Call for Bids NS18-3 – Seismic Interpretation, well summaries, source rock, and exploration leads in the Central Scotian Shelf, Sable Subbasin.

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1. NS18-3 Introduction

Call for Bids NS18-3 comprises two parcels (shaded yellow) located 160 km south of Nova Scotia on the Central Scotian Shelf within the Sable Subbasin, where most of the 23 Significant Discoveries in offshore Nova Scotia are located (Figure 1). There are 3 existing exploration licences on the slope, highlighted in pink and the Gully Marine Protected Area is shaded in green. Significant Discovery Areas and Production Licences are both shaded red. Existing gas pipelines are shown in black.

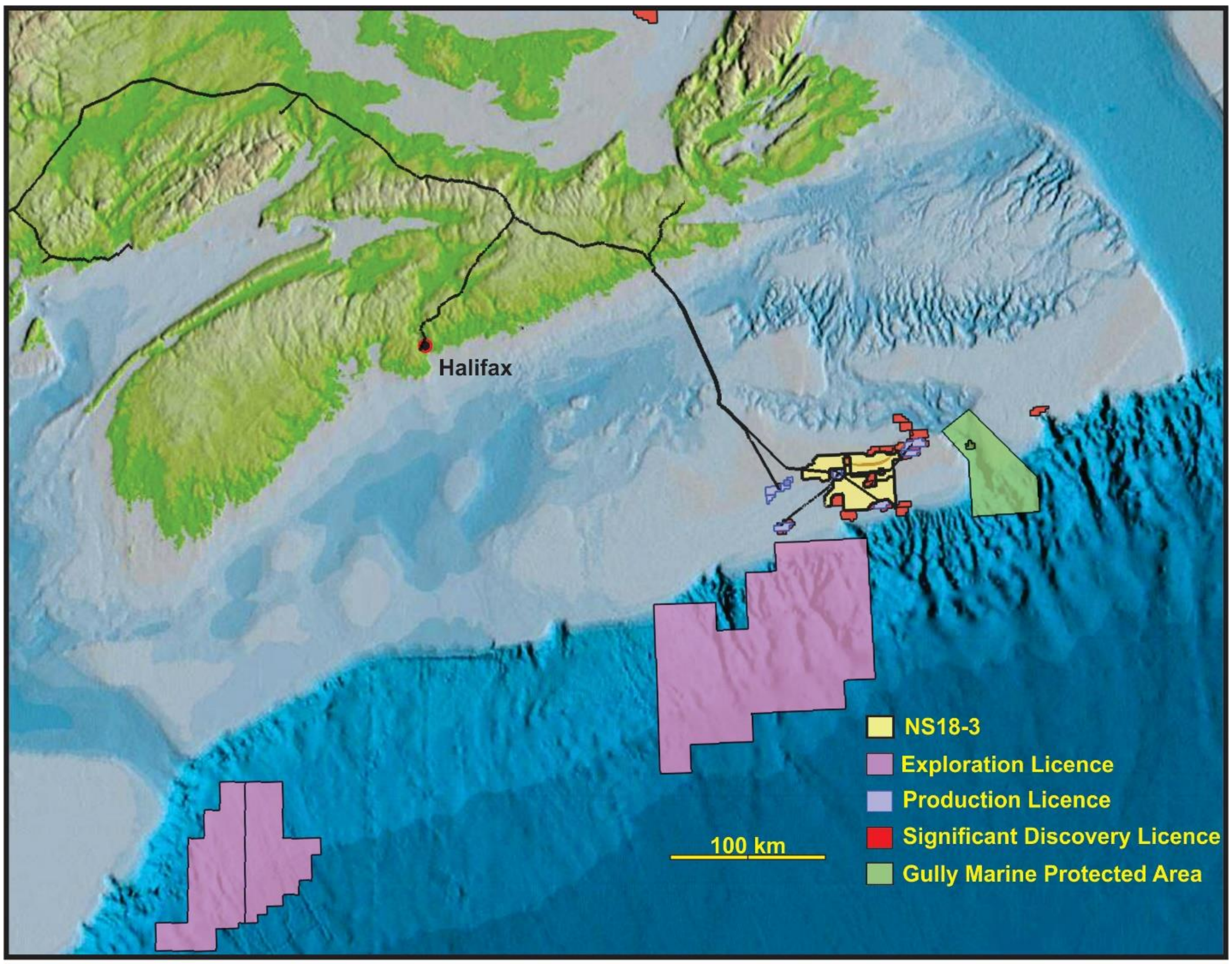

Figure 1. Licences offshore Nova Scotia with Parcels 1 and 2 of Call for Bids NS18-3 shaded yellow. Exploration Licences are shaded mauve, Production Licences blue, Significant Discovery Licences red, and the Gully Marine Protected area green.

For detailed reviews of the regional geology on this portion of the Scotian Shelf, refer to previous CNSOPB Calls for Bids, Smith et al. 2016, Smith et al. 2015, and Kendell and Deptuck 2012.

On the detailed base map, Parcels 1 and 2 are outlined in red and shaded in pink (Figure 2). Four of the five producing gas fields of ExxonMobil's Sable Offshore Energy Project (SOEP) border these Parcels. The four associated Production Licences shaded in blue are:

1. Venture
2. South Venture
3. Thebaud
4. North Triumph

Inter-field pipelines shown in thin black, collect gas from Venture, South Venture, North Triumph, and Alma sending it to the central Thebaud production platform. From Thebaud, the gas is sent to shore via a 26-inch subsea pipeline. From December 1999 to Jan 2018 SOEP has produced 2.08 TCF of gas from these fields.

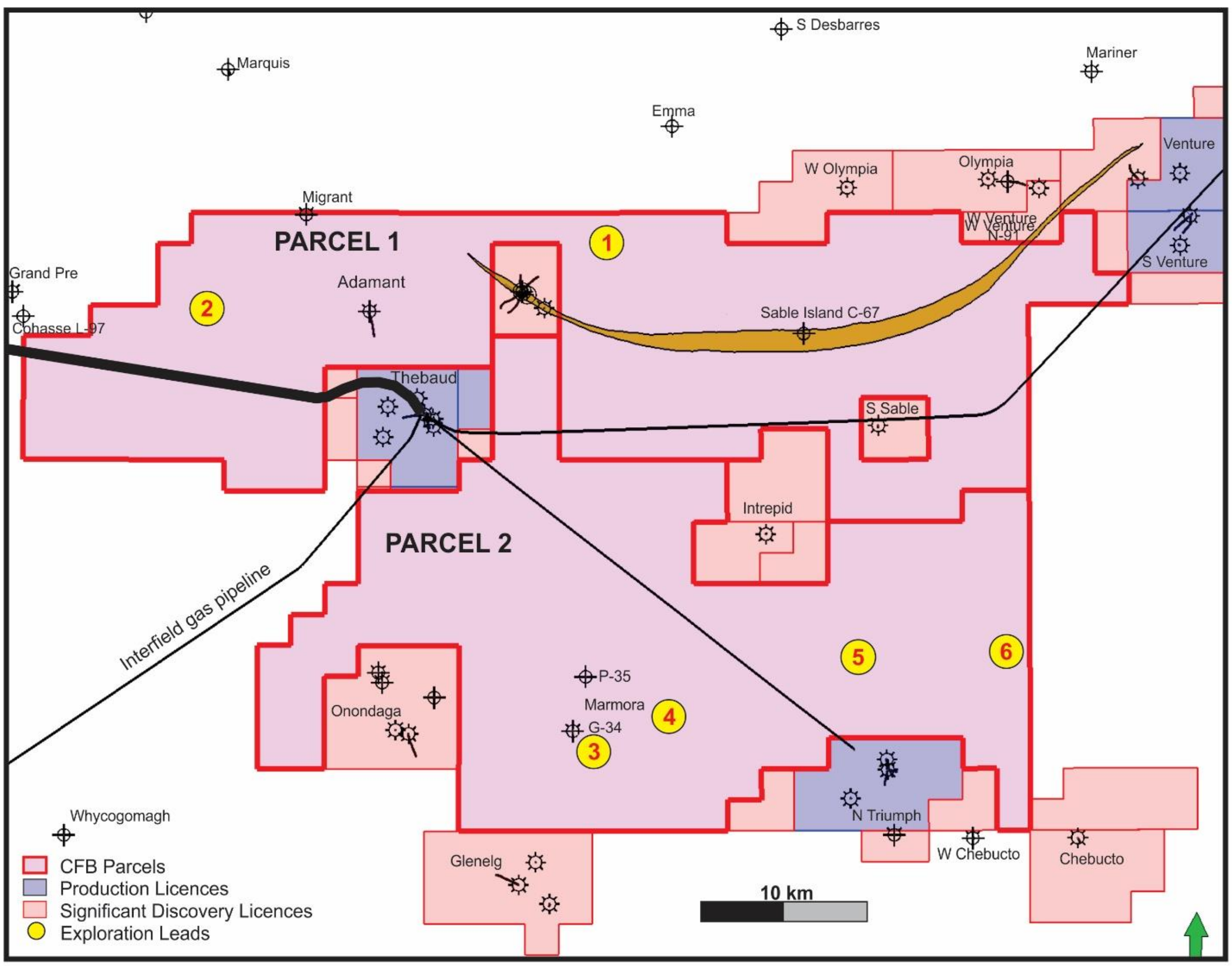

Figure 2. Parcels 1 and 2 are surrounded by 4 producing gas fields with associated interfield subsea pipelines, and 10 Significant Discoveries. The six exploration leads discussed in this report are indicated by the red numbers.

Parcels 1 and 2 also share boundaries with ten undeveloped Significant Discoveries shaded red (Figure 2). These Significant Discoveries have P50 recoverable gas reserves of 1.3 TCF (Smith et al. 2014). This publication contains all maps, log interpretations, and calculations utilized to determine these reserves. The recoverable P50 reserve estimates are listed below.

Undeveloped Significant Discovery	Recoverable Gas P50 (BCF)	Recoverable Oil P50 (MMB)
West Sable	93	15
Olympia	143	
West Olympia	30	
West Venture N-91	68	
West Venture C-62	31	
South Sable	8	
Intrepid	54	
Chebucto	66	
Glenelg	508	
Onondaga	304	
Total	**1305**	

The numbered yellow circles on Figure 2 indicate the locations of six exploration leads discussed in this study. Identification of additional leads would be expected after completion of further work such as depth conversion, seismic reprocessing, and detailed salt mapping.

The CNSOPB adopted the seismic horizon nomenclature proposed in the Play Fairway Analysis (OETRA 2011). The 6 key horizon maps included in this study are shown on the Scotian Basin stratigraphic column (Figure 3). Also shown are the stratigraphic penetrations of five wells on Parcels 1 and 2 along with related oil and gas show zones. Gas has been discovered in the Upper and Lower Missisauga and Micmac Formations on these parcels. A small amount of oil was recovered from the Mic Mac Formation, but only one well (Marmora P-35) had no hydrocarbon shows. The wells are discussed in detail below.

