Petroleum System Modeling of the Shelburne Sub-Basin: An Insight on the Petroleum Potential of Southwest Nova Scotia*

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Abstract

The Department of Energy and the Offshore Energy Research Association (OERA) published in 2015 an integrated hydrocarbon (HC) exploration study concerning the offshore of Southwest Nova Scotia. It extends the 2011 Play Fairway Analysis (PFA) to the western limit of the Canadian Atlantic Shelf, covering the Shelburne Sub-Basin area. The HC resources assessment is based on a 3D model TemisFlow (TF) with a Full Darcy migration of fluids. The Shelburne Sub-Basin (SS) contains as much as 15 km of sedimentary column composed of basal Triassic deposits overlain by a thick salt cover and Jurassic to present-day sediments. No well has been ever drilled on the basin's slope and deepwater areas. Two wells were drilled in the shelf area: Bonnet P23 and Mohawk B93, showing only HC stained intervals.

The TF model consist of a 36 layer grid with 351×199 cells of 1 km side representing the post-salt to present-day interval including reservoirs, carrier, salt bodies and five source rocks (SR). The SR intervals considered in the model represent a Lower Jurassic Complex grouping potential Hettangian to Toarcian type II source rocks; two type II – III source rocks placed at the Callovian and Tithonian position, and finally two type III source rocks placed at the Valanginian-Aptian levels. Potential Jurassic – Cretaceous reservoirs consist of shelf carbonates, deltaic sandstones, slope toe carbonate breccia and clastic to carbonate turbidites. The spatial distribution of these facies was estimated using a forward stratigraphic model. The TF results showed suitable conditions for oil generation in the Jurassic interval, however Cretaceous SR's are immature or at their earlier stage of maturity with no sensible expulsion. The best maturity conditions are present in the Hettangian to Toarcian interval with only local maturity windows in the Callovian and Tithonian SRs. HC accumulations correspond mainly to flank traps on salt cored anticlines, roll-over structures, traps under salt canopy and basin floor turbidites. HC phase is oil at reservoir conditions with API ranging from 25° to 40°. HC resources in the Lower Jurassic interval were estimated at around 6 to 1 BBL OOIP mainly related with slope toe carbonate breccia reservoirs. The Upper Jurassic accumulations correspond to clastic and carbonatic turbidites in the SS with HC resources estimated at around 5 to 3.7 BBL OOIP. The Tithonian to Albian interval contains estimated resources of around 1.5 to 0.8 BBL OOIP, mainly in deepwater clastic and carbonate turbidites.

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AAPG ICE, Cancun, September 6 to 9, 2016
G & G workflow

Petrophysical interpretation

Regional tectono-stratigraphic settings

Data Base construction

Sedimentologic & Stratigraphic framework

Structural framework / seismic interpretation

Horizon/Structural Maps Time depth conversion

GDE Maps / Stratigraphic Modeling

Petroleum Geochemistry/ Petroleum System Modeling

HC Accumulations

Play concepts & identification
Petroleum System Modeling

Model Location and Mesh

Dimension: 306km x 199km
Cells number: nX=198, nY=99, nZ=36
Cells size: 2km x 2km

SW Nova Scotia
5 STRATIGRAPHIC INTERVAL and 5 SOURCE ROCKS are studied:

