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Qualitative petroleum resource assessment of the Magdalen Basin in the Gulf of St. Lawrence

Quebec, Prince Edward Island, New Brunswick, Nova Scotia, and Newfoundland and Labrador

E.A. Atkinson, P.W. Durling, K. Kublik, C.J. Lister, H.M. King, L.E. Kung, Y. Jassim, W.M. McCarthy, and N. Hayward

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Publications in this series have not been edited; they are released as submitted by the author.

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EXECUTIVE SUMMARY

Natural Resources Canada (NRCan) has been tasked, under the Marine Conservation Targets[1] (MCT) initiative announced in Budget 2016, with evaluating the petroleum resource potential for areas identified for possible protection as part of the Government of Canada's commitment to conserve 10% of its marine areas by 2020. As part of this initiative, NRCan's Geological Survey of Canada (GSC) conducted a broad regional study of the petroleum potential over the majority of the Magdalen Basin, which is the principal geological basin in the southern Gulf of St. Lawrence. The GSC resource assessment is visually represented by a qualitative petroleum potential map (Fig. 1).

To conduct this study, an extensive geophysical database was compiled (Fig. 2), along with previous onshore geological mapping, information from petroleum industry wells, and information from the scientific literature (Fig. 3). New geoscience work was completed, including regional mapping and basin modelling, to characterize the petroleum potential. This report provides the results of this qualitative petroleum resource assessment and regional study, and summarizes other geologic resources.

The study area has been explored by the petroleum industry since the 1960's and there continues to be some limited interest in the larger structures in the region. When considered from a global petroleum-basin perspective, this region holds moderate to moderately high potential. Basin modelling suggests a higher chance of natural gas in much of the basin, which currently challenges petroleum industry economics, yet oil accumulations are still possible.

The area surrounding Îles de la Madeleine south to Cape Breton is dominated by significant subsurface salt deposits. The salt moves easily over geologic time, which creates many geologic structures suitable for trapping petroleum. The highest potential for petroleum in the region occurs in two areas associated with these salt related structures (green areas, Fig. 1):

- To the north of Îles de la Madeleine is a significant east west trend of simple fold structures, cored by mobile salt. Some of these structures have been partly tested, yet the possibility of finding significant petroleum accumulations remains. This region has the highest petroleum potential in the study area.
- Southeast of Îles de la Madeleine and northwest of Cape Breton, the salt moved into walls and diapirs, forming excellent traps and seal. At the same time, complex geometry makes imaging these structures difficult, and petroleum exploration challenging. Large accumulations may exist, but would require acquisition of modern seismic data to outline their potential.

Medium to high potential also exists west of Îles de la Madeleine and north of eastern Prince Edward Island (PEI), in similar salt-cored folds, and also in deeper layers deposited in grabens (yellow to green, Fig. 1).

Unconventional petroleum potential in the region includes significant shale gas potential beneath PEI, offshore northern Cape Breton and New Brunswick, and offshore southwestern Newfoundland; limited coal bed methane potential off of Nova Scotia, and very limited gas hydrate potential in the deep Laurentian Channel (Fig. 3).

Mining is important to the economy of the region, and mineral resources include salt, which is currently mined in Îles de la Madeleine, coal resources off Nova Scotia which are mined beneath the seabed, and limestone, gypsum, and base metals mined in Cape Breton and New Brunswick (Fig. 3).

[1] The Marine Conservation Targets (MCT) initiative provides targeted funding to Environment and Climate Change Canada (represented by the Parks Canada Agency), Fisheries and Oceans Canada (DFO), and Natural Resources Canada (NRCan) as part of the Government of Canada's commitment to conserve 10% of Canada's marine and coastal waters within the 200 nautical mile limit by 2020.

1. INTRODUCTION

The Government of Canada has committed to conserve 10% of its marine areas by 2020. Natural Resources Canada (NRCan) is supporting this commitment by evaluating the resource potential in federal waters around Canada so that any conservation decisions made by Parks Canada Agency (PCA) or Fisheries and Oceans Canada (DFO) are informed by resource information that is current, published, and accessible. NRCan's Geological Survey of Canada (GSC) completed a broad regional geological and geophysical study of the southern Gulf of St. Lawrence in 2018 and 2019, centred on the Carboniferous Magdalen Basin, which is the principal geological basin in the southern gulf, and part of the larger Maritimes Basin (Lavoie et al., 2009; Gibling et al., 2008, 2019).

The regional study area was defined based on discussions with PCA and DFO to capture a number of potential areas of interest, and surrounding geoscientific data, whilst staying within the same geological basin as much as possible (Fig. 1). Thus, the analysis could focus on related geological packages which extend across the whole southern Gulf of St. Lawrence. The broad study area allowed geological information from adjacent on-shore areas and wells to be incorporated and extrapolated far offshore, using the geophysical data.

An exception to studying only the Magdalen Basin geology occurs along the north and north-west edge of the study area, where the Magdalen Basin is thin, and the petroleum potential of the Middle Paleozoic Gaspé Belt sequence and the Lower Paleozoic St. Lawrence Platform must be considered to create a complete petroleum potential map. New research was not undertaken on these older rocks; rather the in-depth work of Lavoie et al. (2009) was incorporated into the analysis. To the north-east around Port-au-Port Peninsula, Newfoundland, the study area was curtailed so as to not encroach on more significant petroleum potential in the Lower Paleozoic St. Lawrence Platform sequence. Oil has been discovered in this sequence, and time was not available in this study to address this older petroleum system thoroughly.

Objectives of the study were to: a) review, analyze, and integrate data from previous resource assessments, scientific literature, and available geoscience databases; b) compile and improve an extensive geophysical database to extend the previous science (Fig. 2); c) interpret and map petroleum system elements and regional petroleum plays by applying sound geological principles; d) model the petroleum system in the basin; and e) provide a qualitative summary of the petroleum potential in the study area. In addition, the unconventional petroleum potential and mineral resources in the region were reviewed. This work was accomplished under a tight timeline, which necessitated an expedient, non-exhaustive review.

The qualitative interpretation of petroleum potential is summarized in Figure 1, and additional mineral and unconventional potential is outlined in Figure 3. The following report summarizes the process used to produce these results. More in-depth geological information is included in appendices: A – Regional Geology and Tectonic Setting, B – Petroleum Geology of the Magdalen Basin, C – Exploration and Production History, D – Regional Mapping, and E – Mineral Resources Summary. A list of reviewed documents is provided in Appendix F, and a glossary of terms for non-geoscientists is in Appendix G.

2. GEOLOGIC SETTING

The Carboniferous Magdalen Basin, which is the main subject of this study, underlies the southern Gulf of St. Lawrence. It is a large, clastic dominated basin of Late Devonian to Permian age that forms part of the composite Maritimes Basin (Fig. 3). It rests on Precambrian to Devonian basement rocks of the northern Appalachian Orogen (mountain belt, Williams, 1979), and contains over 12 km of basin fill (Bell and Howie, 1990; Durling and Marillier, 1993a, this study). The Maritimes Basin comprises a number of variably connected, and locally isolated, depo-centers (or structural basins) with roughly similar sedimentary fill (Gibling et al., 2008, 2019). These basins share a largely common regional structural history and are affected by a number of major faults or fault zones. Most of the faults, where observed onshore, exhibit a complex strike-slip initial component of motion and later inversion, leading many researchers to conclude that the Maritimes Basin developed in a transtensional environment (e.g. Bradley, 1982; Waldron et al., 2015; Pinet et al., 2018). Details of basin development are discussed in Appendix A.

The earliest rocks deposited in the Maritimes Basin, the Horton Group and equivalents (Fig. 4, Appendix A), were deposited generally in fault bounded, half-graben style basins (Hamblin, 1989; Durling and Marillier, 1990, 1993b). These rocks are the reservoir (Appendix G) for the commercially produced McCully and Stoney Creek fields in onshore New Brunswick, and represent an early extensional phase of basin development. Shales in the Horton Group are also significant source rocks (Appendix G). They are unconformably overlain by the Sussex Group and equivalent rocks (Waldron et al., 2017), which were deposited as the entire region began to thermally sag. The Sussex Group may contain reservoir sandstones, but they are poorly understood; the group also seals the Horton Group beneath.

There is a time gap between the Sussex Group and the overlying Windsor Group; however, the two rock units are generally concordant. The Windsor Group (Fig. 4) represents the only unequivocally marine and restricted marine rocks in the basin, comprising mainly limestone, evaporites and associated clastic rocks (Giles, 1981). The evaporite rocks include intervals of salt that have flowed into domes and diapirs, forming excellent hydrocarbon traps (Appendix G). The Windsor Group contains a source rock near its base, may contain carbonate reservoirs, and the salt is an excellent seal (Appendix G). Conformably overlying the Windsor Group is the Mabou Group (Fig. 4), which is composed of mainly fine-grained clastic rocks.

A second major unconformity occurs at the top of the Mabou Group and separates it from the overlying coal bearing rocks of the Cumberland and Morien groups ((Fig. 4, Waldron et al., 2017). The coals and shales in these groups are good source rocks and seals, and there are also good sandstone reservoirs in these intervals. The youngest rocks in the basin comprise red sandstone and mudstone rocks of the Pictou Group (Fig. 4). This unit hosts the only documented hydrocarbon pool in the offshore Magdalen Basin (Rehill, 1996).

In the northwest part of the study area, the Magdalen Basin unconformably overlies the Gaspé Belt, another hydrocarbon producing interval of Silurian-Devonian age (Dietrich et al, 2011; Pinet et al., 2013). The rocks in the Gaspé Belt (Fig. 3) were deposited in a variety of depositional and tectonic environments ranging from deep and shallow water marine to fluvial and marginal marine, and form part of the Appalachian Orogen. The Appalachian Orogen is a composite of early Paleozoic terranes that were brought together in a series of mountain building events ranging in age from the Ordovician to the mid-Devonian (Williams, 1979). The Devonian mountain building event deformed the rocks of the Gaspé Belt (Pinet et al., 2008), maturing petroleum source rocks to varying degrees and creating petroleum traps (Lavoie et al., 2009, Dietrich et al., 2011, Pinet et al., 2013). Petroleum production and potential exists in these rocks at the northwest edge of the study area.

Limited potential also exists in older Ordovician rocks of the St. Lawrence Platform (rocks that were deposited on the ancient margin of North America) that may exist beneath the Magdalen Basin within the northern margin of the study area.

3. DATA

3.1 Literature

The geology of the Magdalen Basin and surrounding areas have been the subject of GSC, provincial, and industry reports, as well as a wide range of academic publications. A comprehensive list of literature reviewed is provided in Appendix F, with key references bolded. Rehill (1996, Table 1.1) also contains a summary of relevant geologic literature in the region until 1996. Interpretations published in the literature formed the starting point of our regional mapping and interpretations of the petroleum geology in the basin. Many figures from the literature were georeferenced and imported into our interpretation software, to aide in comparing and incorporating ideas. Geological data from the literature were incorporated into basin models and volumetric calculations.

Consistency (or lack thereof) between published interpretations and between them and our interpretation is one important indication of interpretation confidence. One difference between our work and some previous studies is the more complete seismic database available to us on a workstation (see geophysical data below). Confidence and certainty affect our judgement of “chance of success” for various petroleum system elements, and ultimately our judgement of petroleum potential.

3.2 Geophysical data

A key component of this project was the compilation of a comprehensive multichannel seismic database (Fig. 2). The petroleum industry acquired thousands of kilometers of two dimensional seismic profiles in the Magdalen Basin – the majority were acquired from 1965 to 1985. Much of this data were acquired under the National Energy Board (NEB) regulatory regime that required profiles to be submitted to the government after a set period of time.

Many of these public images were obtained from the NEB and used for interpretation. In addition, many petroleum companies generously shared their digital data with the GSC, to facilitate enhanced regional interpretation. Companies also sometimes provided raw “field data”, and the GSC reprocessed these profiles to improve the digital image. Regional deep crustal scale seismic profiles were also acquired in the Magdalen Basin in 1986, as part of the Lithoprobe project, and some of these profiles were recently reprocessed (Hall et al., 2019).

The large seismic database was compiled into a petroleum industry interpretation software package, to manage and create regionally consistent interpretations. Having the large regional database in a workstation allowed us to manipulate the data more than some previous studies and check our interpretations in three dimensions. Our interpretations also benefited from the recent reprocessing. This added confidence to our regional interpretations. Still, there are areas in the study where seismic coverage is poor, or we could not obtain access to the limited seismic that exists. Some areas also have poor quality seismic images, often due to more complex subsurface geology, or hard water bottom conditions, which prevented energy penetration into the subsurface. These areas of poor coverage or poor quality images were flagged and incorporated into the confidence estimates in the play analysis (Fig. 2).

In addition to seismic data, regional gravity data and aeromagnetic data were incorporated. Satellite gravity data (Sandwell et al., 2014) were modelled and used, to help constrain the interpretations in the salt province area and the region of deep Horton basins, north of Prince Edward Island (Appendix D). Aeromagnetic data interpretations published in the literature (Hayward et al., 2014; Pinet et al., 2005, 2018), were also used to constrain ideas.

3.3 Geological data

The Magdalen Basin has been studied extensively (Appendix F). From geologic outcrops, tracing coal seams, to geochemical assessment of offshore and onshore core, there is a wide variety of information available for review. Geologic information from academic publications and industry reports has been used to define petroleum systems and to help inform the creation of a qualitative petroleum potential map (Fig. 1). Outcrops of age-equivalent strata deposited within subbasins are located in Quebec, New Brunswick, Nova Scotia, and Newfoundland. Some key bedrock sources are as follows. Lavoie et al. (2009) was used for the Gaspé Belt. St Peter and Johnson (2009) was used extensively in New Brunswick. Lynch et al. (1995) mapped Cape Breton, and Knight (1983) studied southwestern Newfoundland. Calder (1998) provides a detailed history of the Carboniferous geology in Nova Scotia, that includes stratigraphic description and correlation, age dating of sediments through biomarkers, paleo-environmental studies, and economic potential.

Gas shows (mud-log gas) or drill stem test (DST) flows were encountered in seven Magdalen Basin wells, (Grant and Moir, 1992), including five offshore. Industry reports include the significant discovery licence surrounding the offshore East Point E-49 well (Hudson Bay Oil and Gas Ltd., 1976). Well logs and core testing of exploration wells drilled offshore have been used to characterize source, reservoir, and seal parameters in multiple petroleum systems (Hu and Dietrich, 2010).

Durling and Marillier (1993b), Giles (2008), Dietrich et al. (2011), Pinet et al. (2013) and Pinet et al. (2018) have published key geologic cross-sections across parts of the Magdalen Basin. A regional geologic cross-section from our regional study is shown in Figure 5.

Rehill (1996) identified 30 key wells drilled in the Maritimes basin for regional study, with 11 of those wells being drilled in the offshore areas of the Magdalen Basin. Bibby and Shimeld (2000) and Hu and Dietrich (2010) compiled reservoir data in these wells in detail. The most current understanding of regional stratigraphy can be found in Giles and Utting (1999), Giles and Utting (2001), Giles and Utting (2003), Waldron et al. (2017), and Gibling et al. (2019).

4. METHODOLOGY

4.1. Play mapping

A petroleum exploration "play" is a family of prospects and pools that share a common history of hydrocarbon generation, migration, reservoir development, and trap configuration (Appendix G). The GSC has developed a methodology to create qualitative petroleum potential maps by analyzing each of the plays that exist in the study area.

For each play, the spatially varying chance of success (COS) for each of the petroleum system elements (source, reservoir, trap, and seal, Appendix G) is estimated. When determining the COS for each petroleum systems element, data quality / caliber, data density, and confirmation of physical data (Lister et al., 2018) must be considered and incorporated into values which reflect all information and confidence. The elements are then combined into the varying COS for the play over the whole study area. Finally, the plays are weighted by an estimated global scale factor to rank their volumetric significance and global competitiveness for offshore exploration, and summed, to create a regional petroleum potential map (Fig. 1). This iterative process creates more detailed maps with higher confidence and is outlined in detail in Lister et al. (2018). Areas with limited data availability should be reassessed after more information has been collected.

In order to establish the plays present, the study began with an extensive literature review. Geological data from wells and outcrop were examined and plays defined in previous studies were sub-divided to examine them in greater detail. A summary of the plays analysed in this study can be found in Table 1. Key geological horizons necessary to understand the various plays were determined; more details of the petroleum geology of the Magdalen Basin are discussed in Appendix B.

4.2. Regional mapping

The extensive database described above was used to create new regional two-way travel time and depth maps of these key geological horizons. Horizons mapped included reservoirs, source rocks, and seals, and mapping also outlined trap geometry concepts (but was not intended to outline specific targets). A cross section of the geometry of the whole basin is illustrated in Figure 5. The regional variation of geological data was also documented from literature.

To create the maps, seismic data were tied to the wells and bedrock outcrop maps, and compared to previous adjacent subsurface interpretations (Appendix D, Seismic horizon interpretation). Reflection packages were followed far from points of known geologic control, to allow a more confident and detailed understanding of the depth, thickness, and petroleum potential of each package. Two-way-time maps were converted to depth maps using regional velocity functions discussed in literature (Appendix D, Depth conversion).

These depth maps were used to calculate isopach (thickness) maps for various prospective intervals, and also the gradient of the isopach maps, where the regional rate of change of thickness may indicate potential for pinch-outs or other stratigraphic traps.

4.3. Basin modelling

Basin modelling uses computer algorithms to analyse the geologic history and burial of source rocks to estimate when, what type and how much petroleum those source rocks produced. Such modelling also estimates when and where petroleum migrated after being produced. Deeper burial generally results in hotter conditions, which can convert source rocks to natural gas rather than oil.

Information gathered from the literature about source rocks in the region was combined with the new more detailed depth maps to create regional scale basin models for the Magdalen Basin (Appendix B, Basin modelling). The basin models were used to estimate the COS for source, and to assess timing and migration at a regional scale.

4.4. Synthesis and scientific review

As this work was ongoing, current ideas about the key reservoirs, seals and source rocks were discussed with experts (e.g. P.Giles, pers.comm., 2018, 2019; D.Lavoie, pers.comm., 2018). The team worked together to synthesize the data sources and mapping into an understanding of each petroleum system element in each play, and to estimate the COS of each element. The plays were mapped and mathematically combined in ArcGIS® to create the final petroleum potential map. A draft version of this report was reviewed by GSC advisors and reviewers for comment and internal technical review.

5. RESULTS AND INTERPRETATION

5.1. Regional depth maps and basin models

Regional depth maps (Appendix D, Depth and isopach maps) were produced for 9 horizons: Cable Head Formation, Green Gables Formation, Bradelle Formation, Mabou Group, Middle Windsor Group, Top of Salt, Base Windsor Group Unconformity, Base Sussex Group Unconformity, and Pre-Horton Group Basement (base of Magdalen Basin). Isopach maps were calculated for seabed to top Cable Head Formation, Green Gables Formation, Mabou Group and Upper Windsor Formation, Middle Windsor and Lower Windsor Group (including salt), Sussex Group, and Horton Group. Isopach maps and their gradients were calculated for Cable Head Formation, and Bradelle Formation and Cumberland Group.

All of these maps were used to develop criteria to estimate the chance of success (COS) of the petroleum system elements in each play identified. For example, reservoir potential decreases with depth and source rocks are more mature with depth (Hu and Dietrich, 2010).

The mapping illustrates that the area surrounding Îles de la Madeleine south to Cape Breton is dominated by significant subsurface salt deposits (Lower Windsor Group, Fig. 4) – the salt moves easily over geologic time, creating many walls, diapirs and pillows in the cores of large folds. These geologic structures provide many opportunities for trapping petroleum (Appendix B, Trap styles). The mapping confirmed that the Base Windsor unconformity (a key marker in the basin and the deepest horizon that can be picked with confidence in the basin core, Fig. 4) is about 12 km deep in the centre of the basin. Mapping also speculates that older Horton Group strata (Fig. 4) may be even deeper, to about 15 km, and outlines possible graben structures at these deepest stratigraphic levels. These grabens trap hydrocarbon in New Brunswick and may also provide traps elsewhere.

Regional depth maps were also input into basin modelling (Appendix B, Basin modelling). Several good source rock layers exist, and models were produced for five key horizons. Shallower source rocks may be immature in the northwest part of the study area, depending on how much eroded sediment existed at the time of burial. However, the majority of the basin will have migration paths from mature source rocks. Significant portions of the basin are deep and thus hot, so, as expected, modelling revealed that source rocks likely produced significant natural gas. In addition, some of the source rocks are gas prone, due to the type of organic matter within them. This gas may flush previously produced oil from traps, yet modelling did indicate that in some scenarios oil may remain in traps. In the very deep centre of the basin, source rocks (especially the older deeper sources) are over-mature and no longer producing hydrocarbons.

5.2. Petroleum plays identified

Seven plays were identified in the Magdalen Basin (Table 1). These plays are subdivisions of the three plays discussed by Lavoie et al. (2009) and Dietrich et al. (2011). Their Upper Carboniferous clastics play is divided into four plays: two stratigraphic subdivisions – Pictou Group, and Morien and Cumberland groups, and two trap types – structural and stratigraphic. Their Lower Carboniferous carbonate play is here called the Windsor carbonate play, and their Lower Carboniferous clastic play is divided in two stratigraphic subdivisions – the Sussex Group play, and the Horton Group play.

Following the approach outlined in Lister et al. (2018), criteria were established to estimate the COS of each petroleum system element of each play, which were combined to give an overall COS for each play. The highest potential play is the Morien-Cumberland Structural play, where good reservoirs may exist in the Bradelle and Boss Point formations, good source rocks in the Bradelle Formation, good seals provided by the Green Gables Formation, and significant untested trapping geometries in both salt-cored folds and against more complex salt structures. The plays are discussed in detail in Appendix B, Plays.

5.3. Qualitative petroleum potential map

The combined conventional petroleum potential in the study area is considered to be medium to high (Fig. 1). The scale of this map ranks this basin against others with a qualitative judgement of exploration significance. For comparison, some parts of the Labrador Shelf rate “very high” (Carey et al., 2019), Lancaster Sound rated slightly higher than this basin (Atkinson et al., 2017), and other regions rated thus far (e.g. Hudson Bay, Pacific Coast) rated lower than this basin. Note that the map illustrates petroleum potential - both natural gas and oil combined. This basin is gas prone.

It also considers exploration significance in an offshore context, where exploration costs are much higher. Global scale factors scale the plays relative to what would be volumetrically significant offshore. Onshore, much smaller accumulations may be economic and areas of “low potential” may still be interesting.

This map does not illustrate individual targets, but rather regions where geological conditions in many layers combine to increase or decrease potential – the steps of colour come from the overlap of many individual petroleum system factors considered, and the map should be read from the general average shade that results in an area.

Nine significant wells have tested these plays in the offshore, and all but East Point E-49 failed to find “discoveries” (Appendix C). These failures are noted and learned from, but are not removed from the map, because one test in an area may not necessarily mean that an adjacent opportunity will not work, and the failure mechanism of a given well is not always clear. This basin is under explored, and one discovery in nine wells matches the world wide exploration average. Early exploration in significant basins was similarly challenged; for example the North Sea Carboniferous basin had six unsuccessful wells prior to any discoveries (Besly, 2018).

The highest petroleum potential in the study area is located to the north of Îles de la Madeleine in a significant east west trend of simple fold structures, cored by mobile salt (green area, Fig. 1). Many of these structures have been partly tested, but significant petroleum accumulations, maybe even at “giant field” scale, may yet be found.

Another area of high petroleum potential is southeast of Îles de la Madeleine, up to the northwest shore of Cape Breton (green area, Fig. 1). Here, the salt moved into walls and diapirs, forming excellent traps and seal. At the same time, complex geometry makes imaging these structures difficult, and petroleum exploration challenging. Large accumulations may exist, and require modern seismic data to outline their potential. Medium to high potential also exists west of Îles de la Madeleine and north of eastern PEI, in simple salt-cored folds, and also in deeper Horton strata deposited in grabens (yellow to green area, Fig. 1).

Immediately beneath Îles de la Madeleine, key clastic reservoirs are likely buried too deep to maintain good porosity. There is a small chance that porosity may be preserved if traps are present and filled with hydrocarbons before significant burial, though this effect has not been observed in this basin. This chance of porosity preservation is not included in the petroleum potential estimate, and thus the estimate may be slightly conservative near the basin centre. Shallower Permian sands (Fig. 4) may provide targets beneath overhangs of mobile salt (Appendix B, Trap styles) near the basin centre, and this potential reservoir is included in the petroleum potential map.

Toward northern New Brunswick and the Gaspé Peninsula the Magdalen Basin becomes shallow and potential decreases. Toward the southwest, under Prince Edward Island and southern New Brunswick, key clastic reservoirs become much less permeable, lowering potential for conventional production.

5.4. Unconventional resources

Unconventional shale gas resources totalling more than 60 trillion cubic feet (Tcf) of natural gas-initially-in-place have been identified in the Horton Group, onshore in southern New Brunswick (Natural Resources Canada, 2017; Corridor, 2018a). Thick, organic-rich shale occurs in the Horton Group, which locally exceeds 1100 m thickness. Equivalent shale-gas resources are likely present beneath the Gulf of St. Lawrence, given the widespread distribution of Horton Group rocks (Durling and Marillier, 1993b; this study). Four areas where unconventional shale resource is considered most likely to occur are beneath PEI, offshore of northern Cape Breton Island, offshore southwestern Newfoundland, and north of western Prince Edward Island and east of northern New Brunswick (Fig. 3). These areas occur adjacent to onshore Horton Group outcrop with significant thickness of organic-rich black shale, and/or where a thick Horton graben is mapped with some confidence.

Significant coal measures exist in the offshore Magdalen Basin (Grant, 1994), so coal bed methane is likely to exist (Hacquebard, 2002; Grant and Moir, 1992). However, the well density and disposal of formation fluids necessary to produce CBM would be difficult to implement offshore. Conditions are favourable for a thin layer of gas hydrates in the deep Laurentian Channel (Majorowicz and Osadetz, 2003) but no direct indicators of gas hydrates have been observed.

CONCLUSIONS

There is significant petroleum potential in the Magdalen Basin of the Gulf of St. Lawrence – large parts of the offshore have medium to high petroleum potential (Fig. 1). Basin modelling suggests a higher chance of natural gas in much of the basin, which currently challenges petroleum industry economics, yet oil accumulations are still possible. The highest potential is located in an east-west trend, north of Îles de la Madeleine, and in an area southeast of Îles de la Madeleine, up to the northwest shore of Cape Breton Island. The highest potential play is the Morien – Cumberland structural play, where Bradelle Formation and Cumberland Group sandstone reservoirs are involved in salt related structures.

Recommended future work

This project was completed under tight time lines, and further work would refine results in support of regional geological understanding. The seismic database assembled in the workstation is a valuable asset that can be used to gain further geological insights, and regional maps and basin models produced to support the petroleum potential map can be further refined to add to the tectonic and stratigraphic understanding of the region.

The qualitative petroleum potential map can be used to support further quantitative analysis, building on the work of Lavoie et al. (2009) and Dietrich et al. (2011). Quantitative results can be apportioned relative to the potential mapped here.

Further regional geological work is underway by team members (e.g. Durling and Giles, Windsor Group facies study, work in progress, 2020), and further collaboration with academia and industry would continue to develop the understanding of the Magdalen Basin. Petroleum potential also exists in the northern Gulf of St. Lawrence, and this methodology could be applied to analyse this potential.

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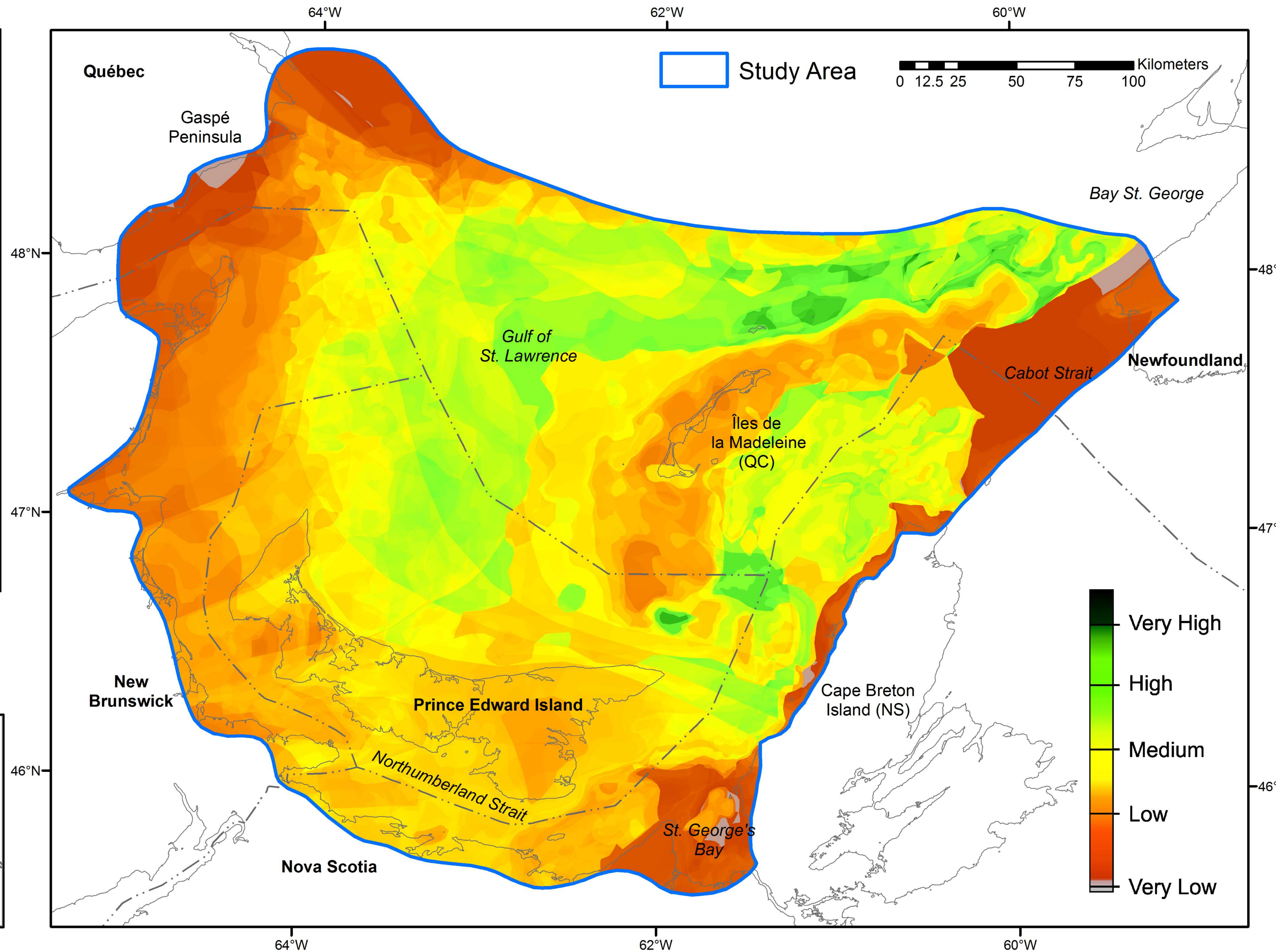
Figure 1 – Magdalen Basin, Gulf of St. Lawrence, petroleum potential map

Petroleum potential is illustrated with a stop light colour bar – grey and deep reds are lowest petroleum potential and dark greens are highest.

Note that this map shows all petroleum potential – oil and natural gas combined (not just oil).

The scale rates this basin for potential / global competiveness relative to other offshore basins – much smaller accumulations may be interesting and economic in adjacent onshore areas.

This map does not illustrate individual targets, but rather regions where geological conditions in many layers combine to increase or decrease potential – the steps of colour come from the combination of many individual factors considered, and the map should be read as the general average shade that results for a specific area.



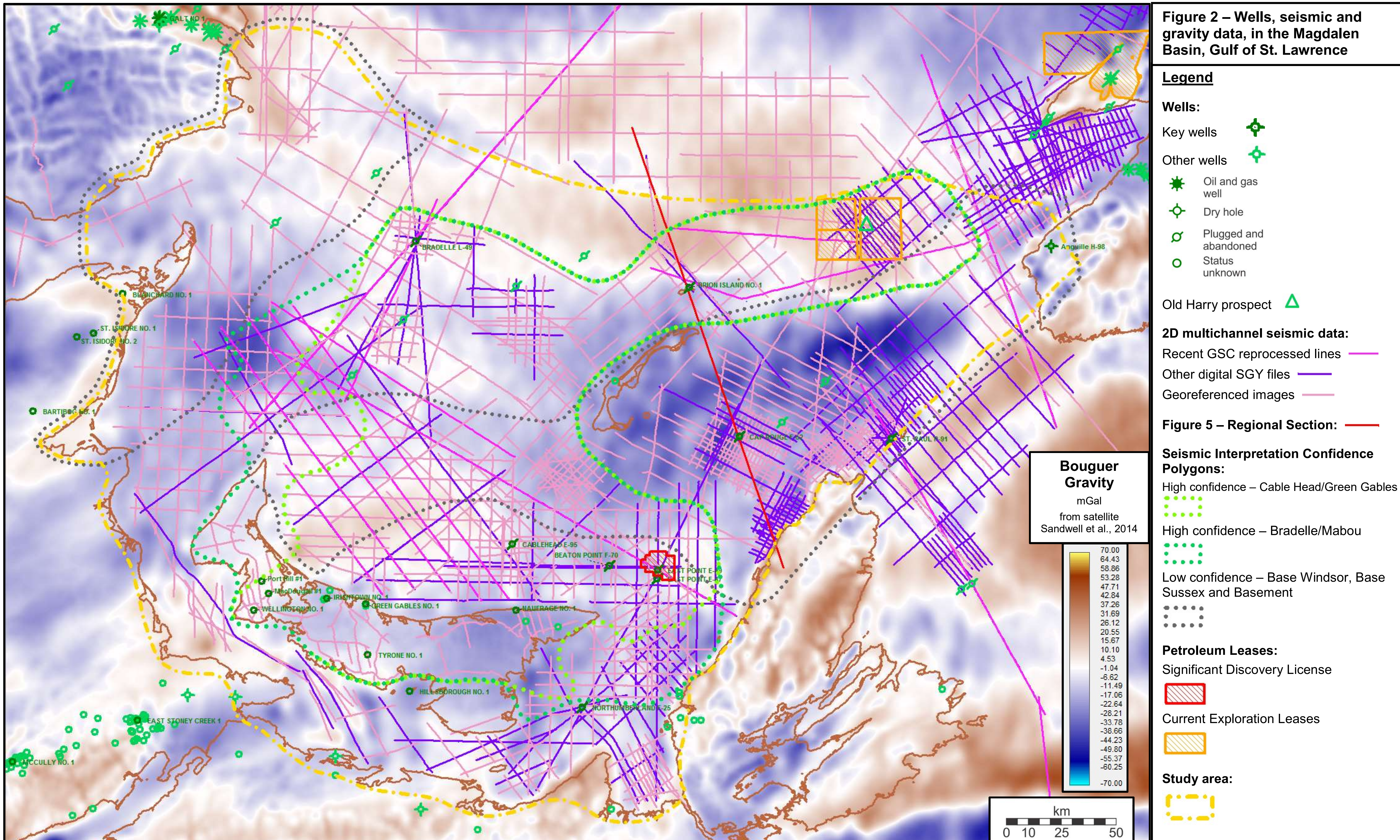


Figure 2 – Wells, seismic and gravity data, in the Magdalen Basin, Gulf of St. Lawrence

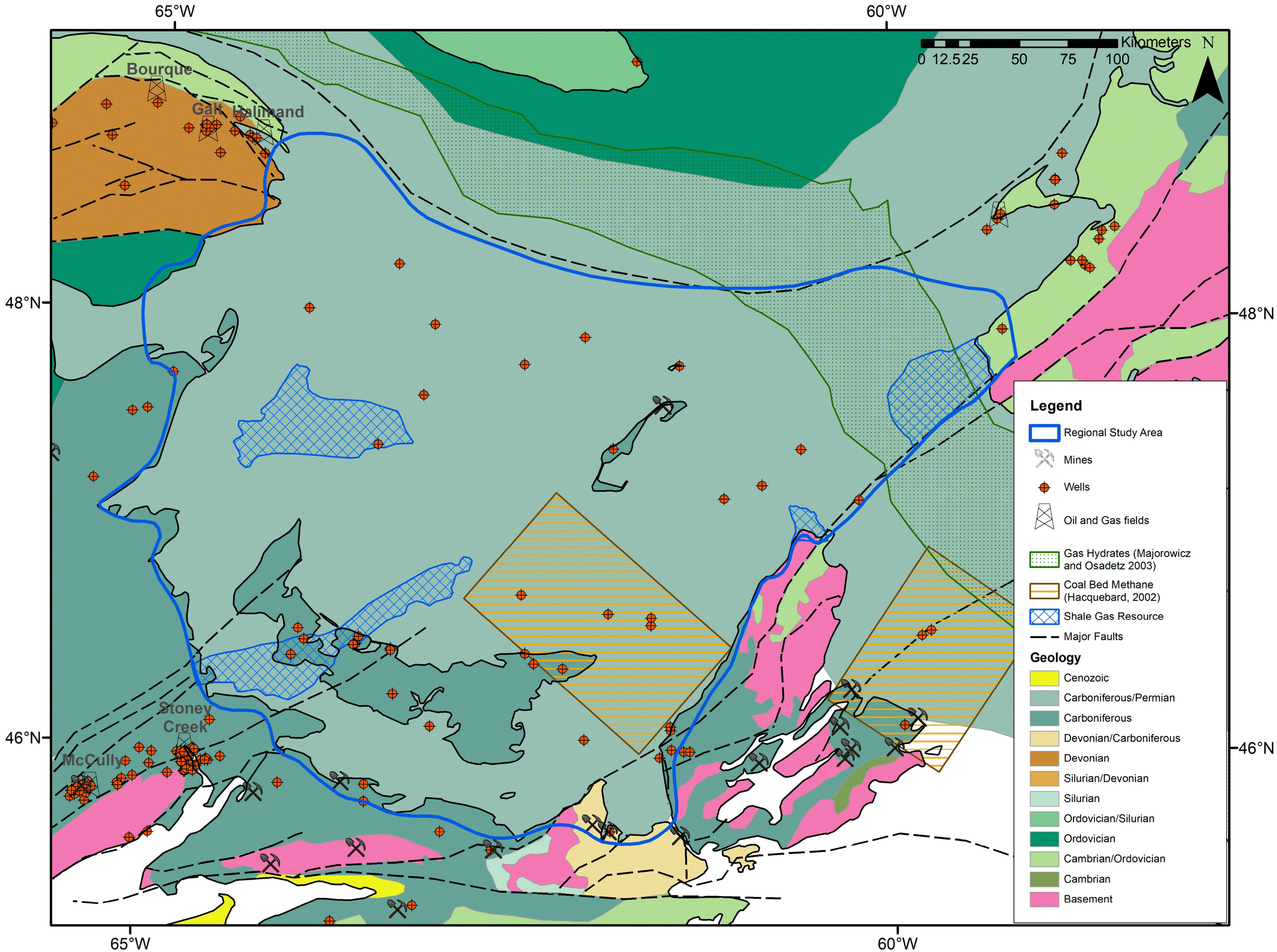


Figure 3 – Regional geology, mineral resources, and unconventional resource potential

Past and Current Mine Operations near the study area. Locations of mines in Quebec come from the Government of Quebec GIS database, in New Brunswick mine and oilfield locations come from Mioc et al., (2015) and mine locations in Nova Scotia (including Cape Breton) come from MANS, 2015.

Unconventional shale gas potential is interpreted where thick Horton Basins are mapped with some confidence. Coal Bed Methane and hydrates potential are illustrated from previous studies.

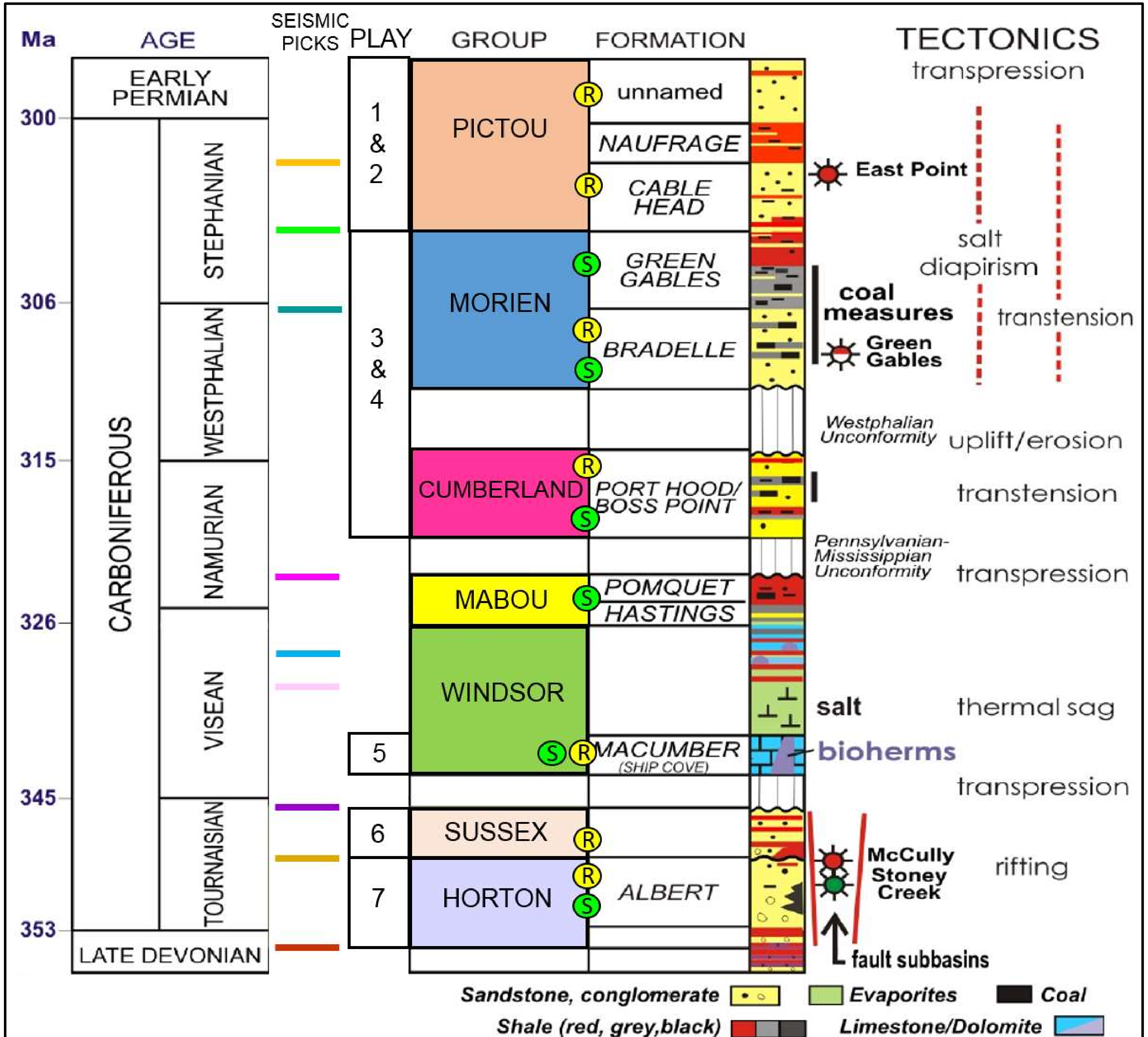


Figure 4 – Litho-stratigraphy of the Magdalen Basin
Modified from Lavoie et al. (2009), Figure 44.

- (S) Source rocks
- (R) Reservoirs
- gas field / discovery
- oil field
- gas show

The stratigraphic position of fields and shows are shown with well symbols, and the tectonics are summarized (Lavoie et al., 2009).

Seismic horizons mapped and illustrated on regional cross section (Fig. 5) and seismic examples (Appendix D) are shown in with coloured markers ("seismic picks"):

- Cable Head Formation
- Green Gables Formation
- Bradelle Formation
- Mabou Group
- Middle Windsor Group
- Top Salt
- Base Windsor Group Unconformity
- Base Sussex Group Unconformity
- Pre-Horton Group Basement

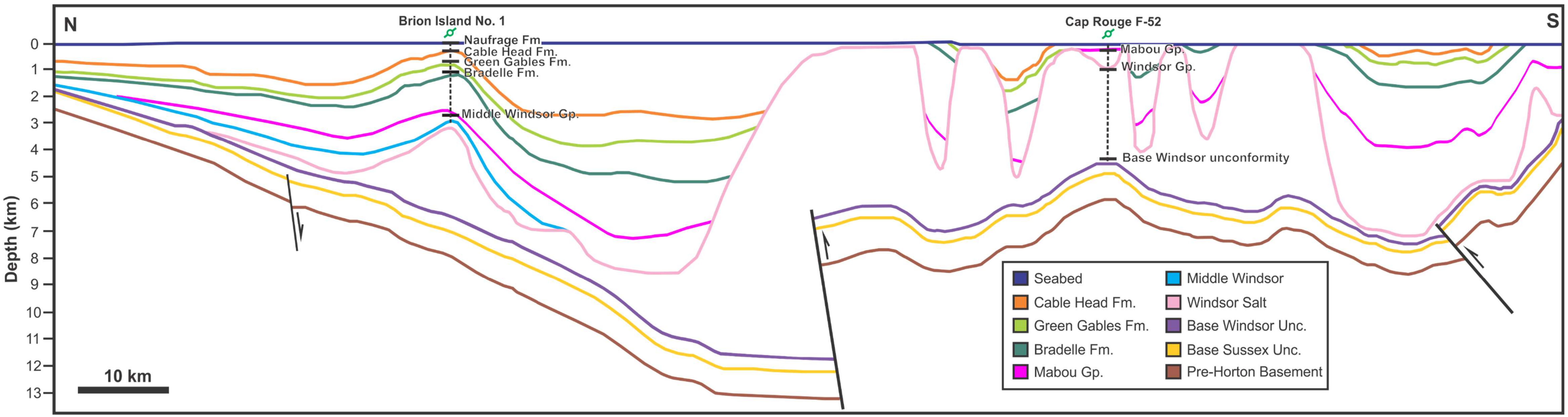


Figure 5 – Geological cross section of the Gulf of St. Lawrence
Cross section across the Gulf of St. Lawrence – constructed from depth grids in Kingdom®. Vertical exaggeration ~ 3:1. For location, see Figure 2.

Table 1 – Plays in Magdalen Basin region, Gulf of St. Lawrence

Greyed out plays are summarized from Lavoie et al. (2009) and Dietrich et al (2011). There is high uncertainty of what geology is beneath the Carboniferous Magdalen Basin offshore.