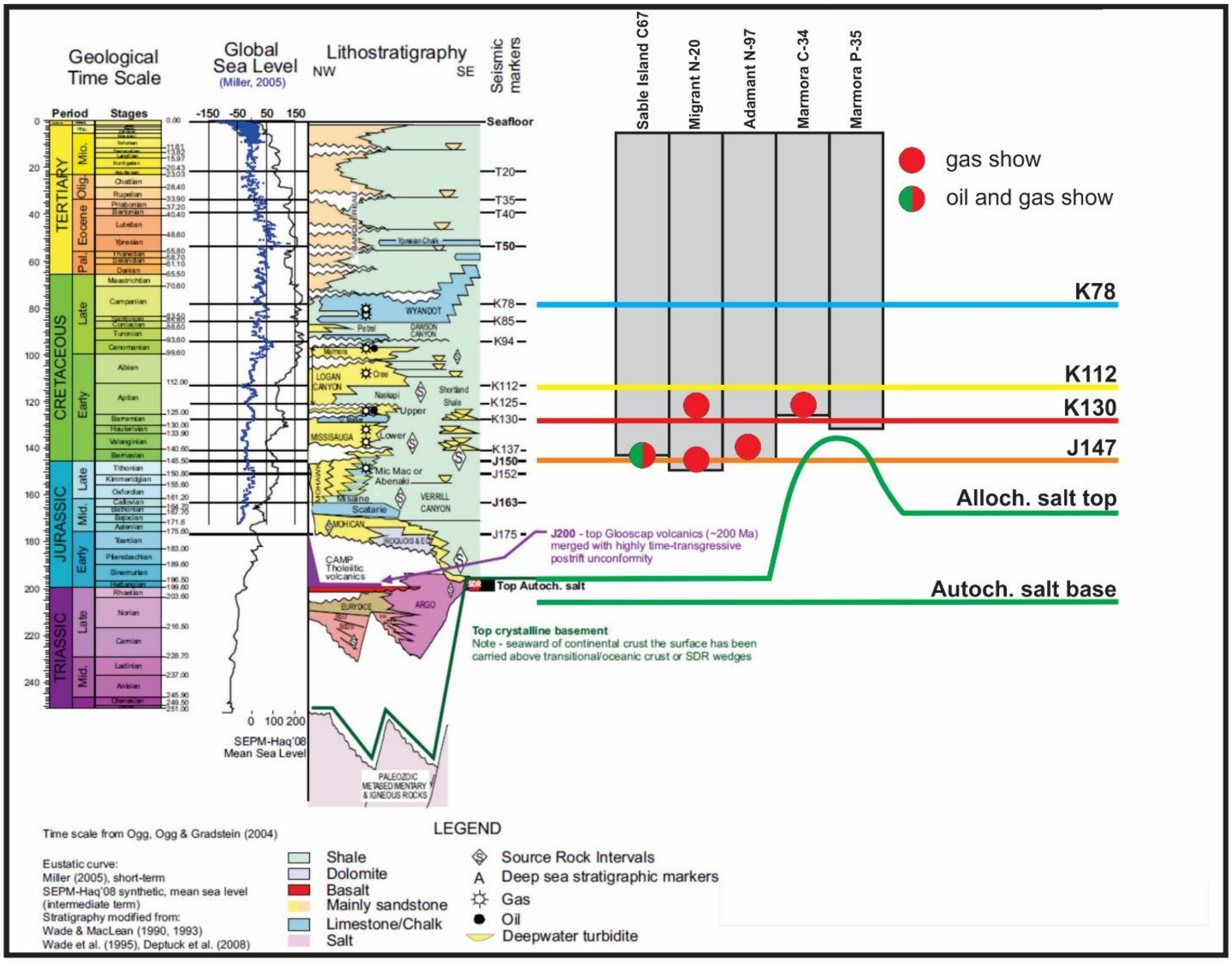

Figure 3. Stratigraphic column adapted from OETRA (2011). The stratigraphic penetration of wells within Parcels 1 and 2 is shown along with the locations of associated oil and gas occurrences. The position of 6 seismic markers included in the report is also shown.

The digital seismic database used for interpretation and mapping over Parcels 1 and 2 included eight 3D data sets (Figure 4):

- Merged 3D Datasets
    - NS24-M003-003E
    - NS24-M003-006E
    - NS24-M003-007E
    - NS24-M003-009E
    - NS24-M003-010E
- NS24-M003-006E
- NS24-M003-007E
- NS24-E040-001E

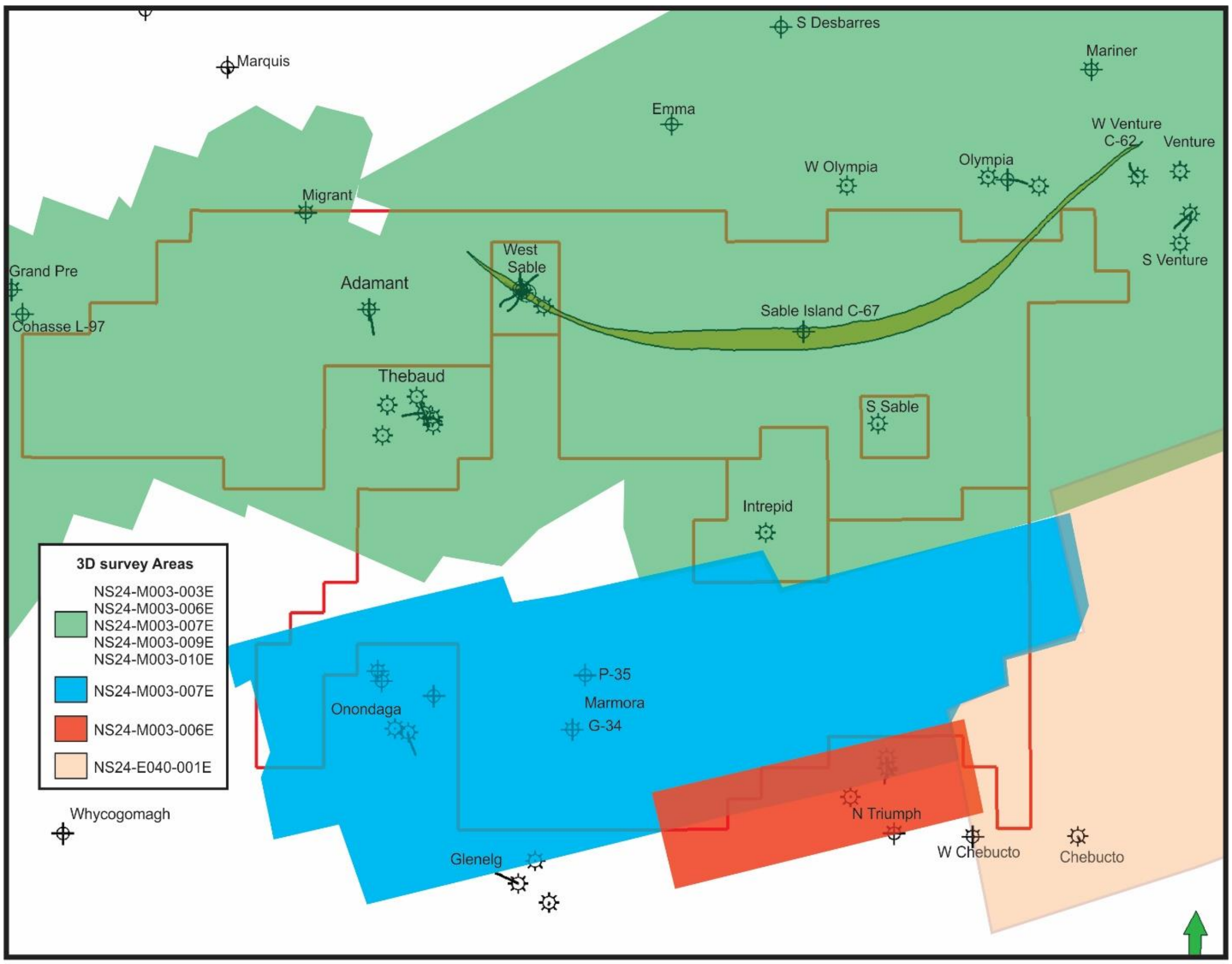

Figure 4. Seismic 3D surveys used in mapping over Parcels 1 and 2.

Water depths over Parcels 1 and 2 are quite shallow, ranging from zero at Sable Island to 120 m at the southeast corner of Parcel 2, with most of the area being less than 75 m (Figure 5). The map contour interval is 25 m.

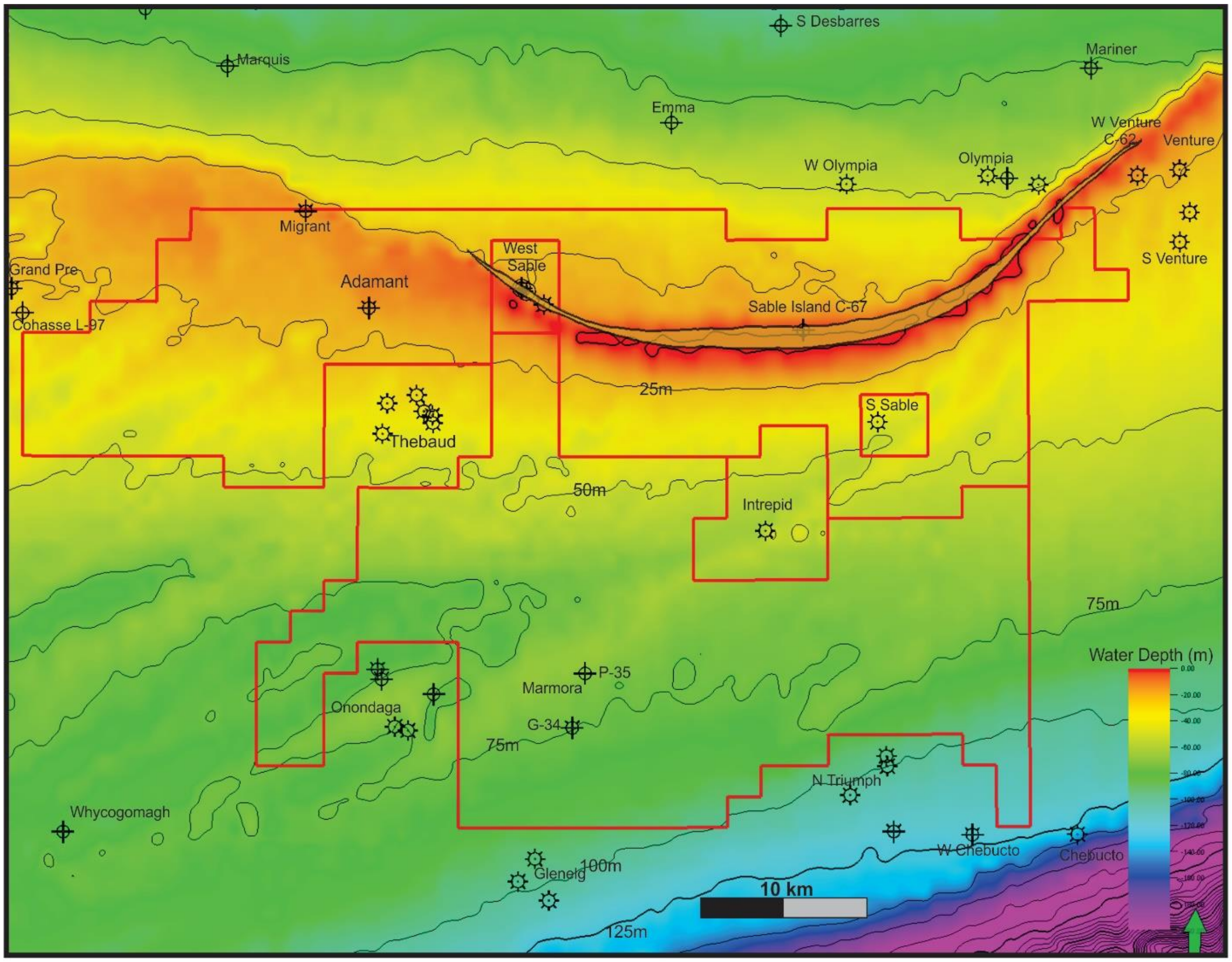

Figure 5. Water depths on Parcels 1 and 2 range from 0 m at Sable Island to 120 m at the southeast corner of Parcel 2.

2. Wells on Parcels 1 and 2

Five exploration wells are located in Parcels 1 and 2 testing Early Cretaceous and Late Jurassic fluvial-deltaic, estuarine, and shallow marine sandstones of the Missisauga and Mic Mac formations respectively.

Well	Spud Year	Total Depth (m)	Parcel	Results
Sable Island C-67	1967	4604	1	gas show
Marmora C-34	1972	4038	2	gas show
Marmora P-35	1973	4093	2	D&A
Migrant N-20	1977	4669	1	tested gas
Adamant N-97	2000	4708	1	gas show

Sable Island C-67
Sable Island C-67 was the first well drilled offshore Nova Scotia, spudded on Sable Island by Mobil Oil in 1967. The well reached a total depth of 4604 m in the Early Cretaceous Lower Missisauga Formation. One DST (#4: 4447.6-4604.3 m) recovered minor gas and oil. There was no gas to surface during DST #4 but a small amount of gas and 50 cc of 39° API oil was recovered from the bottom-hole sampler apparently sourced from a number of poor quality sands near the base of the well.

