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The Minagish Field Tar Mat, Kuwait: Its Formation, Distribution and Impact on Water Flood

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ABSTRACT

In common with many giant oilfields world wide, the Minagish field (Minagish Oolite Formation) in Kuwait has an areally extensive heavy oil zone of variable thickness at the base of the oil column. The heavy oil zone, or tar mat, is thought to act as a partial permeability barrier between the aquifer and oil leg, but its field-wide effect and properties were unknown. A full-field water flood is planned for the Minagish field. Therefore, an understanding of the distribution and properties of the heavy oil zone is critical in deciding whether to inject water above the tar mat (with unavoidable reserve losses) or directly into the aquifer in areas where the tar mat is poorly developed.

The difficulty in discriminating between cemented and bituminous intervals on electric logs has led to the adoption of geochemical techniques to detect the presence and thickness of heavy oil zones. By using detailed Iatroscan analysis, the tar mat is characterized by a high proportion of asphaltenes, but low concentration of saturates, polars and aromatics. Results of geochemical analyses demonstrate that the Minagish tar mat is the result of de-asphalting rather than gravity segregation. Compositional variations through the oil column have been mapped using geochemical parameters measured on core samples. A predictive model for API gravity and live oil viscosities has been established for the field. This new understanding of the Minagish tar mat, its genesis and spatial distribution has helped in developing a water injection strategy that maximizes recovery in the Minagish field.

INTRODUCTION

Background

The Minagish field in West Kuwait (Figure 1) is a north-south trending anticline with hydrocarbons contained in six major reservoirs ranging in age from Early Jurassic to Late Cretaceous. It was discovered in 1959. Its primary reservoir is the Early Cretaceous (Neocomian) Minagish Oolite Formation that contains 84 percent of the field's reserves and has contributed over 80 percent of the field's production. The Oolite is also the primary focus of future development plans that call for a four-fold increase in production from the Minagish field by 2001.

Production History, Future Development Plans and the Need for Water Flood

Although the Minagish Oolite is a mature reservoir, it is under-developed as less than 10 percent of its reserves have been exploited during nearly 40 years of production. To date, production from the Minagish reservoir has been attributable to primary depletion, with very weak aquifer support. Evidence for this is the reservoir's pressure history that has shown a fall of over 1000 pounds per square inch (psi) since start-up. The pressure sensitivity of the field to periods of high off-take was demonstrated during Iraqi-invasion blowouts, when reservoir pressure fell several hundred psi over a period of a few months. Therefore, to conserve reservoir energy production has been maintained at modest levels of about 60 thousand barrels of oil per day (mbopd). In response to pressure decline and a requirement to elevate production from 60 to 210 mbopd over the next few years, a peripheral water flood development scheme was proposed for the field (Sing et al., 1997). The development plan requires 12 to 16 water injectors supporting about 50 mid-flank to crestal producer wells (Figure 2). The average producer-well density will be 1 per 240 acres.

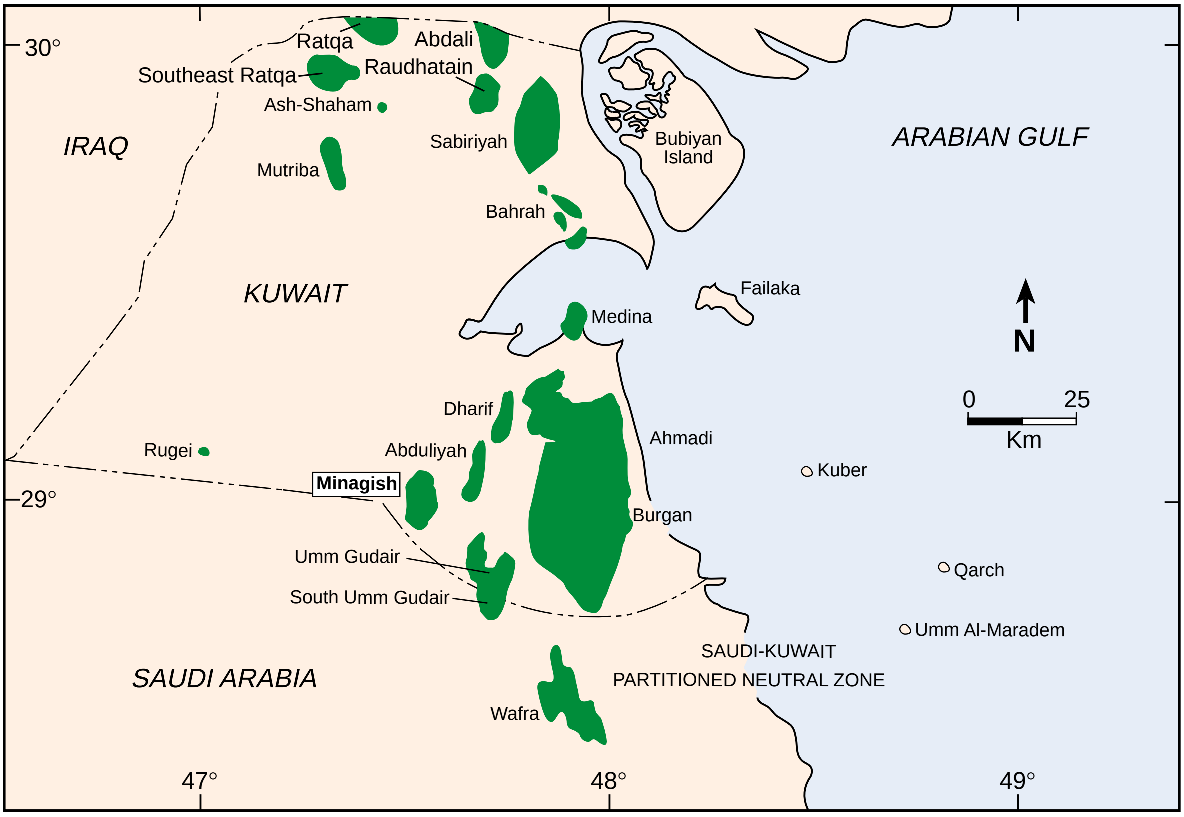

Figure 1: Location map of the Minagish field.

Impact of the Tar Mat on Development Plans

Speculations on the limited pressure support from the aquifer in the field were based on the presence of a 50- to 100-ft-thick tar mat at the base of the oil column (Figure 3). It had been observed on logs and in core but little was known of its formation and characteristics. However, its presence has had a significant influence on the development plan for water flooding the field. It has long been held that water injected into the reservoir to provide pressure support must occur above the tar mat, as it was not thought possible to inject against it. Injecting under the tar mat might result in inadequate pressure support because of poor communication across the tar mat.

With the bulk of new injector wells to be drilled during the period 1998 to 2001, an understanding of the tar mat was critical in choosing the location of new injectors and implementing the field-wide water-injection program. Knowledge of the tar mat would avoid incorrectly positioned perforated zones and the subsequent inefficient sweep of the reservoir flanks (Haldorsen et al., 1985). A better understanding of the tar mat would also minimize reserves of attic oil lost in the wedge behind the injectors.

