbon (TOC) content for the upper Utica Shale. Higher TOC values (around 2%) are found in the area west of the Yamaska Fault and correlates with lower thermal maturation. The lowest TOC values are found in the relatively low thermal maturity Montreal area, this suggests lower level of original organic matter content for that specific part of the depositional basin. Modified from Thériault (2012a).

Hydrogen Index (HI) and Oxygen Index (OI)

HI and OI values are commonly used as a proxy for the nature of the organic matter: hydrogen-rich / oxygen-poor organic matter (e.g., algal- and bacteria-derived lipids) are identified as Type I organic matter and hydrogen-poor / oxygen-rich organic matter (e.g, plant-derived lignin) are designated as Type III organic matter. Type II is an intermediate type commonly associated with marine microorganisms. All three types of organic matter have different potentials to release oil or natural gas. Similar to TOC content, increases in thermal conditions will affect the HI value, as hydrogen is rapidly consumed by the production of hydrocarbons. Based on residual HI and OI values in the least thermally altered domains, the Utica Shale consists of Type II organic matter (Thériault, 2012b), an interpretation supported by organic petrography (Bertrand, 1991).

Exploration focus

Thériault (2012a) has proposed three exploration fairways for the Utica Shale in southern Quebec (Figure 8). These fairways, which are based on the depth of the Utica Shale as well as on structural domains, were proposed following detailed re-examination and reinterpretation of well logs, drilling reports and seismic lines (Thériault, 2012a). The first fairway consists of the shallow domain of the Utica Shale and occurs north and northwest of the Yamaska Fault, where the Utica is found between 0 and 800 m in depth. The second exploration fairway occurs between the Yamaska Fault to the northwest and Logan's Line to the southwest; in this area, the Utica Shale is between 1200 and 2500 m in depth. Finally, the third fairway is located east of Logan's Line where the Utica Shale occurs in thrust slices and also most likely deeper in the autochthonous platform. Geoscientific knowledge on the Utica Shale is highly variable with the shallow and central fairways having a significantly better well coverage compared to the easternmost, thrust-dominated fairway (Thériault, 2012a, b; Séjourné et al., 2013).

Shale gas exploration in the Utica Shale began in 2006 in southern Quebec. A total of 18 vertical wells and 11 horizontal wells have been drilled (Figure 8), and 18 hydraulic fracturations have been performed until 2010. So far, most of the exploration has focused primarily on the central fairway, where 24 of the 29 shale gas wells have been drilled; the shallow and thrust fairways have been little explored (3 and 1 wells, respectively). Based on a limited number of hydraulic fracturations, initial production values (IP) were highly variable, as one would expect in a new basin. The best IP value for a horizontal well was 11 mmscf/d of natural gas (in the northeastern area of the central fairway), whereas in the less mature domain (in the immediate vicinity of Quebec City), limited production of light oil and condensates were encountered during testing of a vertical well.

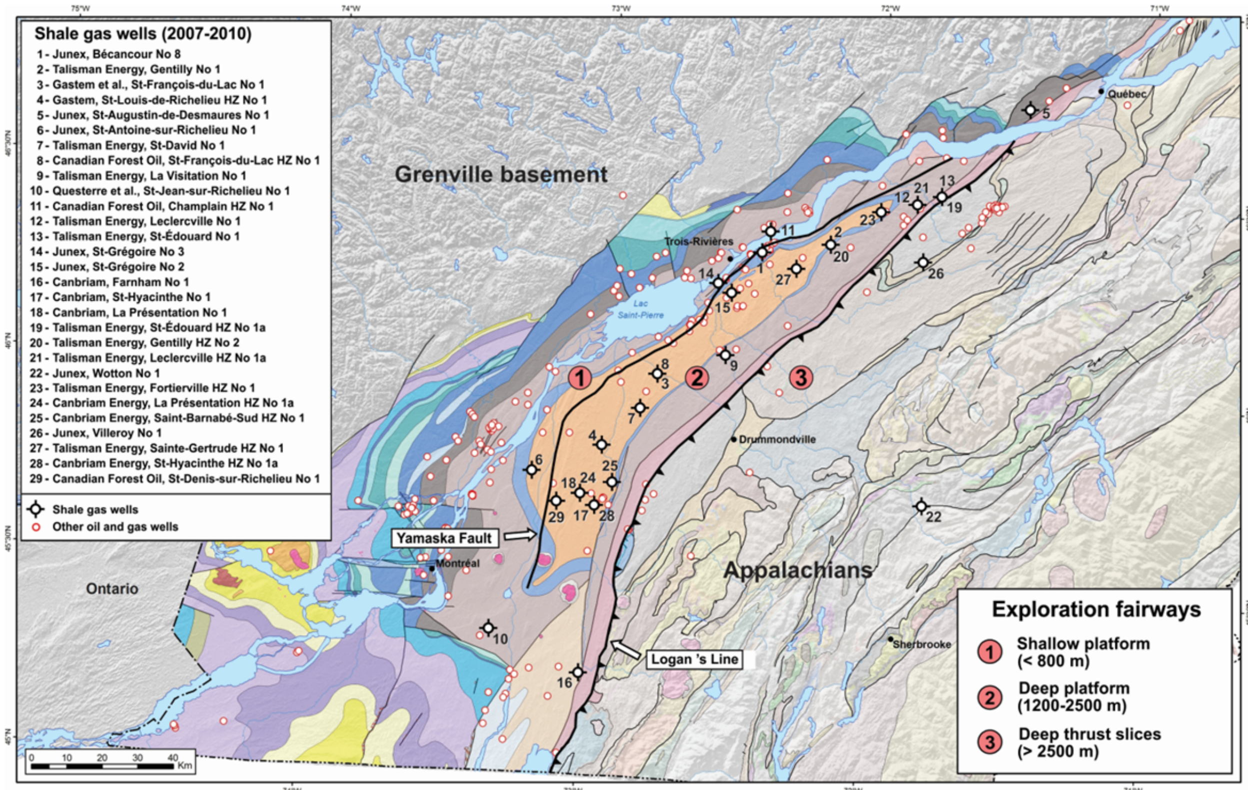

Figure 8: Simplified geological map of southern Quebec with the location of the 29 shale gas wells drilled between 2007 and 2012 (wells 1 and 2 have been drilled in 2006 and targeted conventional reservoirs beneath the shale). The map shows the three exploration fairways as proposed by Thériault (2012a). The fairways are limited by the Yamaska Fault and Logan's line and are based on depth of the Utica and tectonic context. Legend as on Figure 1. Modified from Thériault (2012a).

Resource Assessment Method

Model

The method used in this study is a volumetric approach with a dual-porosity model that quantifies the reservoir storage for oil and gas. The method is designed for resource assessment in a hybrid shale play, in which both the matrix porosity and organic porosity are effective storage for oil and gas resources. The dual-porosity model considers two distinct pore systems, the rock matrix and organic pores in a shale formation. Figure 9 is a petrophysical model of the dual-porosity system, showing different components that have been incorporated for formulating the calculation of oil and gas volumes in such a hybrid reservoir.

