Offshore Newfoundland & Labrador Resource Assessment
Orphan Basin Area NL16-CFB01

An Integrated Project for Nalcor Energy – Oil and Gas Inc., and the Department of Natural Resources, Government of Newfoundland and Labrador

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INTRODUCTION

Nalcor Energy – Oil and Gas Inc. Newfoundland and Labrador’s provincial energy corporation working with the Newfoundland and Labrador Department of Natural Resources (DNR) engaged Beicip-Franlab to conduct an independent resource assessment of the Orphan Basin area following on the resource assessment of the Flemish Pass area (NL15_01EN) in 2015. The underexplored West Orphan Basin has recently demonstrated material potential after new regional seismic data uncovered a large play trend in the Lower Tertiary sands indicative of turbiditic fan complexes. The finding and identification of this new play trend is to be presented at the 2016 Society of Exploration Geophysicists (SEG) international meeting, Dallas, Texas1.

The objective of this project is to conduct a seismic reservoir characterization, basin analysis, play risk analysis and resource assessment for the area subject to the upcoming license round (NL16-CF801 - November 2016) based on available geological and geophysical data. The final deliverables of this project include a detailed Beicip-Franlab internal report for Nalcor and DNR and this Public Atlas which summarizes the main methodologies and key results of the resource assessment project.

WORKFLOW

1. Database generation and QC
2. Geodynamic and tectonic settings
3. Seismic reservoir characterization
4. Sedimentology, sequence stratigraphy and geochemistry
5. Petrophysics evaluation (V_shale) porosity, saturation
6. Gross Depositional Environment (GDE) maps
7. Stratigraphic modelling
8. 2D & 3D petroleum system modelling
9. Play risk analysis, and volumes assessment.

MAIN RESULTS

Beicip-Franlab petroleum system resource assessment of the Orphan area demonstrates a prolific petroleum system with five main reservoirs sourced by four constrained source rocks. Timing of burial regarding traps formation enables hydrocarbons (HC) to be trapped and sealed regionally through rotated Jurassic and Cretaceous blocks and large Cretaceous and Tertiary turbidite/contourite complexes. The petroleum system model is calibrated to the presence of HC fluids independently demonstrated by a seismic reservoir characterization work on 2D and 3D volumes.

STUDY AREA

The Eastern Newfoundland Region represents part of the North Atlantic Mesozoic rift system which includes the Jeanne d’Arc, Orphan and Flemish Pass Basins.

In November 2015, Nalcor Energy and Beicip-Franlab began the resource assessment of the Orphan area. To allow for a transition into the previous resource assessment within the Flemish Pass area, the study scope was set to include the NL-02EN sector (2016 license round area) and surrounding acreage for completeness.

On April 7, 2016 the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) announced the Call for Bids NL16-CFB01. The block definition includes 13 parcels of land – four (4) from the previously announced NL15-01EN Call for Bids and nine (9) from NL02-EN Sector – with bids closing in November of 2016. The land available in this call is under the new Scheduled Land Tenure System: [http://www.cnlopb.ca/pdfs/cfntechdoc.pdf](http://www.cnlopb.ca/pdfs/cfntechdoc.pdf). Interested parties have until 12:00 p.m. NST on November 9th, 2016 to submit bids for the parcels offered in Call for Bids NL16-CFB01. Further detailed information pertaining to this Call for Bids can be found at: [www.cnlopb.ca/exploration/issuance.php#bids-active](http://www.cnlopb.ca/exploration/issuance.php#bids-active).
DATA SET

1. Ten wells were used for the study. Each well contains a set of petrophysical logs, stratigraphic markers and geochemical reports:
   - Baie Verte J-57
   - Great Barasway F-66
   - Bonavista C-99
   - Cumberland B-55
   - Sheridan J-87
   - Blue H-28
   - Linnet E-63 (outside the modelled area)
   - Hare Bay E-21 (outside the modelled area)
   - Margaree A-49 (outside the modelled area)
   - Lona O-55 (outside the modelled area)

2. 2D seismic surveys (regional, 10x10km and 5x5km grids) interpreted by Nalcor covering an area of 38,000 km² within the Orphan/Flemish Pass basins (2012-2015 — Nalcor invested TGS/PGS broadband long offset multiclient NE Newfoundland Slope Seismic Project).

3. 4,600 km² 3D Survey (2015 Nalcor invested TGS/PGS broadband long offset multi-client project).

4. A set of nine horizons were interpreted in both surveys and eight associated isopach maps:
   - Seabed, 0 My
   - C10, Mid Neogene, 10 Ma
   - C24, Top Paleocene, 24 Ma
   - C45, Top Mid Eocene, 45 Ma
   - C54, Top Paleocene/Base Eocene
   - C65, Top Cretaceous, 65 Ma
   - K114, Top Mid Aptian, 114 Ma
   - J145, Top Tithonian, 145 Ma
   - Base Mesozoic, 251 Ma

5. Fault sets picked for structural evolution, reconstruction, and 3D modelling.

The 2016 Orphan Basin Resource Assessment AOI shares its eastern boundary with the 2014 NL01-EN Sector. Nalcor and Beicip-Franlab extended the main structural trends, seismic horizons, and paleogeographic interpretation from the Flemish Basin to the Orphan Basin to secure regional consistency.
DATA SET REVIEW AND RELEVANCY

Regional seismic interpretation
The seismic interpretation of the sector covers the entire Upper Jurassic to present day. It was calibrated on the various wells available for the study area.

The regional seismic interpretation on a 10x10km grid was adapted to the play study scale. It identified the main traps (with a minimum of 10 km³), the main structural features (depositional centers, slopes, main regional faults), seismic response of the regional paleo-environment settings, as well as seismic objects and anomalies that may correspond to sedimentary features such as channels, deep sea fans, etc.

This interpretation highlighted traps with in-place volumes of the order of 100 MMbbl equivalent (10-15 Mm³) or higher.

3D seismic data and inversion
The study had access to a 3D fast-track processed seismic volume. No well penetrated the 3D area and offset and pseudo wells were used as a constraint.

Well geological data
The study also used the comprehensive well information on the 10 wells available within the study area or in its vicinity. These included: logs, paleo-environment data, core, temperature, pressure, HC recordings plus regional geological studies on Eastern NL and existing well correlations. This data provides a reliable framework for the play definition, internal subdivisions, and key characteristics of the wells such as net-to-gross, reservoirs, average porosities, carriers and seal occurrence.

Geochemical and petroleum data
The maturity data for the wells was abundant although not very precise (Ro, Tmax). Maturity data can be correlated to well logs and used for comprehensive building of TOC logs. TOC measurements were made on cuttings and cores. The existence of a proven and efficient petroleum system in the neighboring basins (Jeanne d’Arc and Flemish Pass), with similar geologic characteristics, provides a useful analogue for the Kimmeridgian source rock characterization.

Reliability and accuracy of the resources assessment
The data quality ensured a reliable and reasonably well constrained 3D geological model of the area could be built. The corresponding oil and gas resource assessment can be undertaken within an acceptable accuracy covered through the low and high cases, constrained by independent seismic reservoir characterization analysis.
HYDROCARBON PLAY RESOURCE ASSESSMENT METHODOLOGY

Definitions

- The assessment was based on the deterministic computation in the area of interest of oil and gas volumes in place. The simulation includes 3D numerical geological models of lithofacies distribution (sedimentary system modelling) and of 3D structural oil and gas generation/expulsion/migration and entrapment (petroleum system modelling). The software packages used are DionisosFlow™ (for sedimentation) and TemisFlow™ 3D (for petroleum system).
- The sedimentary system model was calibrated against well data on sand/shale ratio, paleo water depth, and known depositional setting at the wells (shoreface, shelf, slope, etc.). The matching was done at a third order sequence stratigraphic scale resolution. The petroleum system model is calibrated against maturity, temperature, pressure data, oil and gas occurrence, and quality. The matching was done at the resolution of the 3D geological model used in the simulation, and the precision of data (i.e., Vitrinite ±0.15%).
- The calibrated geological model was considered as a Reliable Reference Geological Model (RRGM) or reference scenario of the various plays.