Thus, as a prerequisite to planning the water injection strategy in Minagish, a study was undertaken of the Minagish Oolite tar mat. The study was to determine for the first time in the field's history how the tar mat formed, where it occurred in the field (both areally and vertically), and what controlled its distribution. This information could then be used to plan the location and design of peripheral field injectors and ensure optimum sweep efficiencies. This paper documents the geochemical techniques aimed at detecting the tar mat and presents a new model for its formation.

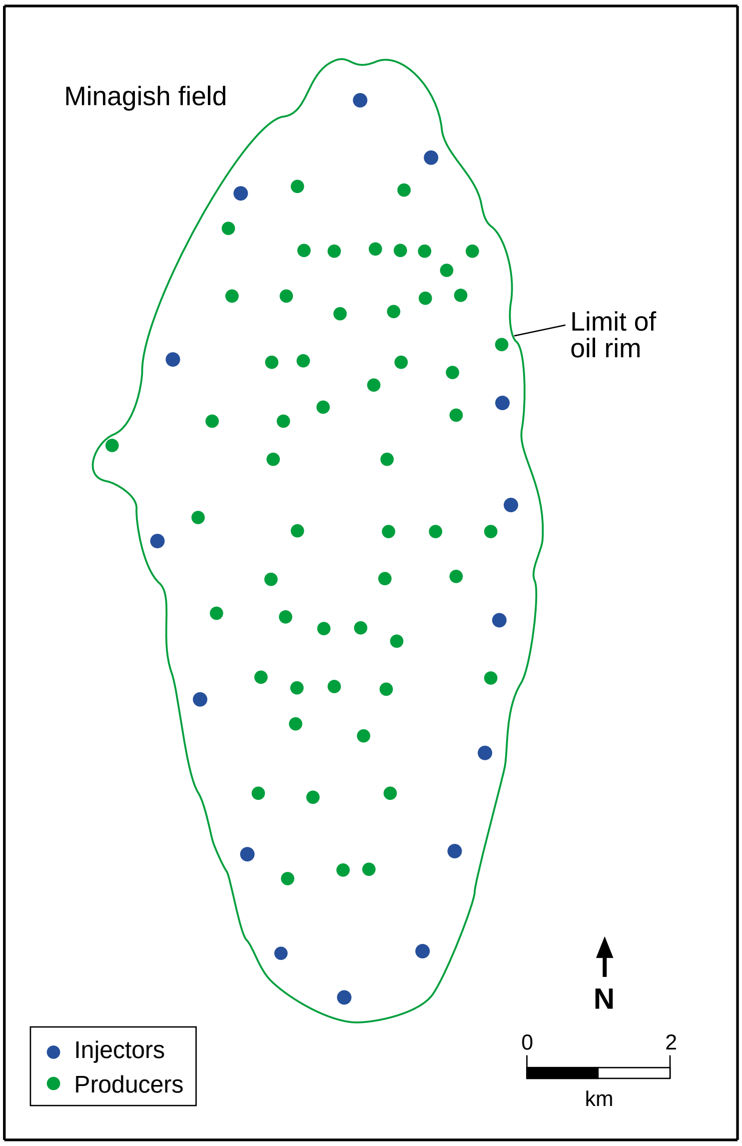

Figure 2: The Minagish field showing producing wells and proposed injector-well locations.

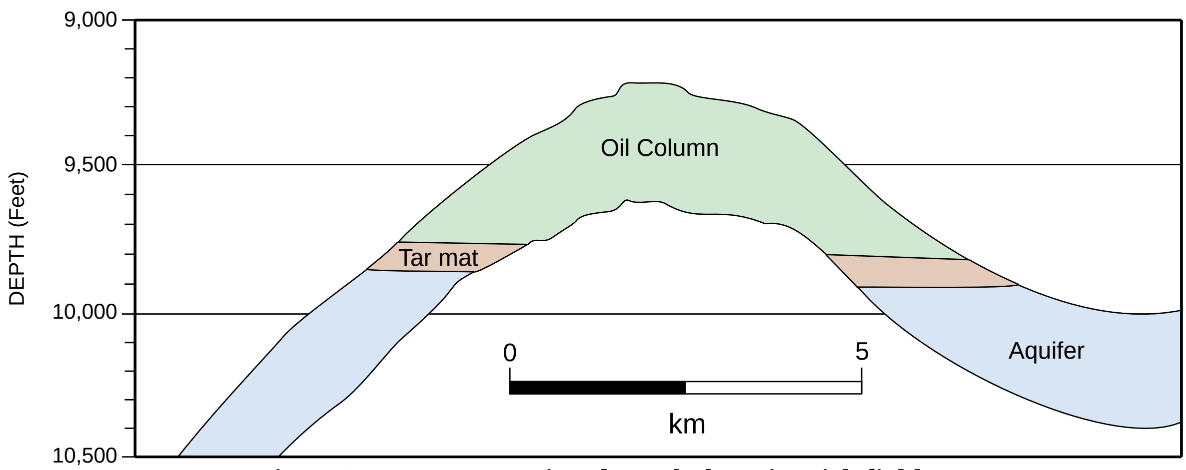

Figure 3: E-W cross-section through the Minagish field.

