Abstract

The Carson Basin is a Mesozoic-Cenozoic passive margin rift basin in a shelf-slope setting; four wells have been drilled on the westernmost margin. The formations in the deep slope area of the basin appear similar to those in the Jeanne d' Arc basin. During the Albian Avalon uplift, erosion occurred down to the caprock over the early Jurassic evaporites on the shallow shelf area. The eroded sediments were deposited in deep-water turbidites to the east, in canyons on the slope. Reservoir and seal are common in such a setting. Extension due to rifting, as well as the movement of salt, formed structural traps; stratigraphic traps are formed by depositional zero edges.

A 4-D basin modelling program (IES Petromod) was used to integrate the study results. All geophysical and geochemical were used to create a model that accurately represents the geological history of the basin, including salt movement. Sensitivity of the model was assessed using best-guess assumptions for heatflow etc. reflecting rifting, as well as one 2 with 20% higher heat flow and one with a flat heatflow of 60 mW/m . The results show that significant hydrocarbon generation is possible in the basin. A critical risk factor is the presence of a Jurassic source rock. Generation in the best-case model started at 125 Ma; peak generation is around 65 Ma tied to the increased heatflow from rifting. Generation stopped soon after. The unrealistic flat heatflow simulation shows present day generation. A Paleocene source rock would not be mature enough in any of the simulations to generate hydrocarbons.

The generation prior to 62 Ma indicates that younger structural traps formed by halokinesis will not have been charged.

INTRODUCTION

This poster shows the highlights of 4-D petroleum system modelling of the Carson Basin. After a brief description of the geology, the images show how the model was built, and some of the detail that went into the formation layers. Then the hydrocarbon traps are shown and the boundary conditions that constrain the model, with as most important the paleoheatflow. The focus turns to the assumed Upper Jurassic source rock, that has geochemical values similar to those of the Egret Member in the Jeanne d' Arc Basin. The figures show the temperatures and hydrocarbon amounts at the peak of generation. Timing of generation, including amounts of hydrocarbons in the subsurface, now, at the start and at the maximum oil generation are shown. The complexity introduced by the salt movement are show next with the temperature regime overlain in relation to the fairly simple configuration of the bottom of the basin.

Figure 1: Tectonic Elements map

This is an excerpt from the tectonic elements map (Edwards et al., 2003) showing basins, major tectonic, geologic features and well locations. The formations underlying the Avalon Unconformity are shown. Major salt structures are shown in dark-green. Several seamounts are visible as yellow patches. The dashed, blue outline shows the area modelled for this study .

The outline of the Carson Basin is constructed mostly from Enachescu (1992), while the adjacent Salar Basin edge is defined by Austin et al. (1989). The boundary between both is a basement high, visible on seismic data, that loses definition to the north.

Figure 2: Chronostratigraphic diagram

The diagram was adapted from McAlpine (1990) and shows the geological framework of the area (the horizontal axis is not a section line). The wells were plotted where their stratigraphic section is best reflected; the division in the Banquereau and Dawson Canyon formations is from Deptuck et al., (2003). That this section from the Jeanne d'Arc Basin can be used with such ease shows how similar both basins are.

The Neogene, Paleogene and Upper Cretaceous formations are underlain by the Avalon Unconformity.

The Avalon Uplift had its strongest influence west of the Carson Basin and eroded rocks from Upper Cretaceous to Carboniferous age. This will have breached reservoirs within this section. The much smaller Top-Cretaceous unconformity shows only a local and small effect.

The Egret Member, source rock for the Jeanne d'Arc Basin and also present in the Flemish Pass Basin, was not penetrated by the wells on Figure 1. Age-equivalent rocks deposited in a coastal setting are present in Skua E-4.

Figure 3: Building the formations

Four seismic depth-converted surfaces and four wells constrain the model. The intervening geology was built in between those layers, based on the lithology found in the wells. Added to this is the movement of the salt and the deepening of the basin with rifting over time. An E-W vertical cut plane shows the formation thicknesses in the centre of the basin. The four images shown are: A. at 204 Ma, after salt (green) deposition; B. at 165 Ma Voyager sands have been deposited and salt is moving up in diapirs; C. at 120 Ma, Thick, unnamed Lower Cretaceous sands have been deposited; D. at 68 Ma the Wyandot limestones precipitated. The orange arrow at left bottom points north and shows the 3D position. Note how the diapirs have grown, and as a result the thinning of the salt layer. (This view looks slightly down to the north).