Unrisked Volumes

- The HC charge in a play includes areas with low (residual) and high (concentrated) HC content (in kg/m²). Cutoffs on HC concentration can be selected to define the low, most likely, and high case.
- Some numerical parameters of the Reliable Reference Geological Model (RRGM) may remain unconstrained while still allowing for a consistent calibration against observed data.
- The computed oil and gas volumes resulting from the RRGM numerical simulation are referred to as Unrisked Volumes.

The sensitivity analysis performed on the RRGM provides a distribution of computed Unrisked Volumes which can be characterized by the P90, P50, and P10 thresholds on the volume distribution curve obtained from the sensitivity runs outcomes.

EXPLORATION HISTORY

The drilling of Tors Cove D-52 in the early 1960s marked the beginning of hydrocarbon exploration in Newfoundland and Labrador’s offshore. To date, nearly 160 exploration wells have been drilled in Newfoundland and Labrador’s offshore jurisdiction. Many of these wells have been drilled in the Jeanne d’Arc Basin where currently four fields are in production and one is slated to start production in 2017. Production to date has been in excess of 1.5 billion barrels of oil. Exploration in the deeper waters of the Eastern Newfoundland Region (Orphan/Flemish Pass Basins) followed the initial exploration on the Grand Banks.

The first well in the assessment area, Gabriel C-60, was drilled in 1979 and encountered Hibernia equivalent reservoir; however, no mature source rock was encountered. The Baccalieu I-78 well (1986) encountered good Early Cretaceous reservoirs and confirmed the presence of good Kimmeridgian source rock. Subsequently, Lancaster G-70 encountered Late Jurassic sandstones and also Kimmeridgian source rock. The Kyle L-11 well, also drilled in 1986, encountered Early Cretaceous reservoir sandstones.

After a decade of no activity, new multi-client, exclusive seismic grids and the first 3D survey were collected. In 2003, Petro Canada et al. drilled Mizzen L-11 and intersected excellent reservoirs in the Early Cretaceous and Late Jurassic. This well had 5m of light oil pay in Early Cretaceous sandstones; however, the resource was deemed non-economic. In the same year, Tuckamore B-27 was drilled by the same companies. Tuckamore drilled through thick Cretaceous sandstone; nevertheless, it was wet and the well was TD’d before reaching the Jurassic interval. However, new 2D seismic over this well location indicates a thick Jurassic aged section.

In December 2008, Statoil et al. spudded Mizzen O-16 and on April 8, 2009, the company announced an oil discovery. The well tested oil from Late Jurassic sandstones, and the results spurred a renewed interest in the Flemish Pass Basin. The most recent oil discoveries by Statoil et al. – Harpoon and Bay du Nord (2013) – are surrounded by the parcels outlining the Call for Bids (NL15-01EN). The Bay du Nord discovery was described as the largest oil find in the world for 2013 with estimates from Statoil of 300 to 600 million barrels of oil recoverable. In 2016, Statoil announced a new discovery at Baccalieu and Bay de Verde.

In the eastern side of the Orphan Basin, the Great Barasway F-66 well (2006) drilled a thick Jurassic aged section containing Tithonian and Kimmeridgian source rock. Even though this well was unsuccessful in a discovery, it yet again demonstrated the presence of regional source rock. The Lona O-55 well drilled in 2010, although an unsuccessful petroleum discovery, also encountered a thick Jurassic section. The most recent activity in the Orphan Basin was in 2013 where Margaree A-49 became the third deepwater well in the basin. Again this well encountered a Jurassic section, but unfortunately, was unsuccessful in discovering petroleum.

With the emergence of Nalcor Energy, Newfoundland and Labrador’s crown energy company in 2007, a commitment was made to invest in new geoscience data to unlock the next offshore areas that may contain material prospectivity. In late 2010, with Airbus Defense and Space, Nalcor undertook a regional oil seep mapping and interpretation study encompassing all of offshore Newfoundland and Labrador (over 1.5M km²). A subset of the satellite data acquired during this survey imaged areas of potential natural seepage in the Eastern Newfoundland Region (Orphan/Flemish Pass Basins), suggesting a regional working petroleum system and, coupled with the recent 2009 Mizzen O-16 discovery, highlighted potential new areas for oil exploration.

To better understand the potential nature of prospectivity in this region, in 2012 Nalcor invested with global seismic companies TGS and PGS in a long offset broadband 2D multi-client seismic grid of 10x10km data over the Flemish Pass area. This survey was an extension of the 2011-2012 Nalcor invested TGS and PGS regional 2D seismic program targeting the slope and deepwater areas offshore Labrador.

In 2014, the initial 10x10km grid was infilled, resulting in a 5x5km grid over the Flemish Pass. With these data, an independent resources assessment of the Flemish Pass area was released in advance of the 2015 Call for Bids. The land sale was the largest in the province’s history, resulting in $1.2 billion in work commitments on seven of the 11 available blocks.

Continuing the investment with TGS and PGS, a 4600 km² 3D survey was acquired in 2015 over a portion of 2016 Call for Bids (NL16-01EN) along with a partial 10X10km infill program for the Orphan area with the intent to complete in 2016. Also in 2015, Nalcor invested with MG3 and AGI on a seabed coring study conducted within the Orphan/Flemish Pass Basins which assisted in providing insight into the petroleum system potential of the region.
GEODYNAMIC SETTINGS

The Orphan Basin is located at the NE-edge of Newfoundland margin. By its geographical position, the Orphan Basin was subject to two consecutive rifting episodes related to the North Atlantic Opening:

• first the NW-SE oriented extension in the Late Jurassic - Early Cretaceous related to the rifting between Newfoundland and Iberia (Phases II, III), and
• the NE-SW oriented extension in the Early Cretaceous related to the Newfoundland - SW Irish margin rifting (Phase IV).

The Charlie-Gibbs Fracture Zone and the Orphan Knoll, just west of the Continent Ocean Transition (COT), mark the northern limit of the basin. The Flemish Cap and the Bonavista Platform bound respectively the eastern and western limits of the basin. Its southern limit is defined by a strong positive free air gravimetry anomaly which separates it from the Jeanne d’Arc Basin.

The Orphan Knoll and Flemish Cap are interpreted as relatively unthinned crustal material with a thickness of about ~20 km and 30 km, respectively. Localized intense thinning areas were detected in the west and east of the basin with crustal thickness less than 7 kilometres. Syn-rift sediments run from the Late Jurassic to the late Early Cretaceous. The Orphan Basin is characterized by the predominance of NE-SW oriented major crustal normal faults initiated in the Late Jurassic. These normal faults root down in the ductile middle or lower continental crust. The largest northwestward-dipping normal faults, defined by large half-grabens and filled by thick successions of Late Jurassic sediments, are found in the centre of the Orphan Basin.
The Late Jurassic rifting episode has been documented over a broad region of the North Atlantic margins. This phase characterized by wide rifting affects Jeanne d'Arc Basin up to the western part of the Orphan Basin. The Top Tithonian lies within the syn-rift sequence. Intense crustal thinning centered in the eastern part of the Orphan Basin has been observed.

Earlier interpretations suggested no Jurassic sediments were present in the western part of the Orphan Basin. However, new data and subsequent interpretations have demonstrated the impacts of Jurassic rifting has extended further than previously thought, allowing for the deposition of Jurassic sediments throughout a large portion of the West Orphan Basin.

The Early Cretaceous rift episode is preferentially localized in the western part of the Orphan Basin. Fault reactivation has been described in the Late Aptian. Failed rift and associated Early Cretaceous igneous intrusions characterize the northernmost part of the West Orphan Basin. In general, the Late Cretaceous (including Albian) sediments are relatively thin throughout the basin and show flat-lying succession above the Top Aptian Unconformity, suggesting minor subsidence.

