## SECTION 5 – GEOCHEMISTRY

Four regional source rock intervals are known in the Scotian Basin, with a fifth – the Early Jurassic – speculative and based on very limited data. They are grouped into major or minor potential contributors of hydrocarbons that are dependent on their geochemical and spatial attributes, depth of burial, maturation and other available data, and all were modelled in the OETRA Play Fairway Analysis – PFA (OETR, 2011) (Figure 5.1). The Late Triassic (lacustrine) synrift succession could be a sixth source rock interval but has not been penetrated or modelled.

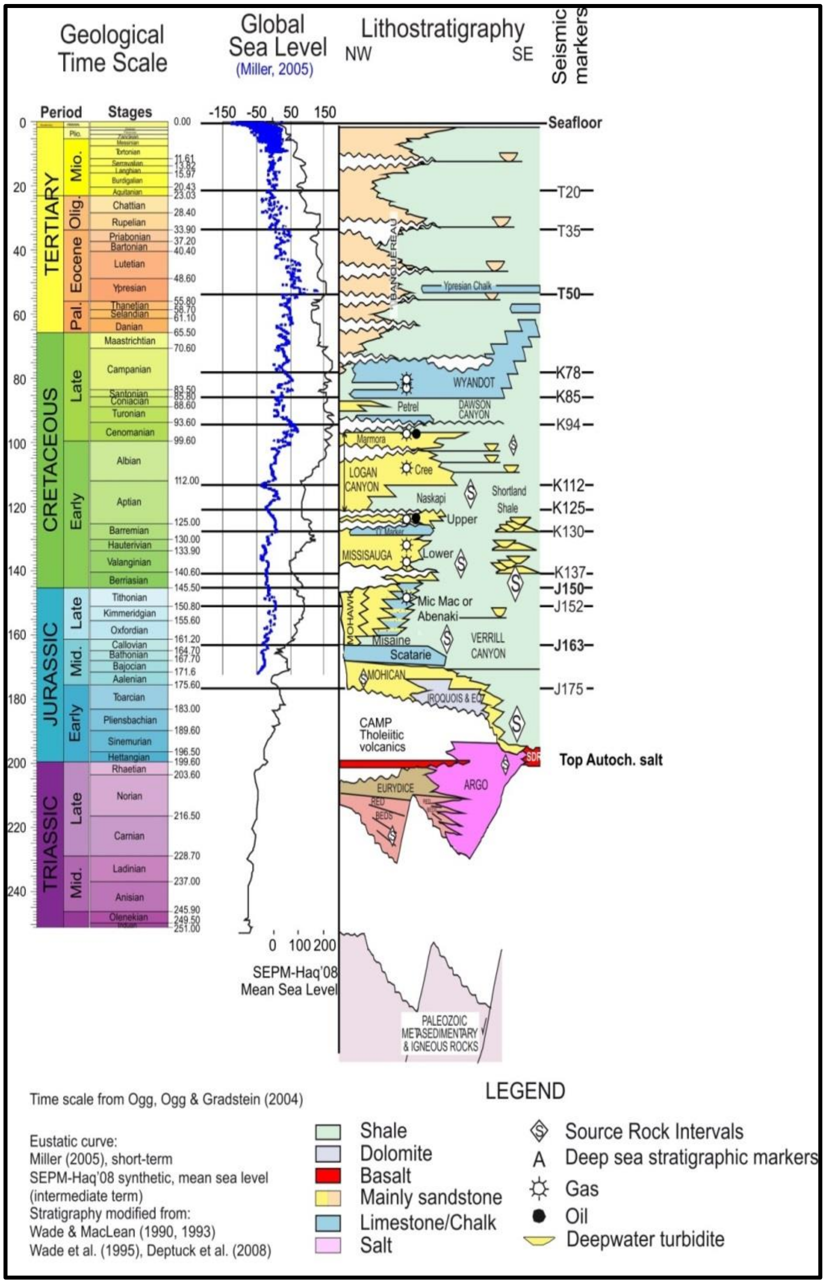


***Figure 5.1:*** *Scotian Basin stratigraphic column with associated main seismic horizons and source rock intervals. The main know and speculative source rock intervals are represented by red diamonds (this report; modified after OETR, 2011).*

Since the first well in 1967, natural gas has been the predominant hydrocarbon discovered and produced in the Scotian Basin, though significant quantities of light oil have also been found and produced. Liquid petroleum – oils and condensates – has been analyzed and differentiated into three to five families as detailed below.

MAJOR

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

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 late synrift pre-salt continental lacustrine successions – GAS & OIL?

Within the Call for Bids NS15-1 Call region, all five defined source intervals were modelled using the Temis™ basin modelling program (1D, 2D and 3D modules) to determine maturation, expulsion, trapped hydrocarbon volumes and characteristics. The speculative Early Jurassic source interval, if present, is modelled to have the best source rock potential for oil and is generating hydrocarbons today. Of the remaining four confirmed source rocks, the Late Jurassic Tithonian major source interval is believed to have very good potential to have generated liquid hydrocarbons. The two Early Cretaceous intervals – the Berriasian / Valanginian, and Aptian – are considered minor source rocks though in the deep water successions they may play a greater role. The Middle Jurassic Callovian MFS interval is greatly influenced by deltaic sedimentation though may have potential distally where under marine influence. The Late Triassic's potential is speculative. In all cases, the products of early hydrocarbon generation and migration would be compromised by risks associated with time of maturation and migration, trap preservation, reservoir degradation, and tectonism.

NOTE: The following sections present an overview of the areas included in this NS15-1 Call for Bids: Western Region (Parcels 1-4) and Central Region (Parcels 5-7), with abbreviated comments for the Eastern Region (Parcels 8-9).

**Source Rocks**

Research on the identification and characterization of Scotian Basin source rock intervals has been ongoing since the mid-1970s. Most of the published geochemical research was by researchers of the Geological Survey of Canada (e.g. J.P. Bujak, T.G. Powell, L.R. Snowden, D.R. Issler, M.G. Fowler, M. Obermajer and M.P. Avery) and others such as P.K. Mukhapadhyay (see References for representative citations). Concurrently, the petroleum industry and specialist firms undertook similar studies and analyses, as well as others by consultants and academics, the results of which are available from the CNSOPB's Geoscience Research Centre / Data Management Centre.

The province of Nova Scotia's Play Fairway Analysis – PFA (OETR, 2011) compiled and updated historical research and existing analyses on petroleum source rocks, and in addition to undertaking some new analyses incorporated these into new petroleum systems modelling for the basin. However, it was recognized that new data and more analysis would be required, and would establish the foundation for new studies.

Beginning in 2014, a new regional research initiative was begun to better understand and quantify source rock successions in the Scotian (Mesozoic-Tertiary) and Sydney (Carboniferous) offshore basins. This research will include the auditing of existing analyses and data to determine gaps, collection of new piston cores on seeps based on satellite seep data, organic and inorganic analyses of source rock intervals, geochemical analyses of selected oils and extracts from reservoir and sources rock, and petroleum systems / basin modelling (1D, 2D and 3D). Particular emphasis is directed towards the western Scotian Basin and confirmation of the Early Jurassic source interval. Results of this major study will be released over the 2014-2015 period.

The cumulative result of the existing studies identified the main source rock intervals, and characterised the properties of several families of oils (Table 5.1). They range from Middle Jurassic to Early Cretaceous age and are marine shales of the Verrill Canyon Formation and its lateral MFS expression within the proximal fluvial-marine successions of the Mic Mac, Missisauga and Logan Canyon formations.

Other source rock intervals identified in Early Cretaceous and younger strata have good TOCs (e.g. Logan Canyon Formation; 2-4%) but shallow in the stratigraphic succession of the Call for Bids area and hence immature. A fifth new marine source rock interval of Early Jurassic age is inferred from geochemical (seep and petroleum analysis) evidence and comparative studies that are described below (OETR, 2011). A speculative sixth source (Late Triassic) is inferred from onshore successions but has no direct evidence to date.

| Source Rock | Approx. Age | Initial TOC | Kerogen type Initial HI | Description |
|---|---|---|---|---|
| APTIAN | 122 Ma | 2 % (constant) | III (continental)<br>HI = 235 mgHC/gTOC<br>(Dogger. North Sea) - Open system kinetics - Vandenbrouke et al. 1999 | Potential source rock in the Naskapi shale (and equivalent), identified in some wells.<br>Variable effective thickness between 0 – 100 m. |
| VALANGINIAN | 136 Ma | 1 % (constant) | III (continental)<br>HI = 235 mgHC/gTOC<br>(Dogger. North Sea) - Open system kinetics - Vandenbrouke et al. 1999 | Very poor and scattered source rock (coal fragments in deltaic environment, through the Mississauga formation)<br>Variable effective thickness between 0 – 200 m. |
| TITHONIAN | 148 Ma | 3 % (constant) | II-III mix<br>HI = 424 mgHC/gTOC | Best defined SR, widely proven.<br>Variable effective thickness between 0 – 50 m. |
| CALLOVIAN | 160 Ma | 2 % (constant) | II-III mix<br>HI = 424 mgHC/gTOC | Potential source rock in the Misaine shale (and equivalent), uncertain extend and richness due to the lack of data.<br>Variable effective thickness between 0 – 20 m. |
| PLIENSBACHIAN (L. M. Jurassic) | 196 Ma | 5 % (constant) | II (marine)<br>HI = 600 mgHC/gTOC<br>(Toarcian. France) - Open system kinetics - Behar et al. 1997 | Suspected, not proven.<br>Potentially present above salt basins only.<br>Assumed average thickness 20 m. |

***Table 5.1**. Scotian Basin source rocks intervals (confirmed and speculative). Information on initial TOC and kerogen types are average values for use with basin modelling (Temis 3D™) is based on well data and global analogues. Not included here are the speculative lacustrine source rocks from the Late Triassic (OETR, 2011).*

Early Jurassic – Pleinsbachian to Toarcian restricted to near-normal marine
Iroquois Formation(?) distal equivalents

The OERA PFA source rock compilation and assessment reviewed and consolidated extant data and interpretations with new data acquired from analyses of bottom seeps (GeoMark, 2001), as well as undertaking its own analyses. From these data and comparative study with known source rocks from other circum-Atlantic basins, a new, fifth regional source rock interval is postulated. Though not yet penetrated, this Pleinsbachian to Toarcian age regional source rock is modelled to be oil-prone with Type II kerogens and deposited in a restricted to normal marine setting.

