### CHAPTER 7

**BASIN MODELING**

**Objectives**

The basin modeling study aims at:
- Improving knowledge on the active petroleum systems of offshore Nova Scotia.
- Integration of petroleum systems elements into the model (source rock layers, plays systems, etc.).
- Thermo-stratigraphic modeling and pressure modeling.
- Description of migration and migration process;
- Simulation of maturity/expulsion/migration/entrapment/preservation timing.
- Estimating hydrocarbon volumes within the study area.
- Expelled volumes for six zones, subdividing the study area for each source rock, and in-place volumes for the six zones, and by plays system. Volumes estimated are unrisked.

The elements of the Petroleum Systems integrated to the models come from the geological model developed in previous Chapters (Chapter 4 – "Petroleum Geochemistry"; Chapter 5 – "Seismic Interpretation"; Chapter 6 – "Tectono-stratigraphic Evolution and Petroleum Systems"). The modeling is performed with Temis Suite 8 software (Temis 1D®, 2D®, 3D®).

**Main Results**

**Temis 1D®**

- Given a first overview of thermal and maturity constraints for the model calibration in drifted areas. Ten wells are considered.
- Known petroleum fields in the Sable Sub-basin (Zone 3) are well modeled. It also appears that: (from the west to the east):
  - Line 1100 (Zone 1 and 2): Maturity is insufficient for effective generation/migration. The Pliensbachian source rock (SR) is mature between Lines 1100 and 1400 providing effective charge in the mini-basin area.
  - Line 1400 (Zone 1 and 2): HC migration/accumulation is possible along the slope (Pliensbachian SR mature down the slope), up, and locally in the deep basin, thanks to a high maturity level. Different kinds of traps may exist depending on the sector; the biggest ones would be located below salt canopies (basinward).
  - Line 1600 (Zone 3 and 4): Accumulations exist both in the slope and on the carbonate platform, and locally in the deep basin. Thanks to a high maturity level. Different kinds of traps may exist depending on the sector.
  - Line 2000 (Zone 5 and 6): Accumulations exist both in the slope and on the carbonate platform. The largest accumulations are deep, due to a limited migration efficiency.

**Temis 2D®**

- Migration Modeling

At the scale of the basin, about 2.3% of "expelled hydrocarbons" through geological times are "in place" at present day.
- The Tithonian SR is a significant contributor in all zones, all play systems (except the Early Middle Jurassic play system). At the scale of the basin it sources 1/2 of the total amount of hydrocarbons in place.
- The Pliensbachian SR is locally a very significant SR (up to 2/4 of the total amount of hydrocarbon in place in Zones 1 and 2).
- The richest zone is Zone 3 which contains the Sable Sub-basin (about 1/4 of the total calculated amount of HC in place). About 2/3 of the total amount of HC in place are "shelved zones" (1, 3, 5).
- Zones 3 and 5 have 5th ranks in Albian-Cenomanian and Barremian-Barramian play systems.
- Zone 6 reaches the first rank in the Barremian-Barramian play system.
- Temis® volumes are consistent with previous hydrocarbon volume estimations from various studies.

<table>
<thead>
<tr>
<th>By ZONE</th>
<th>TOTAL GAS volume in surface (Tcf)</th>
<th>TOTAL OIL volume in surface (Mbbl)</th>
<th>TOTAL OIL EQUIVALENT volume (Billion bbl)</th>
<th>GOR (scf / bbl)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ZONE 1</td>
<td>14</td>
<td>2470</td>
<td>4.4</td>
<td>6000</td>
</tr>
<tr>
<td>ZONE 3</td>
<td>35</td>
<td>1130</td>
<td>6.3</td>
<td>5100</td>
</tr>
<tr>
<td>ZONE 5</td>
<td>27</td>
<td>1600</td>
<td>5.5</td>
<td>16000</td>
</tr>
<tr>
<td>ZONE 6</td>
<td>26</td>
<td>1000</td>
<td>5.0</td>
<td>17000</td>
</tr>
<tr>
<td>ZONE 2</td>
<td>18</td>
<td>990</td>
<td>3.3</td>
<td>16000</td>
</tr>
<tr>
<td>Whole Basin</td>
<td>121</td>
<td>8150</td>
<td>26</td>
<td>15000</td>
</tr>
</tbody>
</table>
CHAPTER 7-1
BASIN MODELING – TEMIS 1D
1D Modeling

The intent of 1D modeling was to have a first pass at testing the consistency of all input data such as temperature, pressure, maturity, burial history, and the thermal history induced by the lithosphere modifications during rifting. A critical answer expected from these models is the role of unconformities, whether deposition/erosion or hiatus, in affecting maturity and timing of hydrocarbon generation.

For this purpose, 1D modeling was carried out on 10 out of the 20 reference wells. The 10 models are displayed in this Chapter.

Input data are:
• Rifting age between 225 Ma and 200 Ma;
• Lithosphere data from SMART lines 1, 2, 3 and OETR 2009 (see below); and
• Well stratigraphy derived from the biostratigraphic scheme developed in this study to reconstruct the burial history at the well locations (see Enclosures).

Model outputs shown below are:
• Maturity calibration;
• Temperature calibration;
• Pressure calibration;
• Burial and maturation history (modeled Vitrinite Reflectance versus time); and
• Transformation ratio for the main source rocks through time in order to estimate a hydrocarbon expulsion time.

Cohasset L-97

Modeled maturity calibrates well with Vitrinite Reflectance (VR) data from Mukhopadhyay (1991). Calibration against Avery’s data (GSC on-line Basin Database) was attempted, but no reasonable combinations of the petroleum system elements can reproduce them. Therefore Mukhopadhyay’s Vitrinite Reflectance data are considered the most reliable for the Cohasset L-97 well.
PL. 7-1-2a  South Griffin J-13 and Hesper P-52

Figure 1: Stratigraphy and lithology (simplified).

Figure 2: Maturity calibration

Figure 3: Temperature calibration

Figure 4: Pressure calibration

Figure 5: Burial history and maturity (Vitrinite Reflectance) and Rifting events Table.

Early Jurassic source rock  Late Jurassic source rock

Figure 6: Transformation ratio history for the various source rocks accounted for and expulsion time. Only the Early Jurassic and Tithonian source rocks expel hydrocarbons at the South Griffin J-13 location.

187Ma  67Ma

Figure 7: Stratigraphy and lithology (simplified).

Figure 8: Maturity calibration

Figure 9: Temperature calibration

Figure 10: Pressure calibration

Figure 11: Burial history and maturity (Vitrinite Reflectance) and Rifting events Table.

Early Jurassic source rock

Figure 12: Transformation ratio history for the various source rocks accounted for and expulsion time. Only the Early Jurassic source rock expelled hydrocarbons at the Hesper P-52 location and very early (estimated 183 Ma ago).

Late Jurassic source rock
**Glenelg J-48**

- **Figure 1:** Stratigraphy and lithology (simplified).
- **Figure 2:** Maturity calibration
- **Figure 3:** Temperature calibration
- **Figure 4:** Pressure calibration
- **Figure 5:** Burial history and maturity (Vitrinite Reflectance) and Rifting events Table.
- **Figure 6:** Transformation ratio history for the various source rocks accounted for and expulsion time. Only the Early Jurassic and Tithonian source rocks expel hydrocarbons at the Glenelg J-48 location.

**Alma F-67**

- **Figure 7:** Stratigraphy and lithology (simplified).
- **Figure 8:** Maturity calibration
- **Figure 9:** Temperature calibration
- **Figure 10:** Pressure calibration
- **Figure 11:** Burial history and maturity (Vitrinite Reflectance) and Rifting events Table.
- **Figure 12:** Transformation ratio history for the various source rocks accounted for and expulsion time. The Early Jurassic, Tithonian and Valanginian source rocks expel hydrocarbons at the Alma F-67. The Aptian (Naskapi) source rock is only incipiently mature (see Figure 11, above) for having expelled hydrocarbons.
Shelburne G-29

Water depth 1153.5m

Figure 1: Stratigraphy and lithology (simplified)

Figure 2: Maturity calibration

Figure 3: Temperature calibration

Figure 4: Pressure calibration

Figure 5: Burial history and maturity (Vitrinite Reflectance) and Rifting events Table.

Figure 6: Transformation ratio history for the various source rocks accounted for and expulsion time. None of the source rocks are mature enough for having expelled any hydrocarbons.

PL. 7-1-3a

Shubnacadie H-100

Water depth 1476.5m

Figure 7: Stratigraphy and lithology (simplified)

Figure 8: Maturity calibration

Figure 9: Temperature calibration

Figure 10: Pressure calibration

Figure 11: Burial history and maturity (Vitrinite Reflectance) and Rifting events Table.

Figure 12: Transformation ratio history for the various source rocks accounted for and expulsion time. The Early Jurassic and Tithonian source rocks expel hydrocarbons at the Shubenacadie H-100 location. Expulsion from the Valanginian source rock is recent and incipient only.
Figure 1: Stratigraphy and lithology (simplified).

Figure 2: Maturity calibration

Figure 3: Temperature calibration

Figure 4: Pressure calibration

Figure 5: Burial history and maturity (Vitrinite Reflectance) and Rifting events Table.

Figure 6: Transformation ratio history for the various source rocks accounted for and expulsion time. The Early Jurassic, Tithonian and Valanginian source rocks expel hydrocarbons at the Balvenie B-79 location. The Aptian (Naskapi) source rock did not expel hydrocarbons.

Figure 7: Stratigraphy and lithology (simplified).

Figure 8: Maturity calibration

Figure 9: Temperature calibration

Figure 10: Pressure calibration

Figure 11: Burial history and maturity (Vitrinite Reflectance) and Rifting events Table.

Figure 12: Transformation ratio history for the various source rocks accounted for and expulsion time. All source rocks expel at the Crimson F-81 location. Expulsion from the Aptian (Naskapi) source rock is recent and incipient only.
Summary and Conclusions

1D modeling applied early in the project, before developing 2D and 3D models confirms that:

- The evolution of the petroleum system(s) - burial and maturity evolution driven by the rifting thermal events based on the lithosphere changes derived from the CETR 2009 and SMART lines, present day thickness of the various layers defined in age and depth – is consistent with observations on Temperature, Maturity and Pressure.
- The evolution of the petroleum system does not require rapid burial before hypothetical erosions of significant thicknesses at any of the unconformities for the models to be calibrated.

As a consequence, burial and sedimentation rates follow a positive evolution with minor erosion phases from rift end to present day. Unconformities correspond essentially to hiatuses (non-deposition, sediment bypass area) or limited erosion surfaces (less than 300 m eroded).
CHAPTER 7-2

BASIN MODELING – TEMIS 2D

7-2-1

2D Modeling Introduction
In Temis2D Modeling, present day geometry (horizons and faults) is defined from the seismic interpretation, past geometries are obtained from the structural restoration, and the lithology distribution is derived from the Dionisos modeling.

**Dionisos® Modeling**

Modeling of Processes of Sedimentation and Erosion in 3D through time

The history of sedimentation within the basin is modeled with Dionisos® Software, which simulates the sediments deposition on topography through a diffusion equation.

In this modeling, the topography, the type of lithology, the water flow and environmental conditions are taken into account. The limit conditions of the model are on one hand, the sources of sediment entering in the study domain on its borders, and on the other hand, the production of sediments by biologic activity.

Outputs of the modeling are:

- Paleoenvironment Maps
- Lithology Maps
- Facies Maps
- Erosions

**Temis2D® MODELING**

In Temis2D Modeling, present day geometry (horizons and faults) is defined from the seismic interpretation, past geometries are obtained from the structural restoration, and the lithology distribution is derived from the Dionisos modeling.

**Restoration with Locace®**

Outputs:

- Past Horizons geometries
- Past Faults geometries
Lithologies used in the Temis2D Models

<table>
<thead>
<tr>
<th>Lithology Name</th>
<th>Shale (%)</th>
<th>Sand (%)</th>
<th>Carbonate Nearshore (%)</th>
<th>Carbonate Mudstone (%)</th>
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<tbody>
<tr>
<td>L01</td>
<td>100</td>
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<tr>
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<td>L33</td>
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<td>0</td>
<td>30</td>
<td>60</td>
</tr>
</tbody>
</table>

Dionisos Modeling gives the lithology composition of each cell in the study domain in terms of percentages of four pure poles that are Sand, Shale, Carbonate Nearshore and Carbonate Mudstone. 33 different discrete lithologies have been defined (see table above). They have been designed to replace the continuous description of the lithologies in terms of composition given by Dionisos modeling.

Rifting events and basement thicknesses in oceanic domain

<table>
<thead>
<tr>
<th>Ages</th>
<th>Upper Crust (thickness)</th>
<th>Lower Crust (thickness)</th>
<th>Upper Mantle (thickness)</th>
<th>Bottom Limit condition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Before Rifting</td>
<td>More than 225 Ma</td>
<td>20 km Continental crust</td>
<td>12 km Continental crust</td>
<td>93 km - Isotherm 1300°C at Bottom</td>
</tr>
<tr>
<td>Beginning of Rifting</td>
<td>225 Ma</td>
<td>20 km Continental crust</td>
<td>12 km Continental crust</td>
<td>93 km - Rise of Isotherm 1300°C</td>
</tr>
<tr>
<td>End of Rifting</td>
<td>200 Ma</td>
<td>4 km Oceanic crust</td>
<td>2.4 km Oceanic crust</td>
<td>93 km - Rise of Isotherm 1300°C</td>
</tr>
<tr>
<td>After Rifting</td>
<td>Less than 200 Ma</td>
<td>4 km Oceanic crust</td>
<td>2.4 km Oceanic crust</td>
<td>93 km - Isotherm 1300°C at Bottom</td>
</tr>
</tbody>
</table>

Rifting was active between 225 and 200 Ma. The consequences on the temperature field are taken into account with the rise of the 1300°C isotherm and the thinning of the crust in the oceanic domain.
Maturation of initial kerogens can generate seven families of chemical components presented in the table above. The "Non-HC" fraction mainly correspond to CO₂. "C" refers to the number of carbon in aliphatic chains. "NSO" refers to Nitrogen/Sulfur/Oxygen rich molecules. This chemical fraction also contains heavy oils. C1-C5 corresponds to the GAS and C6-C13; C14+ - NSO-Oil corresponds to the OIL. A "mobile" fraction can migrate in reservoir layers, while an "immobile" is solid or so viscous that it remains in the source rock. An "unstable" fraction (such as C14+) can be altered by secondary cracking to generate lighter compounds (such as C6-C13) or C1-C5.

<table>
<thead>
<tr>
<th>Name</th>
<th>Color</th>
<th>Compound Type</th>
<th>Mobility</th>
<th>Preferred HC Phase</th>
<th>Thermal Stability</th>
</tr>
</thead>
<tbody>
<tr>
<td>C1-C5</td>
<td></td>
<td>Hydrocarbon</td>
<td>Mobile</td>
<td>Vapor</td>
<td>Stable</td>
</tr>
<tr>
<td>C6-C13</td>
<td></td>
<td>Hydrocarbon</td>
<td>Mobile</td>
<td>Liquid</td>
<td>Unstable</td>
</tr>
<tr>
<td>C14+</td>
<td></td>
<td>Hydrocarbon</td>
<td>Mobile</td>
<td>Liquid</td>
<td>Insoluble</td>
</tr>
<tr>
<td>Non-HC</td>
<td></td>
<td>Non-Hydrocarbon</td>
<td>Mobile</td>
<td>Vapor</td>
<td>Stable</td>
</tr>
<tr>
<td>NSO-Oil</td>
<td></td>
<td>Hydrocarbon</td>
<td>Mobile</td>
<td>Liquid</td>
<td>Unstable</td>
</tr>
<tr>
<td>NSO-GR</td>
<td></td>
<td>Hydrocarbon</td>
<td>Immobile</td>
<td>Liquid</td>
<td>Unstable</td>
</tr>
<tr>
<td>Precocia</td>
<td></td>
<td>Solid Oil</td>
<td>Immobile</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Average Densities at Surface Conditions (for the 4 mobile hydrocarbons classes)
Density are average values for each fraction. These values are used for the calculation of volumes in surface conditions.

C1-C5 326 kg/m³  
C6-C13 841 kg/m³  
C14+ 897 kg/m³  
NSO-Heavy Oil 980 kg/m³

Source Rocks and Kerogen types

<table>
<thead>
<tr>
<th>Name</th>
<th>Kerogen type</th>
<th>Hydrogen Index (mg/gC)</th>
<th>S2 (mg/gC)</th>
<th>TOC (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 Naskapi</td>
<td>Brent (type III)</td>
<td>235</td>
<td>2.35</td>
<td>1</td>
</tr>
<tr>
<td>2 Mississauga</td>
<td>Brent (type III)</td>
<td>235</td>
<td>2.35</td>
<td>1</td>
</tr>
<tr>
<td>3 Tithonian</td>
<td>Intermediate (type II - type III)</td>
<td>424</td>
<td>12.72</td>
<td>3</td>
</tr>
<tr>
<td>4 Misaine</td>
<td>Intermediate (type II - type III)</td>
<td>424</td>
<td>12.72</td>
<td>3</td>
</tr>
<tr>
<td>5 Pliensbachian</td>
<td>Menil (type II)</td>
<td>600</td>
<td>18</td>
<td>3</td>
</tr>
</tbody>
</table>

Five source rocks that correspond to five layers with a content of organic matter were defined for the Temis 2D models, whether 2D or 3D. They are by chronologic order:
- Pliensbachian (196 Ma);
- Misaine (or Callovian 160 Ma);
- Tithonian (148 Ma);
- Mississauga (or Valanginian 136 Ma); and
- Naskapi (or Aptian 122 Ma).