The Base Tertiary is well defined regionally all over the Orphan Basin and merges with the erosion surface on tops of the major tilted fault blocks. Progressive downlaps overlaying the Base Tertiary illustrate a regional thermal subsidence of the basin in the Early Tertiary time.
SEISMIC CHARACTERIZATION – INVERSION & LITHOLOGY PREDICTION

Inversion Process: A constrained 3D pre-stack inversion with wells outside the 3D survey

i. Run 2D sequential inversions; the initial inversions are constrained by existing wells along or near 2D surveys, subsequent intersecting 2D lines are constrained by pseudo-wells extracted from the already performed inversions. These 2D lines allow for loop tie connections to the 3D survey.
   a. The use of robust 2D velocity models to constrain the 2D inversions ensures the consistency between the lines in terms of impedance values.
   b. This sequential workflow ensures a fine estimation of the most appropriate wavelet for each line.
ii. The 3D volume is inverted using more than 20 pseudo-wells extracted from 4 different lines crossing the 3D survey.
iii. Elastic inversion of the 3D volume provides petro-elastic moduli (P and S impedances) for use in lithology prediction and fluid assessments within the Tertiary fan complex.
   a) Interwell, an advanced seismic software from Beicip-Franlab has been used to run the inversion.

Situation and Challenges

• The AVO effects observed in the Orphan Basin have yet to be tested.
• No well data exists within the 3D survey. Several wells are located along 2D seismic lines that allow for a sufficient connection to the 3D survey.
• Lona was the only well with S-Impedance used in the inversion workflow.
 Velocity models

- Velocity models are consistent between 2D lines and provide a comprehensive constraint to the 2D inversions. It is encouraging that the velocity volumes from seismic have high correlations with the well data (DT sonic and VSP).
- The velocity models and local empirical relationships from well data between velocity and impedance provide the very low frequency content of the P & S inverted volumes.

A Priori model: Density, P Impedance, S Impedance

- The a priori model is a combination of the background impedance trends, well data, pseudo well data and correlation lines. The correlation lines were generated from horizons and the depositional model.
- The high correlation of velocities between wells, pseudo-wells, and the seismic data results in a robust a priori model for each inversion.
- The a priori modelling is a key step as it provides the very low frequency information that seismic cannot provide and captures the burial trend that allows for the prediction of P and S absolute values in the inversion result.

Wavelet optimization

- The wavelet is the key operator which translates the seismic amplitudes to impedance variations.
- Zero-phase wavelets are extracted from the angle-stacks using auto and cross-correlation between neighbouring seismic traces.
- The well-to-seismic calibration and the wavelet optimizations (phase and energy) are performed simultaneously using available well data, pseudo wells and seismic angle stacks resulting in unique wavelets for each angle stack and dataset.

Stratigraphic inversion with InterWell

- As the stratigraphic inversion with InterWell is model-based, the tuning of key inversion parameters ensures an attenuation of the overall random noise by discarding unrealistic AVO responses.
- The elastic inversion provides optimal P and S impedance to estimate the lateral and vertical changes of the lithology, porosity, or fluid content.
Petro-elastic model

A petro-elastic model has been established based on available well data with DT, DTS and density logs in Easytrace™, a log manager software dedicated to seismic characterization. The aim of this step is to link the elastic moduli (in this case P and S impedance) to reservoir properties, such as lithology and porosity.

In the petro-elastic model, the burial trend for shales is well captured, from the lower impedances (uncompacted) to the higher impedances (compacted). In sands, the available data samples from highly porous sands (low impedance) to tight sands (high impedance). The sampled sands are in general very clean, water-saturated with porosities up to 30%. P and S impedance from Lona O-55 provide a clear discrimination between clean sands and shale, independent of burial depth.

Discriminant analysis for sand prediction

Using the petro-elastic model as the lithology predictor for the 3D dataset, a discriminant analysis (sand probability) has been produced from the inverted P and S impedances.

The sand probability volumes identify multiple anomalies with high potential for sand on 2D lines and across the 3D survey within the Tertiary and Cretaceous. Some of these bodies appear to have high porosity (~30%), as they correlate with the lower impedances of the sand cluster in the training samples (Lona Data).

The image on the left has been extracted from the sand probability volume. It illustrates that the Tertiary fan complex is clearly distinguishable from bounding lithologies and has potential sand content both in the proximal and distal portions of the fan.

Implementation of multi-disciplinary workflow

The presence of overpressure, which would justify the presence of highly porous sands at prospect depth, is supported by results from the TemisFlow™ petroleum system model. Fluid escape structures observed below the prospect, that potentially act as migration pathways, provide additional evidence of the presence of overpressure within the basin at reservoir levels.

In addition, the succession of sand and shale deposits identified from the inversion help constrain the stratigraphic and lithological DionisosFlow™ model by fine tuning the nature, the number and the positions of the sediment sources to properly simulate the directions and the geometries of the turbidite complex within the 3D area. This integrated approach reduces reservoir presence and quality risks within the 3D area.
SEISMIC CHARACTERIZATION – FLUID CONTENT ASSESSMENT

Introduction and hypothesis

Three main parameters drive the impedance changes:
1. Lithology
2. Porosity - An increase leads to lower impedance values
3. Fluid content - Fluids impact both P impedance (via P velocity and density) and S impedance (via density)

A fluid assessment has been carried out to test for the presence of hydrocarbons and to correct the porosity predictions from the fluid effect as the training samples for porosity assessment are based only on water-saturated wells. Four fluids have been considered: water, heavy oil, light oil, and gas in the analysis. Elastic moduli and density of these fluids have been computed at expected reservoir conditions. Based on existing well analysis it is likely that fluid discrimination in this case can only be interpreted with confidence in the cleanest sands.

Fluid analysis

A water-line was derived from the clean sands at Lona, which associates P impedance and S impedance values to a water saturated clean sand line with a given porosity. The red and blue points plotted on the impedance cross plot represent extracted IP and IS values from within the clean sands on the lithology prediction. Fluid substitution simulations were subsequently run to identify the porosity and the fluid that would bring back the anomalous points to the water line using a Monte Carlo algorithm. The 3D analysis shows that many points in the updip/proximal part of the fan that lie in the cleanest sand locations clearly indicate the presence of hydrocarbons, most probably light oil, with a corrected porosity range from 24% to 28%.

Application on volume and limit of the method

Based on the cross-plot it has been possible, within the cleanest interpreted sand facies, to apply a discriminant analysis on the 2D/3D P and S impedances to identify potential hydrocarbon saturated clean sand locations. Some of the clean sand layers show hydrocarbons while others are water saturated. It is also encouraging that the hydrocarbon points are consistently populating updip from the interpreted water leg on all the lines that intersect the fan complex.

It is still difficult to identify a fluid contact based on this analysis as it is only valid for clean sands and the increase of the shale content from the proximal to distal parts of the fan is likely masking the fluid detection in lower Net to Gross areas.
Nine depth maps were picked from the seismic grid and used to define the skeleton of present-day model geometry. Six are shown here for illustration purposes.
While individual faults have been interpreted on seismic, only the main regional fault trends have been inserted in the model. These structures were deemed likely to affect the regional migration pathways for the area and thus used in the modelling. In the 3D petroleum system model, they behave as either pressure barriers and/or have limited effect on fluid flow. This is especially true from Late Cretaceous on as they are sealed by overlying stratigraphy.

This initial 3D petroleum system model (10 seismic stratigraphic layers) has been subdivided in 37 layers, enabling the identification of the main components of the petroleum system, while preserving the main regional lithological and sequence stratigraphic events.

To create this petroleum system model (shown above), the 3D stratigraphic model (DionisosFlow™) was then upscaled from 546 to 26 layers for the interval between J145 (Top Tithonian) and C24 (Top Oligocene) maintaining regional geological context and keeping the highest degree of information.
GEOLOGY SETTINGS

All geological information (markers, well reports and well logs) were integrated and interpreted in terms of sedimentology and petrophysics in order to provide a consistent stratigraphic framework constraining Gross Depositional Environment (GDE) maps for each sequence.