An important recent contribution to evaluating the Scotian Basin's source rocks was a study by GeoMark (2001) and incorporated into the PFA. This study analysed piston core samples taken along the deep water Scotian Slope, and compared the extracted hydrocarbons with those from the Scotian Basin (shallow water) and the Jeanne d' Arc Basin, Newfoundland (Hibernia Field). In addition to this correlation were interpreted their respective ages and depositional environments, and potential thermal maturation trends.

The analytical results revealed these oils were distinctive from the Jeanne d' Arc and Scotian Shelf oils. The low pristine/phytane versus C19/C23 ratios indicated they were similar to the Newfoundland oils with both sourced from a source dominated by Type II oil-prone kerogen. The Scotian Shelf oils indicated a Type III gas-prone kerogen source. However, analysis of saturate and aromatic hydrocarbon fractions for stable carbon isotope composition revealed that the seep oils were different from both regions. Comparison of terpane mass chromatograms against GeoMark's proprietary global oil data base suggests that the oils match those sourced from distal marine shales and/or calcareous shales / marls. All piston cores samples from the

Scotia Basin showed low levels of gammacerane, a biomarker indicative of stratified water columns during the time of deposition (Sinninghe-Damste *et al.,* 1995). The low level of gammacerane in these samples would infer deposition under less restricted, more normal marine conditions though with some water stratification. The oleanane biomarker (a product from angiosperm remains) was absent, confirming the source was older than Late Cretaceous.

OETR (2011) compared these analyses with its own for oils, condensates and source rock extracts from selected Scotian Basin wells and similar biomarker data from other sources. A condensate sample from the Venture B-13 well from the shallow water Venture gas field (DST #6, 4572-4579 m, base Early Cretaceous Missisauga Fm.) revealed the presence of gammacerance which was confirmed to have come from an indigenous source and not a contaminate. Traces of gammacerane were also found in fluid inclusions from the Late Triassic-Early Jurassic Argo Formation salts in the deep water Weymouth A-25 well, and the homohopane ratio C35/C34=1 suggesting a carbonate depositional environment for the source.

OETR (2011) then compared the analyses with data from Early Jurassic (Pleinsbachian-Toarcian), oil-prone source rock successions from conjugate eastern Atlantic margin basins such as the Portuguese Lusitanian and Peniche basins, and the Essaouira and Tarfaya basins of Morocco. The Portuguese source rock successions are composed of marine black shales, marls and carbonates deposited on a carbonate ramp setting. They contain Type II kerogens and tend to have high gammacerane levels and very high TOCs. Duarte *et al.* (2010, 2012) analysed the latest Sinemurian to earliest Pleinsbachian Água de Madeiros Formation in the Lusitanian Basin. Though the succession is immature onshore (Ro<0.45), it is an excellent potential source rock offshore with its organic-rich (Type II kerogen) shales, marls and limestones having maximum TOC ranges of 15-22%. Additional geochemical data on these source rocks' geochemical properties and distribution in these basins is presented in Silva *et al.* (2011, 2012). In the Peniche Basin, Pleinsbachian age Type II source rocks have a similar TOC maximum range of 14-20% (avg. 3.8%) (Veiga de Oliveira *et al.,* 2006 as referenced in OETR, 2011).

From the Moroccan offshore margin, analysis of extracts from Toarcian age source rocks from the DSDP Leg 79, Site 457 (Hinz *et al.,* 1982; Rullkötter *et al.,* 1984) differ from those in the Portuguese basins. While deposited in a similar deposition setting, the oils reveal no to low (background) levels of gammacerane. The shale / carbonate succession was similar but did not exhibit any characteristics of hypersalinity or stratified water conditions. Further to the south, biomarker analyses of oils from the Sidi Rhalem Field (onshore Essaouira Basin) and offshore Cap Juby Field (offshore Tarfaya Basin) were made available to OETR from GeoMark. They revealed in both the low levels of gammacerane, and C35/C34 ratios being less than one also inferring a carbonate dominated source. There is a good match of the isotopic signatures with the Nova Scotia piston core oil samples, suggesting a similar age source and depositional environment. Though the source interval(s) is uncertain, Morabet *et al.* (1998) suggest that for these regions it is carbonate-dominated Type II source and ranges from Lower Jurassic (presumed Pleinsbachian to Toarcian) to Oxfordian in age.

A recent paper by Sachse *et al.* (2012) studied the organic geochemistry and source rock potential of a Pleinsbachian to earliest Toarcian succession of limestones and marls further to the east in the central portion of the Middle Atlas Rift. The kerogens were determined to be Type II or transitional Type I/II with TOCs ranging from 1.1 to 3.9%. Analysis of a representative sample (their Tab. 5 & Fig.8B) reveals little to no gammacerane. The succession is interpreted to have been deposited in marine depositional environment with a stratified water column with bottom waters that were oxygen-depleted but not anoxic.

New evidence for a Scotian Basin Early Jurassic source rock comes from the analysis by Sassen and Post (2007) of a condensate sample from the Deep Panuke gas field (Late Jurassic Abenaki Formation, M-79A well). Detailed analysis of the sample included GC-MS for common biomarkers and diamondoids, and GC-IRMS for carbon isotopic properties of saturate and aromatic fractions. The GC-MS revealed pristine and phytane with very low peaks in relation to adjacent *n*-alkanes indicating the condensate underwent advanced thermal cracking during deep burial prior to migration in the leached and dolomitized reef margin reservoir. The thermal maturity index was defined as TAI=0.95 that approximates a Ro=1.4, and diamondoid levels in the condensate were very high (~1%) indicative of high thermal cracking of the original oil. While common biomarkers were lost from this petroleum, traces of key ones are present, the most important (for this review) being gammacerane. With the low pristine/phytane ratio (1.23), this supports the interpretation of a hydrocarbon from a Type II marine source. In comparison, the average pristine/phytane ratio for the piston core samples was also low at 1.43 (n=12; 1.23 to 1.56) (GeoMark, 2001). Sassen and Post (2007) suggest that the source lithologies were a calcareous shale or carbonate, which reflects the same interpretation by the GeoMark study.

It is possible that a second, slightly older Early Jurassic source could exist. It would have been deposited immediately post-salt and prior to the pre-Breakup Unconformity during the Hettangian to earliest Sinemurian representing a transitional evaporate to siliciclastic succession (Argo Formation to Heracles unit). The proposed Pleinsbachian to Toarcian source interval was deposited post-BU and the distal (seaward) equivalent to the Mohican (clastic) / Iroquois (carbonate) succession. During the development of the margin in the Late Triassic to Early Jurassic, the depositional setting changed from a subsea level rift basin to a narrow and shallow intra-rift seaway. Hydrographic conditions would likewise reflect this change, and in this near equatorial location evolve from hypersaline to near hypersaline / normal marine conditions that would contribute to water stratification.

While gammacerane is low to absent in the Moroccan oils, this cannot be used alone as a diagnostic feature of a Toarcian age source rock, though this might be a clue to infer these oils are post-BU with marine waters approaching normal salinities. The low gammacerane levels in the Nova Scotia oils may also suggest mixing / diluting of pre- and post-BU oils. The respective source rocks would be separated by an unconformity and could possibly overly each other and thus have the same maturation profile with mixing of produced hydrocarbons during concurrent migration. This two source rock scenario remains speculative.

Late Jurassic – Tithonian carbonate to deltaic transition MFS
Abenaki / Upper Mic Mac to Lower Missisauga formations

The Late Jurassic (Tithonian) MFS succession is believed to be potential contributor of hydrocarbons to selected areas of the 2015 Call region based on Temis™ basin modelling. However, knowledge of this source rock is based on data and interpretations heavily weighted to the Sable Subbasin. Therefore, its presence and characteristics in the western Call regions is less certain due to limited well data.

The Tithonian source interval was deposited during the transition from carbonate to deltaic sedimentation. This interval usually corresponds with the top of the Jurassic (approximate top Abenaki / Mic Mac / Mohawk formations) that is near the MFS. It is recognized as a MFS deposited in a shallow, open marine (neritic) shelf setting that appears to have been slightly anoxic. Distally it corresponds to the lower part of the Verrill Canyon Fm.

Though it is penetrated in a number of wells (particularly in the Sable Subbasin), this source rock can been difficult to sample due to the use of lignosulfate mud additives, and, oil-based muds when the underlying overpressure zone is approached. Kerogen microscopy of carefully selected cuttings samples has thus become the best way to define / identify this source rock. It 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).

In the NS15-1 Call region the Turonian section is identified in the following NS15-1 wells (details in Table 5.2):

- Bonnet P-23 (Parcel 3)
- Mohawk B-93 (Parcel 4)
- Mohican I-100 (Parcel 5)
- Albatross B-13 (Parcel 5 west boundary)
- Moheida P-15 (Parcel 6)
- Glooscap C-63 (Parcel 6)
- Oneida O-25 (Parcel 7)

In the western Scotian Basin, it is a generally interlayered succession of oolitic to micritic fossiliferous limestones, grey calcareous shales, fine grain sandstones, siltstones and grey to brown marls. Siliciclastics are less prevalent in wells along the steep Abenaki bank margin as opposed to those in the in the western and eastern areas. This suggests that the latter were loci / fairways for deltaic sedimentation.