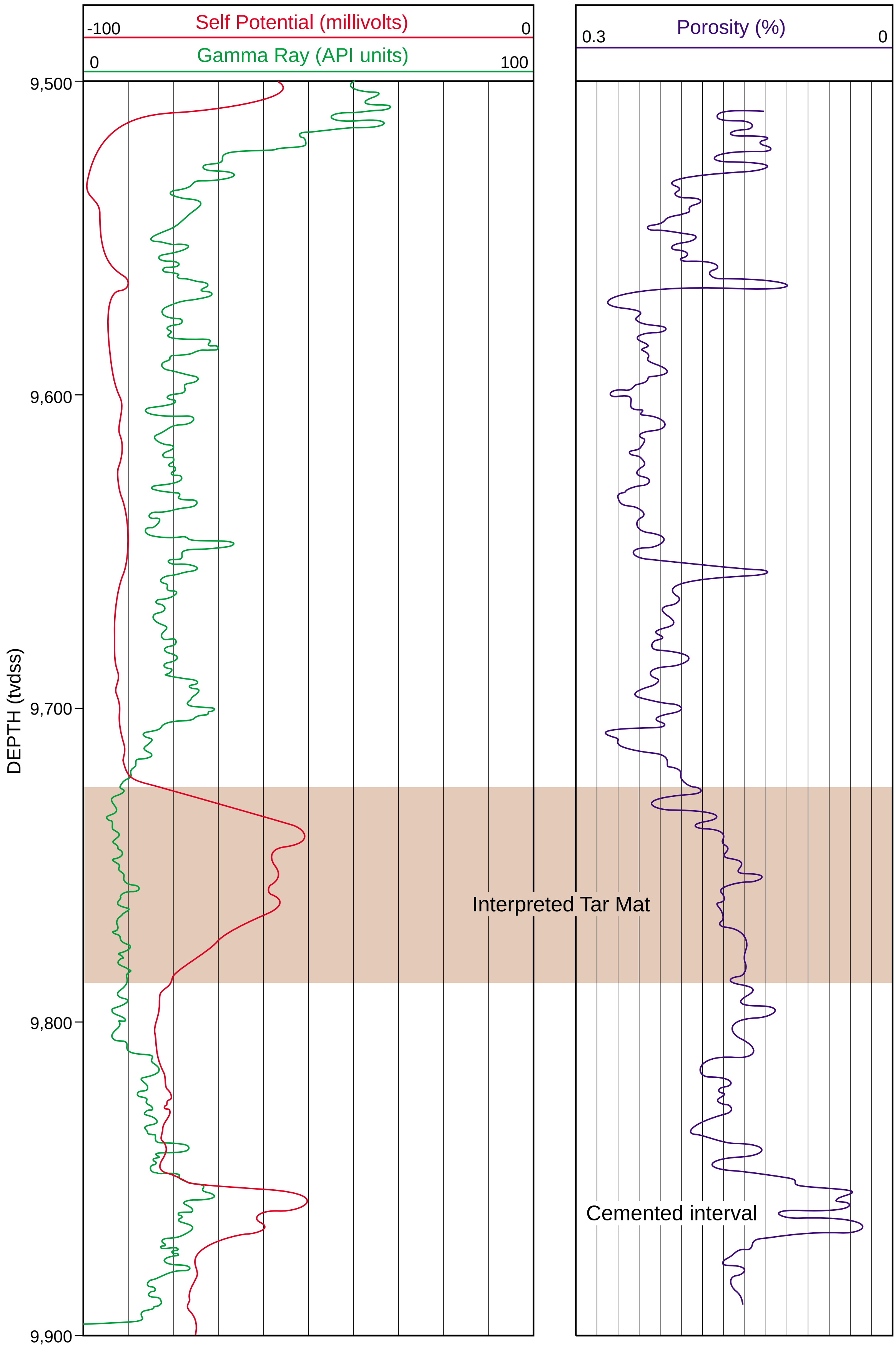

Figure 4: Typical log responses (Self Potential, gamma ray, and porosity) from the Minagish tar mat interval.

MINAGISH OOLITE RESERVOIR AND TAR MAT

The Minagish Oolite is a carbonate reservoir about 400 ft thick at a total vertical depth sub-sea (tvdss) of between 9,000 to 10,000 ft. The difference in elevation between the crest and flank of the field is 700 ft. Permeability is good to excellent (200–2000 millidarcies (md)) and porosity ranges from 17 to 23 percent. The reservoir has good microporosity in the mudstone to wackestone intervals. The best reservoir quality is developed in the oolitic grainstones from which the Formation derives its name. The sedimentary rocks are interpreted as having been deposited in broad facies belts on a low-angle carbonate ramp. The reservoir is subdivided into 13 well-defined layers that have an important control on the development of the tar mat and on its distribution across the field. The layering (defined largely by permeability contrasts) is relatively constant on a broad scale but, in detail, considerable heterogeneity is present within individual layers. This could have an effect on sweep efficiency and the performance of the water flood.

Evidence for the Tar Mat

The tar mat has been seen in several well cores as thick bituminous material that occludes pores. In other cored wells, logs suggest the presence of a tar mat but it is difficult to see because of the poor condition of the older cores. Tar mat occurrences can sometimes be correlated with the Self-Potential (SP) log that shows a positive kick (Figure 4). However, the SP is unreliable. Frequently, the SP kick starts at the top of the tar mat but returns to its baseline level above the tar mat's base. The SP response is mainly due to water in pores near the well bore and it cannot distinguish effectively between (viscous) immobile tar and (residual) immobile lighter oil. Hence, the SP signature becomes indistinct just above the oil / water contact (OWC). Cemented intervals also have SP responses that closely resemble tar mat signatures (Figure 4) and these may lead to the common misinterpretations of tar mats from logs alone. The microspherically-focused log (MSFL) can be useful in identifying the tar mat by showing a characteristic positive kick and, unlike the SP, it gives an indication of the base as well as the top of the tar mat. However, MSFL was not run on most of the older Minagish wells.

No other logs provide a clear signature of the presence of a tar mat and so its detection in the Minagish field has been difficult. Consequently, there has been a poor understanding of where the tar mat occurs and an inability to accurately map its field-wide distribution or to predict its presence in uncored wells.

GEOCHEMICAL TECHNIQUES FOR DETERMINATING THE LOCATION AND COMPOSITION OF THE TAR MAT

Because of the unreliability of both logs and cores, geochemical techniques were employed to detect the tar mat and determine more about its composition. Because tar mats commonly contain oil that differs in composition from the remainder of the oil column, it is often possible to detect them using geochemical techniques (Carpentier et al, 1995). The technique used was Iatroscan. This is an inexpensive analytical means of determining the composition of oil samples extracted from small core samples. It uses rapid thin-layer chromatography to identify the relative proportions of saturated hydrocarbons (saturates), polar fractions (polars), bituminous compounds (asphaltenes), and unsaturated, closed ring hydrocarbons (aromatics).

Experimental Method

The Iatroscan analysis was carried out on samples from all of the wells that had cored the Minagish Oolite on the flanks of the field. Eight wells were sampled at 4 ft intervals, generating 430 samples of approximately 3 cubic centimeters each. Many of the cores were more than 30 years old and had been kept in poor condition. However, this did not affect the applicability of the Iatroscan technique as only the light oil fractions deteriorate over time, and it was the heavier fractions that were analyzed. Residual oil was extracted from the samples using dichloromethane as a solvent. The composition of the oil was determined by thin-layer chromatography of the weighed extracts.

Geochemical Characteristics of the Tar Mat

Extract Yield

Extract yield, the quantity of oil extracted, was determined for each sample. High yields reflect larger proportions of irreducible oil saturation. Figure 5 is a typical plot of the extract yield from a Minagish well. It shows an average extract yield of 5 milligrams/gram (mg/g) throughout much of the reservoir section but just above the OCW this increases to more than 30 mg/g. The results are interpreted as indicating the presence of a tar mat in the zone defined by the high extract yields. Thus, a simple analysis of extract yields from core samples gave a good initial indication of a tar mat in the Minagish field.