Kinetic Scheme
Kerogen maturation follows "kinetic schemes" specific to each kerogen type. The maturation process is divided in "n" parallel chemical reactions (11 to 15 in that case) which have their own reaction speeds. Reaction speed is calculated with the Arrhenius Law and depends on: the Activation Energy, the Arrhenius Coefficient (specific to each chemical reaction), and the temperature. Each reaction generates chemical fractions defined by the chemical scheme. Tables and graphs detail the 3 kinetic schemes used in this study (Type III, Type II-III, Type II). These schemes come from the Temis Default Library (specific data not available for Nova Scotia). Secondary cracking reactions also follow kinetics laws.
CHAPTER 7-2

BASIN MODELING – TEMIS 2D

7-2-2

Section NS 1100 Modeling
Restoration of Section NS1100
Stratigraphy, Basement geometry and Location Map of Section NS1100

The limit between continental and oceanic crust domains is at kilometer 120 in the model. The crust maximum thickness is at the north of the section where the value is close to 40 km. On the contrary, the crust thickness is minimum at the south of the section where it is close to 8 km.

The section NS1100 is 185 kilometers in length and is located at the western limit of the study domain. The northern part of the section lies on the continental platform and the southern part lies on the oceanic domain.
The lithology distribution in the section NS1100 is derived from Dinosus 3D modeling which gives the composition of the mixing in four pure poles, Sand, Shale, Nearshore Carbonate and Mudstone Carbonate. Some faults that were interpreted on seismic have been introduced in the model because of their importance and the role they may have on fluid circulation due to their permeability.

The porosity distribution in the section NS1100 depends on the lithology, the burial and compaction (hydrostatic or over pressured). Low permeability layers in the model produce locally isolated compartments which are over pressured. Since fluids cannot easily escape from over pressured compartments, relatively higher porosities are predicted, compared to porosities under hydrostatic conditions.
Temperatures in Section NS1100 reach values of some 130 °C where burial is maximum at the base of the slope and throughout the diapir zone. On the platform, temperatures at the base of the section range between 70 and 90 °C. Toward the distal part of the basin, temperatures at the base of the section cool down to values ranging between 100 and 110 °C.

Temperature calibration at Bonnet Well location is within uncertainties around measurements. BHT are usually underestimations.

Pressure calibration at Bonnet Well location reproduce overpressure situation above 2600 m depth.

Mud Weight at Bonnet Well location displays overpressure situation in the shale layers above 2500 m depth and then hydrostatic below due to the presence permeable carbonate layers in communication with hydrostatic zones toward the surface.
Transformation Ratio at Present Day for the Source Rocks of Section NS1100

The evolution of the Transformation Ratio through time shows that only the Pliensbachian source rock (SR) is mature enough to generate significant amount of hydrocarbons in the area of the pseudo-well location at km 48. The age of generation and expulsion from the SR starts at 40 Ma until present day.

The evolution of hydrocarbon saturation through time in the Pliensbachian source rock shows that saturation (around 15%) is reached 50 Ma and since then saturation goes on until present day as the Transformation Ratio continues to improve. The Misaine and Tithonian source rocks do not reach the saturation threshold at that location.

The evolution of the Transformation Ratio through time shows that only Pliensbachian SR contribute to effective generation of hydrocarbon in the area of the pseudo-well location at km 62. The age of generation and expulsion from the SR starts at 80 Ma until present day.

The evolution of hydrocarbon saturation through time in the Pliensbachian source rock shows that saturation (around 8%) at present day does not reach the saturation threshold for expulsion from the source rock. The Misaine and Tithonian source rocks do not reach the saturation threshold at that location.

The evolution of the Transformation Ratio through time shows that only Pliensbachian source rock at the km 98 location generates hydrocarbons but not sufficiently for effective expulsion to take place. Expulsion from the Pliensbachian source rock is not reached at present day because the Transformation Ratio is less than 10%.

The evolution of hydrocarbon saturation through time in the Pliensbachian source rock shows that saturation (around 8%) at present day does not reach the saturation threshold for expulsion from the source rock. The Misaine and Tithonian source rocks do not reach the saturation threshold at that location.
Accumulations of hydrocarbons (HC) occur, though they are very limited. HC are mainly retained in the Pliensbachian source rock or diffuse in the Early Jurassic layers. A first accumulation appears at kilometer 47 in the late Jurassic under the Tithonian Layer. A second accumulation against salt diapir appears at kilometer 41 in the Early Cretaceous. A third accumulation appears at kilometer 36 in Jurassic formations.
The mature portion of the section is limited to the deepest part of the slope area (Lias formations).

The mass of hydrocarbons per area indicates where accumulations are located. Some accumulations are predicted in the deep synclines on the slope areas. These hydrocarbons originate from the Pliensbachian mature source rock.

The mass fraction of gas is less than 500 kg/m². Maturity of the Pliensbachian source rock is not high enough to produce gas in significant quantity.

The mass fraction of light oil in the section is less than 50 kg/m². The source rock involved is not mature enough to produce light fractions. The temperature is not high enough for secondary cracking to occur.

The mass fraction of heavy oil is less than 200 kg/m² everywhere. Some areas on the flanks of the synclines display improved HC concentration. The oil produced in the syncline structures tends to be trapped against the salt walls.

The API gravity is intermediate around 30. Some areas display higher values, around 40, corresponding to deep location where secondary cracking may have occurred. Some areas display lower values, around 25, corresponding to shallow location where secondary cracking has not occurred.
CHAPTER 7-2
BASIN MODELING – TEMIS 2D

7-2-3
Section NS 1400 Modeling
The section NS1400 is 214 kilometers long located at the west of the study domain. The northern part of the section is on the continental platform. The southern part is in the oceanic domain from kilometer 95 on.

The limit between continental and oceanic crust domains is at kilometer 95 in the model. The crust maximum thickness of some 30 km is located at the north end of the section. The crust minimum thickness of some 8 km (oceanic) is located at the south end of the section.

Stratigraphy, Basement Geometry and Location Map of Section NS1400
The porosity distribution in the section NS1400 does not only depend on the lithology and the burial, but also depend on the fluid circulations. Low permeability layers in the model lead to overpressure situation. This has the effect of diminishing the compaction that occurs in hydrostatic conditions. As a result higher porosity values are encountered.
The temperature field in section NS1400 displays values around 150°C at depth in the diapir area. The highest values of temperature on the platform and in the deep basin are lower (less than 110°C).

The pressure field displays low values on the platform and high values in the diapir area as well as in the deep basin area. The overpressure domain corresponds to the green colored area. Deep basin and diapir area are in this situation of overpressure.

Temperature calibrations at the Moheida well location are good, particularly in the lower part of the wells.

Pressure calibrations at Moheida and Torbrook locations are good.

Mud Weight at Moheida location displays significant overpressure above 2000 m depth. However, comparatively to Moheida, the simulated thermal gradient is much lower yet still impossible to match by the conditions imposed by the lithosphere thermal constraints. Note that for an equivalent burial, the over-estimation of the simulated temperature is about the same in both wells. Therefore, in Torbrook at greater depth, the temperature may be as realistic as it is in Moheida. Calibration is therefore considered acceptable.
The evolution of the Transformation Ratio through time shows that only the Pliensbachian source rock contributes significantly to hydrocarbon generation in the area of a pseudo-well located at km 80 on the section. Hydrocarbon generation starts 90 Ma ago and goes on until present day.

The evolution of the Transformation Ratio through time shows an early generation of Pliensbachian SR. Between 130 and 100 Ma, the TR evolves quickly, then it slows down until present day.

The transformation ratio, however, exceeds 15% since 20 Ma. Then from that age HC generation and expulsion is intense until present day.

The evolution of hydrocarbon saturation through time in the Pliensbachian source rock shows that the maximum saturation (around 11%) is reached 90 Ma ago. It corresponds to hydrocarbon expulsion from the source rock. Since that time, expulsion goes on until present day.

The evolution of hydrocarbon saturation between 95 and 50 Ma in the Pliensbachian source rock is due to migration of hydrocarbons generated from the through located near km 113 and moving laterally within the source rock. The last increase of saturation from age 20 Ma to present day relates essentially to local generation.

The expulsion from Misaine SR takes place before 90 Ma when the maximum saturation value for the Misaine is reached.

The expulsion from Tithonian SR takes place at 5 Ma when the 10% maximum saturation value for the Tithonian source rock is reached.

The Naskapi source rock remains immature (TR~0%).
In the slope area, hydrocarbons diffuse slowly out of the Pliensbachian source rock.

Hydrocarbons are generated and expelled intensely from the Pliensbachian source rock in the slope.

In the diapir area, expelled hydrocarbons already migrate and accumulate.

In the slope area, hydrocarbon expulsion continues to improve. Migration and accumulation are in progress.

In the diapir area, hydrocarbon expulsion and migration continue to improve.

Accumulations in the slope.

Accumulations above diapirs.

Accumulations against diapirs.

Accumulations at the Jurassic carbonate platform edge.
The maturity field at present day let us define the oil window area in the section. It's the limited domain in the NS1100 section where the generation of hydrocarbon occurred.

The mass of hydrocarbon per area indicates the location of the accumulations and permits to quantify them. The values are more than 4000 kg/m² locally in the slope.

The mass fraction of gas is locally higher than 500 kg/m², and it corresponds to the blue colored area. The values are close to 3000 kg/m² locally in the diapir area.

The mass fraction of light oil is low nearly everywhere in the section NS1400, it is less than 50 kg/m². The values are more than 50 kg/m² locally in the slope.

The mass fraction of heavy oil is close to 200 kg/m² locally in the diapir area. The mass fraction of heavy oil is more than 200 kg/m² locally in the slope.

API gravities of around 25 are found at shallower locations where secondary cracking does not occur. Some areas display API values, close to 40 in deep locations where secondary cracking occurs.

Average API gravity amounts to 30.
CHAPTER 7-2
BASIN MODELING – TEMIS 2D

7-2-4
Section NS 1600 Modeling
The section NS1600 is 225 kilometers long located in the center of the study area.

The northern part of the section is continental and intermediate. From kilometer 170, the southern part is oceanic.

In the model, the limit between continental and oceanic crust domains is fixed at kilometer 170.

The crust maximum thickness of 35 km is located at the north end of the section. The crust thickness is minimum (8 km thick) and oceanic at the south end of the section.

The section NS1600 is 225 kilometers long located in the center of the study area. The northern part of the section is continental and intermediate. From kilometer 170, the southern part is oceanic.

Figure 1: Stratigraphy of the section NS1600 at present day.

Figure 2: Lithosphere geometry of section NS1600 at present day.

Figure 3: Location of section NS1600 on map.
The lithology distribution in the section NS1600 is derived from Dionisos 3D modeling which gives the composition of the mixing in four pure poles: Sand, Shale, Nearshore Carbonate and Mudstone Carbonate. Some faults that were interpreted on seismic have been introduced in the model because of their importance and the role they may have on fluid circulation due to their permeability.

The porosity distribution in the section NS1600 does not only depend on the lithology and the burial but also on fluid circulation. Low permeability layers in the model lead to overpressure situation. This has the effect of diminishing the compaction that occurs in hydrostatic conditions. As a result, higher porosity values are encountered.
The highest values of temperature on the platform are lower than 120°C. The temperature field displays values above 200°C in depth in the diapir and canopy areas.

The pressure field displays low values on the platform and high values in the diapir and canopy areas as well as in deep basin.

The overpressure domain corresponds to the light green and green colored area. Deep basin, diapir and canopy areas are in situation of overpressure.

Mud Weight at well locations displays overpressure situation in the shale layers.
Transformation Ratio at Present Day for the Source Rocks of Section NS1600

Transformation Ratio through time at km 40 location
- Transformation of the Pliensbachian SR begins 125 Ma. Generation is intense until age 70 Ma, slowing down since until present.
- Transformation of the Misaine SR begins 100 Ma. Generation is intense until age 50 Ma, slowing down since until present.
- Transformation of the Tithonian SR begins at 134 Ma. Generation is intense until age 90 Ma, then weaker until present day. The Naskapi SR remains immature.

HC Saturation through time at km 40 location
- Evolution of saturation through time shows that the expulsion saturation (around 10%) is reached at 120 Ma, 120 Ma for respectively Pliensbachian and Misaine SR. It corresponds to the beginning of expulsion.

Transformation Ratio through time at km 84 location
- Transformation Ratio through time shows that the Pliensbachian, Misaine and Tithonian SR began to generate early (around 130 Ma). Their transformation is nearly complete 100 Ma.
- The Valanginian SR began to generate early (180 Ma). Their transformation is nearly complete since 100 Ma.

HC Saturation through time at km 84 location
- Saturation in hydrocarbon through time in the various SR shows that the maximum Saturation (around 10%) is reached at 134 Ma, 130 Ma and 126 Ma for Pliensbachian, Misaine and Tithonian SR, respectively. It corresponds to the beginning of expulsion.
- For the Valanginian SR the Saturation of 10% is reached 50 Ma. It corresponds to the beginning of expulsion.

Transformation Ratio through time at km 157 location
- Transformation Ratio through time of the Pliensbachian SR shows that generation began early (180 Ma). The generation is intense between the ages 140 Ma and 130 Ma. Transformation is nearly complete since 100 Ma.
- The generation is intense until age 90 Ma and then weaker until present day. The Valanginian and Naskapi SR remain immature.

HC Saturation through time at km 157 location
- Saturation through time in the Pliensbachian SR shows that the saturation of expulsion (10%) is reached 130 Ma and 120 Ma, respectively. It corresponds to the ages of expulsion for these two SR.
- The Valanginian SR reaches saturation higher than 10%. This is due to HC invasion migrating from lower SR.
In the salt area, hydrocarbons are expelled from the Pliensbachian source rock and invade the Early Jurassic layers.

Expulsion from the Pliensbachian source rock progresses. The Misaine and Tithonian source rocks also expel in Aptian time. Migrant hydrocarbons reach upward the Jurassic and the Early Cretaceous layers. Hydrocarbons migrate laterally within the Early Jurassic layers toward the Jurassic carbonate platform edge.

The expulsion continues from Pliensbachian, Misaine and Tithonian source rocks. Migration of HC is very much in progress upward. On the platform, at Como location HC are migrating vertically upward reaching Aptian Layer. Another way of migration in direction to the platform exists. HC generated in Misaine and Tithonian SR tends to migrate laterally in the Valanginian Layers.

Hydrocarbon expulsion from the Pliensbachian, Misaine and Tithonian source rocks is progressing. Hydrocarbons expelled from the Pliensbachian SR located in the salt area migrate laterally within the Early Jurassic layers up to the carbonate platform edge. There, they accumulate in antiline structures in the Panuke and Como areas.

At Como location HC are progressing vertically upward to the topography. Another accumulation is forming in the platform at Panuke location in the Valanginian Layers. In the transition area between the platform and the slope, vertical migration also reaches Valanginian-Hauterivian layers, at Alma, Wenonah and at kilometer 80 of the Section.
The model suggests that hydrocarbons migrate laterally in the direction of the platform from the Alma location toward the Panuke area. Large accumulations are forming under the salt canopies. Note that 2D modeling forces hydrocarbons generated in the section to stay in the section except for leaks at section ends. Similarly, accumulations cannot leak sideways off section.

At Como and Panuke, migration and accumulation continue to progress. Large accumulations are forming under the salt canopies. Note that 2D modeling forces hydrocarbons generated in the section to stay in the section except for leaks at section ends. Similarly, accumulations cannot leak sideways off section.
The maturity field at present day defines the oil and gas windows, and the over mature zone in the section. In the salt domain, the gas window and the over mature zone are extensive. Above, the oil window affecting the whole section includes the Jurassic carbonate platform edge.

The mass fraction of gas higher than 500 kg/m² corresponds to the blue colored area. It also corresponds also to the area where hydrocarbons are present in the section (See Figure 2). Gas is therefore the dominant hydrocarbon fraction in the section.

There is light oil in concentrations higher than 50 kg/m² in traps sealed by the Naskapi Formation. Some traps against salt have concentrations of light oil higher than 50 kg/m².

On the platform a shallow accumulation displays concentration of light oil higher than 50 kg/m². The mass fraction of light oil is higher than 50 kg/m² under the salt canopies.

Accumulations on the slope with total mass of hydrocarbons higher than 4000 kg/m². Accumulations under diapir with HC mass higher than 4000 kg/m².

Accumulations on platform with total mass of hydrocarbons higher than 4000 kg/m².

Accumulations under canopy with HC mass higher than 4000 kg/m².

There is light oil in concentrations higher than 50 kg/m² in traps sealed by the Naskapi Formation. Some traps against salt have concentrations of light oil higher than 50 kg/m².

On the platform a shallow accumulation displays concentration of light oil higher than 50 kg/m². The mass fraction of light oil is higher than 50 kg/m² under the salt canopies.

Accumulations on the slope with total mass of hydrocarbons higher than 4000 kg/m². Accumulations under diapir with HC mass higher than 4000 kg/m².

Accumulations on platform with total mass of hydrocarbons higher than 4000 kg/m².

Accumulations under canopy with HC mass higher than 4000 kg/m².

Great amount of gas trapped under salt canopies.

Some sparse traps against salt display concentrations of heavy oil higher than 50 kg/m².

Some sparse traps against salt display concentrations of heavy oil higher than 50 kg/m² locally on platform.

Average gravity value : 30 API.

Shallow or less mature areas, where secondary cracking does not occur, display oil gravity values at around 15 API.

Oil with API gravity values higher than 40 are located in deep areas where secondary cracking occurs.

Some sparse traps against salt display concentrations of heavy oil higher than 50 kg/m².

Mass fraction of heavy oil higher than 50 kg/m² locally on platform.

Great amount of gas trapped under salt canopies.