The petrophysical log interpretation provides updated lithological profiles, porosity, and saturation curves over the main targeted intervals. This interpretation was used to better calibrate the model responses (using stratigraphic and petroleum system modelling software). The methodology used is a classical petrophysical deterministic workflow starting with the Volume of Shale (V_{shale}) calculation. Next, lithology logs were generated using all available information such as mudlogs, cuttings, sidewall cores, etc. Finally, porosity and saturation were evaluated after calibration. Ten wells were included in the petrophysical study: Baie Verte J-57, Great Barasway F-66, Bonavista C-99, Cumberland B-55, Sheridan J-87, Blue H-28 Lona O-55, Linnet E-63, Hare Bay E-21, Margaree A-49.

Depositional and sedimentological observations were obtained from combination of well information and seismic geomorphology analysis. They demonstrate a Cretaceous system consistent with shelf to shallow basinal depositional environments representative of syn-rift to post-rift environments (i.e. shelf dominated by erosion/bypass and depositional turbiditic systems at toe of slope).

The Tertiary systems are mainly dominated by autocyclic sedimentary systems, where giant contourite ridges are developing on remnant paleo highs, and lowstand fans deposited between them. Carbonate systems are developing on eastern and southern Orphan paleo highs, with probable synchronous deposition of organic rich pelagic mud in the troughs, less affected by turbiditic currents than in the western border of the basin.
The Upper Tertiary section displays delta front sand bars potentially feeding turbidite complexes down-dip distributing local reservoirs throughout the Tertiary (see DionisosFlow™ model).

This comprehensive stratigraphic interpretation served as the framework for the sedimentological input to the Gross Depositional Environment (GDE) mapping. When coupled with thickness maps, these inputs served as the fundamental information for the DionisosFlow™ stratigraphic model.
SEQUENCE STRATIGRAPHY AND DEPOSITIONAL ENVIRONMENTS - WORKFLOW

The interpretation in terms of seismic stratigraphy follows criteria for the recognition of sedimentary bodies from seismic data. For the purpose of the present evaluation, two regional seismic cross-sections (see map) were chosen in order to define the key stratigraphic features of the margin. Full sections are displayed on the next two pages. The seismic stratigraphy interpretation is adapted from P. Jerramnaud et al., 2010, with the following guidelines:

- The depositional profile migration and identification of key surfaces are defined on the raw seismic sections (1&2) by recognizing the offlap breaks position and associated truncations geometries (onlap, toplap, downlap). The shelf break is geometrically defined as the upper point of a depositional profile slope break corresponding to either the shoreline (shoreface or delta front) or the shelf break. Its migration is interpreted as a progradation or a retrogradation.
- A progradational succession is interpreted as the highstand system tract (HST) and lowstand system tract (LST), separated by an unconformity (UN; subaerial unconformity; Posamentier et al., 1988a, b – (2-3)). The unconformity forms during the maximum of the progradation rate. A retrogradational succession is interpreted as a transgressive system tract (TST) (3). Maximum flooding surfaces (MFS) are defined as the inversion from retrogradation to progradation, whereas flooding surfaces (FS) or transgressive surfaces (TS) (2), now referred to as maximum regressive surfaces (MRS; Embry, 1993), are defined as the inversion from progradation to retrogradation.
- The sedimentary environments were defined using the geological data available at well (cuttings, biostratigraphy, and well-log signatures (5)) coupled to seismic character to recognize sand-rich systems (slope fans, submarine fans, and slope and ramp systems).

Seismo-stratigraphic and seismo-facies methodology analysis, combined with biostratigraphy, well logs, and core and cuttings data analysis, led to the description of 12 regional sequences (4) and eight major depositional facies (5).

Orogenic uplift: 1988
Depositional environments: 1993
Seismic interpretation: 2010
Not interpreted here
This section highlights the northward progradation of the Bonavista margin from the Late Cretaceous, up to the present day. Please note some wells are tied to the section as they have been stratigraphically used for the interpretation, but they belong to the cross sectioning panel.

Sedimentation rate is increasing throughout the Tertiary, with well-developed clinoforms prograding during the Cretaceous, Late Paleocene, Eocene, and Mio-Pliocene. The coastal margin displays more ramp-like features during the Early Paleocene and Miocene, indicative of transgression and a drowning of the platform.

During the Cretaceous, sedimentary systems are mainly controlled by faulting associated with hyper-extension of the Orphan Basin.

During the whole Tertiary, combined effects of turbiditic currents and deep water bottom currents are controlling the deposition of turbidites from toe-of-slope to the South, alongside major contouritic levees in the central part of the basin, down to the North of the AOI (see red arrows).
The broadly West-East oriented section is displaying: a) Cretaceous lowstand fans and ponded syn-rift deposits; b) the southern border of a major Tertiary contourite with associated turbiditic systems building-up on its flank.

The Eocene sedimentation is also noticeable with significant lowstand fans deposited in the basin. Those fans are synchronous with a period of significant erosion/bypass on the western platform, which indicates a significant increase in the sediment flux synchronous with a relative sea level drop.
MATURITY - SOURCE ROCK DEFINITION - METHODOLOGY

In the studied area, Total Organic Content (TOC) and Rock Eval data allowed for characterization of key parameters of source rock intervals at well locations. In addition, regional extent of source rock was assessed through a Carbolog® approach to constrain the petroleum modelling. In this approach, the TOC was computed from the combined log response between the sonic, density, neutron, and resistivity.

A calibration was made using existing TOC analytic data from the study wells. The method can be represented graphically with ΔT plotted on the horizontal axis and 1/√Rt on the vertical axis. On such a cross plot, the position of the pure components (water, clay, pure TOC, or matrix) allows the derivation of the TOC at a given depth. Calculated TOC is then calibrated against the average of Rock Eval measurements on a core at that depth.

Carbolog dataset for all available wells:
- Baie Verte
- Great Barasway
- Bonavista
- Cumberland
- Sheridan
- Blue
- Lona
- Linnet
- Hare Bay
- Margaree

Arrow indicates an increase in TOC content:
- Jurassic
- Cretaceous
- Paleocene
- Undifferentiated Mesozoic
- Undifferentiated

VITRINITE REFLECTANCE DATA

The percentage Ro measurements are displayed on the graph at right for eight wells, which are of different vintages and from multiple geochemical laboratories. A wide range of values may be found for a given burial depth and a given well, while maturity trends with depth are quite similar between wells and/or laboratories.

The average burial depth at which the 0.6% Ro threshold (top oil window) is reached is around 3200m, in line with a 29 to 33°C/km average geothermal gradient. The trend at Great Barasway displaying similar percentage Ro through depth might be representative of pre-Jurassic reworked material in the Upper Jurassic sediments. The Ro measurements appear scattered below 4000m burial. The initiation of the gas condensate generation zone (> 1.3% Ro) seems to occur around 4500m depth.

IPEN patented methodology to estimate the organic content of potential source rocks
The source rock evaluation shows:

- The existence of a rich TOC interval at the top of the Tithonian in Great Barasway, Baccalieu and Lancaster wells (around 3%) and a Kimmeridgian source rock potential distributed over a large thickness (>200m) with TOC ≥ 1%. (see Flemish Pass Basin resource assessment available at Nalcor energy: http://goo.gl/VFYYdy).

- The Cretaceous level (Turo-Cenomanian) presents a source rock potential here illustrated on Great Barasway and Sheridan and supported by the stratigraphic forward modeling that highlights local ponds favorable to the preservation of organic rich sediments.

- The Lower Paleocene displays a regionally consistent level of rich TOC values constituting a potential source rock. Its average TOC is in the order of 2-5% depending on the basinal settings.

