

Hydrocarbon Potential of the Deepwater Slope, Offshore Nova Scotia Canada*

By

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Introduction

Petroleum exploration and development of offshore Nova Scotia has undergone a major resurgence since the late 1990s. On the Scotian Shelf, gas production from Sable Offshore Energy Project's Tier One fields (Venture, Thebaud, North Triumph) started in late 1999 and quickly ramped up to 500 Bcf/d. Currently, Tier Two fields (Glenelg, Alma, South Venture) are undergoing development drilling. EnCana announced their new discovery at Deep Panuke in the Late Jurassic carbonate reef margin and submitted a development plan for regulatory approval. In recent land sales, industry committed to spend more than C\$1.5 billion dollars in new exploration ventures primarily in the deepwater Scotian Slope that extends along the breadth of Nova Scotia margin. None of recent slope wells were available for inclusion in this assessment, but subsequently three have been drilled and completed (as of May 2003): Marathon Annapolis G-24, EnCana Torbrook C-15, and Chevron Newburn H-23.

Industry's interest in the Nova Scotia's deepwater regime has been driven by the tremendous successes in other deepwater regions like the Gulf of Mexico, off Brazil and West Africa. In fact, attributes of these Atlantic-facing look-alike basins were deemed analogues to those determined by the Scotian Slope deepwater assessment.

Historically, the Geological Survey of Canada (GSC) undertook resource assessments for Canada's frontier regions and in 1983 published the familiar 18 Tcf number (discovered + potential) for the shallow offshore Scotia Shelf. In 2001, the Canadian Gas Potential Committee assessed the shelf region and arrived at a similar value but began the process of dividing the region into geological provinces, such as the Sable Subbasin, Orpheus Graben, Jurassic Carbonate Bank Edge, etc. Up to then, no public assessments of the Deepwater Slope existed.

With projected and increasing industry deepwater exploration activity, the Canada-Nova Scotia Offshore Petroleum Board (CNSOPB; the Board) required a better understanding of the region's undiscovered petroleum potential and in September, 2001, determined it was necessary to evaluate and assess the hydrocarbon potential of the deepwater Scotian Slope.

Deepwater Scotian Slope Area: Geologic Overview

The Nova Scotia portion of the deepwater slope (shown in green in Figure 1) is 850 km long, extending from the American border on Georges Bank in the southwest to the Newfoundland provincial boundary in the Laurentian Channel in the northeast. The average 100 km width of the assessed Slope region was defined by the 200 m isobath on the shelf edge down to the 4000 m isobath, thus defining an area of about 80,000 km².