<table>
<thead>
<tr>
<th>STRATIGRAPHIC INTERVAL</th>
<th>SOURCE ROCKS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cenomanian-Albian (K101-K94)</td>
<td>APTIAN SR (~K124)</td>
</tr>
<tr>
<td>Albian-Barremian (K130-K101)</td>
<td>VALANGINIAN SR (~K136)</td>
</tr>
<tr>
<td>Barremian-Tithonian (J150-K130)</td>
<td>TITHONIAN SR (~J150)</td>
</tr>
<tr>
<td>Tithonian-Callovian (J163-J150)</td>
<td>CALLOVIAN SR (~J163)</td>
</tr>
<tr>
<td>Early-Middle Jurassic (J200-J163)</td>
<td>LOW JURASSIC COMPLEX SR (~J196)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Source Rock</th>
<th>Approx. Age</th>
<th>Initial TOC</th>
<th>Kerogen type</th>
<th>Initial HI</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aptian</td>
<td>124 Ma</td>
<td>2 % (constant)</td>
<td>III (continental)</td>
<td>HI = 235 mgHC/gTOC</td>
<td>Potential source rock in the Naskapi shale (and equivalent), identified in some wells. Variable effective thickness between 0 – 10 m.</td>
</tr>
<tr>
<td>Valanginian</td>
<td>136 Ma</td>
<td>1 % (constant)</td>
<td>III (continental)</td>
<td>HI = 235 mgHC/gTOC</td>
<td>Very poor and scattered source rock (coal fragments in deltaic environment, through the Mississauga formation) Variable effective thickness between 0 – 10 m.</td>
</tr>
<tr>
<td>Tithonian</td>
<td>150 Ma</td>
<td>3 % (constant)</td>
<td>II-III mix</td>
<td>HI = 424 mgHC/gTOC</td>
<td>Best defined SR, widely proven. Variable effective thickness between 0 – 20 m.</td>
</tr>
<tr>
<td>Callovian</td>
<td>163 Ma</td>
<td>2 % (constant)</td>
<td>II-III mix</td>
<td>HI = 424 mgHC/gTOC</td>
<td>Potential source rock in the Missaine shale (and equivalent), uncertain extend and richness due to the lack of data. Variable effective thickness between 0 – 20 m.</td>
</tr>
<tr>
<td>Lower Jurassic Complex</td>
<td>196 Ma</td>
<td>5 % (constant)</td>
<td>II (marine)</td>
<td>HI = 600 mgHC/gTOC</td>
<td>Suspected, not proven (Pleisbachian/Toarcian SR). Potentially present above salt basins only. Assumed average thickness 20 m.</td>
</tr>
</tbody>
</table>
Salt Geometry Reconstruction Through Time

Present Day
TemisFlow Block Construction

Facies distribution at 117.5 Ma

Facies distribution at 145 Ma

Facies distribution at 163.5 Ma

Facies distribution at 179 Ma

Facies distribution at 197 Ma
Petroleum System Definition

Gross Reservoir Thickness

Net Reservoir Thickness

Max Sat

SR Levels
Thermal Calibration

Present Day Temperature

Vitrinite Reflectance

Biodegradation Conditions

Lower Jurassic Complex SR

Vitrinite Reflectance in %R₀

Tithonian SR

Callovian SR
**Relationship**

TR / Vitrinite

TR = 5%

Maturity (oil window)

TR = 50 %

TR = 95 %

Overmaturity

Kerogen Type II

VR₀ = 0.7

VR₀ = 0.9

VR₀ = 2

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

TR map calculated at Present Day.
Transformation Ratio Callovian SR

**CALLOVIAN SR**

<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>VR₀ = 0.7</td>
<td>VR₀ = 0.9</td>
<td>VR₀ = 2</td>
</tr>
</tbody>
</table>

White and Grey = no SR and immature.
TR not calculated in salt diapirs (grey).
TR map calculated at Present Day.

Exploration license 2011
Exploration license 2015
Low Jurassic Complex SR

<table>
<thead>
<tr>
<th>Relationship</th>
<th>TR ≤ 5% Maturity (oil window)</th>
<th>TR ≥ 50% Maturity</th>
<th>TR ≥ 95% Overmaturity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kerogen Type II</td>
<td>VR₀ = 0.7</td>
<td>VR₀ = 0.9</td>
<td>VR₀ = 2</td>
</tr>
</tbody>
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White and Grey = no SR and immature. TR not calculated in salt diapirs (grey). TR map calculated at Present Day.
Low Jurassic Complex SR

HC mass expelled
Gkg / km²

1 Gkg = 10⁹ kg = 1 Million T
~ 7.8 Mbbl

Significant expulsion

Very strong expulsion

Limited expulsion

Oil mass fraction
%

OIL mass fraction
%

Exploration license 2015
Exploration license 2011
Model Calibration: Lower Jurassic
HC Migration Results
Lower Jurassic Play:
**Location:** Base of the slope and depth basin
**Reservoir:** Carbonate Breccia, Reef facies, Detritic carbonate deposits and Sandy turbidites basinward.
**HC Source:** Lower Jurassic SR
**Trap Style:** Tilted block, lateral pinch-out against the slope or salt diapirs

<table>
<thead>
<tr>
<th>HC Sat Cutoff</th>
<th>Total Volume of Liquid (in place)</th>
</tr>
</thead>
<tbody>
<tr>
<td>&gt;1%</td>
<td>23 BBL</td>
</tr>
<tr>
<td>&gt;5% ~P10</td>
<td>5.9 BBL</td>
</tr>
<tr>
<td>&gt;10% ~P50</td>
<td>1.3 BBL</td>
</tr>
<tr>
<td>&gt;12% ~P90</td>
<td>0.97 BBL</td>
</tr>
</tbody>
</table>
HC Total Volume Lower Jurassic [200 – 163 Ma]

