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JEANNE D'ARC BASIN (OFFSHORE EASTERN CANADA) 3D PETROLEUM SYSTEMS MODELING

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Summary

The Jeanne d'Arc (failed-rift) Basin on the northern Grand Banks, offshore (Newfoundland) eastern Atlantic Canada (Figure 1) encompasses an area in excess of 10,000 km^2 with Mesozoic and Cenozoic overburden up to ~22 km. A proven hydrocarbon province with four producing fields (Hibernia, Terra Nova, White Rose, Hebron) and additional extension projects planned or ongoing. According to NALCOR (2020), independent research assessments identified gross potential of 52.2 Bbl (Oil) and 199 Tscf (Gas) in the basin. Hence, compared to currently producing projects, the basin has a huge potential which has led to it attracting attention from the global oil industry.

This study uses Zetaware's software suite (Genesis, KinEx & Trinity) to develop a map-based hydrocarbon system model calibrated with wells, fluids & thermal properties data, towards stepping up the regional understanding of hydrocarbon prospectivity.

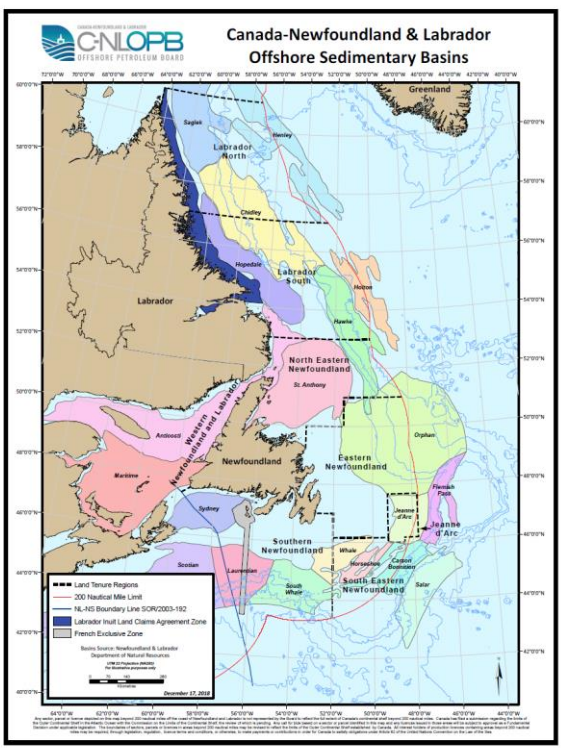

Figure 1: Canada Atlantic Offshore Sedimentary Basins (Source: C-NLOPB)

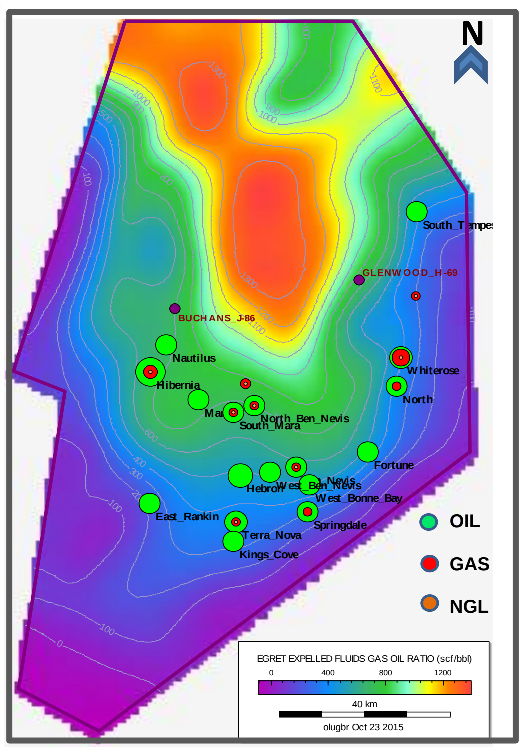

Figure 2: Source rock expelled fluids map (this study) overlain by discovered volumes reported

Methods

Burial and thermal geohistory model of eleven wells; *Terra Nova K-18*, *Port au Port J-97*, *Beothuk M-05*, *Hibernia K-18*, *South Tempest G-88*, *Nautilus C-92*, *Egret K-36*, *Bonanza M-71*, *Adolphus D-50*, *Fortune G-57* & *Flying Foam I-13* were developed as the main framework input into 3D model. The active mature source rock (Kimmeridgian 156 Ma: *Egret Member*) and reservoir formations: *Catalina, Hibernia, Jeanne D'Arc* (Tithonian-Valanginian) & *Ben Nevis* (Aptian-Albian) tops and thickness maps have been integrated to build a 3D petroleum system model with intraformational mudstones as seals.

Reported well intersections of source and reservoir rocks (partial or complete) provided constraints for tops and bases. Other non-direct top depths were obtained from wells correlation and seismic mapping. Source rock typing was accomplished through biomarker oil-source correlation (Pr/Ph, diasterane/sterane) and (pseudo) van Krevelen methods and parameters.

Specifically, inputs and assumptions that are used for the model include; HI, OI, PI, S1, S2, Tmax, TOC (*Rock-Eval*©), temperature gradient, VRo, porosity, paleowater depth, stratigraphy, (average) migration loss of 2 mmboe/km^2 and trap critical point at ~ 60 Ma.

Source rock expulsion to discovered hydrocarbon volumes' "mass balance" overlay (Figure 2) shows a good correlation. The effects of structuration (especially the trans-basin structural fault), updip migration patterns and leakages are not accounted for in the model, which would have resulted in better model to basin fit.

Observations & Conclusions

- Biomarker ratios and organic matter typing suggest source rock depositional palaeoenvironment mainly marine anoxic (Type II OM) in the south-western/central segment and with secondary contribution of terrestrial Type III OM (oxic) towards the eastern/northern structural ridges
- Good source rock quality with average (P50) basin thickness of 104 meters
- Higher GOR prevails in the northern deep basin while proximal south is mostly in the oil prospective window with lower GOR
- Secondary migration and in-reservoir oil to gas cracking has a role as captured by expelled fluids GOR vs. present day thermal maturation
- Indications of above normal geopressure (?) towards the northwest axis
- Organic thermal time slices (0-100 Ma) show a basin-ward increase in maturation
- As more wells are drilled, synergy and technical cooperation between operators in the basin should help in closing the hydrocarbon prospectivity knowledge gaps, especially in the underexplored deep basin where salt plugs might have a major role in structural, thermal and fluid migration patterns

Novel Information

This study integrated geological, geochemical and geophysical data which resulted in an increased understanding of gross rock-thermal-fluid dynamics through basin history. The regional extent of this petroleum system model is noteworthy, as regional inquests into the petroleum systems of Jeanne D'Arc basin have been few and mostly proprietary. Biomarkers have further added credence to the interpretation of source rock quality distribution in the basin while basin organic thermal time slices will help steer and focus exploration efforts. Forward prediction of charge potential, maturation, temperature and pressure is also an accomplishment.

Acknowledgements

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