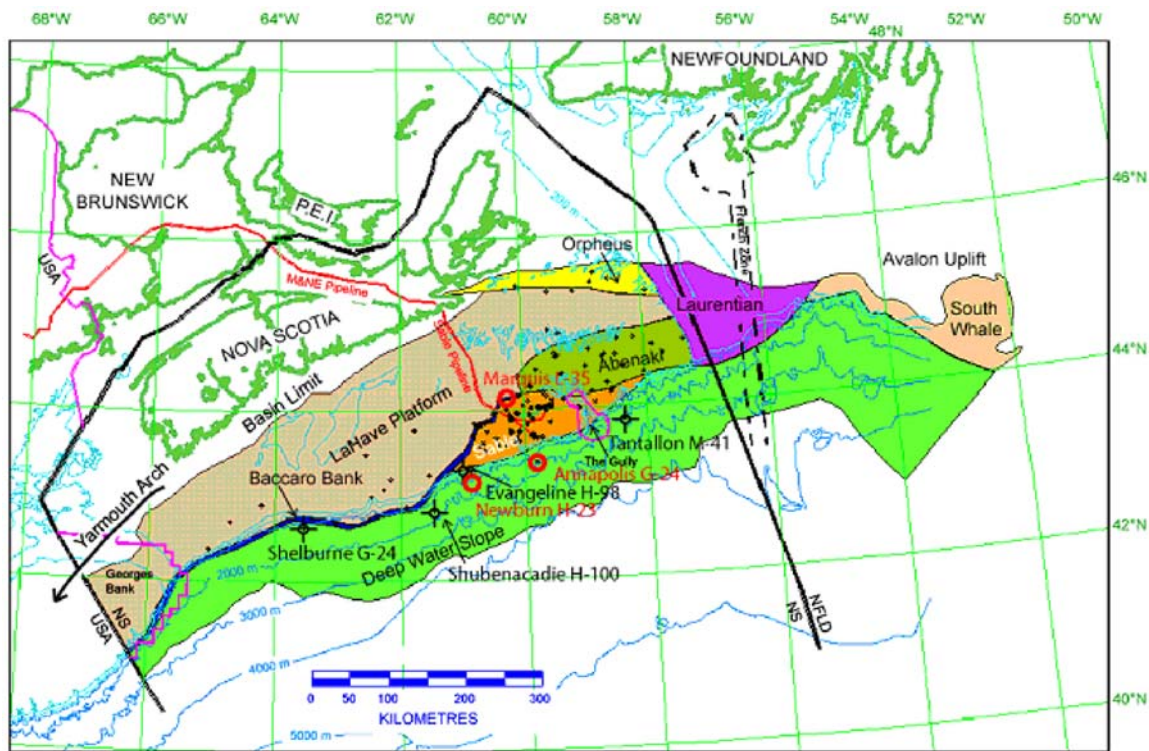


Figure 1. Nova Scotia deepwater slope area.

The deepwater Scotian Slope is located on the seaward portion of the 25+-km thick Mesozoic and Cenozoic sedimentary prism that was deposited along the rifted continental-oceanic crustal hingeline zone. Early synrift Late Triassic-Early Jurassic sediments and evaporites (salts) were deposited in a heavily faulted and rifted terrane. During the subsequent drift phase that followed the separation of Morocco and Nova Scotia, the shelf prograded seaward, with the slope region the locus for deposition of fine-grained sediments. Shelf advancement was punctuated by periodic sea-level falls

with resultant gravity slides and turbidite flows carrying coarser-grained sediments into very deepwater with deposition over and around the seafloor topography created by salt halokinesis. The slope area has been significantly modified by subaerial and submarine erosion during lowstands, especially in the Tertiary and even quite recently with major canyons carved into the slope following Pleistocene glaciation.

In the Late Jurassic, three major deltas existed along the Scotian margin: Laurentian, Sable, and Shelburne deltas. Carbonate banks, ramps, and reefal complexes flourished on stable platforms and interdeltic regions. By Early Cretaceous, carbonate deposition ceased and the Sable Delta became the dominant depositional system in the region and expanded during a period of relative sea level highstand. By Middle Oligocene, a major lowstand exposed the entire shelf. A series of shelf-margin deltas and upper slope canyon systems developed, providing sources and conduits for coarse-grained clastic sediments to reach deepwater depocenters.

Deepwater Scotian Slope Area: Assessment

Methodology

Hydrocarbon resource assessment consists of two major components; geological basin evaluation and numerical analyses. The evaluation of the Scotian Slope basins included significant original work in geology, geophysics, and geochemistry by the Board staff. Stratigraphic correlations from the shelf to the deepwater slope required integration with results from the Deep Sea Drilling Project (DSDP), and correlative charts with the analogue basins were generated. An extensive digital dataset of a regional 2-D seismic survey of 30,000 km was supplied by TGS-NOPEC and loaded on the Board's workstations. Interpretations of the salt bodies and regional sedimentary megasequences were carried out. Mapping of these key horizons was instrumental in the basin study phase. Geochemical modeling of petroleum source rock potential was carried out by Dr. P. Mukhopadhyay (Global GeoEnergy Research - Halifax).

Any assessment methodology has to distinguish between established and proven plays, and conceptual and unproven plays. The Scotian Shelf contains several proven plays within the Sable Subbasin. The Verrill Canyon Petroleum System - distal marine shale succession consisting of source, seal and trap components - is responsible for the discoveries to date. The deepwater slope, while having an extensive recent seismic database, contains only eight wells, and as such hydrocarbon plays are by necessity conceptual; consequently, global analogues from similar depositional settings are required.

