

## Petroleum from Source Rock to Reservoir; Using two offshore eastern Canada basins as examples

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### Summary

This presentation reviews the factors influencing the type of petroleum in the reservoir, whether gas, oil or heavy oil, using two offshore eastern Canada basins as examples. The factors include source rock depositional environment and the source of the organic matter in the source rock, temperature of hydrocarbon generation, fractionation during migration, reservoir cracking, biodegradation, and the possibility of multiple charges. It highlights the need for petroleum systems analysis for understanding risk during exploration and development of oil and gas resources.

### Introduction

The objective of this presentation is to show how an understanding of source rock geochemistry can contribute to predicting petroleum types, as well covering other factors that can help in understanding the properties of the petroleum found in reservoirs within a basin. Two offshore eastern Canada basins are discussed. Despite having a similar age source rock, the predominant type of petroleum found in the Jeanne d'Arc Basin offshore Newfoundland (oil) is different from that found in the Sable Basin on the Scotian Shelf, offshore Nova Scotia (gas). Based on estimates of oil and gas in place (C-NLOPB, 2016; Smith et al 2014), it is 75:25 ratio of oil to gas for the Jeanne d'Arc and 28:72 for the Scotian Shelf. These differences are mostly related to the different depositional environments of the principal source rocks in these basins.

### Observations

The Kimmeridgian-aged Egret member is the main source rock in the Jeanne d'Arc Basin. It was deposited in a silled marine basin with organic matter mostly derived from marine plankton with a bacterial overprint and minimal terrestrial contribution in most of the basin (Fowler and McAlpine, 1995). The main source rock for the Scotian Shelf, is the Tithonian age interval corresponding to the lower part of the Verrill Canyon Formation which was deposited in a deltaic environment with a major contribution from terrestrial organic matter (Nova Scotia Department of Energy 2011; Fowler et al., 2016). Using the organofacies classification of Pepper and Corvi (1995), the Egret Member would be classified as an organofacies B source rock and expected to generate and expel mostly oil. The Tithonian source rock on the Scotian Shelf would be classified as organofacies DE and expected to generate and expel gas and oil. When completely mature (at 200°C), about three quarters of the kerogen mass of a 'typical' Class B source rock was modelled by Pepper and Corvi (1995) to be converted to oil and about 25% to gas, roughly in line with the relative amount of resources estimated for the Jeanne d'Arc. For a 'typical' DE source rock, similar modelling suggested roughly 40% of the kerogen mass to be converted to expelled oil, a larger proportion than suggested by the Scotian Shelf reserves. However, the amount of oil expelled by a DE source rock is highly dependent on the original HI value of the source rock. Pepper and Corvi (1995) used an initial Hydrogen Index (HI) of 333 mg HC/ g TOC for their typical DE kerogen which is significantly higher than the probable initial HI for Scotian Shelf Tithonian source rock. It is difficult to estimate the average initial HI for this source rock because of maturity and drilling

contamination but it was likely in the 200-250 mg HC/g TOC range and hence expected to generate a greater proportion of gas relative to oil than for the 'typical' DE case. Biomarkers are generally in low concentrations in Scotian Shelf oils but where they have been detected they support a predominantly terrestrial contribution to the source rock; e.g. high pristane/phytane, C29 steranes >> C27 steranes and rearranged steranes >> regular steranes (Fowler et al., 2016), and hence support a lower original HI value for the Tithonian source rock than Pepper and Corvi's typical organofacies DE example.

It has been suggested that there is a contribution from an oil-prone source rock to petroleum in the Sable Basin that is possibly of Lower Jurassic age (e.g. Nova Scotia Energy Department 2011; Forkner et al., 2018). It is implied that the presence of mostly gas could partly be a function of oil to gas cracking of hydrocarbons generated from this interval, thus making a contribution from this source rock hard to detect from the gas and light oil generated from the Tithonian source rock. However, higher temperatures are needed to crack oil to gas compared to the generation of gas from a source rock. This is because of the greater proportion of saturated compounds in the reservoir petroleum and there being less catalysts in the reservoir to promote cracking. Hence oil can survive in reservoirs at greater than 200°C suggesting the possibility that some Lower Jurassic oil might still have been expected to have been found as long as it was expelled and able to migrate to shallower reservoirs. However, if this was not possible, then with temperatures as high as 300°C modelled to have been reached in Lower Jurassic strata within the Sable Basin, oil remaining reservoired in this stratigraphic interval would have been cracked (Nova Scotia Energy Department, 2011).

High amounts of diamondoids have been proposed to be the result of oil to gas cracking. Diamondoids are thermally stable C10-C18 compounds with carbon-carbon bonds arranged in a diamond shape. They increase in concentration in oils with increasing maturation due to their greater stability than other compounds. It has suggested that higher than normal concentrations of diamondoids in (Sassen and Post, 2008) or minor differences in the distribution of extended diamondoids (Forkner et al., 2018) in Deep Panuke reservoirs could reflect a contribution to this oil from a deeper source rock but evidence is far from conclusive. More recent data suggests that the concentration of diamondoids in Deep Panuke is not anomalous. There is a rough correlation between GOR and the concentration of diamondoids in Scotian Shelf oils/condensates which might be expected if their abundance is related to the cracking of oil to gas. This could just be related to hydrocarbons derived from the Tithonian source rock rather than a deeper source rock. It would provide another reason for the abundance of gas in this basin.

If an older oil prone SR was present on the Sable Basin, some oil that could clearly be shown to be derived from it might be expected from it provided that it was expelled and was able to migrate into younger reservoirs. This may be the case for the oil staining found at the Mic-Mac, Erie and Wyandot wells that are situated about 100 km northeast of Sable Island. These stains have very different geochemical characteristics to other Scotian Shelf oils suggesting that their source rock(s) was a marine marly source rock that was deposited under more restricted conditions than the Tithonian source rock responsible for the Sable Basin hydrocarbons.

Other factors that complicate predicting the nature of hydrocarbons in reservoirs in both the Jeanne d'Arc and Sable basins is multiple hydrocarbon charging of reservoirs and biodegradation. In the Jeanne d'Arc Basin, several fields show evidence of multiple charges, and in some the

initial oil charge was biodegraded before a later second charge that was also then biodegraded such as at Mara M-54 (Peters and Fowler, 2002). Generally, both these charges are from the Egret Member but in some cases, such as at Ben Nevis, there is a contribution of hydrocarbons from a second deeper source rock. It is more difficult to detect multiple charges to Scotian Basin reservoirs because of the type of hydrocarbons and with there being very little gas data is available for this area, despite this being the bulk of the resource. Biodegradation has occurred or is currently taking place in some shallow reservoirs (<2000 m) in the Sable Island area. The API gravities of the biodegraded oils are still relatively high (e.g. 30-40° API) because the original petroleum was so light (50-60° API). The hydrocarbon stains in the Mic Mac/Eric wells show evidence of extensive biodegradation, such as the presence of 25-norhopanes. The presence of n-alkanes in these oils indicates that they have received more than one hydrocarbon pulse, with later hydrocarbons not degraded.

Multiple oil charge can often be understood by basin modelling and determining if the source rock reached sufficient depth on multiple occasions to generate hydrocarbons. The depth of the source rock for the second generation of petroleum, must by necessity be deeper than the original burial maximum depth as bonds within the kerogen with lower activation energies would have already been broken to generate the first pulse of hydrocarbons. Similarly, biodegradation can also be predicted by modelling the temperature of the reservoir when it was expected to have been charged. Microbial alteration of petroleum only occurs in shallow reservoirs at relatively low temperatures (<60-80C).

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