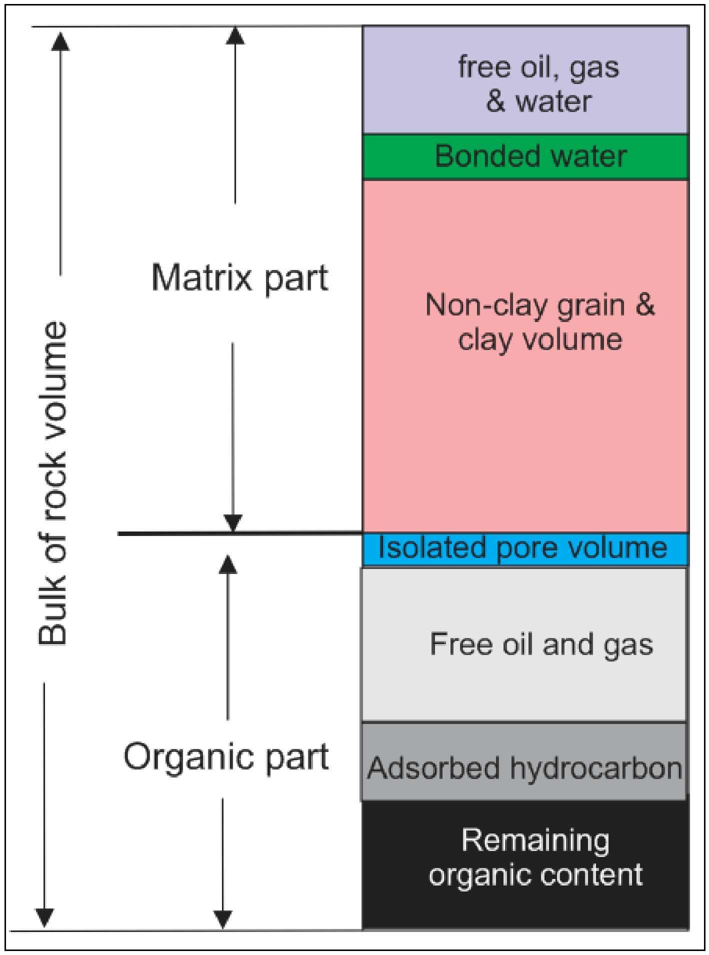

Figure 9: A petrophysical model for resource estimation in a hybrid shale play where both matrix porosity and organic porosity contribute to the storage of oil and gas accumulation (modified from Ambrose et al. 2012). The percentage of the various components forming the bulk of the rock volume is schematic and does not intent to represent a specific case.

The two porosity systems have remarkable difference in physical and chemical characteristics. The pore size of matrix porosity is in an order of micro-metre in scale and primary pore diameter reduces with increase in burial depth. The matrix pore is saturated with water when sediments were deposited and hydrocarbon fluids later migrated into the system. Therefore residue water (bonded water) is present in the matrix pore. The rock matrix pore is likely to be water wet and store no adsorbed hydrocarbons. Conventional evaluation method of tight clastic reservoir is applicable to estimate matrix pore system parameters such as porosity and water saturation in the hybrid shale play. Differing from the matrix pore system, the organic pore has pore size in the order of nano-metre in scale and pore diameter increases with maturity (depth). The organic pore is born with hydrocarbon fluids and is likely to be oil wet. No bonded water exists in the organic pore system. In addition, because of the nano-scale of the pore system, fluid thermodynamics (phase behavior) are quite different from conventional reservoirs and organic pore stores both adsorbed and free hydrocarbon fluids. A significant portion of organic pore space is taken by adsorbed phase (Ambrose et al., 2012). The percentage of adsorbed phase in organic pores depends on the size of the nano-pore (Figure 10). The smaller the diameter of the organic pore is, the greater percentage of adsorbed phase could be stored (Bohacs et al., 2013).

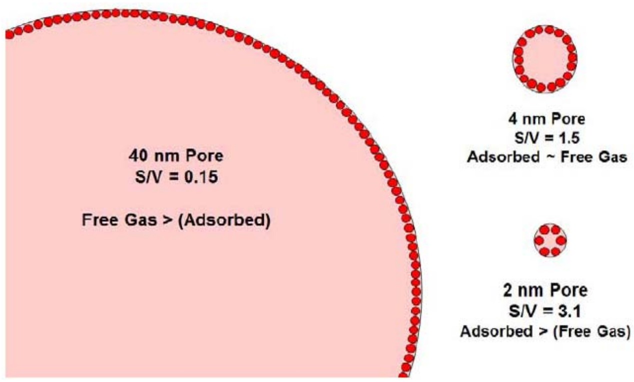

Figure 10: Diagram showing variation in capacity of adsorbed natural gas in nano-pores associated with organic matter (from Bohacs et al., 2013). Depending on the size of nano-pores, adsorbed phase (represented aschematically as small red circles) could dominate in small organic pores. s/v indicate the ratio of volume of sorbed gas and volume a single pore space.

Figure 11 shows general characteristics of the two different porosity systems. The lithic matrix micro-porosity and organic nano-porosity exhibit opposite trends. The matrix porosity decreases with burial depth as a result of mechanical compaction and diagenesis. Study suggests that mineral composition, texture of the sedimentary rock, compaction and diagenetic histories are primary factors affecting matrix porosity (Dutton and Loucks, 2010; Ramm, 1991). Development of matrix porosity shows a remarkable change at a depth around 2500 metres, above which the decreasing rate in porosity is rapid and the primary control is mechanical compaction. Below the depth the decreasing rate becomes slower and chemical (diagenesis) compaction plays a more important rule. In general, secondary porosity development occurs in the lower zone. As a result, the development in secondary porosity could reverse the decrease trend (Dutton and Loucks, 2010). In contrast, organic porosity increases with thermal maturity.

The abundance and size of organic pores are a function of thermal maturity, richness and type of organic matters. The porosity is originated from conversion of organic matter (kerogen) to oil and gas. Therefore, no significant organic porosity is formed above oil generation window and organic porosity approaches the maximum at the end of dry gas generation windows.

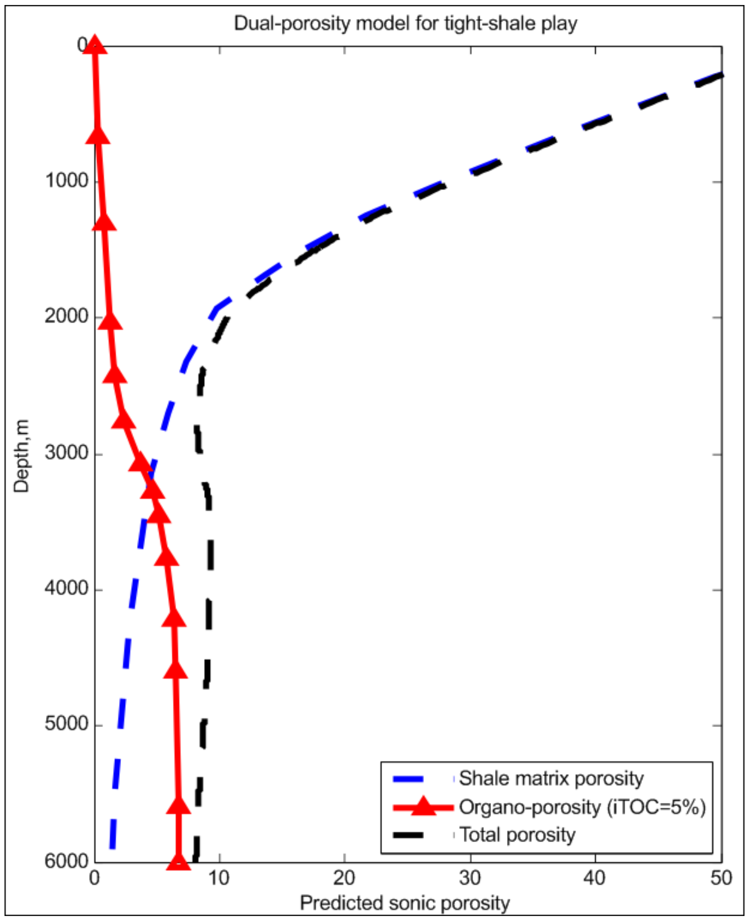

Figure 11: Schematic diagram showing general characteristics of two different porosity trends in a shale basin (lithic matrix micro-porosity and organic nano-porosity). The matrix porosity decreases with depth; whereas the organic porosity increases with depth. These two porous systems are results of different geological processes and have distinct physical and chemical properties in terms of storage of oil and gas. iTOC in the diagram indicates initial TOC.