Generally, the average TOCs in the Tithonian interval for the Sable Subbasin are 2-3% with maximum values approaching 7% (e.g. Louisbourg J-47 well in the eastern Sable Subbasin), and the HI and OI indicate a Type IIB-III / Type III kerogen that is mostly gas-prone (Mukhopadhyay and Wade, 1990; OETR, 2011). However, while penetrated in eight wells on the western Scotian Basin and associated LaHave Platform, there is limited geochemical information and what is available reveals that it is a poor source rock that is significantly leaner (< 1.0%) and more gas-prone:

| Well | NS15-1 Parcel | Interval (m) | Lithologies | Kerogen Type | %TOC (range) | HI (mg/g) (range) | OI (mg/g) (range) | Reference |
|---|---|---|---|---|---|---|---|---|
| Bonnet P-23 | 3 | 2065-2220 | oolitic limestone & dolomite | III | 0.23-0.51 | 31-100 | 50-107 | Altebaeumer et al. 1985 |
| Mohawk B-93 | 4 | 3825-3955 | oolitic limestone & grey shale | III | 0.31-0.32 | -- | -- | Cooper at al., 1976a |
| Shelburne G-29 | 4* | 3825-3955 | grey shale & marl | -- | -- | -- | -- | -- |
| Mohican I-100 | 5 | 2556-2796 | grey shale, oolitic limestone, siltstone & sandstone | III | 0.42-0.57 | 20 (single sample) | -- | Cooper at al., 1976b |
| Albatross B-13 | 5* | 2468-2570 | oolitic limestone | III | 0.03-0.2 | 20-166 | 50-109 | Altebaeumer et al. 1986 |
| Moheida P-15 | 6 | 2688-2852 | oolitic limestone & grey shale | -- | -- | -- | -- | -- |
| Glooscap C-63 | 6 | 2587-2800 | oolitic limestone & grey shale | -- | -- | -- | -- | -- |
| Oneida O-25 | 7 | ~2900-2100 | oolitic limestone, sandstone & grey shale | II | 1.10-1.18 | -- | -- | Cooper et al., 1976c |

***Table 5.2.*** *Tithonian age source rock intervals penetrated by wells in the Western Scotian Basins. Note that wells with an asterisk (*) fall outside the NS15-1 Call parcels.*

An exception is the Oneida well that is the easternmost well on Parcel 7 and on the western edge of the sable Subbasin where the interval is best developed and with an oil and gas potential. It is thought that it exists in the deep water equivalent succession outboard of the basin hingeline with Type II kerogens dominating, in particular seaward of the Shelburne Delta complex in Parcels 1-3 (this report).

Further along the margin, there is evidence for a similar Late Jurassic - Early Cretaceous oil-prone source rock in the Baltimore Canyon Trough region (Sunde and Coffey, 2009). Geochemical biomarker analysis of remnant oils from an onshore well indicates they were sourced from a shale / marine marl succession deposited in a distal marine to slope depositional environment. The presence of oleanane is interpreted to support a Cretaceous age. Malinconico and Weems (2011) studied the geothermal gradient and maturity of a number of wells on the U.S. East Coast and concluded that the maturity of wells in the region was low (Ro=0.4-0.6%). As such, the Cretaceous succession could not have generated the observed oils. This suggests the low maturity indicates that the remnant oils were preserved in carrier beds and oil migration was a later phase. The probable distally-equivalent source rock would now be more deeply buried and currently within the oil window. Such a scenario could exist in the deep water equivalent section offshore Nova Scotia.

<u>Early Cretaceous – Intra Aptian deltaic MFS</u>
Naskapi Member, Logan Canyon Formation

This is the basal member of the Logan Canyon Formation and represents a major MFS interval following deltaic and shallow marine deposition of the Missisauga Formation (Wade and MacLean, 1990). The Naskapi's depositional environment is interpreted to range from tidal flat to marginal marine having Type III kerogens. It is a major regional shale-dominated sequence that thickens seaward with increasing shale content, and proximal to the northern (marginal) part of the Scotian Basin it thins and becomes increasingly sand-dominated. Where it is thick enough, it acts as a regional seal, with a number of gas and oil shows and discoveries in overlying and underlying sandstones; e.g. Panuke (top of Upper Missisauga Fm.) and Cohasset (base Logan Canyon Fm. (Cree Member) oil fields. Distally it merges with the shale-dominated slope succession of the Verrill Canyon formation.

Regionally, the Naskapi has good source rock potential, with maximum TOC values slightly greater than 2%, and ranging between 1-2%. Within the Call region this potential is reflected in the Oneida O-25 well (Parcel 7). Cooper et al. (1976b) define a Type II kerogen with a fair TOC range of 1.45-2.74% and high HIs from 405-1115 mg/g TOC though the interval is immature (Ro=0.45). Along basin hingeline in the Western and Central regions the Naskapi is generally not present having been removed by later Tertiary unconformities. Should the Naskapi's distal equivalent be present it could have potential to generate liquid hydrocarbons.

<u>Early Cretaceous – Berriasian / Valanginian deltaic MFS</u>
Middle and Lower Missisauga Formation

The Berriasian / Valanginian source rock is not a discrete interval but is composed of a number of transgressive, MFS marine shales within the deltaic Missisauga Formation. Based on PFA "Bible" wells in the Scotian Basin, the source rock shales have TOC values that range from 1-2%, averaging about 1%, with the organic matter dominated by Type III kerogens. Distally, the source rock improves in thickness and richness and has the potential to be a very good oil source (Barnard and Dodd, 1984).

On the Scotian Shelf, the Berriasian / Valanginian source interval is volumetrically small and thus is considered a minor source rock. However, data from the deep water Annapolis G-24 and Crimson F-81 wells east of the NS15-1 parcels and outboard of the Sable Delta complex reveal deep water facies having a TOC range of 1.5-2.5% with the succession more deeply buried, such that the entire Missisauga formation is sufficiently organic-rich and mature to charge reservoirs (OETRA, 2011; Plates 4-4-4 & 4-4-5).

Within the western Scotian Basin, the equivalent interval is absent due to erosion in the Western and Central Call regions along the basin hingeline / Abenaki bank margin (Parcels 1-7). In the deep water outboard of the Central region, analysis of the section in the Shelburne G-29 well by Anadarko (1999) shows it to have a low source potential: Types II/III kerogens, TOC=1.02-1.08%, HI=94-113, OI=190-258. Though speculative, there could be a better development of this facies in Western region Parcels 1-3 presuming the development of the Shelburne Delta believed to have prograded across Georges Bank to the west into this region. Ongoing seismic mapping is lending support to this hypothesis and if confirmed would elevate the Naskapi's potential.

Middle Jurassic – Callovian marine MFS
Misaine Member, Abenaki Formation

The Callovian MFS is represented in the Scotian Basin by the Misaine Member, and is the only siliciclastic succession within the thick, carbonate-dominated Abenaki Formation. The velocity contrast between the Misaine MFS shales and underlying Scatarie Member (J213 seismic marker) platformal limestones results in the creation of an excellent regional seismic horizon. As such, the Misaine can be mapped throughout the Scotian Basin though is lost in the distal parts and thins landward on the LaHave Platform. It is present in wells drilled in the Abenaki carbonate margin inboard of and along the basin hingeline in the Western and Central regions, and wells proximal to Parcel 8. No wells have penetrated it in the deep water region hence its regional extent is unconfirmed.

There is limited information available on the source rock potential of the Misaine in the NS15-1 Call parcels. Based on data from adjacent wells / basins, the Misaine shale contains Type IIA-IIB and II-III oil- and gas-prone kerogens with an average TOC of 2.0% (Mukhopadhyay and Wade, 1990). Wells penetrating the Misaine are along the Abenaki carbonate margin encountered a thin section of shale, siltstones and limestones having poor to fair TOCs (0.2-0.8%) with low to moderate HIs (20-200) and were immature (Ro=0.4-0.5), for example in the Central region:

| Well | NS15-1 Parcel | Interval (m) | Lithologies | Kerogen Type | %TOC (range) | HI (mg/g) (range) | OI (mg/g) (range) | Reference |
|---|---|---|---|---|---|---|---|---|
| Mohican I-100 | 5 | 3328-3444 | grey shale, siltstone & marlstone | II | 0.2-0.75 | 20-200 | -- | Cooper at al., 1976b |
| Oneida O-25 | 7 | 3667-3742 | grey shale & limestone | II | 0.9-1.3 | 85-130 | -- | Cooper et al., 1976c |

***Table 5.3**. Wells that penetrated the Misaine Member potential source rock interval in the NS15-1 Call region.*

Better potential exists in the Eastern region (Parcels 8-9) where the Misaine has characteristics similar to those determined by (Mukhopadhyay and Wade (1990). Outboard of the Western and Central regions the Misaine's source rock potential may improve within deposition in intra-salt lows and away from deltaic influences and having higher proportions of marine-dominated kerogens (Type II) that could generate liquid hydrocarbons. However, in this setting they may be deeply buried, overmature and exhausted of hydrocarbon potential.

Late Triassic – Carian-Norian lacustrine synrift successions

Continental synrift successions are well exposed onshore eastern North America and are generically similar reflecting the sedimentary response to paleolatitude, climate and tectonism. These Newark Supergroup basins (Olsen, 1986) range in age from Middle Triassic to Middle Jurassic and are filled with continental fluvial-lacustrine strata and some extrusive volcanics. The Fundy Basin is the largest of these though most of it lies beneath the Bay of Fundy (Wade *et al.,* 1996) with the structurally linked but marine-dominated Orpheus Graben east on the northeast Scotian Shelf (Tanner and Brown, 2003) . Similar though smaller rift basins exist on the LaHave Platform offshore: Naskapi, Mohican and Mohawk Grabens (Wade and MacLean, 1990), Eire Graben Complex (CNSOPB, 2013), and Oneida, Emerald, Oneida and Acadia Grabens (this report). Wells have been drilled on structural highs on the faulted margins of these basins but no hydrocarbon shows found. Outboard of the Scotian Basin hingeline margin, pre-salt successions are observed but are increasing difficult to image and map with increasing depth and overlying sedimentary successions.

Within the Newark Supergroup basins, four tectonostratigraphic (TS) basin-fill intervals are recognized (Olsen, 1986). TS I is an unconformity-bounded, early synrift fluvial-eolian sequence of Late Permian age. TS II is a dominantly fluvial (with some lacustrine) sequence believed representative of an underfilled, hydrologically-open basin (subsidence < sedimentation). This is followed by either a closed basin or one in hydrological equilibrium (subsidence ≥ sedimentation) dominated by lacustrine (TS III), and later playa / lacustrine (and basal CAMP volcanics) successions (TS IV). Potential source rock successions are known in the TS III and IV units of the US basins (Pratt *et al.*, 1985; and compilation in Brown, 2014).

During TS II deposition (approximately Late Anisian to Early Carnian), paleomagnetic data positions the Fundy and offshore basins within the north equatorial humid belt that over time drifted towards the semiarid subtropical climate zone (Olsen & Kent, 1996, 2000). The depocentre seismic reflection character for TS II and III intervals in the Fundy Basin interpreted as representing overfilled and balanced filled lake basin successions (Brown, 2014). Within the Newark Basin, TS II lacustrine strata are also interpreted (Brown, 2015), in addition to those known in TS III.

Similar lacustrine successions could exist outboard of the basin hingeline zone beneath the synrift salts of the Rhaetian-Hettangian Argo Formation within a favourable setting for the creation of source rocks. They would contain Type II and III kerogens based on the lake type generating oil and gas. Early maturation was likely based on the elevated heat flow in this rift central position, though this may have been moderated by later overlying salts and evaporites of the latest Triassic-earliest Jurassic Argo Formation.