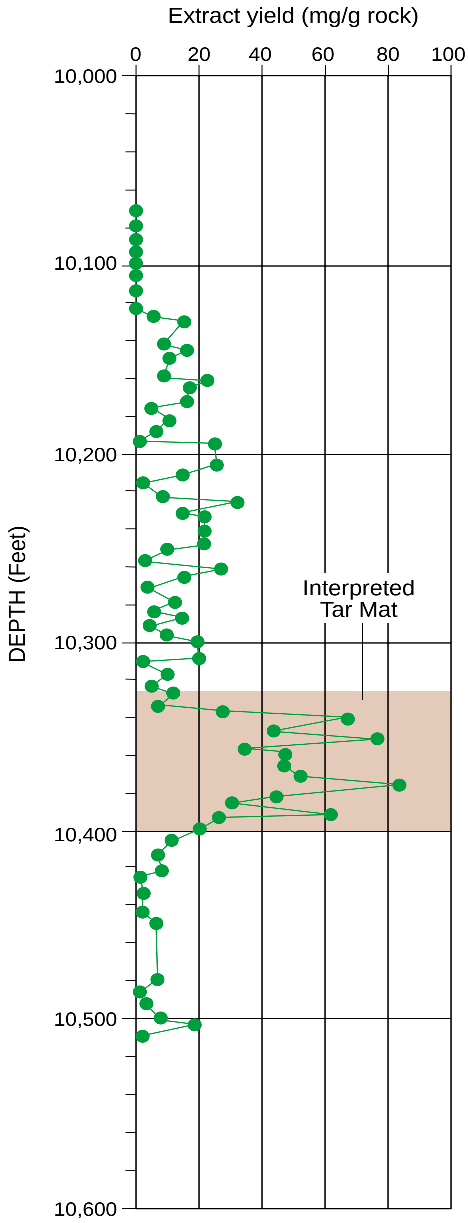

Figure 5: Well-A: extract yield versus depth.

Composition of Yields

In addition to providing information on the total oil yield, Iatroscan thin-layer chromatography afforded an opportunity of investigating the composition of the extracted oil by means of the proportions of asphaltenes, saturates, polars, and aromatics. An examination of the data from each well showed that a variation in extract yield is frequently accompanied by a change in the composition of the oil. This is shown in Well-C in Figure 6. In the upper 300 ft of the reservoir, the extract yield is a relatively constant 2 to 20 mg/g and the asphaltene content of the oil is also constant, at about 5 percent. However, in the lowermost 50 ft, where extract yields peak at 30 to 90 mg/g, the asphaltene content is strikingly elevated at 80 to 90 percent.

The compositional data also indicate that where the proportions of asphaltenes increase, there is a concomitant sharp decrease in the proportions of saturates. Typically, saturates average 15 to 25 percent through the reservoir oil column above the tar mat but where extract yields are high, the proportions of saturates drop to less than 5 percent (Figure 6).

The changing proportion of saturates and asphaltenes observed in each well show a trend that is typical for hydrocarbon columns in which tar mats have formed (Figure 7). Three zones can be identified: (1) a zone of normal oil high in the oil column (average 21 percent saturates); (2) a transition zone just above the tar (average 12 percent); and (3) a tar mat zone, in which saturates comprise only 2 percent of the bulk composition. The profiles for aromatics and polars also show a marked vertical variation throughout the oil column. Above the tar mat, both average between 5 and 10 percent; within the tar mat zone their values drop to small and consistent proportions of less than 1 percent for aromatics and about 5 percent for polars. The geochemical data of extract yields and compositions therefore provide a valuable suite of tools that may be used in detecting the presence of a tar mat.

By using geochemical data (and the increased confidence it provides in picking the tar mat) it is possible to plot tar mat occurrence versus reservoir layer (as defined by permeability contrasts). Whereas the occurrence of a tar mat was previously thought to be solely depth controlled, the new geochemical data show that there is a strong control by reservoir layer (Figure 8). The tar mat does not occur in all

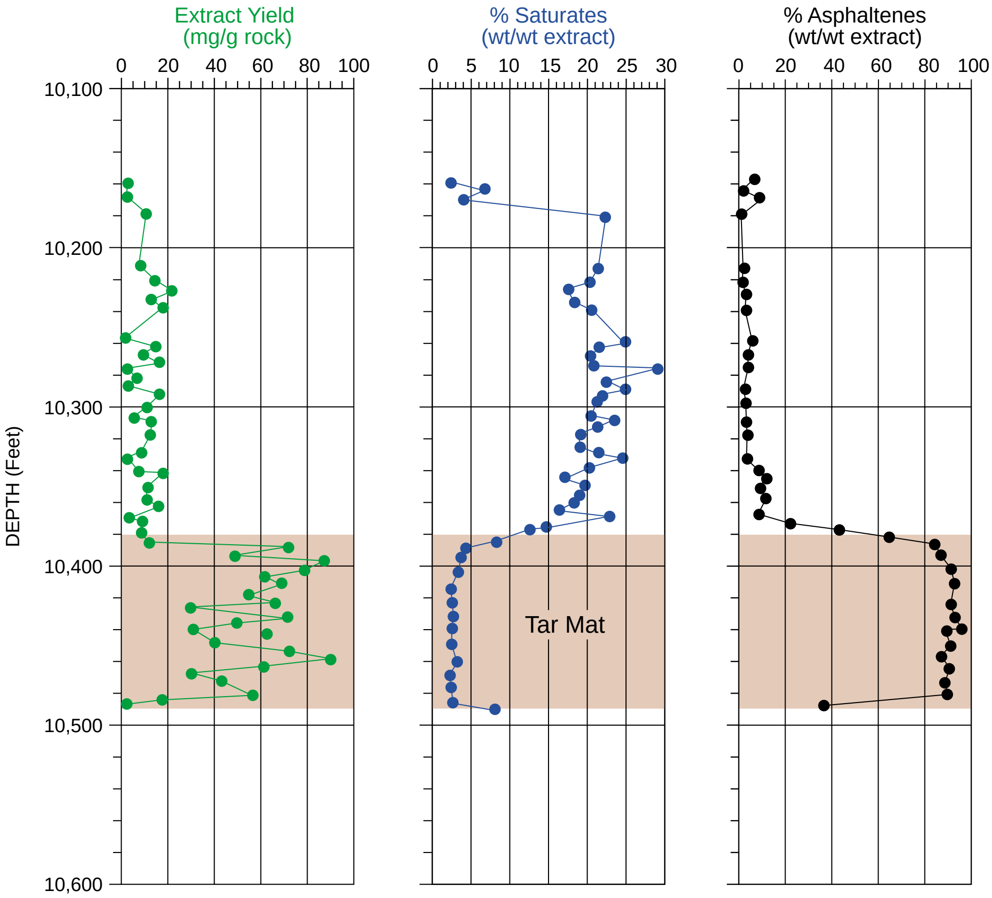

Figure 6: Well-C: extract yield, and proportions of saturates and asphaltenes versus depth.