Marmora C-34
Marmora C-34 was spudded by Shell Canada in January 1972 23 km south of Sable Island in 58 m of water. The well reached a total depth of 4038 m in the upper Missisauga Formation. No DSTs were conducted but well logs and wireline tester samples confirmed the presence of a high quality gas bearing reservoir sand at the top of the upper Missisauga Formation (Sand 1). The Marmora discovery is discussed in detail in section 4.

Marmora P-35
Marmora P-35 was spudded in March 1973 by Shell et al 3.3 km south of Marmora C-34 in 53 m of water. The well reached a total depth of 4093 m in the Lower Missisauga Formation. The Missisauga Formation penetrated in Marmora P-35 is a high net to gross interval with many good quality reservoir sands, however no significant hydrocarbon bearing zones were encountered. Recent mapping of the Marmora structure utilizing current 3D seismic datasets indicate the P-35 structure has no simple or fault dependent closure as originally mapped with 2D data in the 1970s.

Migrant N-20
Migrant N-20, located 12 km west of Sable Island, was spudded by Mobil et al. in July 1977 in 14 m of water. The well reached a total depth of 4669 m in the Mic Mac Formation. Eight DSTs were attempted in three upper Mic Mac sandstones. Three of the DSTs were misruns, four had no recovery and one (DST #2: 4333.0-4361.7 m) flowed gas at a rate of 10 MMscf/d. Depletion noted during the test suggested that the zone has limited areal extent, or a boundary such as a fault near the wellbore. Two other tested Mic Mac sandstones appeared gas-bearing on logs but were unable to flow due to low effective porosities (<7%).

Adamant N-97

The Adamant N-97 well was spudded by Mobil et al. in November 2000 8 km west of Sable Island in 17 m of water. The well reached a total depth of 4708 m in the Upper Jurassic Mic Mac Formation. A total of 18 m of net gas pay was identified within three Lower Missisauga (15.5 m) and one Mic Mac (1.5 m) sandstones. Sands 2 and 3 have log defined gas-water contacts and column heights of approximately 15 m consistent with the simple closure and suggesting a leak at the north bounding fault. Thin gas pay encountered in the upper Mic Mac Formation is also consistent with the simple closure suggesting a leak point at the bounding fault. Thinner than expected inter-sand sealing shales and unexpected sands within these, combined to compromise fault seal integrity resulting in gas leakage across the northern fault. The well was abandoned following a pressure kick of unknown composition within a deep Mic Mac interval over which no logs were run or samples recovered from.

3. Seismic Mapping over Parcels 1 and 2

Seismic interpretation was completed on eight 3-D surveys of varying quality. Seismic time dip line AA' passing through Parcels 1 and 2 is composed of three seismic surveys. This line illustrates the complex structuring below the Cretaceous section, as well as data quality variations between 3 of the surveys (Figure 6). The line location is shown on Figures 11 to 14. Time structure maps for 6 seismic markers (K78, K112, K130 and J147, base salt, and top salt) are presented in this study. The numerical designations of the markers correspond to approximate ages based on work that remains ongoing.

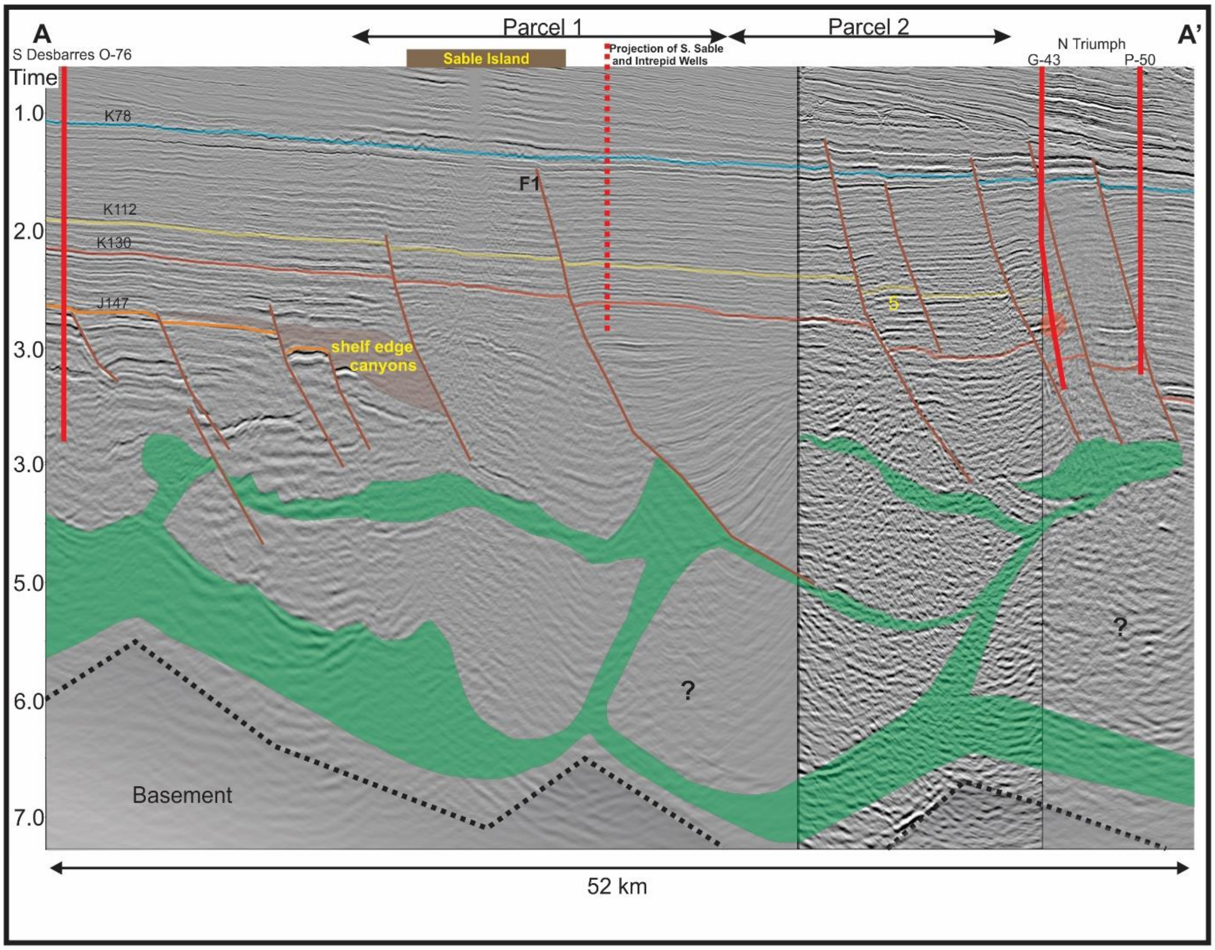

Figure 6. Seismic composite time dip line AA' through Parcels 1 and 2. North Triumph gas pay is indicated by red circle. Complex salt tectonics are influenced by crystalline basement geometries that are poorly imaged on the three seismic surveys in this composite. The J147 is incised by shelf-indenting canyons that define the slope break.

A likely interpretation of the poorly imaged crystalline basement pick is represented by dashed lines on this seismic composite. Salt interpretation on this data is also very challenging for several reasons:

- For deeper salt there is inadequate data for seismic migration due to the relatively shallow 7.5 second record lengths

- The merged seismic survey composed of 5 separate surveys often has insufficient data for adequate seismic migration of structures near the numerous survey edges

- Strong reflectivity from Jurassic carbonates intermingles with high amplitude salt welds, salt feeders and salt remnants that are difficult to differentiate on these data sets

- Seismic data collected from beneath the Sable Island footprint, indicated in brown on the cross section, is poor quality (Figure 6)

Seismic profile BB' is at a larger scale than AA' and crosses the edge of the Sable Horst (Figure 7). The down-to-margin fault of this horst block resulted from Jurassic aged Sable delta deposits loading autochthonous salt and expelling it to form the South Venture diapir system. This progradation is indicated by the black arrow.

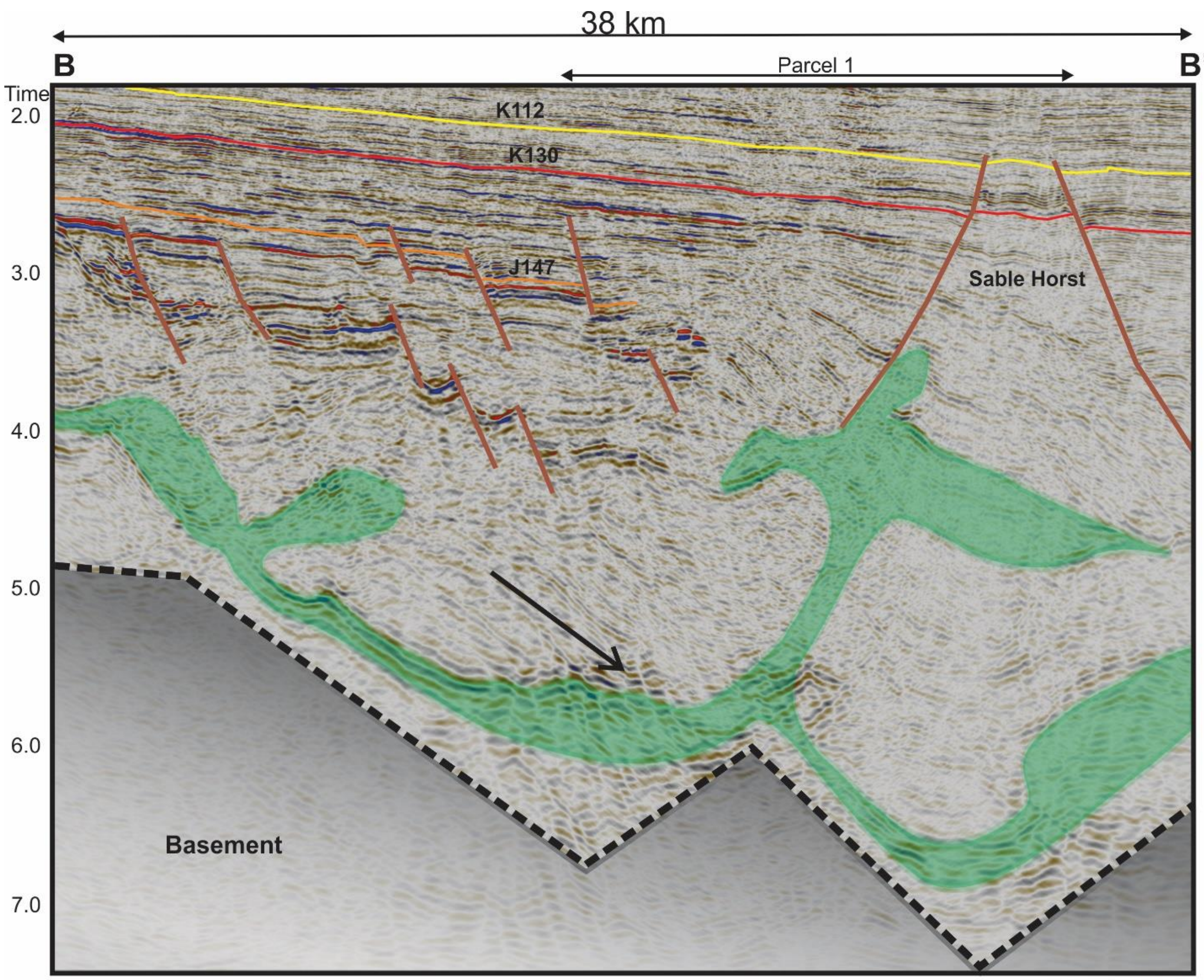

Figure 7. Seismic time dip line showing crystalline basement and salt. Both picks are very difficult on this data set. The black arrow indicates Jurassic aged delta progradation expelling autochthonous salt.

Base Autochthonous Salt

Basement thermal subsidence and salt withdrawal resulted in a thick Jurassic section below the boundary between Parcels 1 and 2 on AA'. A time map was produced on the base of the autochthonous salt which is the top of the synrift section (Figure 8). This shape is highly influenced by the morphology of crystalline basement and has three prominent ridges trending southwest to northeast. The basins observed inboard of these ridges originally contained thick autochthonous salt deposits that were extruded to diapirs and canopies. Salt feeders could have been associated with basement faulting along these ridges.