For proven plays, field-size distributions and success rates from the basin can be applied to the undiscovered component. For conceptual plays, a map of anomalies could be used along with field-size distributions from analogous plays. Because the Nova Scotia deepwater slope area was too large and complex for the Board to create anomaly maps, an overall play area was determined from regional mapping. Discount factors were then

used to arrive at net areas under trapping conditions. All factors were entered as distributions and the procedure is fully stochastic.

Geologic Risking

Geologic risking is critical in assessment work and can be difficult because of its subjectivity. For conceptual plays, geologic risking must be applied at two levels; the prospect level and the play level. These risks are compared in Figure 2.

A prospect is a singular trap feature or structure, whereas a play is a regional area of similar geological conditions that embraces a number of prospects. An unsuccessful prospect does not end the play potential, but if any of the play factors are zero then all prospects will be dry.

<u>Prospect Risk</u>	<u>Play Risk</u>
· expected drilling success rate	· the chance of the play existing
· risk of achieving reservoir volume factors (quantitative) is addressed	· risk of the adequacy of geological factors (qualitative) is determined
· some risk associated with any prospect	· zero for proven play

Figure 2. Risk types.

Assessment Software

The assessment software needs of the Board were determined by the following criteria:

- Easy to use in-house for control and ownership
- Transparent process; i.e., no "blackboxes"
- Relatively inexpensive

The @RISK program was previously used by the Board for an assessment on discovered resources. Kenneth J. Drummond, a recognized authority in assessment methodologies, designed Excel-based routines to be used with the @RISK Monte Carlo simulation. To achieve the dual goals of being easy to understand and allowing the work to remain in-house, it was decided to use the Drummond routines. Volumetric parameters, recovery factors, oil/gas ratios, etc. were estimated using local data wherever possible but supplemented by worldwide analogues. Mr. Drummond spent a week with the Board during the number-crunching and acted as an objective reviewer.

Basin Analogues

It was necessary to employ information from worldwide analogues for play assessment of the deepwater slope because at the time of the assessment there were no discoveries in deepwater depositional systems, only three existing dry wells (Shelburne G-29, Shubenacadie H-100 and Tantallon M-41). Furthermore, new exploration had just been resumed in 2002. Hence, unlike the global analogues, proven petroleum systems on the Scotian Slope remained unknown.

The continental margin off Nova Scotia has long been known as the definitive Atlantic-style passive margin; a pull-apart margin followed by thermal sag and a prograding shelf with a carbonate bank, major river delta system, and a mobile salt substrate. The three major analogue passive margins are all Atlantic facing, namely the Gulf of Mexico (GoM), offshore Brazil, and offshore West Central Africa, all which have enjoyed recent and continued deepwater success.

Once a geotectonic similarity was established, Ulmishek (1984) described four factors to be considered when drawing basin comparisons:

- 1) quality of potential source rocks and their maturation,
- 2) presence of traps, their abundance and size,
- 3) presence of reservoir rocks and their quality, and
- 4) presence of regional seals.

Another important factor is the age of a petroleum system because hydrocarbons appear unevenly distributed spatially and temporally in a basin as well as globally. Analogue data were considered for areas, net pays, porosities, saturations, formation volume factors, recovery factors, and oil-gas ratios.

Play Types

From seismic interpretation, the structural geometry of the identified sequences was mapped. As a result, the slope was divided into six areas based on structural styles, and twelve types of plays were identified. All plays except the subsalt synrift play require deepwater turbidite sands for reservoir, and except for the slope fan play, all others are salt-related to some extent. These twelve plays were assessed independently, and their results combined statistically for the totals:

1. Mini-Basin Floors (Structured and Unstructured)
2. Mini-Basin Flanks
3. Salt Crests (Associated with Mini-Basins)
4. Sub-Salt, Jurassic
5. Supra-Salt Structures, Tertiary
6. Sub-Salt, Cretaceous
7. Salt Crests
8. Salt Flanks
9. Deep Structures
10. Other Supra-Salt Structures
11. Upper Slope Fans and Structures (Tertiary and Cretaceous)
12. Upper Slope Fans and Structures (Cretaceous and Jurassic)

Results

The results consisted of probability distributions for oil, gas, solution gas, and natural gas liquids for each of the twelve plays and statistically summed for the totals. Both in-place

and recoverable values were generated. Because the petroleum system(s) have not yet been proven in the deepwater, the analysis also included values for play risk factors.