	Play	Reservoirs	Trap	Seal	Source	Global Scale Factors	biggest COS challenge(s)
						fields and prospects	general phase risk (likely gas)
1	Pictou structural / salt flank play	Cable Head Fm., unnamed Permian sands	pinch-out against salt walls or overhangs or draped over salt	shales in Naufrage Fm.; low COS in many places where strata above reservoir are thin; Salt for salt flank and overhang traps	Green Gables, also Bradelle and Mabou possible	0.4	seal
			folded by structural inversion, compression, differential compaction	chance of fault breach, especially along anticlinal crests		East Point	
2	Pictou stratigraphic play	Cable Head Fm.	stratigraphic plays (pinch-outs in main basin or channels, shores, etc.)	shales in Naufrage Fm.; low COS in many places where strata above reservoir are thin	Green Gables, also Bradelle and Mabou possible	0.3	trap, seal
				strat play top-seal not affected by trap geometry lateral seal issues in massive			
3	Morien/Cumberland structural / salt flank play	Bradelle Fm.	pinch-out against salt walls or overhangs or draped over salt	Green Gables Fm. Salt for salt flank and overhang traps	Bradelle and possibly Mabou (latter gas prone)	0.8	seal
		Port Hood Fm / Boss Pt Fm	folded by structural inversion, compression, differential compaction	chance of fault breach, especially along anticlinal crests	even deeper sources possible in NW, where salt doesn't impede	Old Harry	
4	Morien/Cumberland stratigraphic play	Bradelle Fm.	stratigraphic plays (pinch-outs in main basin or channels, shores, etc.)	Green Gables Fm.	Bradelle and possibly Mabou (latter gas prone)	0.35	seal
		Port Hood Fm. / Boss Pt Fm.		strat play top-seal not affected by trap geometry, better chance of lateral seals	even deeper sources possible in NW, where salt doesn't impede		
5	Windsor Carbonate play	bioherms/reefs - eg: porosity at Gays River	presence of bioherm/reef creates traps - best chance on basin flanks	tight carbonate and evaporites, upper Windsor	Lower Windsor - Macumber Fm everywhere basinward from bioherms/reefs	0.3	reservoir quality, trap (reservoir presence)
		reservoir quality COS is captured under "reservoir"	"trap" is COS of reservoir presence (estimate from Middle Windsor to Base Windsor isopach)		deeper Horton Gp also possible		
6	Sussex play	clastic reservoir potential poorly known	general stratigraphic traps possible	tight carbonate / salt above	Horton Gp. Below	0.2	reservoir quality, trap
		more often a seal (mainly red-beds / anhydrities)	may be enhance by drape over underlying structures	also self sealing	small chance of self sourcing		
		Bradelle well show, Cape Breton sands	not really related to Horton play, no unconventional (fractured shale) play				
7	Horton play	clastics, producing reservoir onshore NB	stratigraphic traps in grabens (unconformity truncation, strat pinchouts)	Sussex shales, intraformational seals	Horton Gp.	0.4	reservoir quality, trap, seal all moderate COS
		braided streams, beach sands - uneven across rifts	also draped into inversion structures	also Windsor Gp. carbonates and evaporites	deeper Paleozoic sources possible in shallow flanks	McCully, Stoney Creek	
		Albert Fm. - Frederick Brook Member thick rich black shale	unconventional fractured lacustrine shale play - economic onshore	self sealing			
8	Gaspe Belt	altered pinnacle reefs	dolomitization, tight carbonate surrounding	tight carbonate surrounding	Middle and Lower Ordovician Shales	0.35	reservoir quality, timing
	Lower Devonian plays	fractured Gaspe Limestone	anticlines, fracture enhanced	tight carbonate	minor Devonian shaly limestones	Galt, Halimand, Bourque	seal (preservation)
		Gaspe Sandstones	stratigraphic - rapid facies change (channels, deltaic wedges) modified by faults	tight carbonate	local coals (Gaspé Sandstones)		
9	Gaspe Belt	Weir / Anse Cascon Fm - Clastics	open folds / Silurian normal faults or Devonian transpression or mixed structure/strat traps	tight La Vielle carbonate, Upper Silurian Unconformity	Middle and Lower Ordovician Shales	0.2	reservoir quality, timing
	Silurian plays	Sayabec/La Vielle Fm Hydrothermal Dolomites	dolomitization, tight carbonate surrounding	tight carbonate surrounding	minor Devonian shaly limestones		seal (preservation)
		West Point Fm Limestone and Hydrothermal Dolomite	dolomitization, tight carbonate surrounding	tight carbonate surrounding	local coals (Gaspé Sandstones)		
10	Ordovician St. Lawrence Platform plays	L to M Ordovician carbonates (Hydrothermal dolomite/karst), also U Ordovician carbonates, M Ord. - Dev. clastics	Hydrothermal dolomite or karst sytems, fault blocks in platform possible, thrusts likely don't reach area	tight carbonate, overlying shales	Middle and Lower Ordovician Shales	0.2	reservoir quality, timing, seal (preservation)

APPENDIX A. REGIONAL TECTONICS AND STRATIGRAPHY

The sedimentary basins assessed in this report lie within, or rest unconformably upon, the Appalachian Orogen (Williams, 1979). The Appalachian Orogen comprises a number of Paleozoic Cambro-Ordovician zones and Silurian-Devonian belts that were brought together in a series of orogenic events ranging in age from the Ordovician to the mid-Devonian (Pinet et al., 2008; Pinet, 2013; Waldron et al., 2015; Trembley and Pinet, 2016). A description of structure and stratigraphy of the sedimentary basins studied in the report is presented below.

Regional tectonic setting

A hydrocarbon producing sedimentary basin of Silurian-Devonian age (Lavoie et al., 2009; Dietrich et al., 2011) is located at the eastern end of the Gaspé Belt within the Appalachian Orogen. Following the Ordovician Taconian Orogeny, rocks in the Gaspé Belt (Fig. 3) were deposited in a variety of depositional and tectonic environments ranging from deep to shallow marine to fluvial and marginal marine (Lavoie, 2019). Subsequent Appalachian orogenic events deformed the rocks of the Gaspé Belt (Trembley and Pinet, 2016).

The Maritimes Basin developed on basement rocks of the northern Appalachian Orogen between the Late Devonian and the Early Permian (Gibling et al., 2008, 2019). It is a large composite basin that extends from southwestern New Brunswick to the continental shelf northeast of Newfoundland, and from the Gaspé Peninsula to the Grand Banks (Bell and Howie, 1990). It comprises a number of variably connected, and locally isolated, depo-centers or structural basins with relatively similar sedimentary fill and share a largely common structural history.

One of the largest depo-centers within the Maritimes Basin lies beneath the southern Gulf of St. Lawrence. It is called the Magdalen Basin and contains over 12 km of basin fill (Bell and Howie, 1990; Durling and Marillier, 1993a, this study). Early descriptions of the Magdalen Basin included the structural basins and intervening uplifts in southeast New Brunswick and northern Nova Scotia (Howie, 1988). In this report, we follow Durling and Marillier (1993a) and Bradley (1982) and restrict the definition of the Magdalen Basin to the offshore Gulf of St. Lawrence, synonymous to the “Gulf of St. Lawrence Basin” of Gibling et al. (2008).

A number of major faults or fault zones affect the Maritimes Basin (Fig. 3). Waldron et al. (2015) identified three main fault trends: northeast-southwest (Appalachian trend), east-west, and northwest-southeast trend. They used stratigraphic and structural relationships to estimate the amount of slip on many of the significant faults and suggest 200 to 300 km of dextral strike-slip in the northern Appalachian Orogen during the early development of the Maritimes Basin. Many of these faults exhibit multiple phases of deformation (Waldron et al., 2015 and references therein), and subsequent inversion occurs in many parts of the basin (Craggs et al., 2017; Snyder and Waldron, 2018; Pinet et al., 2018).

Various models have been proposed for the development of the Maritimes Basin, such as a strike-slip pull-apart model (Bradley, 1982; Waldron et al., 2015); periods of transpression following episodes of initial transtention and later thermal sag (Pinet et al., 2018); distension or orthogonal extension (Hamblin, 1989; Durling and Marillier, 1993b); lithospheric detachment faults (Lynch and Tremblay, 1994) and passive subsidence (McCutcheon and Robinson, 1987). Whichever model is preferred, it is clear that the Maritimes Basin evolved in several phases as evidenced by at least two regional unconformities: a post-Horton (and equivalents) – pre-Windsor unconformity and a post-Mabou – pre-Cumberland unconformity (Waldron et al., 2017). The time-gap represented by the unconformities may vary in length in different structural basins.

The earliest rocks deposited in the Maritimes Basin, the Horton Group and equivalents, were deposited generally in fault bounded, half-graben style basins (Hamblin, 1989; Durling and

Marillier, 1993b). These early depo-centers may be up to 8 km deep (Durling and Marillier, 1993b) and generally formed parallel to the major fault trends (Waldron et al., 2015). Hamblin (1989) concluded that the Horton Group basins likely developed as extensional basins (in contrast to transtensive or strike-slip basins) based on their half-graben geometry, vertical stacking of internal basin fill, and regional distribution.

The Horton Group is unconformably overlain by the Sussex Group and equivalent rocks (Waldron et al., 2017). In the type area (St. Peter and Johnson, 2009), the Sussex Group oversteps the Horton Group basin boundaries suggesting a change in tectonic environment. Recent reprocessing and interpretation of a 3D seismic dataset in the McCully gas field shows that faults cutting through the Horton Group do not pierce into the Sussex Group (Brake et al., 2019). The Sussex Group strata are commonly concordant with the overlying Windsor and Mabou groups, although a regional time-gap exists between the Sussex and Windsor groups (Waldron et al., 2017). The latter stratigraphic units are widespread throughout the Maritimes Basin, which suggests these rocks were deposited during a thermal subsidence phase following the Horton Group extensional phase (Durling and Marillier, 1993a; Gibling et al., 2008). The Windsor Group represents the only wide spread marine incursion into the basin, and restricted marine conditions lead to the deposition of significant evaporates and limestones (Giles, 1981), including locally thick salt intervals. Waldron et al. (2013) and Brake et al. (2019) demonstrated deposition of the Windsor and Mabou groups in salt-withdrawal mini-basins in the Cumberland and Moncton subbasins, respectively.

The Cumberland, Morien and Pictou groups in the onshore areas were deposited in structurally complicated settings, leading many researchers to conclude that the tectonic setting likely represents continued extension in a strike-slip setting (e.g., Gibling et al., 2008). However, offshore studies using seismic reflection data (Grant, 1994; Durling and Marillier, 1993a) show the Cumberland, Morien and Pictou groups to be widespread and lacking significant deformation. The exception is an area of extensive salt deformation east of the Magdalen Islands (Hayward et al. 2014), which is underlain in part by a feature described as the sub-salt high (Durling and Marillier, 1993a). Hayward et al. (2014) interpret the sub-salt high as an inversion structure resulting from regional dextral transpression. Durling et al. (2019) suggest that Late Carboniferous strata (e.g. Cumberland and Pictou groups) may have been deposited in a foreland basin-style setting.

Regional stratigraphy

The offshore Magdalen Basin is comprised of over 12 km of predominantly clastic sediments, deposited between the Late Devonian and the Permian. Formations defined and mapped in multiple provinces and across multiple subbasins create a nomenclature nightmare. Figure 4 is a generalized stratigraphic column and contains the group and formation names in the Magdalen Basin, based on Lavoie et al. (2009). Correlations were based heavily on Waldron et al. (2017), and the detailed and evolving nomenclature of the Horton and Sussex groups is outlined in Figure A-1, see below. Figure A-2 illustrates the deeper Paleozoic stratigraphy that underlies the Magdalen basin at prospective depths, near the Gaspé Peninsula and along the north flank of the basin.

Pictou Group

The shallowest stratigraphy preserved in the Magdalen Basin belongs to the Upper/Middle Pennsylvanian Pictou Group (Waldron et al., 2017; formally the Upper Pictou Group). The base of the group is the coarse-grained, laterally extensive Cable Head Formation sandstones (Lavoie et al., 2009). The Cable Head Formation contains a tested gas zone at the East Point E-49 well (Hu and Dietrich, 2010). The Naufrage Formation sits atop the Cable Head as a fine-

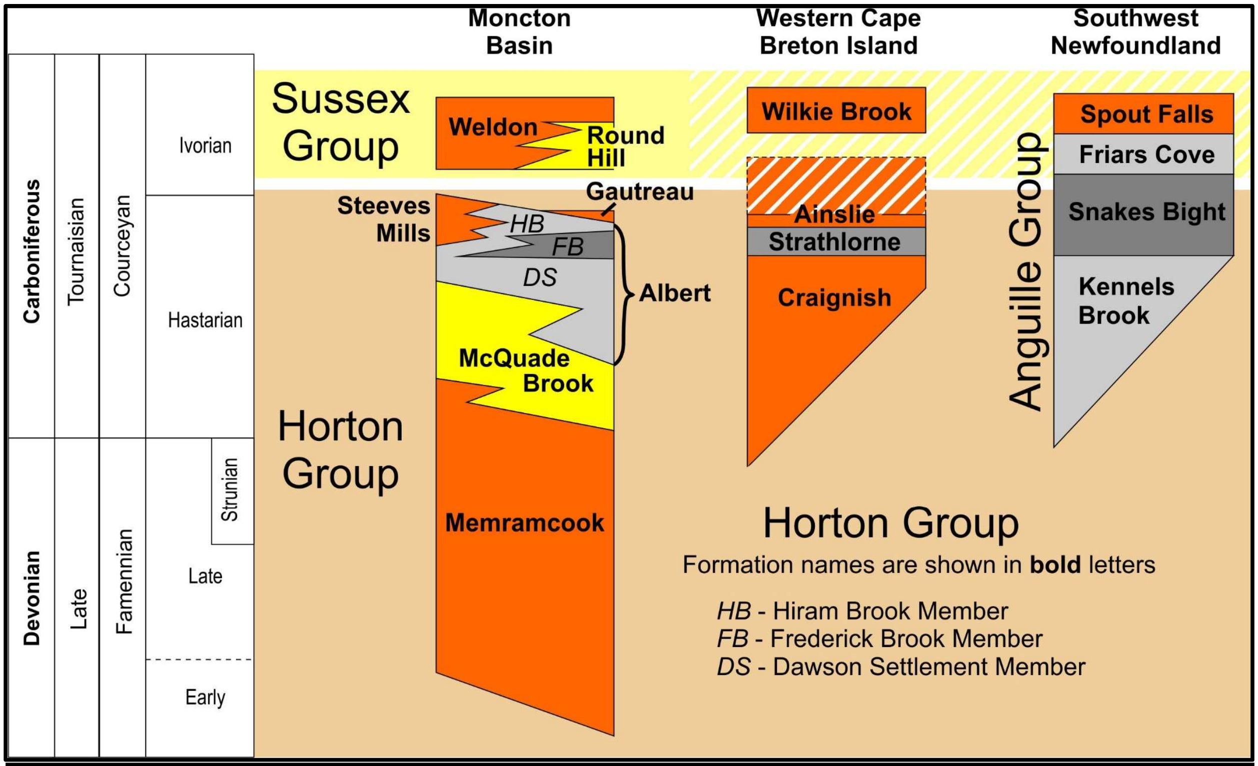


Figure A-1 – Stratigraphy of the Horton and Sussex groups
Relationship of formations and members discussed in text. Yellow hachures – formations time equivalent to Sussex Group, currently formally Horton Group (Waldron et al., 2017), but may be reassigned to Sussex. Red hachures – some rocks mapped as Ainslie Formation in Cape Breton are likely Sussex Group (P.Giles, pers.comm., 2018, 2019).

grained, calcareous red unit (Lavoie et al., 2009). Atop the Naufrage Formation sits (up to) several hundred metres of unnamed Permian coarse-grained conglomerates and sandstones (Lavoie et al., 2009).

Morien Group

The Middle Pennsylvanian Morien Group has been mined for coal for over 200 years; it is composed of interbedded grey and red sandstone and mudrock, with minor limestone, conglomerate, and coal seams (Boehner and Giles, 2008). Where studied in the Sydney Basin, the Morien Group ranges in thickness from 1500-1800m, and contains 13 economic coal seams with thickness ranging from <1 m to >4 m (Sydney Mines Formation; Boehner and Giles, 2008). Thick fluvial sandstones of the Bradelle Formation transition upward into coal measures (Lavoie et al., 2009). The Bradelle Formation contains indications of untested petroleum zones on logs from the Cable Head E-95 well (Hu and Dietrich, 2010). This group was deposited in a basin with high-accommodation events that encouraged and persevered the deposition and preservation of peat; eventually the environment became more arid, stopping peat accumulation (Gibling et al., 2008).

Cumberland Group

Thick fluvial sandstones dominate the Lower Pennsylvanian Cumberland group (Gibling et al., 2008, Figure 15). The laterally equivalent Port Hood and Boss Point formations of the Lower Cumberland Group are up to 1000 m think in Nova Scotia and New Brunswick respectively (Lavoie et al., 2009). The Upper Cumberland contains numerous coal measures which have been mined in Nova Scotia and Cape Breton (Calder, 1998). The Upper Cumberland is up to 2100m thick with grey to black shales (Lavoie et al., 2009). The top of the Cumberland Group is defined by a mid-Westphalian unconformity, which has been shown to locally merge with an earlier unconformity that separates the Cumberland and Mabou groups (Rehill, 1996). The mid-Westphalian unconformity suggests the removal, non-deposition, or faulting of older sediments.

Mabou Group

The lithology of the ~1km thick, Upper Mississippian Mabou Group varies throughout the study area, although it is consistently subdivided into two primary units. Hamblin (2001) published a detailed study on the stratigraphy, sedimentology, tectonics, and resource potential of the Mabou Group. Outcrops have been described throughout Nova Scotia from Sydney to Joggins (Hamblin, 2001), and the Mabou Group has also been reported in wells drilled in the Gulf of St. Lawrence. In eastern Nova Scotia and on Cape Breton Island the lowermost section, the Hastings Formation, is characterized by grey shales and stromatolitic limestone interbedded with anhydrite and halite indicating deposition in a saline setting (Lavoie et al., 2009). In western Newfoundland coeval sediments are composed of lacustrine-fluvial sandstones in the Deer Lake Basin. The Upper Mabou Group in Nova Scotia is characterized by occasional evaporites within fine-grained red strata and thin sandstones; equivalent strata in the Deer Lake Basin are the red sandstones of the Humber Falls Formation (Lavoie et al., 2009). The presence of red strata and evaporates indicates an arid depositional environment (Gibling et al., 2008). Fluvial sandstones of the Searston Formation are coeval sediments in the Bay St. George subbasin. The top of the Mabou Group is marked by a regional unconformity; the nature of this unconformity suggests a base sea-level change coupled with a changing tectonic environment (Gibling et al., 2008). Deposition of the Mabou Group occurred during a climate transition from the arid Visean to the humid Westphalian (Hamblin, 2001).

Windsor Group

The Middle Mississippian Windsor Group is characterised by transgressive-regressive cycles comprising limestone, evaporites and non-marine clastic rocks, deposited in an open marine to restricted marine setting. The Windsor Group can be informally subdivided into lower, middle and upper parts. The lower Windsor Group is represented by a single transgressive-regressive cycle. It includes a basinal organic rich fine-grained limestone facies (Macumber Formation) overlain by anhydrite and halite. In basin margin settings the basal limestone may be represented by coeval locally dolomitized and porous bioherms (Gays River Formation).

The middle and upper Windsor Group comprise repeated transgressive-regressive cycles consisting of alternating limestone, anhydrite, halite and non-marine clastic rocks. The thickness of each cycle ranges from a few tens of metres to hundreds of metres (Giles and Utting, 2001). The middle Windsor Group may be represented by up to 20 limestone rock units (Giles, 2009), whereas the upper Windsor Group generally comprises fewer than ten. Well intersections of the Windsor Group in the Magdalen Basin suggest that the middle Windsor Group is more laterally persistent than the upper Windsor Group and the proportion of non-marine clastic rocks in the Windsor Group generally increases up-section. Indeed, upper Windsor Group time-equivalent rocks in the Bradelle L-49 well consist of clastic rocks assigned to the Mabou Group (Giles and Utting, 2003).

Sussex Group

The Lower Mississippian Sussex Group is historically formally identified in southern New Brunswick, where it consists dominantly of thick grey shale and red mudstone, with some anhydrite bands and limestones. As discussed above, it is interpreted to have been deposited during a thermal subsidence phase. In the New Brunswick type section, the Sussex Group is a reasonable seal for the Horton Group strata beneath, but the Sussex Group equivalent rocks show significant variation and sandstone and volcanics are observed elsewhere in other Maritimes subbasins (Waldron et al., 2017).

How this group correlates to the rest of the Maritimes Basin deposits is being investigated by Peter Giles at GSC Atlantic. As part of this MCT project, we engaged Graham Dolby to curate and provide palynological data from Natmap results from the 90's. Giles used this data and other recent lithological and palynological insights to update his cross section over Prince Edward Island (Giles and Utting, 1999, revised 2018) and correlations to other wells in the basin. He now interprets significant thickness of Sussex Group in Irishtown No.1, Wellington No.1, Northumberland F-25, Cap Rouge F-52, and Bradelle L-49 wells (Fig. 2; P. Giles, pers. comm., 2018).

Peter Giles provided guidance on correlation across the basin (P.Giles, pers.comm., 2018 and 2019; Fig. A-1). He explained that the Sussex Group had not been recognized when the Coldstream and Wilkie Brook formations, in Nova Scotia, were erected. Palynology shows that these two formations have the same assemblages as the Sussex Formation. The Wilkie Brook is unconformable on Horton Bluff shales. The Coldstream is unconformable on Meguma sediments in the Shubenacadie basin and is totally younger than the Cheverie in the Horton Group type section. The Sussex Group is separated from the older Horton by a disconformity or unconformity. Therefore the Sussex Group has the same stratigraphic relationship to the Horton Group as does the Wilkie Brook / Coldstream interval. With the same spore assemblages, Giles surmises that the Coldstream / Wilkie Brook rock units are equivalent to, or at least a portion of the Sussex Group. Similarly, parts of the Ainslie Formation on Cape Breton are now considered part of the Sussex rather than the Horton, based on spore dates.

He also notes, the Fischells Brook / Ingonish / Spout Falls (Fig. A-1) interval in southwest Newfoundland may then be a post-Sussex interval previously unrecognized. Spores from the Fischells Brook / Ingonish / Spout Falls interval are apparently different and younger than the Coldstream / Wilkie Brook assemblages, which allows that the rock units may be quite different and unconformity-bound. However, the base of the Coldstream / Wilkie Brook section is likely diachronous; the Fischells Brook / Ingonish / Spout Falls package could simply represent younger "Sussex" overstepping onto older Horton Group rock units.

Giles' ideas form the basis of our Sussex Group play (see Appendix B, Sussex Group play), and are discussed in detail to support this analysis. These correlations are still being worked, and are incorporated into our regional mapping of the Sussex Group (see seismic discussion below) and are supported by our mapping.

Horton Group

The Upper Devonian to Lower Mississippian Horton Group and its equivalents throughout the Maritimes Basin can be subdivided into a tripartite stratigraphy (Gibling et al., 2008 and references therein, Fig. A-1)) comprising a lower alluvial interval (typically redbeds), a medial grey-bed interval deposited in a lacustrine environment, and an upper alluvial interval (Hamblin and Rust, 1989; St. Peter and Johnson, 2009; Giles, et al., 1997; Knight, 1983). Given the importance of the Horton Group rocks of southern New Brunswick for their petroleum occurrences, these rocks are used to illustrate typical Horton Group stratigraphy for the broader Maritimes Basin, although significant differences may occur locally in other areas.

The lower red-bed interval in southern New Brunswick is represented by the Memramcook and McQuade Brook formations (Fig. A-1). The former comprises mainly red conglomerate, sandstone and siltstone, whereas the latter comprises predominantly red fine-grained rocks. The depositional environment is interpreted as alluvial fan to fluvial. Equivalent units occur in western Cape Breton Island and southwest Newfoundland where they are represented by the Craignish and Kennels Brook formations, respectively.

The medial grey interval is called the Albert Formation in southern New Brunswick (Fig. A-1), which comprises grey sandstone, siltstone, mudstone, and black kerogenous shale, with lesser amounts of conglomerate. These rocks were deposited in a fluvial to lacustrine environment (St. Peter and Johnson, 2009). Equivalent units occur in mainland Nova Scotia (Horton Bluff Formation), western Cape Breton Island (Strathlorne Formation) and southwest Newfoundland (Snakes Bight Formation).

The Albert Formation has been extensively studied owing to its hydrocarbon production history. It has been subdivided into three members: the lower Dawson Settlement Member (grey coarse-grained clastics), medial Frederick Brook Member (grey to black, organic-rich mudstone and shale), and the upper Hiram Brook Member (interbedded grey sandstone, siltstone and black shale). The tight sandstone of the Hiram Brook Member is the main producing unit in both the Stoney Creek oil field and McCully gas field. The Frederick Brook Member is up to 1100 m thick, has significant potential for shale-gas development, and it is interpreted as the main source rock in the Moncton Basin.

The uppermost alluvial interval of the Horton Group in south-eastern New Brunswick is represented by the Steeves Mills and Indian Mountain formations (Fig. A-1). Correlation to the rest of the basin is being revisited based on a new understanding of the Sussex Group.

Stratigraphy of the Gaspe Belt and St. Lawrence Platform

The Gaspé Peninsula in eastern Quebec contains predominantly Lower and Middle Paleozoic fine to coarse-grained clastics with subordinate carbonates. Presumably these rocks extend into the offshore and underlie portions of younger, Magdalen Basin sediments. The geology and petroleum potential of these units has been discussed in detail by Lavoie et al. (2009) and Dietrich et al. (2011). Figure A-2 is a generalized stratigraphic column showing the Paleozoic formations in the Gaspé Belt with source and reservoir rocks annotated.

The Honorat and Matapédia groups (and laterally equivalent units) are Upper Ordovician to Lower Silurian, deep-water clastics overlain by argillaceous limestone (Lavoie et al., 2009; Lavoie, 2019). In the Gaspé Belt and New Brunswick, the Chaleurs Group sits conformably atop the Matapédia Group. The lower Chaleurs Group consists of a second-order regressive event with lower clastic units, which transitions from a basal deep marine mudstone to a shallow marine sandstone and pebble conglomerate, culminating in a thin shallow marine carbonate unit (Lavoie et al., 2009). The rest of the Chaleurs Group consists of an initial transgressive event expressed as a thick succession of fine-grained clastics, followed by another regressive phase leading into major reef development in late Silurian. The Lower Devonian package begins with deep clastics with local pinnacle reefs followed by the establishment of deep offshore marine limestones (Upper Gaspé Limestones). Then, the 6 km thick coarsening-upward Gaspé Sandstone, the nearshore to continental Acadian tectonic wedge, was deposited in response to a major tectonically controlled regressive phase (Lavoie et al, 2009: Lavoie, 2019).

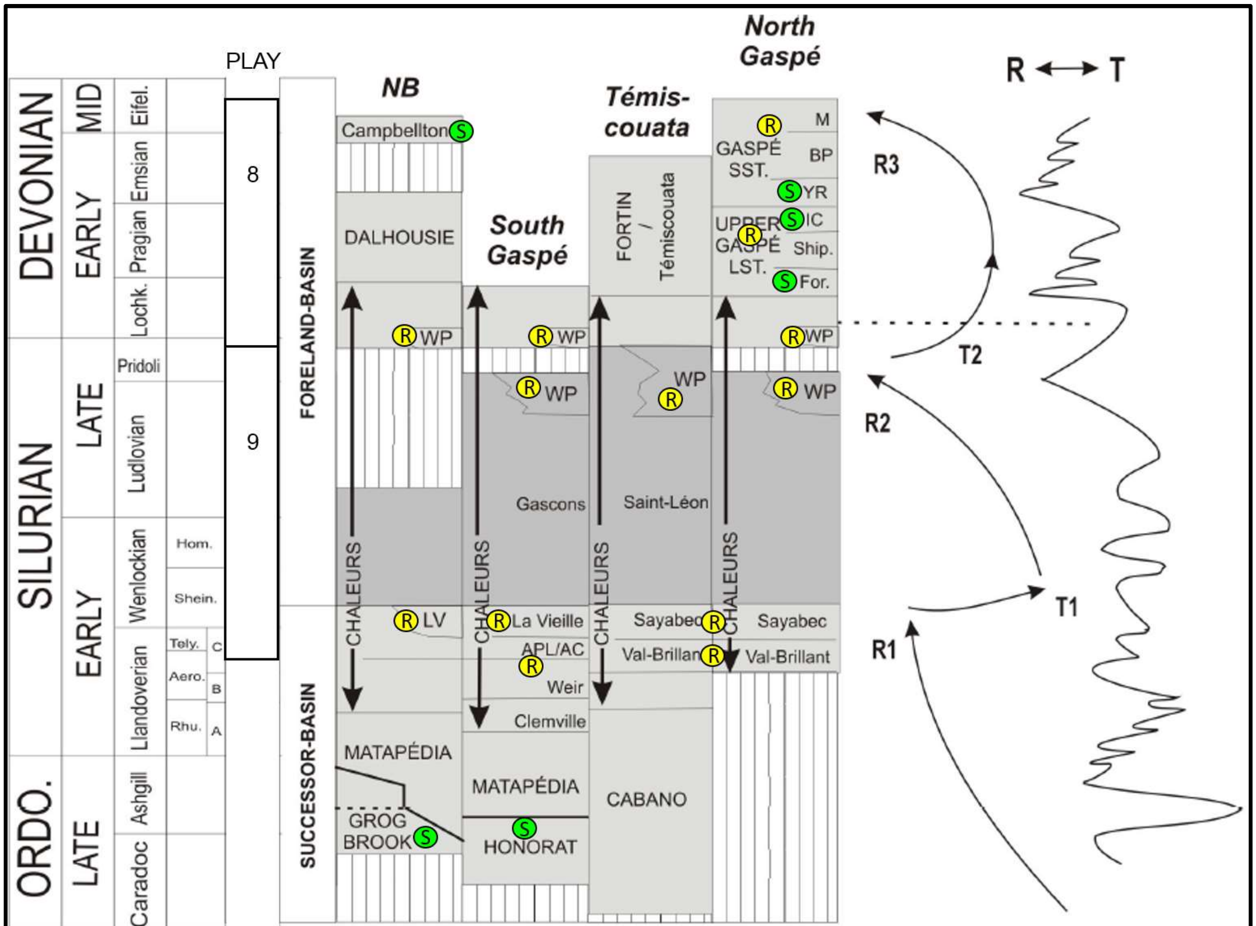


Figure A-2 – Litho-stratigraphy of the Middle Paleozoic Gaspé Belt

With source (S) and reservoir (R) potential annotated.

Modified from Lavoie et al. (2009), Figure 27.

Play numbers for this study are indicated (see Tables 1 and 3).

APPENDIX B. PETROLEUM GEOLOGY OF THE MAGDALEN BASIN

The Magdalen Basin consists primarily of Carboniferous clastics with a unit of marine carbonates and evaporates in the Visean (Middle Mississippian). The Carboniferous stratigraphy can be over 12 km thick in the salt diapir province. A small region of fault bounded Ordovician to Devonian strata exists at shallow depths under the Carboniferous section, in the north-west section of the study area, near the Gaspé Peninsula and along the north basin margin.

This section will outline the elements of the petroleum system within the Magdalen Basin and briefly summarize the older system elements as well. For a successful petroleum accumulation to occur, all four petroleum system elements must be present: source rocks (basin modelling studies their maturity and timing of petroleum migration), reservoirs, trap configurations, and seals. This summary relies heavily on Lavoie et al. (2009). Play definitions and COS mapping criteria are discussed for conventional plays in the basin, and unconventional resource potential is summarized.

Gas shows (mud-log gas) or DST flows were encountered in seven Magdalen Basin wells, (Grant and Moir, 1992), including five offshore, supporting the presence of a working petroleum system. Good reservoirs were also observed. Failure in the eight unsuccessful wells may more likely be due to local trapping configuration or seal, but has not been formally studied.

Source rocks

The following source rocks are listed in order of increasing age. The headings are derived from the group name and correspond to the naming convention in the basin model, but as described below there may be several formations contributing to the source potential of the group. In general, the sources in the basin are good, but have the potential for being over mature in the deeper parts of the basin.

Green Gables and Bradelle formations

The Upper Carboniferous section of the Magdalen Basin is dominated by coal measures and is likely gas prone. Thick coal seams interfinger with sandstones throughout the Morien and Cumberland groups. These coal measures are the most abundant source rocks in the Maritimes Basin. Green Gables, Sydney Mines, Stellarton, Bradelle, and Port Hood are all formations of the Morien and Cumberland groups with source rock potential. The coal-bearing sections can be up to 2000 m thick (Cumberland Basin) and are typically 500 m thick in the offshore Magdalen Basin. These groups also contain significant oil shales, which can be more oil prone. The coal seams and oil shales have a lacustrine and fluviodeltaic origin with dominantly type II/III organic matter and up to 40% total organic carbon (TOC).

Mabou Group

Fluviodeltaic shales (Mukhopadhyay, 2004) of the Hastings Formation (Mabou Group) can be correlated with the Cape Dauphin Formation in the Sydney Basin and the Rocky Brook Formation (Deer Lake Group) in Newfoundland. Organic matter in these formations is predominately type III and a potential source of natural gas. The Mabou Group is heterogeneous, consisting of shales, sandstones, limestone, evaporites, with sparsely distributed coal seams (Dietrich et al., 2011). The organic matter in the Mabou Group may be only locally present and is likely not consistently present throughout the basin. The Mabou source rock may not be regionally important (P.Giles, pers.comm., 2019) and should not be considered a reliable source rock.

Windsor Group calcareous shales and carbonates

The Macumber Formation is a possible hydrocarbon source at the base of the Windsor Group. The calcareous shales and carbonates contain type II/III organic matter reaching up to 5% total organic carbon (TOC; Mossman, 1988). Although laterally extensive, the organic rich layers are thin and separated by evaporitic strata. In places, the shale layers can be up to 25 m thick (Mossman, 1992; Fowler et al., 1993; Rehill, 1996). The bitumen seep at the Pugwash Salt Mine can be attributed to the Macumber Formation based on the biomarker signature (Fowler et al., 1993). Analysis on Cape Breton has shown that the Macumber Formation has crude oil potential and lies within the oil window (Mukhopadhyay, 2004).

Sussex Group

The Sussex Group is the least understood source rock in the basin. The Sussex is a package of non-marine clastic rocks that unconformably overlies the Horton Group with significant lateral thickness and facies variations. Grey shales in the type section are not good source rocks, but the hypothetical potential exists for facies changes in basinal areas, to more organic rich facies (P.Giles, pers. comm., 2018). Sussex source rock potential has not been analyzed in this study.

Horton Group

The oldest source rocks in the Carboniferous section of the Magdalen Basin are found in the Horton Group. Over much of the Magdalen Basin, the Horton source rock is likely over mature due to the thick sedimentary package above it, but less mature areas exist on basin margins. The Lower Carboniferous lacustrine black shales are typically 100-300 m thick with 2-20% TOC and type I/II organic matter, but they can locally reach 1100 m thickness (Corridor, 2018). This algal-sourced shale is oil prone and is spatially limited as these shales are generally confined to rift grabens. For the onshore basins in New Brunswick, biomarkers have traced the produced petroleum of the Stoney Creek oil and gas fields to the Albert Formation (specifically the Frederick Brook Member; Chowdhury et al., 1991). The Albert Formation can be correlated to the Strathlorne Formation on Cape Breton. In Newfoundland, the Horton Group can be correlated to the Anguille Group. Oil seeps on Cape Breton and Newfoundland are attributed to the Horton Group and its equivalents (Hamblin et al., 1995; Fowler et al., 1993).

Possible gas chimneys that may originate from the Horton Group are interpreted on seismic data in the shallow northwestern part of the basin near New Brunswick (Hinds and Fyffe, 2013b; Hinds et al., 2015). These features are interpreted on noisy older seismic data, and thus are not definitively “direct hydrocarbon indicators”. Some features could be faults or just bad data zones. Yet some are enhanced by reprocessing and seem to align with depressions in the sea bed (Hinds et al., 2015), increasing the likelihood that they are indeed gas chimneys. New multibeam bathymetry, high resolution seismic, and sampling could improve the confidence in these seeps and thus the extension of the Horton source offshore.

Ordovician Sources

The distribution of older Paleozoic rocks underlying the Magdalen Basin is uncertain. To the northwest, Lower and Middle Paleozoic rocks extend into the offshore from the Gaspé Peninsula. These petroleum systems are identified in Lavoie et al. (2009). In northern New Brunswick, the overmature Upper Ordovician Boland Brook Formation contains up to 1.4% TOC (Bertrand and Malo, 2005). Outliers of deep marine Middle Ordovician shales are found in eastern Gaspé Peninsula and contain up to 10.7% TOC (Lavoie et al., 2009, 2011). Locally organic-matter rich shaly limestones (Lower Devonian Upper Gaspé Limestones) and aerially restricted coals beds (Lower Devonian Gaspé Sandstone and Campbellton Formation) have limited source rock potential.

Basin modelling

Three-dimensional thermal history models were created in Trinity (Trinity T3 5.85, ZetaWare Inc.) using depth converted surface grids interpreted from seismic. The purpose of the geological modelling was to estimate the extent of maturation within the basin and develop a general understanding of possible migration paths. These models did incorporate the movement of salt over time, but did not account for erosion within the sequence.

A geothermal gradient of 25°C/km was treated as a constant over time, based on the result of apatite fission track modelling by Ryan and Zentilli (1993).

A substantial amount of sediment was deposited during the Permian that was later eroded throughout the Triassic (Ryan and Zentilli, 1993). More deposition will increase the likelihood of entering and surpassing the dry gas window. Two scenarios, one with 1.5 km and another with 4 km of additional Permian deposition and subsequent erosion, were tested in the basin model to account for this uncertainty. For the COS map, the 1.5 km of additional Permian deposition scenario was used as it fit much better with observed vitrinite reflectance values (Grant and Moir, 1992; Hacquebard, 2002; maturity values retrieved from the BASIN database (http://basin.gdr.nrcan.gc.ca)), and the average thickness of eroded strata from Chi et al. (2003), and also supported the possibility of oil expulsion in the basin. The possibility of slightly greater maturity was acknowledged in uncertainty level in the COS values.

Thermal maturity of source rocks

To aid the COS process, five of the source rocks mentioned above were modelled in Trinity to outline zones of petroleum generation potential. Values for the initial kerogen input parameters were taken from the Sydney Basin Play Fairway Analysis (SPFA, Nova Scotia Department of Energy and Offshore Energy Research Association, 2017), and Rehill (1996), and are listed in Table 2. Modelled vitrinite reflectance (ARCO) is used as a proxy for thermal maturity. For any given source the oil and gas windows fill a significant area of the study area (Fig. B-1). The source rock is considered over mature and lacking petroleum potential if the modelled reflectance value is greater than 2.5 %Ro. In general the petroleum generation window is between 2000 and 5000 m.

Table 2 – Kerogen input values based on Sydney Play fairway analysis (SPFA)

Thicknesses are doubled to account for the increased thickness of the Magdalen Basin compared to the Sydney Basin. Rock-Eval analysis from Rehill (1996) provided a second set of average TOC values (HI – hydrogen index, TOC – total organic carbon, GOGI – gas oil generation index, TI – transformation index)

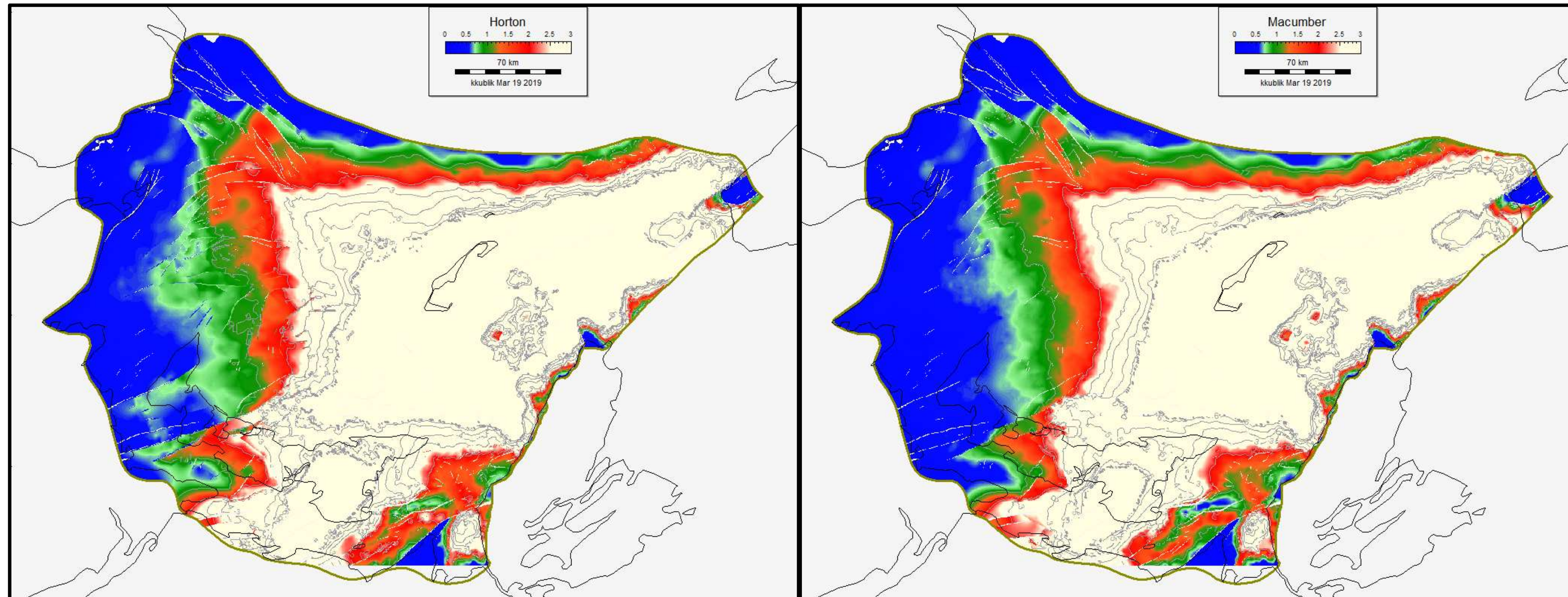
Source Rock	Type	HI (mg HC/g TOC)	TOC (wt%) SPFA	TOC (wt%) Rehill	GOGI	TI (mg/g)	Thickness (m)
Green Gables	D/E terrigenous terrestrial wax/resin	450	5	1	0.28	9	6
	B-Aquatic Marine clay-rich	450	5	1	0.24	14	6
Bradelle	D/E terrigenous terrestrial wax/resin	450	10	1	0.28	9	6
	B-Aquatic Marine clay-rich	450	10	1	0.24	14	6
Mabou	D/E terrigenous terrestrial wax/resin	150	2.5	2	0.57	3	30
	B-Aquatic Marine clay-rich	150	2.5	2	0.3	7	30
Lower Windsor	A-Aquatic marine clay-poor	200	3	4	0.32	11	20
Horton	C-Aquatic non-marine (lacustrine)	650	5	2	0.14	20	100

Figure B-1 – Vitrinite reflectance (maturity) maps from Trinity basin modelling

The following maps show the modelled vitrinite reflectance for the Magdalen Basin. For each map blue represents areas that are immature, green are zones within the oil window, and red are zones within the gas window. The light cream colour are those regions that are overmature and outside the dry gas window.

For these maps it is assumed that 1.5 km of sediment has been deposited in the Permian and eroded in the Triassic. This case was used to estimate source COS in our petroleum potential map (Fig. 1).

The Horton source rock is assigned to the interpreted surface at the base of the Sussex. The Macumber source rock is assigned to the interpreted surface at the base of the Windsor. The Mabou source rock is assigned to the interpreted Mabou surface. The Bradelle source rock is placed 200 m below the interpreted Bradelle surface (to better reflect the middle of the thick coal package). The Green Gables source rock is assigned to the top of interpreted Green Gables surface.



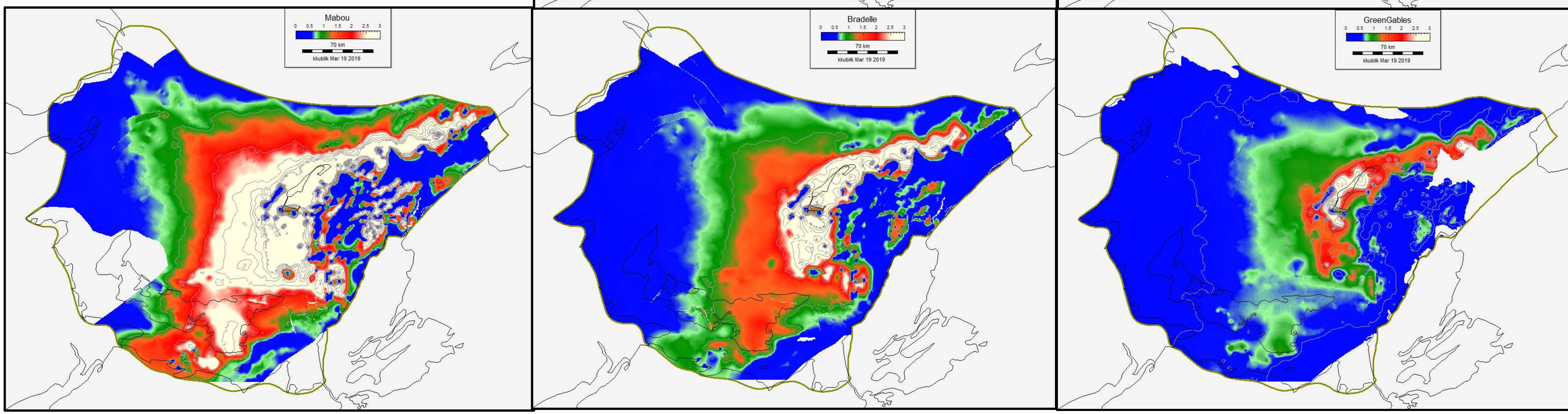


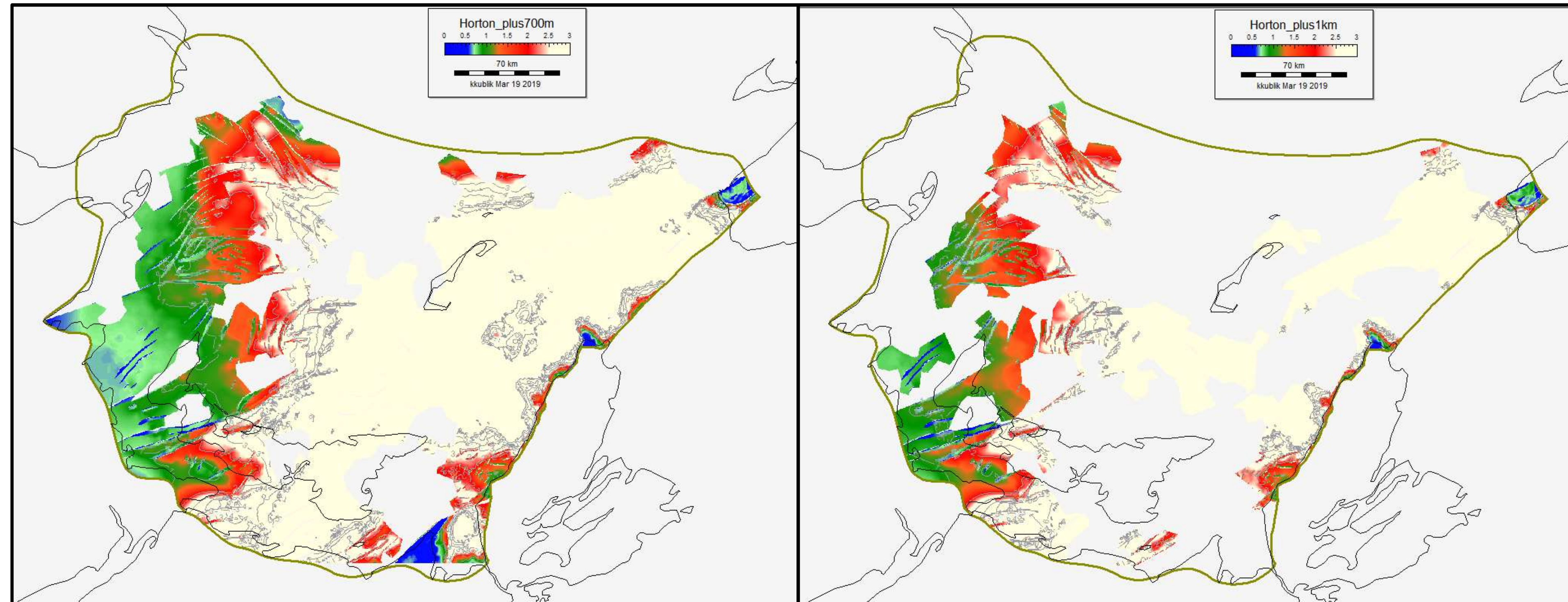
Figure B-1 – Vitrinite reflectance (maturity) maps from Trinity basin modelling, continued

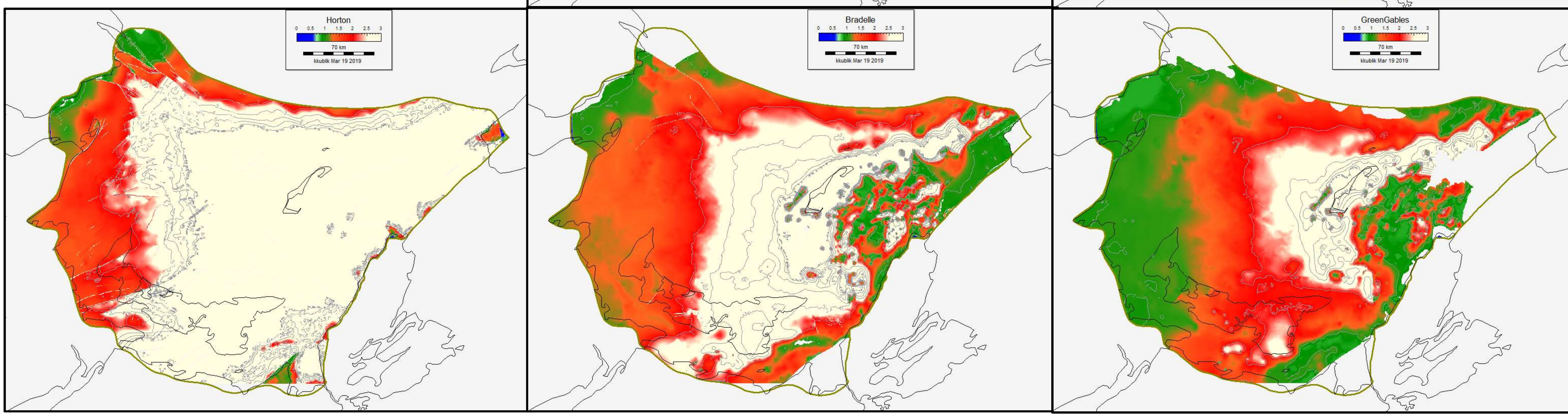
The following maps show the modelled vitrinite reflectance for the Magdalen Basin, for examples of other test cases. For each map blue represents areas that are immature, green are zones within the oil window, and red are zones within the gas window. The light cream colour are those regions that are overmature and outside the dry gas window.