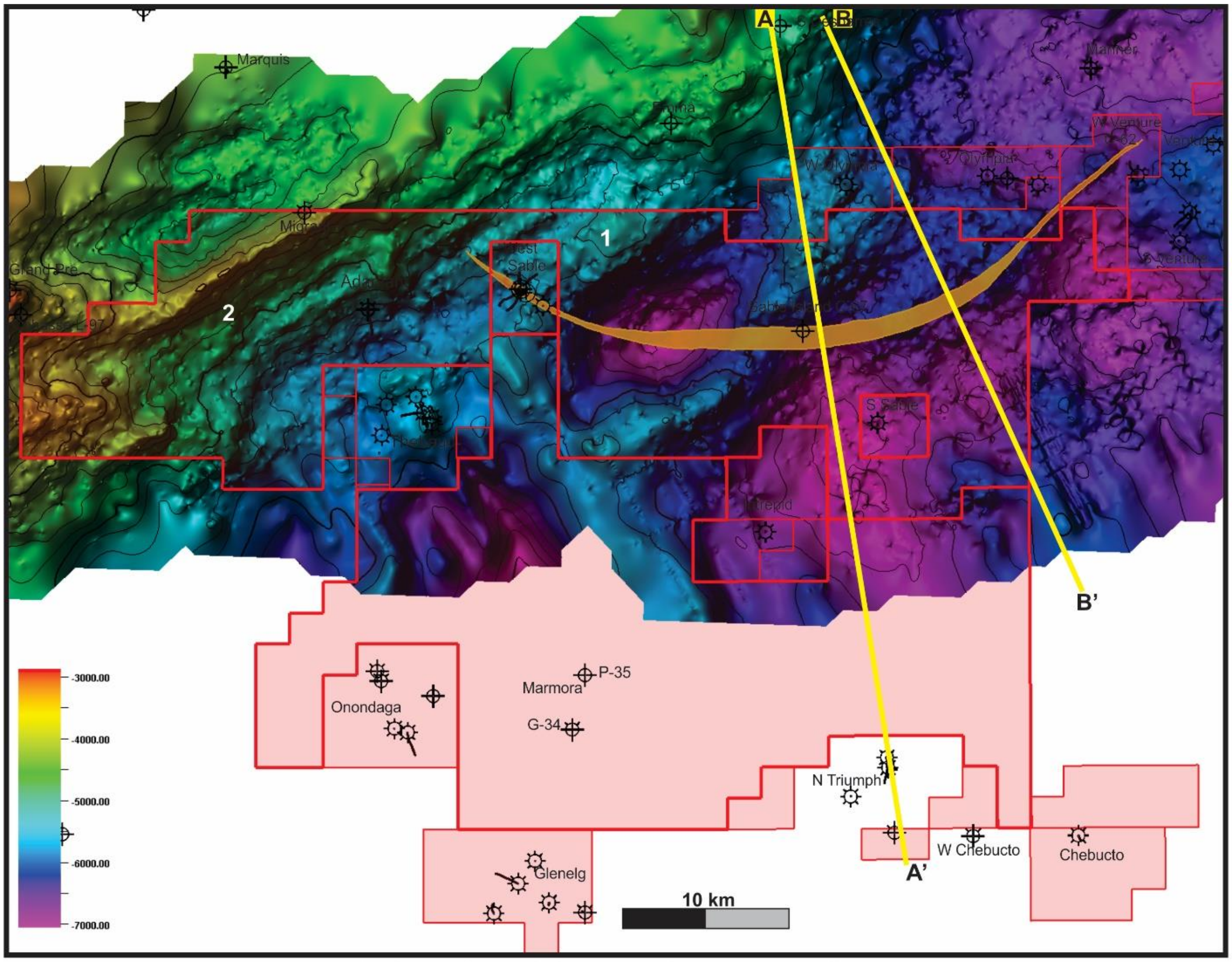

Figure 8. Time structure map on the base of autochthonous salt. Times range from 2800 to 7000 ms. A prominent basement ridge extends through the northwest corner of Parcel 1. Allochthonous salt is extruded out of the low areas forming diapirs and canopies above the ridges.

Top Allochthonous Salt

The top of allochthonous salt was picked over the merged 3-D survey. The main components of this salt were diapirs at Thebaud, Sable Island, South Sable, West Venture and South Venture. These diapirs are often connected and transition to extensive canopy systems. This is very challenging to display on a 2-D map view as many of the surfaces turn over on themselves at multiple levels.

A 3-dimensional view facing east shows the color scaled base of autochthonous salt underlying the red allochthonous diapir and canopy system developed above it (Figure 9). The salt system is a complex combination of remnant in-place bedded salt, feeder systems, welds and canopies. A salt feeder system can be seen sourcing salt from a mini-basin inboard of the plunging basement high.

Potential exists to define numerous salt related traps within this proven petroleum system but new seismic acquisition would be required in order to properly image this complex system.

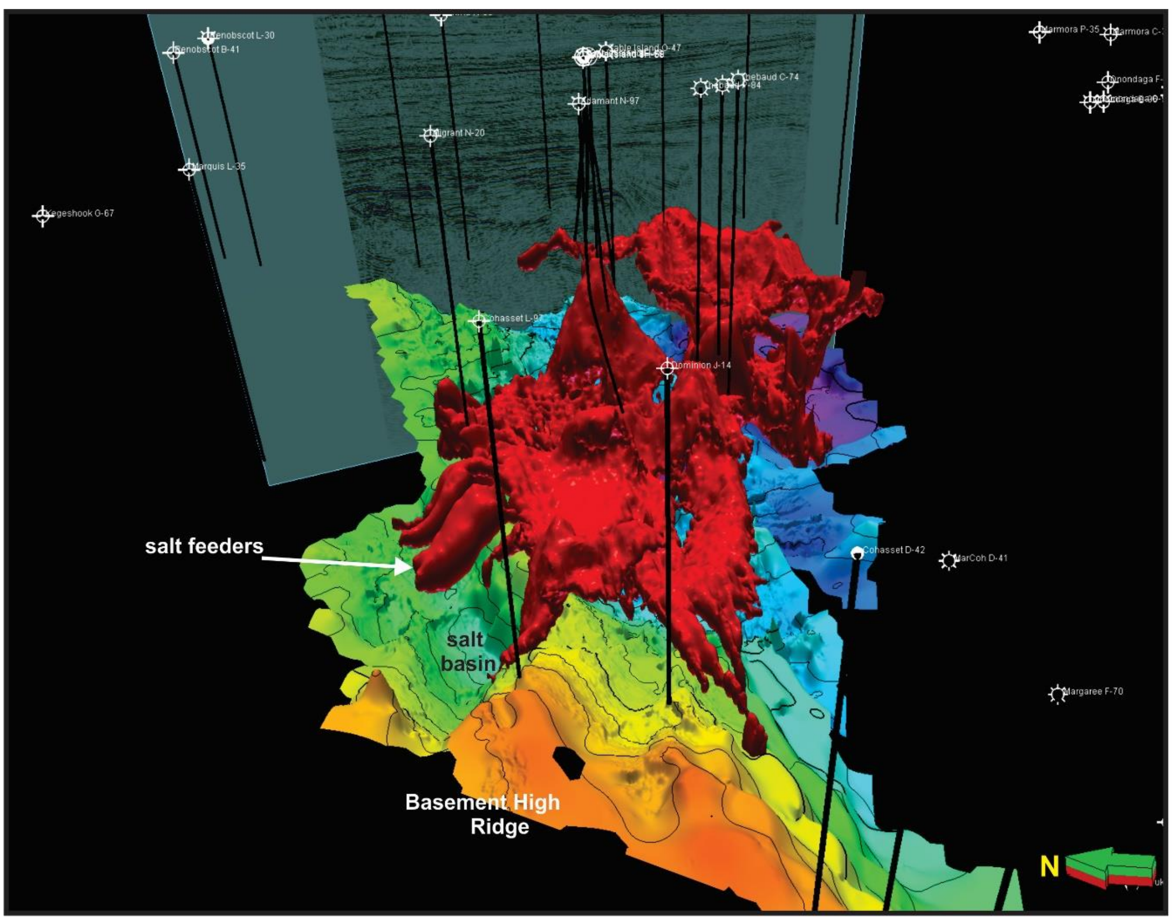

Figure 9. Three dimensional view including the color scaled base of autochthonous salt, and the solid red allochthonous salt. Salt feeders from behind the main ridge source the Thebaud, Sable island, and South Venture diapir systems.

J147

The Upper Jurassic Tithonian J147 marker, within the Mic Mac Formation, is the deepest mapped clastic unit in this study. The yellow shaded J147 surface (Figure 10) can only be confidently correlated over the northern half of Parcel 1 due to contact or proximity to allochthonous salt. As shown on the dip seismic line AA' highlighted in yellow (Figure 6), the J147 progrades over several down-to-basin growth faults before becoming incised by shelf edge canyon heads indicated by the grey shaded areas. Salt withdrawal influenced the shelf break location and subsequent incisions during this period. This area lies beneath the Sable Island footprint and is poorly imaged.

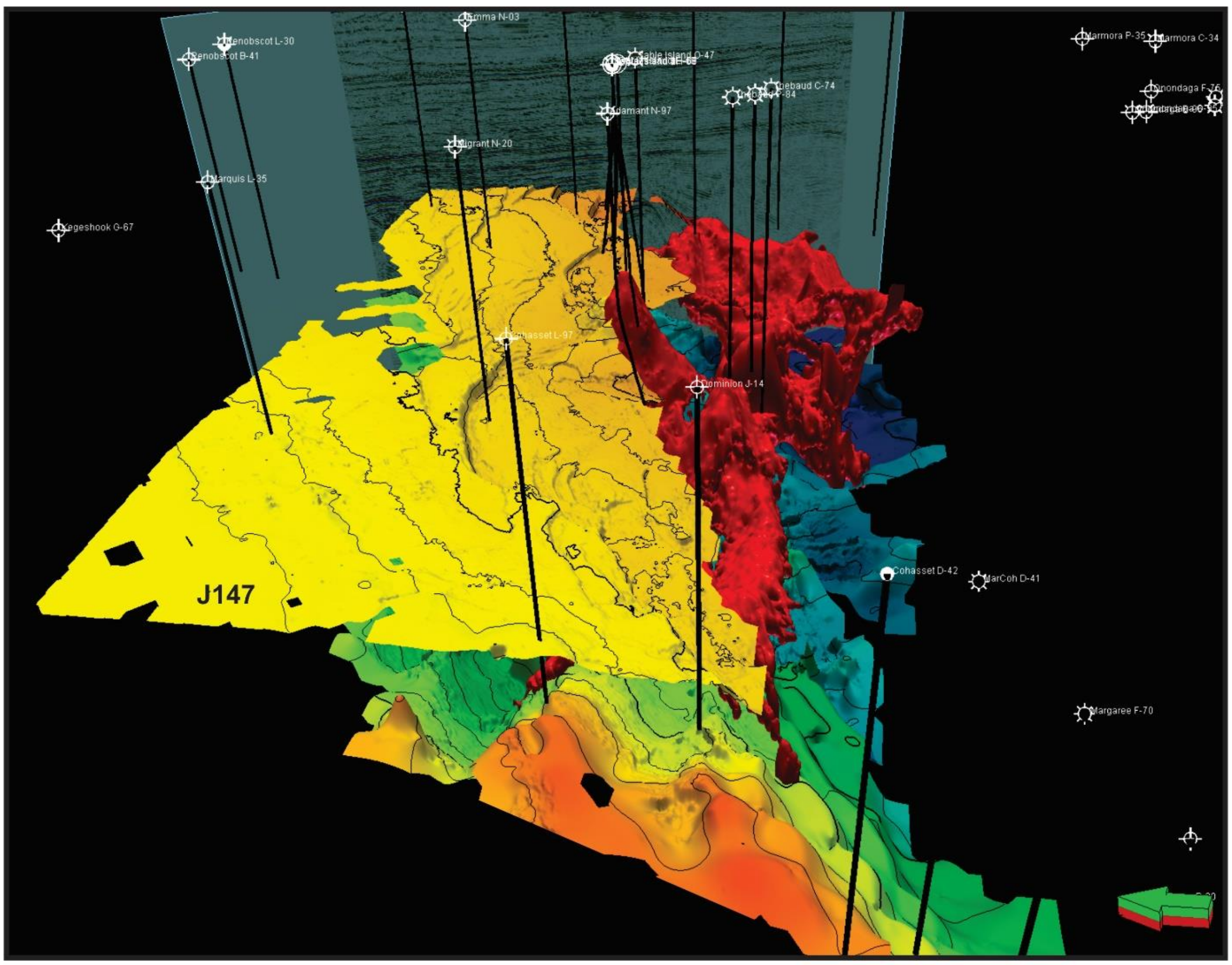

Figure 10. Three dimensional view including the color scaled base of autochthonous salt, solid red allochthonous salt, and the solid yellow J147 surface. The J147 salt contact is well defined along the diapiric section near the crest of the basement high, but becomes more transitional at the lower canopy to the east.