The capacity for hydrocarbon storage is the total porosity, which is the sum of these two porosities. The dual-porosity model indicates three different storing mechanisms (Figure 9) in a hybrid reservoir: a) matrix pore with free hydrocarbon and bonded water, b) organic pore with free hydrocarbons and c) organic pore with adsorbed hydrocarbons. The hydrocarbon volume in the two different porosity systems can be estimated from geochemistry data and geophysical well logs. Additional laboratory tests is necessary to determine the adsorbed hydrocarbons. Figure 12 is a workflow chart showing the processes and components for the estimation of hydrocarbon pore-volume under the dual-porosity model. The estimation of the adsorbed gas is discussed in the following volumetric calculation section.

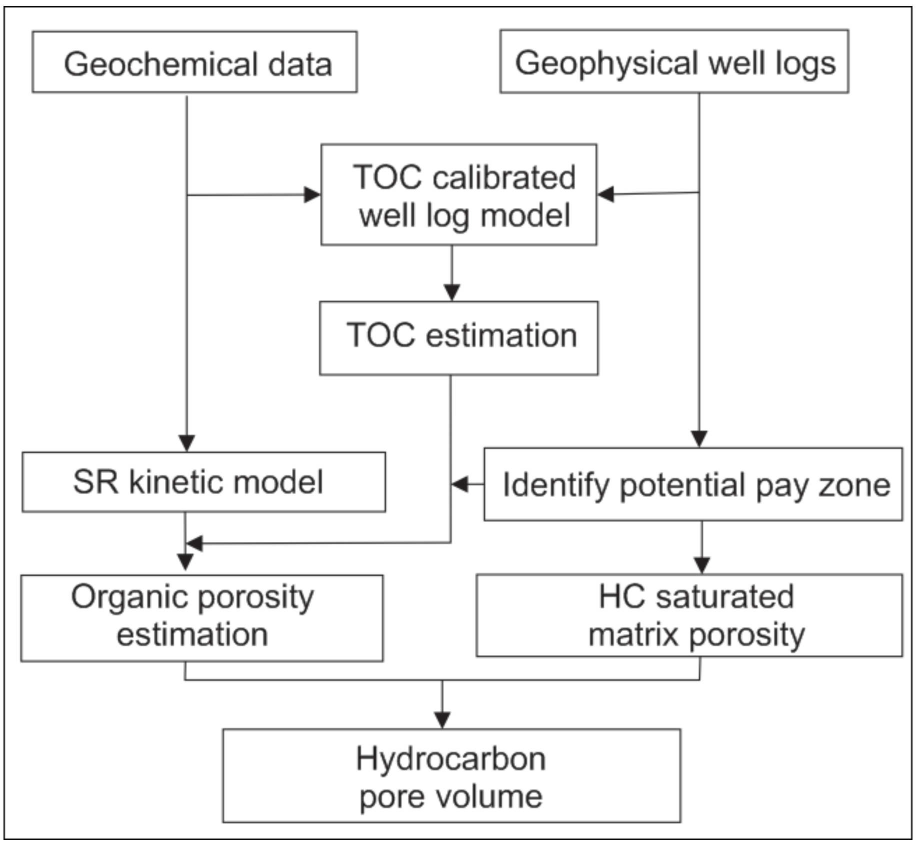

Figure 12: A flow chart demonstrating the work flow and components for hydrocarbon pore volume estimation using geochemical and well log data under the dual-porosity model.

Volumetric Calculation

To capture the spatial variability of the resource potential in tight-shale reservoir, the study area is divided into *N* equal sized cells with location index of *n*. The total hydrocarbon pore volume in a shale play can be estimated from the volumetric equation:

$$HCPV(n) = \sum_{n=1}^{N} A(n)H(n)\,\emptyset_{HC}(n) \qquad (1)$$

Where $A(n)$ is the cell size (m^2), $H(n)$ is the reservoir thickness (m), $\O_{HC}(n)$ is hydrocarbon saturated porosity (in fraction), n is a coordinate indicator. The $\O_{HC}(n)$ (in fraction) is the total hydrocarbon saturated pore volume at location n in the matrix and organic pore systems.

The oil and gas pore volumes are estimated respectively from the following relationships:

$$PV_{oil}(n) = f_{oil}(n)HCPV(n) \quad (2)$$

$$PV_{gas}(n) = f_{gas}(n)HCPV \quad (3)$$

where $f_{oil}(n)$ and $f_{gas}(n)$ are percentages of oil and gas volumes in the total hydrocarbon pore volume respectively *with* $f_{oil}(n) + f_{gas}(n) = 1$. These two parameters were estimated from organic geochemistry and thermal maturity models of the organic matter in the study area.

The PVT equation can be applied to convert the hydrocarbon pore volumes in reservoir condition to the standard oil and gas volumes in surface condition.

$$Oil(n)_{in-place} = PV_{oil}(n) / FVF \quad (4)$$

$$Gas(n)_{in-place}^{free} = PV_{gas}(n) / Bg \quad (5)$$

with

$$Bg = \frac{zP_{surf}}{T_{surf}} \frac{T_{resv}}{P_{resv}} = 0.02827 \frac{zT_{resv}}{P_{resv}}$$

$$Gas(n)_{in-place}^{solution} = PV_{oil}(n)GOR \quad (6)$$

where *FVF* is the oil formation volume factor, *Bg* is the gas formation volume factor and *GOR* is gas oil ratio, which are the reservoir parameters that can be derived from field observations and laboratory tests.

The adsorbed gas can be estimated from the following equation

$$Gas_{in-place}^{adsorbed} = V_{rock}\rho_{mat}C_{toc}V_L \frac{P_{resv}}{P_L + P_{resv}} \quad (7)$$

Where V_{rock} is the rock volume (m^3), ρ_{mat} is bulk rock density (ton/m^3), C_{toc} is the total organic content (in fraction), P_L: Langmuir pressure (kPa), V_L: Langmuir volume (scf/ton), which is a function of TOC content and is derived from the following relationship in this study:

$$V_L = 26.19\, C_{toc} \quad (8)$$

This relationship in Eq. (8) was determined from laboratory test results by Talisman Energy (Talisman Energy, personal communication, 2013).