For the maps on the right, 1.5 km of Permian deposition was used, and the Horton Group source was modelled 700 m below the top of the Horton sequence and then 1000 m below its top, to consider source beds deeper in the Horton Group.

For the maps below, it is assumed that 4 km of sediment has been deposited in the Permian and eroded in the Triassic (high end case of deposition). The deepest Horton Group source, key Bradelle source, and shallowest Green Gables source are shown for comparison to the 1.5 km of deposition cases (previous page).

Significantly more area of over maturation is seen in all cases, and almost no parts of the basin are immature.





Timing of maturation and migration

Basin maturation initiates in the Carboniferous; the Horton Group source enters the oil window during the Middle Mississippian. The final stages of maturation (for all sources) occur in Permian time (300-270 Ma) when 1 to 4 km of additional sediment was deposited and then eroded in the Triassic. Due to the deposition of a (potentially) thick sediment package, hydrocarbon generation in the Magdalen Basin is gas-prone. Additionally, some source rocks in the basin are gas prone at any depth due to their lithologies (e.g. coal measures).

There is little uncertainty about the presence of generating source rocks within the basin as shown by the significant (gas) discovery at the East Point E-49 well, and limited production of oil and gas onshore in southern New Brunswick (Appendix C). Despite gas generation and migration from deeper in the basin, regional modelling suggests that oil may be produced, accumulate and survive, in some scenarios.

Seismically mapped traps in the region were initially modeled to be filled by a single source (the closest potential source rock located stratigraphically lower). Results from one of these models show that a trap containing Bradelle Formation reservoir may be filled with a mixture of oil and gas generated by a Bradelle/Cumberland source rock. These traps were then modeled to be filled by hydrocarbons generated from multiple source rocks. If the previously discussed Bradelle traps are sourced from both a Bradelle/Cumberland source and a Mabou Group source (which was modelled to consider its effect on phase), gas generated from both the Mabou and Bradelle/Cumberland sources likely fills the structure, flushing oil from the traps.

Phase risk (whether petroleum present is oil, gas, or a mixture of both) is a major consideration when assessing the economics of a prospect, and the combination Mabou Group and Bradelle/Cumberland source creates high uncertainty for the presence of oil. However, the Mabou Group has limited potential as a source rock (as discussed above), thereby reducing the phase risk somewhat, because a structure charged only by the Bradelle/Cumberland source has more chance to contain (the more economical) light oil.

Maturity and timing of Paleozoic source rocks in the Gaspé Belt

Exploration wells in the Gaspé Peninsula contain oil with API's ranging from 19.6° to 46.9° API oil (Lavoie et al., 2009), hydrocarbon generation from the potential Ordovician source rocks is thought to have occurred during and after the Taconian Orogeny (Roy, 2008). Evidence for early generation and migration is found in the form of bitumen and fluorescent oil in primary to secondary pore space (Lavoie et al., 2009). Ordovician source rocks are mature at surface Figure B-2, and are the source for the Galt and Haldimand fields.

The Taconian generation and migration of hydrocarbon creates a challenge for the charging of younger reservoirs in the Magdalen Basin. Hydrocarbons would have to have been generated, and trapped for ~100 million years before the reservoirs and traps of the Magdalen Basin were formed. It is unlikely that these lower source rocks have charged Carboniferous sediments offshore.

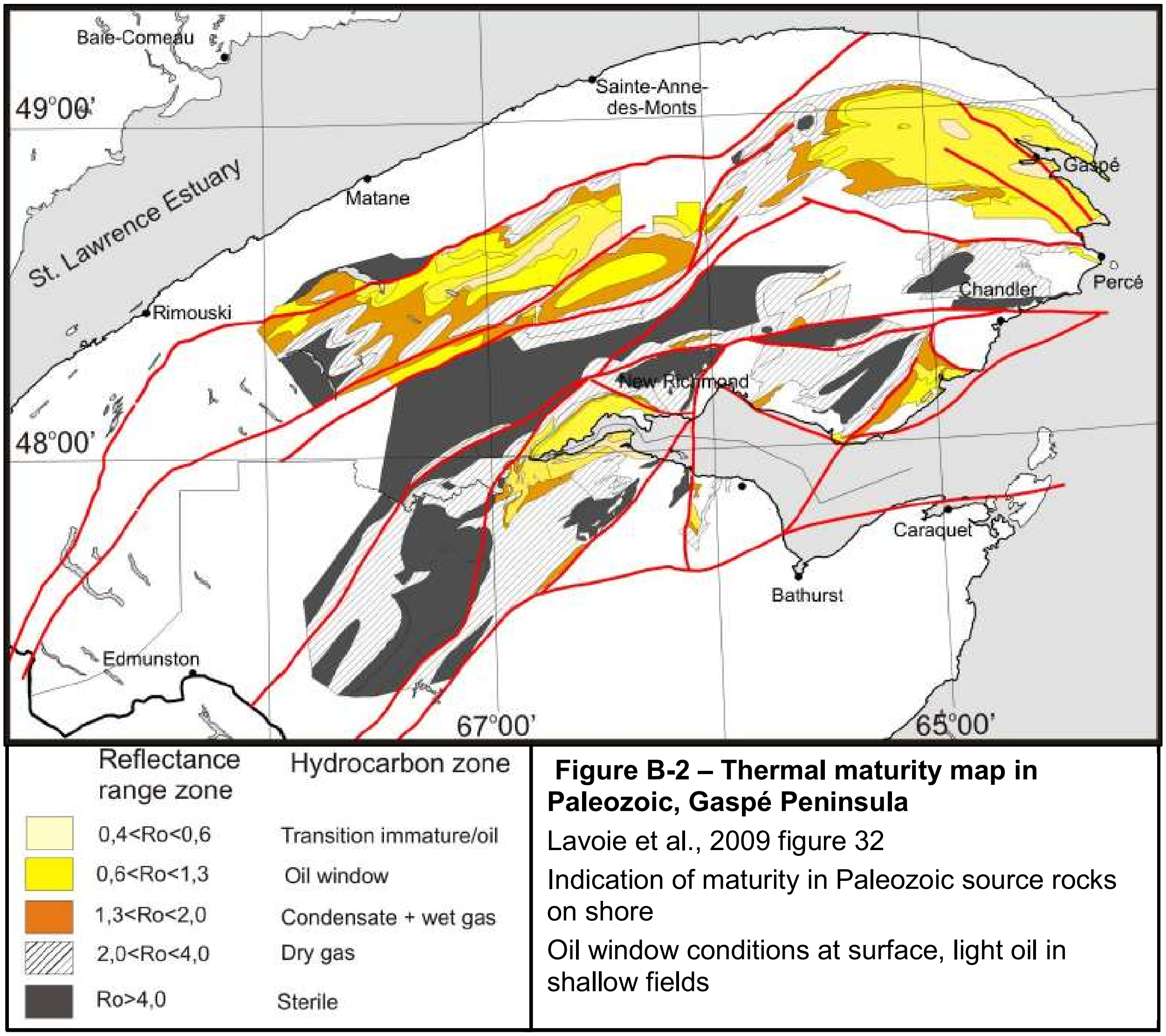


Figure B-2 – Thermal maturity map in Paleozoic, Gaspé Peninsula

Lavoie et al., 2009 figure 32

Indication of maturity in Paleozoic source rocks on shore

Oil window conditions at surface, light oil in shallow fields

Reservoirs

The Magdalen Basin is dominated by clastic (sandstone) reservoirs, with only the Windsor Group having carbonate reservoir potential. As is common elsewhere, the sandstones of the Magdalen Basin show a strong relationship of porosity (from well logs and core) vs. depth (Fig. B-3, Hu and Dietrich, 2010). In this basin, this relationship is quite consistent in all formations, and it was used to establish criteria for predicting reservoir quality from regional depth maps and assigning reservoir COS (see below).

There is a chance that porosity could be preserved at greater depths if it is filled by hydrocarbons before significant burial, but so far this effect has not been seen in this basin. Chi et al. (2003) note that dissolution of calcite cement could also contribute to above average porosity, yet they still observe that porosity values clearly decrease with depth. The COS criteria for reservoir quality are based on the observed porosity versus depth trend (Fig. B-3, Hu and Dietrich, 2010) and as such may be slightly conservative in the deep basin surrounding Îles de la Madeleine, should early hydrocarbon charge preserve porosity at greater depths or calcite dissolution improve local porosity.

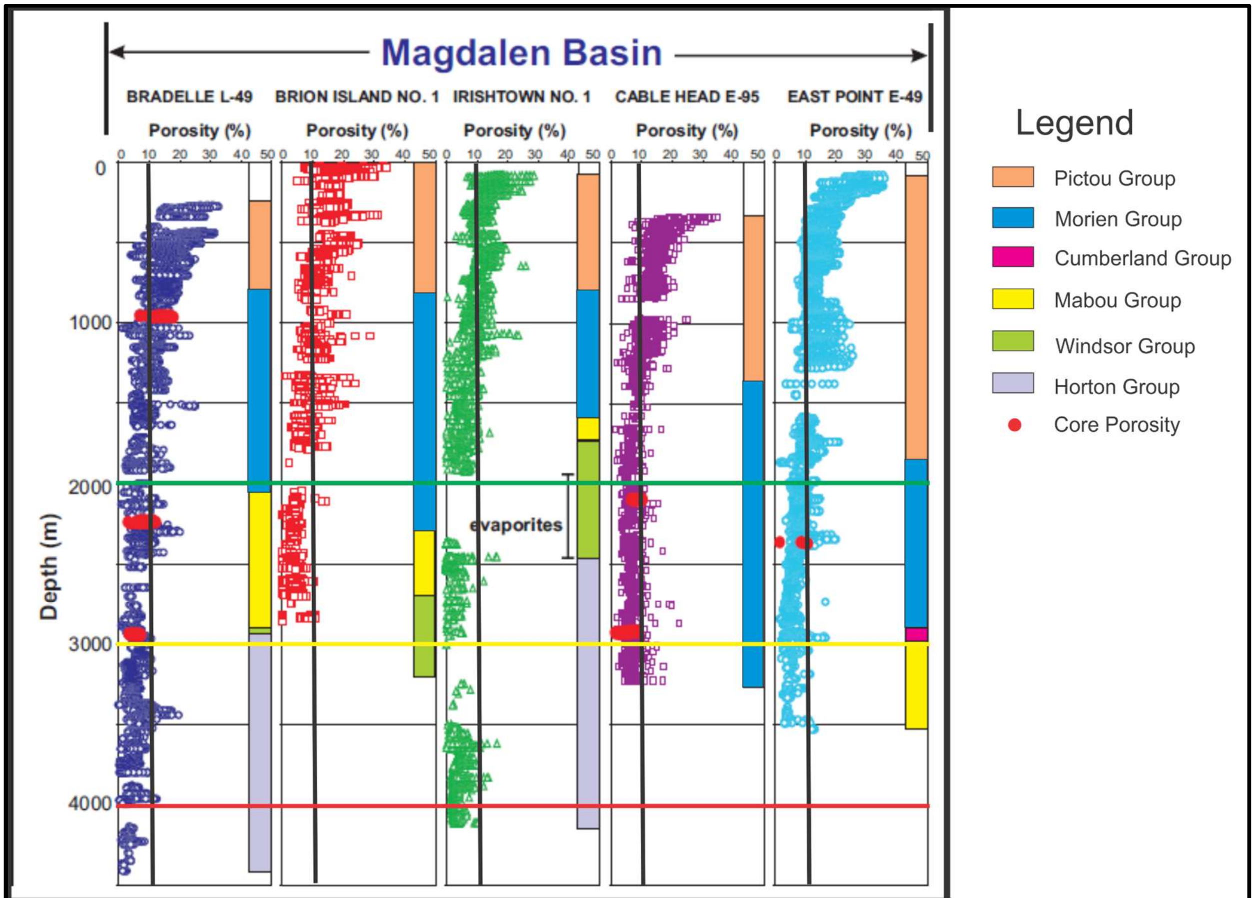


Figure B-3 – Porosity vs. depth in the Magdalen Basin

Modified from Hu and Dietrich (2010), who studied the reservoir potential of the Upper Paleozoic Sandstones in the Magdalen Basin. The porosity in this plot is calculated from wireline logs with the exception of the red circles that indicate core porosity values (Hu and Dietrich, 2010).

Our assessment uses 10% porosity as a cut-off for good quality reservoirs. The green horizontal line at 2000 m is the depth used in the COS map to identify the best quality reservoirs. Depths below the red line at 4000 m are areas that have little to no reservoir potential. Depths between the green and red lines are divided into two zones of decreasing reservoir quality by the boundary at 3000 m (yellow line).

Most of the wells in the Magdalen Basin were drilled on structural highs related to salt movement, which may have be present during deposition. Structures may have diverted coarse-grained sediments into adjacent mini-basins, and thus the thickness and quality of reservoir sands may improve significantly off the structural crests (Durling and Martel, 2005).

Porosity – permeability measurements (Bibby and Schimeld, 2000) for various wells in the Maritimes Basin show low porosity – permeability values for Upper Carboniferous reservoirs located in the southern part of the Maritimes Basin, but much higher values for northern wells (e.g. Bradelle L-49). Based on this information, we applied a gradational permeability overlay to our reservoir COS, to recognize the generally lower permeabilities in the southwestern part of the basin.

Gibling et al. (1992) demonstrated that the sediment source for the southern Maritimes Basin was from an area southwest of the Magdalen Basin, based on northeasterly directed paleoflow measurements. Although the data are sparse, Gibling et al. (1992) show southerly and/or westerly directed paleoflow measurements for Carboniferous age strata in the Gaspé Belt, southwest Newfoundland, and the Magdalen Islands. These strata are not all exactly the same age, which may explain the varying paleoflow directions. The map pattern of paleoflow does hint that a possible explanation for the variation in permeability is that the northern and eastern parts of the basin have a different sediment provenance than the southern and western parts of the basin. Corridor Resources Inc. used this depositional model of sediment supply from the Canadian Shield in the northern half of the Magdalen Basin to support their Old Harry Prospect (Macquarie Tristone, 2011).

Cablehead Formation / Pictou Group

The Cable Head Formation is dominated by thick, coarse grained sandstones (Dietrich et al., 2011) with a high net-to-gross sand ratio, which limits the potential for intra-formational seals. Porosities calculated from logs are typically above 10% (Hu and Dietrich, 2010); however, the core data from the Tyrone No.1 indicates porosities between 2-10% and permeabilities between 0.01 and 1 millidarcies (mD) (Bibby and Shimeld, 2000). There are also some sands in the Naufrage Formation, above the Cable Head, and this can affect the sealing potential of the Naufrage. Above the Naufrage are unnamed Permian sands, which also can have reservoir potential. These Permian Sands usually are very shallow and lack seals; in the very centre of the basin they may be deeper and sealed against overhanging mobile salt. They have good to excellent porosity.

Bradelle Formation

The Bradelle Formation has sandstone quality similar to Cable Head Formation, but it has more shale (lower net-to-gross sand ratio) and coal; however, this formation being stratigraphically below the Cable Head Formation has lower porosity due to compaction. The core data from these coarse-grained fluvial sandstones are found in the following wells: Hillsborough No.1, Green Gables No.1, Cable Head E-95, Naufrage No.1, Bradelle L-49, Cable Head E-95, and East Point E-49. This formation has porosity between 3-12% with permeabilities from 0.01 to 0.2 mD (Bibby and Shimeld, 2000; Hu and Dietrich, 2010).

Port Hood / Boss Point Formation

The Port Hood and Boss Point formations are a mix of non-marine sandstones, shales, and coal measures (Dietrich et al., 2011) that suggest heterogeneity in reservoir quality. Less data are available for this potential reservoir because only the following wells penetrate these Cumberland Group formations: East Point E-49, Hillsborough No 1, Tyrone No 1, and Green Gables No 1. Core data from the Hillsborough No 1 well indicate porosities between 2-11% and permeabilities between 0.1-0.2 mD (Bibby and Shimeld, 2000). Petrophysics estimates porosities up to 20% in the East Point E-49 well (Hu and Dietrich, 2010).

Windsor Group reefs and fractured dolomite

Windsor reefs (Gays River Formation) were deposited on basin margins during the initial transgression of the Windsor seas (see conceptual cartoon – Fig. B-4a and trap discussion below).

In the type section, the Gays River reef complex has a maximum thickness of 50 m and it is approximately 10 km long with a preserved width of up to 2 km (Boehner et al., 1989). Primary porosity was estimated to range between 25 and 40%, but is now filled with mineralization; liquid petroleum was observed in remaining pore space (Sangster et al., 1998). The Gays River Formation and equivalents have been widely reported throughout Nova Scotia (Shubenacadie and Musquodoboit basins, the eastern and western margins of the Antigonish Highlands, and the northern and southwestern margins of the Sydney Basin; Boehner et al., 1989), southern New Brunswick (McCutcheon, 1989) and in western Newfoundland (Dix and James, 1989).

Based on the absence of reported Gays River Formation in western Cape Breton Island and seismic expression of the interpreted basal Windsor reflection in this study, the authors conclude that the likelihood is low for the development of Gays River Formation reef facies on the southern margin of the Magdalen Basin. However, two areas where Gays River Formation reef facies may be developed are on the eastern extension of the New Brunswick Platform (see for example McCutcheon, 1989) and on the northern margin of the Magdalen Basin (see for example Dix and James, 1989).

Sussex Group

In its type section in southern New Brunswick, the Sussex Group has little reservoir potential and seals the Horton Group below it. However, elsewhere in the basin, there is some evidence of sandstone facies with reservoir potential. In Bradelle L-49, a sand with porosity range of 3-8% (Bibby and Shimeld, 2000) and a gas show is observed just below the Base Windsor unconformity and is now interpreted to correlate with the Sussex Group. Sandstones are encountered in the Sussex Group (Giles and Utting, 1999, revised 2018 – P. Giles, pers. comm., 2018) in both Irishtown No.1 and Wellington No.1. Sandstone correlative with the Sussex Group (P.Giles, pers. comm., 2018) is also encountered deep in Cap Rouge F-52 beneath the Base Windsor unconformity, but it has poor reservoir properties, likely due to deep burial. Sandstones suggestive of reservoir potential, which also may correlate to Sussex Group are also mapped in the Ainslie Formation in Cape Breton (P. Giles, pers. comm., 2019). Regionally, the Sussex Group reservoir potential is poorly understood and reservoir COS is judged to be only slightly positive at best.

Horton Group

Alluvial – fluvial sandstones comprise the reservoir for the Horton Group. Bibby and Shimeld (2000) reported porosity and permeability data for the Horton Group from various wells ranging up to 20 percent and 30 mD, respectively. Core measurements from the East Stoney Creek No.1 well show porosity ranges from 3% to 20% and permeability measurements from less than 0.1 mD to 30 mD (Bibby and Shimeld, 2009). Tight sands are reported from the McCully Field with porosity ranges of 4-8% and permeability ranges of 0.01 mD to 1.8 mD (Leblanc et al., 2011). The foregoing indicates that Horton Group reservoir quality can be highly variable.

Deep reservoirs beneath the Maritimes Basin

Lavoie et al. (2009) considered six hydrocarbon plays in the Silurian-Devonian Gaspé Belt that extends offshore beneath the northwestern part of the Gulf of St. Lawrence. Figure B-4b shows schematically each of the plays described in this section. Each numbered paragraph below corresponds to the numbered hydrocarbon plays identified in Figure B-4b. Refer to Dietrich et al (2011) for unit nomenclature.

(1) Lower Silurian nearshore sandstone – the sandstones range from impure sands (abundant feldspars and lithic fragments) to well rounded and sorted quartz arenite with less than 5% feldspars. Porosity and permeability tend to be low.

(2) Lower Silurian limestone rocks deposited on a carbonate ramp – these rocks generally are tight except where secondary porosity is developed through hydrothermal dolomitization. Visible porosity of up to 25% has been reported (Lavoie et al., 2009).

(3) Upper Silurian carbonate reef complexes – Outcrop studies reveal these rocks have very little porosity; however, these rocks have potential to develop secondary porosity through hydrothermal dolomitization and/or fracturing (Lavoie et al., 2009).

(4) Lower Devonian pinnacle reefs - hydrothermal dolomitization associated with movement on Acadian faults has been documented in these rocks.

(5) Lower Devonian fractured and hydrothermally-altered carbonate breccia – this play type includes the Galt Field, which has oil and natural gas in reservoirs in the Upper Gaspé Limestones. High fracture porosity is observed close to northwest-striking faults.

(6) Lower Devonian fluvial sandstones – these sandstone units were the first exploration targets in eastern Gaspé Peninsula due to abundant oil seeps. The Haldimand Field hosts oil and natural gas in sandstone with porosity ranging between 5 to 15%.

Traps styles

The Maritimes Basin has a long and complex tectono-stratigraphic history (Gibling et al., 2008, 2019). The basin has been affected by extensional, compressional and strike-slip faults (Waldron et al., 2015). Combined with the thick and mobile Windsor Group salt layer, this results in a wide range of trap styles. In this section we identify the types of traps that have been recognized on the seismic data, or have been noted in the literature (Lavoie et al., 2009). Figure B-4a shows schematically examples of the various trap styles discussed below, labelled by letter.

(A) Pinchout against salt diapirs and overhangs and drape over salt pillows

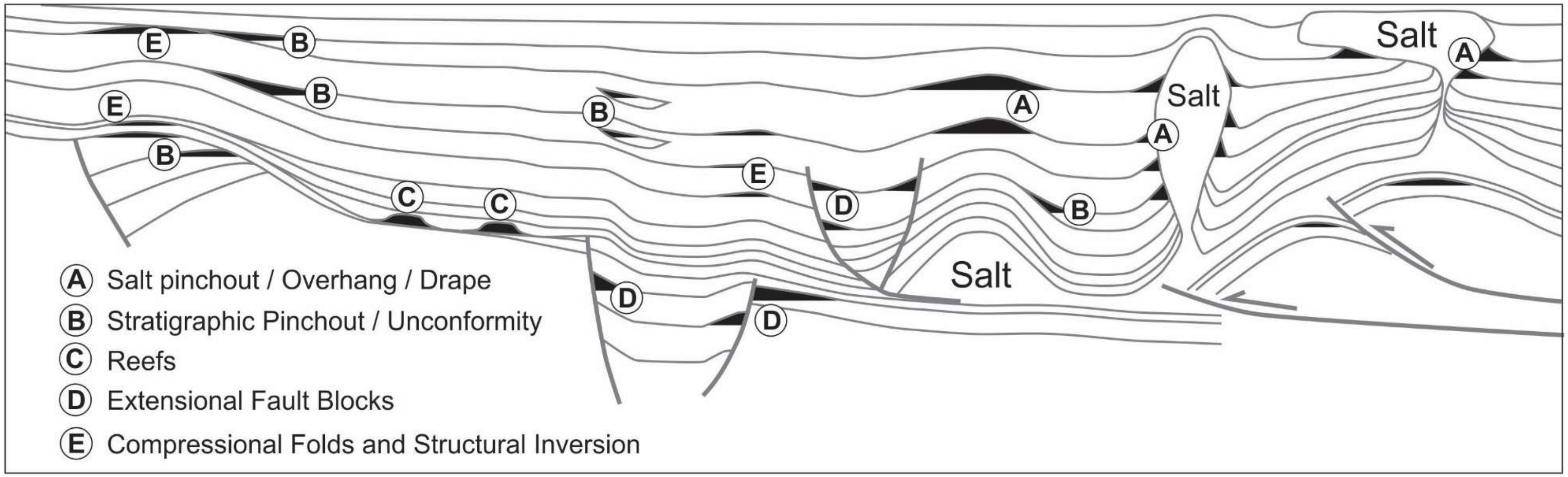
Windsor Group evaporite rocks have been deformed into structures of various sizes and structural complexity. No attempt has been made in this study to specifically study the evaporite structures; however, two main types of evaporite structures are apparent: pillows and diapirs.

Salt pillows occur around the periphery of the salt diapir province. In general, strata are gently folded on the flanks and over the top of the salt pillows, and depending on the timing of salt movement, some strata may thicken off-structure. These relationships suggest that potential reservoir rocks may be thicker and better quality off-structure (Durling and Martel, 2005). The salt pillows have been the target of many of the exploration wells in the basin resulting in one encouraging result (Cable Head E-95) and one significant discovery (East Point E-49). However, a large number of untested salt pillows remain in the basin. The salt pillows are roughly equidimensional in the southwest part of the basin and oblong in the northeast. No salt structures were observed in the northwestern part of the basin.

Salt diapirs are commonly associated with large accumulations of hydrocarbons in many areas around the world, such as the North Sea, the U.S. gulf coast, and the Zagros Mountains of Iran. These structurally and stratigraphically complex diapiric bodies can occur in a range of sizes. In the present study area, the diapirs range from small isolated bodies that are a few hundred metres across to salt masses up to 80 km long. They are imaged as near-vertical pillars of incoherent energy on the seismic reflection data, likely due to inadequate far-offset distance of the seismic data and lack of migration during seismic processing. The geometry of the diapirs is clearly more complicated in cross-section than is revealed by the seismic data.

The geometry of the salt diapirs in map view gives an indication of the trap potential for salt structures in the diapir province. Indentations in the salt body form potential closures where hydrocarbon reservoirs can be trapped against the salt-sediment interface. Furthermore, the larger salt bodies are likely amalgamated or composite salt diapirs that may be detached from the source salt layer, forming overhanging salt bodies and possibly allochthonous salt sheets. The authors consider the salt diapir area not only as an area with abundant trapping potential, but also where potential reservoirs are shallow enough to have higher than average porosity.

(A)



(B)

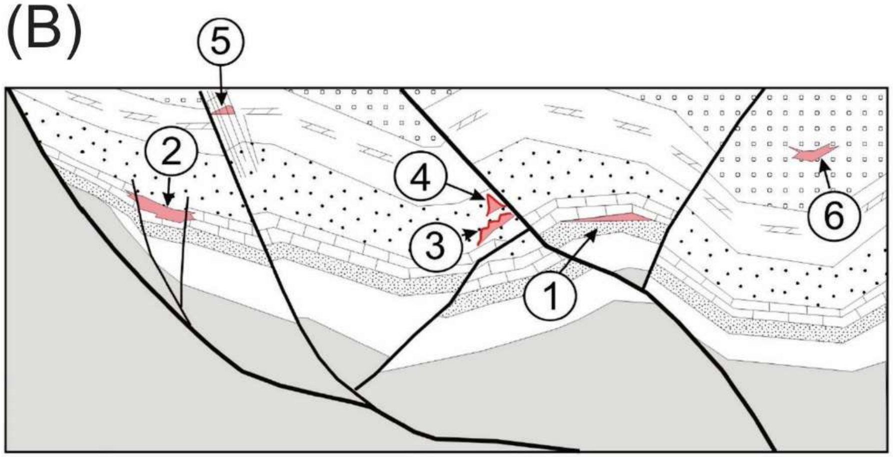


Figure B-4 – Trap Styles

A) Conceptual trap styles for the Maritimes Basin. Black colour fill represents potential hydrocarbons and the circled letters identify the type of trap style. See section titled "Trap Styles" for discussion.

B) Conceptual trap styles for the lower Paleozoic plays in the Gaspé region (Lavoie et al., 2009, Fig. 33). See section titled "Deep reservoirs beneath the Maritimes Basin" for discussion.

(B) Stratigraphic pinchouts and unconformities

The unconformity trap plays an important role in the Maritimes Basin; the top seal for the hydrocarbon bearing rocks for both commercial oil and gas in the basin is an unconformity. Thick red mudstone and grey shale of the Sussex Group rest unconformably on the hydrocarbon bearing Albert Formation at the Stoney Creek and McCully fields. Lateral closure at Stoney Creek appears to be facies change to tight alluvial redbeds, whereas lateral closure at the McCully Field is by structural closure within a doubly-plunging anticline. It is anticipated that similar unconformity traps may have formed in the offshore area, for example in the North Point Basin.

Giles and Utting (1999, 2001, 2003) indicate unconformities at several stratigraphic levels. However, the unconformity at the base of the Westphalian section may have seal potential. It occurs within the lower part of the Bradelle seismic unit mapped in this study (Fig. 4, Appendix D), and it separates the Cumberland Group from the overlying Morien Group (Waldron et al., 2017). Some support for the presence of the unconformity is observed in the seismic reflection data where the upper part of the Bradelle seismic unit displays parallel reflections and the lower part shows divergent reflections. The angular discordance is small, being in the order of only one or two degrees difference in structural dip. However, it may hold promise for a hydrocarbon seal.

By way of comparison to the North Sea Carboniferous fields, the top seal exploited to date has been the lower Permian unconformity (Besly, 2018). A similar unconformity was not identified in this study. However, intra-Carboniferous seals are indicated in the North Sea by fields with multiple pay zones and different gas-water contacts (Besly, 2018). We expect similar intra-Carboniferous seals in the Magdalen Basin.

This class of traps also includes up-dip pinch-out of coarse-grained reservoir rock within dominantly fine-grained mud rock. This may involve the juxtaposition of porous sandstones and impermeable shales by unconformity, whether the unconformity occur locally or regionally. The structural tilt ranging up to 9^{o} for some strata in the northern and western parts of the basin provides an excellent opportunity to form stratigraphic traps.

(C) Reefs

The Gays River Formation and its equivalents are a basin margin facies of the Windsor Group. These rocks have been reported throughout Nova Scotia (Boehner et al., 1989), southern New Brunswick (McCutcheon, 1989) and in western Newfoundland (Dix and James, 1989). The formation in the type area mainly comprises a basal carbonate talus layer (including clasts derived from the underlying basement), algal and skeletal boundstones, skeletal wackestones and packstones, and crystalline dolostones. The Gays River type reef complex has a maximum thickness of 50 m and it is approximately 10 km long with a preserved width of up to 2 km. Although the reef deposits commonly were deposited on pre-Carboniferous basement, they also have been reported to lie on Horton Group and equivalent rocks (McCutcheon, 1989).

Figure B-5 shows an example of the seismic facies likely representative of the basin-margin reef facies (Lavoie et al., 2009), which is represented by two to three discontinuous seismic reflections with variable amplitude. In contrast, the basin centre seismic facies is represented by a number of seismic reflections that are generally higher amplitude and more continuous than the reef facies. The lower panel in Figure B-5 shows an interpreted reef.

Fractured dolomite rocks represent another possible Windsor Group reservoir. However, given that most Windsor Group carbonate rocks tend to be less than 10 m thick, this play would be difficult to recognize and exploit in an offshore setting.

Carbonate traps are also significant trap types in the Gaspé Belt (Fig. B-4b). Fractured carbonates occur in the Devonian, where they form the reservoir and part of the trapping configuration for the Galt Field (type 5 in Fig. B-4b). Hydrothermal dolomite deposits associated with faults are also conjectured to occur in Silurian, as well, but are not an economic trap to date (type 2). Stromatoporoids and coral reefs and pinnacles are also possible traps in both the Silurian and Devonian (types 3 and 4).

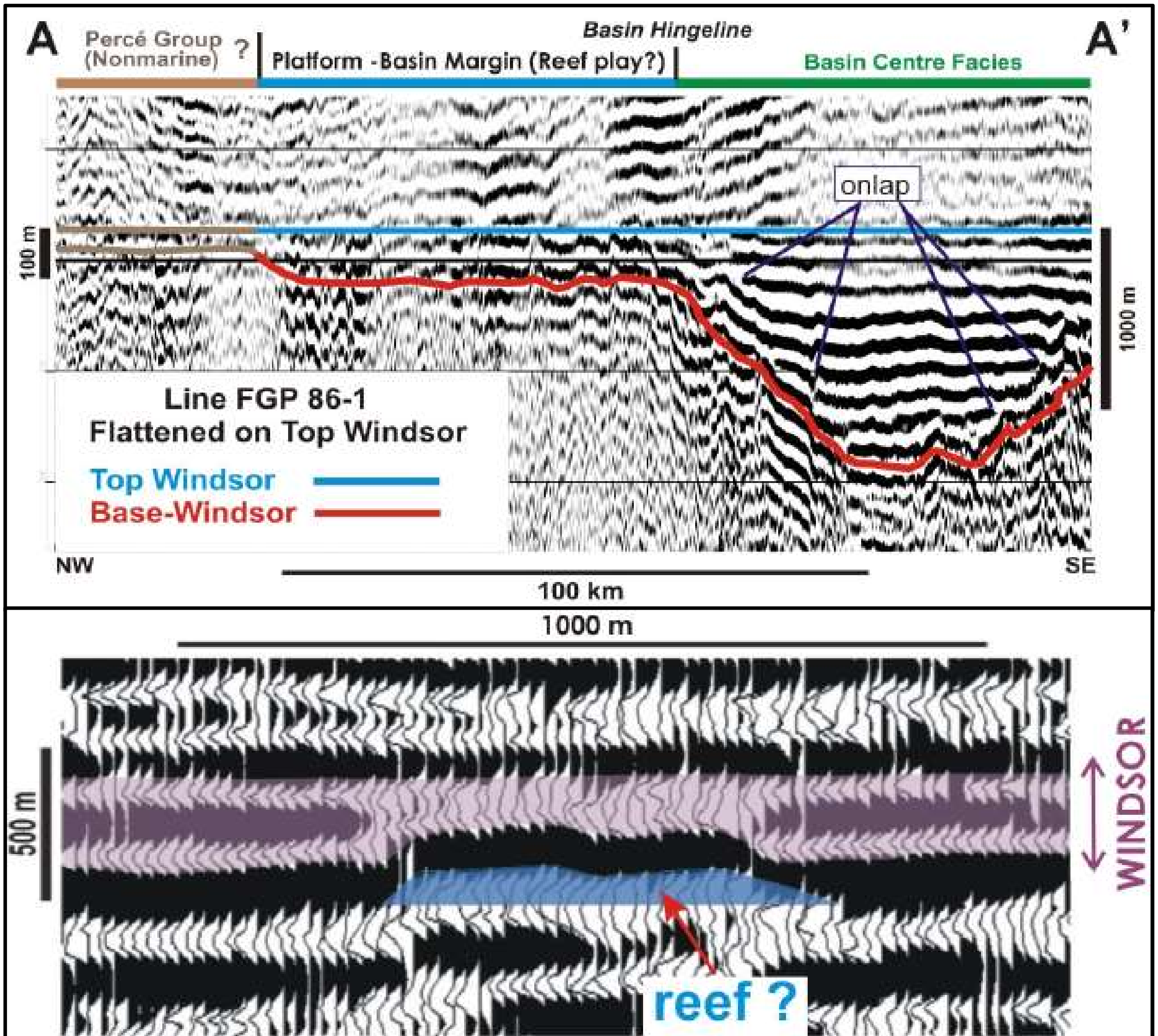


Figure B-5 – Possible reef fairway at platform-basin margin

Example of seismic expression of reef, taken from Lavoie et al. (2009), Figure 70.

Top panel shows a regional seismic reflection profile flattened on top Windsor Group, illustrating interpreted depositional facies belts in Visean Windsor Group, including a prospective reef fairway on the platform-basin margin (location see Figure D-1).

Bottom panel shows a detailed seismic section from same area which illustrates an intra-Windsor seismic anomaly interpreted as a possible reef.

(D) Extensional fault blocks

Horton Group strata were deposited in fault-bounded extensional basins. Many Horton Group basins have a half-graben geometry where accommodation space is controlled by movement on basement-related faults. Hydrocarbon traps may be located at the fault-sediment interface, or they may be located within a closure formed by a roll-over anticline associated with growth on the normal faults. Sand pinch-out traps may occur on the limbs of the roll-over anticline. In addition, growth faults can act as "sediment traps" resulting in an increase in net sand thickness adjacent to the faults. The Stoney Creek and McCully fields occur in half-graben basins and the fields are located on the ramp side of the basin, opposite the normal faults. The top seal of both fields is provided by the Sussex Group unconformity.

Extensional faults that can be traced downward and die-out in Windsor Group salt are recognized in several areas in the Gulf of St. Lawrence. The Old Harry structure is an example of a salt-cored, roll-over anticline where a listric normal fault bounds the northwest side of the structure. The Tyrone No.1 well was drilled in a graben formed by a listric normal fault and a conjugate antithetic fault. Salt-cored, roll-over anticlines associated with listric normal faults occur in eastern PEI. A complex system of normal faults and associated antithetic faults occurs east of PEI in Northumberland Strait, which have potential to form productive hydrocarbon traps.

(E) Compressional folds and structural inversion

Seismic data in the Gulf of St. Lawrence shows that the Horton Group was affected by reverse faults and basin inversion. Some Horton Group basins were highly deformed (Durling and Marillier, 1993b) whereas other basins experienced only mild deformation (e.g. North Point Basin). The timing of the inversion events appear to be both early (post-Horton Group deposition), and also late in the basin history because younger rocks are sometimes affected (Brake et al, 2019). For example, the Horton Group basin in the vicinity of the Bradelle L-49 well was affected by mild basin inversion, which affected the Mabou Group and potentially younger rocks. In areas absent of Windsor Group salt (northwestern part of the Magdalen Basin), the inversion folding generally produced broad open structures.

Inversion structures are widespread in the southeastern part of the Magdalen Basin in the area of extensive salt diapirism. Hayward et al. (2014) mapped the top of a portion of the sub-salt high (Durling and Marillier, 1993a) using a marker they defined as the "base group". The mapped surface is characterized by structural highs and lows that are commonly separated by thrust faults. The regional mapping presented in this report is consistent with Hayward et al. (2014) and supports their conclusion that the subsalt high is a Late Carboniferous inversion structure. Although the Cap Rouge F-52 well was drilled unsuccessfully on one structural closure in the sub-salt high, several other prospective targets remain untested.

Potential traps may have developed associated with an inversion structure where the Northumberland Strait F-25 well was drilled. East-northeast striking faults bound the inversion structure to the north and the south. Horton and Sussex group rocks are offset by the faults with an estimated throw of approximately 1000 m. Traps would rely on fault seal; however, the faults are capped by thick Windsor Group salt.

Subtle anticlinal traps associated with differential compaction of the Horton Group relative to adjacent basement blocks were observed on the margins of some Horton Group basins. These features are best developed adjacent to deeper Horton Group basins. Traps may also be formed by compressional structures associated with regional strike-slip motion.

Clastics incorporated into compressional folds, which formed during the Acadian Orogeny, are important traps in the Gaspé Belt. The Haldimand Field hosts oil and natural gas from sandstone reservoirs within Acadian anticlinal fold structures. The Galt Field is associated with lower Devonian fractured and hydrothermally-altered carbonate breccia, developed along fault structures formed during Acadian structural compression.

Seals

In petroleum geology, a seal is considered an (mostly) impermeable layer that restricts the upward migration of hydrocarbon. The most common types of seals are shales (as different formations deposited on top of reservoir, or as intraformational shales as lithologies change within a formation), evaporites (salt has low porosity, low permeability, and is ductile, all excellent qualities in a seal), and tight carbonates (carbonate rocks with low porosity and permeability). The Magdalen Basin contains examples of all types of sealing units. The following discussion highlights sealing formations assessed and the criteria chosen to define the best sealing COS.

Interbedded and overlying shales

The Naufrage Formation sits atop the sands of Cable Head Formation. Although the Naufrage Formation is predominantly sandstone, the base of the unit is mostly shale (Rehill, 1996). The shales are silty, red brown to light brown, and interbedded with limestone and siltstone stringers (Rehill, 1996). For the purposes of this report the best chance of success for a Naufrage Formation seal is judged to occur where the formation thickness is greater than 600 m, to account for the sandiness of this formation. The Cable Head Formation itself has very few shale intervals, and so it lacks good intraformational and lateral seals, and thus will have less potential for stratigraphic traps.

The Green Gables Formation is a shale dominated sequence deposited on top of the Bradelle Formation (Rehill, 1996). These red to grey silty shales are interbedded with minor sandstones and coal beds; shale quantity increases upwards in the formation. The Green Gables Formation is widely distributed throughout the study area. The best chance of effective Green Gables Formation seal is judged to occur where the Green Gables Formation is greater than 400 m thick. The Bradelle Formation and Cumberland Group have more shale (lower net-to-gross sand ratio) than the Cable Head Formation and also coal, significantly increasing potential for intraformational and lateral seals, and thus stratigraphic traps. Corridor (2018b) explicitly studied the sealing potential of the Green Gables Formation, and found three layers in the upper Green Gables Formation to be very good seals.

The Sussex Group in its type section in New Brunswick consists dominantly of thick grey shale and red mudstone, with some anhydrite bands and limestones. There, it is a reasonable seal for the Horton Group strata beneath. But the Sussex Group equivalent rocks show significant variation, and sandstone and volcanics are observed elsewhere. This variability gives the Sussex Group reasonable potential for intraformational and lateral seals.

Although the Horton Group is predominantly sandy, the existence of a middle fine-grained unit, as well as thin shale/siltstone facies within thicker sand packages creates an opportunity for intraformational seal. Interbedded shales and siltstones are clay-rich and range from red to brown to green in colour (Rehill, 1996). The middle fine grained unit is red to grey shales interbedded with fine grained sandstones; evidence of successful intraformational seals is found onshore at the Stony Creek field. Due to the predominantly sandy nature of the Horton Group the best chance of seal success was in areas where the combined Sussex and Horton groups isopach was greater than 1000 m thick.

Salt

Windsor Group evaporites are composed of halite, anhydrite, and fine-grained clastics, they are present as salt diapirs, salt walls, and salt pillows. This salt province is present from eastern

Prince Edward Island to western Newfoundland along the western shore of Cape Breton Island. The core of the salt province is located off the northwestern tip of Cape Breton. Evaporites can act as an excellent seal due to their ductility and impermeability. This allows the seal to remain impermeable, even during deformation events. Figure B-4a illustrates how salt tectonics can focus (trap) hydrocarbon under salt features, while also sealing the hydrocarbon. The Windsor Group is judged to be an excellent seal where the Middle and Lower Windsor Group isopach exceeds 500 m (and includes significant salt).

Tight carbonate

Carbonates can act as effective seal units when they are considered 'tight'. Tight carbonates have low porosity and/or permeability which effectively inhibits the upward migration of hydrocarbons. When undergoing tectonic stress carbonates can become brittle and fracture. If fracturing occurs, sealing capacity may be compromised.

Tight carbonate seals may exist within the Windsor and Mabou groups. The Mabou Group limestones are light brown, silty, and transition into marlstones (Rehill, 1996); they may be lacustrine in origin (Thomas et al., 2002). The Lower Windsor contains the carbonates of the Macumber and Gays River formations. The Macumber Formation limestone overlies the Sussex and Horton groups, and in some areas the Gays River Formation limestone is deposited ontop of the Macumber (Thomas et al., 2002). The Macumber Formation varies in thickness from 3-25 m in the Antigonish Basin (Thomas et al., 2002) with evidence of deformation present as folding; this thinness and potential for fracturing decreases its sealing potential. These tight carbonates add to the Windsor Group isopach discussed above.

Tight carbonate seals also may exist within the Lower Paleozoic units mapped in the Gaspé Peninsula, where there is an abundance of low porosity/permeability of carbonates (the Matapédia Group, the Chaleurs Group, and the Upper Gaspé Limestones). These tight carbonates have been deformed, and fractured, potentially lowering their chances of being an effective seal.

Risk of breach by faulting / fracturing

Another aspect of long term seal is the risk that faults or fractures may break through key sealing horizons, providing a conduit for petroleum to escape, or limiting hydrocarbon column heights. Faults on the anticlinal crests of salt-cored folds are clearly visible on modern seismic data. More faults may exist throughout the basin than are currently imaged on older vintage seismic. The risk of breach is considered when assigning COS to seals.

