2.3 Type of Oil Likely to be Found at Old Harry (Attachment F)

Ten offshore wells have been drilled to date in the Gulf, an area encompassing approximately 140,000 km^2. Half of those wells encountered non-commercial quantities of natural gas and, with respect to oil, none encountered anything more than oil staining. For reasonable and appropriate oil spill modelling, an oil sample is required to determine the necessary oil properties (e.g., density, viscosity, pour point). Since an oil sample is not available from the Old Harry structure to determine its properties, identification of a suitable surrogate oil is required.

The issue of identifying a suitable surrogate oil was remedied by applying a sequential scientific approach. First, Corridor undertook geochemical studies to identify the types and relative abundance of organic material that is preserved in the shale source rocks in the vicinity of Old Harry. This was followed by petroleum systems modelling to simulate the burial, maturation and generation of hydrocarbons from the organic material, followed by migration and trapping of hydrocarbons at Old Harry. Finally, the geological characteristics of the Old Harry area were compared to other areas with similar geological characteristics to identify a suitable surrogate for the hydrocarbons potentially trapped at Old Harry.

2.3.1 Geochemical Studies of Old Harry Source Rocks

Corridor hired an independent world-renowned organic geochemistry consultant (Dr. Prasanta Mukhopadhyay of Global Geoenergy Research) to complete geochemical studies of rock samples from the source rocks in the Brion Island No. 1 well, which is the closest well to the Old Harry prospect; located approximately 70 km to the west. The geochemical studies included measurements of total organic carbon (TOC), hydrogen index (HI) values (from Rock-Eval pyrolysis) and thermal maturity (vitrinite reflectance and thermal alteration index values). In addition, a scanning organic facies assessment (manual examination and classification of organic material using a high-powered microscope) was completed to determine the type of organic material in the source rocks. The results of geochemical analyses for 16 rock samples from the Brion Island well are provided in Table 2.2.

The first two columns in Table 2.2 indicate the depth of the rock sample studied in either feet (column 1) or metres (column 2). Column 3 shows the thermal maturation data with values that range between 0.6 to 1.0 percent R_o and show an advanced stage of thermal maturation. These sediments fall within the present day main phase of oil (oil window) to early condensate generation (gas window; see column 11). Columns 4 and 5 show the main geochemical results of the TOC, the HI and the production index. The interpretation of the present day TOC (ranges from 0.34 to 1.60; column 4) and HI values (ranges from 7 to 123 mg HC/g TOC; column 4) would typically indicate a moderately organic-rich gas-prone Type III kerogen that is likely to generate only natural gas. However, a more in-depth investigation into the type of organic facies deposited in the rocks reveals a more oil-prone organic material.

Table 2.2 Reconstruction of Original Total Organic Carbon and Hydrogen Index Based on Organic Facies, Present Total Organic Carbon/Rock-Eval and Production Indices of the Brion Island #1 Well

Depth (ft)	Depth (m)	% Ro (Mean)	Present TOC/HI	Prod. Index	Scanning Organic Facies Assessment (approximate percentages; qualitative determination)	SR condition	Original TOC/HI	Kerogen Type	Maturity	HC Zones
4080	1252	0.58	0.34/18	0.5	mixtures of 50% spore, suberin, algae; 50% vitrinite+inertinite	depleted	1.0/225	II-III	mature	oil
4410	1353	0.64	0.36/33	0.33	mixtures of 30% spore, suberin, algae; 70% vitrinite+inertinite	depleted	0.8/150	II-III	mature	oil
4990	1531	0.71	1.09/91	0.12	mixtures of mainly 40% suberin+spore; 65% vitrinite+inertinite	depleted	2.0/200	II-III	mature	oil
5060	1552	0.75	1.6/123	0.06	mixtures of 50% cuticles and algae; 50% vitrinite+inertite	depleted	2.5/250-300	II-III	mature	oil
5500	1687	0.8	1.51/64	0.11	mixtures of 60% AOM 2+spore+resin+algae; 40% vitrinite+inertinite	depleted	3.0/250-300	II-III	mature	oil
5690	1746	0.86	1.03/67	0.14	50% exinite; 10% algae; 10% AOM 2; 30% vitrinite +inertinite	depleted	2.5/250	II-III	mature	oil
5770	1770	0.86	0.73/45	0.15	20% exinite; 5% algae; 5% AOM 2; 70% vitrinite +inertinite	depleted	2.0/150-200	II-III or III	mature	oil
5930	1819	0.84	1.54/68	0.1	70% exinite; 5% algae; 5% AOM 2; and 20% vitrinite+inertinite	depleted	2.5/250-300	II-III	mature	oil
6760	2074	0.92	0.95/73	0.12	60% exinite; 5% algae; 5% AOM 2; and 30% vitrinite+inertinite	depleted	2.5/250	II-III	mature	oil
7030	2156	0.93	1.16/42	0.08	40% exinite; 5% algae; 5% AOM 2; 40% vitrinite +inertinite; 10% bitm.	depleted	2/150-200	II-III	mature	oil
7300	2240	0.9	0.58/19	0.21	30% exinite; 25% AOM 2; 20% vitrinite +inertinite; 10% bitumen	exhausted	2/200-250	II-III	mature	oil
7410	2273	0.94	0.96/53	0.12	50% exinite; 10% algae+AOM 2; 30% vitrinite +inertinite; 10% bitumen	exhausted	2/200	II-III	mature	oil
8370	2568	0.94	0.60/13	0.27	30% exinite; 15% AOM 2; 1-5% Alage; 44-40%vit+inert; 10% bitumen	exhausted	2/200-250	II-III	mature	oil
8570	2629	1.02	0.55/22	0.37	30% exinite; 25% AOM 2; 5% algae; 30% vit+inert; 10% bitumen	exhausted	2.0/200-250	II-III	mature	condensate
8710	2672	1.05	0.59/19	0.31	20% exinite; 15% AOM 2; 45% vit+inert; and 20% bitumen	exhausted	2.5/250	II-III	mature	condensate
8890	2727	1.08	0.34/7	0.43	30% AOM 2; 10% algae; 10% exinite; 30% vit+inert; 20% bitumen	exhausted	3/250-300	II-III	mature	condensate