A 2-dimensional display of the J147 surface shows where the slope break limits the seismic interpretation as canyon heads erode back into the outermost shelf (Figure 11). From the west, the J147 surface is incised by shelf-indenting canyons. At the Thebaud and West Sable structures, the J147 subcrops on the green shaded allochthonous salt diapirs. Continuing west, the J147 is again incised by shelf edge canyons as shown on AA'. The salt contact in this area is difficult to define as the canopy and J147 reflections are very noisy beneath the Sable Island footprint. West of that zone, the J147 dips basinward to the down-to-margin fault of the Sable Horst which begins to appear on BB'. In the South Venture area, the J147 is again incised by shelf edge canyons.

Fault rollover structures associated with underlying salt movement, create Leads 1 and 2, indicated by the white numbers on the map. These leads are discussed in greater detail below.

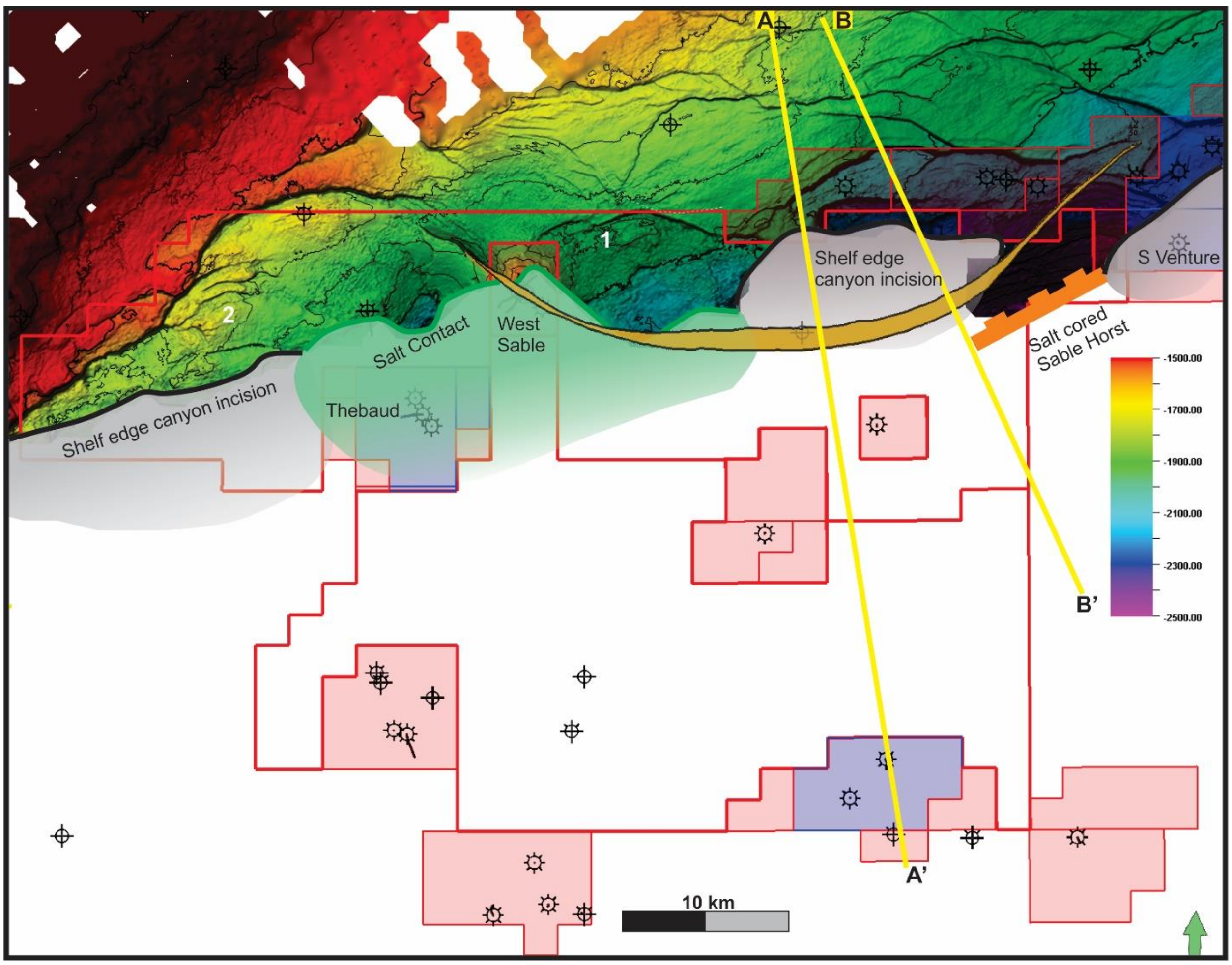

Figure 11. Time structure map on J147 marker. Times range from 2200 to 3800 ms. On Parcel 1, the J147 comes into contact with allochthonous salt. There is also a transition from sands and carbonates to a distal, shale prone sequence.

K130

The Early Cretaceous K130 horizon is near the O-Marker Formation in this area, which is a thin persistent interval of oolitic limestones and sandstones defining the boundary between the Upper and Lower Missisauga Formations (Figure 12). Rollover on the large salt withdrawal induced fault (F1) footwall forms the Intrepid and South Sable Significant Discovery structures, both of which have gas reservoirs near this level.

Structures along the next basinward fault trend, which includes the Marmora discovery, contain several undrilled closures that are discussed below (Leads 3 to 6b). These faults sole into deep salt roller structures that are very poorly imaged as they span the edges of two seismic surveys. Growth across this fault system makes it very difficult to correlate consistent markers below the K130 level across Parcel 2.

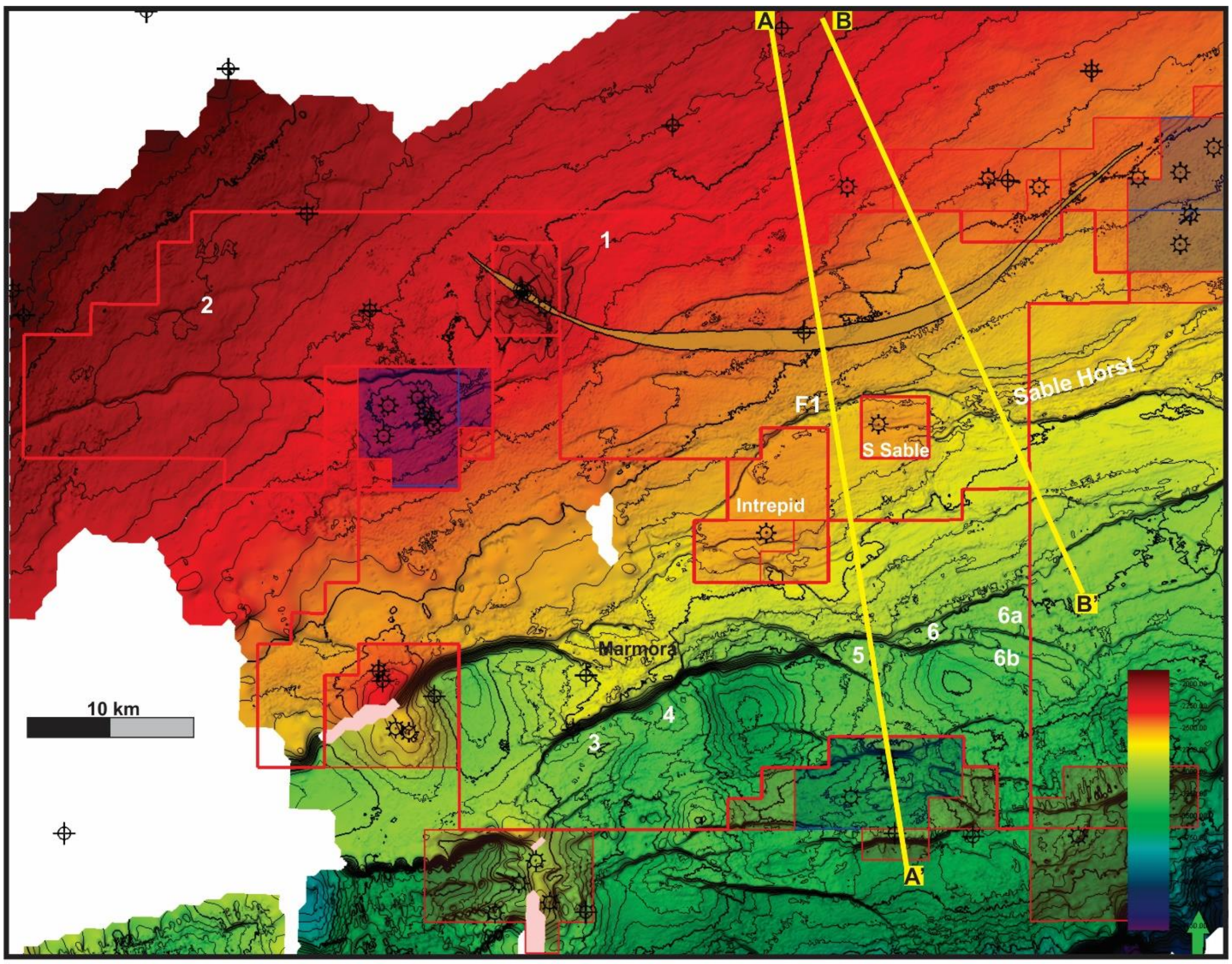

Figure 12. Time structure map on K130 marker which is near the O Marker Formation. Times range from 1500 to 2500 ms.

K112

The Early Cretaceous K112 marker ranges from top of Naskapi Member of the Logan Canyon Formation in the north part of the study area, to middle of the Naskapi Member in the south. The shale-dominated Naskapi Member succession thickens over Parcel 2 forming an effective seal above the Missisauga Formation sands in this part of the basin. The time structure map (Figure 13) indicates fault throws increasing basinward.

The K112 time structure map mirrors structure at the top of the Missisauga Formation, which is the main reservoir section for many of the surrounding Significant Discoveries. Leads 5, 6, 6a, and 6b are faulted closures at this level and discussed below in section 6.