Plays

The methodology developed to create a qualitative petroleum potential map (Lister et al., 2018) requires the definition and analysis of petroleum plays in the study area. A petroleum play is a family of prospects and pools that share a common history of hydrocarbon generation, migration, reservoir development, and trap configuration. Thus, each play will have the same (or similar) spatially varying chance of success (COS) for the petroleum system elements within the play (reservoir, trap, seal, and source/timing/migration).

Lavoie et al. (2009) and Dietrich et al. (2011) outline three composite plays in the Magdalen Basin: Upper Carboniferous clastic play, Lower Carboniferous carbonate play, and Lower Carboniferous clastic play. They also provide quantitative estimates of the petroleum potential for the two clastic plays, but do not highlight the best locations for success within the mapped play areas.

This study builds on their work, and subdivides their clastic plays to include more detail of the history and the varying COS in the petroleum system elements between stratigraphic groups.

Our process also incorporates spatial variation in COS of play elements, and highlights the best locations for petroleum potential, where conditions within play COS are optimum and plays stack. We do not quantify the resource potential as they did, however.

We define seven plays within the Magdalen Basin. Upper Carboniferous clastics play is divided in four plays: two stratigraphic levels – Pictou Group, and Morien and Cumberland groups, and two trap types – structural and stratigraphic. Lower Carboniferous carbonate play is here called the Windsor carbonate play. Lower Carboniferous clastic play is divided in two stratigraphically – the Sussex Group play, and the Horton Group play. Details of these plays, including the criteria to define the COS of their petroleum system elements from regional mapping (Appendix D) and/or calculations based on the regional maps, are outlined in Table 3. The concept of each play is explained below, building on the description of each element above.

In order to sum the COS of each play to estimate overall petroleum potential, each play COS is multiplied by a "global scale factor" (GSF), so each play contributes to the map according to its overall qualitatively estimated volumetric potential and global competitiveness. We generally did not explicitly calculate volumes; we used Dietrich et al. (2011) volumes, volumes from industry reports, and the area of prospects from our own mapping, to create this scale factor for each play. To award a global scale factor of 1, we are looking for one giant field or prospect (> 500 MMbbls or 3 Tcf) and at least three large fields or prospects (> 300 MMbbls or 1.8 Tcf). These GSF scores are also consistent with mapping in other Marine Conservation Targets mapping projects (e.g. Atkinson et al., 2017; Carey et al., 2019).

Note that these scale factor criteria and values are based on what is "globally competitive" in other offshore basins in the world, not what might be attractive onshore. Significant volumes are necessary to be economically attractive offshore, and what is considered "high petroleum potential" reflects this reality. Economics for onshore drilling are very different, and whilst areas labelled "low potential" are judged to most likely contain much lower volumes, these smaller volumes may be economic now or in the near future onshore.

Well failure analysis

Exploration results in the Magdalen Basin are reasonable for such an underexplored area, and support the existence of an active petroleum system. For plays to work, all four petroleum system elements must be present. Exploration failures have not been formally analysed in the literature; the explanation may vary from well to well and is not always clear.

For example, Bradelle L-49 (Fig 2) may have failed due to a lack of closed trap to the northwest, or due to seal breach during subsequent deformation in the basin. It is also possible, though less likely, that the Bradelle location is on the edge of source maturity and migration paths somehow failed to fill the trap.

Similarly, Beaton Point F-70 (Fig 2) targeted a steep complex salt-cored structure, and may have missed the trap closure. Mapping traps accurately on vintage seismic data is challenging, though traps are expected to exist and likely could be better imaged by modern seismic. Again, seal could also be to blame, as many faults likely exist around this structure.

The reasons for failure at a given well, even if understood, may not condemn a play, or even the adjacent part of a given structure. An excellent example is the East Point structure (Fig 2), where the East Point E-49 well discovered a gas pool, but the up-dip delineation well East Point E-47 failed, apparently due to fault breach. The structure is compartmentalized by faults.

For this reason, in this study, we endeavoured to learn from the well data, but did not remove dry holes from play potential. Lower COS values reflect the petroleum system elements we interpret as more likely to explain failures. In particular, long term seal is a significant concern, though no element is 100% certain. Our maps are intended to describe the plays, rather than outline specific targets.

Pictou Group plays – structural/salt flank and stratigraphic

The shallowest pair of plays in the basin are in the Pictou Group (Fig. 4, Waldron et al., 2017) (Upper Pictou in Lavoie et al., 2009). Reservoir for these plays is the Cable Head Formation, which is the reservoir for the East Point Significant Discovery (Fig. 2), and in a small area in the centre of the basin, unnamed Permian sands. The two plays are differentiated by their very different trap concepts – Play 1 has the Cable Head reservoir (or Permian sands) involved in structures – against salt walls, overhangs and diapirs, folded over salt pillows or folded by compression or structural inversion. The geometry and boundaries of salt structures are not well imaged and may include salt canopies, so the salt bodies are not excluded from the valid play area. Play 2 has stratigraphic traps, such as pinch-outs where the formation changes thickness, channels, etc. The Cable Head is a massive sand with limited shale to form lateral seals, so stratigraphic traps are challenged in this formation.

Top seal is the Naufrage Formation above the Cable Head, which can itself have sands, and thus is not always a reliable seal. These plays can be very shallow, with limited top seal thickness, and thus breach by fracturing can also be a concern. In the structural play, the Cable Head or Permian sands can also be sealed by salt overhangs. Source for these plays is firstly from the Green Gables Formation directly beneath, but also can come from Bradelle Formation or Mabou Group deeper in the section. Source COS is based on the probability of any one of these sources, as taken from the 1.5 km deposition maturity models discussed above.

To help choose the GSF for Play 1, volumetrics were run on the East Point Significant Discovery (Hudson's Bay Oil and Gas, 1976), using Rose and Associates software. Reservoir parameters from HBOG's report, their published map, and our own mapping were used to estimate a P50 value of 88 billion cubic feet (Bcf) in place and 61 Bcf recoverable, with a P90 to P10 recoverable range of 8 Bcf to 450 Bcf. These numbers compare well to Rehill's (1996) reported 77.3 Bcf in place and 61.8 Bcf recoverable, and are not particularly competitive with a global standard of 1.8 Tcf as a "large field" and 3 Tcf as a "giant field". East Point is not the largest target by area in this play however, so the scale concern is somewhat mitigated and Play 1 GSF is scored at 0.4. The geometry of possible stratigraphic plays are judged to be even smaller - Play 2 GSF is 0.3.

Morien and Cumberland Group plays – structural/salt flank and stratigraphic

The next pair of plays are in the Morien and Cumberland groups (Fig. 4, Waldron et al., 2017) (Lower Pictou and Cumberland in Lavoie et al., 2009). The Morien and Cumberland groups are combined in one set of plays partly because it is challenging to map the top of the Cumberland Group with confidence regionally, and they also have similar history and COS for all petroleum system elements.

The best reservoir for these plays is the Bradelle Formation, and additional reservoir potential exists in the Port Hood and Boss Point formations of the Cumberland Group. The two plays are differentiated by their very different trap concepts, as above – Play 3 has the reservoirs involved in structures – against salt walls and diapirs, folded over salt pillows or folded by compression, or structural inversion, or associated with normal faults. These various sorts of structural traps (see trap styles above) are sometimes described as separate plays (Durling and Martel, 2005), but as the trap styles generally do not spatially overlap, they could be captured on a single structural trap map, and COS of different styles assigned. Again as above, the geometry and boundaries of salt structures are not well imaged and may include salt canopies, so the salt bodies are not cut out the valid play area. Play 4 has stratigraphic traps, such as pinch-outs where the formation changes thickness, channels, and shore-faces. There is more known variation in stratigraphy in the Morien and Cumberland groups, which may lead to more opportunities for lateral seal and stratigraphic trap geometries.

Top Seal of these plays is the Green Gables Formation, which is a consistently shaly section with good seal potential, as studied by Corridor Resources Inc. (2018b). Breach by faulting continues to be a concern, where faults are imaged at fold crests. Excellent lateral seal potential against salt exists where these groups are involved in salt structures. Source for these plays can come from both the Bradelle Formation, and the Mabou Group below it. As discussed above, the Mabou Group is a less reliable and less consistent source rock and it is also gas prone. The Bradelle Formation source may produce both light oil and gas, and modelling suggests the possibility that prospects may still contain oil with gas if sourced only by the Bradelle Formation and not flushed by Mabou Group gas.

Play 3 has the most significant trap size and volumetric potential in the basin. Old Harry, the most significant prospect in the basin and only current exploration lease in the study area, is in this play. To help choose the GSF for this play, Corridor Resources' size estimates for Old Harry were reviewed and analysed. Corridor suggests that Old Harry may contain 5 Tcf of gas or 4 Bbbls of light oil (Corridor, 2018b), which is a giant field by global standards. We repeated their estimate with our own in-house volumetric calculations and find their numbers reasonable for the whole prospect. Other prospects in the play are not as large, however, and it is difficult to find three large opportunities. Dietrich et al. (2011) gave less generous in-place estimates for the top expected field sizes as well, with the largest undiscovered field estimated to contain 2.6 Tcf (74.1 $10^9 m^3$) in-place, and Hayes et al. (2017) put only 682 bcf in-place for the Cumberland conventional play in the Cumberland Basin. Thus we have set the GSF for the whole play 3 as 0.8. Again, the stratigraphic trapping geometries are judged, on average, to produce smaller accumulations than the large structures, yet the greater chance of stacked reservoir may add some volume to prospects. Play 4 is scored as 0.35.

Windsor Group carbonate play

As discussed in Appendix A, Figure 4, the Windsor Group represents a time of marine incursion into this dominantly terrestrial basin. Reefs formed on the basin margin during the Lower Windsor time, as best exemplified by the Gays River Formation outcrops. These reefs form the reservoir for this play, and the transition from reef to basinal facies gives lateral seal and the trapping geometry for the play. It is not well understood if porosity is primary and fluid enhanced or all secondary. Some primary porosity may be necessary for dolomitizing fluids to penetrate. Porosity is not significantly a function of depth in these carbonates.

The top seal for these reefs are tight carbonates and salt above in the Windsor Group and Mabou Group shales above the Windsor Group where it is thin. The most direct source for this play is the laterally equivalent and assumed coeval Macumber Formation basinal facies, and Horton Group shales beneath the Windsor Group may also provide a source.

This play is not often seen in outcrop, has not been tested in wells, and examples on seismic are limited. This lack of detection may in part be due to the quality, age, and spacing of seismic data (Fig. 2); nevertheless the prospects in this play are not expected to be large and a GSF of 0.3 is assigned to this reef trend.

Sussex Group play

As discussed in the regional stratigraphy (Appendix A, Fig. A-1) and Reservoir (Appendix B) sections above, and developed further in the regional mapping discussion (Appendix D), the understanding of the Sussex Group is being actively revised (P.Giles, pers.comm., 2018, 2019). In its type section, the Sussex Group is a seal rather than a reservoir, but the potential for time equivalent strata to be sandy and have reservoir potential exists, for example in Bradelle L-49. Thus, this more speculative play has been added to acknowledge this concept. Traps in this play would be dominantly stratigraphic, or a combination of stratigraphic and gentle structure, for example above inverted grabens.

The Sussex Group can be sealed by the Windsor Group carbonates and salt above it, the Mabou Group shales above that if necessary, and also by intraformational shales, so top seal is not a major concern in this play. Source would come from the Horton Group beneath, although source rock within the Sussex Group interval may also exist.

This play is not well understood, and thus far with limited reservoir thickness and small stratigraphic traps, pools are not expected to be large; GSF is set at 0.2.

Horton Group play

The only producing play in the Maritimes Basin is in the Horton Group (Fig. A-1). The Stoney Creek and McCully Fields are in the Moncton subbasin in southern New Brunswick (detailed geologic description in Appendix C). Reservoirs are sandstones in the Hiram Brook Member of the Albert Formation. Offshore these reservoirs may often be too deep for good porosity preservation, but may be preserved in shallow parts of the basin (e.g. off of New Brunswick). Reservoir COS in our assessment reflects the current depth of burial at the top of the Horton Group.

Top seal for the play is thick grey shale and red mudstone of the Sussex Group. The Horton Group also contains shaly intervals which may provide intraformational seals. Seal COS is moderate throughout the basin, with the varying clastic deposits. There is also significant Shale Gas potential in the Frederick Brook Member of the Albert Formation (see Unconventional discussion below).

The Horton Group contains good source rock intervals, but the source rocks are modelled to be very over mature over a large area in the basin centre. The Horton Group may be mature in a region on the basin flanks extending through western PEI and the offshore north of it through the most eastern part of New Brunswick's waters, and on the northern flank of the basin. It is modelled as still immature in the shallowest parts of the basin near the New Brunswick and Gaspé coasts (Fig. B-1). As discussed under source, there is some evidence, in the form of potential gas chimneys, for a live petroleum system on the basin flanks where the Horton Group is modelled as mature.

Trapping geometries could be stratigraphic facies changes and unconformities, structure in grabens and inverted grabens, or a combination of these. Larger traps may be found in preserved Horton grabens, and the best opportunity for larger traps coinciding with mature source, reservoir and seal, occur in the North Point Graben and grabens in Northumberland Strait (Fig. D-22).

Trap scale / area may be reasonable in the large Horton grabens interpreted offshore, but the recoverable volumes of the existing fields (Appendix C) were considered when assigning a GSF. The Stoney Creek Field has produced only 28.7 Bcf (Keighley and St. Peter, 2003), and McCully Field has produced only 57 Bcf, with 44 Bcf estimated remaining (Corridor, 2018a), due to challenging recovery factors. Yet McCully has a large in-place estimate of approximately 1 Tcf (Keighley and St. Peter, 2006). Dietrich et al. (2011) estimate the largest undiscovered gas field in the play to contain 1.75 Tcf (49.7 $10^9 m^3$) in-place, and assuming similar challenged recovery factors, this would imply a largest undiscovered field of about 200 Bcf recoverable. Better recoveries may be possible, but these are small volumes for offshore. In addition, the best chance for large traps may be where the reservoir would be too deep, around the salt province. These tight reservoirs and production challenges cause us to assign a GSF of 0.4.

This Horton Group play is the play with the highest chance of success in the Shediac Valley environmentally sensitive area of interest, immediately offshore of New Brunswick, as outlined in Hinds and Fyffe, 2013b. Most other plays in this Shediac Valley AOI are too shallow, though the Morien / Cumberland plays also add to the petroleum potential estimate (these plays have much lower COS but higher GSF). For the Horton play, source is the petroleum element with the highest COS. No significant grabens that would suggest potential for large traps are mapped in this Shediac Valley AOI. Trap, reservoir, and seal are interpreted to have only moderate COS. The lower GSF combined with these trap, reservoir, and seal COS challenges, lead to a medium low to low overall petroleum potential. New evidence for gas seeps (e.g. multibeam surveys that observe pock marks or high resolution seismic confirming gas seeps from a deep source) would increase source COS, but the overall petroleum potential would not change significantly because source is already has higher COS. If new evidence for higher recovery factors and/or much larger traps becomes available, the estimate of petroleum potential in this area could increase. The Shediac Valley AOI as defined in 2013 (Hinds and Fyffe, 2013b) did not include the North Point Graben, where petroleum potential is significantly higher.

Plays in older strata incorporated in petroleum potential map

This study has focused on the petroleum potential of the Magdalen Basin. Near the Gaspé Peninsula and along the northern margin of the Magdalen Basin, the base of the Magdalen Basin becomes shallow and petroleum potential in older strata must be acknowledged to make a complete map. We did not make new maps of these plays – instead we combined the play polygons and play descriptions from Lavoie et al. (2009) with our own Carboniferous thickness map to make COS polygons and scores for these older plays.

Six plays outlined in the Gaspé Belt by Lavoie et al. (2009) and Dietrich et al. (2011) (Fig. B-6) were combined into two plays within our map: Devonian plays and Silurian plays. Details are provided in Table 3. The Devonian play does have two small proven fields in it (Galt and Haldimand, Appendix C). From the descriptions in previous studies, Dietrich et al. (2011) suggest only 47 MMbbls (7.5 $10^6 m^3$) in-place for the largest undiscovered field – and the scale of these existing fields – 71 MMbbls recoverable proved, contingent, and prospective resources (3P), best estimate, for Galt – GSF of 0.35 and 0.2 for these plays are assigned.

In addition, a speculative extension of the older St. Lawrence platform beneath the northern margin of the Magdalen Basin is acknowledged and becomes the oldest and least likely play in the map, with a GSF of 0.2. Plays in the St. Lawrence platform have significantly more potential to the north-east, outside of the study area off of western Newfoundland. This platform was mapped regionally, and the study area was curtailed so as to not encroach on this more significant potential, which lies outside of the Magdalen Basin and could not be studied in the time available (Appendix D).

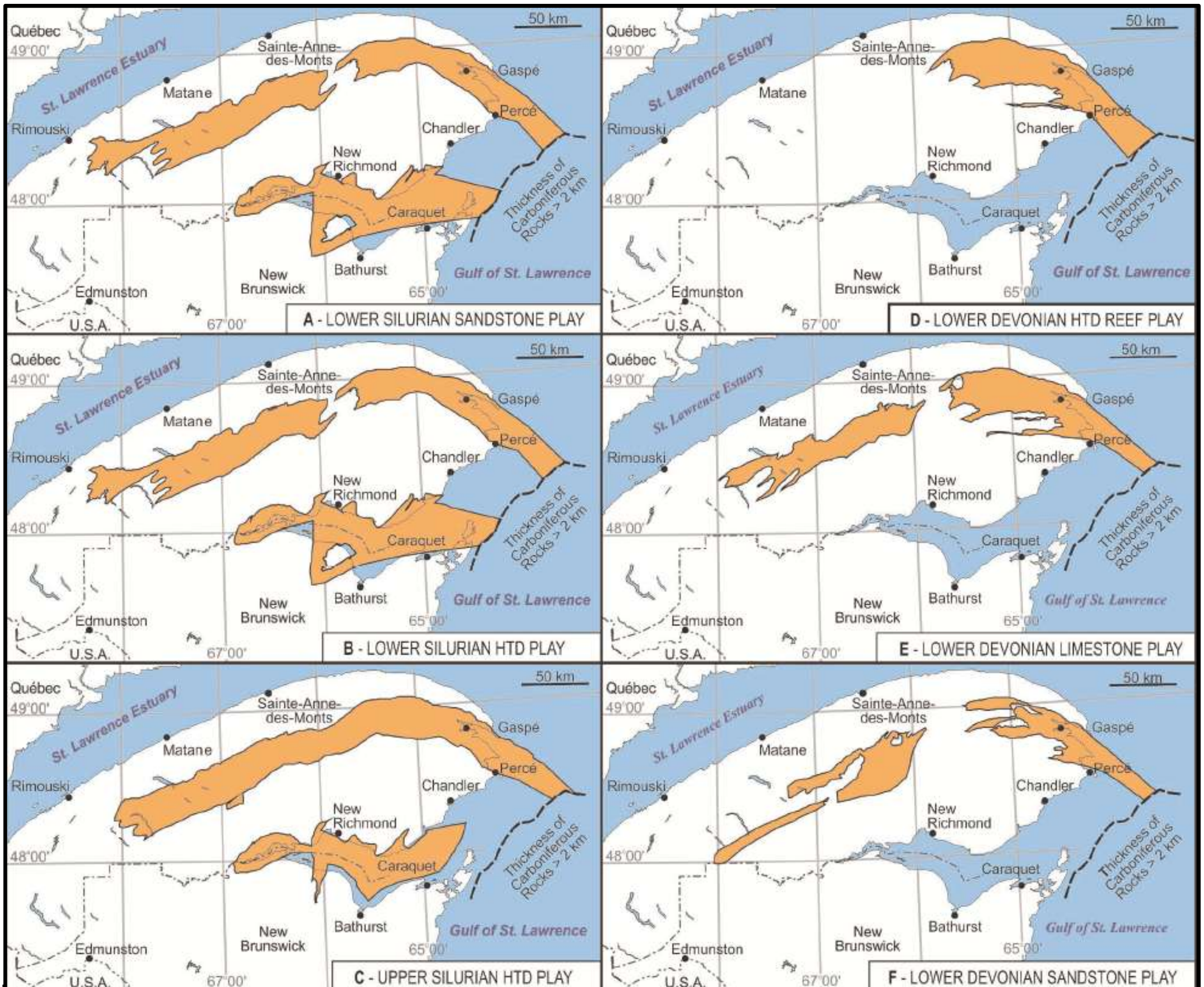


Figure B-6 – Petroleum plays of the Gaspé

Dietrich et al. (2011), Figure 16. Their play polygons were consolidated into our play 8 – Lower Devonian Plays, and play 9 – Silurian Plays, with the best potential where at least two of the three plays stacked and there is less than 2 km of Carboniferous rocks above, on our mapping. Decreased potential exists where only one of their plays is present and where 2 to 4 km of Carboniferous rocks overlie the extension of their plays.

Table 3 – Detailed play description and polygon criteria

Play		Reservoirs	Reservoir polygons	Reservoir COS					Trap	Trap polygons	Trap COS	Seal	Seal polygons	Seal COS	Source	Source polygons	Source COS	Global Scale
1	Pictou structural / salt flank play	Cable Head, Permian Sands in basin core	**matrix for permeability**	Perm - good	OK	fair	low	very poor	pinch-out against salt walls, diapirs or overhangs, potentially biggest traps, though more challenging to image - many traps likely	**same trap as Morien/Cumberland structural/salt flank play** - reuse layer exactly		low COS in many places where overburden thin, thicker Naufrage raises COS	> 600 m Naufrage, good COS - good chance of shale for seal, breach by fracturing possible but less likely	0.65	Green Gables, additional chance of source from Bradelle and Mabou	Vr = 0 to 0.6, immature, needs lateral migration, AND spider diagrams do NOT seem to support	0.25	0.4
		Naufrage can have sands - not accounted for, more sand in Naufrage makes it a less effective seal	0 to 2000 m good reservoir	0.8	0.7	0.6	0.5	0.4	salt cored anticlines and other significant anticlines eg. by compression or structural inversion - very good traps			"Naufrage" isopach (Cable Head to seabed) can include Permian sands, which don't add to seal capacity	300 to 600 m Naugrage, fair COS - better of shale, could still have sands and breach by fracturing	0.55	polygons based on maturity maps from Trinity models for each source rock	Vr = 0 to 0.6, immature, good source chance, but needs lateral migration - spider diagrams support	0.6	
		polygons based on Top Cable Head depth grid, depth grid is less certain but reservoir quality is high	0 to 2000 m good reservoir, low confidence	0.7	0.6	0.55	0.5	0.45	small drapes, inversions, final movement on old faults, differential compaction			Naufrage isopach definitions for seal COS layer - high standard of thickness because we are so shallow (open to seabed)	100 to 300 m Naufrage, low COS - could still have sands and breach by fracturing	0.3	combined chance using P(Green Gables and/or Bradelle and/or Mabou) math for final Source COS	Vr = 0.6 to 2.5, mature for oil or gas, high source chance - immediately above / adjacent to mature source	0.75	
		added lower confidence polygon in mini-basins due to lower confidence seismic picks there AND lower confidence that sands reach mini-basins	2000 to 3000 m fair reservoir	0.65	0.6	0.55	0.45	0.35	large structures may not be tested by one failure, multiple culminations / fault seal possible - can still allow decent trap chance where some failures have occurred			some aspects of seal (along salt flanks and anticlinal crests) inverse to trap COS (lowest seal COS with highest trap presence COS due to chance of fractures/faults),	1 to 100 m Naufrage, very low COS - Naufrage isopach could include Permian sandstone	0.15	Trinity models did not suggest a significant source or timing issue for wells, failures more likely on seal	Vr = 2.5 to 3.0, concern about overmaturity - uncertain success	0.5	
		for deeper criteria, mini-basins have less certain depth (toward coin-toss) but still have sand presence concern (toward negative), so score same as other areas	2000 to 3000 m fair reservoir, low confidence	0.6	0.55	0.5	0.45	0.4				in same structured areas, the seal risk may be mitigated by chance of increased seal from salt	0 m - onshore - confident older surface geology	0	COS shown for Green Gables, see Morien/Cumberland play for Bradelle and Mabou COS	Vr > 3.0, over mature, concerned about cracking	0.25	
		permeability is an issue where provenance is from the SW, vs. the north, overlay of good/fair/poor perm	3000 to 4000 m poor reservoir, low confidence the same	0.4	0.35	0.3	0.3	0.25				Permian Sands use a salt overhang seal but otherwise are very sandy	Permian Sands salt seal, kept same as thick Naufrage (salt geometry complex)	0.65				
		Permian Sands in basin core where they may be sealed by salt - polygon drawn free hand - the base of Permian Sands is at about 1400 ot 2500, so given the 0 to 2000 m low confidence score of 0.7	> 4000 m likely no porosity, low confidence the same	0.25	0.2	0.2	0.15	0.15										
2	Pictou stratigraphic play	Cable Head, Permian Sands in basin core	**same reservoir as structural play** - reuse layer exactly						stratigraphic plays (pinch-outs in main basins and basin flanks, or channels)	> 0.05 m thickness change / m map distance	0.45	Naufrage isopach definitions for seal COS layer - high standard of thickness because we are so shallow (open to seabed)	**same seal as structural play** - reuse layer exactly		Green Gables, additional chance of source from Bradelle and Mabou	**same source as structural play** - reuse layer exactly		0.3
		Naufrage can have sands - not accounted for, more sand in Naufrage makes it a less effective seal							Cable Head reservoir is too sandy for good strat play - significanlty lower COS, shales may be found in thick basin centre of Cable Head	0.02 to 0.05 m thickness change / m map distance	0.35	strat play top-seal not so affected by trap geometry, but can have lateral seal issues, similar COS to structural play						
									criteria picked from gradient (rate of change) of isopach, greater gradient means greater chance of pinchouts and strat traps, stay in low confidence	< 0.02 m thickness change / m map distance	0.25							
3	Morien / Cumberland structural / salt flank play	Bradelle (Morian Group) and Port Hood and Boss Point (Cumberland Group, could not be separated out in regional mapping)	**matrix for permeability**	Perm - good	OK	fair	low	very poor	pinch-out against salt walls, diapirs or overhangs, potentially biggest traps, though more challenging to image - many traps likely	polys drawn free hand around each structural region		Green Gables presence provides seal	greater than 400 m - good chance of shale for seal, breach by fracturing could still happen but less likely	0.7	Bradelle coals and shales (mixed source modelled), Mabou shales - much less reliable for presence, sometimes red vs grey/organic rich	Vr = 0 to 0.6, immature, needs lateral migration, AND spider diagrams do NOT seem to support	Bradelle 0.25, Mabou 0.15	0.8
		polygons based on Top Bradelle depth	0 to 2000 m good reservoir	0.8	0.7	0.6	0.5	0.4	salt cored anticlines and other significant anticlines eg. by compression or structural inversion - very good traps	best structural traps: areas of good structure and high quality data, and around best salt walls (max medium confidence)	0.85	Green Gables isopach definitions for seal COS layer, thinner than Naufrage because Green Gables more consistently shalely and deeper in the section	greater than 400 m - less confident in mini-basins, score in next confidence box down	0.6	polygons based on maturity maps from Trinity models for each source rock	Vr = 0 to 0.6, immature, good source chance, but needs lateral migration - spider diagrams support	Bradelle 0.6, Mabou 0.35	
		COS higher for Morien Cumberland play than Pictou play, for top criteria, because Bradelle seismic pick is very confident	0 to 2000 m good reservoir, low confidence	0.7	0.6	0.55	0.5	0.45	smaller traps where little to no salt, relying on small drapes, inversions, final movement on old faults, differential compaction	salt flank area, traps against walls, diapirs and overhangs	0.8	some aspects of seal (along salt flanks and anticlinal crests) inverse to trap COS (lowest seal COS with highest trap presence COS)	200 to 400 m - OK COS, breach by fracturing possible	0.6	combined chance using P(Bradelle and/or Mabou) math for final Source COS	Vr = 0.6 to 2.5, mature for oil or gas, high source chance - immediately above / adjacent to mature source	Bradelle 0.75, Mabou 0.45	
		added lower confidence polygons in salt province due to lower confidence seismic pick (eg thick Mabou in SW Nfld) AND lower confidence that sands reach mini-basins	2000 to 3000 m fair reservoir	0.65	0.6	0.55	0.45	0.35	large structures may not be tested by one failure, multiple culminations / fault seal possible - can still allow decent trap chance where some failures have occurred	salt cored anticlines and other significant anticlines	0.75	seal risk from faults, eg. Old Harry faults, is well imaged and understood, Brion Island failure occurred in similar circumstance to Old Harry	50 to 200 m - fair COS, thin shales near surface, breach by fracturing worrisome	0.35	evidence of source in Brion Island short migration path, oil stain	Vr = 2.5 to 3.0, concern about overmaturity - uncertain success	Bradelle 0.5, Mabou 0.25	
		for deeper criteria, mini-basins have less certain depth (toward coin-toss) but still have sand presence concern (toward negative), so score same as other areas	2000 to 3000 m fair reservoir, low confidence	0.6	0.55	0.5	0.45	0.4		little to no salt, relying on small drapes, inversions, final movement on old faults, differential compaction	0.6	seal risk due to fractures on flanks mitigated by chance of increased seal from salt	< 400 m low condifidence near salt / W Nfld -	0.65	input from deeper sources only likely in NW, where salt doesn't impede, not included in already complex source layer	Vr > 3.0, over mature, concerned about cracking	Bradelle 0.25, Mabou 0.1	
			3000 to 4000 m poor reservoir, low confidence the same	0.4	0.35	0.3	0.3	0.25					0 m - onshore - confident older surface geology	0	if Mabou not present or contributing, it may actually help oil from Bradelle be preserved in traps - see discussion			
			> 4000 m likely no porosity, low confidence the same	0.25	0.2	0.2	0.15	0.15										

Table 3 – Detailed play description and polygon criteria, continued

Play		Reservoirs	Reservoir polygons	Reservoir COS	Trap	Trap polygons	Trap COS	Seal	Seal polygons	Seal COS	Source	Source polygons	Source COS	Global Scale
4	Morien / Cumberland stratigraphic play	Bradelle (Morian Group) and Port Hood and Boss Point (Cumberland Group, could not be separated out in regional mapping)	**same reservoir as structural play** - reuse layer exactly		stratigraphic plays (pinch-outs in main basins and basin flanks, or channels)	> 0.05 m thickness change / m map distance	0.55	Green Gables presence provides seal	**same seal as structural play** - reuse layer exactly		Bradelle and Mabour source, as structural play	**same source as structural play** - reuse layer exactly		0.35
					based on full Bradelle Fm and Cumberland Group isopach, not just Bradelle Fm	0.02 to 0.05 m thickness change / m map distance	0.45	Green Gables isopach definitions for seal COS layer, thinner than Naufrage because Green Gables more consistently shaley and deeper in the section						
					criteria picked from gradient (rate of change) of isopach, greater gradient means greater chance of pinchouts and strat traps, stay in low confidence	< 0.02 m thickness change / m map distance	0.35	strat play seal not so affected by trap geometry						
5	Windsor Carbonate play	reservoir quality covered under reservoir, reservoir is generally low quality	< 200 m of older strata - best	0.4	trap is reservoir presence	0 - 10 mapped as no Windsor	0.1	seal tight carbonate / salt (excellent seal) above, Upper Windsor, Mabou Group shales above that	> 500 m Windsor - excellent seal, very likely to include significant salt thickness, justifies higher confidence	0.8	Lower Windsor (Macumber) exists everywhere basinward from bioherms	Macumber source: three COS scores for > 500 m, 250 to 500 m, and < 250 m Windsor isopach		0.3
		reservoirs are bioherms, Gays River type section (20 miles N of Halifax airport) is only place porosity is really observed	200 to 1000 m of older strata - OK	0.35	estimate potential for presence in band around basin edge, based on Windsor Isopach (Mid-Windsor to Base Windsor)	10 to 250 m best reservoir presence potential	0.4	same seal as Sussex, point bioherms don't appreciably affect	100 to 500 m Windsor - very good seal, including tight carbonates and potentially some salt	0.7	Trinity maturity model based on Base Windsor depth	Vr = 0 to 0.6, immature, needs lateral migration, AND spider diagrams do NOT seem to support	*0.25/0.2/ 0.1*	
		proper Gays River bioherms with porosity appear most likely to occur when on basement, vs. thicker Horton / Sussex, use summed isopachs of Horton and Sussex Groups	1000 to 2000 m of older strata - getting tough	0.3	observed Middle Windsor pinchout on seismic	250 to 500 m maybe potential for presence	0.25	regional, not a big concern	< 100 m Windor but > 100 m Mabou Gp - decent shale seal	0.6	Macumber source signifcantly less likely toward basin margin, so overprint polygons from trap (basin margin estimated from Windsor isopach) to downgrade source by margin	Vr = 0 to 0.6, immature, good source chance, but needs lateral migration - spider diagrams support	0.6/0.55/ 0.45	
		do not know if porosity primary and fluid enhanced or all secondary, suspect need some primary, porosity not a function of depth in the carbonates	> 2000 m of older strata - worst	0.25		> 500 m probably too basinal, bioherms not present	0.1	polygons based on Windsor Gp isopach (Middle Windsor to Base Windsor Unc), and secondarily on Mabou Gp isopach (Top Mabou to Middle Windsor)	< 100 m Windsor and < 100 m Mabou Gp - problem, potentially struggling for seal (intraformational still possible)	0.3	Horton source also migrates up	Vr = 0.6 to 2.5, mature for oil or gas, high source chance - immediately above / adjacent to mature source	0.75/0.7/ 0.6	
		fractured dolomite also possible but unlikely to be significant, and difficult to estimate COS									combined chance using P(Macumber and/or Horton) math for final Source COS	Vr = 2.5 to 3.0, concern about overmaturity - uncertain success	0.5/0.45/ 0.35	
												Vr > 3.0, over mature, concerned about cracking	0.25/0.2/ 0.1	
6	Sussex play	clastics, low evidence for reservoir, low COS, big size kick	based on Base Windsor depth grid	second figure for lower confidence areas	stratigraphic traps (unconformity truncation, strat pinchouts, etc), also draped into inversion structures	based on Sussex Gp isopach	second figure for lower confiden ce areas	seal tight carbonate / salt above, Upper Windsor, Mabou Group shales above that	**mostly the same as Windsor Carbonate** - lowest box less harsh, given that Sussex can have intraformational seal		Sussex most likely sourced from Horton below	**same source as Horton** - reuse layer exactly		0.2
		mainly red-bed strata with associated anhydritic mudstones deposited in an arid environment, typically conglomerate at base	0 to 3000 m some chance of reservoir	0.55 and 0.5	trap polys from isopach - greater thickness give more strat trap opportunities, also outline best graben locations where structural traps occur, significantly lower COS than more variable Horton	> 700 m fair chance of trap	0.45 and 0.5	Sussex also self sealing some	> 500 m Windsor - excellent seal, very likely to include significant salt thickness	0.8	Giles (pers. comm.) believes that some grey rocks mapped as Horton in Cape Breton may be Sussex Group equivalents, but have not modelled extra chance from Sussex itself			
		reservoir quality from depth cutoffs, based on Base Windsor depth grid (top of Sussex) - all shallower depths lumped, as reservoir quality generally low	3000 to 4000 m fading chance of reservoir	0.35 and 0.4	not really related to Horton play - separated out	400 to 700 m poor chance of trap	0.35 and 0.4	regional, not a big concern	100 to 500 m Windsor - very good seal, including tight carbonates and potentially some salt	0.7	Sussex maturity would be similar to top of Horton, Sussex source quality is not well understood			
		examples of possible reservoir: Bradelle well gas show (best example), Cape Breton sands, McCully typical porosity = 6 to 8%, base of Cap Rouge well (very deep/low quality)	4000 m to 6000 m reservoir likely gone, poor in base of Cap Rouge well	0.15	no unconventional (fractured shale) play in this group	100 to 400 m just maybe trap	0.25 and 0.3		< 100 m Windor but > 100 m Mabou Gp - decent shale seal	0.6				
		lower confidence in mapping in salt province and by Gaspe, polygons outlined areas of low confidence	> 6000 m very high confidence that have really reached 4000 m	0.1		< 100 m no trap	0.15 and 0.2		< 100 m Windsor and < 100 m Mabou Gp - problem, potentially struggling for seal, relying on intraformational seal which is still possible	0.35				

Table 3 – Detailed play description and polygon criteria, continued

Play		Reservoirs	Reservoir polygons	Reservoir COS	Trap	Trap polygons	Trap COS	Seal	Seal polygons	Seal COS	Source	Source polygons	Source COS	Global Scale
7	Horton play	conventional clastics, decent and producing reservoir onshore (McCully, Stoney Crk Fields) - braided streams, beach sands - not even across rifts, often better on ramp side of basin, not master fault side	based on Base Sussex depth grid		stratigraphic traps in grabens (unconformity truncation, strat pinchouts), also draped into inversion structures	based on Horton Gp isopach	second figure for lower confiden ce areas	Horton reservoirs seal with intraformational and Sussex Group seals - interbedded shales between sandier intervals in both Groups, Sussex has higher seal potential, lump for simplicity	based on sum of Sussex and Horton Group isopachs		Horton Group includes good source intervals, Trinity maturity models run at Base Sussex / Top Horton depth and 700 m deeper	Horton presence - Horton Gp isopach cutoff, where 0 to 200 m, lateral migration to shallower strata possible but harder	0.25	0.4
		offshore penetrations deeper and thus low quality	0 to 2000 m good reservoir	0.7 and 0.6 in low confidence	trap polys from isopach - greater thickness give more strat trap opportunities, also outline best graben locations where structural traps occur	> 2000 m good chance of trap	0.7 and 0.6	seal is successful at Stony Creek/McCully	> 1000 m combined isopach, very good chance of seal	0.7	deeper case used to add more gradation to source layer, less COS where deeper source is becoming overmature before top Horton source	Vr = 0 to 0.6, immature, good source chance, but needs lateral migration - spider diagrams support	0.6	
		Horton Black Shale (Albert Fm Frederick Brook Member) thick and rich enough onshore to be economic, but keep separate on unconventional map, to be consistent with all other MCT studies	2000 to 3000 m fair reservoir	0.6 and 0.5 in low confidence	over print of interpretation confidence - some grabens are much less certain to be Horton - covered in the low confidence polygon	1000 to 2000 m fair chance of trap	0.6 and 0.5	slight decrease in seal COS possible in more intensely faulted graben areas, but that is more "prospect scale"	500 to 1000 m combined isopach, good chance of seal	0.6	deeper sources (eg Gaspe Ordovician sources) possible in shallow flanks , but would add little, also could be timing issues - deeper sources mature before Carboniferous traps in place	Vr = 0.6 to 2.5, mature for oil or gas, great - immediately above / adjacent to mature source	0.75	
		polygons based on Base Sussex depth grid (top of Horton Group)	3000 to 4000 m poor reservoir	0.35 and 0.4		200 to 1000 m poor chance of trap	0.3 and 0.4	polygons based on sum of Sussex and Horton Group isopachs, as shales in both groups contribute	200 to 500 m combined isopach, fair chance of seal	0.5		Vr < 2.5 on Top Horton maturity map but overmature (>2.5 Vr) on 700 m into Horton case - some concern depending on depth of reservoir	0.6	
		lower confidence in mapping in salt province, Casumpec graben area, and by Gaspe, polygons outlined areas of low confidence	4000 to 6000 m play is likely gone	0.15 and 0.25		< 200 m possibly no trap	0.15 and 0.2		< 200 m combined isopach, worrisome for seal	0.3		Vr = 2.5 to 3.0, concern about overmaturity - uncertain success	0.5	
			>6000 m very high confidence that have really reached 4000 m	0.1 and 0.2								Vr > 3.0, over mature, concerned about cracking	0.25	
Analysis of contribution of deeper plays in Gaspe region and along basin marging, modified from Lavoie et al. (2009) and Dietrich et al. (2011)						**lump their 6 plays into 2 play groups**								
8	Gaspe Devonian plays, R4	Lower Devonian hydrothermally altered pinnacle reefs	2 or more plays present and -< 2000 m. Production adjacent onshore.	0.7	dolomitization, tight carbonate surrounding	Along strike extrapolation of Appalacian structure. Extension of onshore geology with some confidence. Multiple trap types	0.7	tight carbonate, muddy facies	blanket seal - significant long term preservation risk	0.35	M Ord Ruisseau Isabelle Shales, also L Ord Riviere Ouelle	Extension of Lavoie et al. 2009 Onshore maturity map. Up to 2 km overburden. Source rock still thought to be within oil-gas window.	0.75	0.35
8	R5	Lower Devonian Upper Gaspe Limestones, fractured LS	2 or more plays and 2000 to 4000 m. Clastic porosity lost with depth.	0.55	anticlines, fractured enhanced areas (rheology dependant), Galt Field	Along strike extrapolation of Appalacian structure. Further from onshore geology. Poor seismic. Multiple trap types.	0.6	massive / weakly fractured rock			M Ord Ruisseau Isabelle Shales, also L Ord Riviere Ouelle	Extension of Lavoie et al. 2009 Onshore maturity map. This source has potential to be over mature but hydrocarbon in reservoir may not be cracked.	0.6	
8	R6	Lower Devonian Gaspe Sandstones	Only one play and < 2000 m. Discontinuous reservoir in limestones or pinnacles.	0.45	stratigraphic from rapid facies transition (channels and deltaic wedges), modified by faults, Halimand Field	Only L Devonian Pinnacles. Extension of onshore geology. Reefs thought to exist.	0.55	mud dominated units			M Ord Ruisseau Isabelle Shales and Dubuc Fm, also L Ord Riviere Ouelle			
			Only one play and 2000 to 4000 m. Discontinuous reservoir in limestones or pinnacles.	0.35										
9	Gaspe Silurian plays, R1	Lower Silurian Clastics (Weir / Anse Cascon Fm)	Low Silurian HTD best COS. Clastics and upper silurian htd are unlikely reservoirs. < 2000 m burial	0.4	open folds with Silurian normal faults or Devonian transpression or mixed structure/strat traps	Extension of onshore geology. Chance of HTD.	0.65	tight La Vielle carbonate, U Silurian Unc	Long-term preservation issue including chance of sub-aerial exposure during late Silurian. Devonian preserved.	0.3	M Ord Ruisseau Isabelle Shales and Dubuc Fm, also L Ord Riviere Ouelle, U Ord Bolland Brook	**same source as Lower Devonian Play** - reuse layer exactly		0.2
9	R2	Lower Silurian Hydrothermal Dolomites (Sayabec/La Vielle)	Deeper burial increases reservoir uncertainty especially in the clastics. 2000 to 4000 m burial.	0.3	dolomitization, tight carbonate surrounding	only U Silurian Reefs - no evidence of HTD in U Silurian.	0.35	tight carbonate surrounding	Long-term preservation issue including chance of sub-aerial exposure during late Silurian. Devonian eroded.	0.25	M Ord Ruisseau Isabelle Shales and Dubuc Fm, also L Ord Riviere Ouelle, U Ord Bolland Brook			
9	R3	Upper Silurian Limestone and Hydrothermal Dolomite (West Point)			dolomitization, tight carbonate surrounding	Further from onshore geology. Chance of HTD.	0.6	tight carbonate surrounding			M Ord Ruisseau Isabelle Shales and Dubuc Fm, also L Ord Riviere Ouelle, U Ord Bolland Brook			
10	Ordovician St.Lawrence Platform plays	St.Lawrence Platform - LtoM Ordovician carbonate - HTD or karst, also Cambrian clastics, U Ord Carbonate, where not unduely buried by Carboniferous - very poorly understood, but not out of reach on north flank of basin	Carbonate reservoir (HTD and karst) may survive burial. Long distance extrapolation from data control. Blanket COS where < 2000 m of Carboniferous above	0.55	structural traps unlikely (SOQUIP 1987), rely on HTD or karst strat traps	Structural HTD and karst traps possible. Long distance extrapolation from data control.	0.6	long term preservation greatest risk by far, worse than plays 8 and 9, must survive Appalachian Orogen	Long-term seal preservation major risk. Must survive Appalacian orogeny. Long distance extrapolation from data control. **Blanket COS where < 2000 m of Carboniferous above**	0.3	M Ord Ruisseau Isabelle Shales and Dubuc Fm, also L Ord Riviere Ouelle, U Ord Bolland Brook, Ordovician sources in general (also in W Nfld)	Ordovician source same as Gaspe plays. Long distance extrapolation from data control. Blanket COS where < 2000 m of Carboniferous above	0.6	0.2

Unconventional Resources

Shale gas

Unconventional shale gas resources totalling more than 60 Tcf of natural gas-initially-in-place have been identified in the Horton Group onshore in southern New Brunswick (Natural Resources Canada, 2017; Corridor, 2018a). Thick, organic-rich shale occurs in the Albert Formation of the Horton Group, which locally exceeds 1100 m thickness. Equivalent shale-gas resources are likely present across the region and beneath the Gulf of St. Lawrence given the widespread distribution of Horton Group rocks (Durling and Marillier, 1993b; this study). Studies in Nova Scotia noted significant potential in the Horton Bluff Formation (Albert Formation equivalent) in the onshore Windsor-Kennetcook Basin (20 Tcf; Hayes and Ritcey, 2014, Hayes et al., 2017) and Cumberland Basin (2 Tcf, Hayes et al., 2017, Keppie, 2017). Thick grey shale (> 150 m thick) reported from the bottom of the MacDougal No.1 well (Giles and Utting, 1999) hints at the potential for nearby organic facies; black organic rich shale occurs in the Indian Mountain area in New Brunswick in the same Horton subbasin (St. Peter and Johnson, 2009) .

Figure 3 shows the distribution of the most confident areas of potential shale gas resources within the study area. Four main areas of shale gas potential are identified: PEI, the North Point basin north of PEI and east of northern New Brunswick, northern Cape Breton, and southwestern Newfoundland. Other areas of thick Horton Group are interpreted (Appendix D), but are less well constrained by seismic data and / or are less certain to be Horton age grabens rather than older grabens. The production of shale gas generally requires extensive fracking, which is likely to remain technically and economically challenging. The best hypothetical potential is nearshore.

The shale gas resource identified beneath PEI and extending to the northeast into the Gulf of St. Lawrence represents the potential extension of shale gas resources occurring in southern New Brunswick. Durling and Marillier (1993b) identified a Horton Group basin up to 8 km deep in this area. Similarly, the North Point Basin represents a deep Horton basin with potential for shale resources. Organic-rich shale typically develops in anoxic lacustrine environments which may develop in such relatively narrow basins.

Thick, organic-rich shale has been identified from surface geological mapping in northern Cape Breton Island within the middle part of the Horton Group (Neale and Kelly, 1967; Smith and Naylor, 1990; Hamblin, 1992). Medium to dark grey shale is interbedded with siltstone, sandstone and pebble conglomerate. Neale (1964) estimated the thickness of this stratigraphic interval to be up to 1200 m, whereas Hamblin (1989) interpreted thrust repeats in the section and concluded that the stratigraphic thickness is 400 m or less. Nevertheless, a thick interval of organic-rich shale (TOC values up to 7 weight percent; Smith and Naylor, 1990) occurs on the northern tip of Cape Breton Island that likely extends into the offshore area. Hamblin (1992), based on paleocurrent and isopach data, interprets an offshore location for the master fault that controlled half-graben basin subsidence for this Horton depo-centre. The organic-rich shale may thicken in the offshore toward this master fault. The polygon in Figure 3 shows the estimated offshore distribution.