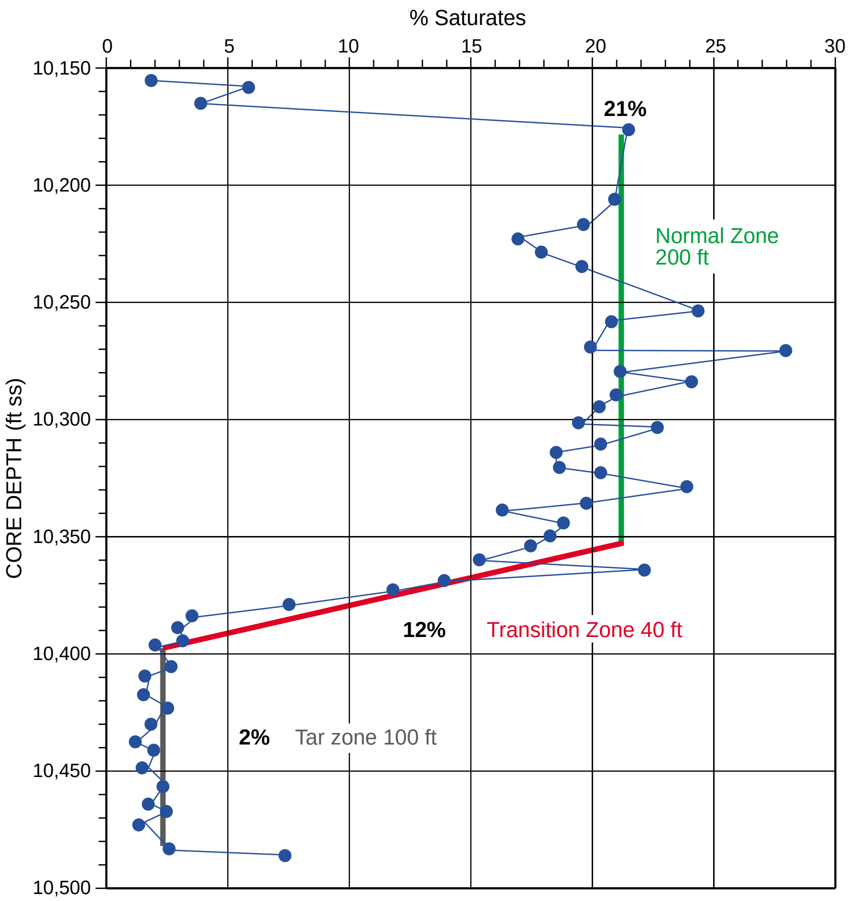

Figure 7: Well-D: vertical profile of saturates.

layers. It occurs preferentially in layers 3 to 10, and layer 12. As the permeability profile in Figure 8 shows, these layers are also the most permeable, with average values greater than 100 md. The resulting stratigraphic distribution of the tar mat shows that it is absent from the upper 50 ft of the reservoir interval, and also from the lower 50 to 100 ft.

A MODEL FOR THE FORMATION OF THE TAR MAT

Four characteristics of the Minagish tar mat can be deduced from the analytical data.

1. It is a zone of high residual oil saturation.
2. It is a site of preferential asphaltene enrichment (values of up to 80 percent).
3. It occurs preferentially within the high permeability layers.
4. The asphaltene content of the oil column above the present-day tar mat cannot account for the quantity of asphaltene in the tar mat.

These characteristics of the Minagish tar mat, when taken together, suggest several possible models for tar mat formation and for its position in the Minagish reservoir.

Asphaltenes are high-molecular-weight oil fractions that are concentrated by precipitation from an oil column usually due to a reduction in their solubility. A reduction in asphaltene solubility can occur if the oil composition changes by the introduction of gas or light oil into the reservoir. But asphaltene solubility in the subsurface is also strongly pressure dependent (Hirschberg et al., 1984; Wilhems and Larter, 1994). As a result, asphaltene precipitation may occur when there is a decrease in pressure to the bubblepoint and a corresponding decrease in asphaltene solubility.

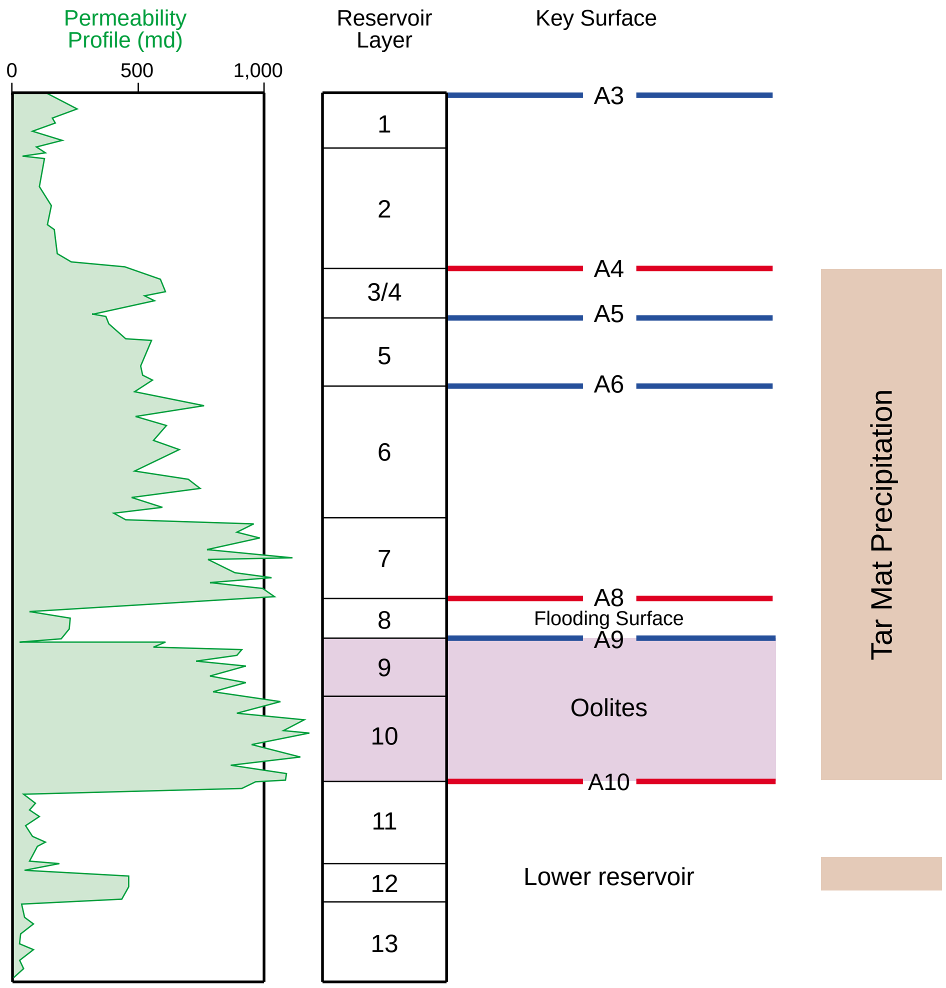

Figure 8: Distribution by reservoir layer of the Minagish tar mat.

Two models for the formation of the Minagish tar mat are possible.

Model 1 is of a light gas or light oil charge entering the Minagish Formation and triggering precipitation of asphaltenes. During the initial migration and filling phase of the Minagish structure, it is probable that no tar mat existed. The oil at this stage would have been of low to medium maturity, but there would have been a degree of gravity segregation within the oil column and a vertical viscosity gradient (Figure 9). Migration of a lighter oil or gas could have taken place along more permeable layers in the reservoir. The presence of this light fraction would have produced a drop in asphaltene solubility and caused the heavy fraction in the oil column to drop out of solution. Direct precipitation of asphaltenes (and the beginning of the formation of the tar mat) would have occurred at the base of the existing oil column (Figure 10). However, precipitation would have taken place only in the more permeable layers. The less permeable layers would not have been conduits for oil migration and would be free of asphaltene precipitates.