Figure 4: The complete model

The formation surfaces were constructed between the seismic surfaces while keeping the constraints of the regional geology in mind. Colours represent the lithology and are shown in this view from the northeast. Note the shelf and slope, the large range of water depth in the slope area and that the wells were all drilled on the western shelf margin of the basin.

Figure 5 Fine-tuning the formations

Because few formations are homogeneous, each requires the right facies configuration, based on well data, seismic and general knowledge of the area. Shown are sandstone channels of the South Mara Member encased in shales. These channels will be conduits for the migration of hydrocarbons, especially if they are cut by faults that tap into the source rock.

Figure 6: Depositional zero edge

There are no Jeanne d’Arc sands present in the four wells, but Hibernia sand was found in Skua E-41 and Jeanne d’Arc equivalent rocks in Bonnition H-32. As an interpretational compromise, a sand was projected, based on seismic, and shown by the yellow colour that directly overlies the Egret Member. We will refer to this as the “Hibernia” clastics. The zero edges will form stratigraphic traps with the overlaying shales as seal. They are the ideal trap with regards to the timing of hydrocarbon generation, because they existed well before generation time. The blue, grey etc. are underlying formations. The green patch in the blue is due to displacement caused by the movement of a diapir. The diapirs are also visible on the cut plane face.

Figure 7: Oil and gas generated, trapped by zero edge

When the oil and gas generated from the Egret Member are shown, they are trapped with high efficiency largely by the depositional zero edge of the “Hibernia” clastics. The solid patches are the accumulations, the green and red lines the migration paths for oil and gas respectively. The configuration is shown as at present. Some of the hydrocarbons moved into overlying Lower Cretaceous sandstones through leaks in the surrounding seal rocks. We did not apply any faults, because our vintage seismic did not allow an accurate assessment of the faulting density, direction or vertical extent. This also means that the reservoir remains unbreached in the model, somewhat unlikely in this extensional rift setting.

Figure 8: Temperatures, heat flow and water depth used

The green line shows sediment-water interface temperature and the red line shows the heatflow, over time, as

influenced by rifting events. Paleo-water depth is entered in the model by a series of maps with depth varying
over time. All three variables are constrained by vitrinite reflectance data. The peak in the green line reflects the
Paleocene thermal maximum event. It has a marginal effect on the amounts of hydrocarbon generated: only a
fraction more oil and a fraction less gas is generated without it.
The rifting values were taken to reflect passive-margin rifting, but the hot-spot activity that created the sea mounts
was not taken into account, because we could not find any relevant heatflow data.

Figure 9: The Kimmeridgian Egret Member equivalent
The Egret Member source rock is absent from the wells due to erosion or facies change. It is present in the
Jeanne d’Arc Basin and in Flemish Pass Basin (McCracken et al., 2000), and source rocks of this age are
found in the North Sea, as well as in numerous other basins around the world where rifting took place in this
era. We postulated an Egret Member equivalent source rock in the deeper parts of the basin and gave it
conservative Egret source rock values: 4% TOC, 600 HI and a thickness of 50 m. The surface is depicted
here. The green patches within the surface are salt caused by diapir growth. The full potential of this source
rock is: area x thickness x s.g. rock x TOC x HI x % oil in hydrocarbon x volume increase oil, or 260 x 50 x
9 3 0.05 x 2.3 x 0.04 x 0.6 x 0.8 x 1.15 = 33x10 m or **200 billion barrels.** The Tilton Member in the Dawson
Canyon Formation was also given source rock properties, but it did not generate any hydrocarbons
because it did not reach the right temperature.

Figure 10: The heat regime in the Egret Member equivalent.
The temperatures during peak hydrocarbon generation at 62 Ma, as an overlay on the source rock
surface, shows with the yellow to red colours where the Egret was mature enough to generate
hydrocarbons. About half of the area reached the oil window, while the deepest parts reached the gas
window. That translates into a realised hydrocarbon potential of about 100 billion barrels.