- Finally another potential TOC rich level is recorded around 45 Ma (Eocene) with a fair lateral consistency. This source rock is not sufficiently buried in the basin to represent a significant contribution to the petroleum system.
PLAY DEFINITION

According to the PRMS definition accepted by the Society of Petroleum Engineers (SPE), a "play or petroleum play" is a model of how a petroleum system (HC charge, reservoir, seal, or trap) may combine to produce petroleum accumulations at a given stratigraphic level (e.g., the Lower Paleocene play). A play may contain prospective resources and reserves (in the economic sense). The wheeler diagram is constructed using the DionisosFlow™ result grid (see below). The Jurassic is not included since it wasn’t simulated (lack of stratigraphic constraints). The Jurassic was simulated in the petroleum system model using neutral lithologies, source rock, and a top reservoir (Tithonian age).
Within the NL16-CFB01 license area, there are multiple Eocene Fan plays. These fans are large in scale and have been imaged over multiple 2D seismic lines within the license area. The 3D seismic survey also images two or more of these fans. Many display a type class 2p AVO response when viewed in the gathers and on the near and far angle stacks.

North American polarity convention was used in this study. Increase in impedance (positive amplitude) is blue; decrease in impedance (negative amplitude) is orange.

This particular example of an Eocene Fan play within the license round area may contain a flat spot coinciding where the AVO anomaly dims significantly.
Within the NL16-CFB01 license area, there are multiple Eocene Fan plays. These fans are large in scale and have been imaged over multiple 2D seismic lines within the license area. Many display a type class 2p AVO response when viewed in the gathers and on the near and far angle stacks.

North American polarity convention was used in this study. Increase in impedance (positive amplitude) is blue; decrease in impedance (negative amplitude) is orange.
Within the NL16-CFB01 license area, there are a number of structural/stratigraphic plays. These plays are large in scale and have been imaged over two or more 2D seismic lines within the license area. Many display an AVO response when viewed in the gathers and on the near and far angle stacks.

North American polarity convention was used in this study. Increase in impedance (positive amplitude is blue); decrease in impedance is orange.

This particular example of a Cretaceous Structural/Stratigraphic play within the license round area shows stacked AVO supported leads.
Within the NL16-CFB01 license area, there are multiple Jurassic tilted fault block plays. These structural plays exhibit a classic architecture, and some have been imaged over two or more 2D seismic lines within the license area. Many display an AVO response when viewed in the gathers and on the near and far angle stacks.

North American polarity convention was used in this study. An increase in impedance (positive amplitude) is blue; a decrease in impedance (negative amplitude) is orange.

This particular example of a Jurassic structural play within the license round area shows an increase in amplitude strength updip in the far angle stack.
GEOLOGY & GROSS DEPOSITIONAL ENVIRONMENT MAPS

A set of eight GDE maps spanning the main sequences were built from the stratigraphic / sedimentological information coupled to the seismic data (thickness, structural maps and seismic stratigraphy analysis). They represent the paleoenvironments at given ages that served as input to the stratigraphic basin modelling (DionisosFlow™), specifically through constraining the paleobathymetric/paleoenvironmental changes through time and space. From the Jurassic onwards, facies are mainly driven by rift related fluvo/deltaic environments that transition basinwards into distal turbidite complexes. The Tertiary marks the onset of the sedimentary source from the Bonavista Platform remodeled by the deep water bottom current from the Labrador Sea. A variety of reservoir types can be expected from the Jurassic rift related graben terrains, to the turbidite channels, lobes and contourites preserved within the Cretaceous/Tertiary basin.
FORWARD STRATIGRAPHIC MODELLING: Objectives and Workflow

A forward stratigraphic simulation was performed using DionisosFlow™ (an IFPEN software) in order to (1) better understand the 3D sedimentary architecture of the basin, (2) quantify the sedimentary volumes at the basin scale, and (3) predict the location of prospective areas in regions with less geological information. This modelling was performed from the base of the Tithonian, up to the base of the Cenozoic, in sequential time steps. For each time step, three main environmental parameters were taken into account:

- The Accommodation (corresponding to subsidence and eustasy) reflects the space available for sedimentation. This information is provided by the combination of structural/depth map and paleobathymetry maps, which leads to the computation of Subsidence/Accommodation maps.
- The Sediment Supply, which may correspond to an external input (with added in situ erosion of local highs with associated drainage basins), or to in situ marine carbonate production. The sediment supply can be tuned by defining clastic sources at the edge of the model, which reproduce the sediment and water fluxes evolution through time and space.
- The quantification of Sediment Transport, using macro-scale sediment transport laws (equation of diffusion). These diffusive equations enable the simulation of the sediment distribution based on its content (grain type and density) and local paleobathymetric variations over tens of kilometers.

Sedimentation and erosion were simulated at each point of the basin using mass balance principles, and then calibrated by tuning all of the environmental parameters (sources, subsidence map, transport/diffusion). Carefully considering the interplay between these three parameters, the main steps of the stratigraphic modelling analysis consisted of:

- Reproducing regionally the overall basin geometry evolution from Late Jurassic to Mid Tertiary. This implies (a) a calibration of regional sequence thickness with existing structural interpretation and sequence stratigraphic definition; (b) a reproduction of internal geometries observed on seismic profiles and (c) a reproduction of sand probability estimated during the seismic reservoir characterization.
- Reproducing lithological vertical succession observed at the six available well locations.
- Predicting and quantifying the sedimentological distribution inside described seismic geometries away from well calibration, and in unexplored areas.
- Extracting refined GDE and lithological 3D volume to the petroleum basin modelling Software (TemisFlow 3DM™) and play assessment.

The simulation time ranges from the base of Berriasian (145 Ma) to the top Oligocene (24 Ma). The time step used in the simulation is 0.1 Ma in the Tertiary (to be representative of main eustatic variations) and 0.5 Ma in the Cretaceous (lower seismic resolution). The final 3D cube model comprises 166 layers in the Cretaceous and 380 layers in the Tertiary. The five main seismic stratigraphic sequences (J145-K114-C65-C54-C45-C24) served as the key input for building the stratigraphic reference model.
FORWARD STRATIGRAPHIC SIMULATION: Calibration Results

The calibration phase consisted of a step-by-step setting of each time interval in-between the five selected time horizons. It calibrates both geometry/thicknesses for each one of the five intervals (seismic thicknesses), respecting shale/sand ratios recorded at the study wells.

- The thickness calibration was controlled by the difference between the input thickness and the simulated thickness after simulation. Errors were then calibrated by modifying the sediment supply and the source locations.

- Both markers and $V_{shale}$ logs were used for calibration of the stratigraphy and the shale lithology at six well locations. The model produced good thickness calibration of simulated markers between the wells and input markers. The main lithologies observed at wells were also respected in the simulated results.
FORWARD STRATIGRAPHIC SIMULATION : Seismic stratigraphy calibration

Seismic control of the general (thickness) and specific geobodies and stratal terminations (such as onlap, toplap and truncation geometries) were reproduced. A random line is displayed below.
FORWARD STRATIGRAPHIC SIMULATION : SRC Calibration

Five 2D lines and a 3D seismic volume were inverted and characterized to estimate sand probability; these results were used for the calibration of the forward stratigraphic model. Calibration was performed respecting main sand packages observed during the reservoir characterization. Note that the seismic reservoir characterization is optimized for the Upper Cretaceous/Tertiary interval.

Seismic Reservoir Characterization: sand probability

DionisosFlow™ lithological result: sand proportion

TemisFlow™ lithological result: lithological facies

Jurassic level not simulated in Dionisos

Note that the seismic reservoir characterization is optimized for the Upper Cretaceous/Tertiary interval.
FORWARD STRATIGRAPHIC SIMULATION : SRC Calibration

Once calibrated, DionisosFlow™ lithologies were upscaled in facies and implemented in the petroleum system model.
3D FORWARD STRATIGRAPHIC MODELLING: Facies Definition – Berriasian

The facies model inputs were set as a function of percentage of clastic lithologies (percentage of sand, shales and carbonate) and paleoenvironmental data (paleobathymetry and water flow energy on the slope). Eighteen individual facies were discriminated at relevant stratigraphic intervals based on main tectono-stratigraphic system tracks such as highstand and lowstand to capture large scale lithological variation spatially and vertically. From 145 Ma to 24 Ma, 24 gross depositional maps were created and integrated in the TemisFlow™ modelling as lithology properties (seven in the Cretaceous and 17 in the Tertiary).