Some sparse traps against salt display concentrations of heavy oil higher than 50 kg/m².
CHAPTER 7-2
BASIN MODELING – TEMIS 2D

7-2-5
Section NS 2000 Modeling
BASIN MODELING – TEMIS 2D

PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA – June 2011

Restoration of Section NS2000

- 0 Ma
- 50 Ma
- 101 Ma
- 137 Ma
- 150 Ma
- 200 Ma

Color Legend:
- Oxfordian - Tithonian
- Early Jurassic
- Triassic - Salt
- Triassic - Continental deposits
- Continental crust
- Oceanic crust
- Oligocene - Neogene
- Eocene - Oligocene
- Paleocene - Ypresian
- Turonian - Maastrichtian
- Albian - Cenomanian
- Barremian - Albian
- Valanginian - Hauterivian
- Berriasian
The section NS2000 is 280 kilometers in length, located in the center of the study domain. The northern part of the section is on the continental platform, and the southern part is oceanic domain.

The limit between continental and oceanic crust domains is at kilometer 165 in the model. The crust’s maximum thickness is at the north of the section where the value is close to 40 km. On the contrary, the crust’s thickness is minimum at the south of the section where it is close to 8 km.

The section NS20000 is 280 kilometers in length, located in the center of the study domain. The northern part of the section is on the continental platform, and the southern part is oceanic domain.

The section NS2000 is 280 kilometers in length, located in the center of the study domain. The northern part of the section is on the continental platform, and the southern part is oceanic domain.

The section NS2000 is 280 kilometers in length, located in the center of the study domain. The northern part of the section is on the continental platform, and the southern part is oceanic domain.
The lithology distribution in section NS2000 is derived from Dionisos 3D modeling which gives the composition at the mixing in four pure poles: Sand, Shale, Nearshore Carbonate and Mudstone Carbonate. Some faults that were interpreted on seismic have been introduced in the model because of their importance and the role they may have on fluid circulation due to their permeability.

The porosity distribution in section NS2000 does not only depend on the lithology and the burial but also depends on the fluid circulations. Low permeability layers in the model lead to an overpressure situation. This has the effect of diminishing the compaction that occurs in hydrostatic conditions. As a result higher porosity values are encountered.
The highest values of temperature in the deep basin are around 150°C.

The highest values of temperature on the platform are lower than 120°C.

The temperature is over 300°C in depth in the diapir area.

The overpressure domain corresponds to the light green, green and yellow colored areas. Deep basin under the ramp, and late Jurassic layers of the platform are in situation of overpressure.

Pressure calibration at the well locations is good and reflects the overpressure situations displayed by measurements.

Temperature calibration in the wells is good, taking into account uncertainties around measurements that are usually underestimations.

Mud Weight at well locations displays overpressure situation in the shale of Late Jurassic layers.
Transformation Ratio at Present Day / Timing of Transformation Ratio and Expulsion at 3 Pseudo Well Locations

For Pliensbachian SR, saturation through time shows that expulsion takes place at 160 Ma. Generation is so quick that a high saturation value is reached (24%) at that time and a lower value (15%) of saturation is reached later.

Evolution of saturation through time shows that the expulsion saturation (higher than 15%) is reached at 155 Ma for Misaine SR.

Transformation of Pliensbachian SR begins at 160 Ma. The generation is intense and quick. It is totally transformed at 150 Ma.

Evolution of saturation through time shows that the expulsion saturation (higher than 15%) is reached at 155 Ma for Misaine SR.

Evolution of saturation through time shows that the expulsion saturation (higher than 15%) is reached at 155 Ma for Misaine SR.

Saturation through time in the SR shows that the Saturation of expulsion (15%) is reached at 125 Ma for Misaine SR. It corresponds to the beginning of expulsion.

Saturation through time shows that the Saturation of expulsion (15%) is reached at 125 Ma for Misaine SR. It corresponds to the beginning of expulsion.

For Tithonian SR, the Saturation of 15% is reached at 100 Ma. It is the age of expulsion.
The hydrocarbon is expelled from the Pliensbachian source rock in the salt area and invades the Early Jurassic layers.

Hydrocarbon is expelled from the Misaine source rock in the platform close to the slope.

Migration is progressing in the Early Jurassic layers on the platform upward along the slope.

Expulsion continues from Pliensbachian and Misaine source rocks in the platform salt area.

Migration is in progress; HC reaches layers close to the surface on the platform.

Expulsion occurs at the east between diapirs in the slope region.

Accumulations appear in depth in border of platform.

Migration is in progress; HC migrates upward on the platform along the slope in Early Cretaceous layers.

Accumulations increase in depth in border of platform.

Expulsion occurs on the fault ramp.

Migration is in progress; HC migrates upward on the platform along the slope in Early Cretaceous layers.

Accumulations increase in depth in border of platform.
Figure 1: Maastrichtian - 65 Ma

Figure 2: Ypresian - 50 Ma

Figure 3: Rupelian - 29 Ma

Figure 4: Langhian - 14.5 Ma

Figure 5: Present day – 0 Ma
The maturity field at present day lets us define the oil window, gas window and overmature areas in the section. The slope and the platform close to the slope are the domains the more in depth, gas window and overmature area represent a large proportion of these domains. The deepest part of the basin and the north of the platform belong to the oil window.

The mass fraction of gas higher than 500 kg/m² corresponds to the blue colored area. It also corresponds to the area where hydrocarbon is present in the section. This means that gas is the majority fraction of hydrocarbon in the domain.

There is a big amount of gas trapped in depth on anticline structure above diapir.

Some shallow accumulations are more than 4000 kg/m² locally on the platform. The mass of hydrocarbon per area indicates the location of accumulations and permits to quantify them.

In depth accumulations on platform have values higher than 9000 kg/m².

Some sparse accumulations have values of light oil higher than 50 kg/m².

Some sparse accumulations have values of heavy oil higher than 50 kg/m².

The average API gravity is intermediate at around 30. Some areas display API values around 25. They correspond to a high location where secondary cracking is ineffective.

Some areas display API values close to 40. They correspond to a depth location where secondary cracking occurs.

The mass of HC/Area (Kg/m²)

The mass of C1-C5/Area (Kg/m²)

The mass of C6-C13/Area (Kg/m²)

The mass of NSO_OIL/Area (Kg/m²)

API GRAVITY in API

The maturity field at present day lets us define the oil window, gas window and overmature areas in the section. The slope and the platform close to the slope are the domains the more in depth, gas window and overmature area represent a large proportion of these domains. The deepest part of the basin and the north of the platform belong to the oil window.

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Some areas display API values close to 40. They correspond to a depth location where secondary cracking occurs.
CHAPTER 7-3

BASIN MODELING – TEMIS 3D

7-3-1

3D Modeling Introduction
Stratigraphic Chart in the Reference 3D Block:
Eleven horizons provided by geophysicists are used in the models. Other horizons correspond to subdivisions with limited geological constraints.

For more details on source rocks and play systems/reservoirs, see PL. 7-3-1 and PL. 7-3-1-4.

<table>
<thead>
<tr>
<th>Age (horizons)</th>
<th>Horizon</th>
<th>Play Systems</th>
<th>Top &quot;Virtual&quot; Reservoirs in the 3D block</th>
<th>Top Source Rocks in the 3D block</th>
<th>Seismic Horizons from interpretation</th>
<th>Horizon Color</th>
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3D Modeling Introduction – TEMIS 3D® Workflow

**Mesh Refining** (Dionisos grid resolution 10 * 10 km).
- Conversion in petrophysical facies.
- Definition of petrophysical properties with:
  - Temis® default lithologies library;
  - Log and core data (porosity, permeability, etc.); and
  - Temperature and pressure calibration.

**Correction and smoothing.**
- Identification of salt bodies.
- Additional subdivisions for:
  - Reservoirs (with gross sand maps);
  - Source rocks (with effective thickness maps);
  - Refining of sedimentary sequences (automatic subdivisions proportional to the age); and
  - Technical subdivisions (refining time steps).
- Restoration through time.

**Source Rocks Parameter**
- Kerogens types;
- Chemical kinetics; and
- TOC.

**Thermal boundaries**
- Surface temperature history;
- Thermal basement (lithosphere modeling); and
- Rifting history.

**Restoration through time.**

**3D Modeling Introduction – TEMIS 3D® Workflow**

**Structural Maps from Seismic Interpretation**

**Geological Data**
- Geological context.
- Geological history.
- Deep geophysics.
- Geochemical data.
- Well log data.
- Petroleum field data.

**Temis 1D and 2D®**
- Preliminary evaluation of calibration data (petrophysical parameters, thermal boundaries).
- Estimation of migration processes (full Darcy migration in 2D models).

**PRESSURE / TEMPERATURE / MATURITY MODELING**

**Calibration Phase**
- Pressure;
- Temperature; and
- Vitrinite.

**SR Modeling**
- Present day maturity level;
- Maturity history; and
- Expelled volumes.

**Drainage Area Modeling**
- Migration path in reservoir layers.
- Closed structures and porous volumes.

**HC Volume Estimations**
- "Ray Tracing" Method (HC migration through time between SRs and reservoirs).
- HC in place (mass, volume, composition).
- Unrisked results.
Notes on Subzone Definition
Several criteria have been used for Subzones definition:
- Distinction between “Basin” (also called “deep basin”) and “Shelf” Zones. Limits between “Basin Zones” and “Shelf Zones” roughly correspond to isobath 2000 m.
- All drilled wells are in “Shelf Zones”. “Basin Zones” are completely unexplored (no exploration well).
- The shape of the “salt basin” and structural style: Basin Zone 2 corresponds to the diapir area with isolated mini-basins; Basin Zone 4 corresponds to “canopy domain”; Basin Zone 6 is mainly covering the “Banquereau wedge” zone with reduced diapir activity except in the northeastern most part of the area where autochthonous salt induced diapirs.
- All the discoveries are in Zone 3 (Sable Sub-basin is included in Zone 3), except Banquereau (Zone 5).

Modeling Result Confidence Chart
For main 3D modeling results, a “Modeling Result Confidence” is provided. It corresponds to a value between 1 and 5 (1 → quantitative / well constrained result ; 5 → qualitative / speculative result).
The definition of this chart is empirical and can be used to compare uncertainties on different results, but does not give an absolute “uncertainty range” on each result.

It depends on:
- The position on the workflow (uncertainties are cumulated along the 3D modeling workflow, for example the definition of source rocks transformation ratio is better constrained than the definition of in place hydrocarbon volumes, which partly depends on the source rock maturity).
- The number of hypothesis necessary to obtain the result (for example the calculation of hydrocarbon volumes in surface conditions depends on an hypothesis on hydrocarbon densities, which induces a higher uncertainty on hydrocarbon volumes in comparison with hydrocarbon masses).
For each source rock, the “Source Rock Thickness” corresponds to the cumulated thicknesses of organic-rich intervals (“effective source rock thickness”). This thickness is estimated with well geochemical data (Rock Evaluation data) and structural data. It is extrapolated in “basin zones” (2; 4; 6). Thickness of the Pliensbachian SR is speculative.

As a consequence for each source rock a single organic-rich layer is considered in the 3D model.

Source rocks petrophysical facies is defined as a specific shaly facies, and is assumed uniform.

The thickest source rocks are (by order):
- The Valanginian;
- The Aptian;
- The Tithonian;
- The Pliensbachian; and
- The Callovian.

See the table below for more details.

<table>
<thead>
<tr>
<th>Source Rock</th>
<th>Approx. Age</th>
<th>Initial TOC</th>
<th>Kerogen type</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>APTIAN</td>
<td>122 Ma</td>
<td>2 % (constant)</td>
<td>III (continental) HI = 235 mgHCgTOC</td>
<td>Potential source rock in the Naskapi shale (and equivalent), identified in some wells. Variable effective thickness between 0 – 100 m.</td>
</tr>
<tr>
<td>VALANGINIAN</td>
<td>136 Ma</td>
<td>1 % (constant)</td>
<td>III (continental) HI = 235 mgHCgTOC</td>
<td>Very poor and scattered source rock (coal fragments in deltaic environment, through the Mississauga formation) Variable effective thickness between 0 – 200 m.</td>
</tr>
<tr>
<td>TITHONIAN</td>
<td>148 Ma</td>
<td>3 % (constant)</td>
<td>II-III mix HI = 424 mgHCgTOC</td>
<td>Best defined SR, widely proven. Variable effective thickness between 0 – 50 m.</td>
</tr>
<tr>
<td>CALLOVIAN</td>
<td>160 Ma</td>
<td>2 % (constant)</td>
<td>II-III mix HI = 424 mgHCgTOC</td>
<td>Potential source rock in the Misaine shale (and equivalent), uncertain extend and richness due to the lack of data. Variable effective thickness between 0 – 20 m.</td>
</tr>
<tr>
<td>PLIENSACHIAN</td>
<td>196 Ma</td>
<td>5 % (constant)</td>
<td>II (marine) HI = 600 mgHCgTOC</td>
<td>Suspected, not proven. Potentially present above salt basins only. Assumed average thickness 20 m.</td>
</tr>
</tbody>
</table>

5 Source Rocks in the 3D Block.
Type III kerogen
(Brent – Dugger, North Sea) - Vandenbrouke et al., 1999.

Type II-III kerogen (mix)

Type II kerogen (Mesnil-2 - Toarcian, France) - Behar et al., 1997.

<table>
<thead>
<tr>
<th>Name</th>
<th>Color</th>
<th>Compound Type</th>
<th>Mobility</th>
<th>Preferred IC Phase</th>
<th>Thermal Stability</th>
</tr>
</thead>
<tbody>
<tr>
<td>C1-C5</td>
<td></td>
<td>Hydrocarbon</td>
<td>Mobile</td>
<td>Vapor</td>
<td>Stable</td>
</tr>
<tr>
<td>C6-C13</td>
<td></td>
<td>Hydrocarbon</td>
<td>Mobile</td>
<td>Liquid</td>
<td>Unstable</td>
</tr>
<tr>
<td>C14+</td>
<td></td>
<td>Hydrocarbon</td>
<td>Mobile</td>
<td>Liquid</td>
<td>Unstable</td>
</tr>
<tr>
<td>NSO-OIL</td>
<td></td>
<td>Non-Hydrocarbon</td>
<td>Mobile</td>
<td>Vapor</td>
<td>Stable</td>
</tr>
<tr>
<td>NSO-III+</td>
<td></td>
<td>Non-Hydrocarbon</td>
<td>Mobile</td>
<td>Liquid</td>
<td>Unstable</td>
</tr>
<tr>
<td>NSO-III+</td>
<td></td>
<td>Non-Hydrocarbon</td>
<td>Immobile</td>
<td>Liquid</td>
<td>Unstable</td>
</tr>
<tr>
<td>NSO-III+</td>
<td></td>
<td>Non-Hydrocarbon</td>
<td>Immobile</td>
<td>Liquid</td>
<td>Unstable</td>
</tr>
</tbody>
</table>

Chemical Scheme
IFP seven classes (+ coke) – five mobile fractions (Behar et al., 2008).
Maturation of initial kerogens can generate eight families of chemical components.
All chemical “fractions” are not hydrocarbons, the “Non-HC” fraction mainly correspond to CO₂.
“C” refers to the number of carbon in aliphatic chains.
“NSO” refers to Nitrogen / Sulfur /Oxygen-rich molecules. This chemical fraction also contains heavy oils.

Average Densities at Surface Conditions (for the three mobile hydrocarbons classes)
Density is empirically defined for each fraction, and calibrated with API gravity observed in the basin. The C1-C5 density (gas) is close to the methane density: methane is dominant in the Sable Sub-basin where calibration is possible.
Note that densities (and other parameters not presented here, such as PVT parameters) are “average” values for each fraction.

Kinetic Scheme
Kerogen maturation follows “kinetic schemes” specific to each kerogen type.
The maturation process is divided in “n” parallel chemical reactions (11 to 15 in that case) which have their own reaction speeds. Reaction speed is calculated with the Arrhenius Law and depends on: the Activation Energy, the Arrhenius Coefficient (specific to each chemical reaction), and the temperature. Each reaction generates chemical fractions defined by the chemical scheme.
Tables and graphs detail the three kinetic schemes used in this study (Type III, Type II-III, Type II). These schemes come from the Temis Default Library (specific data not available for Nova Scotia).
Secondary cracking reactions follow the same kind of kinetics laws.

Relationship TR / Vitrinite
The Transformation Ratio (TR) corresponds to the fraction of initial kerogen that has been affected by maturation reactions. It is expressed in percent: TR = observed HI / initial HI
The TR is representative of the maturity level of a given kerogen (and so of a source rock), while the vitrinite reflectance is an absolute maturity marker (not specific to a kerogen type).

<table>
<thead>
<tr>
<th>Kerogen Type</th>
<th>VR₀</th>
<th>VR₀</th>
<th>VR₀</th>
</tr>
</thead>
<tbody>
<tr>
<td>Type II</td>
<td>0.7</td>
<td>0.9</td>
<td>2</td>
</tr>
<tr>
<td>Type II-III</td>
<td>0.75</td>
<td>1</td>
<td>2.7</td>
</tr>
<tr>
<td>Type III</td>
<td>0.8</td>
<td>1.2</td>
<td>3.2</td>
</tr>
</tbody>
</table>

TR vs. VR₀ Conversion Graph
Each curve corresponds to a kerogen type (see the table below)
Maturity (TR = 50 %)
Overmaturity (TR = 95 %)
For each “play system”, a “virtual” reservoir layer is implemented in the 3D model. Hydrocarbon volumes and characteristics are computed in this layer.

“Reservoir Thicknesses” correspond to “Net Thicknesses” in the sedimentary sequences corresponding to play intervals, that is to say, cumulated thicknesses of porous intervals. The “Net thickness” is estimated with well log data and extrapolated with Dionisos® in “basin zones” (2, 4, 6). Thicknesses of “Oxfordian-Tithonian” and “Early-Middle-Jurassic” play systems are speculative.