Figure 11: Hydrocarbon volume in reservoir in this model
The hydrocarbons are shown in their trapped location, above the Egret surface of Figure 10, at 62
Ma, just after the time of peak generation, using the best-estimates model. The green and red
patches are the respective oil and gas accumulations, the matching lines are the migration paths.
The inset shows graphically and in numbers how much oil and gas was trapped in the sandstones

overlying the source rock: 58 billion barrels and 20 million cubic metres of gas. The outer circle shows the subsurface composition of the oil in orange, the inner one of the gas (blue). At the surface, there would be much more gas and less oil due to shrinkage from the lower pressure conditions. Because no seal rock is perfect, the quantities now present in the reservoir are less, due to leakage.

Figure 12: Trapped and escaped oil

The oil now trapped is shown above the Egret surface (looking straight down). Amounts are in the inset with numbers and colours, where the orange represents oil and blue gas. Substantial amounts of hydrocarbons have moved west out of the model area. The stratigraphic trap reservoirs outline the “Hibernia” unit. Note that the 40 billion barrels present is a significantly lower amount of oil than there was at peak generation.

Figure 13: 4-D modelling, going back in time.

The start of oil generation for this simulation run is at 125 Ma. Only a small amount of oil has been generated, and it is represented by the small green patches; the green of the salt diapirs that replaced the source rock areas is cross-hatched.

Figure 14: 4-D modelling, 60 Ma later.

The maximum amount of **oil** has been generated and migrated at 68 Ma with almost no gas. Compare these amounts to those shown in Figure 11 or 12: 61 billion barrels versus 40 billion barrels. The difference in amount of hydrocarbons over time is due to thermal cracking to gas and/or migration away during the intervening period.

Figure 15: The tectonic factor

This image shows the surface of the salt layer complete with diapirs as used in the model. The real configuration is much more complex. Note how the well Osprey G-84 was drilled into a salt mass. The salt appears as diapir in this well due to the vertical exaggeration, but seismic indicates that this salt may be in original place, while around this location the salt has been withdrawn and moved into other diapirs. In Osprey G-84 the salt was divided into Osprey and Argo Formations, both separated by a shaly layer (e.g. McAlpine, 1990). That distinction has not been made in this model, because it would have added complexity while serving little purpose for the modelling.

Figure 16: The temperature distribution on the salt

The salt surface with its present temperature distribution as a colour overlay showing the configuration
of the deeper part of the basin. A careful inspection of the temperatures that is not possible with this
static figure shows that the temperature over the diapirs is elevated as compared to the adjacent strata,
because of the high conductivity of salt.

Figure 17: The bottom of the basin with temperature overlay

The surface of the Eurydice Formation underlying the salt is shown here with a present-day
temperature overlay. It shows how deep the basin is and how the salt has complicated the
overlying structure. The temperature scale is different from that in Figure 16. Note at the location
under the right-most diapir of Figure 16, the temperature is lower than around it: the excess heat
has been conducted away by the diapir acting as a heat conduit.

CONCLUSIONS

The significant findings of this study are that, provided there is an Upper Jurassic source rock, 1. substantial amounts of hydrocarbons can be generated, and 2. the time of generation was between 125 and 62 Ma during the elevated heatflow due to rifting, and there is no generation now. This means that traps have to be in place during this interval. Younger halokinesis will have created later traps.
The amounts of hydrocarbon indicated assume a closed, non-breached system, which is highly unlikely in this setting. Nevertheless, significant accumulations may have been preserved. Careful inspection of the model results show that the four wells were not drilled in the right locations, on structural traps. For future drilling, stratigraphic traps in areas without faulting will have the highest likelihood to contain hydrocarbons.
The presence of the source rock is likely from a paleo-geographic viewpoint. Only a well deeper in the basin will prove its presence.
The model contains the westernmost part of the Salar Basin. The findings of this study have a strong bearing on its prospectivity.
Future research will be needed to determine the quality of the seals and reservoirs, and the integrity of the traps. High-quality 3D seismic will be required.

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