Ambrose et al. (2012) indicated that the calculation using Eq. (7) over-estimate the adsorbed gas in shale reservoir. The over-estimation (in scf/ton) can be quantified by the following equation:

$$Gas_{ov}^{ad} = \frac{32.0368}{B_g}\{\frac{0.000001318\widehat{M}}{\rho_b}\, V_L \frac{P_{resv}}{P_L + P_{resv}}\} \quad (9)$$

where ρ_b: rock bulk density, and $\widehat{M}$ is natural gas apparent molecular weight (g/mole).
The unbiased adsorbed gas resource is estimated by subtracting the amount of gas calculated by Eq. (9) from the amount of gas calculated by Eq. (7). For details of the derivation of the equation (9) and application examples, the readers are referred to Ambrose et al. (2012).

The uncertainties in spatial extrapolation for each component (oil, free gas, associated gas and adsorbed gas) at the locations without well control are estimated using geostatistical tools and aggregated using Monte Carlo method. The ranges of aggregated distributions of oil and gas resources represent the uncertainties in the assessment.

Assessment

Data and assessment procedure

Three types of data (summarizes from Lavoie et al., 2014) were used in this assessment : a) geological map and compiled data tables from the Ministère des Ressources Naturelles du Québec (Thériault, 2012a and b) that provide information on the spatial extend of the Utica shale, its burial depth and thickness, b) digital geophysical log curves of previous exploration wells from the Ministère des Ressources Naturelles du Québec, and c) geochemical data from rock-eval pyrolysis and thermal indicators of source rock compiled by Thériault (2012 a and b). The assessment follows the procedure described in the workflow chart (Figure 11). Additional attempt was made to estimate the adsorbed natural gas resource by using the established relations in Eqs. 7 and 8 for this basin and was followed by a volumetric correction using Eq. 9.

A total of forty six exploration wells with digital gamma ray, sonic and resistivity logs were available to this study, forming an essential part of the dataset for volumetric calculation of resource potential. The geophysical well log data were used to estimate matrix porosity and to calculate water saturation. Figure 13 is a location map showing the exploration wells with log data used in this study.

Another important dataset comprises of the results of rock-eval pyrolysis analysis and measured thermal maturity indicators of the Utica Shale. Analytical results from more than 700 samples in 74 wells and 23 outcrop locations are available to this study. The average value of the 707 TOC measurements is 0.85% with highest observed value of 5.1% in the study area. It is important to remember that the measured TOC is the residual content after thermal degradation. Due to a high thermal maturity in this basin, a large portion of initial TOC content has been converted into hydrocarbons. Because of high thermal maturity of the source rock, the Tmax derived from rock pyrolysis contains little information on the level of thermal maturity. Therefore vitrinite reflectance equivalent values converted from organic reflectance were used to quantify the thermal maturity and to calculate the transformation ratio of kerogen in the source rock to hydrocarbons across the basin.

Data analysis indicates that laboratory TOC measurements have a low vertical resolution and poor vertical representation of TOC variability. A revised Passey model (Passey, 1990) was used to estimate TOC content at each log data points. Well logs were first calibrated by available TOC measurements from the rock-eval pyrolysis analysis and used to establish the revised Passey model (Chen et al., 2013), based on which TOC content can be estimated at any given depth within the Utica shale interval and well locations with adequate digital well log data (Figure 13). Figure 14 shows statistical distribution of the measured TOC contents of the Utica Shale wells used in this study derived from rock-eval pyrolysis (Figure 13).

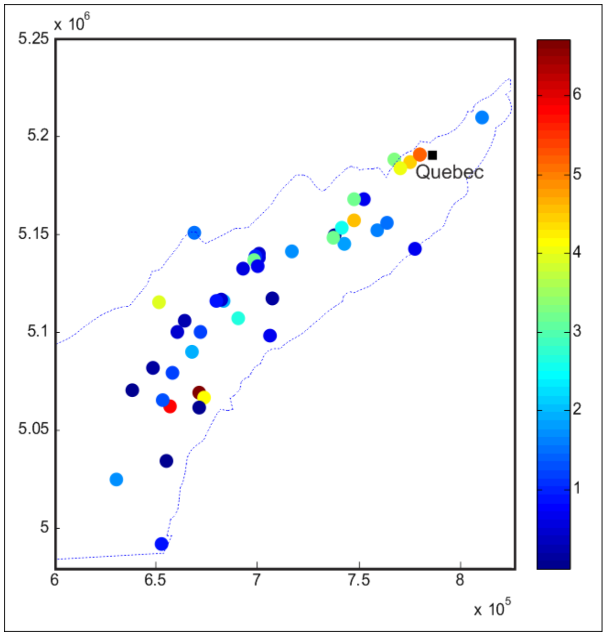

Figure 13: Wells location map showing the locations of data wells with adequate physical log curves for evaluation of hydrocabon pore volumes.The color of the dots and colorbar on the right indicate the estimated hydrocarbon net thickness in metre. The black square is the location of Quebec City. The coordinate is an UTM projection (zone 18).

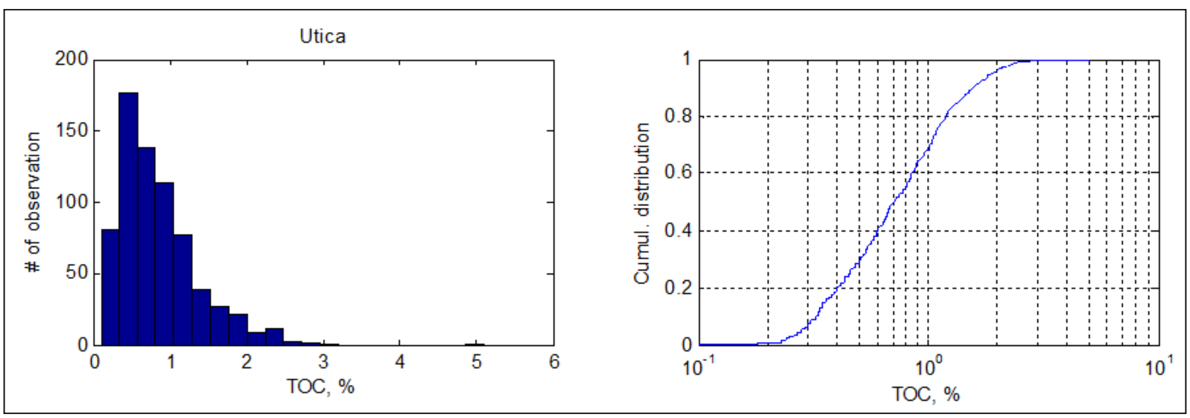

Figure 14: Histogram (left) and cumulative distribution (right) of 707 measured total organic carbon content (TOC in wt%) values from Rock-Eval samples showing general characteristics of organic richness in the Utica Shale.

The estimated initial TOC contents with an organica geochemistry model of the source rock in the Utica Shale were used to estimate organic porosity. Modica and Lapierre (2012) have provided mathematical details of the methods for estimation of organic porosity with an application example in resource assessment. The hydrocarbon saturated porosity in Eq. 1 is the sum of hydrocarbon saturated matrix porosity and the organic porosity, and the hydrocarbon pore volume is the sum of hydrocarbon saturated pore volumes in the identified potential pay zone within the Utica Shale at each well location. Figure 15 is a krigged map of the hydrocarbon pore volume of the Utica Shale in the study area showing the spatial variation of the estimated hydrocarbon pore volume across the basin. Geostatistical data analysis suggests a better continuety of in-place resource in the NE-SW direction. The magnitude of estimated hydrocarbon pore volume at each well location is indicated in Figure 13 by color codes.