Kettanah (2011) identified liquid and vaporous hydrocarbons in fluid inclusions within salts of the Late Triassic-Early Jurassic Argo Formation from the Glooscap C-63 and Weymouth A-45 wells. The characteristics of the liquids were determined to be characteristic of “complex, high molecular weight, aromatic or cyclic hydrocarbon compounds higher than methane”. The author commented that given their stratigraphic position, the potential source could have been the underlying sediments of the Norian-Rhaetian Eurydice Formation.

Later analysis of the fluid inclusions revealed the gammacerane biomarker was absent in the authochthonous salts in the former well, but present in the allochthonous salts of the latter (see Pl.4-3-6, OETR, 2011). The profile was considered very similar to one for a condensate sample from the Deep Panuke gas field. The PP3C sample had a very similar homophone C34-C35 ratio (~1.0) inferring a carbonate depositional environment for the source facies (Fowler and Obermajer, 1999). This sample was obtained from the Late Jurassic Abenaki Formation carbonate reservoir that was probably from an older, deeper and more mature source interval as indicated by Sassen and Post (2007). The arid, redbed depositional environment represented by the Eurydice sediments is based on limited penetrations along the basin margin, though the succession could be different and more favourable for source rock deposition in the deeper central parts of the rift basin.

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## Maturation / Expulsion

As part of the Play Fairway Analysis (OERA, 2011) 1D (20 wells), 2D (single regional seismic lines) and 3D basin modelling was performed utilizing the Temis™ software that incorporated data on petroleum system elements and processes. From the 3D modelling, Common Risk Segment (CRS) maps were created to determine the probability of occurrence for source rock intervals (presence, maturity and migration), and for reservoir and seal intervals. From these, composite CRS maps were generated for five designated petroleum systems for the Scotian Basin. Burial history and maturation were modelled deriving information from published and newly acquired datasets.

For the 31 selected calibration wells, temperature, maturation and pressure data were derived to generate well and composite regional burial curves for temperature, maturation (vitrinite reflectance, Ro) and pressure (Figure 5.2). Maturation history and potential expelled hydrocarbons were calculated utilizing input parameters for each source rock interval (age, TOC, kerogen type, initial hydrogen index, thickness) (OETR, 2011; Plate 7-3-1-3a). Incorporating these data and results into the Temis™ 2D and 3D modelling programs generated the transformation ratio (TR) through time for selected source rock and play intervals for the entire Scotian Basin (TR defined as the observed versus initial hydrogen index; it differs for kerogen types) (OETR, 2011, Plate 7-3-1-3b). This is representative of the maturation level of a given kerogen (SR) as opposed to vitrinite reflectance (Ro) which is indicative of absolute maturity irrespective of kerogen type.

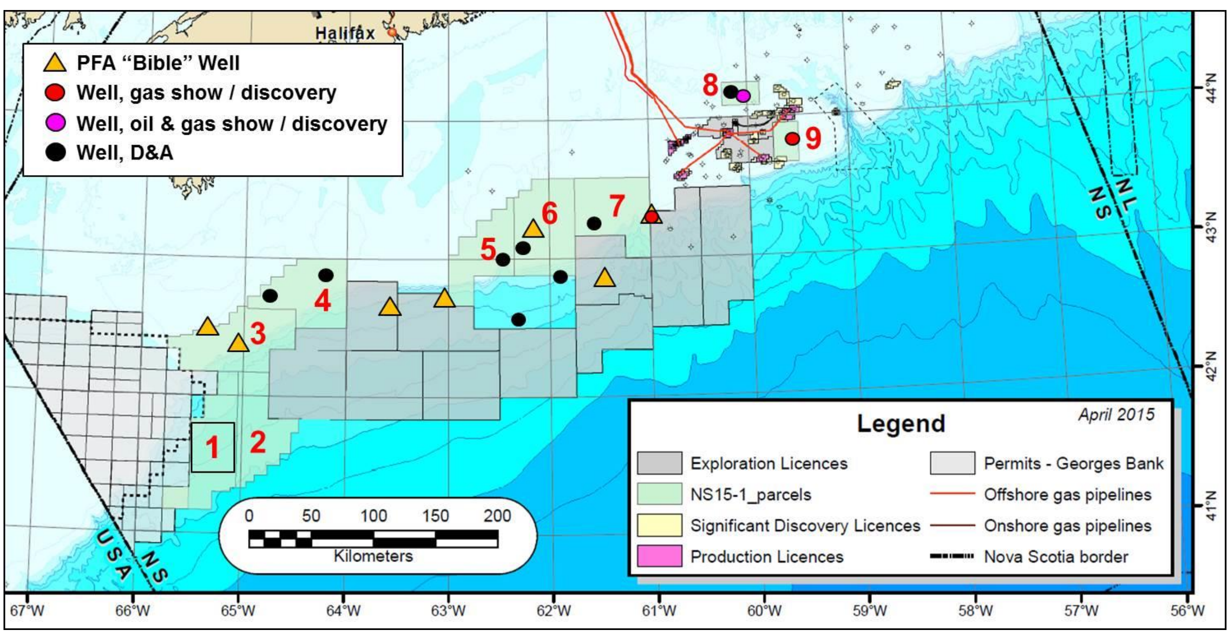


***Figure 5.2.*** *Bathymetric map of the NS15-1 Call for Bids region showing key wells used to define source rock intervals and incorporated into the Temis™ 1D, 2D and 3D basin and maturity / expulsion modelling.*

The Temis™ 3D maturity / expulsion modelling was run for the entire Scotian Basin and covers the six PFA-defined play / modelling zones. As shown in the relevant figures (below), most parcels have variable portions of their areas falling outside the defined zones with Parcel 1 almost completely outside Zone 1. There are ten (10) key Temis™ calibration wells located within Zone 1, with the asterisk indicating a key PFA "Bible" reference well.

Zone 1 – LaHave Platform

- Bonnet P-23 ***** (Parcel 3)
- Mohawk B-93 (Parcel 4)
- Montagnais I-94 (Parcel 4)
- Mohican I-110 (Parcel 5)
- Glooscap C-63 ***** (Parcel 6)
- Moheida P-15 (Parcel 6)
- Torbrook C-15 (south of Parcels 5 & 6)
- Oneida O-25 (Parcel 7)
- Shubenacadie H-100***** (south of Parcel 7)
- Evangeline H-98 ***** (eastern border Parcel 7)

Zone 2 – Shelburne Subbasin

- No wells (Parcels 1 & 2)

Zone 3 – Sable & Abenaki Subbasins, LaHave Platform

- Not Applicable (Parcels 8 & 9)

**Existing TOC & Rock Eval Data (Geological Survey of Canada's "BASIN" online database):**

- Acadia K-62
- Albatross B-13
- Bonnet P-23
- Eagle D-21
- Evangeline H-98
- Glooscap C-63
- Mohican I-100
- Penobscot L-30
- Shelburne G-29
- Shubenacadie H-100

**Existing Maturation Data (Geological Survey of Canada's "BASIN" online database):**

- Acadia K-62
- Albatross B-13
- Bonnet P-23
- Eagle D-21
- Evangeline H-98
- Glooscap C-63
- Mohawk B-93
- Mohican I-100
- Oneida O-25
- Penobscot B-41
- Penobscot L-30
- Shelburne G-29
- Shubenacadie H-100

The following section reviews the results of the Temis™ 3D maturation / expulsion modelling and summarizes the characteristics of the source rock intervals in the Call region starting with the speculated Pleinsbachian interval, then the known Tithonian interval, followed by the remainder. The Late Triassic was not modelled and thus not discussed.

It should be noted that given the well distribution - especially that there are none in the deep water Zones 2, 4 and 6 - the model and results have less confidence. Therefore the results required extrapolation into the outer margins of these zones and thus their predictive ability in the in deep water and boundary areas are limited (OETR, 2011). For the associated figures (5.3

to 5.12), the black lines delineating the nine NS15-1 Call for Bids Parcels, violet lines the Temis™ modelling zones, small red diamonds the key PFA "Bible" reference wells, and large red or blue triangles the key "Bible" wells in / near the Call region.

Pointedly, there are no wells in these three deep water regions that comprise about 50% of the entire PFA study area. Furthermore, it should be noted that this modelling is based on defining and mapping of regional seismic horizons from the shelf into large regions with no well and limited seismic control. Changes in the vertical position of regional seismic markers would therefore have a profound influence on the determination of a source rock's presence, character and expulsion potential. This is especially true for seismically hard to define Jurassic age source intervals in deep water with no well control.

Early Jurassic: Pleinsbachian to Toarcian restricted to near-normal marine
Mohican and Iroquois Formations distal equivalents
*Dominantly OIL, Minor GAS*

This source interval in the PFA (OERA, 2011) is considered to be the most significant potential oil-prone source rock interval in the Scotian Basin's. However, it has not been penetrated by any well and evidence of its existence is based on analogue and offset data from the Moroccan (conjugate) and Portuguese margins. Equivalent successions have been penetrated on the LaHave Platform but are dominated by proximal fluvial-marine sandstones and shallow water dolomites of the lower Iroquois Formation.

The modelled paleogeography and depositional setting of the Early Jurassic offshore Nova Scotia is of a narrow, relatively shallow, early post-rift seaway separating the Morocco and Nova Scotia conjugate margins. Based on the analogue data, the source interval is modelled to be thin (20 m) and deposited under restricted marine conditions but is contiguous across the basin composed of Type II marine kerogens with a TOC=5% and HI=600 mgHC/gTOC (OERA, 2011, Plate PL.7-3-1-3a). The deposition of this source is regional in scope across the entire Scotian Basin except for the LaHave Platform inboard of the basin hingeline.

The TR for this source interval is modelled to be highly variable in the western half of the Scotian Basin, particularly in the deep water Shelburne Subbasin. This region encompasses the western salt basin that is dominated by diapiric, pillow, swell and thrust-related structures with intervening depositional lows. A patchwork of TRs is evident with the post-salt source interval displaying modelled values from <1% (top of salt features) to 100% in depocentres, the majority of which have TRs of 60-80%. Lower TRs are present in a narrow belt along the hingeline margin from 40-10% (Figure 5.3).