For the Berriasian interval, 10 layers were simulated in the stratigraphic forward model. These layers were upscalled into one representative layer. The associated lithofacies properties were then used in petroleum system modelling to assess the basin/study area.

Lithofacies Map
1 Sample out of 10 Berriasian Layers

Environmental Parameters (water flow energy, wave energy, etc.)

Depositional Environment Setting (paleobathymetry information)

Lithofacies Discrimination
- Slope fan
- Offshore clean sands
- Silty turbidite
- Shaly turbidite
- Basinal silty shale
- Basin shale
- Organic-rich-environment
- Carbonate inner ramp
- Continental sandy
- Shaly alluvial plain
- Upper shoreface
- Lower shoreface
- Sandy channel mouth
- Delta front
- Sand turbidite channel

Sand
Shale
3D FORWARD STRATIGRAPHIC MODELLING: Facies Definition – Valanginian

Facies model inputs were set as a function of percentage of clastic lithologies (percentage of sand, shales and carbonate) and paleoenvironmental data (paleobathymetry and water flow energy on the slope). Eighteen individual facies were discriminated at relevant stratigraphic intervals based on main tectono-stratigraphic system tracks such as highstand and lowstand to capture large scale lithological variation spatially and vertically. From 145 Ma to 24 Ma, 24 gross depositional maps were created and integrated in the TemisFlow™ modelling as lithology properties (seven in the Cretaceous and 17 in the Tertiary).

For the Valanginian interval, eight layers were simulated in the stratigraphic forward model. These layers were upscaled into one representative layer. The associated lithofacies properties were then used in petroleum system modelling to assess the basin/study area.
3D FORWARD STRATIGRAPHIC MODELLING: Facies Definition – Senonian

Facies model inputs were set as a function of percentage of clastic lithologies (percentage of sand, shales and carbonate) and paleoenvironmental data (paleobathymetry and water flow energy on the slope). Eighteen individual facies were discriminated at relevant stratigraphic intervals based on main tectono-stratigraphic system tracks such as highstand and lowstand to capture large scale lithological variation spatially and vertically. From 145 Ma to 24 Ma, 24 gross depositional maps were created and integrated in the TemisFlow™ modelling as lithology properties (seven in the Cretaceous and 17 in the Tertiary).

For the Senonian interval, 70 layers were simulated in the stratigraphic forward model. These layers were upscaled into one representative layer. The associated lithofacies properties were then used in petroleum system modelling to assess the basin/study area.
3D FORWARD STRATIGRAPHIC MODELLING: Facies Definition – Early Paleocene

Facies model inputs were set as a function of percentage of clastic lithologies (percentage of sand, shales and carbonate) and paleoenvironmental data (paleobathymetry and water flow energy on the slope). Eighteen individual facies were discriminated at relevant stratigraphic intervals based on main tectono-stratigraphic system tracks such as highstand and lowstand to capture large scale lithological variation spatially and vertically. From 145 Ma to 24 Ma, 24 gross depositional maps were created and integrated in the TemisFlow™ modelling as lithology properties (seven in the Cretaceous and 17 in the Tertiary).

For the Early Paleocene interval, four layers were simulated in the stratigraphic forward model. These layers were upscaled into one representative layer. The associated lithofacies properties were then used in petroleum system modelling to assess the basin/study area.

Lithofacies Discrimination

- Slope fan
- Offshore clean sands
- Silty turbidite
- Shaly turbidite
- Basinal silty shale
- Basin shale
- Organic-rich-environment
- Carbonate inner ramp
- Continental sandy
- Shaly alluvial plain
- Upper shoreface
- Lower shoreface
- Sandy channel mouth
- Delta front
- Sand turbidite channel

Lithofacies Map

1 Sample out of 4 Early Paleocene
3D FORWARD STRATIGRAPHIC MODELLING: Facies Definition – Early Eocene

Facies model inputs were set as a function of percentage of clastic lithologies (percentage of sand, shales and carbonates) and paleoenvironmental data (paleobathymetry and water flow energy on the slope). Eighteen individual facies were discriminated at relevant stratigraphic intervals based on main tectono-stratigraphic system tracks such as highstand and lowstand to capture large scale lithological variation spatially and vertically. From 145 Ma to 24 Ma, 24 gross depositional maps were created and integrated in the TemisFlow™ modelling as lithology properties (seven in the Cretaceous and 17 in the Tertiary).

For the Early Eocene interval, 18 layers were simulated in the stratigraphic forward model. These layers were upscaled into one representative layer. The associated lithofacies properties were then used in petroleum system modelling to assess the basin/study area.
3D FORWARD STRATIGRAPHIC MODELLING: Facies Definition – Mid/Late Eocene

Facies model inputs were set as a function of percentage of clastic lithologies (percentage of sand, shales and carbonate) and paleoenvironmental data (paleobathymetry and water flow energy on the slope). Eighteen individual facies were discriminated at relevant stratigraphic intervals based on main tectono-stratigraphic system tracks such as highstand and lowstand to capture large scale lithological variation spatially and vertically. From 145 Ma to 24 Ma, 24 gross depositional maps were created and integrated in the TemisFlow™ modelling as lithology properties (seven in the Cretaceous and 17 in the Tertiary).

For the Mid/Upper Eocene interval, 41 layers were simulated in the stratigraphic forward model. These layers were upscaled into one representative layer. The associated lithofacies properties were then used in petroleum system modelling to assess the basin/study area.

Lithofacies Discrimination

Sand

Shale
FROM SEDIMENTOLOGY / STRATIGRAPHY TO MODELLING

Initial Seismic and Stratigraphic Interpretation
(Seismic interpretation & GDE mapping)

3D Forward Stratigraphic Model
(sand proportion over 546 layers; 2x2 km grid)

3D Forward Stratigraphic Model Facies Distribution

3D Petroleum System Model
(24 upscaled facies layers in 0.5x0.5 km grid)
PETROLEUM SYSTEM MODELLING

The basin and petroleum system modelling used the present day information (geometry, facies and source rock properties) and the conceptual basin evolution (sequence stratigraphic analysis, and mainly paleo-environment and basin tectonic evolution) to reproduce the physical, thermal and chemical processes that occurred during its deposition. The hydrocarbon generation, expulsion, migration and entrapment, from the source rock until the reservoirs were simulated, taking into account both the paleo-geometry, the thermal state, fluid flow and the rock petrophysical properties.

1D modelling: A first understanding of the geothermal context and pressure field was rapidly assessed by a series of 1D models at key well locations, helping to evaluate oil and gas generation timing in the various Jurassic source rock candidates.

3D Model construction: The 3D static petroleum system model was built using TemisFlow™ with the structural depth maps used to create the present day model geometry with additional subdivisions from DionisosFlow™. The 3D stratigraphic cube with lithological and source rock distribution maps was populated using gross lithofacies maps extracted from the DionisosFlow™ results.

2D Basin Modelling Calibration: Two 2D sections were extracted from the 3D framework to perform the calibration of the thermal and pressure regimes. The sections were chosen for their representativeness of the petroleum system (passing through the source rock kitchen) and to include key wells with relevant data for calibration. The model boundary conditions through time were defined. This enabled the thermal calibration of the model for both history and present day temperature. The model properties, especially the fine tuning of facies distribution and permeability parameters, were taken into account for pressure calibration.

3D Hydrocarbon migration calibration: The hydrocarbon generation and migration simulation was performed using Full Darcy Compositional Migration in TemisFlow™ and taking into account the results of 2D modelling. Source rock intervals were selected in agreement with Carbolog® results and regional understanding. Their type and richness were also defined in the model. The known oil and gas accumulations and their properties were used to calibrate the model and understand its limitations.