% Ro = mean random vitrinite reflectance for autochthonous vitrinite grains (main maturity)
TOC: total organic carbon content in wt %; **HI** = hydrogen index in mg HC/g TOC determined from Rock=Eval Pyrolysis
Prod. Index = production index (ratio of S1 and C2 curves) determined by Rock-Eval pyrolysis
exinite = exine rich organic components includes spore (sporinite), cutin (cutinite), and suberin (suberinite) - various lipid components derived from plants
AOM 2 = amorphous organic matter type 2 variety that are oil prone
Bitumen = solid bitumen - a secondary hydrocarbon transformation products derived from primary macerals (phytoclasts)
Original TOC/HI = the original TOC and HI was calculated based based on present day TOC and HI, production indedices, and organic facies reconstruction

Column 6 in Table 2.2 shows the results of the scanning organic facies assessment. The majority of the organics were derived from a terrestrial source (exinites and vitrinites). Vitrinite is basically the woody portion of plants and is generally by far the most abundant organic material in terrestrially-derived source rocks. Vitrinite is gas-prone Type III organic matter. However, in some deltaic deposits such those identified at Old Harry, much less vitrinite is deposited and the terrestrial lipid (oil- and gas-prone) organic components (exinites) can be dominant. These terrestrial lipid components are mainly Type II-III suberinite (plant suberin), resinite (plant resin) and cutinite (plant cuticles). These types of organic material usually generate liquid hydrocarbons within C_{17} to C_{27} normal alkanes during the early stages of thermal maturity (oil window) and, like all organics, will generate natural gas at higher stages of thermal maturity (gas window).

Other less abundant organic material found in the Brion Island source rocks is Type II amorphous liptinite (biodegraded algae). Together, all of the organic material in the Brion Island well form a Type II-III condensate-, oil- and gas-prone source rock. The C_{30+} hydrocarbons (mainly wax and asphaltene components) that are usually present within the *botryococcus* type lacustrine algae are absent in the various source rocks in the Brion Island well. These data suggest that asphaltene or wax-rich heavy oil is very unlikely at Old Harry because of the organic facies (nature of the terrestrial lipids) of the major source rocks and their thermal maturity.

Given that these rocks are greater than 250 million years old, it is reasonable to expect that at least some hydrocarbons would have been generated over geologic time. This is confirmed by the high production index. The various geochemical and organic facies data were assessed to determine the present-day condition of the source rocks, and column 7 lists the source rock condition. The fluorescence characteristics of the source rocks in the Brion Island well indicate that they have been depleted in liquid hydrocarbons. In general, the source rocks from the Brion Island well are depleted of their hydrocarbon generation potential above approximately 2,200 m depth and those below 2,200 m are exhausted. Since these source rocks are depleted or exhausted, the original source rocks prior to burial and thermal maturation would have had higher TOC and HI values. Therefore, the original TOC and HI values were recalculated on the basis of maturity, present day TOC, HI and production index values, and the scanning organic facies data. The recalculated values are presented in column 8 of Table 2.2.

2.3.2 Petroleum Systems Modelling

The organic facies and geochemical data were integrated with the interpreted 2-D seismic reflection data to develop a series of 2-D Petroleum System Models of the Old Harry structure. The Petroleum System Modelling was completed using the PetroMod 2D modelling software (version 11.04; Patch 3) of IES GmbH, Aachen, Germany (currently of Schlumberger Incorporated). A key part of petroleum systems modelling involves determining the development of the Old Harry structure through geologic time, including the stratigraphy, burial history, heat flow, hydrocarbon migration paths and other geological and geochemical information. The modelling incorporated the following information:

- lithology for each stratigraphic unit based on the Brion Island well and 2-D seismic interpretation;
- timing of erosion, palaeowater depths, and palaeotemperature (through time) from biostratigraphic analysis;
- heat flow in relation to basement structures;
- the hydrocarbon reservoirs and seals in relation to the structure;
- organic richness of various source rock intervals and hydrocarbon potential (HI values in mg HC/g TOC);
- trends of palaeoheat flow, palaeowater depths, and palaeotemperatures;
- multi-component kinetics of selected default source rocks; and
- oil and gas properties for each individual source rock, based on compositional analysis using pyrolysis-gas chromatography (Mukhopadhyay 2006) and the PetroMod 2D software database.