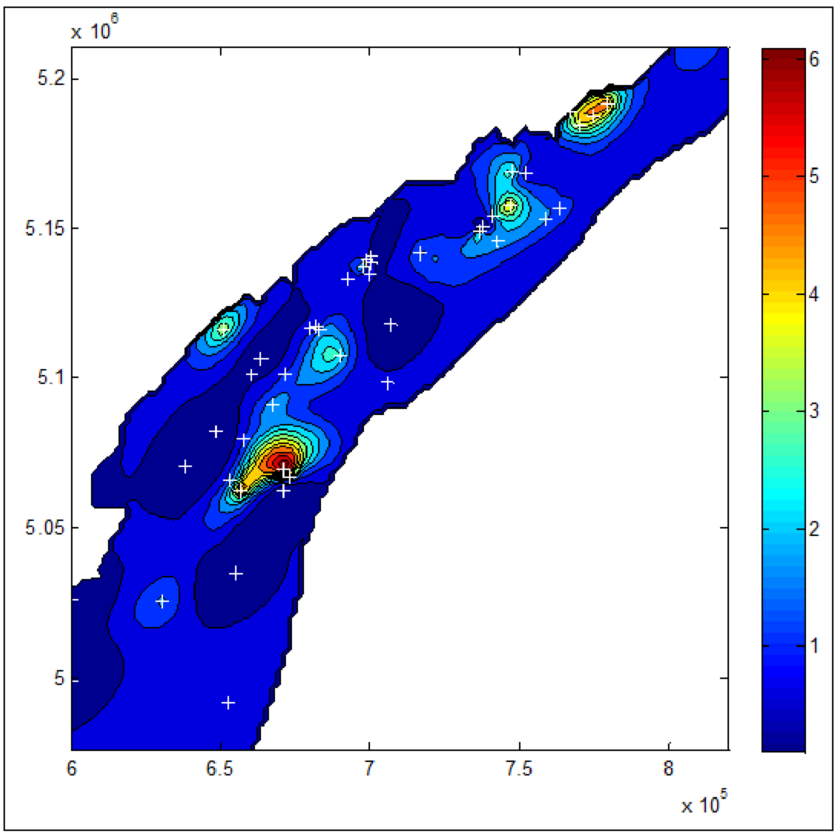

Figure 15: Krigged map of the hydrocarbon pore volume of the Utica Shale showing the locations of the data well (white cross) used for the resource assessment and the spatial variation of the estimated pore volume (in million m^3/km^2).

The estimated hydrocarbon pore volume was divided into oil and gas pore volumes based on the organic geochemistry model of the source rock in the Utica shale. This kinetic model provides estimates for the capacities of oil and gas generation and degree of thermal degradation of the source rock. By incorporating observed geochemical evidence, such as hydrocarbon in sample, types of organic matter and level of thermal maturity, the model calculates the ratio of oil and gas remained in the shale reservoirs. The oil and gas pore volumes in reservoir condition were then converted into the in-place oil and gas volumes at standard surface condition by reservoir engineering equations (eqs. 4, 5, 6).

Results

The assessment resulted in four different in-place resources: oil, free-gas, dissolved gas and adsorbed gas. Three gas components are aggregated into total gas. Statistic distribution is used to describe the uncertainty in the estimated resource potentials. No attempt is made to estimate the portion of technically recoverable of the in-place resources.

The estimated in-place oil resource is shown as statistical distributions graphically in Figure 16 and numerically in Table 1 illustrating the range of uncertainty for the oil resources in the assessment. The estimated oil resource potential varies from 0.78 to 5.24 billion of barrels (Bbls) with a mean of 2.3 (Bbls).

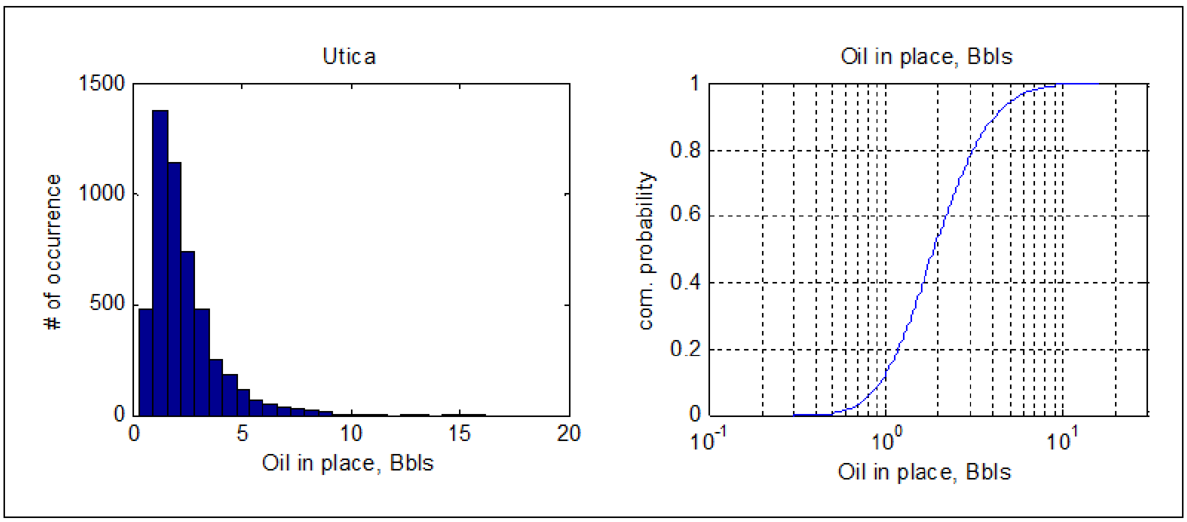

Figure 16: Diagrams showing statistical distributions of estimated in place oil resource in Quebec Utica Shale, a) histogram and b) cumulative distribution based on 5000 Monte Carlo simulations.

Table 1 Summary table of estimated oil and gas resources in Utica shale as cumulative distribution.

Probability distribution	95%	90%	75%	50%	25%	10%	5%	Mean
Oil in-place (Billion Barrels)	0.78	0.94	1.29	1.87	2.83	4.18	5.24	2.30
Aggr. Total dgas in-place (TCF)	117.09	127.45	147.50	176.73	214.75	257.90	287.14	186.41

This study also provides spatial distribution of the estimated oil resource as oil resource density map (Figure 17) to outline the geographical location of possible "sweet-spots" of the oil resource in Utica Shale. This oil resource density map was derived from kriging, a geostatistical method for spatial extrapolation. The oil resource in the Utica Shale occurs primarily in the northwestern margin of the Basin, where the source rock is still in oil or condensate generation window. This confirms that the source rock thermal maturity is the major control factor for oil resource in the Utica Shale, Quebec.