The hydrocarbon generation through kerogen cracking was simulated using the Arrhenius Law. Each hydrocarbon component was defined in a kinetic scheme which is dependent on the basin temperature history:

- The Transformation Ratio property is the ratio of generated HC to initial potential. The transformation ratio is calculated only in the kerogen bearing cells, according to the kinetic reaction of petroleum formation. It is not dependent on the source rock potential, and can be used to evaluate the level of maturity of the source rock.

- The hydrocarbon saturation of the source rock during its generation engenders an intense increase of the source rock capillary pressure, and consequently, the expulsion of hydrocarbons.

The evaluation of charge within main plays was calculated by taking into account the physical processes governing the migration of hydrocarbon fluids. That is why full 3D Darcy migration simulation was performed. The Darcy Law correctly models macroscopically the velocity of migration of hydrocarbon fluids with respect to buoyancy, hydro-dynamism and capillarity. It also takes into account the effect of pressure, temperature, and the composition, viscosity, and density of each hydrocarbon phase. For instance, expulsion is facilitated when hydrocarbons are lighter, and if the hydrocarbon pressure is higher.
PRESSURE MODELLING

The top section is simulated on 2D modeling and covers a wider area than the bottom three sections that are extracted from the 3D TemisFlow™ model. Results are displayed here on 3D only.

The main regional pressure boundaries lie within the Jurassic, Cretaceous, and the Paleogene in relation with regional shale units that appear to be relatively continuous at basin scale. These regional shale units also correspond to the main organic-rich layers.

The most important pressure jump occurs below the Kimmeridgian source rock. The presence of overpressure below the Kimmeridgian source rock level is a regional feature. This level acts as a regional seal. Each graben (or half graben) has a specific overpressure regime. Overpressure distribution is also linked to rapid Tertiary sedimentary burial.
In the deepest part of the depocenters the temperature reaches 230°C. The maximum simulated temperature is 230°C for the Kimmeridgian source rock interval, 215°C for the Tithonian source rock, and 168°C for the Cretaceous source rock interval.

The overall reservoir temperatures are above 80°C at present day. Early migrated oil may have been biodegraded as reservoir temperature could be below 80°C (Pasteurization temperature) at the time of filling. In the western part of the section, reservoir temperature reaches levels allowing secondary cracking of oil into gas.

The present-day source rock maturity field shows the Kimmeridgian source rock is highly mature (wet and dry gas window) to overmature over the entire section.

The Tithonian source rock maturity ranges from immature to early oil generation where the sedimentary burial is limited to overmature in the deepest depocenters.

The Cretaceous source rock is mainly in the oil window but can reach the condensate window where its burial is maximum.
VERTICAL MIGRATION PATHWAYS IN ORPHAN BASIN

Context

The study area is globally dominated by shale deposition with numerous isolated sand bodies. The vertical HC migration from deep source rocks (Jurassic, Lower Cretaceous) toward Tertiary reservoirs has to overcome the shaly barriers. Seismic evidence support the presence of numerous vertical drains (chimneys) located at the apex of main Jurassic rift structures. These features represent migration pathways up to shallow levels in the Tertiary.

Pressure/Geostatic Stress maps generated during the basin burial using the TemisFlow™ model help to illustrate where the seal resistance is minimal and mechanical failure can occur.

Solutions

When the Pressure/Stress ratio reaches 0.9, the geostatic stress is close to the pore pressure, and natural hydraulic fracturing can occur. Major seismic faults are aligned along these “weakness zones” corresponding to fracture conditions and form vertical drainage corridors from Cretaceous to Paleocene, along the inherited rift structures. Some “weakness zones” are neither persistent through time nor linked with the Jurassic rifting structures.

The recognition of these vertical drains in 3D using the Geomodel grid proposes HC migration pathways in the model.
HYDROCARBON MIGRATION

Below is an example within the Orphan Basin Resource Assessment AOI showing fluids migrating from Mesozoic sediments in present day time.

The escape feature displays the migration of fluids through the Lower Tertiary into the Eocene fan (Cape Freels prospect).
In the deeply buried depocenters, the kerogen Transformation Ratio of Jurassic source rocks can be as high as 95% for the Kimmeridgian and 100% for the Tithonian, depending on their reactivity.

Cretaceous kerogen transformation can reach 87% in the deepest basins. Paleocene kerogen transformation never exceeds 30% along this section.

Expelled masses are sensitive to the thickness and richness of the source rocks (i.e. their potential depending on effective thickness in the model, porosity, bulk density, initial TOC, and initial Hydrogen Index), and the transformation ratio. The Tithonian source rock has expelled large amounts of hydrocarbons (between 2.5 and 3 t/m²).

Cretaceous source rock displays important lateral variations based on DionisosFlow model results, and can reach up to 5 t/m². Other source rocks are minor contributors to the system.

The HC quality was computed from the HC composition in oil (C₆⁺) and gas (C₁⁻C₅). Oil is predicted over most of the studied area. Gas and condensate are to be found in the local depocenters.
The source rock maturity was computed for each layer of the 3D reference model through geological time. The source rock maturity (in equivalent Ro) is presented for the Kimmeridgian source rock interval:

The source rock entered the oil window during the Lower Cretaceous. In the area with limited burial to the northeast, the maturation was stopped after the Cretaceous. Elsewhere, the maturity rapidly evolved to the wet gas window during the Lower Cretaceous to Early Neogene. The Kimmeridgian is mature in the NL16-CFB01 area.
The source rock maturity was computed for each layer of the 3D reference model through geological time. The source rock maturity (in equivalent Ro) is presented for the Tithonian source rock interval:

In the deepest depocenters, the source rock entered the oil window during the Lower Cretaceous. In the areas with limited burial, 0.7% of vitrinite equivalent is reached during the Early Paleogene. The maturity further evolved to the wet gas window during the Late Paleogene to Early Neogene. The Tithonian is mature in the western half and in restricted depocenter in the eastern part of the NL16-CFB01 area.
The source rock maturity was computed for each layer of the 3D reference model through geological time. The source rock maturity (in equivalent Ro) is presented for the base of the Cretaceous source rock interval:

This source rock entered the oil window only in the western and southern part of the 3D model during the Early Eocene. The maturity further evolved to the wet gas window during the Late Paleogene to Early Neogene. The dry gas window is reached in the deepest depocenters. The Cretaceous is mature in the western part of the NL16-CFB01 area.
The source rock maturity was computed for each layer of the 3D reference model through geological time. The source rock maturity (in equivalent Ro) is presented for the base of the Paleocene interval:

This source rock entered the oil window only in the western and southern part of the 3D model during the Late Paleogene. The maturity further evolved to the wet gas zone in the deepest areas. It remains in the oil window in the western part of the NL16-CFB01 area.
The timing of hydrocarbon migration is variable in the basin depending on burial and source rock richness. The timing of expulsion allows different scenarios for the oil and gas migration and entrapment to be expected throughout the basin. In some depocenters, the expulsion is almost completed before the end of the Cretaceous while in other areas the expulsion takes place mainly during the Tertiary up to the present day.

The Kimmeridgian source rock expulsion is shown at three different locations in the graphs.
The unrisked volume of hydrocarbons corresponds to the amount of oil (in Bbbl), gas (Tcf) and oil+gas (in BOE) that can be present in the plays (expressed as high, most likely, and low cases) according to one base case geological scenario. Uncertain variables such as TOC, seal retention capabilities, and oil and gas saturation cutoffs have been accounted for. The base case scenario also honours the observations on pressure, temperature, and oil accumulations within the resolution of the geological model and within the uncertainties on measurements/observations. The impact of the uncertain variables is evaluated through sensitivity analysis.

The unrisked volumes are presented as high, most likely and low cases over 10 TemisFlow™ scenarios (all calibrating the thermal and pressure models and direct hydrocarbon indication) for each of the four main plays.