The Anguille Group (Horton Group equivalent) occurs onshore in southwestern Newfoundland and locally exceeds 4900 m thickness (Knight, 1983). It has been subdivided into several formations comprising a basal alluvial unit, a medial lacustrine unit and an upper alluvial unit. The middle unit is called the Snakes Bight Formation (Albert Formation equivalent), which comprises interbedded black shale, siltstone, and grey sandstone. The sandstone intervals have turbidite characteristics (Knight, 1983), suggesting steep slopes that may be associated with a spatially restricted lacustrine environment. The formation is 785 m thick in the type section and it is estimated to be 1000 m thick on the southern limb of the

Anguille anticline. Potential shale resources from the Snakes Bight Formation are interpreted to extend southwesterly from the Anguille anticline into the Gulf of St. Lawrence.

Shale gas and tight oil are also possible in the Ordovician platform at the northern edge of the Magdalen Basin. There is significant potential in equivalent rocks on southwestern Anticosti Island (Chen et al., 2018).

Coal bed methane

Coal bed methane (CBM) is formed during the process of transforming plant material to coal. The methane is adsorbed to the coal (held as a thin film on the surfaces of coal cleats). To produce it, the pressure in the coal seam must be lowered, by formation water production, so that the methane will desorb from the coal. Techniques to accomplish this pressure reduction include open hole cavitation, advance hydraulic fracturing, horizontal drilling and nitrogen injection (Hacquebard, 2002). Well density is typically high. Formation fluids must be reinjected or responsibly disposed of. All of these requirements would be difficult to implement offshore – nearshore development may be more plausible.

Grant and Moir (1992) studied the coal bed methane (CBM) under Prince Edward Island, and they noted the appropriate rank of coals in the region, and the higher drilling costs offshore. Hacquebard (2002) studied the coal bed methane (CBM) potential throughout Atlantic Canada, and worked in the heyday of CBM production at the beginning of this century. He noted coals in many wells in the offshore Gulf of St. Lawrence, and in over 60% of the coals, high vitrinite / inertinite ratios indicate the presence of highly fractured coals with high permeability and flow efficiency, suitable for the storage and flow of methane gas. According to his study, the offshore Gulf of St. Lawrence has CBM resources of 69 Tcf, the largest in the region. The prime zone for CBM underlies much of the southern and eastern Gulf and extends into the offshore Sydney Basin (Fig. 3). The in situ resource is very large, but the production is challenging.

Gas hydrates

Gas hydrates are an occurrence of hydrocarbon in which molecules of methane are trapped in ice molecules. Hydrates form in cold climates, such as permafrost zones and in deep water, in a specific “stability zone” where appropriate pressure and temperature exist. To date, economic liberation of hydrocarbon gases from hydrates has not occurred, but hydrates contain quantities of hydrocarbons that could be of great economic significance.

“Bottom simulating reflectors” parallel to the sea bed are typical evidence of gas hydrates on seismic data. However, due to the quality and vintage of the seismic no indicators of gas hydrates were identified because the sea bed was often muted. The gas hydrate stability zone is limited to the deeper water of the Laurentian Channel in the northeast area of the study area (Fig. 3; Majorowicz and Osadetz, 2003), and they estimate that hydrates will be less than 200 m thick there. This region is unlikely to be competitive with other gas hydrate opportunities.

APPENDIX C. EXPLORATION AND PRODUCTION HISTORY

Exploration history

Petroleum exploration in the Maritimes Basin began near Moncton, New Brunswick, in the 1850's with Abraham Gesner who invented a process for obtaining kerosene from Albertite (a pitch-like substance found in the Albert Formation of the Horton Group). The first oil wells in North America were drilled in the late 1850's and by 1859 four shallow wells (up to 60 m) were drilled in New Brunswick, which yielded small quantities of oil and gas. This was the first of two drilling campaigns undertaken in the late 1800's to investigate surface petroleum shows in the Dover area southeast of Moncton (Howie, 1968). Minor amounts of oil (up to 20 bbls/d) were produced. Further encouragement resulted from the drilling of several wells between 1899 and 1905 in the same area; one well reportedly produced up to 50 bbls/d. In 1909 the Stony Creek oil and gas field was discovered and by 1912 the field supplied natural gas to the city of Moncton. Since discovery, over 100 wells have been drilled in the field with cumulative production of 28 Bcf of gas and 1 MMbbls of oil. Recent daily oil production averages approximately 26 bbls/d and gas production is limited.

Exploration activity began in Nova Scotia with the first well drilled in 1869 on the basis of surface petroleum shows in the Lake Ainslie area (McMahon et al., 1986). The most encouraging wells in Nova Scotia were those drilled in the Lake Ainslie area, which yielded only a few barrels of oil and salt water. In the late 1920's Imperial Oil Limited and Eastern Gulf Oil Company conducted the first large scale exploration program in Nova Scotia with the drilling of 27 wells in a five year period, but with no success. Approximately 72 wells were drilled in Nova Scotia prior to 1950 with no discoveries.

Shell Oil Company conducted a regional seismic program in southern New Brunswick in the late 1940's (Gussow, 1953) and subsequently drilled five wells without commercial success. In the late 1950's, Imperial Oil Limited returned to the Maritimes Basin to conduct the first regional exploration program that spanned New Brunswick, Nova Scotia and Prince Edward Island. A similar large-scale exploration program comprising seismic reflection surveys and drilling was conducted in the early 1980's in a joint venture involving Chevron Canada Resources Limited and Irving oil Limited. Although minor petroleum shows were encountered, no commercial success was achieved.

Offshore exploration in the Maritimes Basin began in 1944-45 with the drilling of the Hillsborough No.1 well from an earthen platform in Hillsborough Bay, PEI. Delineation of the offshore basin in the Gulf of St. Lawrence was attempted with seismic refraction surveys in the 1950's and 1960's. This was followed by widespread seismic reflection surveys in the Gulf of St. Lawrence between 1965 and 1985 (Fig. 2). Most of the offshore wells used in this report (Fig. 2) were drilled during this same timeframe with only one discovery (see East Point SDL below).

The most recent exploration phase in the Maritimes Basin was associated with the construction of the Maritimes and Northeast Pipeline, which was commissioned in late 1999. Seismic and drilling was conducted in all three Maritime Provinces (NS, NB, and PEI) as well as three small seismic programs in the Gulf of St. Lawrence. It was during this phase of activity that the McCully natural gas field was discovered in 2000, by Corridor Resources Inc. and Potash Corporation, in the Sussex area of southern New Brunswick.

Exploration success and analysis

The protracted exploration history in the Maritimes Basin has resulted in three significant oil and gas discoveries: two commercial fields (Stoney Creek and McCully) and one noncommercial discovery (East Point). The Stoney Creek and McCully fields are located onshore and are relevant to this report only because they provide data on known productive capability.

Of primary concern in this report is the offshore area, where a total of nine exploration wells have been drilled resulting in one discovery (a success rate of approximately 1 in 9; the world wide average). By comparison, approximately 143 exploration wells have been drilled in the North Sea Carboniferous basins (with comparable stratigraphy and structure to the Maritimes Basin), resulting in 37 discoveries with an estimated recoverable volume of 3.6 Tcf of gas (Besly, 2018). However, six unsuccessful wells were drilled for North Sea Carboniferous targets prior to the first discovery in 1984 (Besly, 2018); a success rate not unlike that of the offshore Maritimes Basin. Given the large offshore area, the discoveries described below should be considered a small sample of the ultimate potential for the offshore Maritimes Basin.

Rehill (1996) noted that the primary objective of early exploration programs was oil, and indications of natural gas may have been ignored. Grant and Moir (1992) compiled mud logs of gas detected in drilling mud and cuttings for several wells in the Gulf of St. Lawrence and onshore PEI. They noted that gas shows commonly coincided with occurrences of coal measures strata.

Hu and Dietrich (2010) conducted an analysis of core measurements and wireline logs from nine wells in the Maritimes Basin to assess reservoir characteristics. In general, the majority of the sandstones were characterized by low porosity and permeability. However, there were many sandstone intervals with higher than average porosity-permeability values (Hu and Dietrich, 2010), perhaps due to secondary porosity development and enhancement (Chi et al., 2003). Hu and Dietrich (2010) suggest, based on their analysis and qualitative comparison to the gas-bearing zone in the East Point E-49 discovery well, the potential to flow-test natural gas from charged reservoirs (by-passed pay). Examples cited by them include the Horton Group in the Bradelle L-49 well and multiple zones in the Cable Head E-95 well. In the latter well, "multiple log-indicated petroleum zones occur in sandstones with calculated porosity of 6 to 12 % and permeability of 0.1 to 2.0 mD" (Hu and Dietrich, 2010). Elevated values of gas in drilling mud were encountered in the Cable Head well from approximately 2400 m to total depth (Grant and Moir, 1992), suggesting the potential for the well to flow natural gas.

Discoveries and production history

East Point SDL

The East Point E-49 discovery well was drilled on a salt-cored anticline and tested natural gas at a rate of 5.5 MMcf/d from the Cable Head Formation. The gas accumulation is located on the north side of a normal fault with closure formed by fault-seal and down-dip drape on the anticline. A delineation well (East Point E-47) was drilled to the south of the original well; the Cable Head reservoir was up-dip and water bearing. The discovery was granted a Significant Discovery License (SDL) (Fig. 3, Hudson's Bay Oil and Gas Ltd., 1976), but was deemed too small to develop in an offshore setting with estimated gas-in-place of approximately 80 Bcf (Rehill, 1996).

Stoney Creek

The Stoney Creek field is located approximately 14 km south of Moncton on the west side of the Petitcodiac River (Fig. 3). The field has an east-west strike length of about 4 km and about 2 km in a north-south dip direction. Discovered in 1909 the field has produced approximately 1 MMbbls of oil and 28 Bcf of gas from a section of the Albert Formation approximately 600 m thick (Keighley and St. Peter, 2003, 2006). The productive sandstones comprise discontinuous, lenticular bodies ranging in thickness up to 30 m with average porosities of 12% (Keighley and St. Peter, 2006). The sandstone appears to grade laterally into gray to black shale, kerogenous shale, and siltstone (St. Peter and Johnson, 2009). The sandstones occur in packages and were subdivided into six informal units labeled I to VI, from shallowest to deepest (Howie, 1968). The sandstone units are separated by grey shales, kerogenous shales and siltstone. The main gas-productive units were the up-dip parts of units III and IV whereas most of the oil was produced from the down-dip, southeastern part of the field in unit VI (Howie, 1968). Revised stratigraphy for the Albert Formation (see Appendix A, Horton Group) at Stoney Creek field assigns units I through IV to the Hiram Brook Member, unit V to the Frederick Brook Member and unit VI to the Dawson Settlement Member (St. Peter and Johnson, 2009).

The top seal for the Stoney Creek field is interpreted to be thick grey shale and red mudstone of the Sussex Group (St. Peter and Johnson, 2009). To the west of the field, the grey sandstones and shales of the Albert Formation transition laterally into redbeds comprising coarse, immature, alluvial conglomerate rocks and lithic sandstones (St. Peter and Johnson, 2009).

McCully

The McCully field (Fig. 3) is located approximately 80 km southwest of Moncton near the town of Sussex, New Brunswick. The field has a northeast-southwest strike length of approximately 12 km and a width of about 3 km in the northwest-southeast direction. The southwestern part of the field is the structurally highest part of the field located at the crest of a doubly-plunging anticline. The top seal on the field is the overlying mudstones of the Sussex Group above the unconformity (Keighley and St. Peter, 2006; Brake et al., 2019).

Since discovery in 2000, the field has produced approximately 57 Bcf of gas from the Hiram Brook Member of the Albert Formation (Fig. A-1, Corridor Resources, 2018a). The productive intervals generally comprise sandstone packages up to 95 m net sand thickness separated by grey to black shale, similar to the Stoney Creek field. Sandstone porosities average about 8% and permeabilities are low (Keighley and St. Peter, 2006). They are considered “tight-sands” and generally require hydraulic fracturing to optimize production. The unit is overpressured (approximately 500 psi over hydrostatic), and combined with low geothermal gradients in the area can lead to the formation of gas hydrates (Keighley and St. Peter, 2006) during production.

The Hiram Brook Member sandstone packages (see Appendix A, Horton Group, Fig. A-1) have been informally subdivided into seven units labeled A through G, from deepest to shallowest. The main producing sand units are sands A and B at the base of the Hiram Brook Member in the southwestern part of the field. They are interpreted as braided stream deposits derived from source areas located to the southwest of the field. These sands transition laterally to shale toward the northeast. In the northeastern part of the field, the upper sands (C sand and younger) are interpreted to be deposited in a marginal lacustrine environment comprising shoreline sand deposits (Martel and Gibling, 1991).

The gross thickness of the Hiram Brook Member at the McCully field can exceed 800 m, combined with the large aerial extent, suggest a large in-place resource (approximately 1 Tcf; Keighley and St. Peter, 2006). However, the nature and distribution of sands in the field limits the total volume of hydrocarbons likely to be produced; a contingent resources report (Corridor Resources, 2018a) indicates 44 Bcf of unrisked, best estimate, gross contingent resources in the Hiram Brook Member of the McCully Field (yet to produce). In addition, the underlying Frederick Brook Member (Fig. A-1), a hydrocarbon-rich shale up to 1100 m thick, has unconventional resource potential of approximately 53 Tcf of petroleum-initially-in-place at McCully (Corridor Resources, 2018a).

Galt, Haldimand, and Bourque

The Galt, Haldimand, and Bourque fields were discovered in Lower Paleozoic sediments. A comprehensive summary of the petroleum potential of these rocks can be found in Lavoie et al.

(2009), and they discuss the first two discoveries. These fields are located onshore on the Gaspé Peninsula.

The Galt oil project is located 20 km west of Gaspé and was initially drilled in 1983. It has an estimated 557 million barrels (best estimate) of oil-initially-in-place (OIIP) (Junex, 2017). This volume includes 81 million barrels of discovered oil and 476 million barrels of undiscovered oil in the Forillon and Indian Point formations (part of the Upper Gaspé Limestones and Chaleurs Group, respectively). In 2014 Junex drilled the Galt No 4 Horizontal well and recovered 17,798 barrels of light oil at an average rate of 240 bbls/d during production testing. Recovery factors are expected to be low and best estimate of contingent resources is 8.1 milllion barrels (Junex, 2017). Cuda Oil and Gas (2018, new owner) expects the Galt No. 4 well to produce 150 bbls/d once a production license is granted.

The Haldimand field was discovered in 2006 and is operated by Pieridae Energy. The field is located on the outskirts of the town of Gaspé. It is hosted by Lower Devonian Gaspé Sandstone, and has an OIIP of 69.7 million barrels (P50) with an estimated 7.7 million barrels of recoverable oil (Pieridae Energy, 2018). Also operated by Pieridae Energy is the Bourque project, 50 km west of Gaspé. This project has ~750 Bcf (P50) of wet natural gas in-place (Pieridae Energy, 2018), located in the Forillon Formation.

APPENDIX D. REGIONAL MAPPING

In order to create the petroleum potential map, a program of regional mapping of key geologic horizons was undertaken. Horizons were chosen by their petroleum system significance and by their mappability on the regional seismic data. The discussion below explains how reflection packages were defined from wells and other geologic constraints, and followed around the basin, at all levels of the Magdalen Basin.

IHS's Kingdom® Suite interpretation platform was used for regional mapping. As discussed above, a large petroleum industry seismic database was compiled for this project. The regional seismic data were loaded into Kingdom®, allowing the comparison of multiple datasets and processing vintages of data. Over 40,000 km of 2D multichannel seismic data were available for this study. Many maps from literature, and published interpreted grids, were also loaded to Kingdom®, to compare published ideas with seismic data and constrain new interpretation as appropriate. Gravity and aeromagnetic data were also used as interpretation constraints.

Due to limited interpretation time, a regional approach to mapping was used, with minor misties (less than about 50 ms) accepted. Similarly, a straightforward basin-wide function for depth conversion was employed. Good regional scale maps were produced in the time available, suitable for outlining the plays present and estimating the COS of the petroleum elements within those plays, and also for basic basin modelling.

Seismic quality and reprocessing

Seismic data quality ranges from good to poor. In some areas, a hard water bottom lead to significant multiples masking the seismic signal. In many cases, especially when only images of the seismic are available, we had to interpret the old processing. However, several petroleum companies generously provided both post-stack and field digital data, allowing modern reprocessing.

Thus, as part of the project the GSC has fully reprocessed, from field tapes when available, over 1100 km of 2D marine seismic data and performed post-stack processing on over 2300 km of scanned and digitized sections. In addition 1200 km of Lithoprobe seismic data was reprocessed by a 3rd party contractor (Hall et al., 2019). Lines reprocessed from field tapes are highlighted in hot pink on Figures 2 and D-1.

Much of the reprocessed seismic data was recorded and originally processed between the 1960's and early 1980's, during a time period when computing power and digital storage space was very expensive. In many cases the original processing did not include seismic processing steps such as source de-signature, de-multiple, deconvolution, modern noise attenuation, relative amplitude preservation, residual statics, and other work flows that are now considered standard.

By utilizing modern techniques, software, and computer performance, the original recorded data are transformed into images of the subsurface that are vastly improved when compared to what was available previously (example, Fig. D-2). Taking a new look at this old data is helping GSC scientists gain new geological and geophysical insights.

Gravity modelling

Bouguer anomalies derived from satellite altimetry (Topex, Sandwell et al., 2014) and shipborne measurements from the Gulf of St. Lawrence were used to examine the character and structure of sedimentary rocks in two key areas, the salt province north of Cape Breton Island, and grabens in the area north of western Prince Edward Island (Fig. 1).

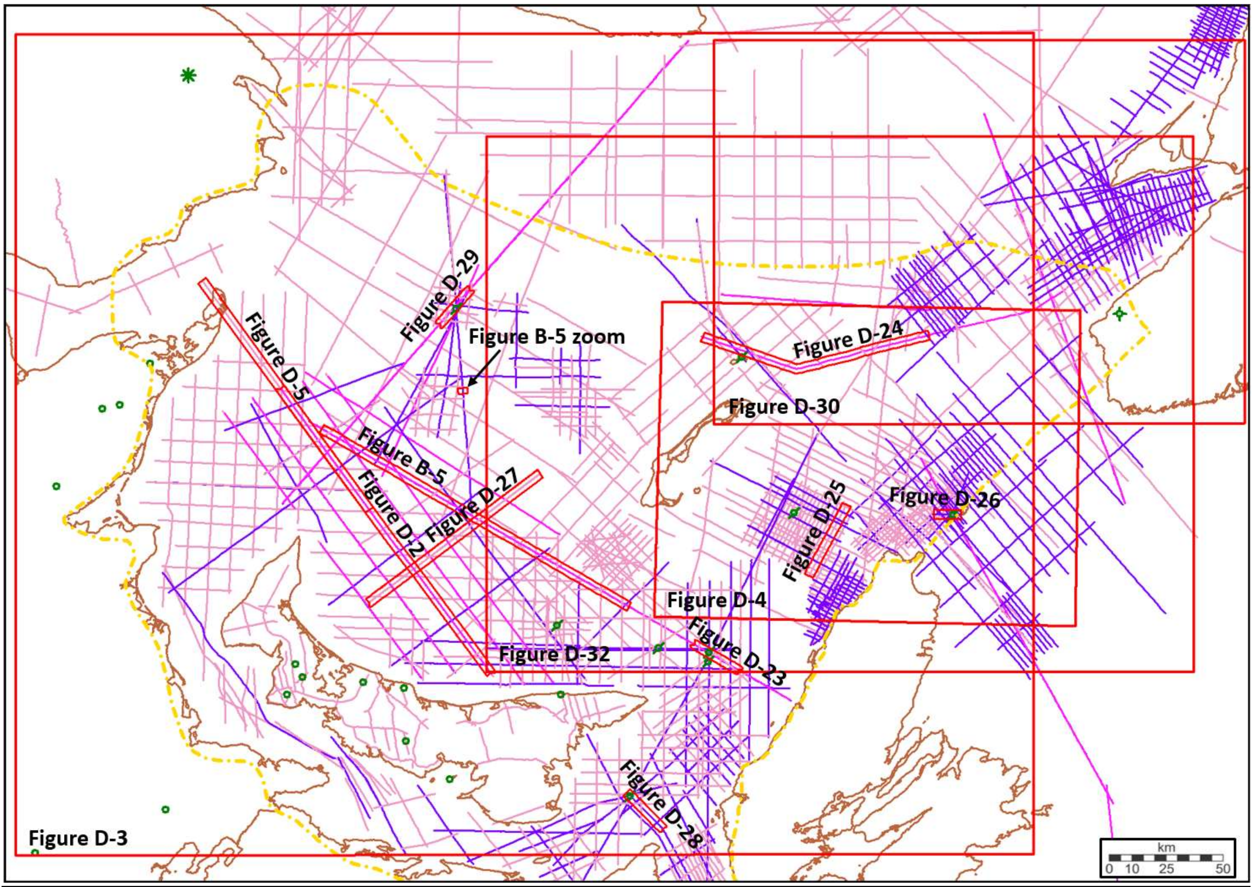


Figure D-1 – Appendix D figure locations and seismic database

Locations of seismic and gravity data examples are highlighted.

Figure locations | **Seismic data types** | **Wells**

Study area

Recent GSC processing

Digital SGY data

Georeferenced images

Oil and gas well

Dry hole

Plugged and abandoned

Status unknown

The gravity anomalies were initially processed through the calculation of a residual map (Marillier and Verhoef, 1989). This map, which accentuates the gravity signature of the grabens and salt bodies, is a first-order approach to examine the gravity data and to help interpret regional seismic reflection data. Figure D-3 shows a residual Bouguer anomaly created by subtracting the long-wavelength component of the anomaly, calculated through upward continuation by 10 km. Anomaly lows in the residual map highlight the salt bodies in the east, north of Cape Breton, and the deep grabens in the northwest, north of Prince Edward Island.

The 3D inversion of the Bouguer anomaly provides a model of subsurface density contrast that may further constrain regional seismic interpretations. The 3D inversions were constructed to focus on negative density contrasts, in order to model anomalously low-density rocks such as evaporites and sedimentary rocks, through the techniques outlined in Hayward (2019) using the GRAV3D software (Li and Oldenburg, 1998). Comparison of model results with preliminary interpretations of seismic lines were used to guide the selection of the optimal gravity inversion parameters for use in final models, including model cell size and the predicted density contrast.

In the salt province north of Cape Breton Island and south of Îles de la Madeleine (Fig. 1), the contrast in density between sediments and salt helps outline the salt bodies (e.g. Hayward et al., 2014). Figure D-4 is an example of a horizontal depth slice through a density model in this region, based on inversion of the shipborne data. There is a reasonable correlation between low-density zones and salt bodies interpreted on seismic, despite the moderate noise content of the shipborne gravity data. The cell size of the models is 2 x 2 x 0.2 km, which optimises model resolution versus artefacts that increase with the use of smaller model cells. The density models were used to constrain the interpretation of salt pillars and walls on the seismic data and draw polygons outlining the salt extent at each horizon.

In the area north of western Prince Edward Island, and east of northern New Brunswick, many authors have interpreted grabens on seismic reflection profiles. These grabens are interpreted to be equivalent in age to the Horton and Sussex groups (Durling and Marillier, 1990; Pinet et al., 2018; Fig. 3, see below also). The largest and deepest graben was named North Point Basin by Durling and Marillier (1990). The grabens correlate with low Bouguer anomalies, derived from satellite gravity data in a region of limited shipborne coverage. The results of the 3D inversion of these data were used to highlight and investigate graben structure. Depth converted seismic reflection data were again used to guide the selection of inversion parameters, including a representative density contrast for input into the inversion (Fig. D-5). Rocks in the Cumberland, Morien and Pictou groups are broadly up to -0.3 g/cm^3 lower in density than those below (Watts, 1972, and the references therein). Younger, relatively lower density, rocks within the interpreted North Point Graben are clearly defined by their higher density contrast. The greatest density contrast is in younger rocks near faults, where significant fracturing may lower density. Salt is not expected from seismic geometries in this area, and densities are overall higher than in the salt province to the east, but a component of salt offers an alternative explanation for the low graben densities. The 3D inversion results were then used to extrapolate the depth of the base of the Magdalen Basin sediments into areas with poor or no seismic. Steps in the model contours roughly correlate with interpreted faults, but model resolution does not allow a definitive, quantitative correlation.

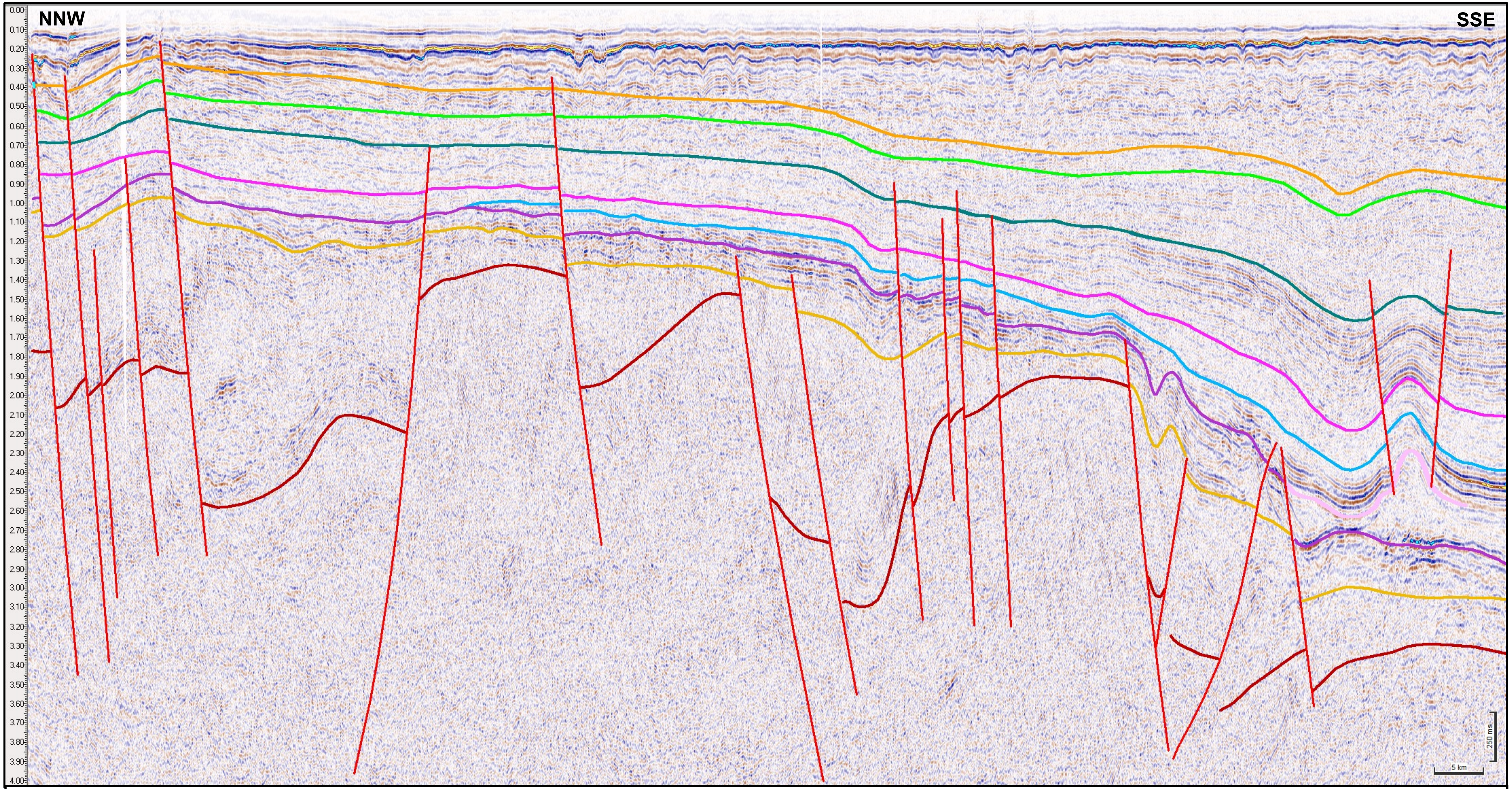


Figure D-2 – Reprocessing example and regional cross section

Chevron Line GSL70 – field tapes provided courtesy Chevron and reprocessed at GSC Calgary. Horizon colours are identified in Figure 4. Approximately 8:1 vertical exaggeration (@ 5000m/s).

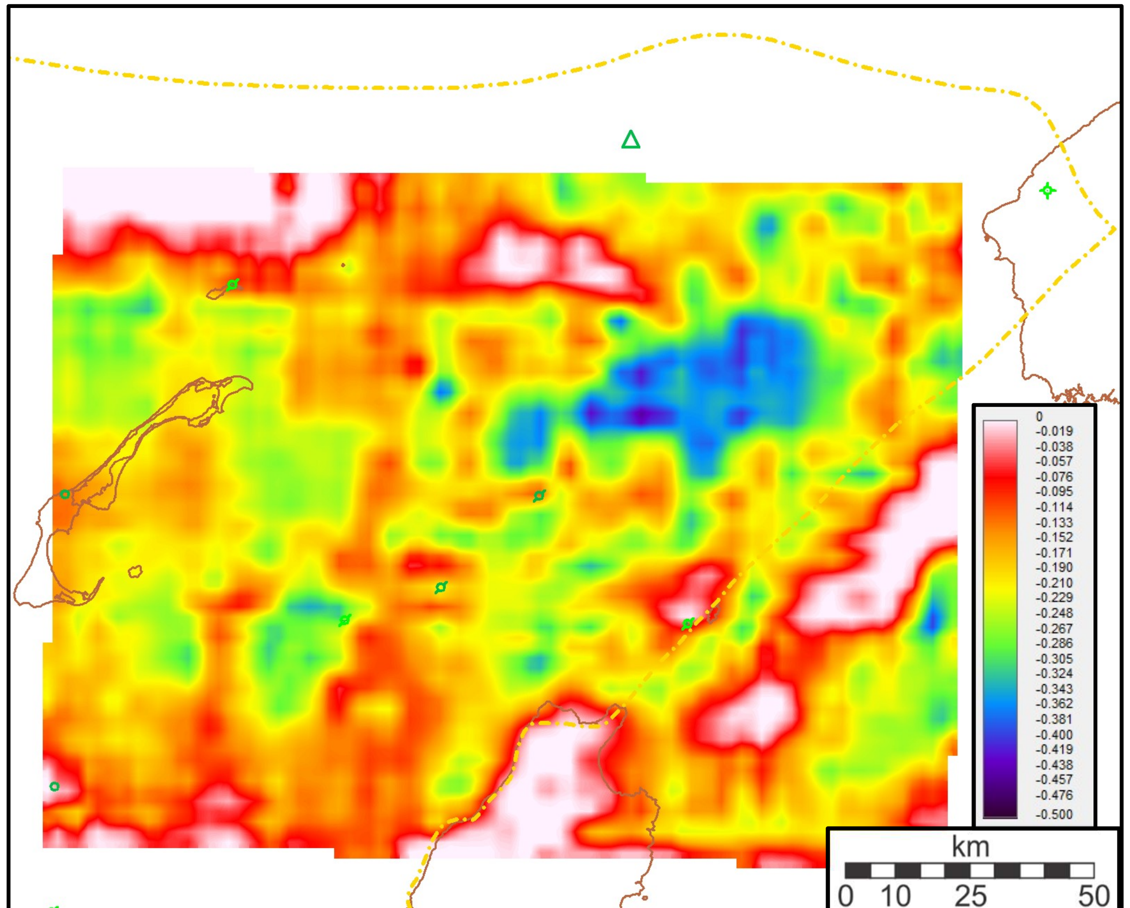


Figure D-4 – Inversion model of salt province

Inversion of ship borne gravity measurements, displayed as density contrast in g/cm^3 below datum. Example slice through model at 1500 m depth. Large negative contrast (over -0.4 g/cm^3) highlights large salt body north of Cape Breton and west of SW Newfoundland. Figure location in D-1.

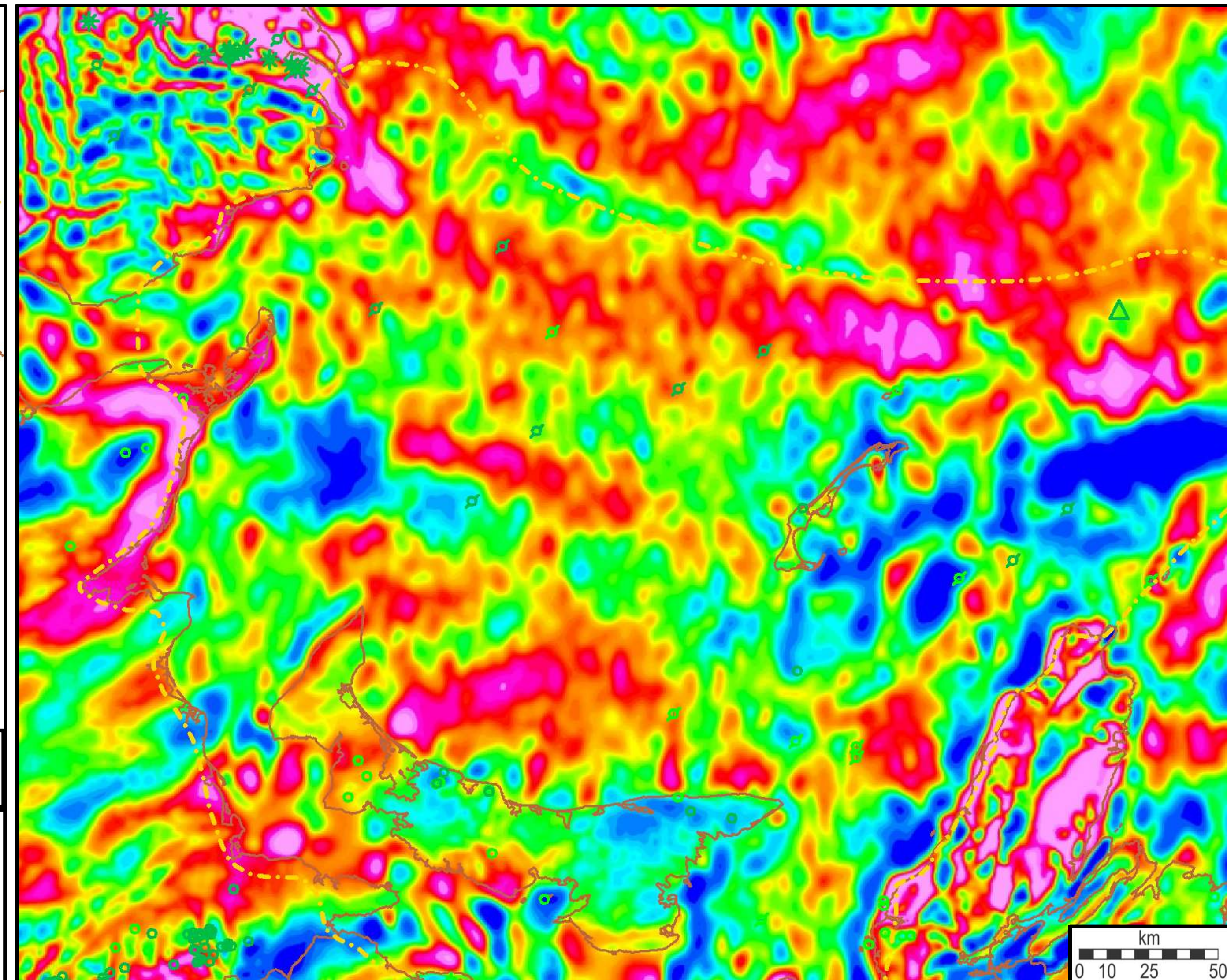


Figure D-3 – Satellite Bouguer gravity residual map

Bouguer gravity map calculated from satellite data (Topex, Sandwell et al., 2014), with standard density of 2.67 g/cm^3.

Bouguer was upward continued to 10km and then subtracted from original Bouguer to create residual map.

Residual lows highlight salt bodies and grabens with less dense sediments.

Figure location in D-1.

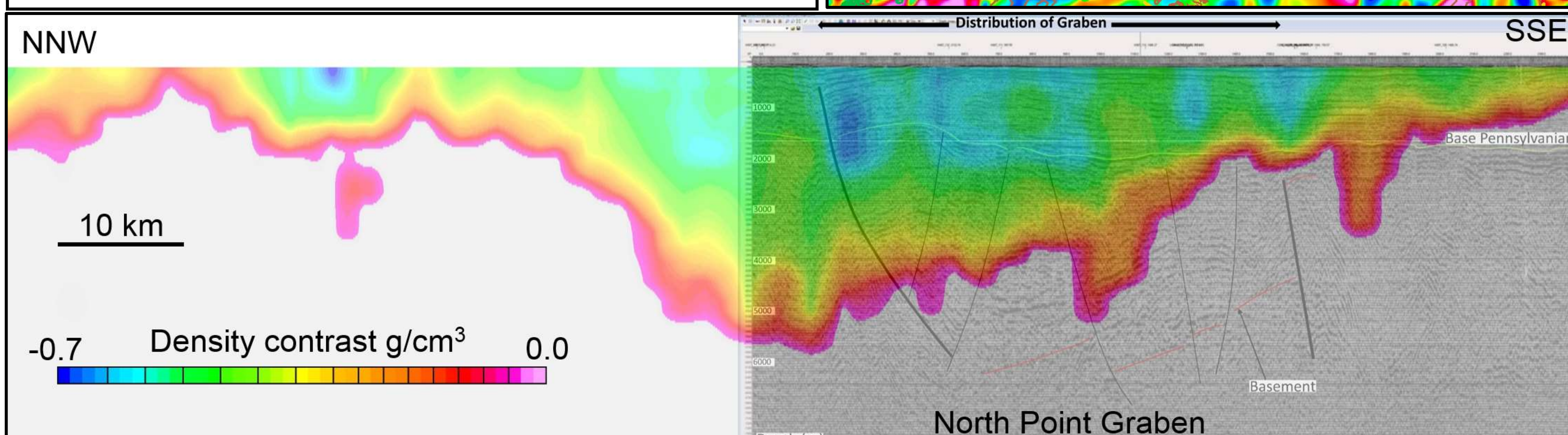


Figure D-5 – Inversion model cross section – North Point graben

Inversion model superimposed on preliminary depth interpretation of regional seismic line (Fig. D-2). Figure location in D-1.

Rocks in the Cumberland, Morien and Pictou groups are broadly up to -0.3 g/cm^3 lower in density than those below.

Younger rocks within the interpreted North Point Graben are well imaged by higher gravity contrast.

Gravity model and maps used to extrapolate the base of the Magdalen Basin to NW, in areas with poor or no seismic.

Depth and isopach maps

Regional two-way-time mapping of horizons, faults and fault polygons was conducted based on the geophysical database discussed above. Further detail of well ties, seismic horizon definition and interpretation, and depth conversion is provided below.

Nine regional depth maps were produced. The map extents reflect the boundary of the study area, as discussed at the beginning of the report, and not necessarily the edge of the geological package mapped. The stratigraphic position of these horizons is indicated on the regional stratigraphic column (Fig. 4):

- Figure D-6: Top of Cable Head Formation
- Figure D-7: Top of Green Gables Formation
- Figure D-8: Top of Bradelle Formation
- Figure D-9: Top of Mabou Group
- Figure D-10: Top of Middle Windsor Group
- Figure D-11: Top of Salt (Lower Windsor Group)
- Figure D-12: Base Windsor Group – Early Visean Unconformity
- Figure D-13: Base Sussex Group Unconformity (top of Horton Group)
- Figure D-14: Pre-Horton Group Basement (base of Magdalen Basin)

Isopach maps were also calculated from the depth horizons. For the Upper Carboniferous and Windsor isopach calculations, the upper surfaces were truncated at the modern bathymetry and topography. For the Sussex and Horton isopach calculations, bounding surfaces were projected up-plunge in the limited areas eroded (as part of tying to outcrop constraints), and isopach maps represent the pre-erosion thickness. In all cases, apparent (vertical) thickness is calculated (strictly speaking, isochores; in the Magdalen Basin, dips are generally low and the vertical thickness is a good approximation of the stratigraphic thickness).

- Figure D-15: Naufrage Formation isopach map – (bathymetry to Cable Head Formation)
- Figure D-16: Cable Head Formation isopach map
- Figure D-17: Green Gables Formation isopach map
- Figure D-18: Bradelle Formation and Cumberland Group isopach map
- Figure D-19: Mabou Group and Upper Windsor Group isopach map
- Figure D-20: Middle Windsor and Lower Windsor Group isopach map (including salt)
- Figure D-21: Sussex Group isopach map
- Figure D-22: Horton Group isopach map

Many of these maps were used to constrain both reservoir quality (as a function of depth) and stratigraphic trap potential (as a function of gross reservoir thickness and thickness gradient). The play polygons were created directly from map contours, as described in Tables 1 and 3.