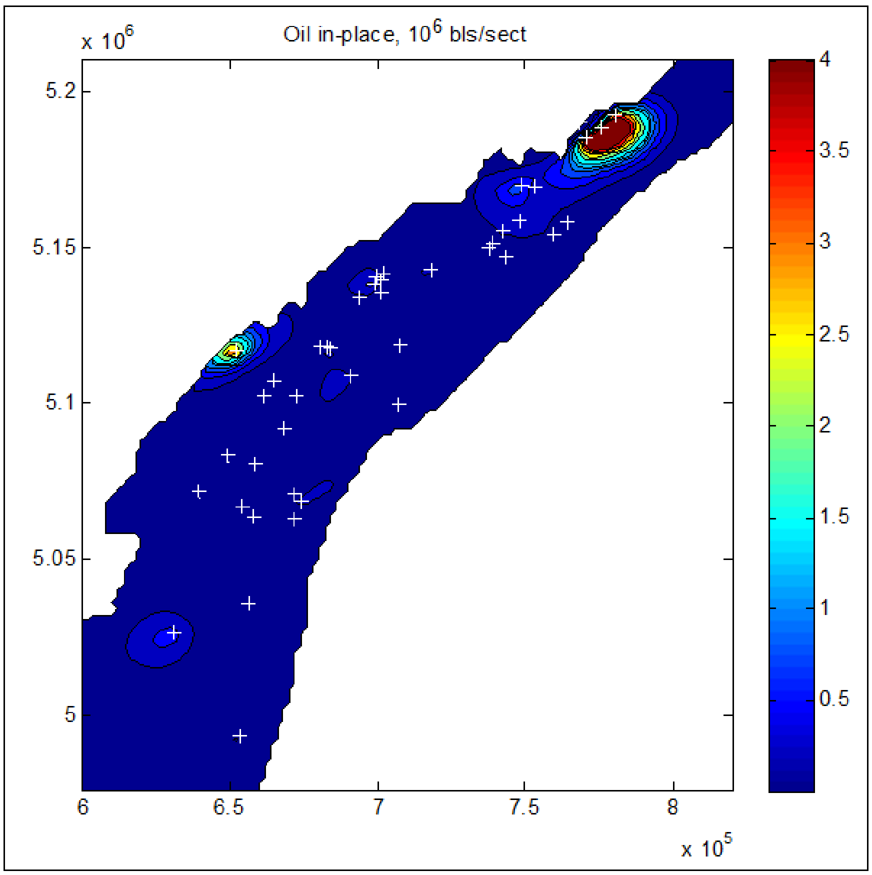

Figure 17: Oil resource (in-place) density map (million barrels/section) showing spatial distribution of the predicted oil resource in the Utica Shale, Quebec. Inferred oil resource occurs primarily in the northwestern basin margin where thermal maturity of source rock is still in oil generation or condensate window.

The estimated in-place free gas and dissolved gas resources are listed in Table 2. The estimated free gas resource varies from 58.16 to 178.58 TCF with a mean of 105.6 TCF. The estimated solution gas varies from 22.66 to 70.80 TCF with a mean of 35.66 TCF. As these two gas resources were estimated from hydrocarbon pore volume, they are plotted together in Figure 18 as histogram and cumulative distribution to show the uncertainty graphically. The geographic distribution of the combined free and dissolved gas resource together is plotted as a resource density map in Figure 19 showing the spatial variation of resource abundance across the basin.

Table 2 Distributions of in-place resource potentials of different gas components and aggregated total in-place gas resources in Utica Shale, Quebec.

Probability distribution	0.95	0.90	0.75	0.50	0.25	0.10	0.05	Mean
Adsorbed gas (TCF)	24.69	27.52	32.47	39.00	46.99	55.59	61.23	40.52
Free gas (TCF)	58.16	65.33	78.55	97.77	124.56	155.89	178.58	105.61
Solution gas (TCF)	22.66	24.71	28.89	35.66	46.24	60.15	70.80	35.66
Aggregated total gas, TCF	117.09	127.45	147.50	176.73	214.75	257.90	287.14	186.41

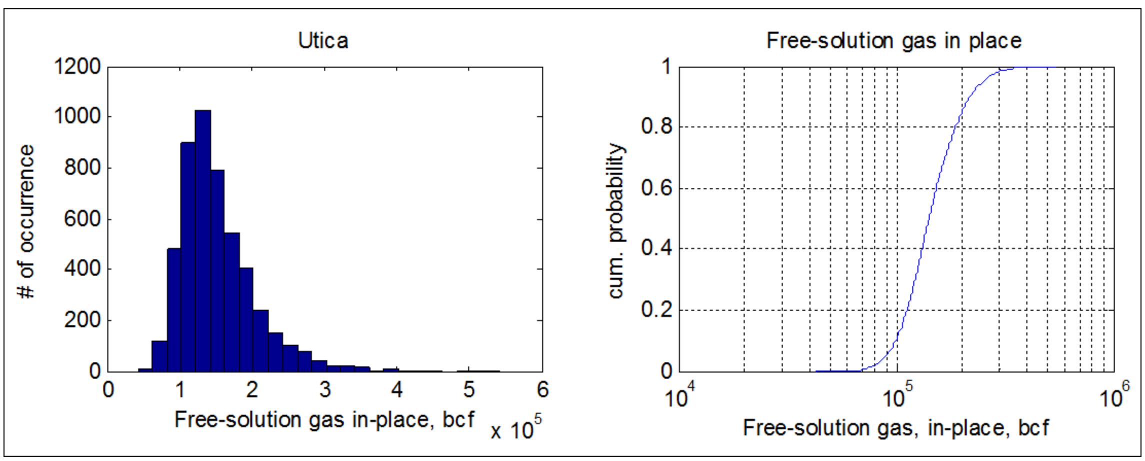

Figure 18: Diagrams showing statistical distributions of estimated free and solution gas resource combined (in-place) in Utica Shale, Quebec, a) histogram and b) cumulative distribution based on 5000 Monte Carlo simulations.

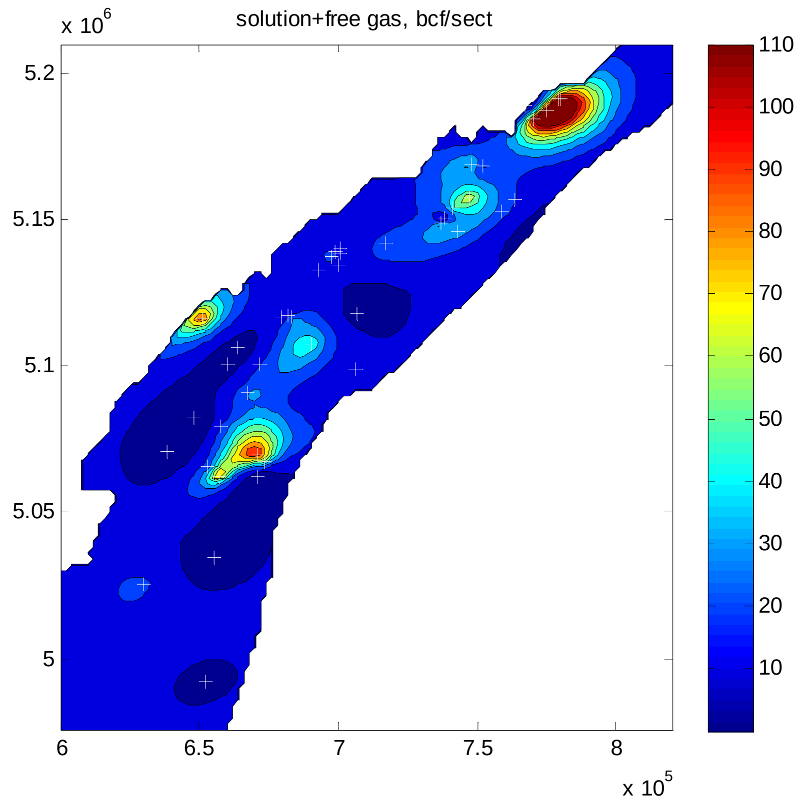

Figure 19: Free and solution gas combined density map (BCF/section) showing spatial variation of natural gas resource in Utica shale, Quebec.