The volumes described here are aggregate, summed volumes for the nine blocks and do not include additional volumes outside of the blocks but within the study area.

### UNRISKED VOLUMES FOR NL16-CFB01

(Volumes contained in the 9 parcels)

<table>
<thead>
<tr>
<th></th>
<th>Upper Jurassic</th>
<th>Lower Cretaceous</th>
<th>Upper Cretaceous</th>
<th>Paleocene</th>
<th>Eocene</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Oil (Bbbl)</strong></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>P90 Low case</td>
<td>0.8</td>
<td>1.1</td>
<td>2.6</td>
<td>1.2</td>
<td>5.1</td>
</tr>
<tr>
<td>P50 Most likely</td>
<td>3</td>
<td>1.6</td>
<td>3.9</td>
<td>2.7</td>
<td>14.3</td>
</tr>
<tr>
<td>P10 High case</td>
<td>5.3</td>
<td>2.6</td>
<td>6.7</td>
<td>4.2</td>
<td>20.6</td>
</tr>
</tbody>
</table>

### Gas (Tcf)

<table>
<thead>
<tr>
<th></th>
<th>Upper Jurassic</th>
<th>Lower Cretaceous</th>
<th>Upper Cretaceous</th>
<th>Paleocene</th>
<th>Eocene</th>
</tr>
</thead>
<tbody>
<tr>
<td>P90 Low case</td>
<td>0.2</td>
<td>0.8</td>
<td>2</td>
<td>4.4</td>
<td>5</td>
</tr>
<tr>
<td>P50 Most likely</td>
<td>0.9</td>
<td>1.2</td>
<td>2.9</td>
<td>5.4</td>
<td>10.2</td>
</tr>
<tr>
<td>P10 High case</td>
<td>1.5</td>
<td>2.2</td>
<td>6.4</td>
<td>7.1</td>
<td>16.4</td>
</tr>
</tbody>
</table>

### Total Oil & Gas (BOE)

<table>
<thead>
<tr>
<th></th>
<th>Total Oil (Bbbl)</th>
<th>Total Gas (Tcf)</th>
<th>Total Oil &amp; Gas (BOE)</th>
</tr>
</thead>
<tbody>
<tr>
<td>P90 Low case</td>
<td>10.8</td>
<td>12.4</td>
<td>12.9</td>
</tr>
<tr>
<td>P50 Most likely</td>
<td>25.5</td>
<td>20.6</td>
<td>29.1</td>
</tr>
<tr>
<td>P10 High case</td>
<td>39.4</td>
<td>33.6</td>
<td>45.2</td>
</tr>
</tbody>
</table>
The uncertainty on HC volumes is given by the distribution of volumes in place. This uncertainty varies from 12.9 BOE to 45 BOE in place in the AOI. The POS (Probability of Geological Success) of the AOI is estimated to 16%. A graph combining the distribution of un-risked volume in place and POS reflects the risk/reward status of the AOI.

### PROBABILITY OF GEOLOGICAL SUCCESS FOR NL16-CFB01
(Volumes contained in the 9 parcels)

![Graph showing the probability of geological success and un-risked volume distribution.]

### UNRISKED VOLUMES FOR NL16-CFB01
(Volumes contained in the 9 parcels)

<table>
<thead>
<tr>
<th></th>
<th>Total Oil (Bbbl)</th>
<th>Total Gas (Tcf)</th>
<th>Total Oil &amp; Gas (BOE)</th>
</tr>
</thead>
<tbody>
<tr>
<td>P90 Low case</td>
<td>10.8</td>
<td>12.4</td>
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<tr>
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<tr>
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<td>39.4</td>
<td>33.6</td>
<td>45.2</td>
</tr>
</tbody>
</table>
RISK ANALYSIS

Probability of Success POS = Pc x Ps x Pr x Pt
The RRGM has a certain probability of being accurate. This global probability is usually separated into four main independent terms, which are partly addressed during the sensitivity analysis:

- Pc = HC charge probability
- Ps = Seal Presence and efficiency
- Pr = Reservoir presence and quality
- Pt = Trap existence (in the case of regional 2D seismic grid and interpretation)

RISK EVALUATION AND POS

The risk analysis defines semi-quantitative thresholds on the POS of the petroleum system components applicable over the studied area.

The HC charge thresholds are defined by average amount of charge HC/kg/m² (e.g., > 500 kg/m³) in the play or play sector (accumulated over the source rock vertical thickness).

The reservoir risk was defined by threshold on estimated net thickness and individual sand layer thickness (Total > 100 m, 1 individual sand layer > 5 m).

The seal risk was defined by threshold on the seal thickness and continuity (faulted and < 10m, unfaul ted and > 50m).

The trap risk was defined by trap volume threshold and fill spill analysis (number of traps with porous volumes > 10, 50, or 100 million m³ resulting from the spill analysis). In the fill-spill analysis, the excess charge of individual traps filled up to spill point may charge a trap updip. In this case, the individual traps may be merged into a single larger trap.

Risk maps of the individual petroleum system components are known as Common Risk Segment (CRS) maps.

The global exploration risk for the play is defined as Composite Common Risk Segment map (CCRS) and is obtained by superimposing the individual CRS maps.

CCRS multiply maps may also be built to evaluate the global exploration risk.

RISK SCALE

- High risk that the petroleum system component is not efficient (or low probability that it is efficient)
- Medium risk
- Low risk

Risks volumes are the product of:

\[ Ps \times Pc \times Pr \times Pt \times \text{UNRISKED volumes at a given probability (e.g., P50)} \]

In this approach, the risked volumes are usually lower than the Prospective Oil Initially In Place (OIIP) and Gas Initially In Place (GIIP) resources, and will not correspond to actual volumes to be expected during the exploration of the traps and leads. The risked volumes are used to rank the blocks or sectors between themselves. The plays can also be ranked by adding all risked volumes.
PETROLEUM SYSTEM ELEMENTS RISKING

Common Risk Segment (CRS) mapping was performed based on the reservoir and seal elements and it considered their presence and efficiencies. Using the full resolution forward modelling stratigraphic 3D grid (one play example presented here) CRS maps took into account elements such as net sands and net shale and the thickness of vertically continuous beds. For example low risk reservoir areas are characterized by net sand thicker than 100m with at least one vertically continuous bed > 20m. A good seal is characterized by at least 20m of continuous shales. The risks are classified as low, medium or high.

The HC charge risk map was derived from the computed HC charge within a given play through petroleum system modelling. (HC volumes present in traps - structural and/or stratigraphic).

The HC charge risk has been evaluated in the Beicip-Franlab Internal Nalcor/DNR report and is not shown here.

For each play, HC Composite Common Risk Segment (CCRS) maps were obtained by combining the HC charge (expulsion and migration) with the geological CRS maps. These CCRS maps express the relative exploration risk throughout the acreage for a given play (Beicip-Franlab Internal Nalcor/DNR report).
CONCLUSION PETROLEUM SYSTEM CHART

A synthetic petroleum chart illustrating the petroleum components and timing of generation, expulsion, migration and entrapment of hydrocarbon is proposed:

- The main and proven source rocks (Kimmeridgian and Tithonian) are generating oil during the lowermost Cretaceous and are starting to expel oil a few million years later. The Cretaceous (Cenomanian) source rock is generating during Late Eocene and expulsion is still ongoing. The Paleocene source rock is sufficiently mature.

Since the basin evolution was well advanced, the Tithonian and lowermost Cretaceous sands were already deposited. The timing of maturation and expulsion is compatible with oil and gas entrapment in these main plays.

The Tithonian appears to yield the highest oil and gas volumes in place due to an efficient vertical migration from the source and significant lateral migration within the Tithonian interval.
REFERENCES:


http://archives.datapages.com/data/sepm_sp/SP42/Eustatic_Controls_on_Clastic_Deposition_I.htm

http://archives.datapages.com/data/sepm_sp/SP42/Eustatic_Controls_on_Clastic_Deposition_II.htm