In the Western region (Parcels 1-4), Temis™ modelling shows that the interval has a variable TR with significant levels of hydrocarbons yet to be expelled. Expulsion started at ~165 Ma (5% TA) and covers the eastern two-thirds of the Scotian Basin (Zones 3-6), and a significant part of the undrilled Zone 2. Over-maturity (TA=95%) is variable, ranging from Early Cretaceous (~Aptian) to Paleogene at the northern basin margin (Zones 3 & 5). This source rock is immature in Parcels 1-6 with a strong maturation gradient in Parcel 7 (TR=10 to >90%) reflecting its thickness and distribution. This source rock has expelled all its hydrocarbons in

Parcel 9, with 10-40% in Parcel 8. The oil mass fraction is about 40%, and while this Type II-III source tends to be more gas-prone, this fraction can exceed 60% locally where it is less mature.

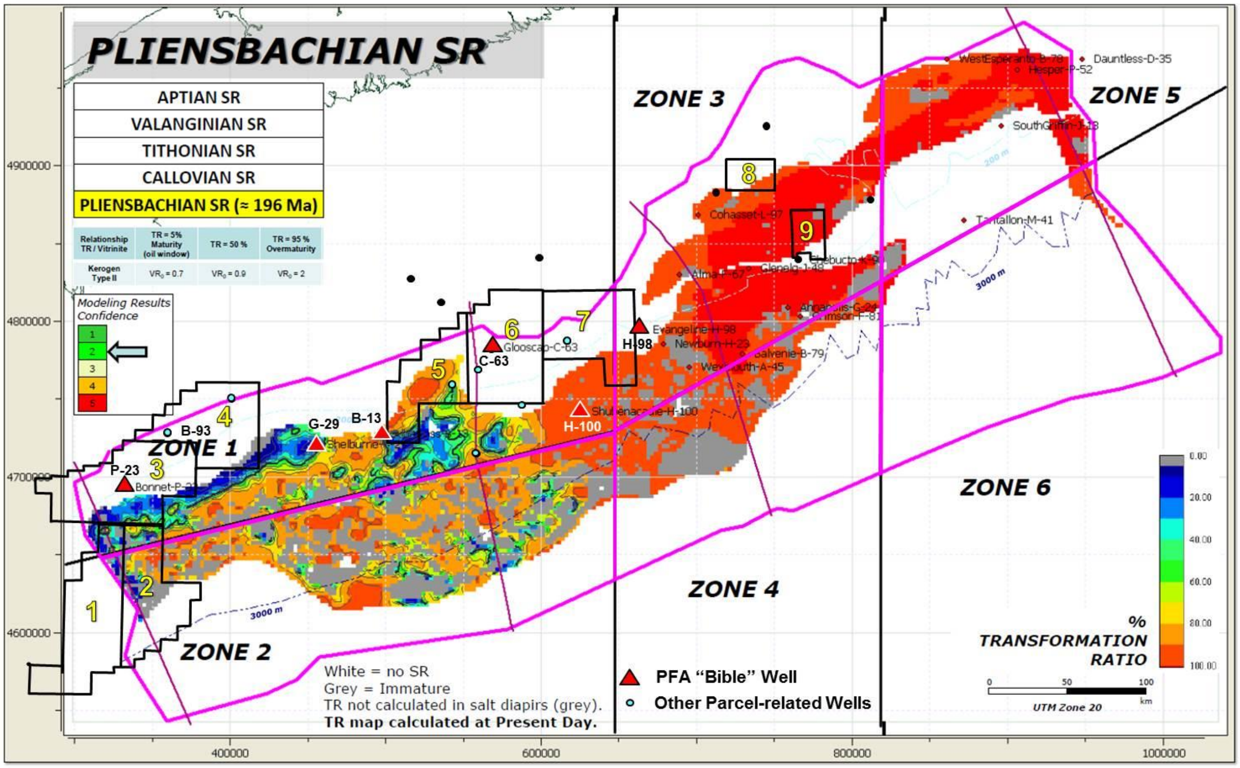


***Figure 5.3:*** *Pleinsbachian source rock transformation ratio (TR) map (Temis™ 3D maturity / expulsion modelling). Modified after OETR, 2011 (Plate 7.3.2.10).*

The Pleinsbachian CRS SR maps for this interval (Figure 5.4) show a generally low source rock potential (high risk) for Parcels 8-9 in the Sable Subbasin where it is very deeply buried and overmature, though vertical migration along listric fault planes at various stages of the basin's history could be considered. The Central region parcels have a moderate to high source rock and maturation / migration potential. There is a risk for its presence on the northern parts of Parcels 6 and 7 though is higher in the southern parts with accompanying short to moderate distance migration from the adjacent Shelburne Subbasin. Parcel 5 is considered to have low risk with short lateral migration from the hingeline margin and better source rock presence. Though having limited data, the western Parcels 1-4 (especially 1-3) have low to moderate risk for source rock presence and proximal to moderate distance migration. Higher risk is expected inboard of the basin hingeline and the extreme southwest deep water region.

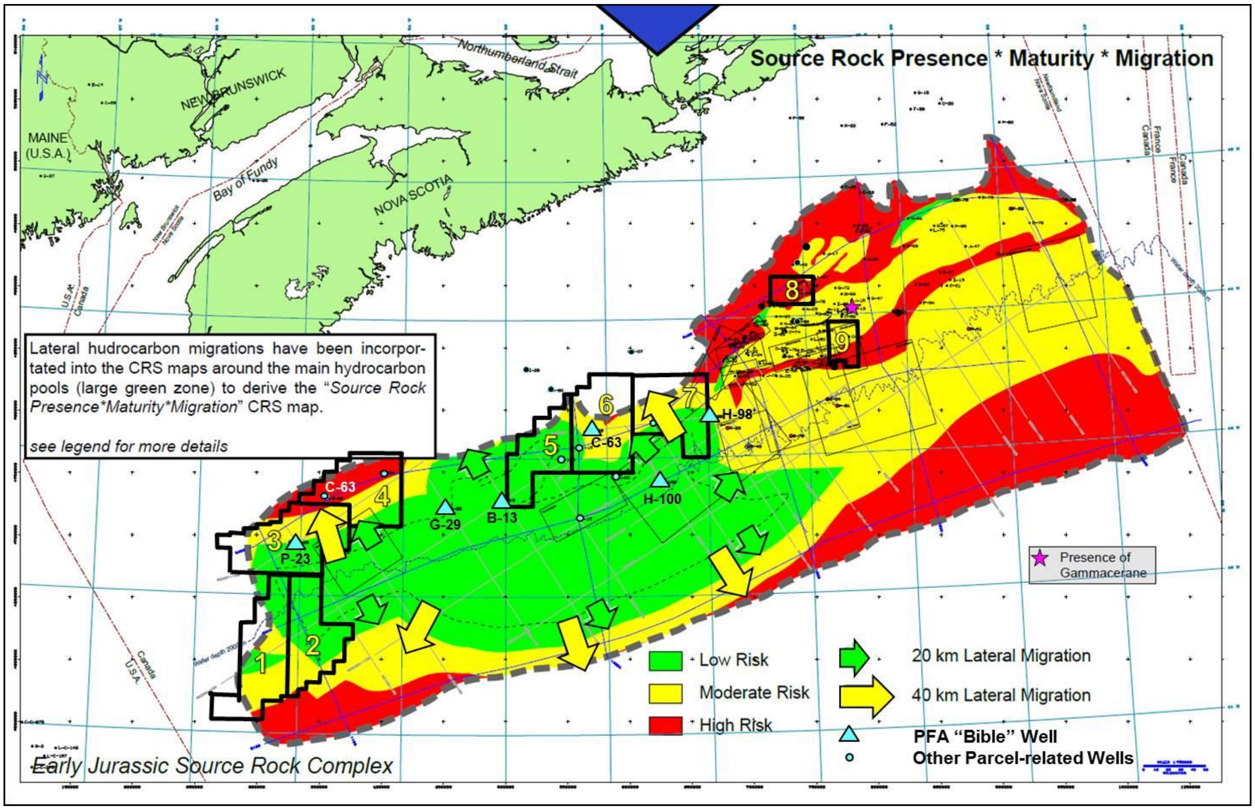


***Figure 5.4:*** *Pleinsbachian source rock Common Risk Segment (CRS) map (Temis™ 3D SR presence, maturity and migration modelling). Modified after OETR, 2011 (Plate 8.2.14).*

<u>Late Jurassic: Tithonian carbonate to deltaic transition MFS</u>
Abenaki / Upper Mic Mac to Lower Missisauga formations
*Dominantly OIL & GAS*

Modelling of this source interval in the PFA (OERA, 2011) revealed that it should be considered as a significant contributor to the Scotian Basin's hydrocarbon endowment. As described above, it represents deposition in a transitional setting from a carbonate-dominated marine (Abenaki) to siliciclastic fluvial-deltaic environment (Mic Mac). The source interval lithologies have an average TOC of about 3% composed of mixed Type IIA/IIB-III kerogens capable of generating gas, condensate, and oil (Mukhopadhyay and Wade, 1990). The deposition of this source is regional in scope centred in the central and eastern parts of the Scotian Basin.

Temis™ modelling indicates that the interval has a high TR with most hydrocarbons expelled over time (Figure 5.5). Expulsion started at ~136 Ma (5% TA) and covers the eastern two-thirds of the Scotian Basin (Zones 3-6), and a significant part of the undrilled Zone 2. Over-maturity (TA=95%) is variable, ranging from Early Cretaceous (~Aptian) to Paleogene at the northern basin margin (Zones 3 & 5). This source rock is immature in Parcels 1-6 with a strong maturation gradient in Parcel 7 (TR=10 to >90%) reflecting its thickness and distribution. It has expelled all its hydrocarbons in Parcel 9, with 10-40% in Parcel 8. The oil mass fraction is about 40%, and while this Type II-III source tends to be more gas-prone, this fraction can exceed 60% locally where it is less mature.