“Real” reservoir layers may be scattered in the sedimentary sequence corresponding to the play interval, particularly if the “net to gross” is low (clay >>> sand). These “virtual reservoirs” are arbitrarily located at the upper part of play intervals (see the stratigraphic chart, PL. 7-3-1-1).

Reservoir rocks petrophysical facies are defined as specific sandy facies (Cretaceous Plays), or special sandy / carbonaceous facies (Jurassic Plays). The distribution is not uniform: sediment grain size is considered coarser on the shelf than in the deep water basin. Moreover, a distinction is done in the Oxfordian-Tithonian Play between “Baccaro-type” (Zone 1 and part of Zone 3), “Mi-C Mac-type” (Zone 5 and part of Zone 3), and “intermediary-type” reservoirs (Zone 3).

Reservoirs are thicker in Zone 3 and Zone 5, on the shelf.

<table>
<thead>
<tr>
<th>Reservoir Sequence</th>
<th>Age Interval</th>
<th>Petrophysical Facies</th>
<th>Depth(m)</th>
<th>Porosity()</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aptian-Albian-Cenomanian</td>
<td>112-94 Ma</td>
<td>-Sandstone on the Platform Slope and basin areas.</td>
<td>[1000;5000]</td>
<td>[0.12; 0.35]</td>
<td>In the northeastern part of the basin this sequence contains the Oxfordian.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>-Shale and basin areas Depth[5000;7000]</td>
<td></td>
<td>[0.05; 0.15]</td>
<td>Model: Logan and Cree formations.</td>
</tr>
<tr>
<td>Hauterivian-Barremian</td>
<td>130-123 Ma</td>
<td>-Sandstone on the Platform Slope and basin areas.</td>
<td>[1200;6000]</td>
<td>[0.10; 0.32]</td>
<td>In the northeastern part of the basin this sequence contains the Lower Mississauga formation.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>-Shale and basin areas Depth[4000;7000]</td>
<td></td>
<td>[0.03; 0.13]</td>
<td></td>
</tr>
<tr>
<td>Berriasian-Valanginian-Hauterivian</td>
<td>150-130 Ma</td>
<td>-Sandstone on the Platform Slope and basin areas.</td>
<td>[1200;6000]</td>
<td>[0.14; 0.35]</td>
<td>In the northeastern part of the basin this sequence contains the Lower and Middle Mississauga formations.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>-Shale and basin areas Depth[4000;8000]</td>
<td></td>
<td>[0.03; 0.12]</td>
<td></td>
</tr>
<tr>
<td>Oxfordian-Tithonian</td>
<td>163-150 Ma</td>
<td>-East of Platform: Sandstone.</td>
<td>[2000;4000]</td>
<td>[0.10; 0.37]</td>
<td>In the northeastern part of the basin this sequence contains the Mac-Mac formation. and in the northwestern part of the basin it contains the Baccaro formation.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>-West of Platform: Carbonates</td>
<td>[2000;8000]</td>
<td>[0.03; 0.28]</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>-Sand and Silt Mixed Lithology in the slope and basin areas</td>
<td>[4000;12000]</td>
<td>[0.02; 0.09]</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>-East of Platform: Porosity [0.02; 0.09]</td>
<td></td>
<td>[0.01; 0.07]</td>
<td>In the northwestern part of the basin this sequence contains the Scabarle formation.</td>
</tr>
<tr>
<td>Early-Middle-Jurassic</td>
<td>200-163 Ma</td>
<td>-Laggon Carbonates on the Platform Slope and basin areas.</td>
<td>[2000;9000]</td>
<td>[0.02; 0.09]</td>
<td></td>
</tr>
</tbody>
</table>
**3D Modeling Introduction – Thermal Boundaries – Basement Structure – Rifting**

---

**Moho Depth (in km)**

The Moho depth varies between 14 and 33 km in the study area. It reaches 42 km below Newfoundland (S. Dehler, GSC).

---

**Crust Thickness (in km)**

The thickness of the crust in the model is calculated with the Moho depth map (S. Dehler, GSC) and the Top Basement depth map provided by seismic interpretation (this study).

---

**Upper Crust Lithology**

The Upper Crust lithology has a strong influence on the thermal modeling: the continental crust is usually rich in radiogenic elements, while the oceanic crust does not generate radiogenic heat. Different types of continental crust with different content in radiogenic elements are considered.

---

**Other Basement Parameters**

- **Initial Crust Thickness before Rifting**: 42 km (cte)
- **Upper / Lower Crust Ratio in %**: 60% (continental domain) 30% (oceanic domain)
- **Initial Lithosphere Thickness before Rifting**: 120 km (cte)
- **Bottom Temperature Lithosphere / Asthenosphere Boundary**: 1330 °C (cte)

**BASEMENT STRUCTURE**

Basement structure has a strong impact on thermal modeling due to:

- The rifting at the beginning of the modeling (about 225 → 200 Ma);
- The disintegration of radiogenic elements in the crust; and
- The better constraint on the “Blanketing Effect” due to high sedimentation rates.

---

**Before Rifting (225 Ma)**

Relatively uniform temperature field. 1330 °C at the base of the lithosphere (base of the model).

---

**After Rifting (196 Ma)**

Heating due to the rifting. The thinning of the crust is stronger seaward (ocean opening). The mantle plume is also bigger southward.

---

**Present Day (0 Ma)**

Slow cooling after the rifting. At the same depth below the surface, temperature is lower seaward than on the shelf at present day.

---

**CROSS SECTION – RIFTING HISTORY**

Temperature in the Lithosphere at 3 key ages (in °C)

- **North**: 290 km
- **South**: 120 km

---

**BASEMENT STRUCTURE**

Basement structure has a strong impact on thermal modeling due to:

- The rifting at the beginning of the modeling (about 225 → 200 Ma);
- The disintegration of radiogenic elements in the crust; and
- The better constraint on the “Blanketing Effect” due to high sedimentation rates.

---

**Surface Temperature Through Time**

Surface temperature has a significant impact on thermal modeling. Sea bottom temperature evolution through time is required. Paleotemperatures are estimated in function with the paleobathymetry and paleoclimates/paleoenvironments.

---

**Zenith**

**Paleotemperatures**

- **0 Ma (present day)**: Variable with the depth average = 6.2°C
- **29 Ma**: average = 13.5°C
- **50 Ma**: average = 24°C
- **94 Ma**: average = 25°C
- **150 Ma**: average = 26°C

---

**PL. 7-3-1-5**
CHAPTER 7-3

BASIN MODELING – TEMIS 3D

7-3-2

3D Maturity & Expulsion Modeling
The first modeling stage consists of the temperature, pressure, maturity, and expulsion modeling, with the basin modeling software Temis 3D®.

The evolution of the whole 3D block (geological model) is simulated through geological times:

- Modeling of progressive burial due to sedimentation;
- Sediment compaction with the “back stripping method”;
- Structural evolution (uplift, subsidence, normal faults activity, etc.);
- Water flow modeling;
- Rifting of the lithosphere (thermal effect on the sedimentary basin);
- Computation of temperature and pressure through time in the whole 3D block;
- Computation of SR maturity through time; and
- Computation of HC expulsion through time (primary migration).

Results will be used for the migration and reservoir modeling, and later for the definition of some CRS maps (maturity maps, porosity maps, etc.).

### Calibration Wells

**List of the 31 Calibration Wells**

<table>
<thead>
<tr>
<th>Calibration Wells</th>
<th>X (UTM 20)</th>
<th>Y (UTM 20)</th>
<th>Temperature Data</th>
<th>Maturity Data</th>
<th>Pressure Data</th>
<th>Zone</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hesper - P 47</td>
<td>614890</td>
<td>4670220</td>
<td>x</td>
<td>x</td>
<td>x</td>
<td>Zone 3</td>
</tr>
<tr>
<td>Glenelg - W 13</td>
<td>636789</td>
<td>4548790</td>
<td>x</td>
<td>x</td>
<td>x</td>
<td>Zone 5</td>
</tr>
<tr>
<td>Evangeline H</td>
<td>658970</td>
<td>4558790</td>
<td>x</td>
<td>x</td>
<td>x</td>
<td>Zone 5</td>
</tr>
</tbody>
</table>

### Calibrations

**TEMPERATURE Calibration**

**VITRINITE REFLECTANCE Calibration**

**PRESSURE Calibration**

The 3D model is calibrated in pressure / temperature / maturity (vitrinite reflectance) with available well data. 31 wells are used. All wells are in zones 1, 3, 5, with a higher density in Zone 3 (Sable Sub-basin – 16 wells used).

A second calibration phase uses well test data (API, GOR, oil and gas repartition within the basin).
Temperature is relatively high in that part of the basin. The temperature exceeds 300°C in the Lower Jurassic since the Lower Cretaceous (11 km of burial at present day). On average, kerogens are overmature (above 200°C). A slight decrease of the thermal gradient occurred since the Lower Jurassic.

Vitrinite
Vitrinite reflectance reached 2% in the Pliensbachian SR (Lower Jurassic) during the Pliocene. The maturity level increased progressively since the Upper Cretaceous.

Overpressure
Moderate overpressure appeared progressive during the Tertiary. It is related to an increase of the burial, likely related to halokinesis and progressive salt withdrawal in the deepest part of the mini-basin.

Temperature
Temperature is relatively low in that part of the basin. The temperature reaches 170°C maximum since Pliocene time (at 8 km of burial).

Vitrinite
Vitrinite reflectance reached 2% in the Pliensbachian SR (Lower Jurassic) during the Pliocene. The maturity level increased progressively since the Upper Cretaceous.

Overpressure
Moderate overpressure appeared progressive during the Tertiary. It is related to an increase of the burial, likely related to halokinesis and progressive salt withdrawal in the deepest part of the mini-basin.
APTIAN SR

APTIAN SR (≈ 122 Ma)

Valanginian SR

Tithonian SR

Callovian SR

Pliensbachian SR

Relationship / Vitrinite

TR ≤ 5% (Maturity (oil window))

TR ≤ 50% (50%)

TR ≥ 95% (Overmaturity)

Kerogen Type III

VRI = 0.8

VRI = 1.2

VRI = 3.2

Modeling Results

Confidence

TR / Vitrinite

TR = 5%

Maturity (oil window)

TR = 50%

TR = 95%

Overmaturity

Kerogen

Type III

VR0 = 0.8

VR0 = 1.2

VR0 = 3.2

Modeling Results

Confidence

1

2

3

4

5

ZONE 1

ZONE 2

ZONE 3

ZONE 4

ZONE 5

ZONE 6

White = no SR

Grey = Immature

TR not calculated in salt diapirs (grey).

TR map calculated at present day.

3D Maturity / Expulsion Modeling – APTIAN SR – Transformation Ratio Map

PL. 7-3-2-2
Age of Maturity

TR > 5 %

Neogene
Paleogene
Upper Cretaceous
Lower Cretaceous
Jurassic

Age of Maturity (Ma)

The map indicates the age at which the source rock reached a given level of maturity: 5% of Transformation Ratio for the beginning of maturity, 95% of Transformation Ratio for over-maturity.

Maturation of the Aptian SR usually started at the end of the Cretaceous in the depression south of Zone 3, and locally earlier between Glenelg and Annapolis. Maturity is very recent in the easternmost part of Zone 3.

The Aptian SR did not reach the over-maturity level.

Evolution of the Maturity

In the deep mini-basin between Chebucto and Annapolis

The graph indicates the evolution of the Transformation Ratio through time at the deepest point of the mini-basin located between Chebucto and Annapolis (black star on maps, Zone 3, south of the shelf break). This is one of the most mature zone in the basin.

At this location, the Aptian SR is not overmature. It experienced one main phase of maturation related to the end of the Lower Cretaceous rapid burial episode: between 110 and 90 Ma.

Since that time the maturation speed decreased progressively. This part of the basin is almost inactive (from the generation / expulsion point of view) since Eocene time.
The map gives HC mass expelled through time (cumulated mass). HC mass expelled = oil mass expelled + gas mass expelled. The expulsion process corresponds to primary migration of HC out of SR layers. Expelled volumes are smaller than generated volumes and depend on petrophysical properties of source rocks (porosity, relatives permeability between hydrocarbons and water, irreducible water saturation, capillary pressure, etc.). Locally, the source rock can be slightly mature without expulsion. In this study case, it is unlikely that zones with expulsion lower than 0.4 Gkg / km² (~ 3.1 Mbble / km²) significantly contribute to an active petroleum system.

To convert HC mass (Gkg) in equivalent barrels of oil (Mbble), multiply values by about 8 (average oil density estimated at 810 kg/m³).

Expulsion mainly occurs in Zone 3. It is not very significant except locally in the deepest part of the depression between Glenelg and Annapolis.
VALANGINIAN SR

APTIAN SR

VALANGINIAN SR (≈ 135 Ma)

TITHONIAN SR

CALLOVIAN SR

PLIENSCHABIAN SR

Relationship
TR / Vitrinite

Maturity
TR = 5%
TR = 50%
TR = 95%
Overmaturity

Kerogen Type III
VR₀ = 0.8
VR₀ = 1.2
VR₀ = 3.2

Modeling Results

Confidence

ZONE 1

ZONE 3

ZONE 2

ZONE 4

ZONE 5

ZONE 6

TR map calculated at present day.

White = no SR
Grey = Immature
TR not calculated in salt diapirs (grey).

3D Maturity / Expulsion Modeling – VALANGINIAN SR – Transformation Ratio Map

PL. 7-3-2-4
**Age of Maturity (Ma)**

Neogene

Paleogene

Upper Cretaceous

Lower Cretaceous

Jurassic

**Age of Maturity and of Over-Maturity (in Million Years)**

Maps indicate the age at which the source rock reached a given level of maturity: 5% of Transformation Ratio for the beginning of maturity, 95% of Transformation Ratio for over-maturity.

Maturation of the Valanginian SR started early in the depression south of Zone 3 and Zone 5, and in a wide part of Zone 4, usually 20 – 30 Ma after the SR deposition (Lower Cretaceous). Maturity is more recent on the platform in Zone 3 and 5 (Latest Cretaceous and Paleogene).

The Valanginian SR reached the over-maturity level early in the deepest part of the depression between Glenelg and Annapolis (about 110 Ma).

**Evolution of the Maturity (in the deep mini-basin between Chebucto and Annapolis)**

The graph indicates the evolution of the Transformation Ratio through time at the deepest point of the mini-basin located between Chebucto and Annapolis (black star on maps, Zone 3, south of the shelf break). This is one of the most mature zones in the basin.

At this location, the Valanginian SR experienced one main phase of maturation related to the Lower Cretaceous rapid burial episode: between 130 and 110 Ma for this source rock. The decrease of the maturation speed after 110 Ma is more related to a specificity of the kerogen kinetic than to a decrease of the burial rate.
VALANGINIAN SR

Expulsion Map at Present Day (by square kilometer)

The map gives HC mass expelled through time (cumulated mass). HC mass expelled = oil mass expelled + gas mass expelled. The expulsion process corresponds to primary migration of HC out of SR layers. Expelled volumes are smaller than generated volumes and depend on petrophysical properties of source rocks (porosity, relative permeabilities between hydrocarbons and water, irreducible water saturation, capillary pressure, etc.).

Locally, the source rock can be slightly mature without expulsion. In that study case, it is unlikely that zones with expulsion lower than 0.4 kg / km² (~ 3.1 Mbble / km²) significantly contribute to an active petroleum system. To convert HC mass (Gkg) in equivalent barrels of oil (mbble), multiply values by about 8 (average oil density estimated at 810 kg/m³).

Expulsion is mainly significant in Zones 3 and 5. In Zone 4, expulsion remained limited, and elsewhere (Zone 1, 2, 6) Valanginian source rock did not contribute to any charge.

OIL / TOTAL HC Ratio Map at Present Day (in percent)

The map gives the fraction of oil expelled by the source rock through time: ratio = mass of expelled oil / total mass of expelled HC. This ratio takes into account secondary cracking of heavy HC occurring within the source rock layer, before expulsion, but cannot be representative of the amount of oil in place if secondary cracking occurs within reservoir layers.

The Valanginian SR expelled more gas than oil. It is a gas prone SR. The amount of oil fraction is predominantly between 20% and 30% at the exception of the deepest part of the basin where secondary cracking in the SR occurs significantly. In the deepest part the oil fraction is less than 20%, and can be less than 10%.

Modeling Results
Confidence
1
2
3
4
5

Modeling Results
Confidence
1
2
3
4
5

Gkg / km²
1 Gkg = 10⁹ kg = 1 Million T
~ 7.8Mbble

HC mass expelled
Limited
expulsion
Significant
expulsion
Very strong
expulsion

OIL mass fraction

%
TITHONIAN SR

APTIAN SR
VALANGINIAN SR
TITHONIAN SR (∼ 148 Ma)
CALLOVIAN SR
PLIENSBACKHIAN SR

Kerogen Type II-III
VR₀ = 0.75
VR₀ = 1
VR₀ = 2.7

Modeling Results
Confidence
1
2
3
4
5

White = no SR
Grey = Immature
TR not calculated in salt diapirs (grey).
TR map calculated at present day.

ZONE 1
ZONE 2
ZONE 3
ZONE 4
ZONE 5
ZONE 6

3D Maturity / Expulsion Modeling – TITHONIAN SR – Transformation Ratio Map

PL. 7-3-2-6
**Age of Maturity**

TR > 5 %

**Age of Maturity (Ma)**

Neogene
Paleogene
Upper Cretaceous
Lower Cretaceous
Jurassic

**Age of Maturity and of Over-Maturity**

(in Million Years)

The map indicates the age at which the source rock reached a given level of maturity: 5% of Transformation Ratio for the beginning of maturity, 95% of Transformation Ratio for over-maturity.