Model 2 is one of pressure reduction associated with petroleum migration from source rocks leading to the precipitation of asphaltenes. When petroleum leaves a source rock it experiences very large pressure-volume-temperature (PVT) changes (Wilhelms and Larter, 1994). For example, Miles (1990) documented changes in the solubility of asphaltenes as the petroleum moved through the Brent sandstone carrier beds in the North Sea. However, in such a model it is not clear why the tar mat would occur close to the OWC as is the case in Minagish, Prudhoe Bay and elsewhere. It may imply that asphaltenes have settled out through some vertical distance, as it is unlikely that the entry point of petroleum has always been near to the current OWC.

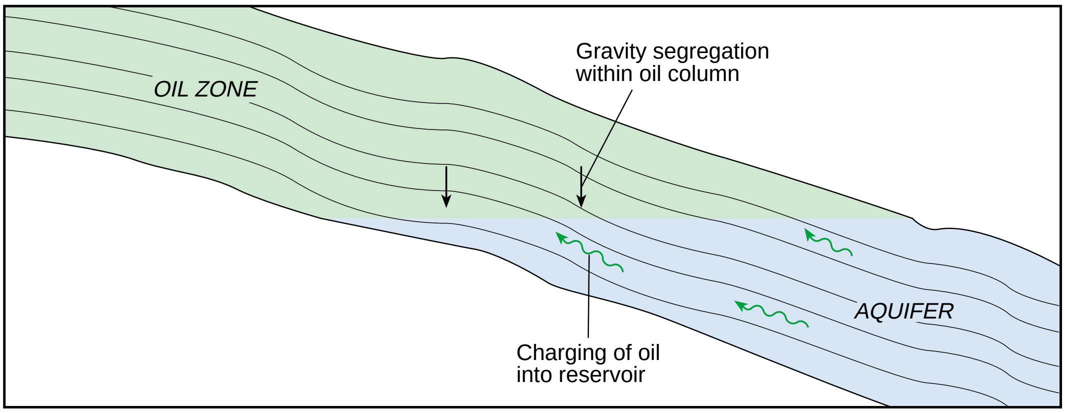

Figure 9: Model for tar mat formation from an initial oil charge.

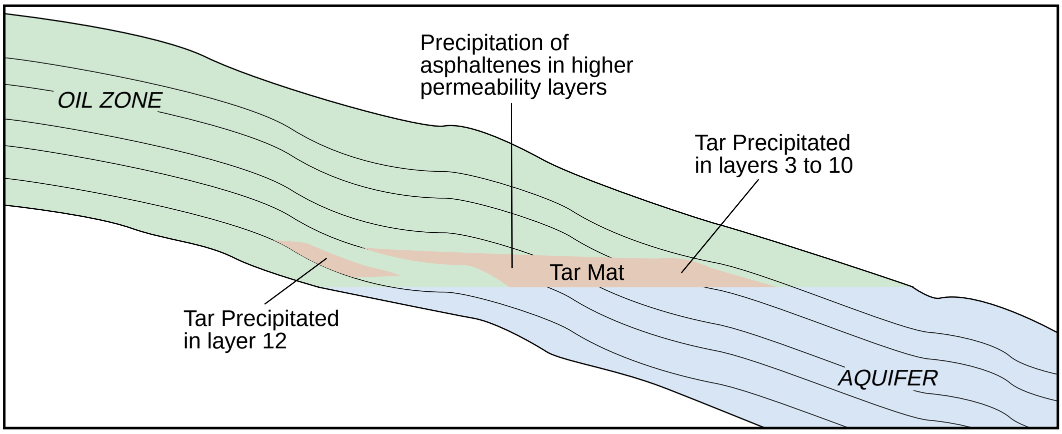

Figure 10: Possible model for the precipitation of asphaltenes and formation of the Minagish tar mat.

The spatial distribution of the Minagish tar mat is controlled by a combination of two factors: layer permeability and depth. More transmissible rocks provided conduits for migration of a later oil charge, and were the sites of later asphaltene precipitation. The depth control on the tar mat is imposed by precipitation occurring at the base of the oil column. This occurs from 9,700 to 9,925 ft true vertical depth across the field and is the 'tar mat depth window' within which the tar mat can form. By combining these two factors, it is possible to predict where the tar mat may form, as shown in Figure 11. It explains, for the first time in the history of the Minagish field, why some wells on the flanks of the field intersect a tar mat and others do not.

The thickness of the tar mat in the Minagish field varies from 34 ft to 108 ft. The model for tar mat formation shows that the thickness is controlled by the available vertical extent of the particular high-permeability layer within the 'tar mat depth window'. The mat is thickest in the northern part of the field where a thick permeable reservoir layer lies within the 'tar mat depth window'. At the other extreme, the thin tar mat on the west flank relates to the thin permeable layers within the 'depth window'.