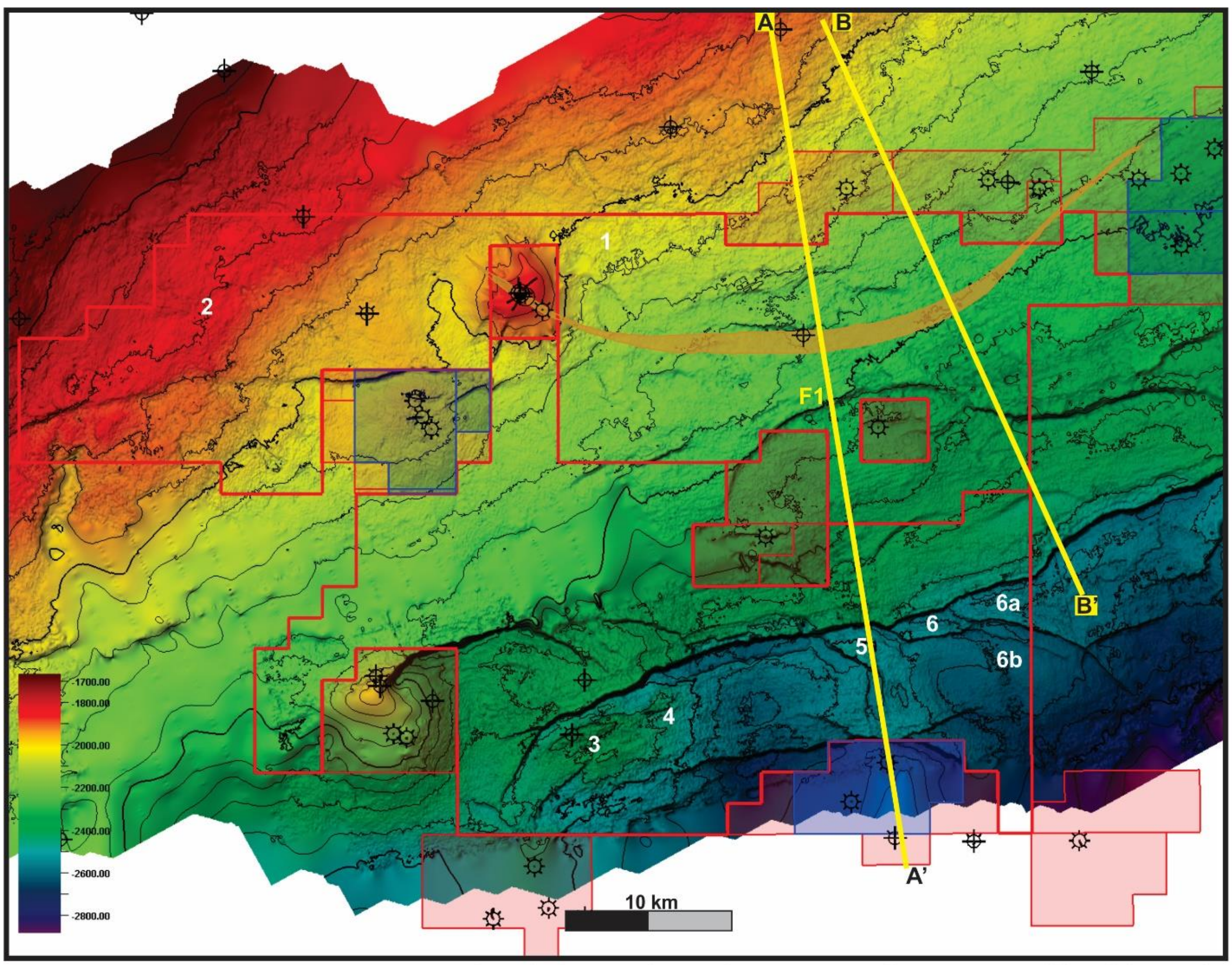

Figure 13. Time structure map on K112 marker which, over this study area, ranges from top to middle of the Naskapi Member of the Logan Canyon Formation. Times range from 1700 to 2700 ms.

K78

The Late Cretaceous K78 marker approximates the top of the Wyandot Formation in this area. The time structure map (Figure 14) reveals a large mass transport system (Smith et al., 2010) near the center of Parcel 2 just east of the Marmora wells. The Eagle gas discovery 14.5 km east of Parcel 2 has 52 m of net gas pay within the Wyandot Formation with 1.27 TCF mean original gas in place (Smith et al., 2010).

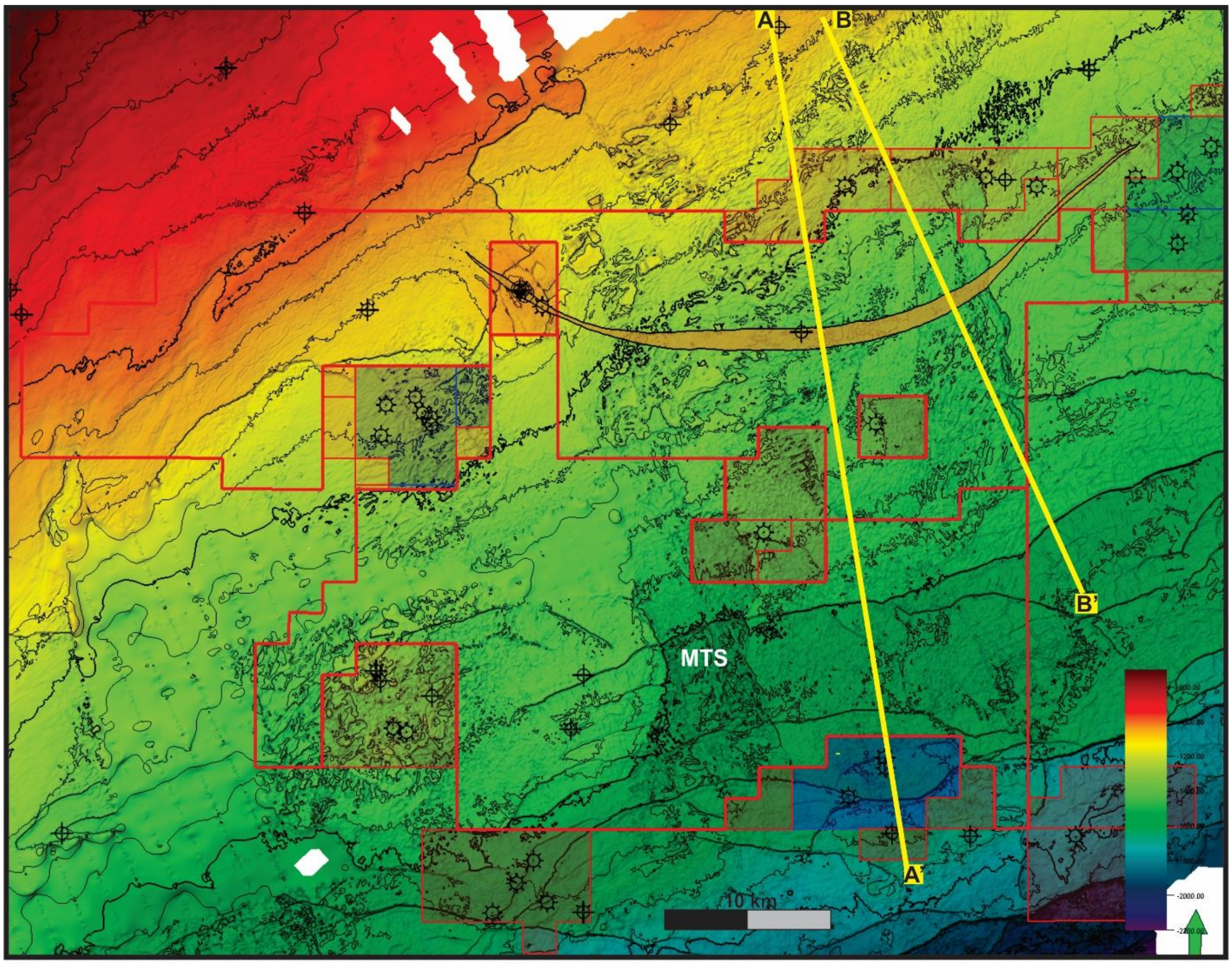

Figure 14. Time structure map on K78 marker which approximates the top of the Wyandot Formation. Times range from 800 to 2200 ms.

4. Marmora Discovery

The Marmora structure was discovered in 1972 and remains undeveloped. The fault-bounded rollover anticline resulted from sediment induced motion of the deep underlying salt (Figure 15). The main Marmora fault is a large seaward dipping down-to-basin growth fault soling into allochthonous salt. A smaller antithetic landward dipping fault, less than 1 km south of the main Marmora fault, creates a narrow graben between these two faults and defines the northern limit of the Sand 1 gas pool. The Marmora structure has several crestal faults resulting from deeper salt movement. While fault throws are generally minor, sand-to-sand juxtaposition may have created a spill point for the Sand 1 gas pool. The Marmora Sand 1 trap combines three-way dip with fault dependent closure and is located at the top of the Early Cretaceous Upper Missisauga Formation. Sand 1 is just below the thick Naskapi Member shale, which provides top and lateral seal along the northern Marmora fault. The trap configuration at Marmora is similar to the Onondaga and North Triumph gas discoveries, both having over 30 m of net gas pay at the top of the Missisauga.

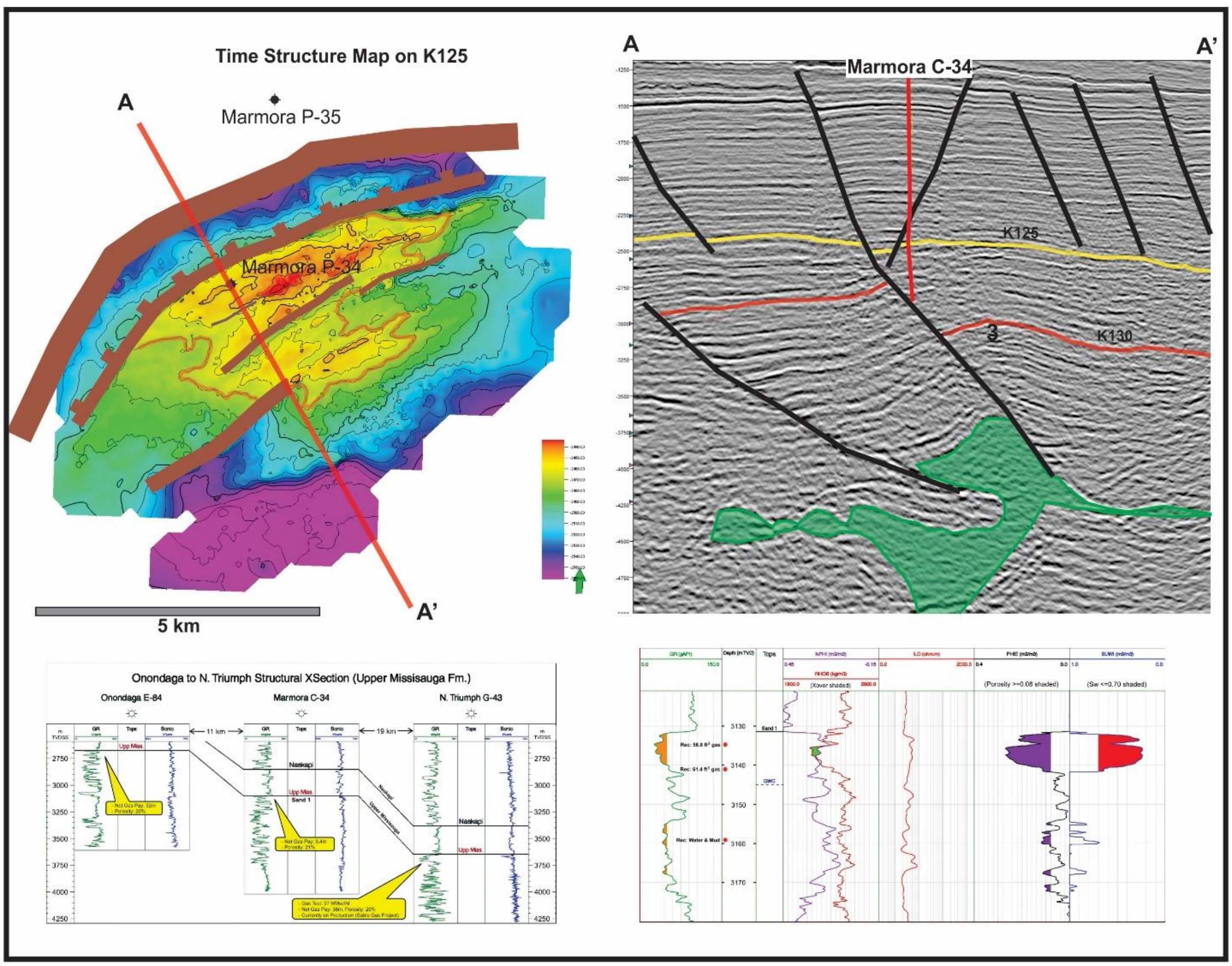

Figure 15. Marmora gas discovery panel with time structure map, seismic dip line, geologic cross section, and well logs indicating the pay zone.