Maturation of the Tithonian SR started at Lower Cretaceous in the zones 3, 4, 5 and 6. On the contrary, maturation started very lately in the western area (Zones 1 and 2).

The second map indicates at which age the source rock reached over maturity (TR>95%). This over maturity is very early (Lower Cretaceous) for the deepest part of Zones 3, 5 and 6 that are located on the slope.

**Evolution of the Maturity**

(in the deep mini-basin between Chebucto and Annapolis)

The graph indicates the evolution of the Transformation Ratio through time at the deepest point of the mini-basin located between Chebucto and Annapolis (black star on maps, Zone 3, south of the shelf break). This is one of the most mature zones in the basin.

At this location, the Tithonian SR experienced one main phase of maturation related to the Lower Cretaceous rapid burial episode: between 130 and 110 Ma. The decrease of the maturation speed after 110 Ma is more related to a specificity of the kerogen kinetic than to a decrease of the burial rate.

**Modeling Results**

Confidence

1 2 3 4 5

**TITHONIAN SR**

**SR deposition (148 Ma)**

PL. 7-3-2-7a

3D Maturity / Expulsion Modeling – TITHONIAN SR – Maturity Timing Maps and Graphs
Expulsion Map at Present Day (by square kilometer)

The map gives HC mass expelled through time (cumulated mass). HC mass expelled = oil mass expelled + gas mass expelled.

The expulsion process corresponds to primary migration of HC out of SR layers. Expelled volumes are smaller than generated volumes and depend on petrophysical properties of source rocks (porosity, relative permeability between hydrocarbons and water, irreducible water saturation, capillary pressure, etc.). Locally, the source rock can be slightly mature without expulsion.

In this study case, it is unlikely that zones with expulsion lower than 0.4 Gkg/km² (~ 3.1 Mbble/km²) significantly contribute to an active petroleum system.

Strong expulsion occurred in Zones 3, 5, and 6, in the slope and the platform margin, where the expelled quantity exceeds 100 Gkg/km². Expulsion is also significant in Zone 4. Elsewhere, expulsion is very limited and cannot contribute significantly to HC accumulations (except locally in salt mini-basin of Zone 2).

OIL / TOTAL HC Ratio Map at Present Day (in percent)

The map gives the fraction of oil expelled by the source rock through time: ratio = mass of expelled oil / total mass of expelled HC. This ratio takes into account secondary cracking of heavy HC occurring within the source rock layer, before expulsion, but cannot be representative of the amount of oil in place if secondary cracking occurs within reservoir layers.

In the domain where the source rock is over mature the oil mass fraction is lower than 40% and even 30% locally. On the contrary, in the domain where the maturity of the source rock is less advanced, the oil mass fraction is higher and can reach values greater than 60% locally.
3D Maturity / Expulsion Modeling – CALLOVIAN SR – Transformation Ratio Map

ZONE 1
ZONE 2
ZONE 3
ZONE 4
ZONE 5
ZONE 6

Relationship TR / Vitrinite

<table>
<thead>
<tr>
<th>Kerogen Type</th>
<th>TR ≤ 5% Maturity (oil window)</th>
<th>TR ≤ 50%</th>
<th>TR ≤ 95% Overmaturity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Type II-III</td>
<td>VR₀ = 0.75</td>
<td>VR₀ = 1</td>
<td>VR₀ = 2.7</td>
</tr>
</tbody>
</table>

Modeling Results Confidence

1 2 3 4 5

White = no SR
Grey = Immature
TR not calculated in salt diapirs (grey).
TR map calculated at present day.

CALLOVIAN SR
APTIAN SR
VALANGINIAN SR
TITHONIAN SR
PLIENSBACHIAN SR

CALLOVIAN SR (= 160 Ma)

Kerogen Type II-III
VR₀ = 0.75
VR₀ = 1
VR₀ = 2.7

% TRANSFORMATION RATIO

0.00 20.00 40.00 60.00 80.00 100.00

0 50 100 km

UTM Zone 20

ZONE 1: Albatross B-13, Shuburne B-29
ZONE 2: Bonnet F-23
ZONE 3
ZONE 4
ZONE 5: Foremost F-11
ZONE 6: White Rose A-78, Spirit E-82

% Transformation Ratio

0 50 100 km

UTM Zone 20

3D Maturity / Expulsion Modeling – CALLOVIAN SR – Transformation Ratio Map

PL. 7-3-2-8

BASIN MODELING – TEMIS 3D

PLAY FAIRWAY ANALYSIS – OFFSHORE NOVA SCOTIA – CANADA – June 2011
**Age of Maturity (Ma)**

- Neogene
- Paleogene
- Upper Cretaceous
- Lower Cretaceous
- Jurassic

Age of Maturity and of Over-Maturity (in Million Years)

The map indicates the age at which the source rock reached a given level of maturity: 5% of Transformation Ratio for the beginning of maturity, 95% of Transformation Ratio for over-maturity.

Maturation of the Callovian SR started during late Jurassic or early Lower Cretaceous in Zones 3, 4, 5 and 6. In the eastern part of Zones 1 and 2 the maturity occurred later (Upper Cretaceous). In the rest of Zones 1 and 2 the maturity began during Paleogene or Neogene times. The Callovian SR reached the over-maturity level early in the deepest part of the depression (about 130 Ma) in Zones 3, 5 and locally in Zone 6. On the platform of Zones 3 and 5, the TR exceeds 95% since the Uppermost Cretaceous.

**Evolution of the Maturity**

(in the deep mini-basin between Chebucto and Annapolis)

The graph indicates the evolution of the Transformation Ratio through time at the deepest point of the mini-basin located between Chebucto and Annapolis (black star on maps, Zone 3, south of the shelf break). This is one of the most mature zones in the basin.

At this location, the Tithonian SR experienced one main phase of maturation related to the Lower Cretaceous rapid burial episode: between 135 and 115 Ma. The decrease of the maturation speed after 115 Ma is more related to a specificity of the kerogen kinetic than to a decrease of the burial rate.

**Age of Over Maturity (TR > 95%)**

- Neogene
- Paleogene
- Upper Cretaceous
- Lower Cretaceous
- Jurassic

**SR deposition (160 Ma)**

Earliest Maturation

- CALLOVIAN SR

**Confidence Modeling Results**

1. 2. 3. 4. 5.
**Expulsion Map at Present Day**

(by square kilometer)

The map gives HC mass expelled through time (cumulated mass). HC mass expelled = oil mass expelled + gas mass expelled.

The expulsion process corresponds to primary migration of HC out of SR layers. Expelled volumes are smaller than generated volumes and depend on petrophysical properties of source rocks (porosity, relative permeability between hydrocarbons and water, irreducible water saturation, capillary pressure, etc.). Locally, the source rock can be slightly mature without expulsion.

In that study case, it is unlikely that zones with expulsion lower than 0.4 Gkg / km$^2$ (~3.1 Mbble / km$^2$) significantly contribute to an active petroleum system.

To convert HC mass (Gkg) in equivalent barrels of oil (mbble), multiply values by about 8 (average oil density estimated at 810 kg/m$^3$).

Expulsion for the Callovian Source Rock exists in Zones 3, 4, 5 and 6 but remained limited in intensity. Even in the area where expulsion is maximum (in the eastern part of Zone 5) its magnitude is less than 400 Gkg / km$^2$. This source rock does not significantly contribute to a petroleum system.

**Expulsion Map at Present Day (by square kilometer)**

The map gives HC mass expelled through time (cumulated mass). HC mass expelled = oil mass expelled + gas mass expelled.

The expulsion process corresponds to primary migration of HC out of SR layers. Expelled volumes are smaller than generated volumes and depend on petrophysical properties of source rocks (porosity, relative permeability between hydrocarbons and water, irreducible water saturation, capillary pressure, etc.). Locally, the source rock can be slightly mature without expulsion.

In that study case, it is unlikely that zones with expulsion lower than 0.4 Gkg / km$^2$ (~3.1 Mbble / km$^2$) significantly contribute to an active petroleum system.

To convert HC mass (Gkg) in equivalent barrels of oil (mbble), multiply values by about 8 (average oil density estimated at 810 kg/m$^3$).

Expulsion for the Callovian Source Rock exists in Zones 3, 4, 5 and 6 but remained limited in intensity. Even in the area where expulsion is maximum (in the eastern part of Zone 5) its magnitude is less than 400 Gkg / km$^2$. This source rock does not significantly contribute to a petroleum system.
BASIN MODELING – TEMIS 3D

PLAY FAIRWAY ANALYSIS – OFFSHORE NOVA SCOTIA – CANADA – June 2011

PLIENS BACHIAN SR

APTIAN SR
VALANGINIAN SR
TITHONIAN SR
CALLOVIAN SR

PLIENS BACHIAN SR (~ 196 Ma)

<table>
<thead>
<tr>
<th>Relationship</th>
<th>TR ≤ 5% Maturity (oil window)</th>
<th>TR ≤ 50 %</th>
<th>TR ≤ 95 % Overmaturity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kerogen Type II</td>
<td>VRi = 0.7</td>
<td>VRi = 0.9</td>
<td>VRi = 2</td>
</tr>
</tbody>
</table>

Modeling Results Confidence

1
2
3
4
5

ZONE 1
ZONE 2
ZONE 3
ZONE 4
ZONE 5
ZONE 6

White = no SR
Grey = Immature
TR not calculated in salt diapirs (grey).
TR map calculated at present day.

3D Maturity / Expulsion Modeling – PLIENS BACHIAN SR – Transformation Ratio Map

PL. 7-3-2-10
**Age of Maturity (Ma)**

- **Neogene**
- **Paleogene**
- **Upper Cretaceous**
- **Lower Cretaceous**
- **Jurassic**

**Age of Maturity and of Over-Maturity (in Million Years)**

The map indicates the age at which the source rock reached a given level of maturity: 5% of Transformation Ratio for the beginning of maturity, 95% of Transformation Ratio for over-maturity.

Maturation of the Pliensbachian SR started early at Jurassic times northeast of section NS1600 (Zones 3 and 5). In the westernmost part of Zone 3, in Zone 4, and in the deepest parts of Zones 1 and 2 (Glooscap and mini-basins), the maturation started during the Lower Cretaceous. Globally the maturation started much later in Zones 1 and 2, during Paleogene times. The over maturity level was reached very early in Zones 3, 4, and 5 (Lower Cretaceous or Jurassic).

**Evolution of the Maturity (in the deep mini-basin between Chebucto and Annapolis)**

The graph indicates the evolution of the Transformation Ratio through time at the deepest point of the mini-basin located between Chebucto and Annapolis (black star on maps, Zone 3, south of the shelf break). This is one of the most mature zones in the basin.

At this location, the Pliensbachian SR experienced two main phases of maturation: between 170 and 160 Ma; around 130 Ma (Lower Cretaceous rapid burial episode).
**Pliensbachian SR**

**3D Maturity / Expulsion Modeling – Pliensbachian SR – Expelled Volumes Maps**

---

**Expulsion Map at Present Day (by square kilometer)**

The map gives HC mass expelled through time (cumulated mass). HC mass expelled = oil mass expelled + gas mass expelled. The expulsion process corresponds to primary migration of HC out of SR layers. Expelled volumes are smaller than generated volumes and depend on petrophysical properties of source rocks (porosity, relative permeability between hydrocarbons and water, irreducible water saturation, capillary pressure, etc.). Locally, the source rock can be slightly mature without expulsion. In that study case, it is unlikely that zones with expulsion lower than 400 Gkg / km² (~ 3.1 Mbble / km²) significantly contribute to an active petroleum system.

For the Pliensbachian Source Rock, expulsion mainly occurs in Zones 3 and 5 and in the north of Zone 4 where the quantity exceeds 1200 Gkg/km². Expulsion is also very important at east of Zone 1 and locally in scattered area of Zones 1 and 2 where it can exceed 1000 Gkg/km².

---

**OIL mass fraction**

The Pliensbachian SR expelled more oil than gas. It is a oil prone SR. The oil mass fraction is close to 60% at the east of the study domain and is even higher, close to 70%, at the west of the study domain.
### Expelled HC Masses and Volumes – By ZONE – By SOURCE ROCK (numerical table)

Amount of expelled HC are computed in mass and converted in volumes (surface conditions, \(d_{oil} = 807 \text{ kg/m}^3; d_{gas} = 0.657 \text{ kg/m}^3\)). The model takes into account secondary cracking in source rock layers, before expulsion (but not secondary cracking that occurs later in reservoir layers). No threshold on expelled masses per km².

<table>
<thead>
<tr>
<th>ZONE</th>
<th>GAS expelled (Gkg)</th>
<th>OIL expelled (Gkg)</th>
<th>TOTAL HC expelled (Gkg) and oil equivalent</th>
<th>WHOLE SR HC mass expelled (in Gkg Or MT)</th>
<th>WHOLE SR HC volume expelled (in Tcf for gas; in Billion bbl for oil and oil equivalent)</th>
<th>WHOLE SR ORGfeed expelled (in kg/kg)</th>
<th>WHOLE SR GOR expelled (in scf/stb)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>8</td>
<td>4</td>
<td>12</td>
<td>4200</td>
<td>230</td>
<td>0.7</td>
<td>4600</td>
</tr>
<tr>
<td>2</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>35</td>
<td>50</td>
<td>0.7</td>
<td>4600</td>
</tr>
<tr>
<td>3</td>
<td>723</td>
<td>1439</td>
<td>1026</td>
<td>10400</td>
<td>80</td>
<td>1.5</td>
<td>10400</td>
</tr>
<tr>
<td>4</td>
<td>2</td>
<td>655</td>
<td>2</td>
<td>10700</td>
<td>580</td>
<td>1.5</td>
<td>9700</td>
</tr>
<tr>
<td>5</td>
<td>23</td>
<td>527</td>
<td>284</td>
<td>12100</td>
<td>650</td>
<td>1.3</td>
<td>9300</td>
</tr>
<tr>
<td>6</td>
<td>0</td>
<td>4</td>
<td>0</td>
<td>10200</td>
<td>80</td>
<td>1.7</td>
<td>11400</td>
</tr>
<tr>
<td>WHOLE BASIN</td>
<td>800</td>
<td>300</td>
<td>1100</td>
<td>16800</td>
<td>71400</td>
<td>9</td>
<td>980</td>
</tr>
</tbody>
</table>

**Expelled HC Masses and Volumes – By ZONE – By SOURCE ROCK (numerical table)**

Amount of expelled HC are computed in mass and converted in volumes (surface conditions, \(d_{oil} = 807 \text{ kg/m}^3; d_{gas} = 0.657 \text{ kg/m}^3\)). The model takes into account secondary cracking in source rock layers, before expulsion (but not secondary cracking that occurs later in reservoir layers). No threshold on expelled masses per km².
**BASIN MODELING – TEMIS 3D**

**PLAY FAIRWAY ANALYSIS – OFFSHORE NOVA SCOTIA – CANADA – June 2011**

---

**Surface Conditions**

**3D Maturity / Expulsion Modeling – Synthesis on Expelled Volumes (Graphs)**

---

**Expelled HC Masses and Volumes**

(by Source Rock / by Zone)

**By Source Rock**

The main contributors at the scale of the basin is the Tithonian SR (48% of expelled HC) and the Pliensbachian SR (32% of expelled HC, 43% of expelled oil). Callovian SR and Valanginian SR are less significant contributors (respectively 15% and 11% of expelled gas), and contribution of Aptian SR is negligible.

Graphs show that Pliensbachian SR is the only oil prone source rock, while Valanginian SR is a clear gas prone source rock.

**By Zone**

Zones with the largest amount of expelled HC are:

- Zone 3 (31%), Zone 6 (22%), Zone 5 (17%), Zone 4 (14%), Zone 2 and Zone 1.

Zone ranking for oil or gas expulsion is the same.

Surface volumes are calculated with $d_{oil} = 807 \text{ kg/m}^3$ and $d_{gas} = 0.657 \text{ kg/m}^3$.

---

**Expelled HC Masses and Volumes**

(by Zone - All SR)

**By Zone**

Zones with the largest amount of expelled HC are:

- Zone 3 (31%), Zone 6 (22%), Zone 5 (17%), Zone 4 (14%), Zone 2 and Zone 1.

---

**Expelled HC Masses and Volumes**

(by Source Rock - Whole Basin)

**By Source Rock**

- APTIAN SR (Type III)
- VALANGIAN SR (Type III)
- TITHONIAN SR (Type II)
- CALLOVIAN SR (Type II)
- PLEISNBACHIAN SR (Type II)

---

**Expelled HC Masses and Volumes**

(by Zone - All SR)

**By Zone**

Zones with the largest amount of expelled HC are:

- Zone 3 (31%), Zone 6 (22%), Zone 5 (17%), Zone 4 (14%), Zone 2 and Zone 1.

Zone ranking for oil or gas expulsion is the same.

Surface volumes are calculated with $d_{oil} = 807 \text{ kg/m}^3$ and $d_{gas} = 0.657 \text{ kg/m}^3$.

---

**Expelled HC Masses and Volumes**

(by Zone - All SR)

**By Zone**

Zones with the largest amount of expelled HC are:

- Zone 3 (31%), Zone 6 (22%), Zone 5 (17%), Zone 4 (14%), Zone 2 and Zone 1.

Zone ranking for oil or gas expulsion is the same.