The stratigraphy, timing of sediment deposition, erosion, salt migration, folding and faulting were determined based on the interpretation of 2-D seismic reflection profiles. The seismic data were correlated to the Brion Island well to facilitate the identification of source rocks, reservoir and shale seal rocks. The stratigraphic ages of the individual formations were determined using the International Geological Time Scale of Ogg et al. (2008) and Giles and Utting (2003).

The palaeowater depth and palaeowater temperatures for each formation were incorporated in the models. The thermal maturity data (vitrinite reflectance and thermal alteration index values) indicates that the majority of the source rocks from the Brion Island #1 well are between 0.6 to 1.0 percent R_o (column 3 in Table 2.2). The calibration of the heat flow model used the measured vitrinite reflectance data points and their corresponding trend as seen in the Brion

Island well. The heat flow calibration was later corroborated by one measured bottomhole temperature and Apatite Fission Track analysis by Grist et al. (1995).

As described above, the original TOC and HI values were recalculated on the basis of maturity, present day TOC, HI and production index values and the scanning organic facies data. Based on the early oil generation potential as seen from the scanning organic facies data, a range of source rock kinetics were selected for modelling. The kinetics of a source rock describes the generation of hydrocarbons from the source rock during thermal maturation (i.e., when hydrocarbons are generated, what volume and whether oil or gas is generated). Three different classes of modelling simulations were completed to test the range of hydrocarbons that could be generated at Old Harry:

a) IES Gmbh default kinetics of kerogen Type II-III Monterrey source rock and Taranaki Basin Type II-III source rock;
b) Mahakam Delta Type III kinetics and Taranaki Basin kerogen Type II-III kinetics; and
c) IES default kinetics of kerogen Type II-III Monterrey source rock and Taranaki Basin Type II-III; however, higher TOC and HI values were used for source rocks in the deep basin to the south of the Old Harry structure.

The results of this modelling indicate that, at the present stage of thermal maturation of the source rocks, the hydrocarbons within the Old Harry structure, if present, are likely to comprise a very light, 45 to 56° API gravity oil with low to moderate gas-oil ratio. In fact, none of the model simulations indicated that the gravity of the hydrocarbons would be less than 50° API; however, oils with an API gravity of 45 to 56° API were included as a conservative estimate of the range of predicted hydrocarbons at Old Harry.

Various input parameters for the models were modified for each simulation to assess the change in hydrocarbon composition and saturation in the Old Harry reservoirs. The API gravity of the modelled hydrocarbons for all model simulations consistently fell within a narrow range, indicating the robust model results irrespective of variations in TOC and HI. However, it should be noted that increases in Type III kerogen relative to Type II kerogen in the modelled source rocks tends to decrease the amount of liquid hydrocarbons (oil) and increase the amount of gas, while the API gravity of the hydrocarbon liquids remains within the modelled range.

Note that the modelling cannot confirm that a structure is trapping and therefore the structure may contain no hydrocarbons and only water. As well, if hydrocarbons migrate from deeper within the basin where the organics are in the gas window, the structure could potentially be filled with natural gas.

2.3.3 Identification of Surrogate Oil

Petroleum Systems Modelling identified the potential range of hydrocarbons that could be trapped at Old Harry and the next step was to identify an appropriate surrogate oil for use during oil spill modelling. Corridor considered geological parameters such as depositional environment, the type of organic material (kerogen) and types of hydrocarbons encountered in several areas. Although only natural gas has been encountered in offshore Gulf wells, high API gravity oils have been identified in Gaspé (47° API), Port-au-Port, Newfoundland (51° API) and the Scotian

Shelf (47 to 52° API). Several characteristics of the geology in the Maritimes Basin (Old Harry area) compare favourably to the geological conditions encountered in the Scotian Basin. as shown in Table 2.3. The clastic reservoir rocks in the fields on the Scotian Shelf typically comprise fluvial and shallow marine, stacked, sandstone sequences that are analogous to the fluvial sandstone reservoir rocks at Old Harry. Of particular note is the known kerogen type in both basins is Types II-III and III. In addition, light oil was produced from the Cohasset / Panuke / Balmoral Fields on the Scotian Shelf (Kidston et al. 2005). Consequently, Corridor geoscientists have selected the Cohasset oil from the Scotian Basin as an appropriate surrogate for the oil that could be found at Old Harry.

Table 2.3 Comparison of Geologic Characteristics of the Maritimes and Scotian Basins.

Characteristic	Maritimes Basin (Old Harry)	Scotian Basin
Tectonic Environment	Strike-Slip Rift	Extensional Rift
Depositional Environment	Fluvial-Deltaic	Fluvial-Deltaic to Shallow Marine
Kerogen Type	Types II-III and III	Types II, II-III and III
Hydrocarbon Types	Natural Gas and Light Oil	Natural Gas and Light Oil