Marmora C-34 was drilled the in 1973 and although no well tests were conducted, well logs and wireline tester samples confirmed the presence of a high quality, gas bearing, normally pressured reservoir sand in the upper Missisauga Formation (Sand 1). Sand 1 was the only significant hydrocarbon-bearing zone encountered in in the well. The sand is a coarsening-upward shoreface sequence that is fine- to coarse-grained, with subangular to rounded and medium to well sorted grains. Sand 1 has very good to excellent reservoir properties with porosities up to 27% (average 21%) and estimated permeabilities up to 400 mD. The sand has a log-defined gas-water contact that is consistent with the recovered wireline tester samples.

The CNSOPB conducted a probabilistic resource assessment of the Marmora gas field. All closure areas are based on time structure maps. The most likely area was determined by projecting the interpreted gas water contact (GWC) onto the Sand 1 (Upper Missisauga) time structure map that results in an area of 8 km^2 (Figure 11). The minimum area of 7.2 km^2 was determined by reducing the most likely area by 10% to allow for mapping uncertainty. The maximum area of 12.5 km^2 was assigned by lowering the interpreted GWC to the next closing contour. The remaining probabilistic input parameters were based on petrophysical analysis results, with consideration given to the position of the Marmora C-34 well on the structure.

Marmora C-34 Sand 1 Petrophysical Results					
Top Sand	Base Sand	Net Pay (TVD)	Area	Average Porosity	Average Water Saturation
3132.8 m	3176.3 m	9.4 m	8 km^2	21%	33%

Marmora C-34 Sand 1 Original Gas In Place			
P90	P50	P10	Mean
113 BCF	145 BCF	187 BCF	148 BCF

Marmora C-34 Sand 1 Recoverable Gas			
P90	P50	P10	Mean
78 BCF	102 BCF	132 BCF	104 BCF

5. Exploration Leads on Parcels 1 and 2

In addition to the Marmora discovery, eight specific exploration leads were identified in Parcels 1 and 2. The numbers displayed on the maps correspond to the leads discussed below. All of the leads are described on time structure maps as depth conversions have not been completed.

There is also wide potential for plays involving salt trapping, but new seismic acquisition would be required to properly assess this potential.

1. Dolphin

The Dolphin lead is located on Parcel 1 approximately five kilometers north of Sable Island. The structure is a fault-bounded rollover anticline with three-way dip closure at the J147 level (Figure 16). Aerial closure is restricted by dip reversal towards the West Sable salt diapir, which could be better defined through detailed depth conversion. The structure is under varying degrees of closure extending from the early Cretaceous Lower Missisauga Formation, to the mid to late Jurassic Mic Mac Formation. Within this target interval, reservoirs are expected to be stacked fluvial deltaic sands similar to those encountered in nearby wells.

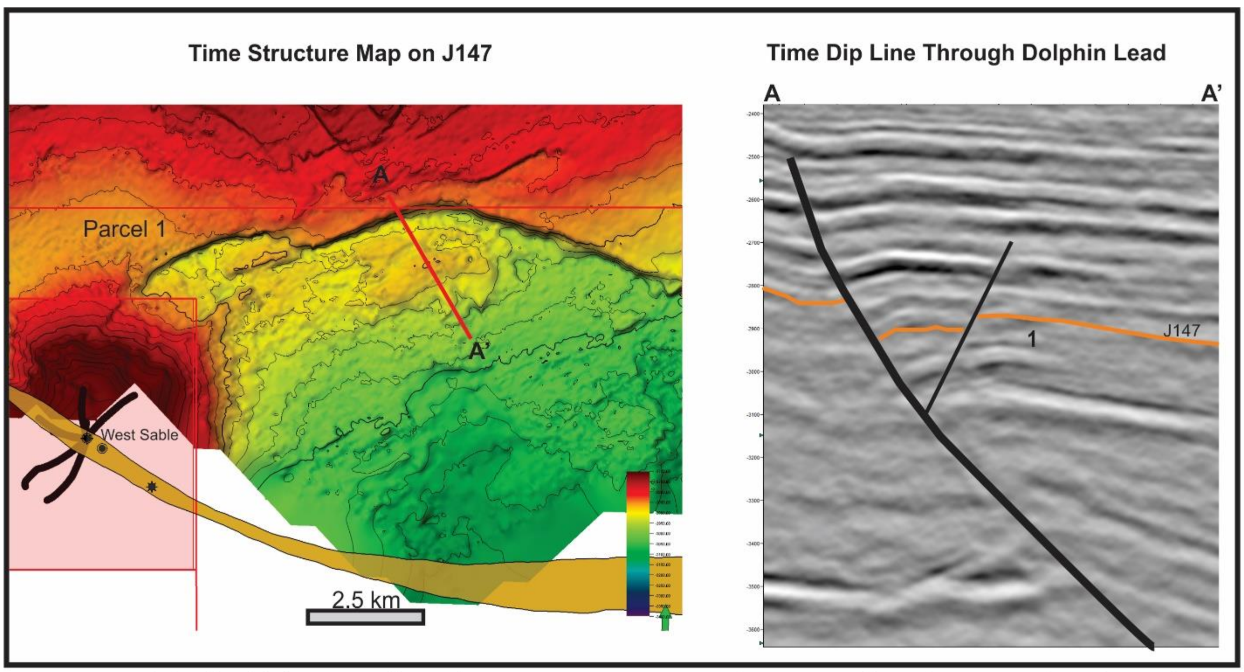

Figure 16. Dolphin lead (1) on Parcel 1 with time structure map on the J147 marker. The seismic line shows the J147 marker in orange.

2. Propeller

The Propeller structure is a group of leads separated by faults located 18 km west of Sable Island in Parcel 1 (Figure 4). The faulted rollover anticlines are formed by movement of the underlying salt canopy, caused by sediment loading (Figure 17). The traps are a combination of simple and fault dependent closures that extend from the mid to late Jurassic Mic Mac Formation, up to the early Cretaceous Lower Missisauga Formation. Expected reservoirs would be stacked fluvial deltaic sands. There may also be potential for subsalt Jurassic traps but poor seismic resolution of salt and basement structure makes trap definition challenging on this data set.

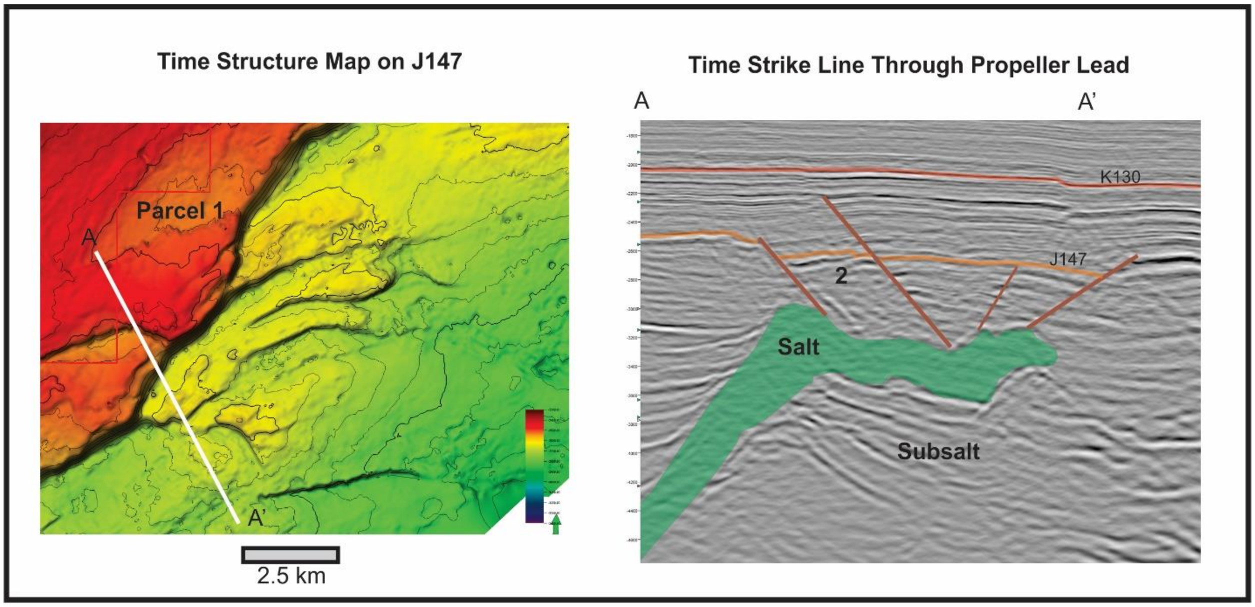

Figure 17. Propeller lead (2) on Parcel 1 with time structure map on the J147 marker. The seismic line shows the J147 marker in orange and the K130 in red.

3. South Marmora

The South Marmora lead is located on Parcel 2, two kilometers southeast of the Marmora gas discovery (Figure 18). The structure defined by the K130 marker, is a fault bounded rollover anticline resulting from sediment-induced motion of the underlying salt. The South Marmora trap has simple closure interpreted to extend from the mid to late Jurassic Mic Mac Formation, up to the early Cretaceous Lower Missisauga Formation. Within the Missisauga to Mic Mac target interval the reservoir sands are expected to be stacked deltaic sands similar to those encountered in nearby wells.

Four kilometres southwest and updip of South Marmora is the North Glenelg lead, which is within in the footwall of the Glenelg bounding fault. The Glenelg J-48 gas well was declared as a Significant Discovery in 1989 and although approved for development within SOEP, the Glenelg field was never put on production.

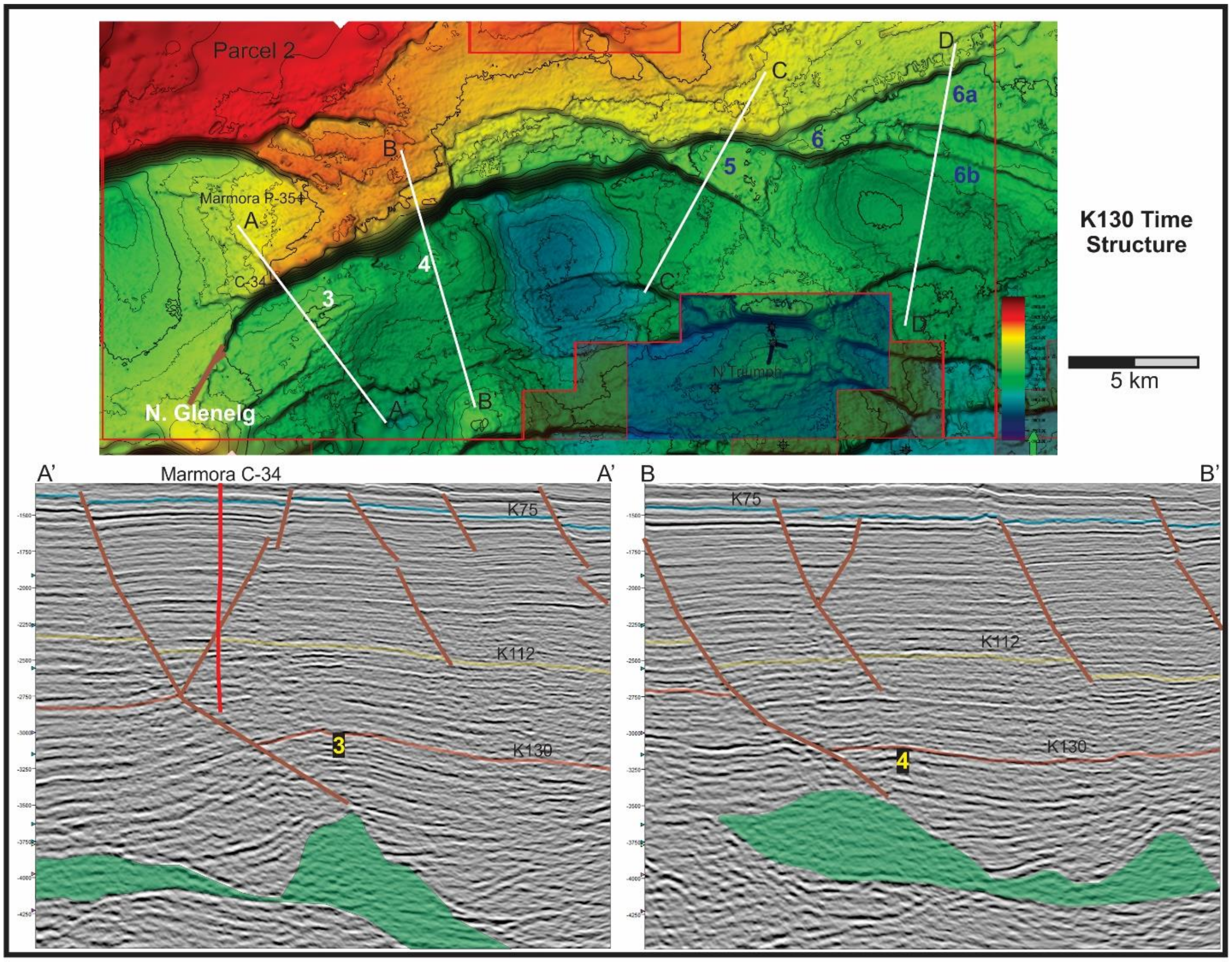

Figure 18. Time structure map on K130 marker with seismic lines showing South Marmora (3) and East Marmora (4) leads at this level.