Surface volumes are calculated with $d_{oil} = 807 \text{ kg/m}^3$ and $d_{gas} = 0.657 \text{ kg/m}^3$. 
CHAPTER 7-3
BASIN MODELING – TEMIS 3D

7-3-3

Play System Modeling
**Concept of Source Rock Efficiency**

"SR efficiencies" used in PetPot correspond to the ratio of hydrocarbons expelled from a given SR reaching a given reservoir through geological times. It is expressed in %. The "SR efficiency" is higher than the "Migration efficiency", usually expressed as:

\[
\text{Migration Efficiency} = \frac{\text{HC mass in a trap (present day)}}{\text{HC mass expelled in the corresponding drainage area}}
\]

TEMIS 2D® simulations in "full Darcy migration" (Chapter 7-2) give a first estimation of these parameters. In such 2D simulations "Efficiencies" are not input parameters but calculated by the software, taking into account complex migration processes (including the modeling of rocks petrophysical properties, HC geochemical properties, PVT conditions, maturation timings, etc.). Results are averaged and extrapolated in 3D.

The model is also calibrated with field data (known petroleum fields). If calculated HC volumes do not match known HC volumes, source rock efficiencies are adjusted.

Geological concepts, knowledge on petroleum system dynamics, and analogs, give precious information too.

In that study case, a simplified set of "SR efficiencies" has been approximated by all these means. A lower efficiency is assumed for downward migration. This scheme is conceptual and uncertain, but it calibrates known petroleum fields.

The following "SR efficiencies" are defined for each system (SR // Reservoir layers):

<table>
<thead>
<tr>
<th>Reservoir Layer</th>
<th>Source Rock Layer</th>
<th>APTIAN SR</th>
<th>VALANGINIAN SR</th>
<th>TITHONIAN SR</th>
<th>CALLOVIAN SR</th>
<th>PUENBACHIAN SR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aptian-Albian-Cenomanian (K112-K94)</td>
<td>5%</td>
<td>3%</td>
<td>3%</td>
<td>1%</td>
<td>1%</td>
<td></td>
</tr>
<tr>
<td>Hauterivian-Barremian (K130-K123)</td>
<td>3%</td>
<td>5%</td>
<td>5%</td>
<td>3%</td>
<td>1%</td>
<td></td>
</tr>
<tr>
<td>Berriasian-Valanginian-Hauterivian (J110-J130)</td>
<td>0%</td>
<td>3%</td>
<td>5%</td>
<td>3%</td>
<td>3%</td>
<td></td>
</tr>
<tr>
<td>Oxfordian-Tithonian (J63-J150)</td>
<td>0%</td>
<td>0%</td>
<td>3%</td>
<td>5%</td>
<td>3%</td>
<td></td>
</tr>
<tr>
<td>Early-Middle-Jurassic (J200-J163)</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>3%</td>
<td>5%</td>
<td></td>
</tr>
</tbody>
</table>

Downward migration
The second modeling stage consists of determining main reservoir characteristics and charge for each play system, at the scale of each subzone:

- Temperature / pressure / secondary cracking and biodegradation risk;
- Drainage area maps and main closure maps → “Drains” Module;
- Trapped HC volumes (in place) and HC characteristics → “PetPot” Module; and
- SRs contribution.

“Drain” and “PetPot” modules of Temis 3D© take into account:

- HC volumes expelled by each SR through geological time;
- Porous volume change through geological time (compaction);
- Structural and drainage changes through geological time;
- Structural and closure changes through geological time; and
- Pressure and temperature changes through geological time (PVT).

Migration and Accumulation Modeling (Play System Modeling) directly uses results of the Temperature / Pressure / Maturity / Expulsion Modeling, and is constrained by reservoir layers definition in the 3D block (structural maps, thickness maps, facies maps).

NOTE: Results are calibrated with field data (mainly in Subzone 3).

**HYPOTHESIS for the DRAINAGE ANALYSIS**

(Drain Module)

- “Drain” and “PetPot” use a simplified version of the TEMIS 3D block. Only SR and Reservoir layers are considered for drain and migration modeling. Structural maps have the highest available resolution.
- Only 4 way traps with a closure surface bigger than 2 km² are considered. Most of fields in the Sable Sub-basin are associated to rollover with a spill point against “relatively” permeable faults. This assumption is not restrictive at the scale of the basin, given the lateral resolution of structural data (1 km). Closed areas, closure heights, and closed volumes, are computed.
- To each trap corresponds a drainage area. A leakage network exists between traps.
- Inside reservoir layers, HCs migrate laterally up to a trap or a permeable fault. Migration pathways are defined by slope lines. Combinations of migration pathways define drainage areas.
- Salt bodies are impermeable and are excluded from drainage areas.
- Most of salt bodies are bordered by “relatively” permeable faults. Closure against diapirs are unlikely (assumption based on observations, such as “seeps” in the salt basin, or absence of such traps in the Sable Sub-basin).
- HCs that reach a permeable faults or the model border are lost.
- The migration in each reservoir layer is computed independently.

NOTE: New drainage areas are computed for each time step.

**HYPOTHESIS for the MIGRATION / ACCUMULATION ANALYSIS**

(PetPot Module)

- Between source rocks and reservoir layers, upward and downward migration is assumed vertical and instantaneous (at each time step). At the scale of the basin this assumption is correct and consistent.
- A “SR efficiency” is defined for each couple (SR // Reservoir layers), see verso.
- In each trap the PetPot module defines:
  - The volume of different phases (liquid, vapor, critical fluid);
  - The composition of different phases (“oil” fraction C6+, “gas” fraction C1-C5); and
  - Various petroleum parameters such as the CGR, theGOR, the API.
- It is possible to identify relative SR contribution.
- Leakage through spill points depends on PVT conditions (volume in bottom conditions for different phases, water/oil contact and gas/oil contact), and on the porous volume at each time step.
- Volumes in surface condition are computed with:
  - API gravities for the Oil; and
  - V=nRT/P for the gas (with P=0.1 MPa, T=20°C, n=16 if methane is dominant).

NOTE: New volumes and phases are computed for each time step.

NOTE: “PHASES” and “FRACTIONS” are different concepts.

→ 5 PLAY SYSTEMS are studied (see PL. 7-3-1-5)

All volumes and masses calculated by Petpot are IN PLACE. The software considers only HC trapped in structures (of any size).

Volumes and masses are UNRISKED.

Volumes calculated by Temis® are equivalent to P10 VOLUMES (optimistic scenario): 5 potential Source Rocks and 5 plays are considered.

Masses and volumes are computed in International Units and converted in Imperial Units.

It is better to manage masses rather than volumes in intermediary results (comparing easily amounts of oil and gas, avoiding uncertainties on conversions in surface condition).

There is no indication on the distribution of HCs within each subzone. This distribution may be heterogeneous, particularly in Zone 1.
Due to the complex shape of drainage areas in Zone 2 (salt mini-basins), long distance lateral migration is unlikely in that part of the basin. Moreover, the existence of relatively permeable faults along active salt bodies would increase the vertical migration, and so the hydrocarbon "leakage" out of this play (presence of seeps in this area).

As a consequence, potential mature SR in Zone 2 can hardly feed reservoirs in Zone 1. Potential migration pathways are longer in the upper slope and on the platform (Zone 1).

### Closed Areas / Closed Porous Volumes / Drainage Areas

The closed area (or closure area) is defined by structural maps. It corresponds to the extend of a structural trap (four way closure). About 2% of the study area is a closed area. Closed areas evolve during the geological history due to structural evolutions.

The closed porous volume is the volume of voids in a structural trap. This volume can be filled with water or hydrocarbons. It usually decreases during the geological history due to the compaction. Porosity modeling is done by Temis®.

Each trap is associated to a drainage area defined by slope lines, impermeable lithologies, permeable faults. The size of the drainage area may impact the charge of the trap.

The Albian-Cenomanian play system includes: the Cree Formation Play, the Logan Canyon Play, the Albian Low-Stand Sandstone Play, etc.

### Albian-Cenomanian – SW

The pink lines represent the main drainage divide. The blue lines represent the slope lines and flow path. The white contour represents the closure area. The background corresponds to horizon K101 depth. Light brown indicates the salt.
Due to the complex shape of drainage areas in salt mini-basins (southern Zone 3, Zone 4), long-distance lateral migration is unlikely south of a line Evangeline-Annapolis. However, relatively long distance lateral migration appears possible in the Sable Sub-basin (Zone 3), the play being sourced from mature SR located in the deep depression between Evangeline, Annapolis, and Glenelg (north of the line Evangeline-Annapolis). Potential migration pathways are longer in the upper slope and on the platform (Zones 3 and 5). Very long horizontal migration pathways are also possible in the deep basin (southern Zones 4 and 6).
Biodegradation risk below 80 – 60 °C

Temperature at K101

Temperature reaches a maximum of 130°C in the slope along the shelf break, particularly in Zones 1, 2, and 3. Risk of biodegradation exists on the platform, particularly in Zones 1 and 3 (minimum temperature around 50°C), and in the deep basin, particularly in Zones 4 and 6.

The possibility of secondary cracking is very limited in the deepest part of the basin, and only concerns the heaviest hydrocarbon fraction.

Overpressure is low to moderate in the slope along the shelf break, with highest values between Zones 1 and 2, and locally between Zones 3 and 4, around salt diapirs. There is no overpressure on the platform, and very low overpressure in the deep basin. Average value for the whole study area is around 5MPa.
Albian-Cenomanian Play System

HC Repartition (masses and volumes – by Zone)

HC type by zones (in Gkg) - Apt-Ceno.

HC Characteristics (Composition / Phase / Origin)

GOR by Zones (scf / stb) - Apt-Ceno.

API Gravity by Zones - Alb-Ceno.
This figure illustrates for each subzone:
- The relative HC composition (what kind of HC fraction could be found in the play system?)
- The relative SR contribution (which SRs feed the play system?)
- The relative HC phase distribution (HCs: are they in vapor, liquid, or critical phase in the play system?)
Due to the complex shape of drainage areas in Zone 2 (salt mini-basins), long-distance lateral migration is unlikely in that part of the basin. Moreover, the existence of relatively permeable faults along active salt bodies would increase the vertical migration, and so the hydrocarbon "leakage" out of this play (presence of seeps in this area).

As a consequence, potential mature SR in Zone 2 can hardly feed reservoirs in Zone 1. Potential migration pathways are longer in the upper slope and on the platform (Zone 1).

---

The **Hauterivian-Barremian play system** mainly includes the Upper Mississauga Formation Play.
Due to the complex shape of drainage areas in salt mini-basins (southern Zone 3, Zone 4), long-distance lateral migration is unlikely south of a line Evangeline-Annapolis. However, relatively long distance lateral migration appears possible in the Sable Sub-basin, with mature SR in the deep depression between Evangeline, Annapolis, and Glenelg (north of the line Evangeline-Annapolis).

Potential migration pathways are longer in the upper slope and on the platform (Zones 3 and 5). Very long horizontal migration pathways are also possible in the deep basin (southern Zones 4 and 6).
**Temperature / Biodegradation/ Secondary Cracking**

Temperature reaches a maximum of 180°C along the shelf break in Zone 3. A temperature higher than 100°C is usually observed in the slope zone.

Risk of biodegradation exists on the platform, particularly in Zones 1 and 3 (minimum temperature around 50°C in Zone 1). The risk is more limited in some areas of the deep basin, particularly in Zones 4 and 6.

The possibility of secondary cracking exists in the deepest part of the basin, and only concerns the heaviest hydrocarbon fraction.

**Hauterivian-Barremian Play System**

**Overpressure at K125**

Overpressure is moderate in the slope along the shelf break, between Zones 1 and 2, and between Zones 3 and 4. Locally, overpressure reaches very high values in the Zone 3, with the highest values close to 50 MPa.

There is no overpressure on the platform (except maybe in Zone 5 and in southern Zone 3). There is a low overpressure field in the deep basin (around 10 MPa, mainly in Zones 2 and 4).
Hauterivian-Barremian Play System

**Volume of OIL EQUIVALENT in Place - by Zone**

- **ZONE1**: 4.2 billion bbls
- **ZONE3**: 3.2 billion bbls
- **ZONE5**: 2.0 billion bbls
- **ZONE6**: 2.0 billion bbls
- **ZONE4**: 1.8 billion bbls
- **ZONE2**: 1.4 billion bbls

**API Gravity by Zones - Hauteriv-Barr.**

- **ZONE1**: 40 API
- **ZONE3**: 46 API
- **ZONE5**: 52 API
- **ZONE6**: 50 API
- **ZONE4**: 48 API
- **ZONE2**: 51 API

**Volume of OIL In Place - by Zone**

- **ZONE1**: 2000 Bbbe
- **ZONE3**: 470 Bbbe
- **ZONE5**: 1400 Bbbe
- **ZONE6**: 547 Bbbe
- **ZONE4**: 470 Bbbe
- **ZONE2**: 1000 Bbbe

**HC Repartition (masses and volumes – by Zone)**

- **ZONE1**: 10% mass, 15% volume
- **ZONE3**: 15% mass, 10% volume
- **ZONE5**: 5% mass, 20% volume
- **ZONE6**: 20% mass, 5% volume
- **ZONE4**: 5% mass, 20% volume
- **ZONE2**: 10% mass, 15% volume

**HC Characteristics (Composition / Phase / Origin)**

- **GOR by Zones**:
  - **ZONE1**: 7100 scf/stb
  - **ZONE3**: 14200 scf/stb
  - **ZONE5**: 22000 scf/stb
  - **ZONE6**: 31400 scf/stb
  - **ZONE4**: 5700 scf/stb
  - **ZONE2**: 16400 scf/stb

- **API Gravity by Zones**
  - **ZONE1**: 40 API
  - **ZONE3**: 43 API
  - **ZONE5**: 52 API
  - **ZONE6**: 50 API
  - **ZONE4**: 38 API
  - **ZONE2**: 46 API

- **Total GAS Volume in Place**
  - **Whole Basin**: 6.9 billion bbls

- **Volume of OIL EQUIVALENT In Place**
  - **Whole Basin**: 6.9 billion bbls

- **Volume of GAS In Place**
  - **Whole Basin**: 33 Tcf

- **By ZONE**
  - **ZONE1**: 40 (Gkg)
  - **ZONE3**: 40 (Gkg)
  - **ZONE5**: 60 (Gkg)
  - **ZONE6**: 60 (Gkg)
  - **ZONE4**: 60 (Gkg)
  - **ZONE2**: 60 (Gkg)

- **Total GAS Mass (Gkg) - Hauteriv-Barr.**
  - **Whole Basin**: 612 (Gkg)

- **Total OIL mass (Gkg) - Hauteriv-Barr.**
  - **Whole Basin**: 255 (Gkg)

- **Total HC volume in surface (Tcf) - Hauteriv-Barr.**
  - **Whole Basin**: 867 (Tcf)

- **Total OIL volume in Place - Unrisked**
  - **Whole Basin**: 1.0 (Tcf)

- **Total OIL volume in surface (Mbbi) - Unrisked**
  - **Whole Basin**: 1.0 (Mbbi)

- **Total OIL EQUIVALENT volume in surface - Unrisked**
  - **Whole Basin**: 1.0 (Mbbi)
**Hauterivian-Barremian Play System**

- **ZONE 1** - Hauteriv-Barr. (% mass)
  - Hauteriv-Barr. (% volume in place)

- **ZONE 2** - Hauteriv-Barr. (% mass)

- **ZONE 3** - Hauteriv-Barr. (% mass)

- **ZONE 4** - Hauteriv-Barr. (% mass)

- **ZONE 5** - Hauteriv-Barr. (% mass)

- **ZONE 6** - Hauteriv-Barr. (% mass)

---

**Hydrocarbon Characteristics (by Zone)**

- **(HCs: are they in vapor, liquid, or critical phase in the play system?)**
  - **HC Phase**
  - **in Bottom Conditions**

- **(what kind of HC fraction could be found in the play system?)**
  - **HC Composition Chemical Fractions**

- **(which SRs feed the play system?)**
  - **SR Contribution**

- **(The relative HC phase distribution)**

- **(The relative HC composition)**

- **(The relative HC phase distribution)**

(HCs: are they in vapor, liquid, or critical phase in the play system?)

---

**This figure illustrates for each subzone:**
- The relative HC composition
- The relative SR contribution
- The relative HC phase distribution

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**Play System Modeling – Hauterivian-Barremian Sequence (K130-K123) – Hydrocarbon Characteristics (by Zone)**

**PL. 7-3-3-7**
Due to the complex shape of drainage areas in Zone 2 (salt mini-basins), long distance lateral migration is unlikely in that part of the basin. Moreover, the existence of relatively permeable faults along active salt bodies would increase the vertical migration, and so the hydrocarbon “leakage” out of this play (presence of seeps in this area). As a consequence, potential mature SR in Zone 2 can hardly feed reservoirs in Zone 1. Potential migration pathways are longer in the upper slope and on the platform (Zone 1).

The **Berriasian-Valanginian-Hauterivian play system** mainly includes the Upper Mississauga Formation Play and the Lower Mississauga Formation Play.
Due to the complex shape of drainage areas in salt mini-basins (southern Zone 3, Zone 4), long-distance lateral migration is unlikely south of a line Evangeline-Annapolis-Tantallon. However, this does not disturb petroleum systems in the Sable Sub-basin (Zone 3) because the most mature SRs are found in the deep depression between Evangeline, Annapolis, and Glenelg (north of the line Evangeline-Annapolis). Potential migration pathways are longer in the upper slope and on the platform (Zones 3 and 5). Very long horizontal migration pathways are also possible in the deep basin (southern Zones 4 and 6).
**Berriasian-Valanginian-Hauterivian Play System**

**Temperature / Biodegradation/ Secondary Cracking**

Temperature locally reaches a maximum of 200°C in the slope along the shelf break in Zone 3. Temperature reaches 140°C in Zone 5, 120°C in Zones 1 and 2, always in the slope zone.

Risk of biodegradation exists on the platform, mainly in Zone 1 (minimum temperature around 50°C). Temperature is close to 80°C on the platform of Zone 3, and in the deep basin of Zones 4 and 6.