The estimated adsorbed gas also shows considerable uncertainty ranging from 24.69 to 61.23 with a mean value of 40.52 TCF (Figure 20 and Table 2). The spatial variation of the adsorbed resource is closely related to the TOC content and formation thickness as shown in Figure 21.

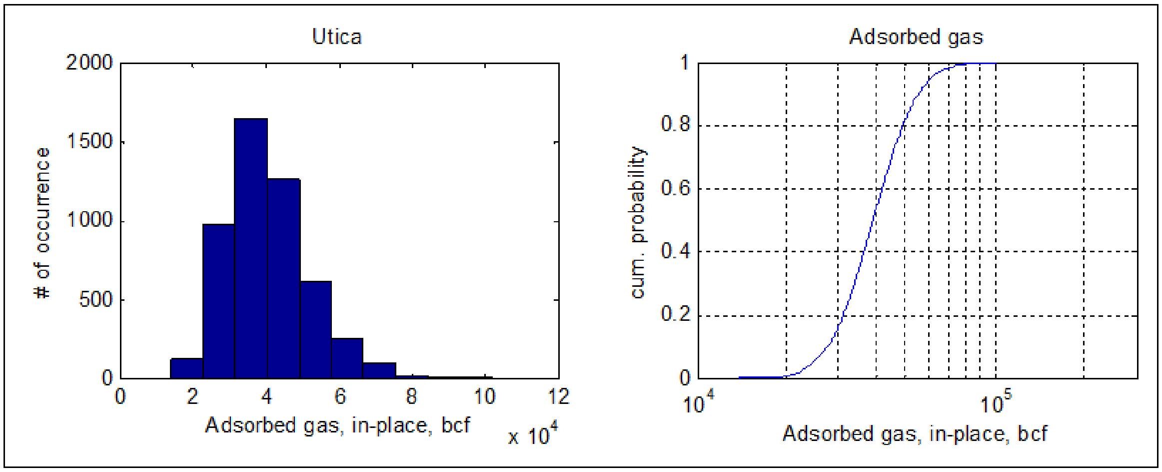

Figure 20: Diagrams showing statistical distributions of estimated adsorbed as histogram (left) and cumulative distribution (right). The estimated mean value of the adsorbed gas is 40.52 TCF.

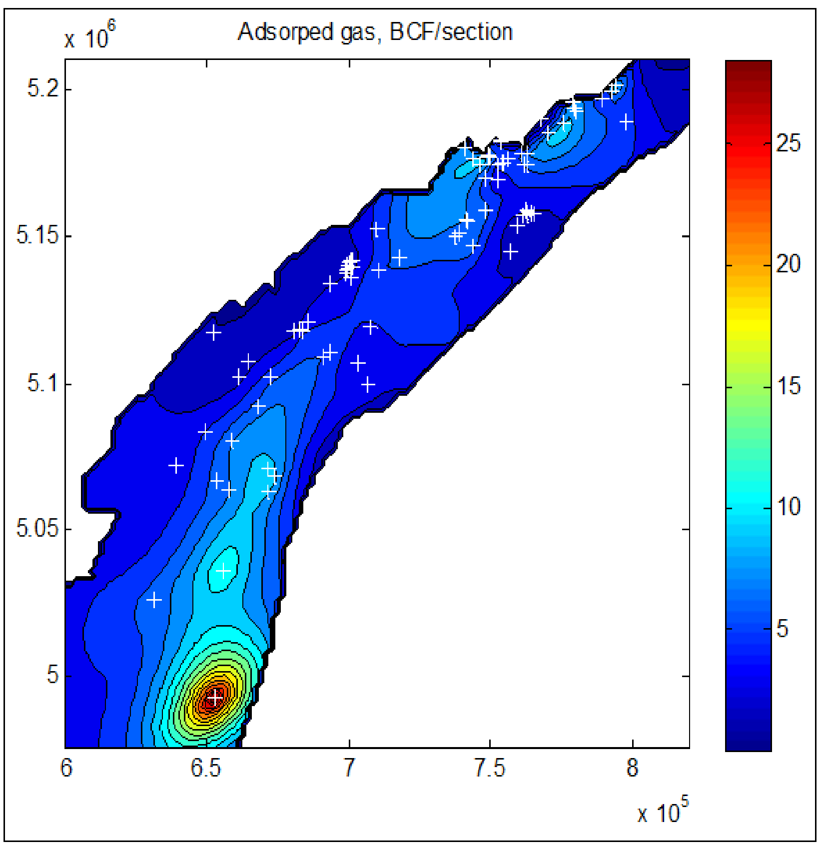

Figure 21: Resource density map (bcf/section) showing the spatial variation of the estimated adsorbed gas resource (in-place) in Utica Shale in Quebec. The adsorbed gas resource concentrated in two centres, one in the northeast and another in the southwest.

Figures 22 and 23 are results of aggregated total natural gas (free, disolved and adsorbed gases) in Utica Shale of this basin. The expected resource value of the total gas in-place is 186.4 TCF with an uncertainty range from 117.09 TCF to 287.14 TCF. The statistic distribution and spatial variation of the total gas resource is nearly similar to those of the combined free and dissolved gas because adsorbed gas contributes only about 15% to the total natural gas potential.

To validate the well log interpretation and the predicted spatial distribution of the resources, publically available well locations that were tested with gas or oil flows released by industry were collected from various conference presentations and were plotted on the hydrocarbon pore volume map (Figure 24). Twenty two oil and gas exploration wells in a period from 1970 to 2007 have been tested for oil and gas, among which seventeen wells show significant gas and oil flows. Since 2007, twenty-nine horizontal and vertical wells some with hydraulic fracture stimulations were drilled. Industry has released results from few wells which indicate encouraging results (Marcil et al., 2012), with the best well (Talisman St. Edouard #1) having an initial production of 11 mmcf/d and a stabilized rate of close to 6 mmcf/d after 30 days.