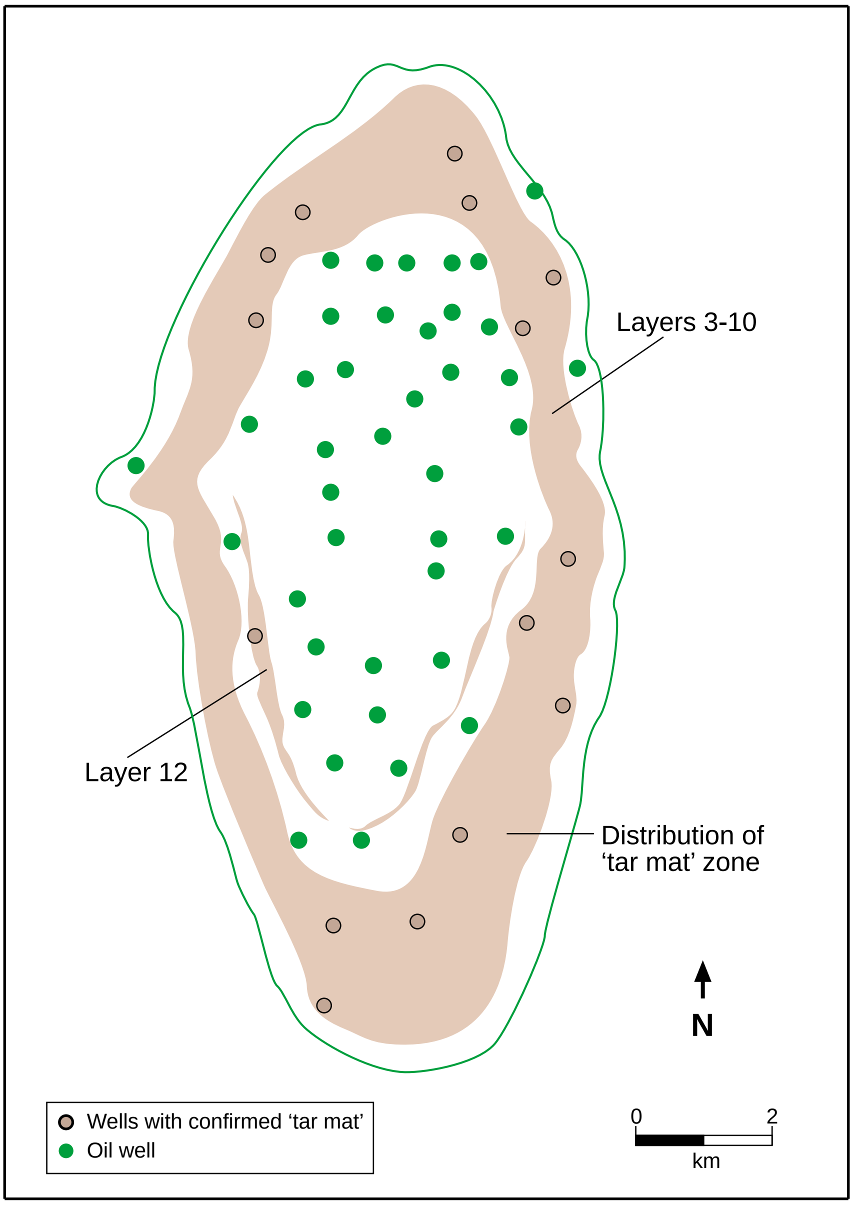

Figure 11: Field-wide distribution of the Minagish tar mat; asphaltenes are concentrated in high-permeability layers at the base of the oil column.

GEOCHEMICAL COMPOSITION

Density and Viscosity

Iatroscan analysis provides not only information on the location of tar mats (from which a model for their formation can be constructed), but also an alternative technique for measuring reservoir fluid viscosity. Oil viscosity will have an important controlling influence on water flood in the Minagish field if water is to be injected into the oil column above the tar mat (Figure 3). Although PVT measurements are vital to the understanding of fluid properties, they are only representative of fluids over the perforated intervals of a test column. An important feature of the Iatroscan technique is its ability (as long as core is available) to predict variations in live oil viscosity throughout the oil column and into the tar mat where there has been no PVT sampling.

Key data provided by Iatroscan are the asphaltene profiles. Using data from various Middle East oils, a tentative relationship can be established between dead oil density and asphaltene content (Figure 12) and hence of viscosity. The scatter is in part because the oil data represent a variety of source rocks and partly because the amounts of asphaltene can be difficult to measure accurately. An exponential fit through this plot gives the following relationship:

$$\text{Dead oil density} = 0.847^{(0.00445 \times \%\text{asphaltene})} \qquad \text{(Equation 1)}$$

It infers that at densities of less than 0.847, asphaltene contents are very low and have little effect on density. Conversely, at high asphaltene contents, the density increases rapidly and at 100 percent asphaltene, the density would be 1.32 grams per cubic centimeter (g/cm^3).

Asphaltene measurements are available from two live oil samples from the Minagish Oolite reservoir of the Minagish field and are summarized in Table 1. The oils have an asphaltene content of between 6 and 8 percent, which is very similar to the Iatroscan values for the wells. For example, Well-C (Figure 6) has asphaltene contents of between 5 and 15 percent in the main body of the reservoir, with increasing asphaltene content at greater depths. The oil asphaltene contents are an average of oils flowing from the perforated intervals and therefore are not directly comparable to core results. When this averaging effect is taken into account, the oil values are similar to those from the Iatroscan determinations from the core. In addition, Iatroscan deals with solvent extracts. Dichloromethane is very effective at dissolving asphaltenes and, consequently, the amount of asphaltenes recorded by the Iatroscan technique will generally be higher than the flow of asphaltenes into a well.

Table 1
Minagish oil samples

	Oil sample data (single well sample)	Oil sample data (generic field sample)
API Gravity		33.2
Density (g/cm^3)		0.859
Saturates (%)	46	42.8
Aromatics (%)	33	40.2
Polars (%)	15	9.0
Asphaltenes (%)	6	8.3

PVT data are available for several wells drilled into the Minagish Oolite reservoir. A problem in trying to compare core-extract data with PVT data is that PVT data, like the asphaltene contents, may be from fluids that represent an average of several perforated intervals. This makes it difficult to compare directly core data with PVT data. The best comparison is PVT data that were measured in several

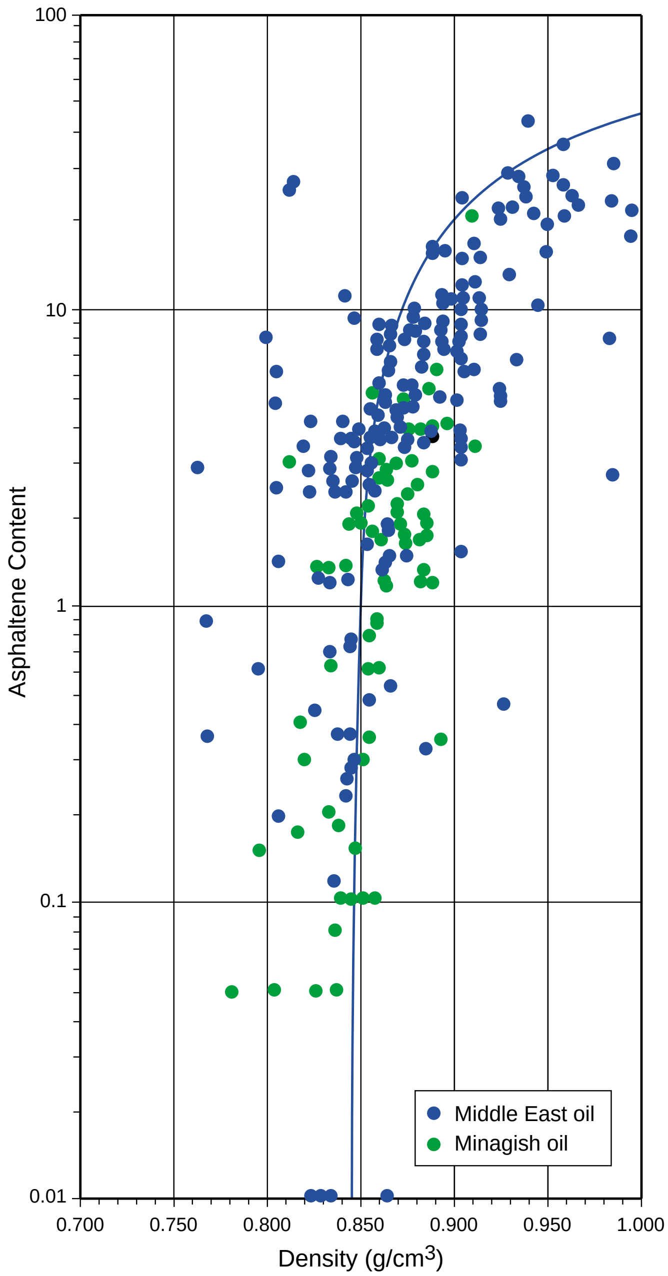

Figure 12: Dead oil density versus asphaltene content for Middle East and Minagish oil.

narrow perforation intervals of Well-A (Figure 14). They include one sample from near to the top of the tar mat zone that is the heaviest oil (density 0.8997 g/cm^3) obtained from the Minagish field.