The possibility of secondary cracking exists in the deepest part of the basin, and only concerns the heaviest hydrocarbon fraction.

**Pressure / Overpressure**

Overpressure is moderate in the slope along the shelf break between Zones 1 and 2. Between Zones 3 and 4 overpressure reaches higher values, locally up to 40 MPa (along the shelf break in Zone 3).

There is no overpressure on the platform, except maybe in Zone 5 and in southern Zone 3.

There is a low overpressure field in the deep basin (Zones 2, 4, 6), the average value is around 10 MPa.
This figure illustrates for each subzone:
- The relative HC composition (what kind of HC fraction could be found in the play system?)
- The relative SR contribution (which SRs feed the play system?)
- The relative HC phase distribution (HCs: are they in vapor, liquid, or critical phase in the play system?)
Due to the complex shape of drainage areas in Zone 2 (salt mini-basins), long-distance lateral migration is unlikely in that part of the basin. Moreover, the existence of relatively permeable faults along active salt bodies would increase the vertical migration, and so the hydrocarbon “leakage” out of this play (presence of seeps in this area).

As a consequence, potential mature SR in Zone 2 can hardly feed reservoirs in Zone 1. Potential migration pathways are longer in the upper slope and on the platform (Zone 1). In Zone 1, traps seems bigger and more numerous eastward.

**Oxfordian-Tithonian – SW**

**PLAY SYSTEMS**

- Albian-Cenomanian (K112-K94)
- Hauterivian-Barremian (K130-K123)
- Berrissian-Vanganghian-Hauterivian (J150-K130)
- Oxfordian-Tithonian (J163-J150)
- Early-Middle-Jurassic (J200-J163)

**CLOSED AREAS / CLOSED POROUS VOLUMES / DRAINAGE AREAS**

<table>
<thead>
<tr>
<th>Zone</th>
<th>Total Surface (km²)</th>
<th>Number of Traps (in 1000 km²)</th>
<th>Number of Traps per 1000 km²</th>
<th>Total Closed Areas in km³ (sum of traps surface + voids)</th>
<th>% Closed Area (sum of traps + voids)</th>
<th>Average Drainage Area Surface in km²</th>
<th>Total Closed Porous Volume in Mm³ (sum of traps volumes)</th>
<th>Total Closed Porous Volume in Billion bbl (sum of traps volumes)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Whole Basin</td>
<td>141963</td>
<td>317</td>
<td>2.2</td>
<td>4310</td>
<td>3%</td>
<td>230</td>
<td>4200</td>
<td>26</td>
</tr>
<tr>
<td>ZONE 1</td>
<td>26806</td>
<td>32</td>
<td>1.9</td>
<td>1200</td>
<td>3%</td>
<td>310</td>
<td>1900</td>
<td>12</td>
</tr>
<tr>
<td>ZONE 2</td>
<td>33123</td>
<td>44</td>
<td>3.3</td>
<td>2770</td>
<td>3%</td>
<td>160</td>
<td>100</td>
<td>1</td>
</tr>
<tr>
<td>ZONE 3</td>
<td>24359</td>
<td>57</td>
<td>4.3</td>
<td>600</td>
<td>3%</td>
<td>220</td>
<td>700</td>
<td>4</td>
</tr>
<tr>
<td>ZONE 4</td>
<td>18250</td>
<td>50</td>
<td>2.7</td>
<td>530</td>
<td>3%</td>
<td>220</td>
<td>0</td>
<td>3</td>
</tr>
<tr>
<td>ZONE 5</td>
<td>16802</td>
<td>32</td>
<td>2.2</td>
<td>230</td>
<td>3%</td>
<td>300</td>
<td>600</td>
<td>4</td>
</tr>
<tr>
<td>ZONE 6</td>
<td>24281</td>
<td>31</td>
<td>4.3</td>
<td>1540</td>
<td>6%</td>
<td>210</td>
<td>500</td>
<td>3</td>
</tr>
</tbody>
</table>

The Oxfordian-Tithonian play system includes:

- the Baccaro Formation Play, the MicMac Formation Play, etc.

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** PL. 7-3-3-11a Play System Modeling – Oxfordian-Tithonian Sequence (J163-J150) – Drainage Areas Overview (SW) **

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Due to the complex shape of drainage areas in salt mini-basins (southern Zone 3, Zone 4), long-distance lateral migration is unlikely south of a line Evangeline-Annapolis. Potential migration pathways are longer in the upper slope and on the platform (Zones 3 and 5). Very long horizontal migration pathways are also possible in the deep basin (southern Zones 4 and 6).

**Oxfordian-Tithonian – NE**

**Modeling Results Confidence**
1
2
3
4
5

**Play System Modeling – Oxfordian-Tithonian Sequence (J163-J150) – Drainage Areas Overview (NE)**
**TEMPERATURE / BIODEGRADATION / SECONDARY CRACKING**

Temperature reaches a maximum of 280°C in the slope along the shelf break (Zone 3). The average temperature in the slope along the shelf break in Zones 3 and 5 is around 220°C. Temperature is lower in the slope along the shelf break between Zones 1 and 2 (up to 140°C).

A very limited risk of biodegradation exists on the platform, only in Zone 1 (minimum temperature around 50°C). There is no risk in the basin part.

The possibility of secondary cracking exists nearly everywhere in Zones 3, 4, 5, and 6 (cracking of heavy components), and particularly in the deepest parts of Zone 3 (cracking of lighter components).

---

**Oxfordian-Tithonian Play System**

**Overpressure at J150**

Overpressure is very high in the slope along the shelf break, between Zones 3 and 4 and between Zones 5 and 6. The overpressure field in those areas is higher than 50 MPa (up to 80 MPa). Between Zones 1 and 2 overpressure reaches lower values along the shelf break, around 25 MPa. There is no overpressure or low overpressure on the platform, except along the shelf break (high overpressure).

Overpressure field in the deep basin is low to moderate in Zone 2 with an average value around 18 MPa. In the deep basin of Zones 4 and 6, overpressure field is high close to the slope, and moderate seaward (around 30 MPa).
### Oxfordian-Tithonian Play System

#### HC Repartition (masses and volumes – by Zone)

<table>
<thead>
<tr>
<th>Zone</th>
<th>TOTAL GAS mass (Gkg)</th>
<th>TOTAL OIL mass (Gkg)</th>
<th>TOTAL HC mass (Gkg)</th>
<th>TOTAL GAS volume in place (Tcf)</th>
<th>TOTAL HC volume in place (Mmbl)</th>
<th>TOTAL OIL volume in place (Mmbl)</th>
<th>TOTAL OIL EQUIVALENT volume in place (Mmbl)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zone 1</td>
<td>132</td>
<td>91</td>
<td>4.2</td>
<td>110</td>
<td>350</td>
<td>700</td>
<td>900</td>
</tr>
<tr>
<td>Zone 2</td>
<td>127</td>
<td>911</td>
<td>4.3</td>
<td>250</td>
<td>900</td>
<td>700</td>
<td>380</td>
</tr>
<tr>
<td>Zone 3</td>
<td>111</td>
<td>82</td>
<td>4.0</td>
<td>80</td>
<td>800</td>
<td>300</td>
<td>280</td>
</tr>
<tr>
<td>Zone 4</td>
<td>97</td>
<td>60</td>
<td>4.0</td>
<td>180</td>
<td>800</td>
<td>300</td>
<td>280</td>
</tr>
<tr>
<td>Zone 5</td>
<td>29</td>
<td>26</td>
<td>0.5</td>
<td>110</td>
<td>200</td>
<td>200</td>
<td>200</td>
</tr>
<tr>
<td>Whole Basin</td>
<td>534</td>
<td>300</td>
<td>55</td>
<td>1200</td>
<td>4200</td>
<td>800</td>
<td>800</td>
</tr>
</tbody>
</table>

#### HC Characteristics (Composition / Phase / Origin)

- **HC Composition Chemical Fractions**
  - Total basin: 30% CI-C5, 40% C6-C8, 30% C9-C15

- **HC Phase in Bottom Conditions**
  - Vapor Phase: 10%, Liquid Phase: 50%, Critical Phase: 40%

- **API Gravity by Zones - Oxfordian-Tithonian**
  - Zone 1: 37, Zone 2: 47, Zone 3: 53, Zone 4: 54, Zone 5: 53, Zone 6: 44

- **GOR by Zones (scf/stb) - Oxfordian-Tithonian**
  - Zone 1: 1200, Zone 2: 19000, Zone 3: 87500, Zone 4: 21000, Zone 5: 4800, Zone 6: 15900

#### Oxf-Titho. - Surface Conditions (in Billion bble)

- **Volume of OIL EQUIVALENT in Place - by Zone**
  - Zone 1: 4800, Zone 2: 15900, Zone 3: 67500, Zone 4: 22300, Zone 5: 4800, Zone 6: 15900

- **Volume of GAS in Place - by Zone**
  - Zone 1: 127, Zone 2: 111, Zone 3: 82, Zone 4: 97, Zone 5: 29, Zone 6: 26

- **Volume of OIL in Place - by Zone**
  - Zone 1: 77, Zone 2: 81, Zone 3: 75, Zone 4: 75, Zone 5: 10, Zone 6: 15

#### Whole Basin - Oxfordian-Tithonian (% mass)

- **API gravity**: 16%, 20%, 24%, 28%, 32%, 37%

- **GOR by Zones (scf/stb)**: Oxfordian-Tithonian

- **HC Composition Chemical Fractions**
  - Total basin: 30% CI-C5, 40% C6-C8, 30% C9-C15

- **HC Phase in Bottom Conditions**
  - Vapor Phase: 10%, Liquid Phase: 50%, Critical Phase: 40%

- **API Gravity by Zones - Oxfordian-Tithonian**
  - Zone 1: 37, Zone 2: 47, Zone 3: 53, Zone 4: 54, Zone 5: 53, Zone 6: 44

- **GOR by Zones (scf/stb) - Oxfordian-Tithonian**
  - Zone 1: 1200, Zone 2: 19000, Zone 3: 87500, Zone 4: 21000, Zone 5: 4800, Zone 6: 15900

- **Volume of OIL EQUIVALENT in Place - by Zone**
  - Zone 1: 4800, Zone 2: 15900, Zone 3: 67500, Zone 4: 22300, Zone 5: 4800, Zone 6: 15900

- **Volume of GAS in Place - by Zone**
  - Zone 1: 127, Zone 2: 111, Zone 3: 82, Zone 4: 97, Zone 5: 29, Zone 6: 26

- **Volume of OIL in Place - by Zone**
  - Zone 1: 77, Zone 2: 81, Zone 3: 75, Zone 4: 75, Zone 5: 10, Zone 6: 15

#### Whole Basin - Oxfordian-Tithonian (% volume in place)

- **Tithonian**
  - Total basin: 77%, 75%, 74%, 73%, 72%, 70%

- **APTIAN**
  - Total basin: 23%, 25%, 26%, 27%, 28%, 30%

#### Whole Basin - Oxfordian-Tithonian (% mass)

- **API gravity**: 16%, 20%, 24%, 28%, 32%, 37%
This figure illustrates for each subzone:
- The relative HC composition (what kind of HC fraction could be found in the play system?)
- The relative SR contribution (which SRs feed the play system?)
- The relative HC phase distribution (HCs: are they in vapor, liquid, or critical phase in the play system?)
Due to the complex shape of drainage areas in Zone 2 (salt mini-basins), long distance lateral migration is unlikely in that part of the basin. Moreover, the existence of relatively permeable faults along active salt bodies would increase the vertical migration, and so the hydrocarbon “leakage” out of this play (presence of seeps in this area).

As a consequence, potential mature SR in Zone 2 can hardly feed reservoirs in Zone 1. Potential migration pathways are longer in the upper slope and on the platform (Zone 1).

In Zone 1, traps seem bigger and more numerous eastward.

**Early-Middle-Jurassic – SW**

**Play Systems**
- Albian-Cenomanian (K112-K94)
- Hauterivian-Barremian (K130-K123)
- Berriasian-Valanginian-Hauterivian (J150-J130)
- Oxfordian-Tithonian (J163-J150)
- Early-Middle-Jurassic (J200-J163)

**Closed Areas / Closed Porous Volumes / Drainage Areas**

The **closed area** (or closure area) is defined by structural maps. It corresponds to the extend of a structural trap (four way closure). About 2% of the study area is a closed area. Closed areas evolves during the geological history due to structural evolutions.

The **closed porous volume** is the volume of voids in a structural trap. This volume can be filled with water or hydrocarbons. It usually decreases during the geological history due to the compaction. Porosity modeling is done by Temis®.

Each trap is associated to a **drainage area** defined by slope lines, impermeable lithologies, and permeable faults. The size of the drainage area may impact the charge of the trap.

The **Early-Middle-Jurassic play system** includes the Scatarie Formation Play, and other poorly known formations.
Due to the complex shape of drainage areas in salt mini-basins (southern Zone 3, Zone 4), long-distance lateral migration is unlikely south of a line Evangeline-Annapolis-Tantallon. However, this does not disturb petroleum systems in the Sable Sub Basin (Zone 3) because the most mature SRs are found in the deep depression between Evangeline, Annapolis, and Glenelg (north of the line Evangeline-Annapolis). Potential migration pathways are longer in the upper slope and on the platform (zones 3 and 5). Very long horizontal migration pathways are also possible in the deep basin (southern zones 4 and 6).

Early-Middle-Jurassic – NE

Modeling Results

Confidence

1

2

3

4

5

Play System Modeling – Early-Middle-Jurassic Sequence (J200-J163) – Drainage Areas Overview (NE)
Early-Middle-Jurassic Play System

**TEMPERATURE / BIODEGRADATION / SECONDARY CRACKING**

Temperature reaches a maximum of 300°C in the slope along the shelf break in Zones 3 and 5 (temperature always above 200°C). Maximum temperature is lower between Zones 1 and 2, reaching 150°C in the slope along the shelf break.

A very limited risk of biodegradation exists on the platform, only in Zone 1 (minimum temperature around 70°C).

Possibility of secondary cracking exists nearly everywhere in Zones 3, 4, 5 and 6 (cracking of heavy components), particularly in Zones 3 and 5 (cracking of lighter components), and locally in Zone 2 (cracking of heavy components).

**PRESSURE / OVERPRESSURE**

Overpressure is very high in the slope along the shelf break, between Zones 3 and 4 and between Zones 5 and 6. The overpressure field in those areas is higher than 50 MPa (maybe up to 100 MPa). Between Zones 1 and 2 overpressure reaches moderate values along the shelf break, around 30 MPa.

There is no overpressure on the platform in Zone 1. On the platform of Zones 3 and 5 overpressure increases to the east, starting from low overpressure values overpressure in the west to reach high values (more than 50 MPa) in the eastern part. High overpressure also exists along the shelf break (southward).

Overpressure field in the deep basin is low to moderate in Zone 2 with an average value around 18 MPa. In the deep basin of Zones 4 and 6, overpressure field is high close to the slope, and moderate seaward (around 30 MPa).
Early-Middle-Jurassic Play System

**HC Repartition**
(masses and volumes – by Zone)

**HC Characteristics**
(Composition / Phase / Origin)

**OIL EQUIVALENT In Place** = 3.8 Billion bble

**GAS In Place** = 1.8 Tcf

**OIL In Place** = 1.1 Billion bble

---

**By ZONE E-M-Jur.**

<table>
<thead>
<tr>
<th>By ZONE E-M-Jur.</th>
<th>TOTAL GAS Mass (Gkg) In Place - Unrisked</th>
<th>TOTAL OIL mass (Gkg) In Place - Unrisked</th>
<th>TOTAL HC mass (Gkg) In Place - Unrisked</th>
<th>TOTAL GAS volume in surface (Tcf) In Place - Unrisked</th>
<th>TOTAL OIL volume in surface (Mbbl) In Place - Unrisked</th>
<th>TOTAL OIL EQUIVALENT (in Billion bble) In Place - Unrisked</th>
</tr>
</thead>
<tbody>
<tr>
<td>ZONE1</td>
<td>78</td>
<td>123</td>
<td>200</td>
<td>4.2</td>
<td>910</td>
<td>1500</td>
</tr>
<tr>
<td>ZONE2</td>
<td>90</td>
<td>2</td>
<td>52</td>
<td>4.8</td>
<td>50</td>
<td>800</td>
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<tr>
<td>ZONE3</td>
<td>75</td>
<td>0</td>
<td>75</td>
<td>4.0</td>
<td>0</td>
<td>600</td>
</tr>
<tr>
<td>ZONE4</td>
<td>52</td>
<td>3</td>
<td>55</td>
<td>2.8</td>
<td>30</td>
<td>500</td>
</tr>
<tr>
<td>ZONE5</td>
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<td>1</td>
<td>28</td>
<td>1.2</td>
<td>40</td>
<td>200</td>
</tr>
<tr>
<td>ZONE6</td>
<td>11</td>
<td>17</td>
<td>28</td>
<td>8.6</td>
<td>130</td>
<td>200</td>
</tr>
<tr>
<td>Whole Basin</td>
<td>329</td>
<td>150</td>
<td>479</td>
<td>18</td>
<td>1130</td>
<td>3800</td>
</tr>
</tbody>
</table>

---

**API Gravity by Zones - E-M-Jur.**

**GOR by Zones (scf /stb) - E-M-Jur.**

**API Gravity by Zones**

**Volume of OIL EQUIVALENT In Place**
by Zone

---

**API Gravity**

**GOR by Zones**

**Volume of GAS in Place**
by Zone

---

**HC Characteristics**

**HC Repartition**
(masses and volumes – by Zone)

**HC Composition Chemical Fractions**

---

**Volume of OIL EQUIVALENT in Place**
by Zone

---

**Volume of GAS in Place**
by Zone

---

**Volume of OIL in Place**
by Zone
This figure illustrates for each subzone:
- The relative HC composition
- (what kind of HC fraction could be found in the play system?)
- The relative SR contribution
- (which SRs feed the play system?)
- The relative HC phase distribution
(HCs: are they in vapor, liquid, or critical phase in the play system?)