The simplified results are summarized in Figure 3 for oil and gas only. The minimum (P90), mean, and maximum (P10) are shown for the unrisksed and play-risked recoverables. The risked category was used to quantify the risk that the petroleum system(s) may not exist. Given certain degrees of future success, the play risk factors can be lowered or removed. Therefore, the undiscovered gas potential for the deepwater slope offshore Nova Scotia was deemed to be between 15 to 41 Tcf depending on the assumed geological risk factors. The oil potential of 2 to 5 billion barrels is very significant and in keeping with the high oil-to-gas discovery ratios seen in other deepwater areas.

The lateral ranges for the unrisksed and risked categories indicate the broad spectrum of possible outcomes. Additionally, the associated gas and natural gas liquids, shown below, are also significant. Figure 4 provides the total results of the assessment.

On a risked basis, these numbers doubled the gas potential for offshore Nova Scotia while adding significant oil. Adding the traditional 18 Tcf shelf value to a risked value of 15 Tcf for the slope results in a total potential of 33 Tcf . Similarly, combining the traditional 1 BB of oil (and liquids) to the 2 BB for the slope gives a total potential of 3 BB for offshore Nova Scotia.

On an estimated ultimate recovery (EUR) per unit area, the Scotian Slope is on the low side and more in line with other Canadian frontiers such as the Beaufort-MacKenzie Basin, the Labrador Shelf and the Sverdrup Basin in the Arctic Islands. If the plays were proven and the play risk removed, it would rank much higher along with offshore Brazil in richness per unit area but would still be smaller in total area. On a fully risked basis, offshore Nova Scotia. has about 50 MBOE/km², while offshore Brazil and West Africa has between 100-200 MBOE/km² and the Gulf of Mexico about 400 MBOE/km² (Federal waters only).

The complete Scotian Slope assessment report is available on the CNSOPB website at: http://www.cnsopb.ns.ca/Whatsnew/Hydrocarbon_Potential_Scotian_Slope.pdf.

Category	Min-Mean-Max Gas (Tcf)	Min-Mean-Max Oil (BB)
Unrisksed Recoverable	31 - 41 - 53	3 - 5 - 6
Play Risked Recoverable	5 - 15 - 28	0 - 2 - 3

Figure 3. Simplified assessment results for the deepwater slope offshore Nova Scotia

	UNRISKED In-Place			UNRISKED Recoverable		
	P90	Mean	P10	P90	Mean	P10
Gas (Tcf)	45.8	60.4	77.2	30.7	41.1	52.8
Oil (BB)	10.7	14.4	18.6	3.4	4.7	6.2
sub-total (BOEB)	18.3	24.5	31.5	8.5	11.6	15.0
Solution Gas (Tcf)	17.2	23.0	29.5	5.4	7.5	9.8
NGL (BB)	1.4	1.8	2.3	0.9	1.2	1.6
sub-total (BOEB)	4.3	5.6	7.2	1.8	2.4	3.2
Total (BOEB)	22.8	30.1	38.3	10.5	14.0	18.0
	RISKED In-Place			RISKED Recoverable		
	P90	Mean	P10	P90	Mean	P10
Gas (Tcf)	7.0	22.1	39.5	4.6	15.2	27.7
Oil (BB)	1.3	5.0	9.4	0.4	1.7	3.2
sub-total (BOEB)	2.5	8.7	16.0	1.2	4.2	7.8
Solution Gas (Tcf)	2.1	7.9	14.7	0.7	2.6	5.0
NGL (BB)	0.2	0.7	1.2	0.1	0.5	0.8
sub-total (BOEB)	0.55	2.02	3.65	0.22	0.9	1.63
Total (BOEB)	3.1	10.7	19.6	1.5	5.1	9.3

Figure 4. Assessment results for the deepwater slope offshore Nova Scotia (IMPERIAL Units).