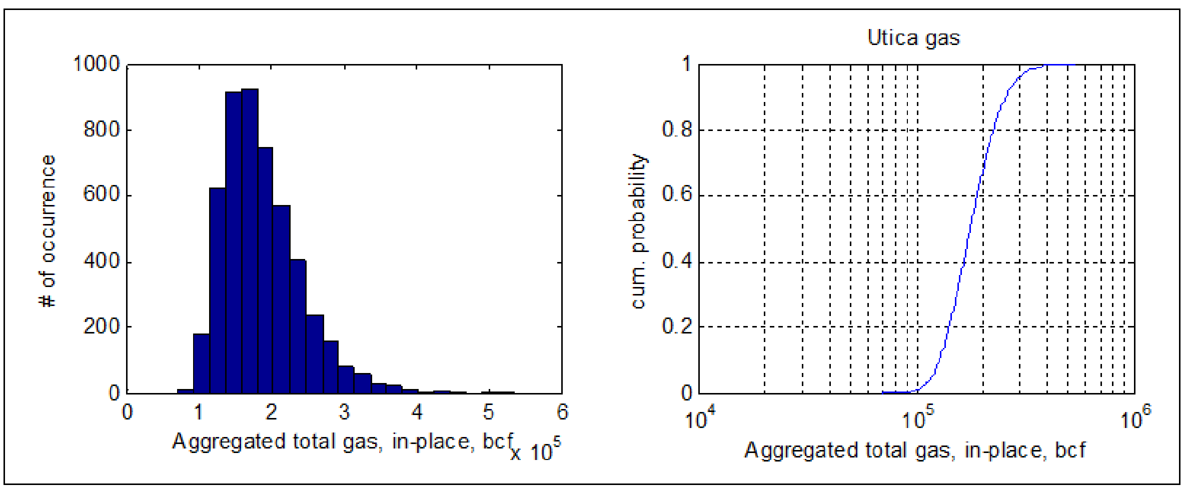

Figure 22: Diagrams showing statistic distributions of the estimated total natural gas in-place in Utica Shale. The mean of value of the estimates is 184.4 TCF and median of 176.73 TCF. The range of possible resource in the basin varies from 117.09 TCF to 287.14 TCF.

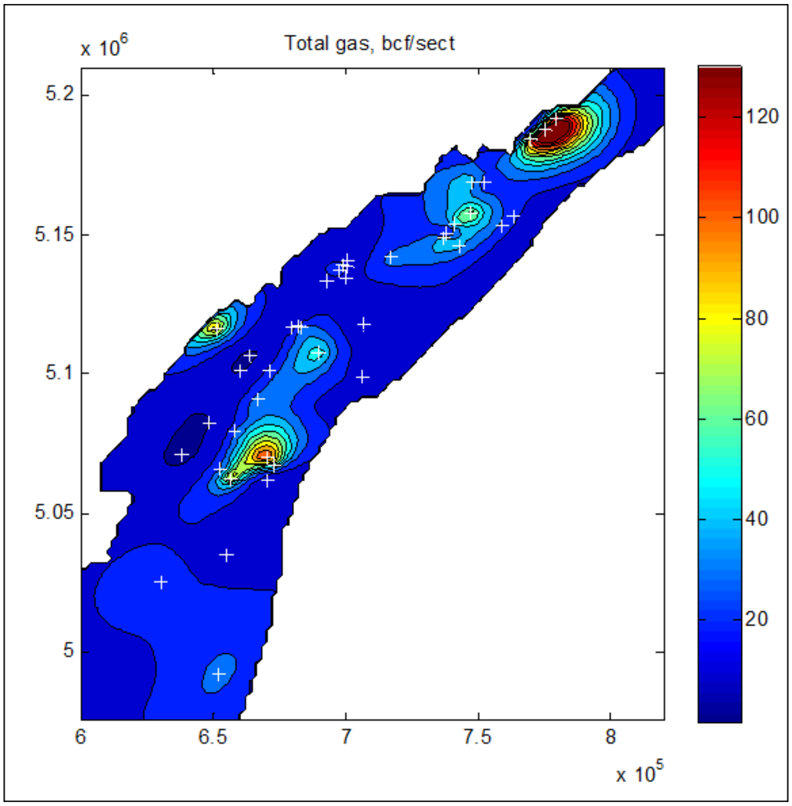

Figure 23: Resource density map showing the spatial variation of total natural gas resource abundance in the Utica Shale in Quebec. The crosses indicate well locations for the calculation (colorbar indicates BCF gas/section).

For the tested wells, we do not have access to the detailed test results. However, the comparison shows that all wells with tested gas or oil flows are located in the areas or on the trends with estimated high resource abudance (high hydrocarbon pore volume). The geographical coicidence of two completedly independent datasets suggested that the spatial variation of the resource abundance indicated by the hydrocarbon pore volume in this study may reflect the general trend of resource potential in the Utica Shale.

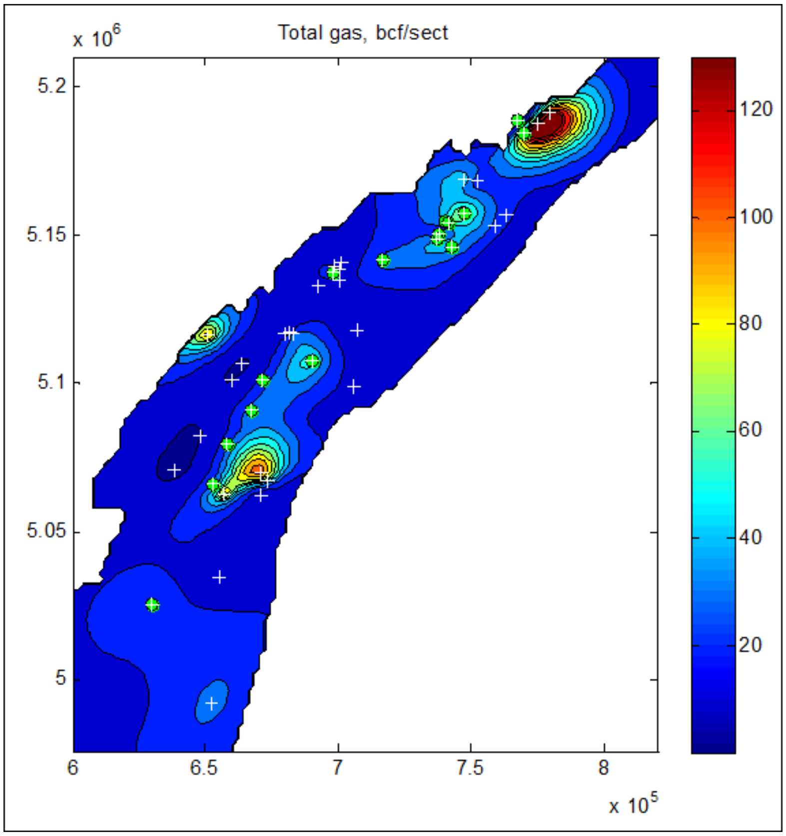

Figure 24: A comparison between the estimated well log hydrocarbon pore-volume estimation (as contour map) and the wells with gas and oil flows reported by the industry (green circles). Data well locations are indicated by crosses.

However, the resource density maps are calculated from the krigged mean hydrocarbon pore volume map, source rock kinetic models and reservoir PVT models. Because of little information on reservoir PVT is available, it is expected that there are a large uncertainty in the conversion from hydrocarbon pore volume to the standard surface volume that may not be captured in the resource volumetric calculations.

Conclusions

A new method based on a dual-porosity model is developed for assessing oil and gas resource potentials in the Utica hybrid shale resource play in Quebec. The method integrates geochemistry data with geophysical well log data to quantitatively estimate the hydrocarbon pore volume and resource potential.

The volumetric calculations suggest that the Quebec Utica Shale contains large volume of in-place hydrocarbon resources. The expected in-place resources include 183 TCF of natural gas and 2.3 billion barrels of oil. The assessment also indicates substantial uncertainties in the estimated oil and gas resources due to inadequate data coverage, uncertainties in the data that were used and understanding of the geology in the basin. Those uncertainties are indicated graphically and numerically as figures and summary table in this report.

This assessment report presents also the estimates as oil and natural gas resource density maps to illustrate the spatial variations of the predicted oil and gas resources. These maps outline the geographical locations with high resource abundance and provide additional information than might be useful for various decision needs.

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