Play System Modeling – Early-Middle-Jurassic Sequence (J200-J163) – Hydrocarbon Characteristics (by Zone)

PL. 7-3-3-16
CHAPTER 7-3

BASIN MODELING – TEMIS 3D

7-3-4

3D Modeling
SYNTHESIS and CONCLUSION
There is no indication on the distribution of HCs within each subzone. This distribution may be heterogeneous.

To convert HC mass (in Gkg), multiply values by about 8 (average oil density estimated at 810 kg/m³). Masses are in-place and unrisected.

There is no indication on the distribution of HCs within each subzone. This distribution may be heterogeneous.

To convert HC mass (Gkg) in equivalent barrels of oil (mbbl), multiply values by about 8 (average oil density estimated at 810 kg/m³). Masses are in place and unrisected.

HC compositions by play:

- ZONE 1
- ZONE 2
- ZONE 3
- ZONE 4
- ZONE 5
- ZONE 6
HC Composition by Play Whole Basin (in Gkg)

The bar graph shows the HC composition by play for the whole basin in Gkg. There are different play systems including Apt-Ceno., Hauteriv-Barr., Berrias-Hauteriv, Off-Tihlo, and E-M-Jur.

HC Masses in Place - UNRISKED

This table presents the HC masses in place for the whole basin in Gkg.

<table>
<thead>
<tr>
<th>PLAY SYSTEMS</th>
<th>TOTAL GAS mass (Gkg)</th>
<th>TOTAL OIL mass (Gkg)</th>
<th>TOTAL HC mass (Gkg)</th>
<th>GORfeed (kg GAS / kg OIL)</th>
<th>TOTAL GAS volume in surface (Tcf)</th>
<th>TOTAL OIL volume in surface (Mbbl)</th>
<th>TOTAL CONDENSATE volume (Mbbl)</th>
<th>GOR (scf / stb)</th>
</tr>
</thead>
</table>
BASIN MODELING – TEMIS 3D

PLAY FAIRWAY ANALYSIS – OFFSHORE NOVA SCOTIA – CANADA – June 2011

Volume of OIL EQUIVALENT in Place by Zone All Plays (in Billion bble)

Total Volume of GAS in Place by Zone All Plays (in Tcf)

Total Volume of OIL in Place by Zone All Plays (in Mbbl)

HC Type by Zone - All Plays (in 10^8 kg)

Fraction of oil reaching surface in CONDENSATE form by Zone - All Plays (in Mbbl)

Synthesis by ZONE

Volumes are IN PLACE and UNRISKED (surface conditions). No indication on the distribution of HCs within each subzone.

The richest zone is Zone 3, which contains the Sable Sub-basin (about 1/4 of the total calculated amount of HC in place). The poorest zones are Zone 4 and Zone 2. About 2/3 of the total amount of HC in place are in “shell zones” (1, 3, 5), except Zone 6 where turbidites can be more abundant, and where salt diapirs do not dramatically affect drainage areas, “basin zones” would be less prospective than “shell zones”.

The average GOR change between the six zones (between 5000 and 29500 scf/stb). Zone 3 and 6 are particularly rich in gas, while Zone 1 and 2 contain more oil than gas. Such differences come from changes in maturity / secondary cracking intensity, and in SR contributions. As a consequence about 1/3 of the oil in place at the scale of the basin would be trapped in Zone 1.

The condensate fraction is calibrated with well test data in the Sable Sub-basin. It represents about 20% of the oil in place (up to 40% in the Zone 3 – Sable Sub-basin). An average condensate density of 770-780 kg/m^3 is assumed.

<table>
<thead>
<tr>
<th>Subzone</th>
<th>TOTAL GAS mass (Gkg)</th>
<th>TOTAL OIL mass (Gkg)</th>
<th>TOTAL HC mass (Gkg)</th>
<th>GOR feed (kg GAS / kg OIL)</th>
<th>TOTAL GAS volume in surface (Tcf)</th>
<th>TOTAL OIL volume in surface (Mbbl)</th>
<th>TOTAL OIL EQUIVALENT volume (Billion bble)</th>
<th>GOR (scf / stb)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zone 1</td>
<td>254</td>
<td>329</td>
<td>584</td>
<td>0.8</td>
<td>14</td>
<td>2430</td>
<td>4.4</td>
<td>6000</td>
</tr>
<tr>
<td>Zone 3</td>
<td>645</td>
<td>140</td>
<td>785</td>
<td>4.6</td>
<td>45</td>
<td>1130</td>
<td>6.3</td>
<td>31000</td>
</tr>
<tr>
<td>Zone 5</td>
<td>498</td>
<td>210</td>
<td>708</td>
<td>2.4</td>
<td>27</td>
<td>1650</td>
<td>5.5</td>
<td>16000</td>
</tr>
<tr>
<td>Zone 6</td>
<td>486</td>
<td>135</td>
<td>621</td>
<td>3.6</td>
<td>26</td>
<td>1090</td>
<td>5.0</td>
<td>24000</td>
</tr>
<tr>
<td>Zone 4</td>
<td>288</td>
<td>123</td>
<td>411</td>
<td>2.4</td>
<td>16</td>
<td>950</td>
<td>3.3</td>
<td>16000</td>
</tr>
<tr>
<td>Zone 2</td>
<td>78</td>
<td>109</td>
<td>187</td>
<td>0.7</td>
<td>4.2</td>
<td>820</td>
<td>1.4</td>
<td>5000</td>
</tr>
<tr>
<td>Whole Basin</td>
<td>2250</td>
<td>1046</td>
<td>3295</td>
<td>2.2</td>
<td>121</td>
<td>8150</td>
<td>26</td>
<td>15000</td>
</tr>
</tbody>
</table>
### BASIN MODELING – TEMIS 3D

#### PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011

#### 3D Modeling SYNTHESIS and CONCLUSION – Play Systems and Zones Rankings (unrisked equivalent volume)

**PL. 7-3-4-3**

**3D Modeling Results Confidence**

**ZONE 1**

**ZONE 2**

**ZONE 3**

**ZONE 4**

**ZONE 5**

**ZONE 6**

---

#### PLAY SYSTEMS and ZONES Rankings

Volumes are IN PLACE and UNRISKED (surface conditions). No indication on the distribution of HCs within each subzone.

Zone ranking changes in function with the play considered. The most significant features are:

- Zones 3 and 5 have first ranks in Albian-Cenomanian and Hauterivian-Barremian play systems.
- Zone 6 reaches the first rank in the Berriasian-Valanginian-Hauterivian (J150-K130).
- Zone 1 reaches the first rank for Oxfordian-Tithonian and Early-Middle Jurassic play systems.

**Play ranking** in function with the zone considered reflects the same tendencies.

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#### PLAY SYSTEMS

- Albian-Cenomanian (K112-K94)
- Hauterivian-Barremian (K130-K123)
- Berriasian-Valanginian-Hauterivian (J150-K130)
- Oxfordian-Tithonian (J163-J150)
- Early-Middle Jurassic (J200-J163)

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#### TOTAL OIL EQUIVALENT UNRISKED VOLUME (Billion bble)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Zone 1</td>
<td>0.5</td>
<td>0.6</td>
<td>0.9</td>
<td>1.5</td>
<td>4.4</td>
</tr>
<tr>
<td>Zone 3</td>
<td>1.0</td>
<td>2.0</td>
<td>0.7</td>
<td>0.8</td>
<td>6.3</td>
</tr>
<tr>
<td>Zone 5</td>
<td>1.2</td>
<td>1.4</td>
<td>0.9</td>
<td>0.6</td>
<td>5.6</td>
</tr>
<tr>
<td>Zone 6</td>
<td>0.2</td>
<td>1.4</td>
<td>0.7</td>
<td>0.5</td>
<td>2.6</td>
</tr>
<tr>
<td>Zone 4</td>
<td>0.2</td>
<td>1.2</td>
<td>0.8</td>
<td>0.2</td>
<td>3.4</td>
</tr>
<tr>
<td>Zone 2</td>
<td>0.2</td>
<td>0.3</td>
<td>0.2</td>
<td>0.2</td>
<td>0.9</td>
</tr>
<tr>
<td>Whole Basin</td>
<td>3.3</td>
<td>6.9</td>
<td>7.7</td>
<td>4.2</td>
<td>26</td>
</tr>
</tbody>
</table>

---

#### ZONE RANKING (for each PLAY)

**by Absolute Oil Equivalent Volume (in Billion bble)**

**ZONE RANKING (for each ZONE)

**by Absolute Oil Equivalent Volume (in Billion bble)**

**by Relative Oil Equivalent Volume (in Billion bble)**

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#### HC repartition in % (normalised)

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#### TEMIS 3D PLAY FAIRWAY ANALYSIS BASIN MODELING

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#### 100%

#### 90%

#### 80%

#### 70%

#### 60%

#### 50%

#### 40%

#### 30%

#### 20%

#### 10%

#### 0%
BASIN MODELING – TEMIS 3D
PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA – June 2011

Source Rocks Contributions
Source rock contributions depend on four phenomena: (1) maturity levels of SRs; (2) hydrocarbon potentials of SRs; (3) “migration efficiencies” (partly related to the distance between the SR and the reservoir, the “upward” or “downward” migration); and (4) complex timings between SRs expulsion and traps formation.

Cretaceous Source Rocks are not significant contributors except in Zone 3 where Valanginian SR and Aptian SR feed Aptian-Cenomanian and Hauterivian-Barremian play systems, up to 1/4 of the total amount of hydrocarbon in place.

The Tithonian SR is a significant contributor in all zones and all play systems (except the Early-Middle-Jurassic play system). At the scale of the basin it sources 1/2 of the total amount of hydrocarbon in place.

The Callovian SR is not a significant contributor, except maybe in Zone 6, and in Early-Middle-Jurassic play system.

The Plenusbachian SR is locally a very significant SR (up to 3/4 of the total amount of hydrocarbon in place in zones 1 and 2). It feeds mainly Oxfordian-Tithonian and Early-Middle-Jurassic play systems where its maturity is not excessive.

API and Gas Oil Ratio
API gravity varies significantly between plays and zones. Except in Zones 1 and 2 where maturity levels are lower, the highest API values are found in the deepest play systems (Oxfordian-Tithonian and Early-Middle-Jurassic). This is mainly due to secondary cracking in reservoirs.

Except in Zone 5, API values increase also in Cretaceous play systems (Hauterivian-Barremian and/or Aptian-Cenomanian) despite a lower maturity of near source rocks. This is the consequence of two phenomena: (1) the higher contribution of Cretaceous/Upper Jurassic gas prone source rocks; and (2) the late trap formation in Cretaceous play systems versus early source rock maturity and hydrocarbon expulsion.

GOR values are correlated with API values and depend on the same processes. The lowest GOR are found in Zones 1 and 2, the highest GOR are found in Zone 3 and 6. Extremely high GOR exist in the Early-Middle-Jurassic play system: in this sequence there is only gas in Zones 3, 5, and 6 (ultimate stage of secondary cracking).
Expelled / Available / In Place Hydrocarbon Volumes

Expelled volumes correspond to the total amount of hydrocarbon (oil + gas) expelled through geological times by all existing source rocks in subzones. Note that expelled volumes depend on kerogen types, maturity levels (secondary cracking generates lighter and more mobile hydrocarbons), petrophysical properties of source rock layers.

Available volumes (or Charge Volume) correspond to the total amount of expelled hydrocarbon that migrated through geological times inside the play system (are not taken into account: amount of hydrocarbons that vertically migrated through faults and never penetrated a reservoir layer, amount of hydrocarbons remaining in source rocks or diluted in carrier beds/shale). Available volumes are the maximum volumes that might be trapped in plays.

In Place volumes correspond to the amount of hydrocarbons present in traps of the plays at present day (in porous volumes of closed structures).

About 2-3% of “expelled hydrocarbons” through geological times are “in place” at present day. This ratio corresponds to the “migration efficiency”. About 10-20% of “available (charged) hydrocarbons” through geological times are “in place” at present day.

The difference between oil and gas ratios (apparent better migration of the gas) is mainly due to secondary cracking between expulsion time and present day (secondary cracking in traps and along migration pathways).

NOTE: Hydrocarbons can migrate from one zone to another (lateral migration inside reservoir layers). This phenomenon partly explains higher ratios observed in Zone 1: maturity and expulsion are low in Zone 1, but hydrocarbons migrate from Zones 2 and 4 into Zone 1.

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3D Modeling SYNTHESIS and CONCLUSION – Comparison HC Expelled / Available / In Place

PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011

By ZONE

By PLAY

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PLAY

Aptian-Albian-Cenomanian (K112-X94)
Hauterivian-Barremian (K123)
Berriasian-Valanginian-Hauterivian (J150-K130)
Oxfordian-Tithonian (J63-J150)
Early-Middle-Jurassic (J200-J163)
### Comparison of hydrocarbon volume estimations

Temis® results are consistent with previous hydrocarbon volume estimations from various studies.

**At the scale of the Zone 3 / Sable Sub-basin**, it appears that both distribution between different plays and global GOR are calibrated. Volumes calculated with Temis® are bigger, but the study area is also wider. Temis® results are equivalent to P10 volumes (optimistic), calculated with five source rocks and five reservoirs.

**At the scale of the whole basin**, the estimation done by A.G. Kidston et al. (2004) is the only one which does not match with Temis® results. This study, mainly dedicated to the deepwater part, overestimated oil volumes.

### Comparison Whole Basin

Table displaying the comparison between Temis® results and previous studies for the whole basin.

<table>
<thead>
<tr>
<th>ZONES</th>
<th>TOTAL HC mass (Gkg)</th>
<th>TOTAL GAS volume in surface (Tcf)</th>
<th>TOTAL OIL volume in surface (Mbbl)</th>
<th>TOTAL HC mass (Gkg)</th>
<th>TOTAL GAS volume in surface (Tcf)</th>
<th>TOTAL OIL volume in surface (Mbbl)</th>
<th>Ratio TEMIS / Previous</th>
</tr>
</thead>
<tbody>
<tr>
<td>ZONE 1</td>
<td>164</td>
<td>20</td>
<td>0.11</td>
<td>188</td>
<td>24</td>
<td>0.16</td>
<td>108</td>
</tr>
<tr>
<td>ZONE 2</td>
<td>207</td>
<td>32</td>
<td>0.28</td>
<td>277</td>
<td>40</td>
<td>0.36</td>
<td>267</td>
</tr>
<tr>
<td>ZONE 3</td>
<td>785</td>
<td>110</td>
<td>1.11</td>
<td>121</td>
<td>18</td>
<td>0.21</td>
<td>106</td>
</tr>
<tr>
<td>ZONE 4</td>
<td>411</td>
<td>100</td>
<td>1.10</td>
<td>49</td>
<td>7</td>
<td>0.09</td>
<td>44</td>
</tr>
<tr>
<td>TOTAL / 3</td>
<td>1648</td>
<td>84</td>
<td>1.40</td>
<td>542</td>
<td>18</td>
<td>0.22</td>
<td>480</td>
</tr>
</tbody>
</table>

**Total Volume**:
- **Total HC**: 542 Gkg
- **Total Gas**: 84 Tcf
- **Total Oil**: 1.40 Mbbl

**Volume distribution**:
- **Zones 1 and 2**: 50% of HC, 65% of Gas, 50% of Oil
- **Zones 3 and 4**: 50% of HC, 35% of Gas, 50% of Oil

**Comment**

- Basin modeling approach. Volume “IN PLACE”.
- Default hypothesis (unrisked).
- Study area: 141963 km².
- Approximate volume study (at “play” or “basin” scale).
- The study area is wide and partly unexplored (basinward and deep plays).
- All closed structure (four ways traps) are considered, even subtle ones (in term of closure height, reservoir thickness).
- The study is rather optimistic in term of source rocks and plays (five SRs and five potential reservoir layers).
- Real reservoirs can be scattered in the play interval, non economic and/or non significant (in production tests).

**Statistical approach**

- Volume “IN PLACE”.
- Approximate volume study: > 100 000 km².
- Mean value / “Median value” (unrisked).
- High resolution study (at “plays” or “basin” scale).
- Results (2004).

**Hydrocarbon volume**

- “Volumes” can be several times higher.
- Statistical approach (at “basin” or “study area” scale).
- **Temis® study**: 300 000 km².
- **Previous study**: 100 000 km².
- Volume “IN PLACE”. Only “risked” volumes are available for the whole basin.

**Conclusions**

- Temis® volumes are more realistic and closer to the potential of the basin.
- However, the study area is wider, and the results are more optimistic.

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**3D Modeling SYNTHESIS and CONCLUSION**

**Comparison with previous studies**

- **Temis® results** are generally higher than previous studies.
- **Statistical approach** tends to underestimate the potential of the basin.
- **Temis® study** is more optimistic and closer to the potential of the basin.

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**Bibliographic synthesis of previous studies**

- Volume “IN PLACE”.
- Default hypothesis / Risked hypothesis.
- Approximate study area: > 100 000 km².
- Mean value / “Median value” (unrisked).
- High resolution study (at “basin” scale).

**Previous studies**

- **Temis® study**: 300 000 km².
- **Previous studies**: 100 000 km².
- **Risked volumes** are available for the whole basin.

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**Graphical representation**

- **Comparisons** between Temis® results and previous studies.
- **Histograms** of HC and Gas volumes.
- **Maps** showing the distribution of HC and Gas volumes in the basin.

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**References**

- Previous studies (1990s - 2004).
- **Various authors** and studies.