HC Accumulations > 10 MMBL

The total volume of HC retained in the interval is projected to the top of the structures.
Upper Jurassic Play:
Location: basin
Reservoir: Calciturbidites, detritic carbonates and Sandy turbidites.
HC Source: Lower Jurassic SR; Callovian SR Locally
Trap Style: lateral pinch-out, stratigraphic traps, pinch-out against salt diapir flanks; doming structures linked to salt deformation.

<table>
<thead>
<tr>
<th>HC Sat Cutoff</th>
<th>Total Volume of Liquid (in place)</th>
</tr>
</thead>
<tbody>
<tr>
<td>&gt;1 %</td>
<td>8.2 BBL</td>
</tr>
<tr>
<td>&gt;5 % ~P10</td>
<td>5.2 BBL</td>
</tr>
<tr>
<td>&gt;10 % ~P50</td>
<td>4 BBL</td>
</tr>
<tr>
<td>&gt;12 % ~P90</td>
<td>3.7 BBL</td>
</tr>
</tbody>
</table>
HC Accumulations > 10 MMBL

The total volume of HC retained in the interval is projected to the top of the structures.
Upper Jurassic / Lower Cretaceous Play:

Location: basin

Reservoir: Calciturbidites, detritic carbonates and Sandy turbidites.

HC Source: Lower Jurassic SR; Callovan and Tithonian SR locally

Trap Style: lateral pinch-out against salt diapir flanks; stratigraphic traps, Top of salt diapirs.

<table>
<thead>
<tr>
<th>HC Sat Cutoff</th>
<th>Total Volume of Liquid (in place)</th>
</tr>
</thead>
<tbody>
<tr>
<td>&gt;1 %</td>
<td>5 BBL</td>
</tr>
<tr>
<td>&gt;5 % ~P10</td>
<td>1.4 BBL</td>
</tr>
<tr>
<td>&gt;10 % ~P50</td>
<td>0.9 BBL</td>
</tr>
<tr>
<td>&gt;12 % ~P90</td>
<td>0.7 BBL</td>
</tr>
</tbody>
</table>
HC Accumulations > 10 MMBBL

The total volume of HC retained in the interval is projected to the top of the structures.
Lower cretaceous Play:
Location: basin
Reservoir: Calciturbidites, and Sandy turbidites.
HC Source: Lower Jurassic SR; Callovan and Tithonian SR locally
Trap Style: Top of salt diapirs.

<table>
<thead>
<tr>
<th>HC Sat Cutoff</th>
<th>Total Volume of Liquid (in place)</th>
</tr>
</thead>
<tbody>
<tr>
<td>&gt;1 %</td>
<td>0.2 BBL</td>
</tr>
<tr>
<td>&gt;5 % ~P10</td>
<td>0.15 BBL</td>
</tr>
<tr>
<td>&gt;10 % ~P50</td>
<td>0.10 BBL</td>
</tr>
<tr>
<td>&gt;12 % ~P90</td>
<td>0.1 BBL</td>
</tr>
</tbody>
</table>
Conclusions

• The SW Nova Scotia Basin exhibit suitable conditions for hydrocarbon generation and preservation at different stratigraphic levels.
• Hydrocarbons generation is almost restricted to a Lower Jurassic source rock (Plienbachian to Toarcian). Younger SR levels will have only a local influence in the HC charge of the Upper Jurassic / Lower Cretaceous intervals.
• Generated hydrocarbons correspond to Oil with a API gravity ranging from 25 to 40 degrees.
• The most prospective area for the lower Jurassic interval extends East to West close to the base of the slope. Reservoirs correspond to carbonatic deposits and sandy turbidites basinward.
• The Upper Jurassic, Upper Jurassic / Lower Cretaceous and Lower Cretaceous plays correspond to stratigraphic traps, pinch-out against salt diapirs flanks and doming deformation at the top of salt diapirs. Reservoirs for these plays mainly correspond to calciturbidites and turbidites.
• Main Risks: The presence and quality of a lower Jurassic source rock is a major risk in the area as well the quality of reservoirs.
Q & A

Thank you for your attention!