4. East Marmora

The East Marmora lead on Parcel 2 is located approximately five kilometers northeast of the South Marmora lead (Figure 18). The structure identified on the K130 time structure map is a fault bounded rollover anticline resulting from underlying salt movement. The East Marmora trap has simple and fault-dependent closure extending from the mid to late Jurassic Mic Mac Formation, up to early Cretaceous Lower Missisauga Formation, with reservoirs interpreted to consist of stacked deltaic and increasingly shallow marine sands with depth.

5. Tuna

The Tuna lead on Parcel 2 is 10 km east of the East Marmora lead along the same fault trend (Figure 19). The structure is a fault bounded rollover anticline within Upper Missisauga strata with fault bounded closure at the K112 level. Amplitude anomalies are also evident on the displayed seismic line at various levels. Underlying salt movement has resulted in a north-south trending anticline extending south and forming the hanging wall for the North Triumph gas field, which is a significant gas producer within SOEP.

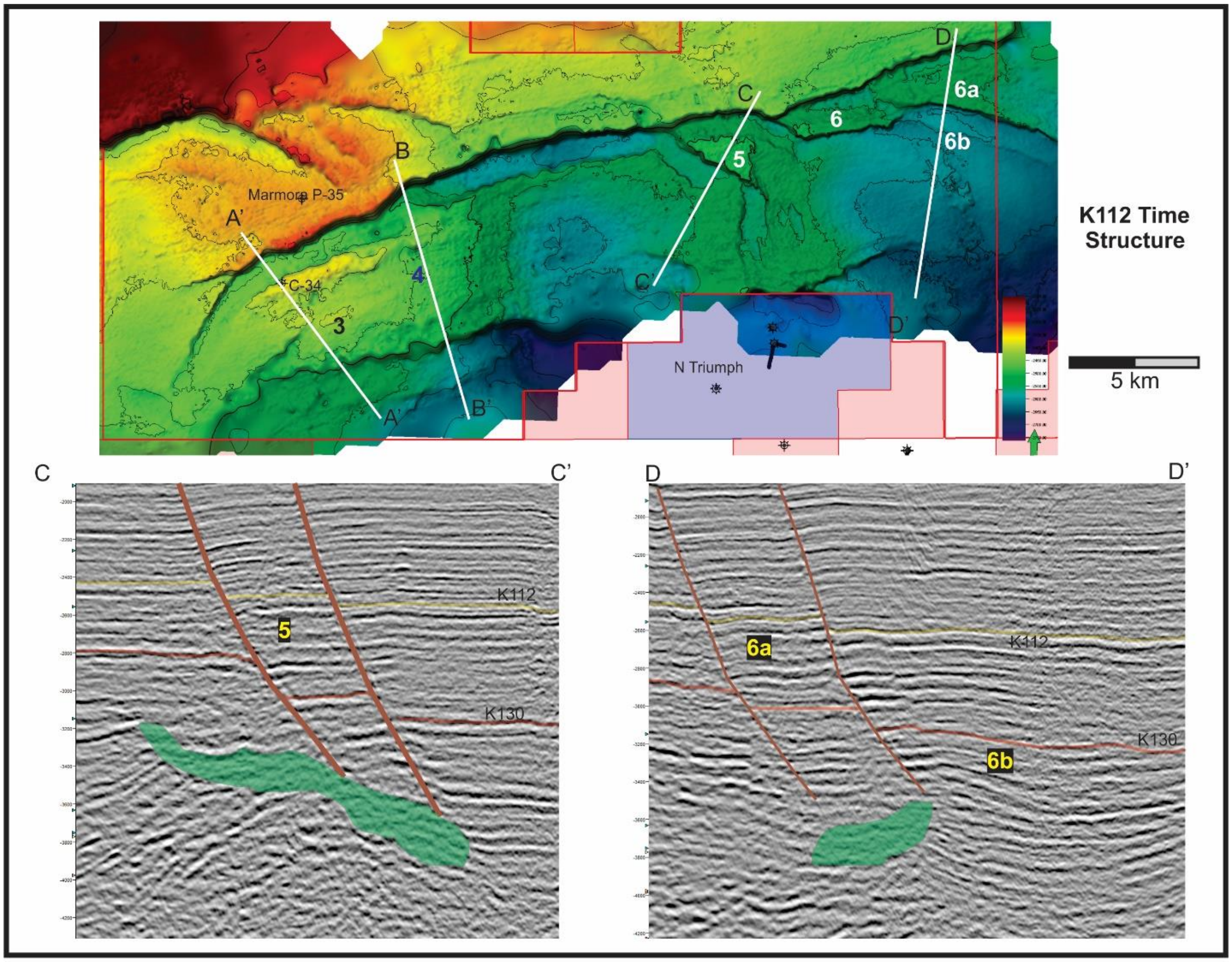

Figure 19. Time structure maps on K112 marker with seismic lines showing Tuna (5) and Molega (6, 6a, 6b) leads.

6. Molega

The Molega series of leads (6, 6a, 6b) are located at the eastern extent of Parcel 2 along the same fault trend as Leads 3, 4 and 5 (Figure 15). The structures are rollover anticlines within the Upper Missisauga Formation and located along strike of Upper Missisauga gas discoveries such as Alma, Onondaga, Glenelg, South Sable, North Triumph and Intrepid (Figure 13). These outer margin discoveries correspond to a zone across the shelf where both the Upper Missisauga Formation and Naskapi Member are thickening. The Naskapi Member is over 200 m thick in this area providing an effective top seal for the Upper Missisauga Formation. The Molega 6b structure has elevated amplitudes that may correspond to structure and fault contacts, suggesting an effective fault seal similar to proven Upper Missisauga traps nearby.

6. SOURCE ROCKS

The Province of Nova Scotia's Play Fairway Analysis (OETR, 2011) compiled and updated historical research on petroleum source rocks, and in addition to undertaking new analyses incorporated these into new petroleum systems modelling for the basin. The cumulative result of this and all previous studies established the identities of the main source rock intervals, and characterised the properties of several families of oils. Four main intervals are known. A fifth (marine) source rock interval of Early Jurassic age is interpreted from geochemical (seep and petroleum analysis) evidence and comparative studies (OETR, 2011). A speculative sixth source (Late Triassic-earliest Jurassic) is inferred from onshore successions but has no direct evidence to date. All source intervals are grouped into major, minor or potential contributors of hydrocarbons that are dependent on their geochemical and spatial attributes, depth of burial, maturation and other available data.

Major

- Late Jurassic: Tithonian carbonate to deltaic transition MFS (Abenaki / Upper Mic Mac to Lower Missisauga Formations) – OIL & GAS – (known)
- Early Jurassic: Pleinsbachian to Toarcian restricted to near-normal marine (Mohican and Iroquois Formation distal equivalents) – Dominantly OIL, Minor GAS (interpreted / modelled)

Minor

- Early Cretaceous: Intra-Aptian deltaic MFS (Naskapi Member, Logan Canyon Formation) – Dominantly GAS, Minor OIL
- Early Cretaceous: Berriasian / Valanginian deltaic MFS (Lower Missisauga Formation) – Dominantly GAS
- Middle Jurassic: Callovian marine MFS (Misaine Member, Abenaki Formation) – Dominantly GAS, Minor OIL

Potential

- Late Triassic: Carnian-Norian lacustrine to restricted marine (Eurydice Formation and equivalents) – Dominantly GAS, Minor Oil?

The Tithonian source rock interval is believed through previous research and modelling to be the most important contributor of hydrocarbons in the Scotian Basin. It was deposited during the transition from carbonate (Abenaki Formation) to deltaic (Mic Mac Formation) sedimentation corresponding to the lower part of the Verrill Canyon Fm. MFS. The shale was deposited in a shallow, open marine shelf setting that appears to have been slightly anoxic. This source rock has been difficult to identify due to the use of lignosulfate in the drilling mud in well penetrations when approaching overpressure zone that usually corresponds with the top of the Jurassic. Kerogen microscopy appears to be the best way to define / identify this source rock, which is composed of Type IIA/IIB-III kerogen capable of generating gas, condensate and oil from a terrestrial to mixed terrestrial-marine source (Mukhopadhyay and Wade, 1990).

Although natural gas has been the predominant hydrocarbon discovered and produced in the Scotian Basin (i.e. Sable Subbasin), liquid petroleum is present and through analyses has been differentiated into three to five families. Powell and Snowdon (1979) defined three oil and condensate families source predominantly by terrestrially dominated deltaic and marine shales of the Mic Mac, Missisauga and Verrill Canyon formations. In the 1990s, P.K. Mukhopadhyay undertook a comprehensive study of Scotian Basin hydrocarbon and source rock characterizations and relationships in association with the Geological Survey of Canada with a number of important papers and research contributions published. Mukhopadhyay *et al.* (1995), using cluster analysis of polyaromatic compounds, defined two oil families. Group I comprises high maturity condensates and associated gas derived from a terrestrial source (Type IIB/III kerogens). Group II oils from the Cohasset-Panuke-Balmoral fields suggest a marine source generated from mixed organic matter types (Type IIA/III kerogens).

In a geochemical analysis of oils and condensates from the Sable Subbasin, Illich *et al.* (1999) defined five oil families (three larger groupings). Two Families, A and B, were determined to have been generated from terrestrial type (III) organic matter from two closely related sources. The third, Family C, may represent the products of oil mixing since they have geochemical compositions indicative of terrestrial (Type III prodeltaic) and marine (Type II, carbonate-rich) source rocks. The remaining oils were grouped into two catch-all families, D and E. These contain very mature oils, some with unique compositions, and others that could be contaminated with drilling additives. They all have slightly different maturities that could represent separate source intervals. A Family D oil from the Venture D-23 well (4889m, DST No.4, 6U sand, Missisauga Fm.*) contained an above background level of gammacerane though the source rock and its age is unknown, but could be from an older, Early Jurassic source. (* Note: Illich *et al.* (1999) do not indicate the formation and DST number, and the 4771 m sample depth is incorrect.)

Fowler and Obermajer (2001) defined three families of liquid hydrocarbons (1, 2 and 3a & 3b) in the Scotian Basin. Each has characteristic properties, maturation profiles and geographic separation suggesting they came from separate source rocks, with most sourced from terrestrially-derived organic matter (Type II-III). The high gravity (47-55 API) oils from the Cohasset, Panuke, Balmoral and Penobscot fields are from Family 1 and are probably the least mature. Family 2 oils are found in the Arcadia, Banquereau, Glenelg and North Triumph shelf-edge fields in the Sable Subbasin and were generated from rocks with greater levels of higher land plant material than the others, or, that they are less mature. Family 3 oils may be due to a mixture of the Family 1 and 2 oils. Since Family 1 oils are only found in the Cohasset area on the west side of the Sable Subbasin, and Family 2 in the North Triumph area in the south, this significant geographic separation supports the interpretation that they are from different sources. This study indicated that the Scotian basin oils and condensates had Ro equivalents of between 0.7 and 0.94% confirming generation in the central part of the oil window.

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