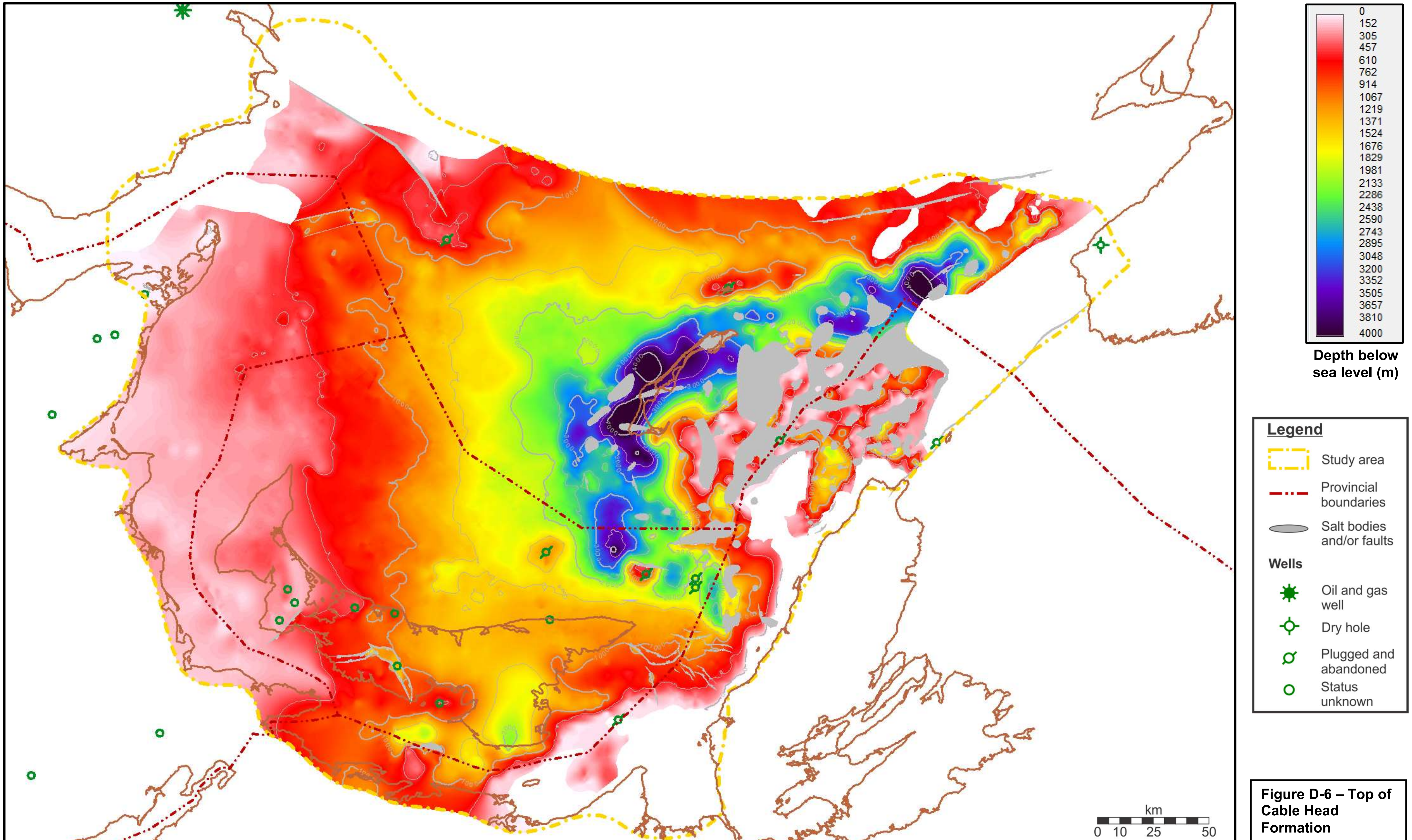


Figure D-6 – Top of Cable Head Formation

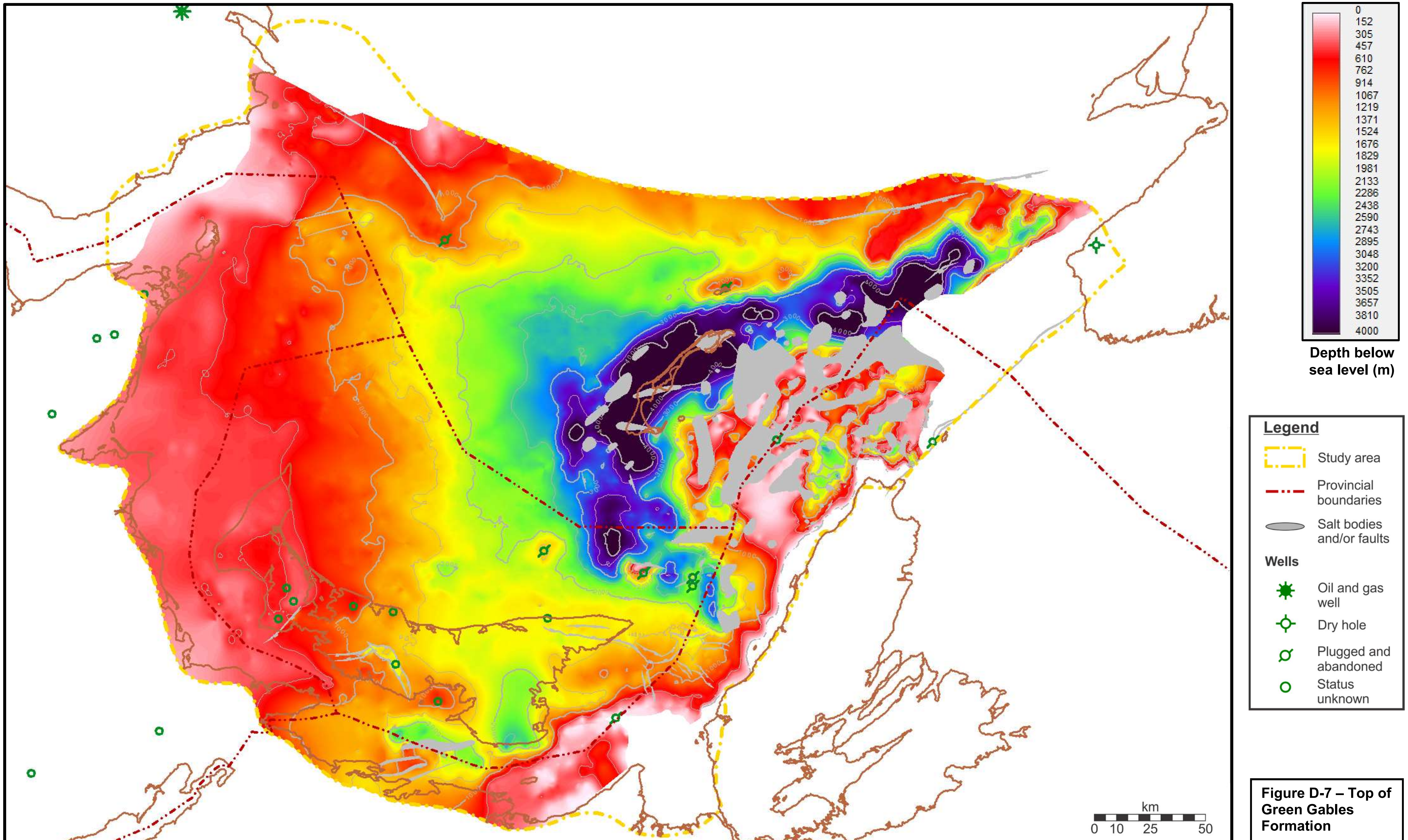


Figure D-7 – Top of Green Gables Formation

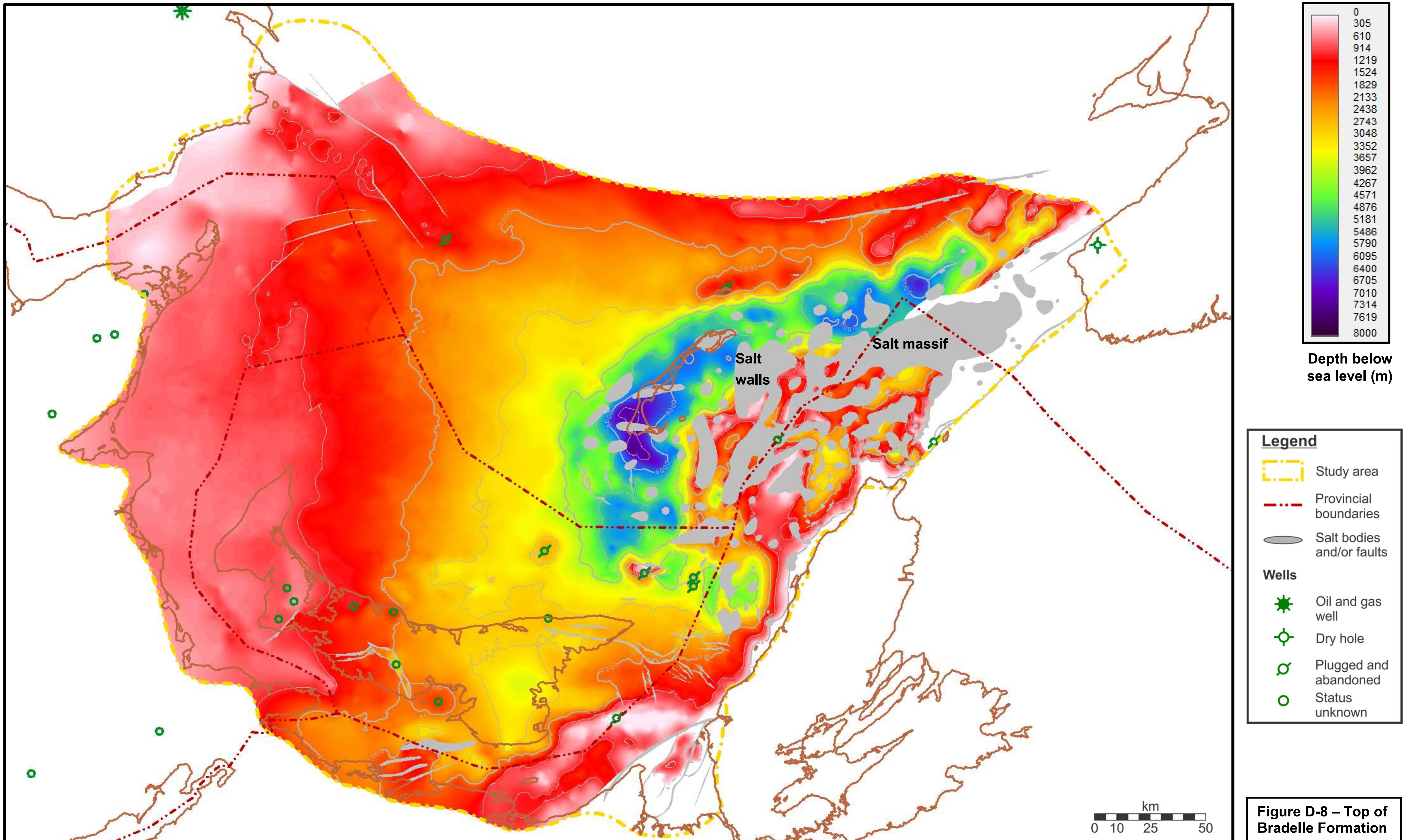


Figure D-8 – Top of Bradelle Formation

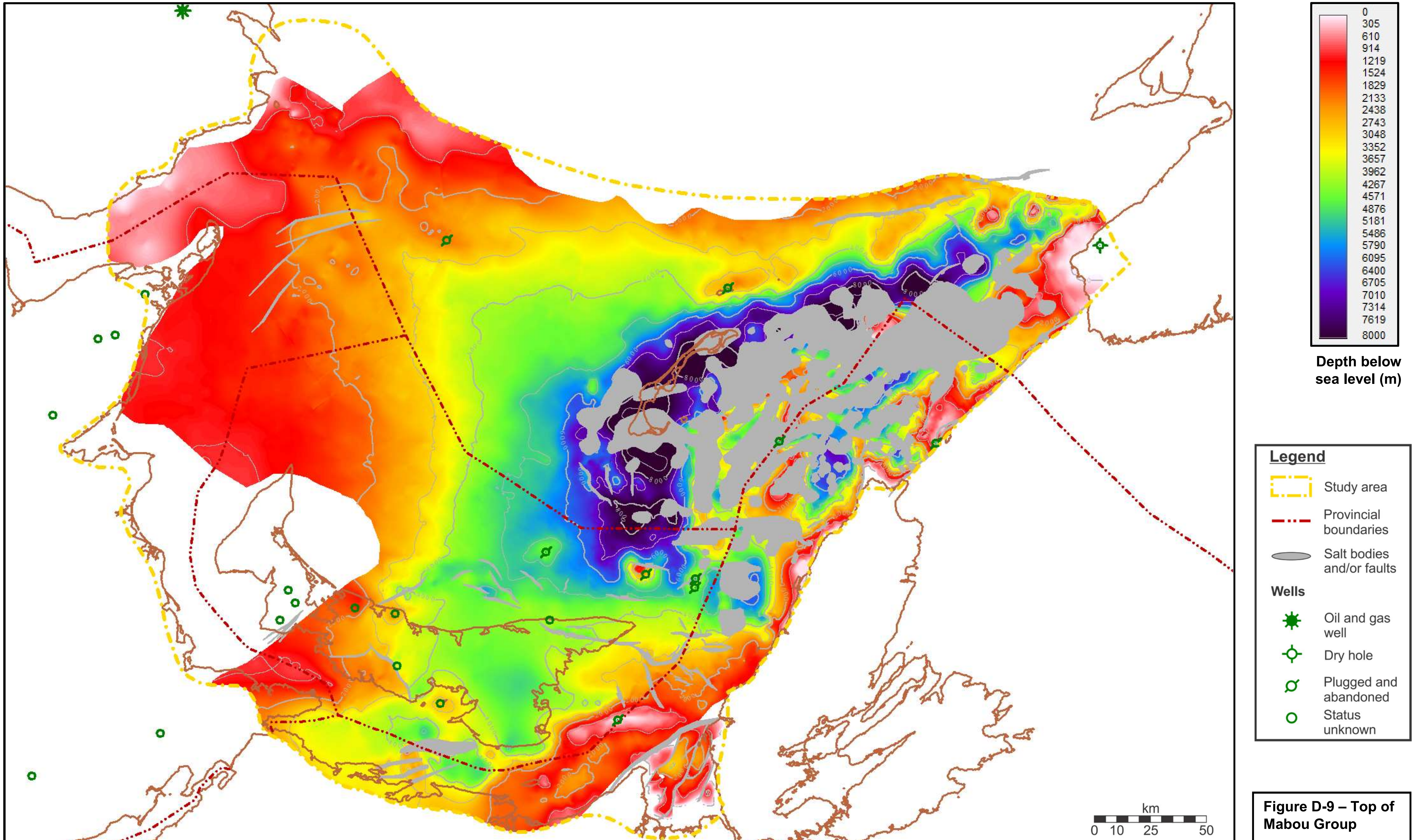


Figure D-9 – Top of Mabou Group

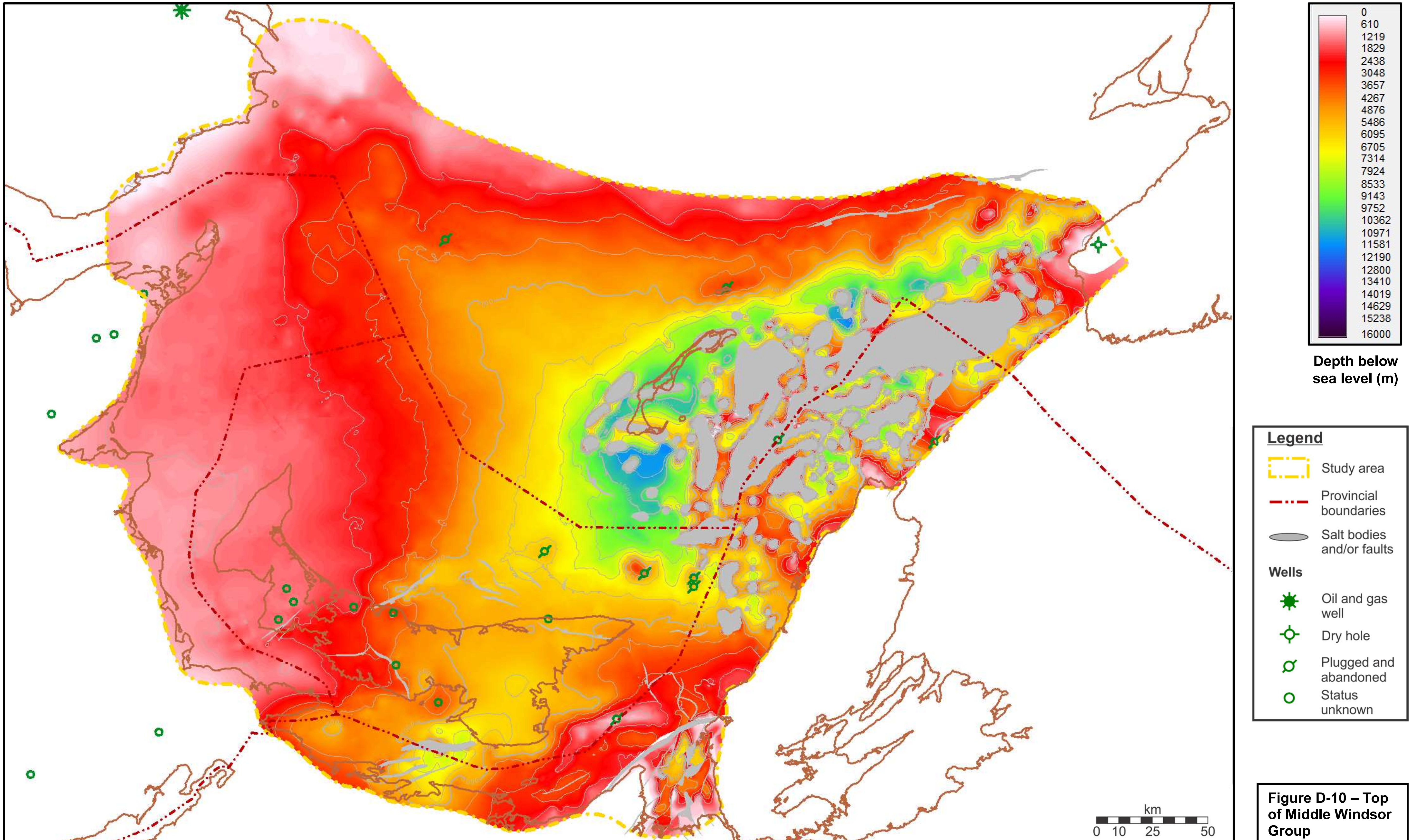


Figure D-10 – Top of Middle Windsor Group

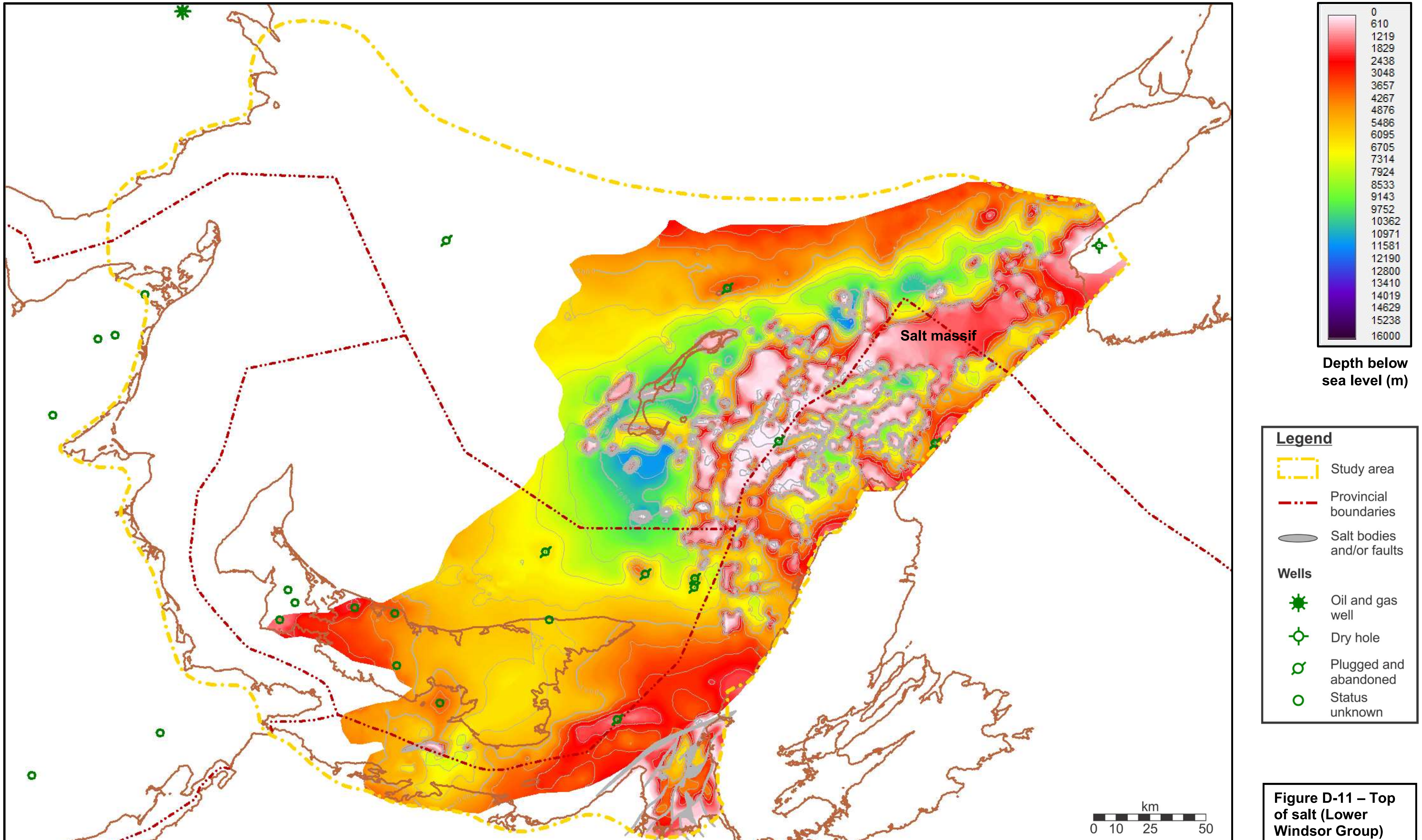


Figure D-11 – Top of salt (Lower Windsor Group)

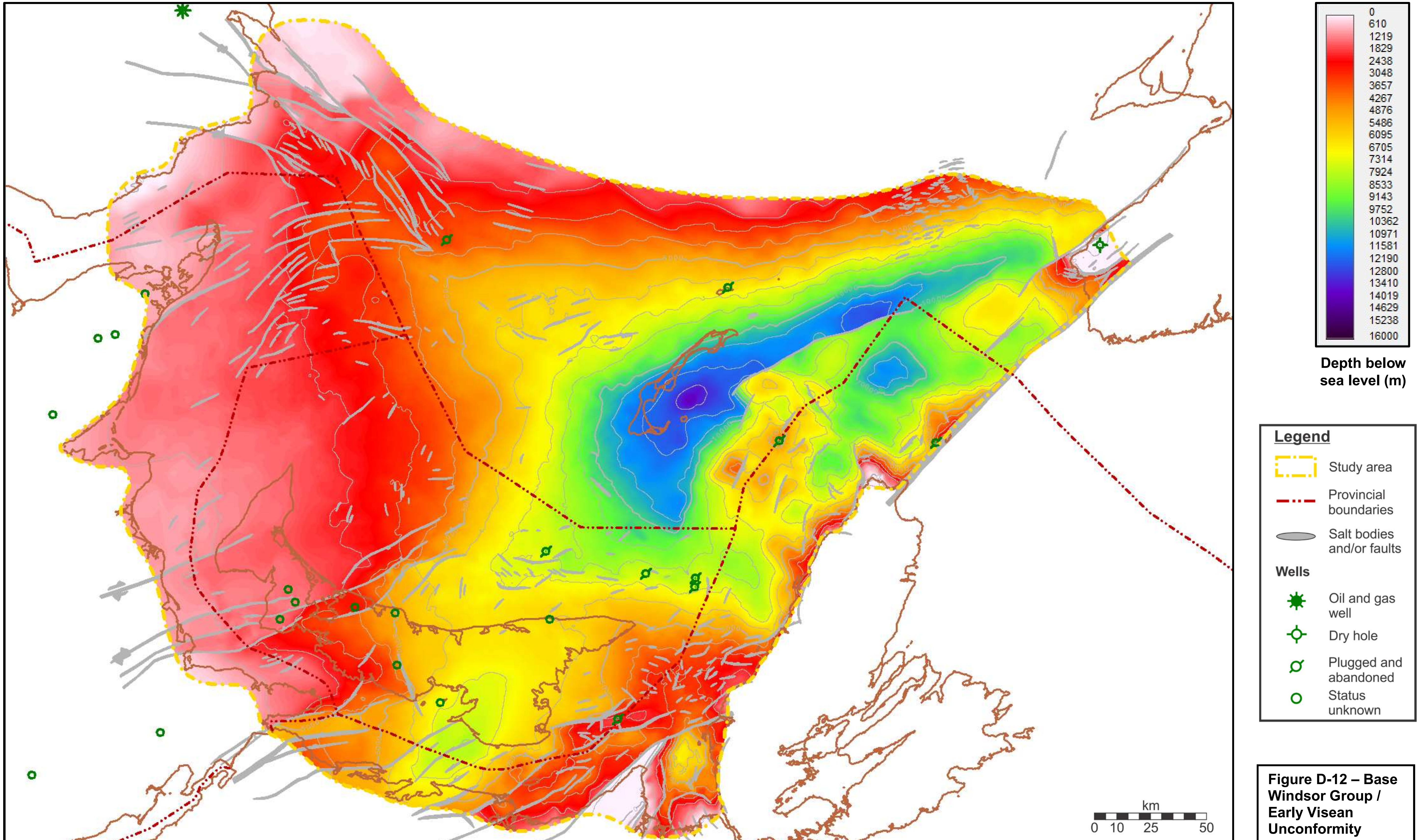


Figure D-12 – Base Windsor Group / Early Visean Unconformity

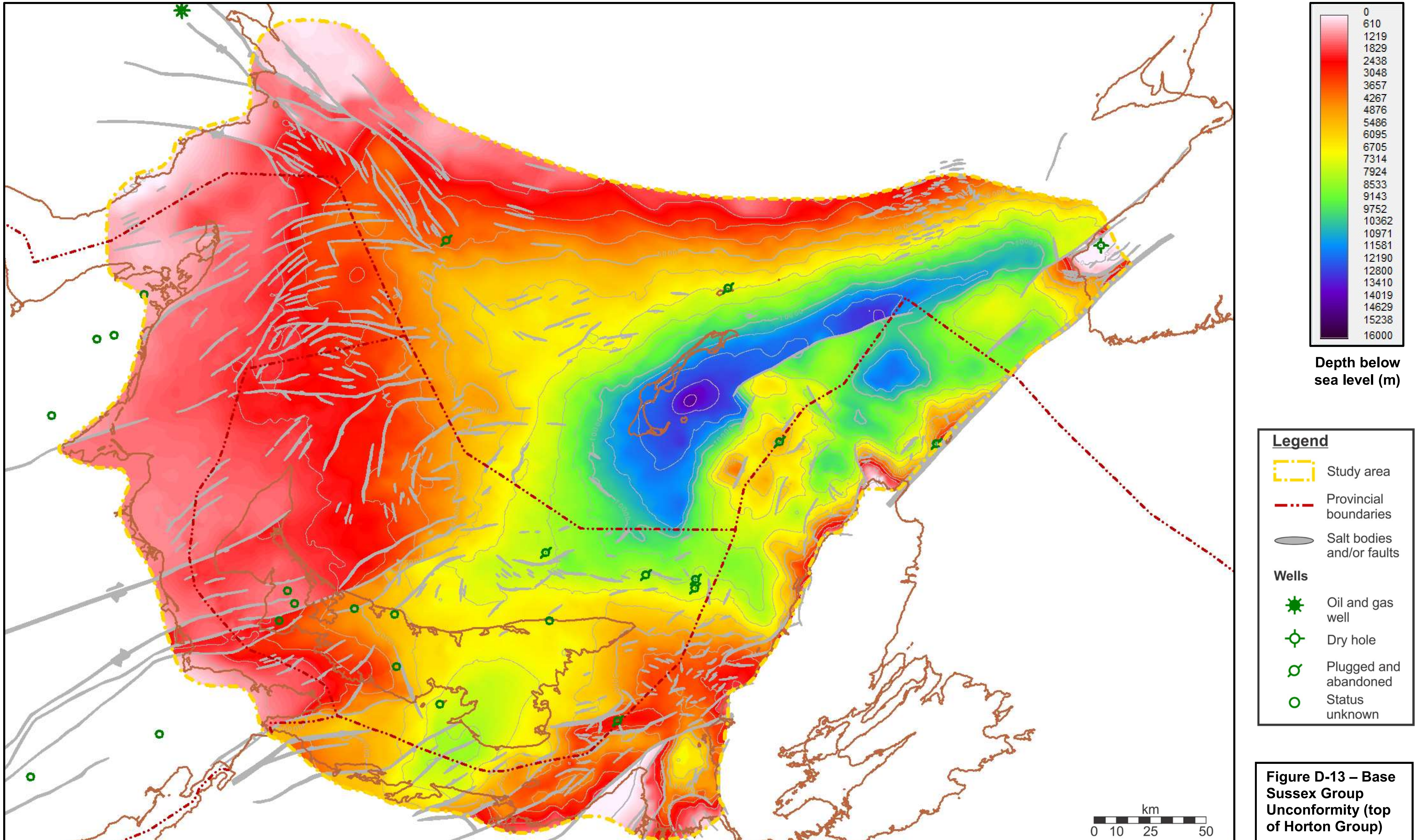


Figure D-13 – Base Sussex Group Unconformity (top of Horton Group)

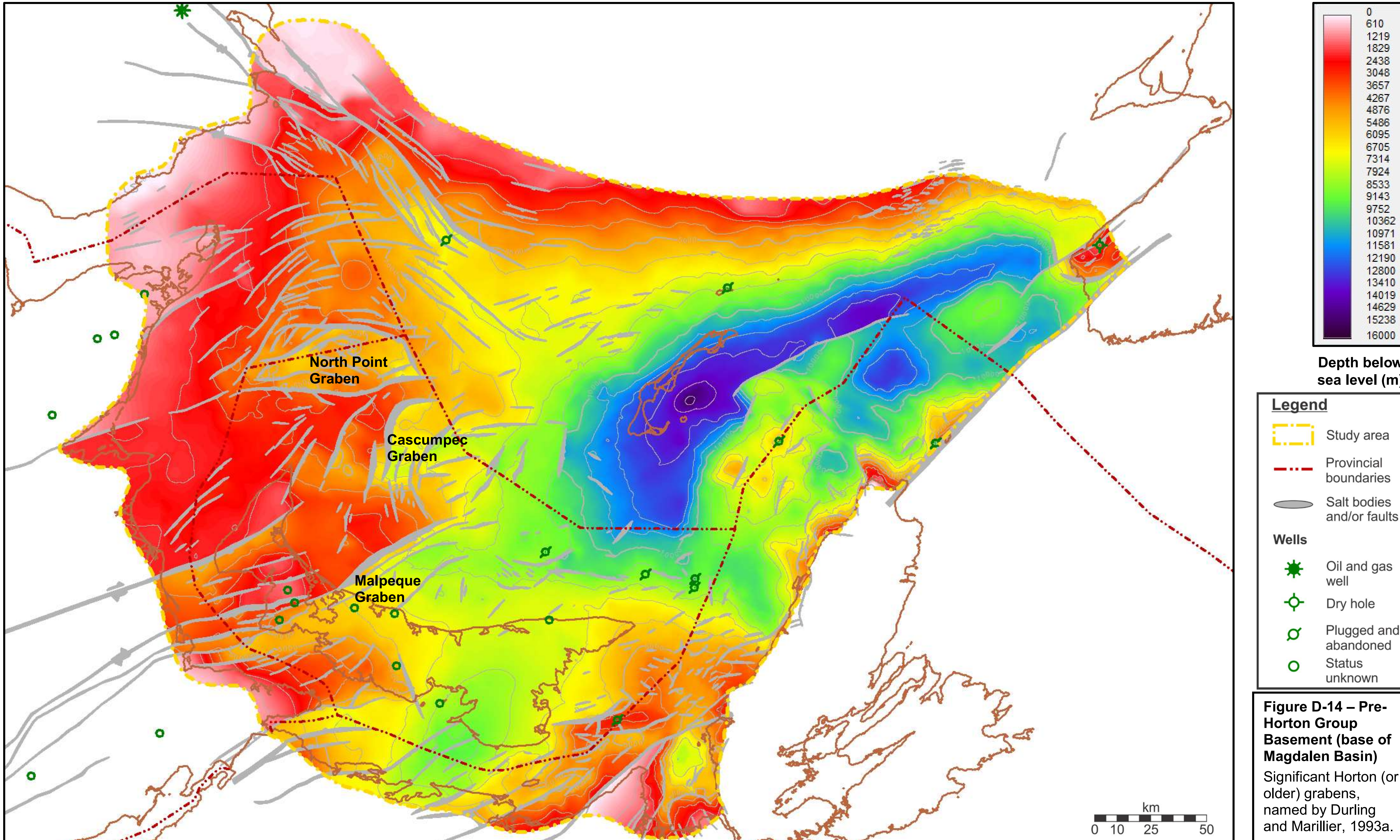


Figure D-14 – Pre-Horton Group Basement (base of Magdalen Basin)

Significant Horton (or older) grabens, named by Durling and Marillier, 1993a.

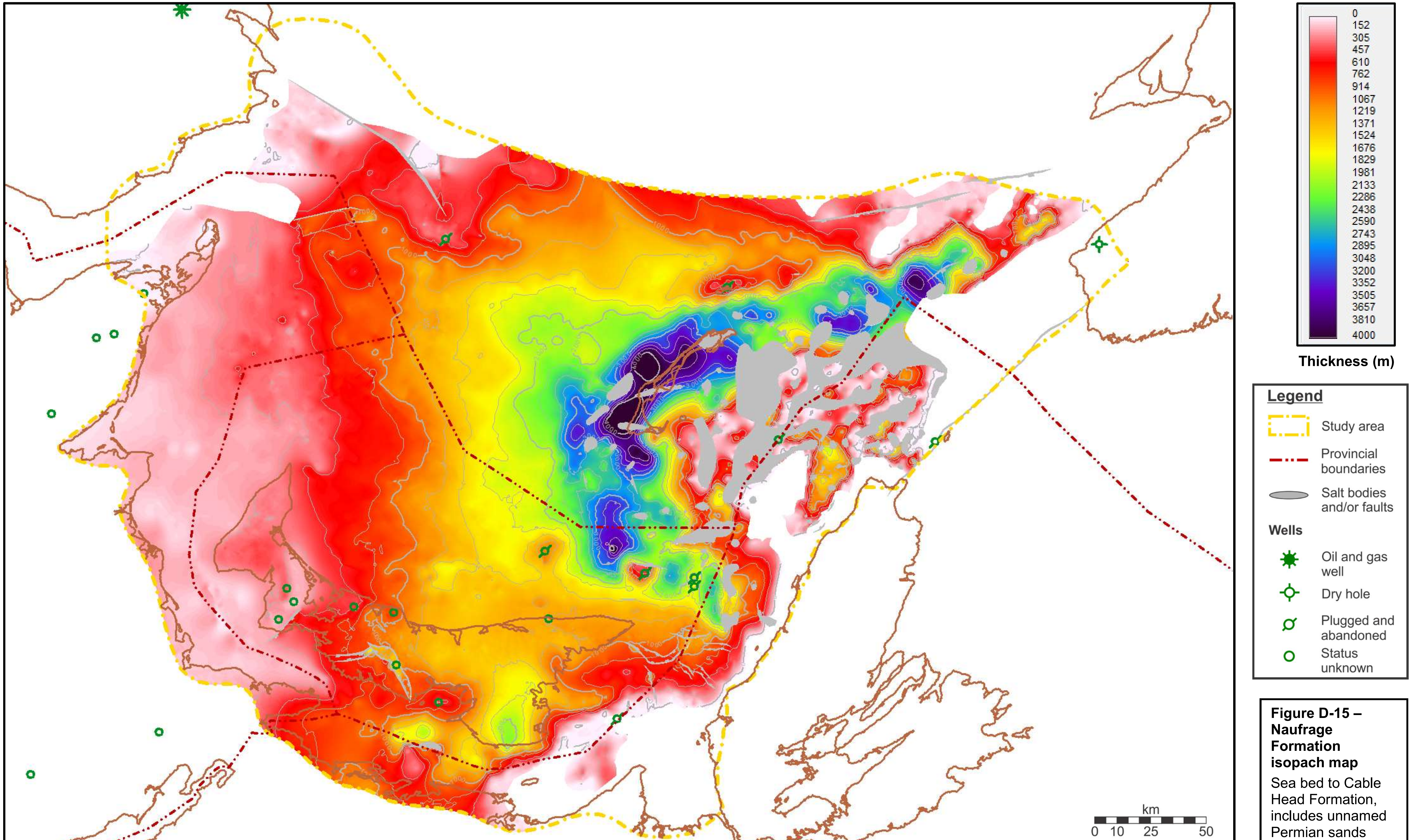


Figure D-15 – Naufrage Formation isopach map

Sea bed to Cable Head Formation, includes unnamed Permian sands

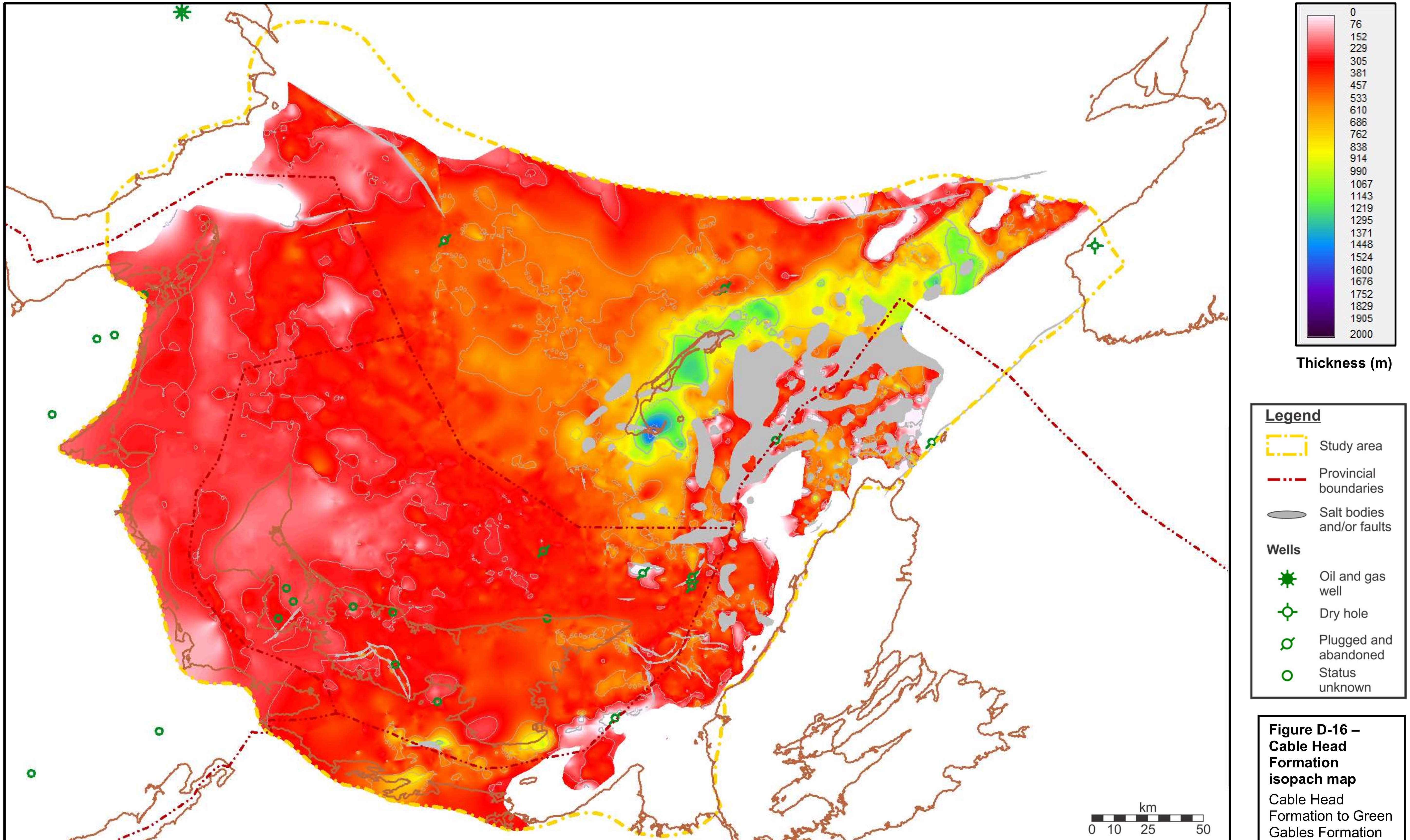


Figure D-16 – Cable Head Formation isopach map

Cable Head Formation to Green Gables Formation

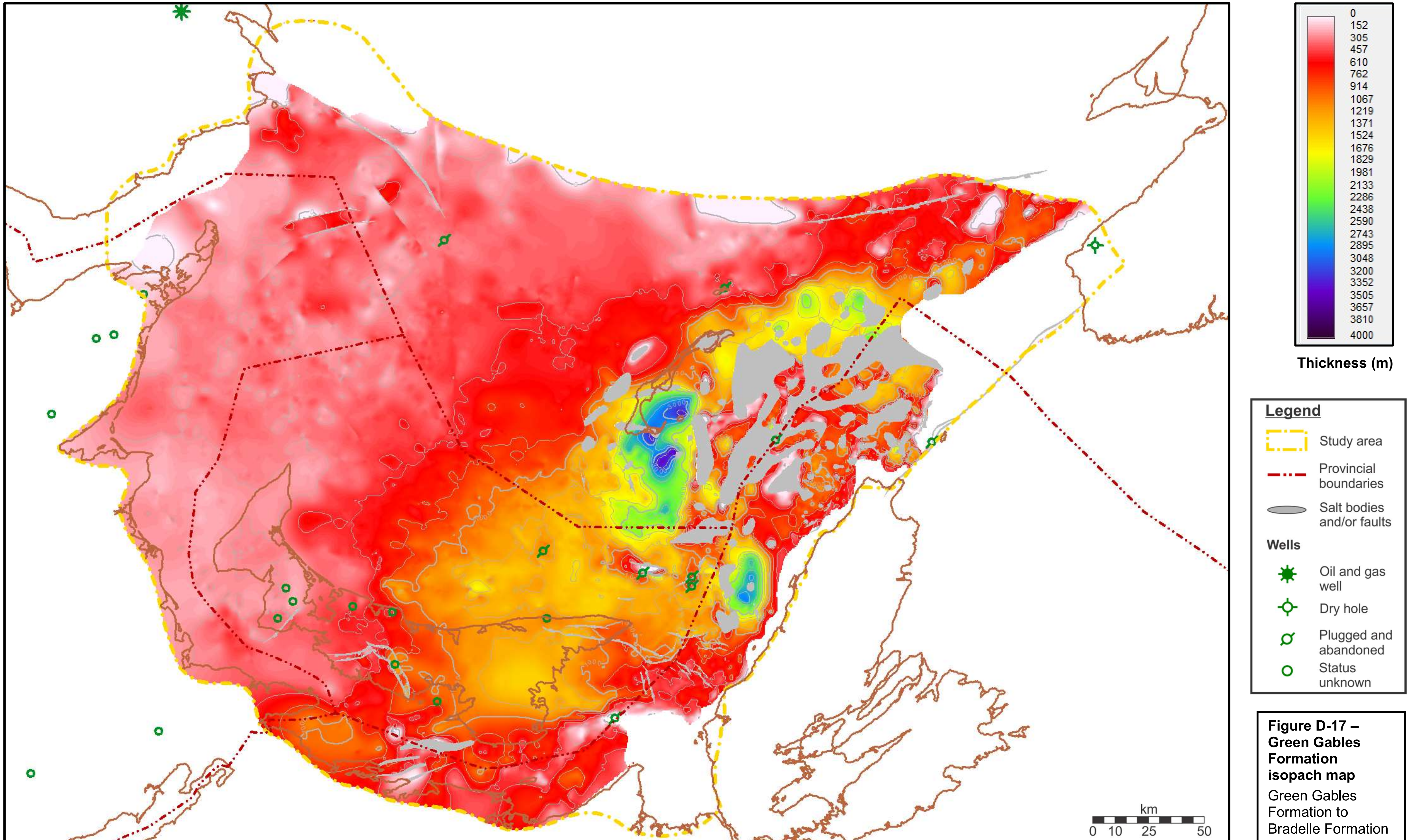


Figure D-17 – Green Gables Formation isopach map

Green Gables Formation to Bradelle Formation

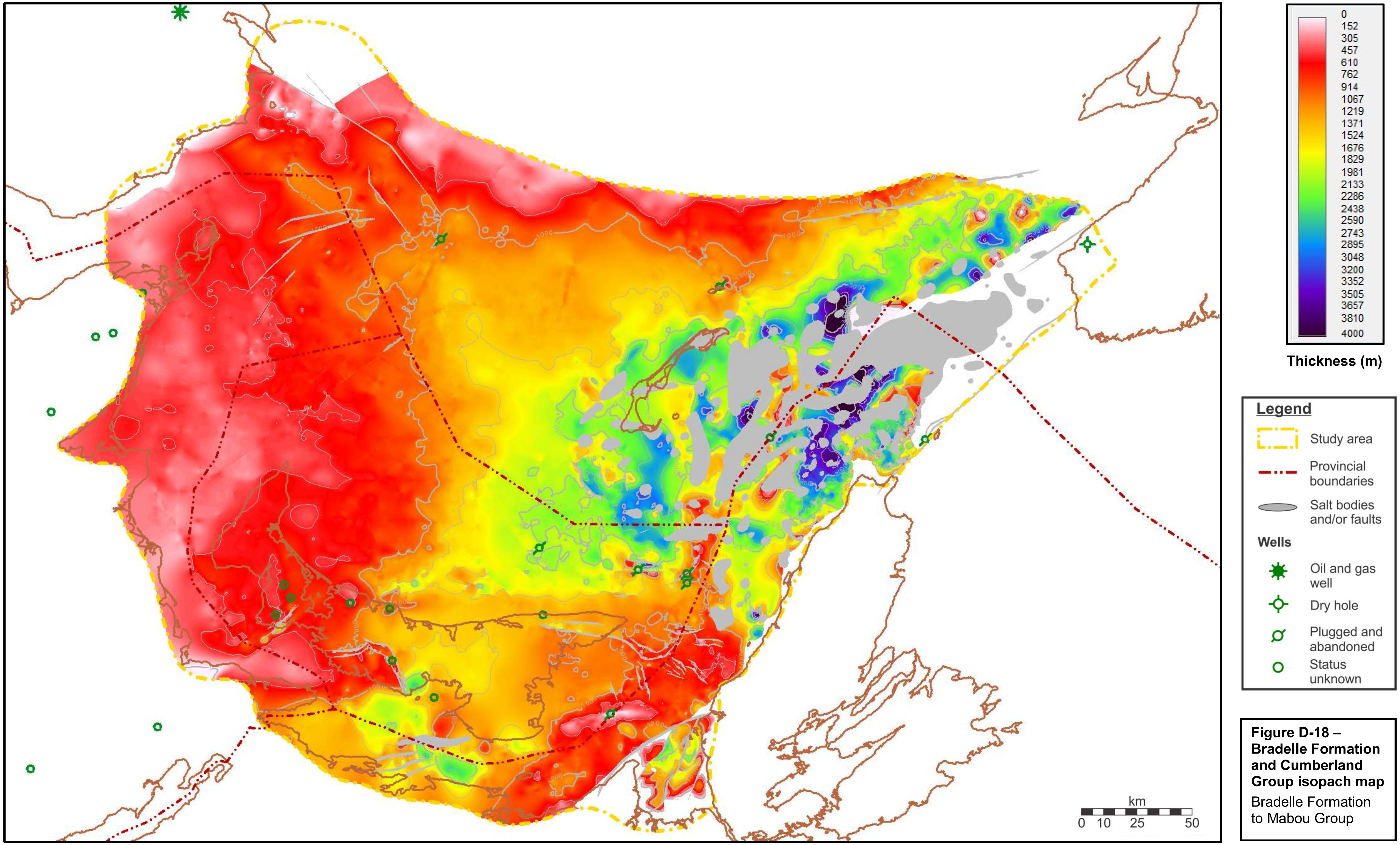


Figure D-18 – Bradelle Formation and Cumberland Group isopach map

Bradelle Formation to Mabou Group

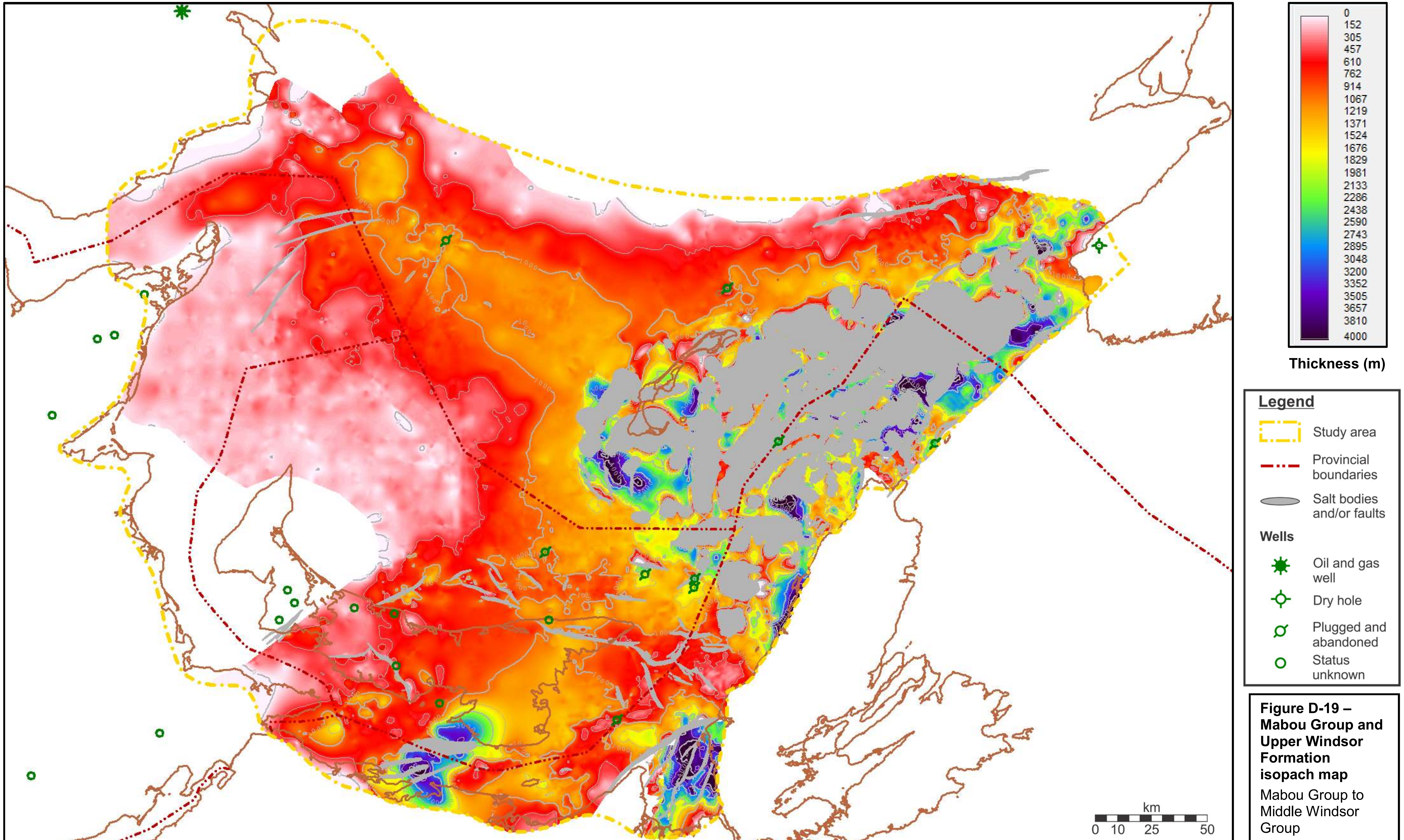


Figure D-19 – Mabou Group and Upper Windsor Formation isopach map

Mabou Group to Middle Windsor Group

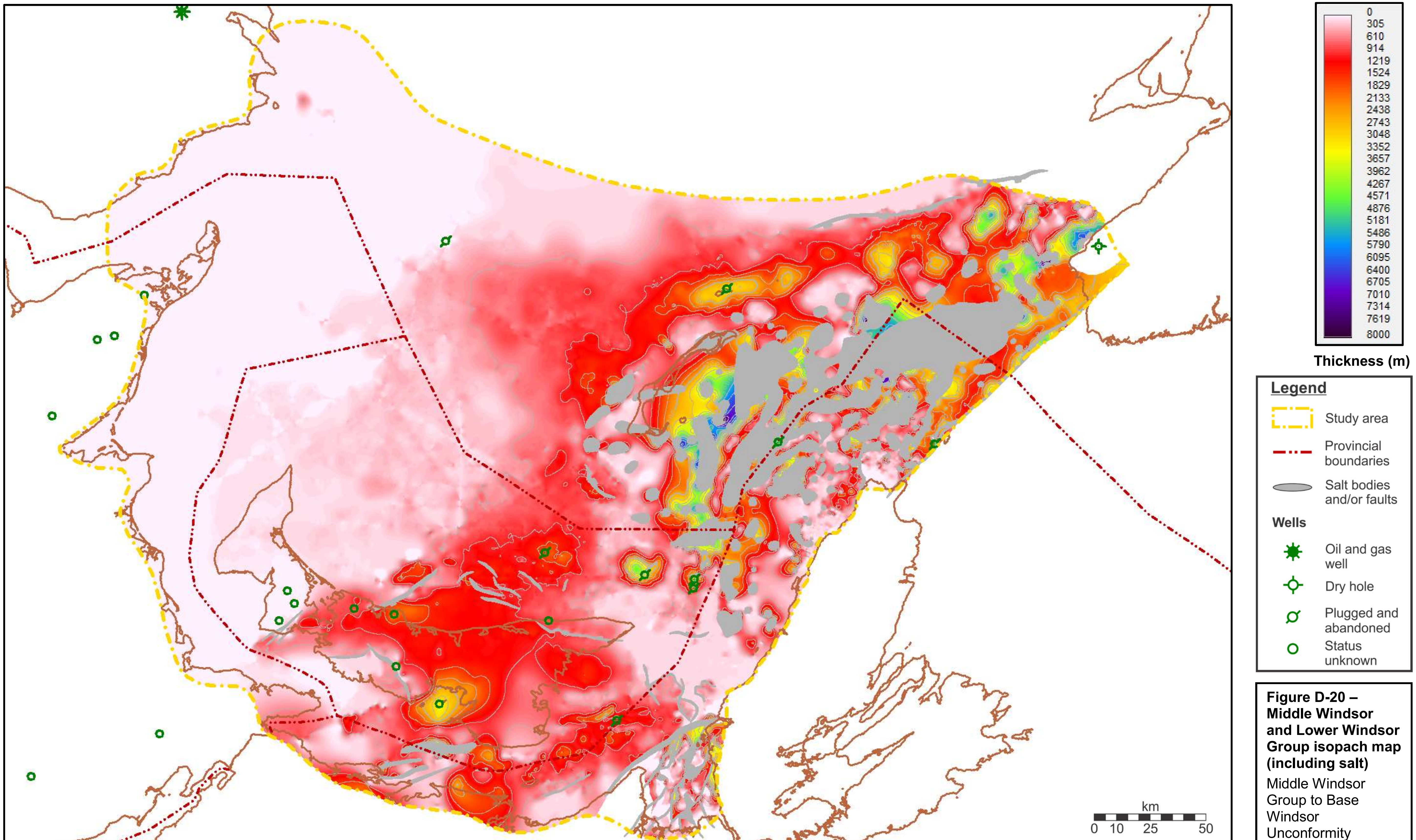


Figure D-20 – Middle Windsor and Lower Windsor Group isopach map (including salt)