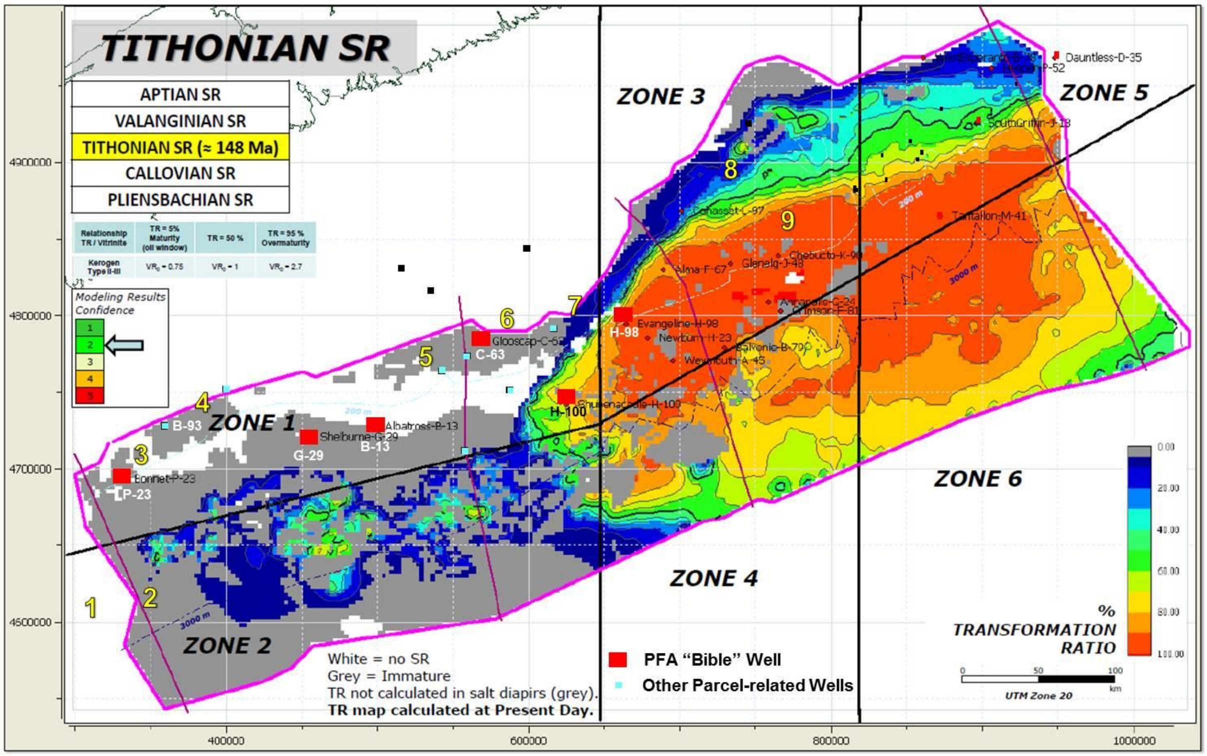


***Figure 5.5:*** *Tithonian source rock transformation ratio (TR) map (Temis™ 3D maturity / expulsion modelling). Modified after OETR, 2011 (Plate 7.3.2.6).*

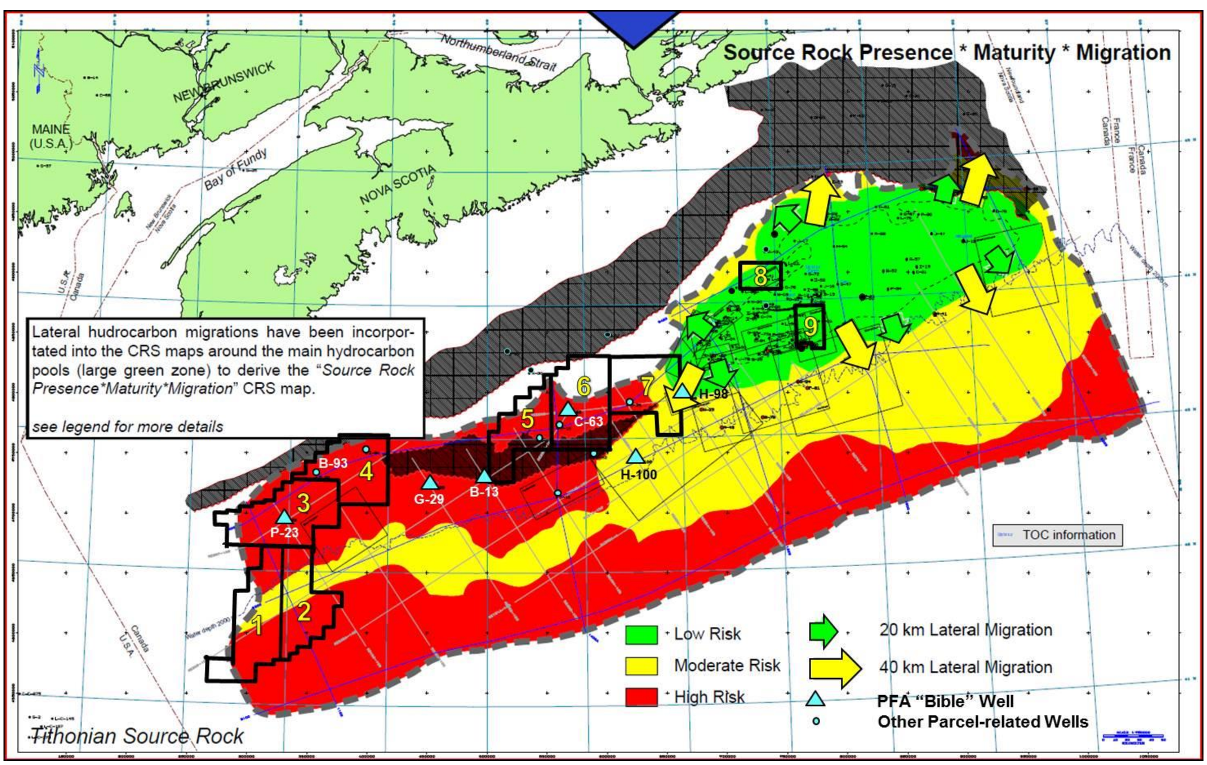


***Figure 5.6:*** *Tithonian source rock Common Risk Segment (CRS) map (Temis™ 3D SR presence, maturity and migration modelling). Modified after OETR, 2011 (Plate 8.2.16).*

The Tithonian CRS SR maps for this interval show that lowest potential (high risk) for this source rock is in Parcels 3-6 with some moderate risk in the undrilled Parcels 1 and 2 (Figure 5.6). Better potential is found in the eastern half of Parcel 7 where there is a moderate risk for some source rock presence, maturation and moderate distance lateral migration. The highest source rock potential (low risk) exists in Parcels 8-9 that could include vertical migration along listric fault planes.

Early Cretaceous: Intra-Aptian deltaic MFS
Naskapi Member, Logan Canyon Formation
*Dominantly GAS, Minor OIL*

The Aptian MFS source rock interval is present across most of the Scotian basin save for the basin margin though is hard to discern within the shale-dominated slope region though can be identified biostratigraphically. The Naskapi is positioned high in the stratigraphic section and thus is immature except within a narrow northeast-southwest trending band in the Sable Subbasin where it is more deeply buried (Figure 5.7). In the Western and Central regions (Parcels1-6) it is quite thin and along the hingeline is eroded out by later Tertiary unconformities. Some potential exists in the deep water portion of Parcel 7 with TRs from 10-40% (moderately mature). The Eastern region shows the Naskapi as immature in Parcel 8 and some modest early maturity in the south portion of Parcel 9. CRS maps for the Naskapi reveal that it has a high risk for presence / maturation / expulsion for all parcels except Parcels 7 and 9 (Figure 5.8). It is modelled to have a low to moderate risk for these proximal parcels with a moderate (~40 km) lateral migration potential to the southwest for a portion of Parcel 6.

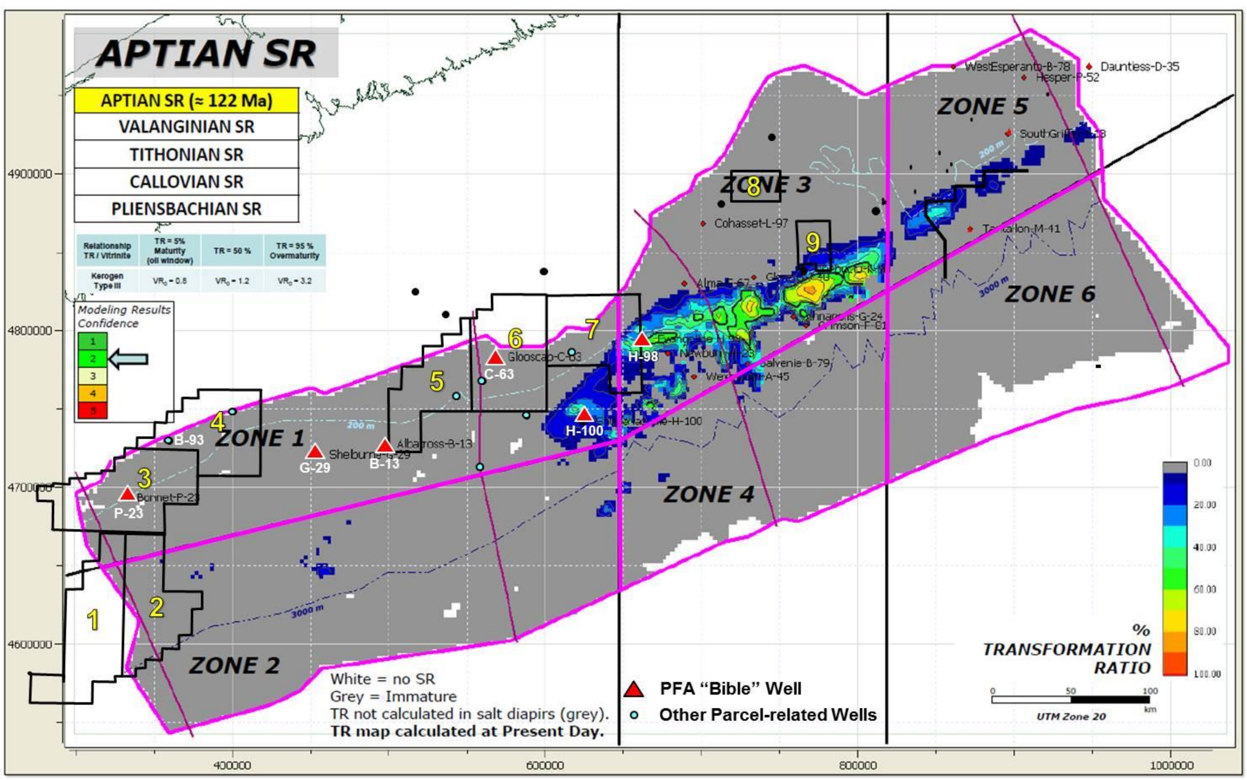


***Figure 5.7:*** *Aptian source rock transformation ratio (TR) map (Temis™ 3D maturity / expulsion modelling). Modified after OETR, 2011 (Plate 7.3.2.2).*

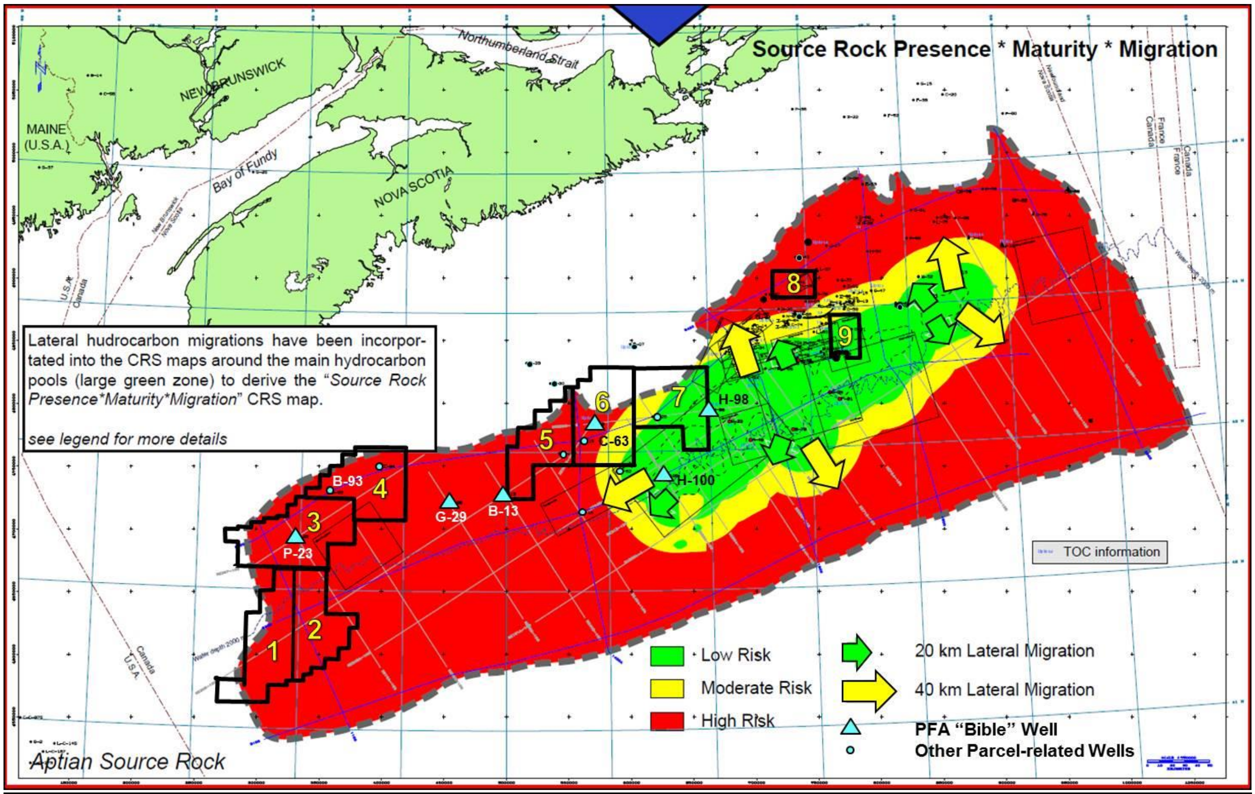


***Figure 5.8:*** *Aptian source rock Common Risk Segment (CRS) map (Temis™ 3D SR presence, maturity and migration modelling). Modified after OETR, 2011 (Plate 8.2.18).*

Early Cretaceous: Berriasian / Valanginian deltaic MFS
Lower Missisauga Formation
*Dominantly GAS*

This source interval's distribution is focused in the Sable Subbasin, the depocentre for the Missisauga Formation. This source facies is not present in the western Parcels 1-6 and the equivalent age rocks are immature (Figure 5.9). The western edge of this source interval extends into the portion of Parcel 7 on the Scotian Slope and is variably mature with the transformation ratio ranging from 10-85%, the maximum being calculated based on the Evangeline H-98 well that fall just outside the Parcel. In the east, Parcel 8 falls reveals an immature section whereas Parcel 9 has a TR range of 50-100% (partial to overmature) belying its position near the basin depocentre.

The Berriasian / Valanginian CRS maps for this source rock interval reflect the Missisauga Formation's distribution. Modelling shows that low risk short (20 km) and medium risk (40 km) distance lateral migration move away from the depocentre to the hingeline margin and distal basin / paleo-slope regions (Figure 5.10). Vertical migration up listric fault systems is likely and could source traps within Parcels 7, 8-9.

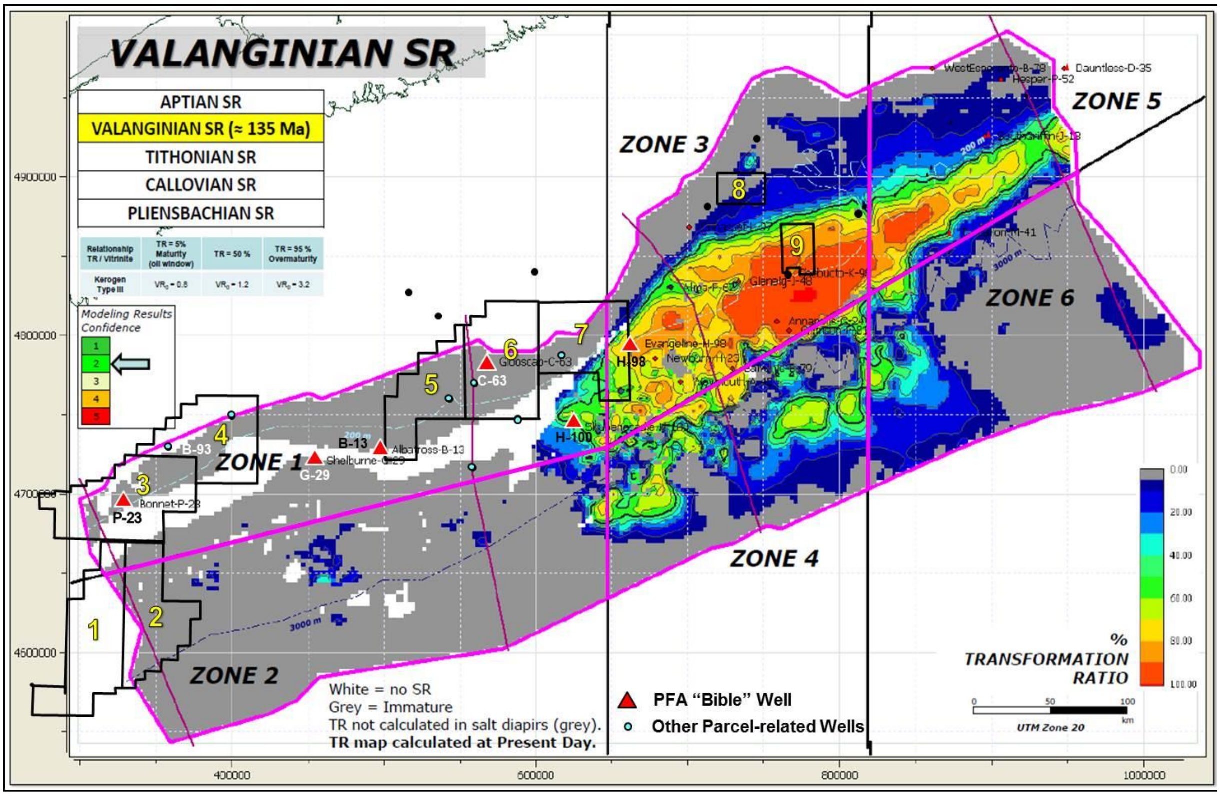


*__Figure 5.9:__ Berriasian-Valanginian source rock transformation ratio (TR) map (Temis™ 3D maturity / expulsion modelling). Modified after OETR, 2011 (Plate 7.3.2.4).*

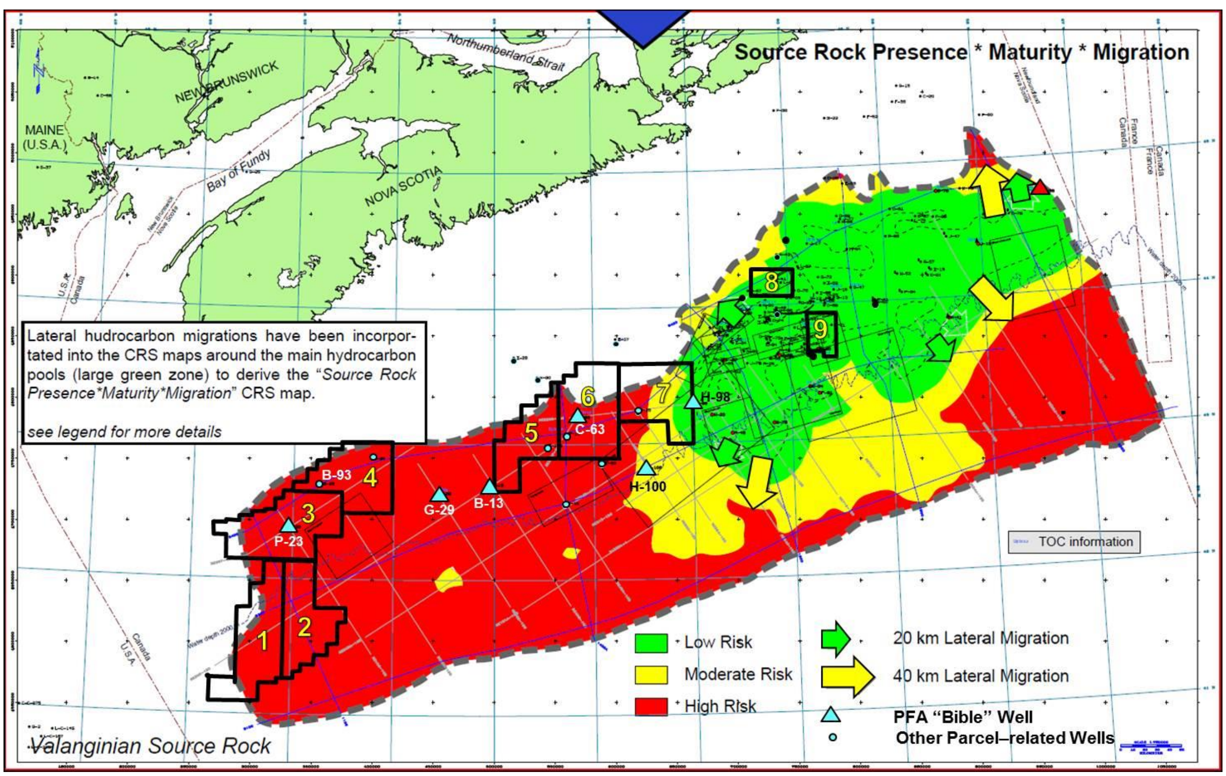


*__Figure 5.10:__ Berriasian-Valanginian source rock Common Risk Segment (CRS) map (Temis™ 3D SR presence, maturity and migration modelling). Modified after OETR, 2011 (Plate 8.2.17).*

<u>Middle Jurassic: Callovian marine MFS</u>
Misaine Member, Abenaki Formation
*Dominantly GAS, Minor OIL*

The Misaine Member is widespread across the Scotian Basin and Call region. Like the potential Early Jurassic source interval, the presence of underlying basement structural elements during the time of its deposition could have exerted an influence on its formation though to a lesser degree. On the western LaHave Platform the Misaine is a ~100 m interval of shale-sand-lime that is shalier basinward and absent inboard of the Abenaki carbonate margin (e.g. Mohawk B-93 and northern parts of Parcels 3-6). It is mapped seismically in Parcels 1-2 but its lithological characteristics are unknown.