Middle Windsor Group to Base Windsor Unconformity

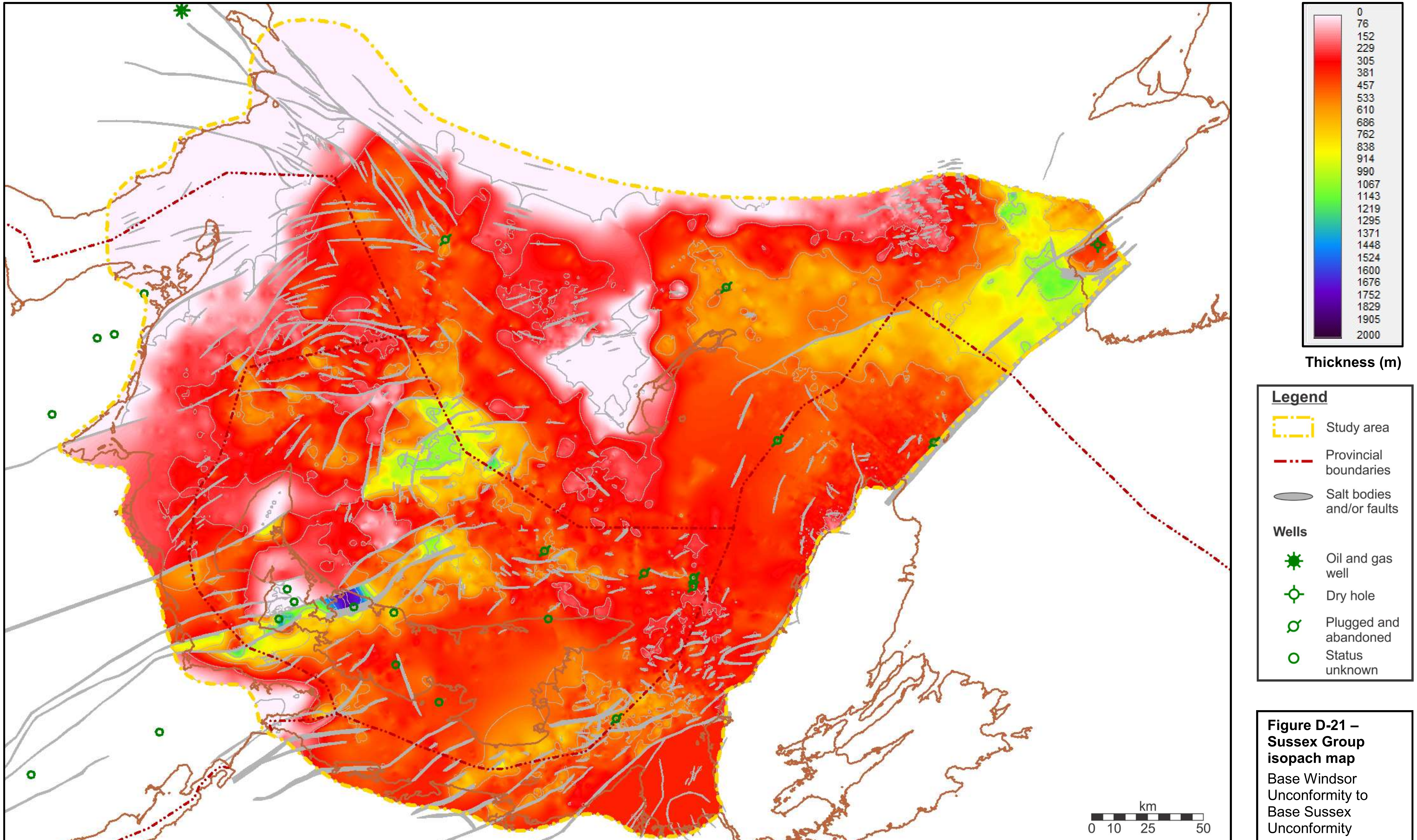


Figure D-21 – Sussex Group isopach map
Base Windsor Unconformity to Base Sussex Unconformity

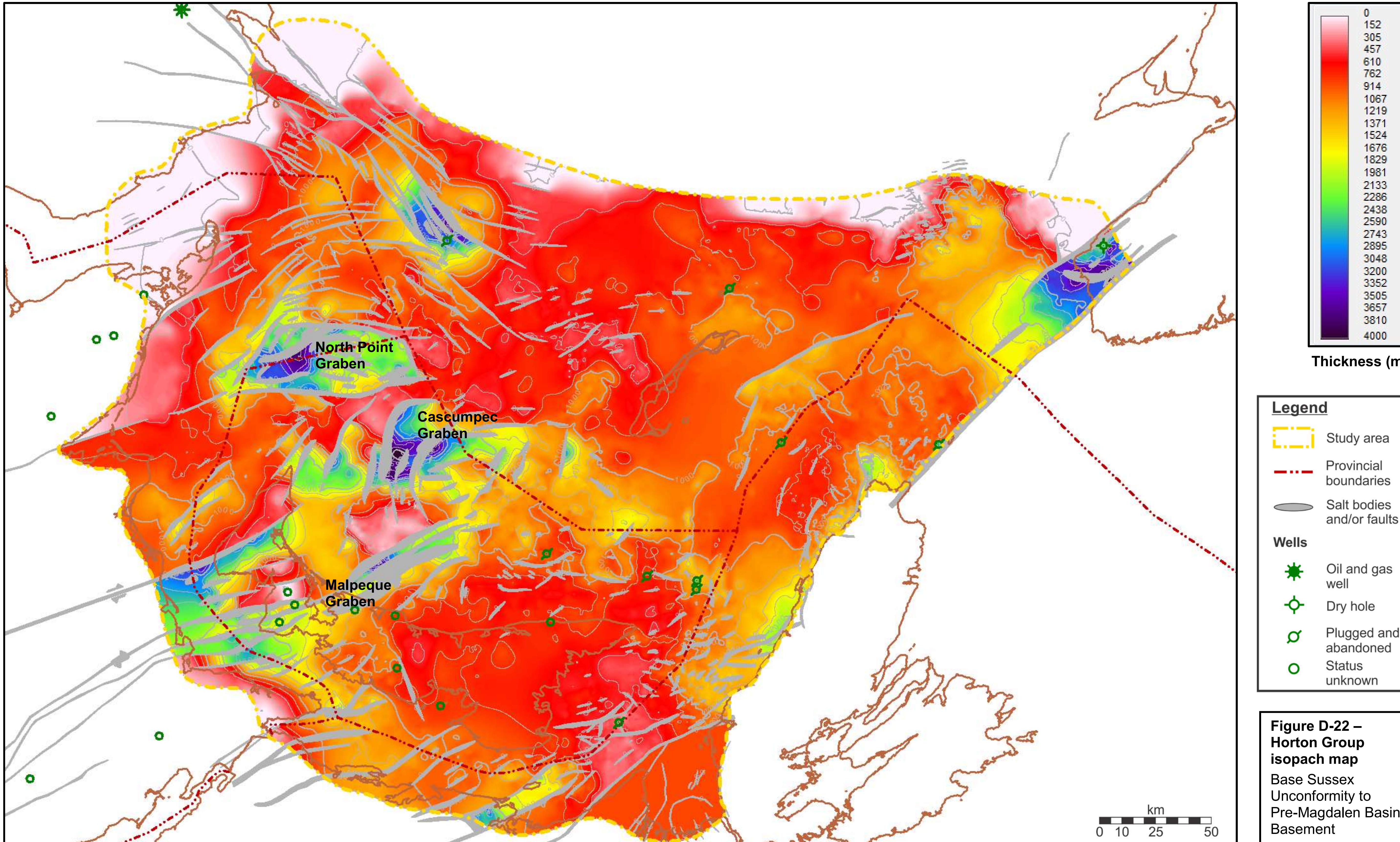


Figure D-22 – Horton Group isopach map

Base Sussex Unconformity to Pre-Magdalen Basin Basement

Seismic horizon interpretation, and ties to wells

Cable Head and Green Gables formations, unnamed Permian sands

Long, composite seismic transects comprising multiple seismic lines were constructed to correlate between the wells. Seismic correlations between four key wells (Cable Head E-95, East Point E-49, Bradelle L-49 and Brion Island No.1, Fig. D-1) provided a seismic-stratigraphic framework consistent with the interpretation of the wells (Giles and Utting, 1999, 2001, 2003).

The most reliable seismic marker for the upper Carboniferous stratigraphy was provided by the top of the Bradelle Formation (Giles and Utting, 1999, 2001, 2003). In general, the consistent seismic response of the top Bradelle horizon was widely recognized and facilitated the interpretation of horizons above and below the Bradelle horizon. The general approach used for interpretation of the horizons representing the Cable Head, Green Gables, and Bradelle Formations, and Mabou Group was to interpret the top Bradelle seismic horizon first, and then “flatten” the seismic data on the top Bradelle horizon. This flattened seismic section revealed sub-horizontal reflections that allowed the interpreter to discern and correlate subtle seismic events, especially in areas of poor seismic data quality. This method proved useful in distinguishing between primary reflections and water bottom generated noise, such as multiples and seabed reverberation. One caveat of this method is the tendency of the interpreter to interpret seismic noise as weak seismic events. In the poorest data quality areas where interpretations were deemed suspect, the interpreter used regional thickness relationships to guide the interpretation.

The Cable Head and Green Gables horizons were mapped concurrently because these two events bracket the top and bottom of the sand dominated Cable Head Formation (Giles and Utting, 1999). Correlation of seismic reflection data to the Cable Head E-95 and East Point E-49 wells show that the Cable Head Formation corresponds to 2 to 3 reflections that are generally higher amplitude than reflection packages above and below (Fig. D-23). The top Cable Head horizon was interpreted at the top of this package and the Green Gables horizon at the base.

North and west of the Brion Island No.1 well, the Cable Head Formation generally corresponds to low amplitude reflections, and is overlain by moderate amplitude reflections in synclinal troughs between salt structures. The top Cable Head and top Green Gables horizons in this area do not have a unique reflection character and were interpreted as phantom horizons (horizon interpretation that is parallel to adjacent reflections to indicate structural attitude where a single reflection event is not continuous enough to be used alone). A similar methodology was used in the northeastern part of the basin. There is low confidence on the Green Gables and Cable Head markers in these areas. However, on the southeast side of the Brion Island structure the Green Gables and Cable Head horizons were interpreted above and below a package of relatively higher amplitude reflections, consistent with higher confidence seismic mapping elsewhere in the basin.

Southeast of PEI in Northumberland Strait, some seismic lines have severe mutes, up to 500 ms, and the Cable Head and Green Gables horizons are not imaged. The depth of these horizons in this area was based on regional isopach data. The Cable Head and Green Gables horizons are speculative in this area. On those lines where the seismic data was not muted, the Cable Head and Green Gables horizons were interpreted as phantom horizons. Similarly, in the northwestern part of the basin, the Green Gables and Cable Head horizons are mainly phantom horizons because these markers are shallow (up to 600 ms) and strong water bottom reverberation in this area commonly obscures shallow primary reflections. The strata in this area are not deformed and seismic transects tied to the wells provided for an interpretation that honours the well data.

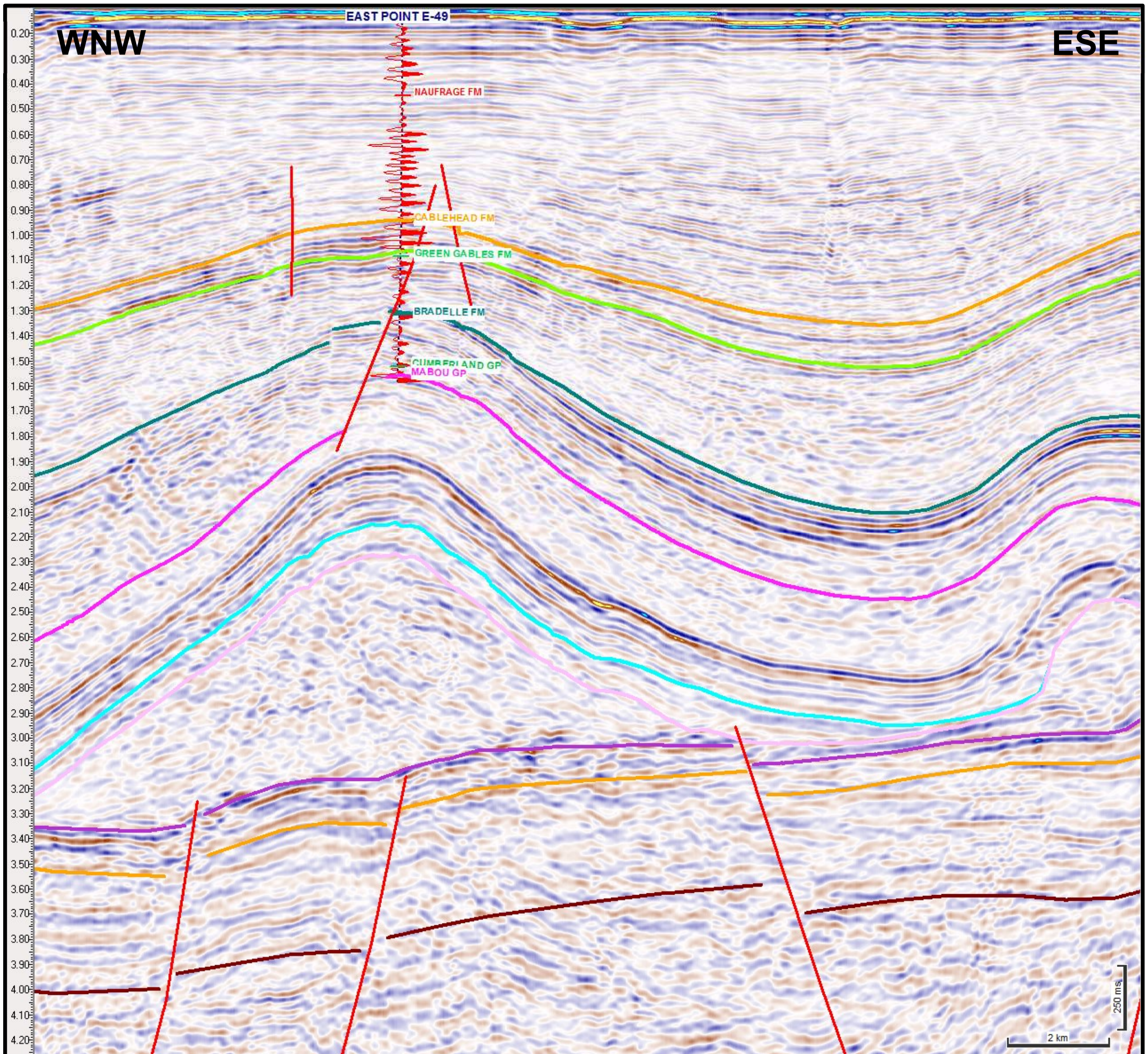


Figure D-23 – East Point E-49 well tie

Regional seismic line Lithoprobe 86-1, ~2:1 vertical exaggeration. Example of seismic character of Cable Head, Green Gables, and Bradelle Formations and Mabou Group, and salt-cored anticline and adjacent salt weld. Horizon colour legend – Figure 4.

Onshore western PEI the seismic data display a seismic character with more uniform reflectivity than eastern PEI and the offshore area. For example, the amplitude of reflections in the Cable Head, Green Gables and Bradelle formations was similar. The onshore wells (Fig. D-1, Giles and Utting, 1999) provided adequate control to provide confident seismic interpretation between the wells.

In general, the Cable Head and Green Gables horizons were not mapped in the salt diapir area, but were assumed to present, where appropriate, on the basis of regional isopach data.

The Base Permian Sands horizon corresponds to the top of the Naufrage Formation (Giles and Utting, 1999). In the offshore area the seismic horizon was correlated with the top

Naufrage Formation marker in the East Point E-49 well and the Cable Head E-95 well. The Base Permian Sands seismic horizon is best developed near the Magdalen Islands in deepest part of the Magdalen Basin. In this area the seismic marker corresponds to the contact between low amplitude, continuous to discontinuous reflections above the marker to discontinuous to chaotic reflections below. A regional depth map was not created for this horizon, but it was used to create a polygon outlining where the Permian sands may be a valid reservoir, trapped under salt canopies.

Bradelle Formation

As described above, composite seismic transects comprising multiple seismic lines were constructed to correlate between four key wells (Cable Head E-95, East Point E-49, Bradelle L-49 and Brion Island No.1, Fig. D-23 and D-24). Correlation between these wells using the seismic data resulted in a high confidence correlation of the top Bradelle Formation stratigraphic

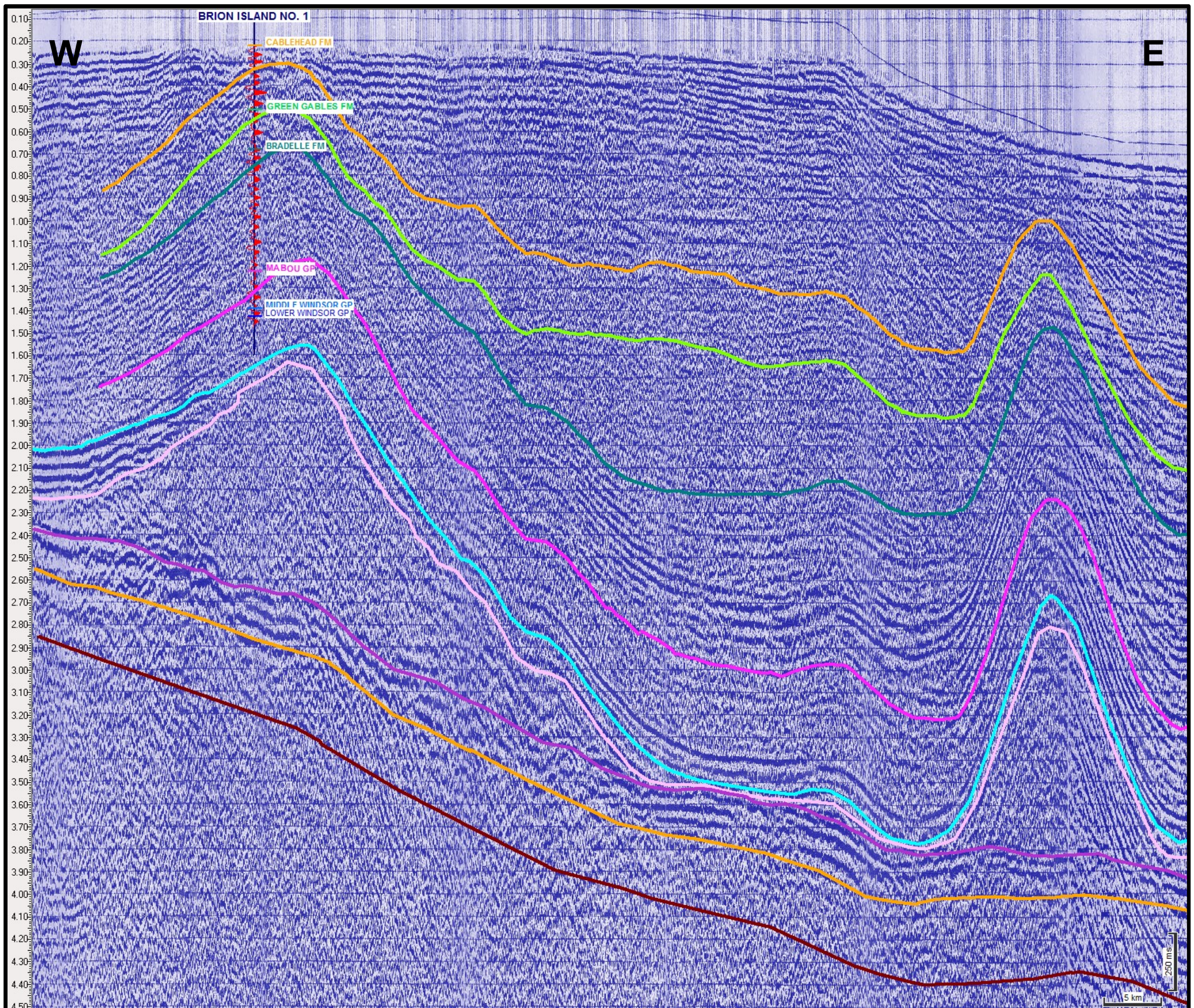


Figure D-24 – Brion Island well tie and salt structures

Projected onto regional seismic line E-7 (courtesy Exxon Mobil). ~8:1 vert.ex. Horizon colour legend – Figure 4. Illustrates tie to Bradelle package and salt-cored anticline structures.

marker, which correlates to the top of a thick (up to 800 ms), high amplitude seismic unit. Grant (1994) referred to this high amplitude reflection package as the "Coal Measures". He argued that the interbedded and variable thickness of coal, sandstone and mudstone results in reflections of variable amplitude and continuity where no one reflection can be traced for long distances. However, this study shows that the top of this reflection package can be mapped with confidence between four wells as described above. A fifth well (Beaton Point F-70) ties the seismic line upon which it was drilled, but generally yields a poor well tie due to the location of the well on a steep sided, salt-cored fold.

The top of the Coal Measures seismic package (Bradelle horizon) is remarkably persistent and can be mapped confidently between the 2000 and 4000 metre contours (Fig. D-8, Top Bradelle Formation depth map) in most areas north and west of the salt diapir area, onshore PEI, and in Northumberland Strait. In the extreme northeastern part of the basin, the Bradelle horizon is truncated by the seabed unconformity, consistent with the interpretation of Grant (1994). In the western part of the basin to the west of the 2000 m contour (Fig. D-8) the seismic amplitude contrast between the Bradelle and Green Gables formations decreases and mapping of the Bradelle horizon was lower confidence in this area. Similarly, the seismic data east of the New Brunswick coastline were processed using aggressive mutes (up to 500 ms) and the Bradelle horizon was mapped by honouring isopach information from the onshore wells (Bartibog and St. Isidore wells).

Mapping of the Bradelle horizon in the salt diapir area is somewhat conjectural since the Bradelle Formation was not encountered in any wells in this area. However, a package of high amplitude reflections occurs in a broad syncline offshore from Pleasant Bay, Cape Breton Island that is of similar thickness and seismic character to the Bradelle seismic unit mapped to the west (Fig. D-25). Mapping of this reflection package to the east shows that these rocks sub-crop and are younger than the Mabou Group, which occurs at the seabed in the St. Paul P-91 well (Fig. 3, Fig. D-26). The high amplitude reflection package (Fig. D-25) was speculatively correlated with the Bradelle seismic unit and the top of this package was mapped as the Bradelle horizon.

Mabou Group

Rocks corresponding to the Mabou seismic horizon were intersected in the Bradelle L-49, Brion Island No.1 and East Point E-49 wells, as well as several onshore PEI wells. The horizon marks the boundary between a reflection poor interval on the seismic reflection data and the overlying high amplitude seismic reflection package interpreted in this report as the Bradelle seismic unit. It is noted that the Bradelle seismic unit used in this report comprises two lithostratigraphic units: the Bradelle Formation and the Port Hood Formation (Giles and Utting, 1999). In general, the Mabou horizon corresponds to the base of the Bradelle high amplitude seismic unit (base of the Port Hood Formation), which roughly corresponds to the Coal Measures seismic package of Grant (1994). This boundary is interpreted to be transitional based on the absence of persistent seismic reflections; the seismic character at this boundary is highly variable and interpretation of the Mabou horizon is considered approximate. Mapping of the Mabou horizon was facilitated by "flattening" the seismic sections on the Bradelle seismic horizon, as described above.

In Northumberland Strait between PEI and Cape Breton Island, tracing the top Mabou horizon on the seismic data was complicated by the presence of numerous extensional faults, which appear to sole into the Windsor Group and generally do not involve basement. However, the amplitude contrast between the Bradelle seismic unit and the underlying reflection poor interval was recognized on most seismic lines. Further west where the Cumberland Basin extends offshore into Northumberland Strait, the seismic amplitudes decrease in the lower part

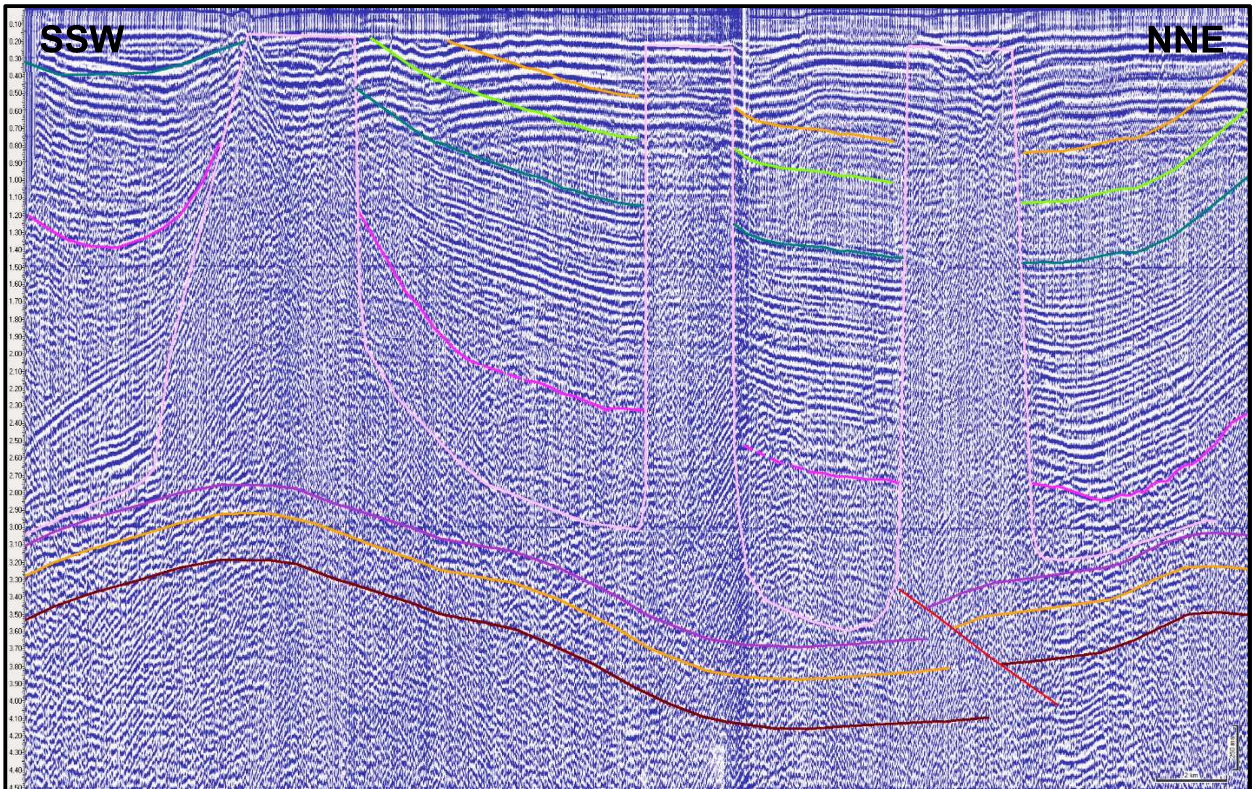


Figure D-25 – Seismic character in salt province

Seismic line S006_4840 (courtesy Shell). Illustrates examples of salt walls and Bradelle package (dark green) in salt mini basins. ~2:1 vert.ex. Horizon colour legend – Figure 4.

of the Bradelle seismic unit resulting in lower confidence on the interpretation of the Mabou seismic horizon.

Giles and Utting (1999) show the Bradelle Formation resting directly on Windsor Group in the Port Hill No.1 well, located in northwestern PEI. Similarly, seismic data offshore northwestern PEI show onlap of the Bradelle high amplitude seismic facies onto reflections interpreted as Windsor Group (Fig. D-27). These seismic relationships are consistent with the interpretation of the Port Hill No. 1 well. However, in the vicinity of the North Point Basin the seismic data indicate that there was likely a low area over the North Point Basin during deposition of the Mabou Group. Up to 200 m of Mabou Group rocks maybe present in this area. To the west and onshore in northeastern New Brunswick, the Bartibog and St. Isidore wells (Rehill, 1996) show the Mabou Group to be absent, similar to the Port Hill No.1 well (Utting and Giles, 1999).

The interpretation of the Mabou horizon is speculative in the salt diapir province. The two wells drilled in this area (Cap Rouge F-52 and St. Paul P-91) collared in the Mabou Group, and by definition, the Mabou seismic horizon would occur stratigraphically higher than the shallowest rocks in these wells. The Mabou horizon was interpreted at the base of the high amplitude seismic unit in the salt diapir province (Fig. D-25) consistent the interpretation of the Mabou horizon elsewhere in the basin.

The St. Paul P-91 well was drilled on the southeastern margin of the basin adjacent to the offshore extension of the Aspey Fault. Revised lithostratigraphic assignments in the well (Nova Scotia Department of Energy and Offshore Energy Research Association, 2017) show that the well collared in the Mabou Group. The Mabou seismic horizon interpreted in the salt diapir area

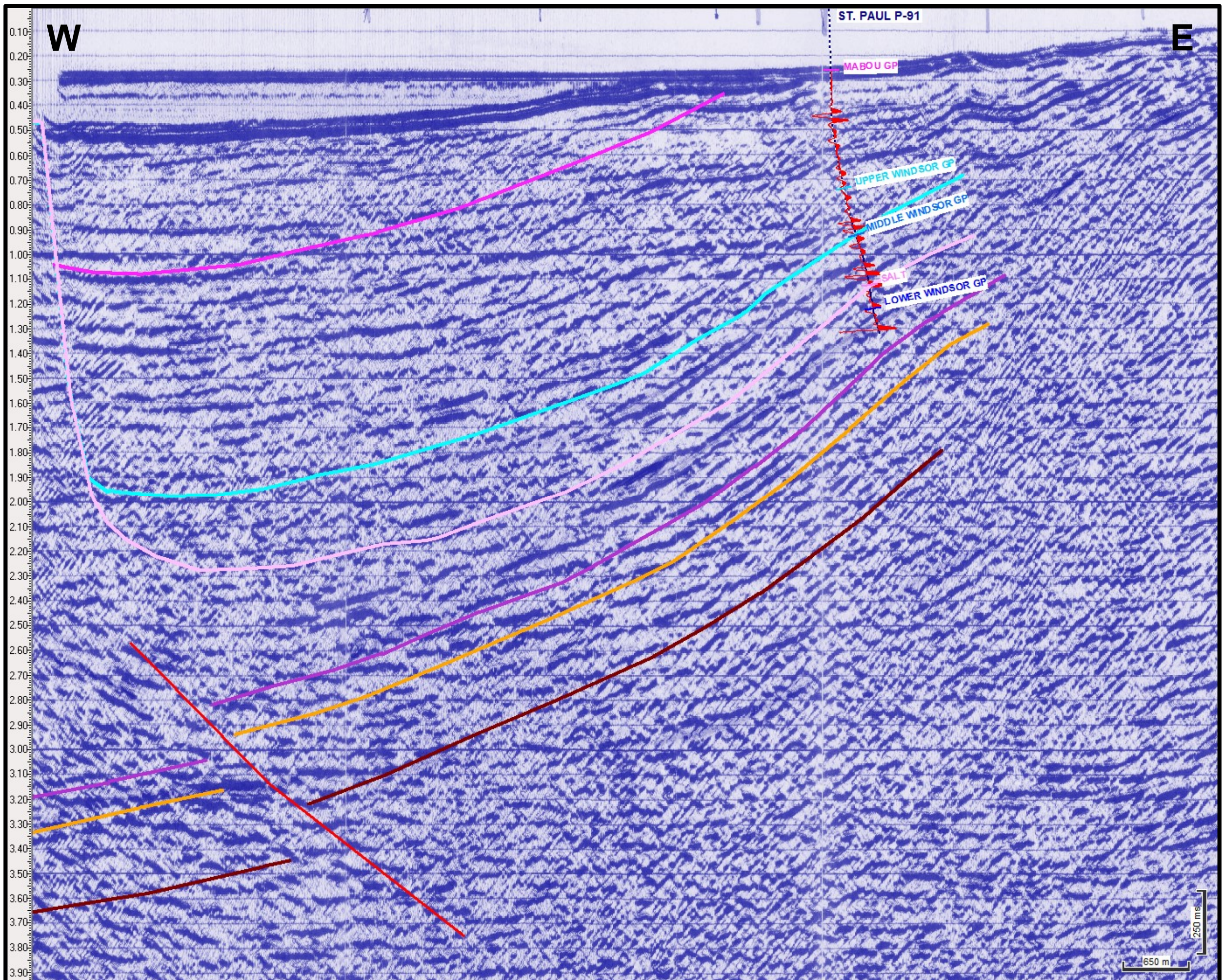


Figure D-26 – St. Paul P-91 well tie
Seismic line P028_4076-83 (courtesy Suncor), ~1:1 vert. ex. Horizon colour legend – Figure 4.

(Fig. D-25) subcrops to the north and west of the St. Paul P-91 well (Fig. D-26), consistent with the well interpretation. Interpretation of the Mabou horizon is speculative in the area northeast of the well. In a subbasin identified as the Searston Graben (Langdon and Hall, 1994), the Mabou horizon was interpreted at the top of reflection poor seismic unit and the bottom of a seismic unit displaying continuous reflections, analogous to the top Mabou horizon mapped in other parts of the basin. The reflections above the Mabou horizon are interpreted in this report as Bradelle Formation equivalents. The Mabou horizon interpreted in this report approximately corresponds to the Windsor-Codroy event mapped by Langdon and Hall (1994).

Middle Windsor

Windsor Group rocks are intersected in several wells; however, most of these wells intersected incomplete Windsor Group sections or basin margin facies. The Northumberland Strait F-25 well intersected a complete Windsor Group section. Figure D-28 shows the well tie from the F-25 well to seismic line 81-83-11F, where the Middle Windsor Group is represented by three high amplitude reflections. This characteristic reflection signature is recognized on most seismic reflections profiles in the deeper parts of the basin outside the salt diapir province.

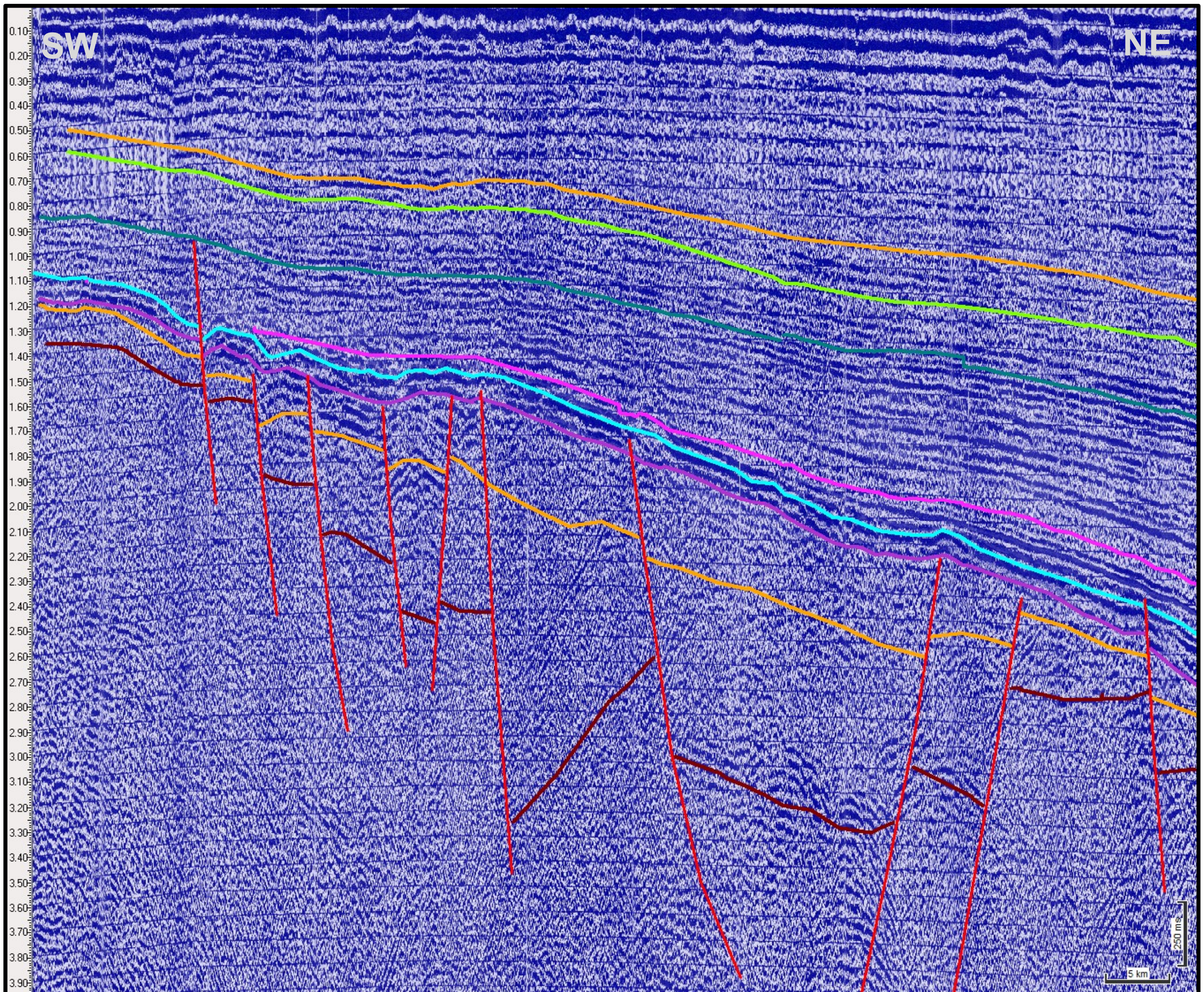


Figure D-27 – Onlap of Upper Carboniferous stratigraphy onto Windsor Group
Seismic line 81-14-11M (courtesy Chevron), ~8:1 vert. ex. Horizon colour legend – Figure 4.

Around the perimeter of the salt diapir province, the Middle Windsor horizon downlaps onto the basal Windsor unconformity forming an apparent salt weld (See Fig. D-23 for example). The Middle Windsor reflections onlap the basal Windsor Group unconformity on the offshore extension of the New Brunswick platform and the western part of the northern basin margin (Fig. D-27). To the east of the Brion Island No.1 well, the limit of the Middle Windsor horizon is marked by a listric normal fault that soles into the lower Windsor Group salt. This fault forms the northern limit of the Old Harry structure.

The reflections typical of the Middle Windsor Group were rarely recognized in the salt diapir province and it was assumed that stratified middle and upper Windsor strata are present, but were deformed by salt tectonics and not imaged on the seismic data. See the section on the Top Salt Horizon for a more detailed discussion of salt structures.

Durling et al. (1995b) and Durling and Harvey (1996) had more data available in the St. George's Bay (between mainland Nova Scotia and Cape Breton Island), and they published a detailed map of Top Windsor there. Thus, their map was used to constrain, by isochron, the Middle Windsor and Top Salt picks in this subbasin.

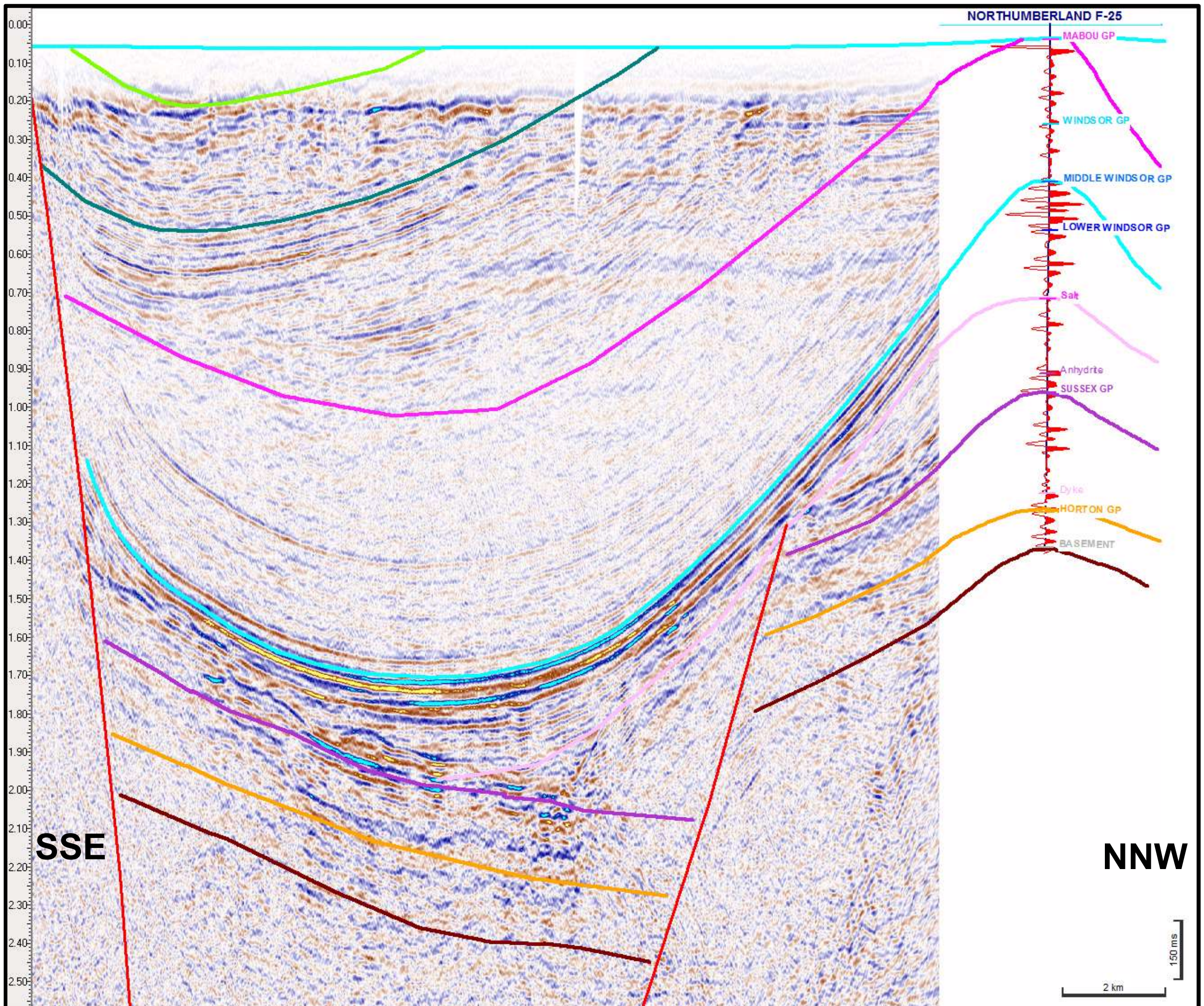


Figure D-28 – Northumberland F-25 well tie

Seismic line C004_81-83-11F (courtesy Chevron), approximately 3:1 vertical exaggeration. Horizon colour legend – Figure 4. Jump tie of seismic character and Windsor, Sussex, Horton and Basement formation tops.

The Windsor Group in the St. Paul P-91 well is characterized by a clastic dominated succession; the top of the Middle Windsor was reported at approximately 1765 m. Low amplitude discontinuous reflections (Fig. D-26) correspond to the Middle Windsor horizon, which were mapped with difficulty away from the well due to structure and salt diapirs. To the west of the well, the horizon cannot be traced near salt diapirs and the Top Salt horizon was used as a proxy. To the northeast of the St. Paul well the horizon is speculative due to poor data quality and complex structure. However, reflections with a similar character to the Middle Windsor horizon in the western part of the basin were observed in a subbasin located north and east of St. Paul Island (Searston Graben of Langdon and Hall, 1994). These reflections were identified on most seismic lines in the Searston Graben and provided some confidence in the seismic interpretation in this part of the basin.

Top Salt

The Top Salt horizon was intersected in the Irishtown No.1 (onshore PEI), Brion Island No.1, and Northumberland Strait F-25 wells. The wells were drilled on salt structures where the salt thins laterally to salt welds. The top salt horizon was interpreted at the base of the high-amplitude, Middle Windsor reflection package and at the top of a chaotic reflection package interpreted as Windsor Group salt.