This source rock is modelled to be immature with no expulsion of hydrocarbons in Parcels 2 to 4, and not modelled in Parcel 1 (Figure 5.11). Based on Temis™ modelling, the source rock has not reached maturity (TR>10%) in any of the Western region, with only 10-40% TR in the deep water areas outside the parcels. In the Central region maturation and expulsion increases to the east with TR=10-20% in parts of Parcel 5 and 10-40% in the southern half of Parcel 6 (its northern half was not modelled). The highest TRs are in Parcel 7's deep water area where complete maturation (95%) is modelled and occurring at about 115 Ma (Aptian) time (Plate 7.3.2.9a; OETR, 2011). The Misaine is highly overmature in the Sable Subbasin under Parcels 8-9.

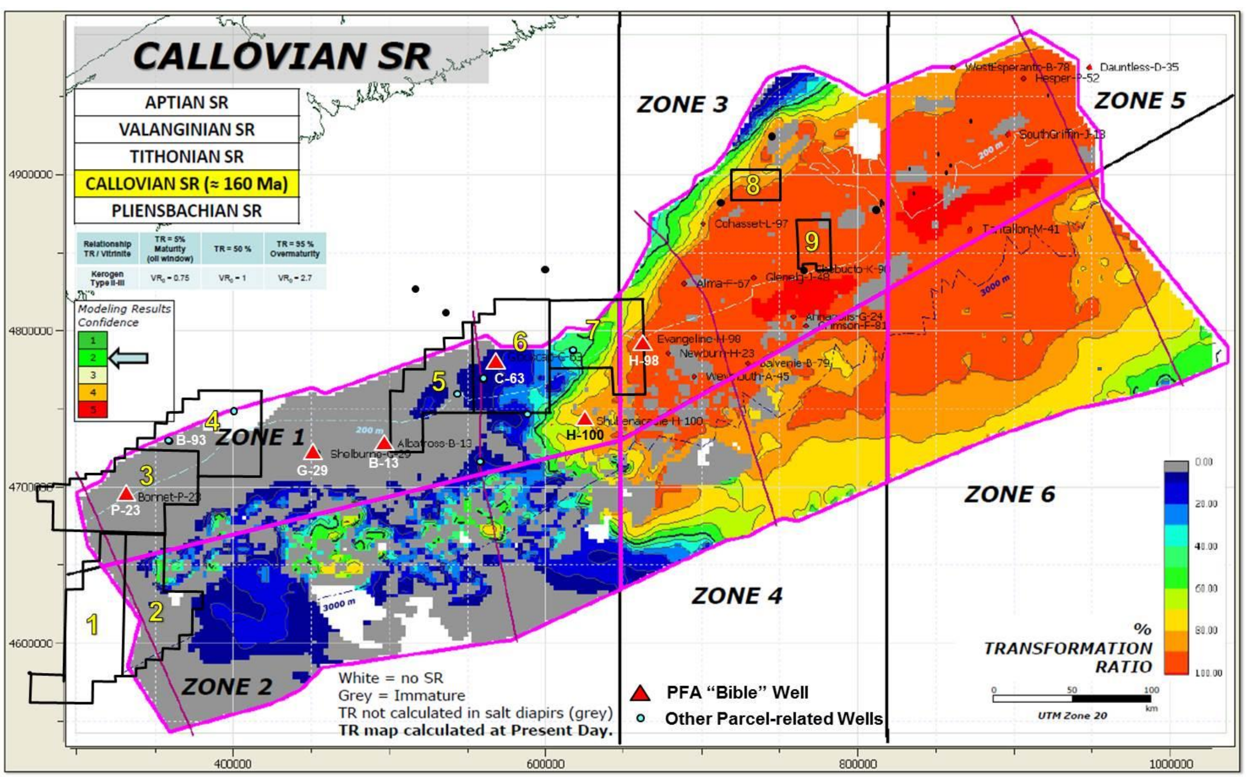


***Figure 5.11:*** *Callovian source rock transformation ratio (TR) map (Temis™ 3D maturity / expulsion modelling). Modified after OETR, 2011 (Plate 7.3.2.8).*

The Misaine's CRS maps reveal a high risk for source rock presence and associate maturation and migration over Call Parcels 1-5, though given the limited data available a moderate risk region could be extended westward across the northern parts of Parcels 1-2. Provided suitable carrier beds / zones exist, the potential exists for hydrocarbon migration to move updip towards the basin margin hingeline along the outer edges of Parcels 2-4.

Far better potential / lower risk exists for Parcels 6-7 based on improved lithological and areal distribution from well and seismic data. Though more deeply buried, potential hydrocarbons could migrate via short to moderate length pathways along and up the slope through faults or slope fan aprons along the Abenaki bank margin. South and southeast-directed charge is also modelled that could feed shallower potential reservoirs (Figure 5.12). Any hydrocarbons generated in the Parcel 8-9 region would have migrated either north to the basin margin or south into the deep water realm.

It is acknowledged that due to limited data (especially in deep water and western and eastern Scotian Slope, an accurate estimate of the Misaine's potential is uncertain (OETR, 2011). Indeed, no indication is given in the Temis™ results of landward, northwest-directed migration from any of the five recognized source rock successions in the deep water realm. Furthermore, acquisition of new seismic data and interpretation may elevate it structurally, and this could have significant implications regarding its modelled generative potential and upside potential

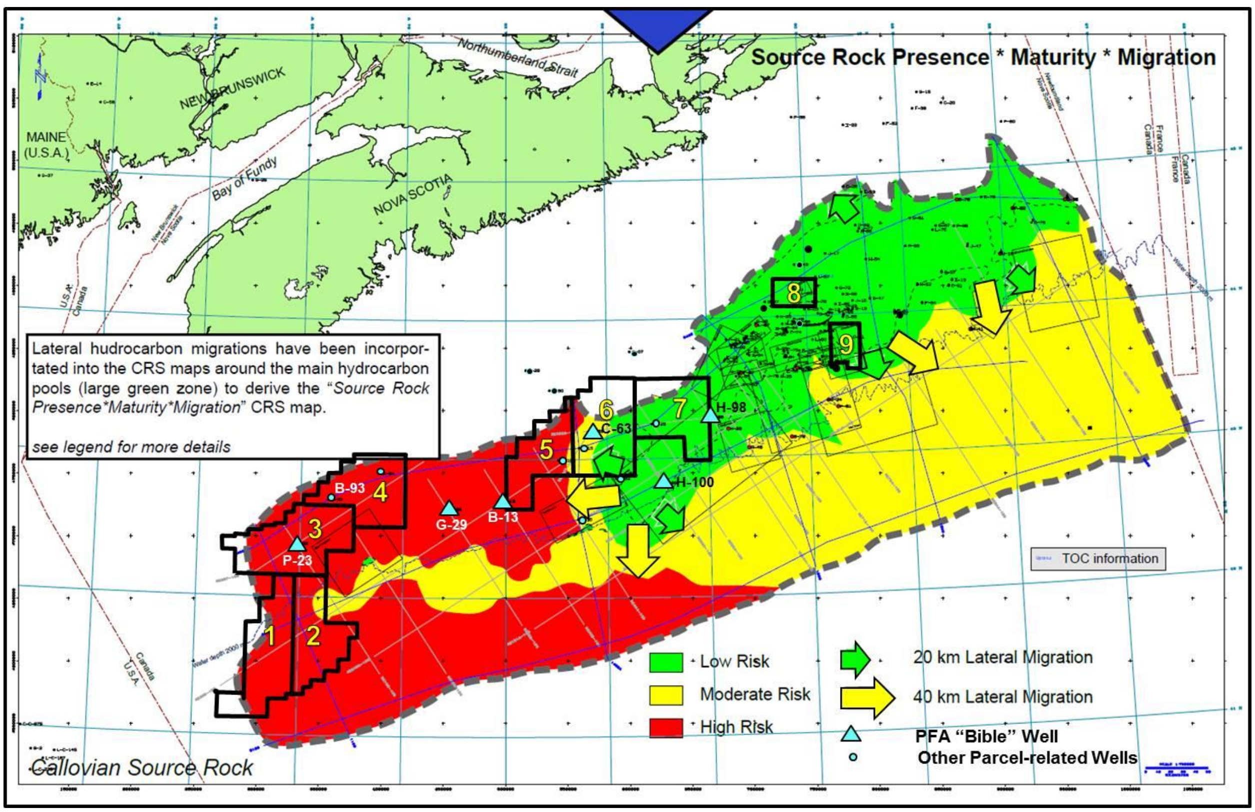


***Figure 5.12:*** *Callovian source rock Common Risk Segment (CRS) map (Temis™ 3D SR presence, maturity and migration modelling). Modified after OETR, 2011 (Plate 8.2.15).*

**Hydrocarbons**

The Scotian Basin is primarily gas-prone based on the great volume of source rock successions that had significant input from deltaic depositional systems. Most discoveries and production were of gas with associated condensates, yet there are a number of significant oil shows and discoveries, and previous oil production.

Since the late 1970s, researchers have undertaken analyses of these liquids in order to classify them and derive information related information on maturation and source rock relationships. 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 is comprised of 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 might 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 they were generated in the central part of the oil window.

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