In most areas the Windsor Group salt is interpreted to be less than 500 m thick and it thickens locally into salt pillows and diapirs. The diapirs were interpreted as steep-sided near-vertical structures where seismic reflections are absent, and adjacent to observed reflections indicating stratified rocks (Fig. D-25). It is recognized, however, that the structure of the salt diapirs is likely far more complicated. Many of the diapirs resemble those imaged in Figure D-25, where parallel-stratified reflections terminate against the near-vertical salt-sediment interface. These structures likely represent tear-drop shaped salt bodies located at the top of the near-vertical column, with strata folded upward to form a vertical salt weld beneath the salt mass (Hudec and Jackson, 2007). The appearance of the salt diapirs as near vertical columns on the seismic data is due the imaging limitations of the vintage seismic data (limited far offset data, for example). Some diapirs in the study area exhibit reflections that converge or diverge away from the salt mass suggesting differential subsidence associated with salt evacuation and mini-basin development (Hudec and Jackson, 2007). The largest salt bodies (see “Salt Massif” in Fig. D-11, for example) likely represent allochthonous salt or salt canopies.

Seismic data near the Cap Rouge F-52 well provides some insight to the structure at the well location. A complete Windsor Group section was intersected in the Cap Rouge well (Giles and Utting, 2001). However, adjacent seismic profiles show steeply dipping and chaotic reflections at the well location, suggesting that the well drilled through a salt structure. The Malagawatch salt deposit (Giles, 2003) from Cape Breton Island may provide an analogue for the internal structure of the salt structure at the Cap Rouge well. At Malagawatch the Windsor Group evaporite strata are complexly folded and we speculate that seismic data over the structure, if available, would show chaotic reflections. However, intact blocks of dipping strata are observed on fold limbs, perhaps analogous to the section encountered at the Cap Rouge well. The absence of seismic reflections at the Cap Rouge well suggests complexly folded strata or strata dipping more steeply than can be resolved by the seismic data (approximately 45°), not unlike the Malagawatch deposit (Giles, 2003).

Base Windsor Group unconformity

The Base Windsor Group unconformity is encountered in seven wells within the study area (including four onshore PEI), and is consistently found to correlate with a strong reflection, which is often the top of a distinct package of moderately strong reflectors. A good example of this tie is the Bradelle L-49 well, which is shown projected onto Lithoprobe line 86-2 in Figure D-29. Here the unconformity as picked by Giles and Utting (2003) correlates to a strong trough at the top of the package of strong reflectors. A similar correlation can be made from Irishtown No.1 and Northumberland F-25 (Fig. D-28), and the same character is noted at Wellington No.1 and Port Hill No.1. This package can be followed between these wells with good confidence, and into many parts of the basin.

In deeper parts of the basin, strong reflectors representing the Middle Windsor Group strata overlie this Base Windsor Group unconformity. These reflectors onlap onto the unconformity toward the New Brunswick platform and northern basin margin (Fig. D-27) and downlap onto it around the perimeter of the salt province (see above). These geometries also help identify the unconformity surface.

A detailed map of the Base Windsor Group unconformity in St George’s Bay (between mainland Nova Scotia and Cape Breton Island) was published by Durling et al. (1995b) and

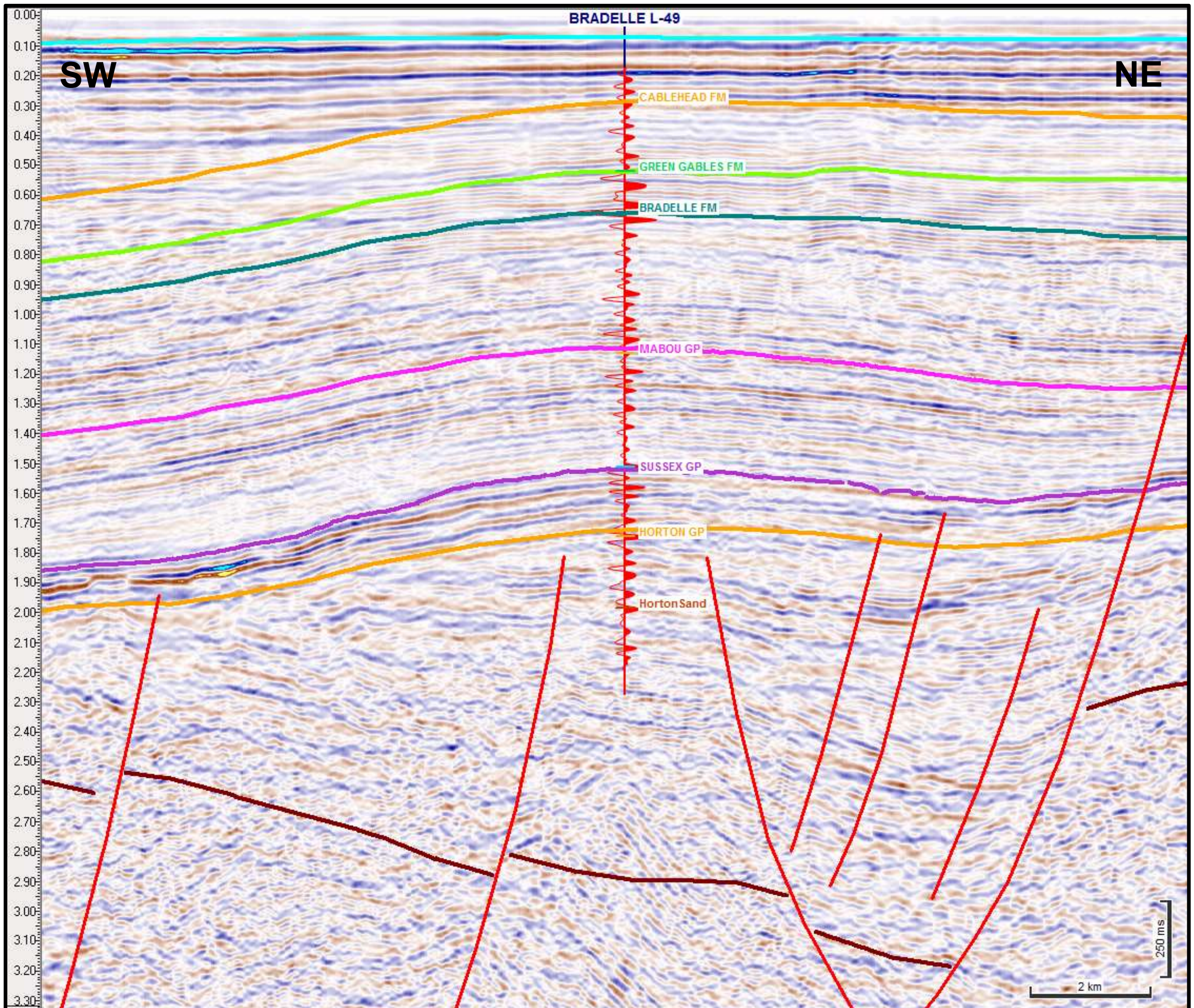


Figure D-29 – Bradelle well tie with Windsor, Sussex, and Horton groups

Regional seismic line Lithoprobe 86-2, ~2:1 vert. ex. Horizon colour legend – Figure 4.

Base Windsor Group (purple, equivalent to top Sussex Group), Base Sussex Group (gold, equivalent to top Horton Group), and Pre-Horton Basement horizons are well established here. In addition, the character of the Bradelle Formation and Mabou Group are illustrated.

Durling and Harvey (1996). As they had more data available in this subbasin than available to us, we incorporated their mapping into our regional map. Further ties were made to wells, outcrop and subsurface interpretations along the coast of Nova Scotia and New Brunswick (Durling and Marillier, 1996; Durling et al., 1995a; St. Peter and Johnson, 2009).

It is harder to follow this package with high confidence within the salt province of the basin. However, a key tie is provided near the base of the Cap Rouge F-52 well. Hayward et al. (2014) modelled magnetic data in the salt basin and interpreted seismic in the region of Cap Rouge in concert with this modelling. Their published map of the Base Windsor horizon was used to guide a re-examination of the seismic, along with seismic mapping by Langdon (1996) (also in Langdon and Hall, 1994) in Cabot Strait. A regional interpretation in this salt dominated area was developed, that honours the weaker reflection package where visible and builds on these previous interpretations, finding compromise between previous opinions and between seismic and gravity evidence. Ties to outcrop in southwestern Newfoundland and Cape Breton Island were also considered (see below). This area of lower confidence interpretation is outlined by a polygon (Fig. 2), and the lower confidence is incorporated into estimates of COS in the play analysis.

It is also challenging to follow the Base Windsor horizon to the northwest along the New Brunswick coast and adjacent to the Gaspé Peninsula, north of the North Point graben (Figs. D-14 and D-22, see gravity discussion above). In this area the seismic quality is very poor and struggles with extreme multiples, probably due to hard water bottom conditions. This area of low confidence is also outlined by a polygon used in COS play analysis (Fig. 2). The gravity data and gravity model profile (Fig. D-5) were used to aid the interpretation in this challenging area.

The Base Windsor Group unconformity erodes deeper in the section to the west and northwest, cutting out underlying strata of the Sussex and Horton groups and eroding into Pre-Magdalen Basin basement. Successively younger strata also onlap this unconformity (see above), such that Bradelle Formation lies directly upon the basement in northern New Brunswick (Bartibog No.1 and St. Isidore No.2 wells). For the purposes of regional mapping, this Base Windsor Group unconformity merges with the two unconformities beneath it (Base Sussex Group and Basement, see below), and with younger unconformities, and the regional unconformity is extended to the edge of the study area.

Base Sussex Group unconformity

As discussed above, the Sussex Group is typically concordant with the overlying Windsor and Mabou groups, although a regional time-gap exists between the Sussex and Windsor groups (Waldron et al., 2017). The Sussex Group is represented by a moderate amplitude, fairly continuous reflection package beneath the Base Windsor Group unconformity that exhibits this concordance. The base of this package is picked as the Base Sussex Group unconformity horizon. This horizon is less distinct than the Base Windsor pick, and in many areas there is latitude in the interpretation. Angularity between Horton Group reflectors beneath and the Sussex Group package often assists picking the unconformity.

The Sussex Group is now interpreted in five wells in the study area, using Giles current correlations (see regional stratigraphy above, P.Giles, pers.comm., 2018, 2019). He now places the base of Sussex Group at 2805 m measured depth (MD) in Wellington No.1 and interprets all of the stratigraphy beneath the Base Windsor Group as Sussex Group in Cap Rouge F-52 and Irishtown No.1. In Northumberland F-25, Giles places most or all of rocks between Base Windsor Group and metamorphic basement in the Sussex Group. The volcanics just above basement may be Fisset Brook Formation (oldest Magdalen Basin deposits, here lumped with Horton Group for mapping, see below), and Base Sussex Group can be tied to the top of these volcanics at 2711 m MD.

For Bradelle L-49, Giles, though having no palynological constraints, suggests that significant Sussex Group may also be present beneath the Base Windsor unconformity. Here the seismic geometry particularly supports this regional stratigraphic concept (Fig. D-29). The Base Windsor Group unconformity at 2925 m MD correlates to the top of the Sussex Group reflection package followed regionally, and a distinct angular unconformity can be observed at 3425 m MD, where a definite change in lithostratigraphy from red and grey shales to a more sandy sequence also occurs. These stratigraphic relationships strongly resemble the relationships observed at the McCully Field, which is the type area for the Sussex Group – there the Sussex Group is a succession of clastic rocks concordant with the overlying Windsor Group, which lies unconformably upon older clastic rocks. Thus in Bradelle L-49, we place the Base Sussex Group unconformity at 3425 m MD.

Current interpretations were also used to tie the Base Sussex Group horizon to outcrop (P.Giles, pers.comm., 2018, 2019; Lynch et al., 1995; Knight, 1983). In Cape Breton, Giles suggests the upper part of the Ainslie Formation is correlative with the Sussex Group, which fits with the interpretation of some Sussex Group reflections just offshore of Cape Breton.

In southwest Newfoundland, the Fischells Brook / Ingonish / Spout Falls sequence may be a younger portion of the Sussex Group, or a similar slightly younger unconformity bounded stratigraphic unit (see regional stratigraphy above). In any case, it is lumped with Coldstream Formation and Sussex Group proper in the same seismic unit, represented by moderate seismic reflections, generally concordant with the Windsor Group above it. This seismic package can be interpreted, although with less certainty, some distance into Bay St. George, directly north of the southwest Newfoundland outcrop. Thus, Sussex Group is interpreted to persist there and the Base Sussex Group unconformity is again placed beneath this reflection package. An alternative interpretation is that Windsor Group lies directly upon St. Lawrence Platform rocks in Bay St. George subbasin.

As with the Base Windsor Group, interpretation confidence decreases to the northwest near northern New Brunswick and the Gaspé Peninsula. Confidence is even lower in the heart of the salt province, where the deepest reflector that can be picked with some constraint is Base Windsor Group. Deeper horizons are more conjecture based on the extrapolation of thicknesses observed in outcrop and wells (Cap Rouge F-52), following weak reflectivity. These low confidence areas are outlined with polygons (Fig. 2) and incorporated into the COS estimates and play analysis. The unconformity is merged with the Base Windsor Group unconformity above it, where the Sussex Group isopach becomes zero, and extrapolated to the edge of the study area.

Pre-Horton Group (Pre-Magdalen Basin) Basement

As discussed in regional tectonics and stratigraphy, the Horton Group was deposited in localized extensional grabens. Beneath the Base Sussex Group unconformity, localized tilting seismic reflection packages are observed, and interpreted to represent Horton Group grabens (e.g. beneath Bradelle L-49, Fig. D-29). The base of each package of moderate to strong amplitude discontinuous reflections is interpreted to represent the unconformity at the base of the Horton Group or Fountain Lake Group where present (the earliest rocks in the basin – the Fountain Lake Group, including the Fisset Brook volcanics – are lumped with the Horton Group for regional mapping). This surface is also the Basement to the Magdalen Basin. Angular discordance can sometimes aide in the picking of this horizon. This seismic character used to identify the Horton Group (and Sussex Group above) is consistent with that observed on more modern 3D seismic data in New Brunswick imaging the same strata (Brake et al., 2019).

Interpretation from previous studies (Durling and Marillier, 1990, 1993; Hinds and Fyffe, 2013a; Pinet et al., 2018) influenced mapping, as the definition of this horizon is not well constrained. This study benefitted from more seismic data loaded on a digital workstation compared to previous studies, and reprocessed seismic, which helped image these deeper packages. Images from many seismic lines influence the final Basement pick in an area. Graben bounding faults were interpreted and correlated with a 3D viewer into reasonable fault planes. Fault names and correlations to tectonic features in outcrop from previous work (Pinet et al., 2018; Durling and Marillier, 1990) were incorporated and extrapolated. These efforts lead to good self consistency (structural viability) in the interpretation as an additional guide. Gravity data and models (see above) also provided significant constraint.

Pre-Magdalen Basement is penetrated in three wells in the study area, and nearby in two wells just onshore in northern New Brunswick, three in southern New Brunswick and Nova Scotia and one more in southwest Newfoundland. Well ties were adjusted for increased recognition of the Sussex Group as discussed above (P.Giles pers.comm., 2018), which affects interpreted Horton Group isopach maps. Giles still interprets significant thickness of Horton Group in MacDougall No.1, with basement below total depth (TD), and he still interprets Windsor Group to unconformably overlie Pre-Magdalen Basin basement at Port Hill No.1. This Basement horizon tied each of these penetrations within the regional maps and is consistent with the onshore wells.

The regional Basement pick is also tied to outcrop in the Gaspé Belt (Lavoie et al., 2009, Fig.26), New Brunswick (New Brunswick Department of Natural Resources, 2008; St. Peter and Johnson, 2009), Cape Breton (Lynch et al., 1995), and southwestern Newfoundland (Knight, 1983). Concepts interpreted from outcrop studies about the likely location of Horton graben basin-bounding faults (Hamblin, 1989, 1992) were also incorporated into mapping, and affected the interpretation of faults where sense of motion is not clear from seismic. No localized grabens are imaged within Bay St. George, and thus Horton Group is not interpreted within that subbasin (offshore of southwestern Newfoundland). However, significant thickness of Horton Group equivalent (Anguille Group – Kennells Brook and Snakes Bight formations and equivalents) are preserved in southwestern Newfoundland, which is interpreted as a large inverted graben (Knight, 1983; Enachescu, 2006). Horton Group could extend further north from this main graben into Bay St. George, and is interpreted along strike from southwestern Newfoundland into Cabot Strait.

As with the Base Windsor Group and Base Sussex Group above, interpretation confidence decreases to the northwest near northern New Brunswick and the Gaspé Peninsula. Like the Base Sussex Group, confidence is even lower in the heart of the salt province, where the deepest reflector that can be picked with some constraint is Base Windsor Group. Like the Base Sussex Group, this Basement horizon is conjecture based on the extrapolation of thicknesses observed in outcrop and wells (Cap Rouge F-52), following weak reflectivity. Significantly more variation in the Horton Group isopach could occur in the basin centre than can be imaged currently.

Another source of lowered confidence is where various studies published in the literature disagree with each other and/or with this study. Conceptually, if, despite the challenging seismic quality, various workers agree that a graben of Horton age is likely present (e.g. North Point Graben, Figs. D-14 and D-22, see gravity discussion above), confidence increases. Elsewhere, where different studies interpret or do not interpret a Horton graben in the same location, then interpretation confidence is lower (as all studies were undertaken by knowledgeable competent interpreters). A good example of difference of opinion is in the Cascumpec graben/basin, east of northern PEI. Hinds and Fyffe (2013a) and this study interpret dipping reflectors in this area as a thicker Horton graben and put the Basement horizon deeper, whereas Durling and Marillier (1990) and Pinet et al. (2018) interpret these same reflectors as older strata. Either could be correct; the most recent reprocessing enhances these reflectors, and the interpretation in this study is the more optimistic for petroleum potential.

These low confidence areas are outlined with polygons (Fig. 2) and incorporated into the COS estimates and play analysis – Horton Group reservoir and trap COS are not as high in these areas. The Cascumpec graben and related areas east of PEI are included in the low confidence areas due to the uncertainty from varying valid opinions. This Basement unconformity surface is also merged with the Base Sussex Group and Base Windsor Group unconformities above it, where Horton Group and Sussex Group are eroded and their isopachs become zero, and the horizon is extrapolated to the edge of the study area.

Deeper Paleozoic horizons

For this study, we did not have time to fully analyse the plays in older strata off western Newfoundland near Port au Port Peninsula. Petroleum potential exists in the region in the Lower Paleozoic St. Lawrence Platform (Lavoie et al., 2009; Cooper et al., 2001; Enachescu,

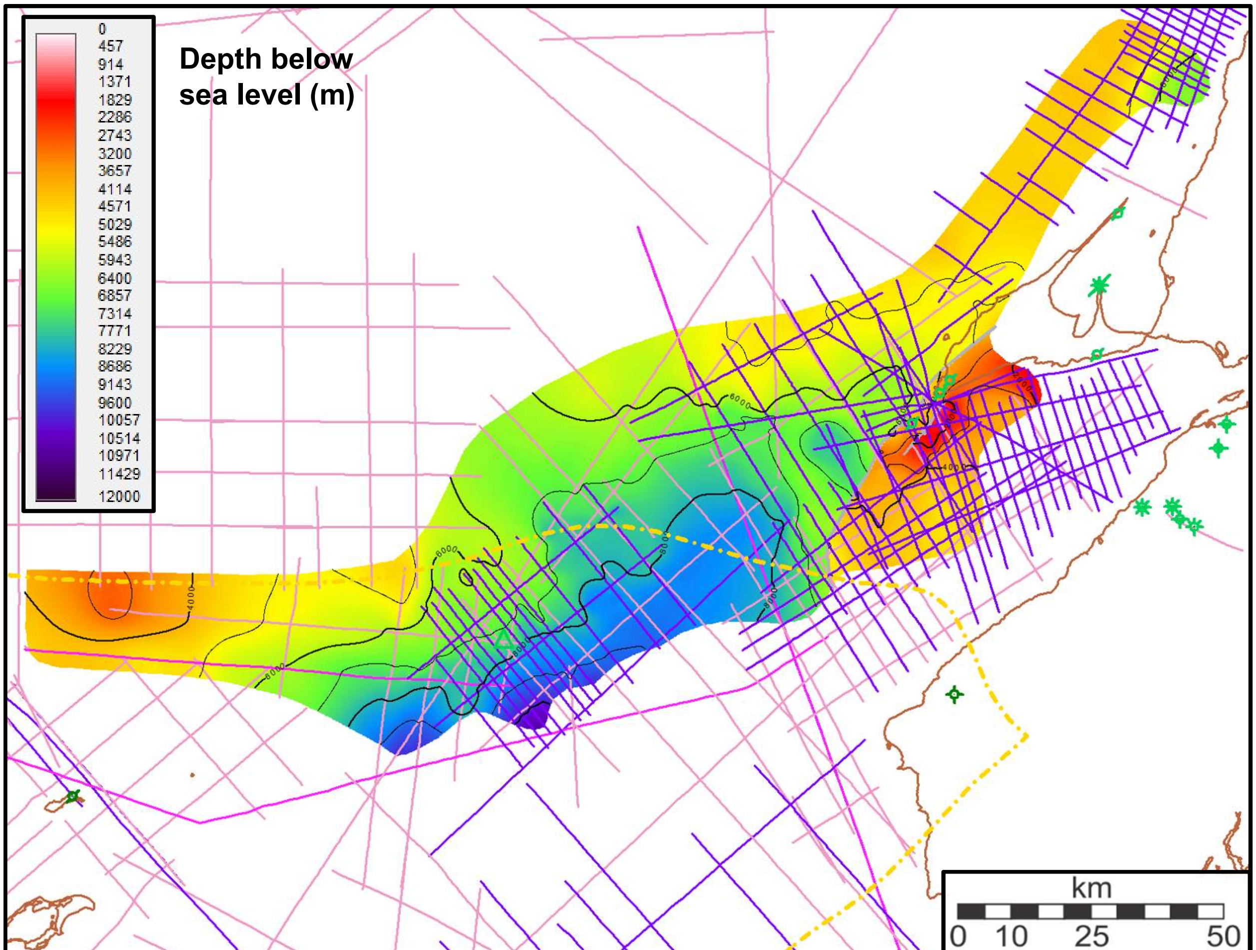


Figure D-30 – Preliminary map of Grenville Basement near western Newfoundland
Depth to Grenville basement beneath the St. Lawrence platform plays, used to define study area. St. Lawrence platform is approximately 1100 to 1400 m thick above basement.

2006, 2008, 2013), and industry has drilled several prospects in the area, with some success (one oil discovery in Lower Ordovician hydrothermal dolomites). We followed platform and basement away from wells and outcrop on western Newfoundland in order to define our study area to exclude most of this potential (Fig. D-30). Very speculative potential in these plays exists along the north edge of the Magdalen Basin and is captured in our petroleum potential map (Fig. 1) as play 10 (Tables 1 and 3).

Depth conversion

The objective of this regional mapping exercise is to support the analysis of plays and estimate the COS of petroleum system elements. As such, precise depth conversion is not crucial. Furthermore, with so few well penetrations, and many of those well penetrations not reaching deeper horizons, the development of a more sophisticated layer-cake time to depth conversion would be very challenging and not well constrained. Thus, we chose a straightforward approach for depth conversion - using a single regional time-depth curve throughout the basin.

We sourced three such regional time depth curves from the literature and collaboration. Durling and Marillier (1993a) compiled the work of Hobson and Overton (1973) into a time depth function based on the average of 42 models derived from seismic refraction profiles in the Magdalen Basin (Fig. D-31). They observed that stacking velocities available to them had much larger scatter than refraction velocities, and refraction velocities are also similar to velocities derived from sonic logs in the basin. Grant (1994) made a study of the coal measures of the Magdalen Basin, and in the process developed a regional time depth curve from sonic logs. He shared this function with GSC colleague P.Durling (A.Grant, unpub. data, 1994; Fig. D-31). Grant later co-authored a paper where they created a simpler function by fitting a second order polynomial to sonic logs (Hayward et al., 2014; Fig. D-31). The authors of this paper describe the function as “a first-order estimate” and discuss that the polynomial “may underestimate the depth below salt bodies”. They intended it for drilling depths, and it may not be suitable for deeper extrapolation.

Test depth maps were created from all functions (named for the authors), for comparison. In the core of the salt province, the Base Windsor Group horizon just exceeds 5 seconds two-way time. At 5 s, the Durling and Marillier refraction based function is deepest (12272 m), with Grant’s Coal function giving very similar results, 12250 m. The Hayward et al. polynomial function calculated this deep basin horizon at 10912 m, 1360 m shallower and not agreeing with other basin estimates developed from this horizon (e.g. Waldron et al., 2015). It is likely estimating the deepest basin depths too shallow, as the interval velocities at depth are likely too slow for compacted sediments at deep burial.

Depth estimates for 2 s two-way time were calculated as examples of moderate depths in the basin. From local checkshots, 2 s is just below Base Windsor Group near TD in the Cap Rouge F-52 well, and in the Horton Group near TD in the Bradelle L-49 well. These wells show that the depth corresponding to 2 s travel time does vary locally around the basin: Cap Rouge checkshot = 4466 m and Bradelle checkshot = 3960 m. Regionally, 2 s corresponds to: Durling and Marillier function = 4413 m, Grant’s Coal function = 4722 m, and Hayward et al. function = 4063 m. These results suggest that at moderate depths, estimates from the Durling and Marillier function to Hayward et al. function are reasonable, and Grant’s Coal function may be estimating too deep.

Similar calculations were undertaken for a shallow time of 0.5 s. They showed the Durling and Marillier function gives a good match to wells away from salt pillars, Hayward et al. function 46 m deeper and still reasonable, and Grant’s Coal function 127 m deeper – likely too deep in the Pictou Group and Morien Group stratigraphy but a reasonable match where Windsor Group is near surface.

Thus, the Durling and Marillier function gives the most robust depth estimates, at both deep and shallow levels in the basin. The maps published here used this Durling and Marillier function, and are not explicitly tied to the well tops. The match to wells tops is very reasonable for regional play mapping. Further studies could incorporate well ties into this regional function to develop a more complex velocity model.

All three of these regional time depth curves were developed in areas of very shallow water, and the velocity of the water column was not explicitly taken into account. Much of the Gulf of St. Lawrence, including the location of most wells, have water depths of less than 80 m, so the residual error from neglecting the much slower water column is small. However, the Laurentian Channel in the eastern end of the study area reaches depths of over 600 m, and the error in the depth maps from the incorrect water column depth becomes significant there. It is assumed that increasingly higher velocity stratigraphy with depth observed elsewhere is eroded into by the recent channel. Thus, a residual depth correction for the water column was created by calculating the depth added to maps due to the difference between the velocity used (too high rock velocity) and the velocity of sea water (that should be used in the channel). The velocity

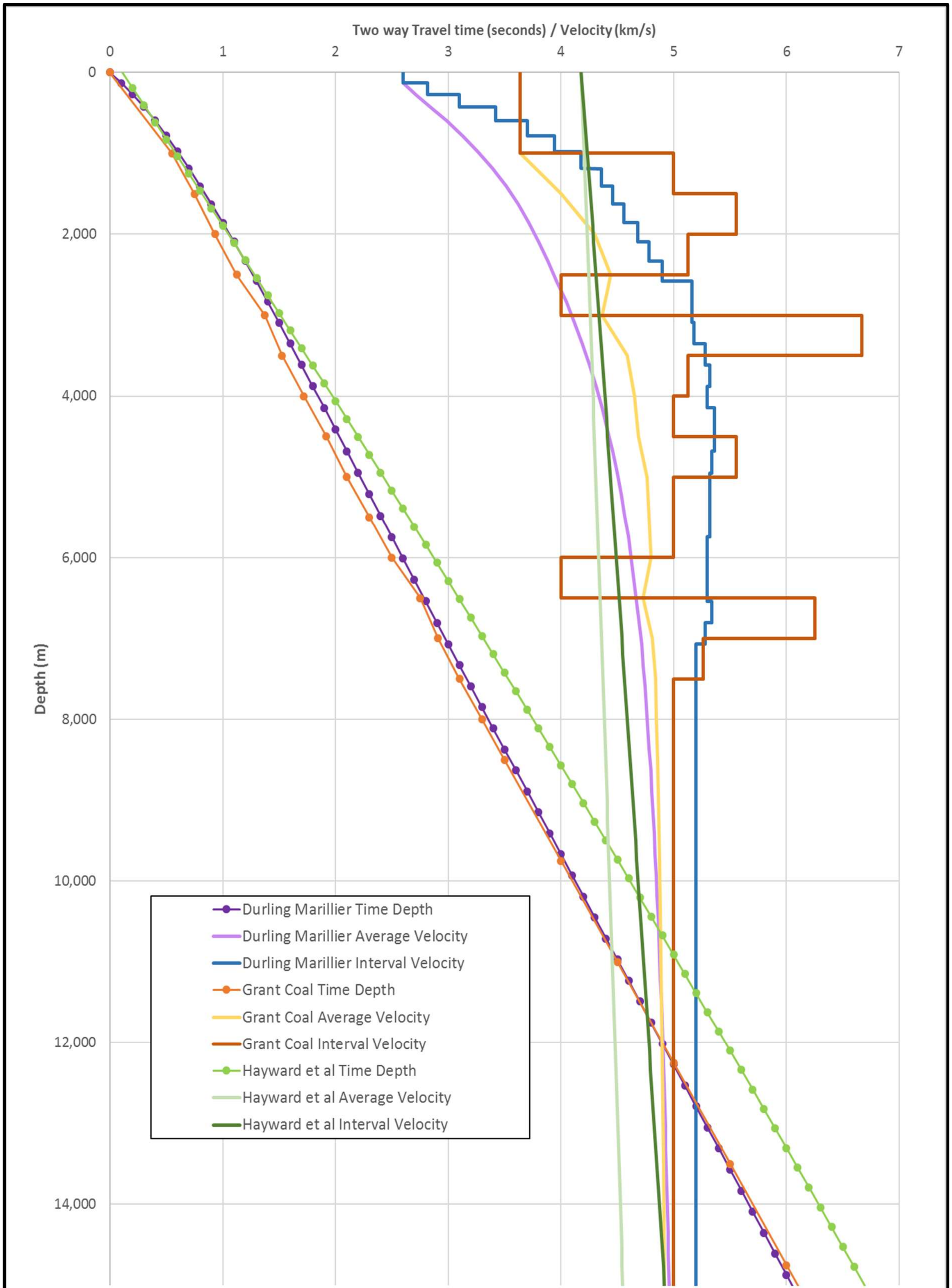


Figure D-31 – Time - depth functions

used is described by fitting a linear equation to the shallow portion of the Durling and Marillier function.

$D = (V_{used} - V_{water}) * T/2$ where D=depth correction, V=velocity, T=two-way travel time

$D = ((1313.5\ T + 2329.1) - 1500) * T/2$

The resulting residual correction is shown in Figure D-32. This correction was subtracted from all regional depth maps to remove the effect of velocity variation in the deeper water.

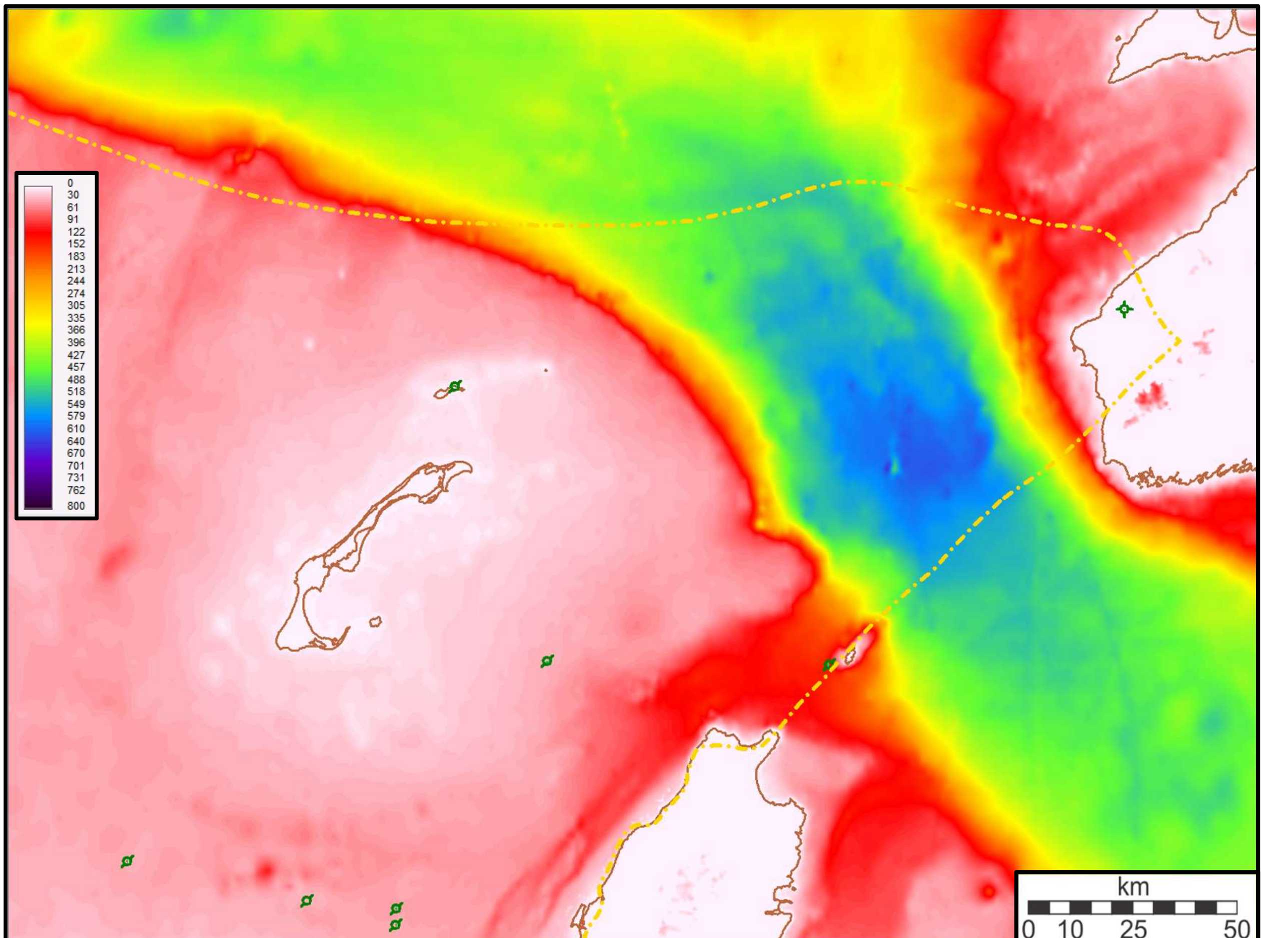


Figure D-32 – Residual depth correction for water column

Correction (in m) subtracted from depth grids to account for water column, which has significantly lower seismic velocity. Eastern end of study area (gold dotted line) shown, where the most significant correction is located, in the Laurentian Channel.

APPENDIX E. MINERAL RESOURCES SUMMARY

Nova Scotia, New Brunswick, and Quebec have long histories of mining and mineral extraction. Mineral resources near to the study are were identified through scientific articles, industry press releases, and interpretation on geologic maps (Fig. 3). This section is a brief summary of mineral resource activity highlighting some past and current mining activity.

Mines Seleine, operated by K+S Windsor Salt Ltd. is located on the Magdalen Islands in the middle of the study area and is Quebec's only salt mine (MinesQC, 2017). This active mine produces over 1.3 million tonnes of salt per year and employs 150 personnel (MinesQC, 2017).

It is estimated that mining in Nova Scotia directly and indirectly creates over 5,000 jobs and generates over $400 million towards the provinces GDP (Nova Scotia Department of Natural Resources, 2013). Cape Breton has been extensively mined for hundreds of years. Figure 3 shows locations of most producing mines and quarries as determined by the Mining Association of Nova Scotia (MANS, 2015). The main mineral resources extracted are coal, limestone, and gypsum. Aggregates are also produced near the coast in Nova Scotia, for example in the Strait of Canso, where aggregate is shipped out by sea. Historically Nova Scotia has been mined for base metals, iron, and gold (Nova Scotia Department of Natural Resources, 2013).

The Magdalen Basin contains a number of proven coal measures, although there are currently no active coal mines offshore in western Cape Breton. The areas outlined for Coal Bed Methane potential in Figure 3 highlight where coal measures are nearshore. Hacquebard (2002) estimated a remaining coal resource in the region of 175 million tonnes, nearly all in the submarine area. The Donkin Coal Mine has been recently reactivated on Cape Breton's eastern shore, mining into age-equivalent strata of the Sydney Basin. The onshore portion of coal measures is only 5% of the total coal measure sequence (Mining-Technology, 2019) and the Donkin Mine extends up to 3 km under the seafloor with an estimated reserve of 58 Mt of high-quality metallurgical coal (Mining-Technology, 2019). A detailed listing of mines and mine related activity from 1600-1992 in Nova Scotia is available at: https://novascotia.ca/archives/meninmines/timeline.asp?Language=English.

In 2016 mineral production in New Brunswick generated $375 million (Natural Resources Canada, 2018). The majority of mine operations are further inland with currently or previously developed resources ranging from base metals and gold to potash (Mioc et al., 2015).

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APPENDIX G. GLOSSARY OF TERMS

(* from or modified from The Oilfield Glossary: http://www.glossary.oilfield.slb.com)

***Anticline:** An arch-shaped fold in rock in which rock layers are upwardly convex – anticlines form many excellent hydrocarbon traps. A trough-shaped fold in which rock layers are downwardly convex is called a **syncline**.

***Basin:** A depression in the crust of the Earth, caused by plate tectonic activity and subsidence, in which sediments accumulate. Sedimentary basins vary from bowl-shaped to elongated troughs. Basins can be bounded by faults.

***Carbonate:** A class of sedimentary rock whose chief mineral constituents (95% or more) are calcite and aragonite (both $CaCo_3$) and dolomite [$CaMg(CO_3)_2$]. **Limestone, dolostone** and **chalk** are carbonate rocks.

Carboniferous: Geological Period approximately 359 to 299 million years ago. The Carboniferous is divided into two epochs, the Mississippian (359 to 318 Mya) and the Pennsylvanian (318 to 299 Mya)

Cenozoic: Geological Era approximately 66 million years ago to present.

***Clastic:** Sediment consisting of broken fragments derived from pre-existing rocks and transported elsewhere and redeposited before forming another rock. Examples of common clastic sedimentary rocks include siliciclastic rocks such as conglomerate, sandstone, siltstone and shale. Carbonate rocks can also be broken and reworked to form clastic sedimentary rocks.

Concordant: Sedimentary rocks laid down parallel to each other.

Devonian: Geological Period approximately 419 to 359 million years ago.

Diapirs: A geological structure in which a more mobile and ductily deformable material, such as salt, flows into pillars and other vertical structures, displacing surrounding rocks.

Evaporite: Sedimentary rocks that form as precipitates from the evaporation of seawater. Generally evaporates indicate seawater flooded a restricted basin and then began to dry out. As evaporation occurs, carbonate is first deposited, then gypsum, and finally halite (salt).

Extension: Motion on faults where the blocks are pulled apart; structures formed by the stretching of the earth's crust; extension creates **normal faults**. **Compression** is the opposite, and produces **thrusts** and **reverse faults**.

***Field:** An accumulation, pool, or group of pools of hydrocarbons in the subsurface. Typically, the term implies an economic size.

Field data: Seismic data as originally collected, stored in the past on "**field tapes**". Field data must be computer processed to create interpretable seismic profiles.

Fluvial: Geological processes and rocks associated with / deposited by rivers and streams.

***Formation:** A body of rock that is sufficiently distinctive and continuous, and can be mapped.

Graben / Half-graben: A (full) graben is a depressed block of rock bordered by two near parallel faults). A half-graben is a geological depression bounded by a fault on one side of its boundaries.

***Hydrate:** An unusual occurrence of hydrocarbon in which molecules of natural gas, typically methane, are trapped in ice molecules. More generally, hydrates are compounds in which gas molecules are trapped within a crystal structure. Hydrates form in cold climates, such as permafrost zones and in deep water. To date, economic liberation of hydrocarbon gases from hydrates has not occurred, but hydrates contain quantities of hydrocarbons that could be of great economic significance. Hydrates can affect seismic data by creating a reflection or multiple.

Isopach: The stratigraphic thickness between two geologic horizons. Strictly speaking, an isopach map should be corrected for the dip of the rock layers and measured perpendicular to the layers. In the Magdalen Basin, dips are generally low.

***Maturation:** The process of a source rock becoming capable of generating oil or gas when exposed to appropriate pressures and temperatures.

Mesozoic: Geological Era approximately 252 to 66 million years ago.

Migration: The movement of hydrocarbons from their source into reservoir rocks. The **timing** of this migration can be an issue for petroleum accumulation – migration must occur after the trapping configuration has been created.

***Mineral:** A crystalline substance that is naturally occurring, inorganic, and has a unique or limited range of chemical compositions. Minerals are homogeneous, having a definite atomic structure. Rocks are composed of minerals, except for rare exceptions like coal, which is a rock but not a mineral because of its organic origin. Minerals are distinguished from one another by careful observation or measurement of physical properties such as density, crystal form, cleavage (tendency to break along specific surfaces because of atomic structure), fracture (appearance of broken surfaces), hardness, lustre and colour. Magnetism, taste and smell are useful ways to identify only a few minerals.

Mississippian: Geological Epoch approximately 359 to 323 million years ago (lower half of Carboniferous Period).

Ordovician: Geological Period approximately 485 to 444 million years ago.

Orogen: A region of the earth's crust involved in the formation of mountain ranges, primarily by the collision of tectonic plates or terranes.

Paleozoic: Geological Era approximately 541 to 252 million years ago.

Pennsylvanian: Geological Epoch approximately 323 to 299 million years ago (upper half of Carboniferous Period).

Permian: Geological Period approximately 299 to 252 million years ago.

***Petroleum system:** Geologic components and processes necessary to generate and store hydrocarbons, including a mature source rock, migration pathway, reservoir rock, trap and seal. Appropriate relative timing of formation of these elements and the processes of generation, migration and accumulation are necessary for hydrocarbons to accumulate and be preserved.

***Pinch-out:** A type of stratigraphic trap. The termination by thinning or tapering out ("pinching out") of a reservoir against a nonporous seal creates a favorable geometry to trap hydrocarbons.

Play: A family of prospects and/or discovered pools that share a common history of hydrocarbon generation, migration, reservoir development, and trap configuration; forms a natural geological population limited to a specific area.

***Pool:** A subsurface oil accumulation. An oil field can consist of one or more oil pools or distinct reservoirs within a single large trap. The term "*pool*" can create the erroneous impression that oil fields are immense caverns filled with oil, instead of rock filled with small oil-filled pores.

***Reservoir:** A subsurface body of rock having sufficient porosity and permeability to store and transmit fluids. Sedimentary rocks are the most common reservoir rocks as they have more porosity than most igneous and metamorphic rocks and form under temperature conditions at which hydrocarbons can be preserved. A reservoir is a critical component of a complete petroleum system.

***Salt:** [NaCl] A soft, soluble evaporite mineral also known as halite or rock salt. Because salt is less dense than many sedimentary rocks, it is relatively buoyant and can form salt domes, pillars or curtains by flowing and breaking through or piercing overlying sediments, as seen in the Gulf of Mexico and the Zagros fold belt. Halite can be critical in forming hydrocarbon traps and seals because it tends to flow rather than fracture during deformation, thus preventing hydrocarbons from leaking out of a trap even during and after some types of deformation.

***Seal:** A relatively impermeable rock, commonly shale, anhydrite or salt that forms a barrier or cap above and around reservoir rock such that fluids cannot migrate beyond the reservoir. A seal is a critical component of a complete petroleum system.

Seismic (survey, data): A method of investigating subterranean structure, particularly as related to exploration for petroleum and mineral deposits. The technique is based on determining the time interval that elapses between the initiation of a seismic wave at a selected shot point (the location where an explosion generates seismic waves) and the arrival of reflected or refracted impulses at one or more seismic detectors. Seismic air guns are used to initiate the seismic waves offshore. Onshore, dynamite exploding dynamite underground in shallow holes, vibrators trucks or falling weights (thumpers) are used. Upon arrival at the detectors, the amplitude and timing of waves are recorded to give a seismogram (record of ground vibrations). Many such recordings are processed with computers into seismic profiles. (modified from Britannica.com)

***Sequence:** A group of relatively conformable strata that represents a cycle of deposition and is bounded by unconformities or correlative conformities.

Silurian: Geological Period approximately 444 to 419 million years ago.

***Source rock:** A rock rich in organic matter which, if heated sufficiently, will generate oil or gas. Typical source rocks, usually shales or limestones, contain about 1% organic matter and at least 0.5% total organic carbon (TOC), although a rich source rock might have as much as 10% organic matter.

***Stratigraphy:** The study of the history, composition, relative ages and distribution of strata, and the interpretation of strata to elucidate Earth history. The comparison, or correlation of separated strata can include study of their lithology, fossil content, and relative or absolute age.

Strike-slip: Motion on faults (which are typically near vertical) where the blocks have mostly moved horizontally, sheared side-to-side.

Stromatoporoids: A class of aquatic invertebrates common in the fossil record from the Ordovician through the Devonian. They are the main reef builders of the Middle Paleozoic.

Structural inversion: The reactivation of an extensional fault in the opposite direction to its original movement / the relative uplift of a sedimentary basin or structure, as a result of crustal shortening / compression.

Structural viability: A viable section / interpretation is one that can be restored to an undeformed state without gaps or overlaps that cannot be explained by geologic observation, which implies strain compatibility. A related concept is admissibility, where interpretations fit with known structural styles in a region. An interpretation or cross-section which is both viable and admissible is known as balanced.

Tectonism: is a geological term used to describe major structural features and the processes that create them, including compressional or tensional movements on a planetary surface that produce faults, mountains, ridges, or scarps (encyclopedia.com).

Terrane: A fragment of crustal material broken off of a tectonic plate and accreted to another.

Thermal sag: The subsidence or depression of an area as the stretched earth's crust cools.

Transtension: The state in which a rock mass experiences both extension (being pulled apart) and strike-slip (being sheared sideways) at the same time. Transtension often creates basins in which sedimentary rocks can be deposited. **Transpression** is where a rock mass experiences both compression (being pushed together) and strike-slip.

***Trap:** A configuration of rocks suitable for containing hydrocarbons and sealed by a relatively impermeable formation through which hydrocarbons will not migrate. Traps are described as structural traps (in deformed strata such as folds and faults) or stratigraphic traps (in areas where rock types change, such as unconformities, pinch-outs and reefs). A trap is an essential component of a petroleum system.

Unconformity / Unconformable: A geologic surface over which the direction or attitude of the layers of rock change; not parallel to layers beneath. Such a surface indicates a period of erosion between the two layers of rock. Parallel strata deposited in succession are **conformable**.

***Unconventional resource**: An umbrella term for oil and natural gas that is produced by means that do not meet the criteria for conventional production. What has qualified as unconventional at any particular time is a complex function of resource characteristics, the available exploration and production technologies, the economic environment, and the scale, frequency and duration of production from the resource. Perceptions of these factors inevitably change over time and often differ among users of the term. At present, the term is used in reference to oil and gas resources whose porosity, permeability, fluid trapping mechanism, or other characteristics differ from conventional sandstone and carbonate reservoirs. Coalbed methane, gas hydrates, shale gas, fractured reservoirs, tight gas sands, oil shales and oil shales are considered unconventional resources.