The Iatroscan data suggest that oil quality decreases with increasing depth in the reservoir. The corresponding PVT data for the oil samples provides corroborative evidence of a general increase in oil density and viscosity with increasing depth. For example, a cross-plot of density versus asphaltene content (Figure 12) shows that an increasing asphaltene content causes deterioration in oil quality, as expected. However, a limitation in the comparison with PVT data is that only a small number of data points are available; a predictive method based on well core is therefore needed.

Calibration data from the oil database were used to predict live oil density for Well-A from the Iatroscan asphaltene data (Figure 13). Predicted densities in the oil leg are 0.77 to 0.87 g/cm^3 at about 10,300 ft followed by rapidly increasing density toward the tar mat. These predictions agree with the measured oil densities of 0.87 to 0.90 g/cm^3 for Well-A PVT data (Figure 14).

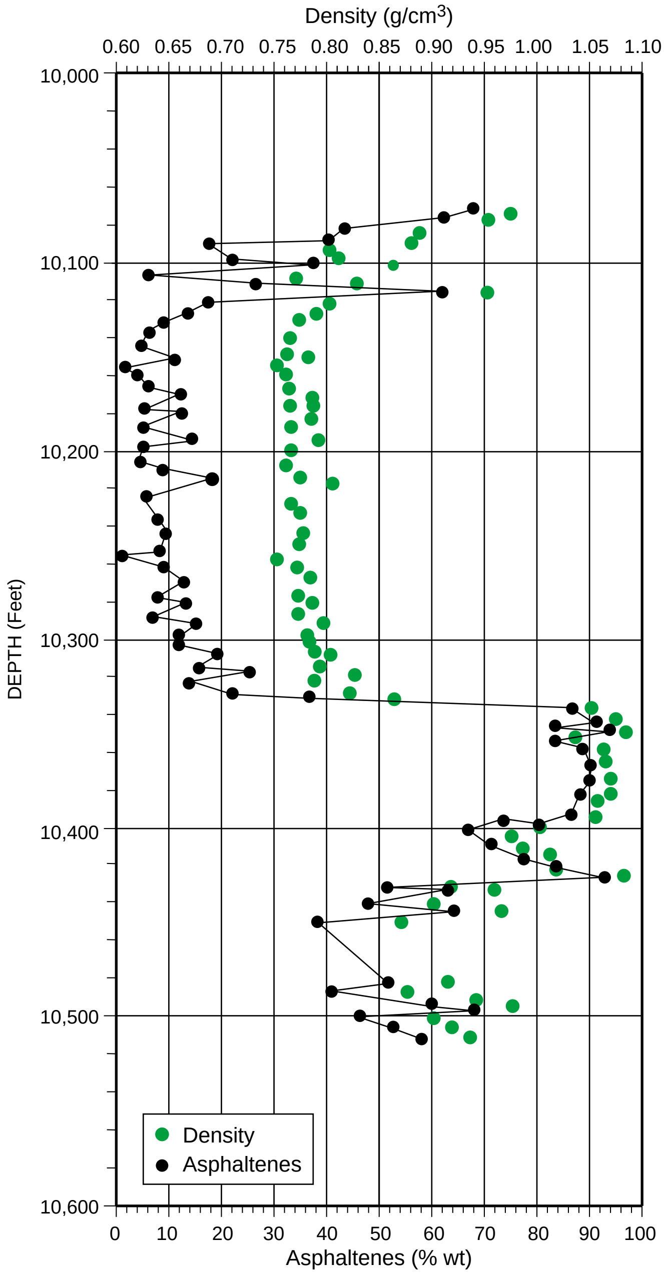

Figure 13: Well-A: predicted live oil density from Iatroscan asphaltene content.

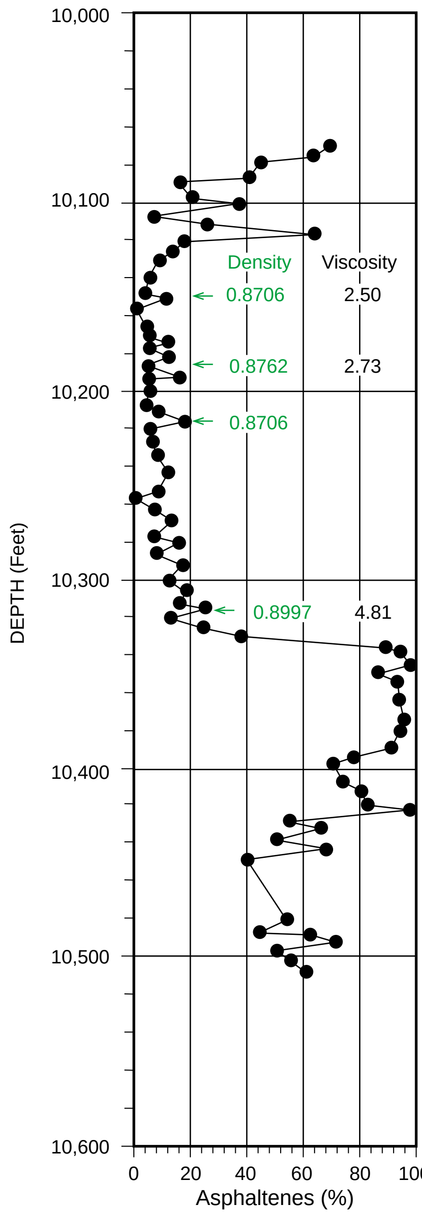

Figure 14: Well-A: asphaltene content and PVT properties as a function of depth.

Live Oil Density Prediction

Given the tentative relationships outlined above between the asphaltene content and dead oil density (Equation 1) the next step is to predict live oil density in the reservoir. Stevens (BP Exploration, written commun. 1997), has investigated general correlations between the gas-to-oil ratio (GOR), gas gravity, dead oil density and live oil density from a PVT data set as follows:

$$GOR = \frac{1.0623 - \frac{\rho}{\rho_{st}}}{0.0006594\,\frac{\rho}{\rho_{st}} - 0.0002314\,\frac{\gamma_g}{\rho_{st}}} \quad scf/stb \qquad \text{(Equation 2)}$$

where ρ is live oil density, ρ_{st} is dead oil density and γ_g is gas density (all in g / cm^3). This equation was rearranged so that live oil density could be predicted from the remaining parameters:

$$\rho = \frac{1.0623\,\rho_{st} + 0.0002314\,\gamma_g\,\text{GOR}}{1 + 0.0006594\,\text{GOR}}\ g/cm^3 \qquad \text{(Equation 3)}$$

Live oil density was calculated using an estimated average GOR of 600 standard cubic feet / barrel (scf / bbl) and a gas gravity of 1.05 g / cm^3 from the compiled reservoir fluid data. Figure 15 shows the predicted live oil density for Well-A plotted against depth compared to the asphaltene content of the core extracts. The plot shows that fluid density is predicted to increase with increasing reservoir depth and for there to be a rapid increase in density toward the top of the tar mat. Such was also the case in the prediction of dead oil density.

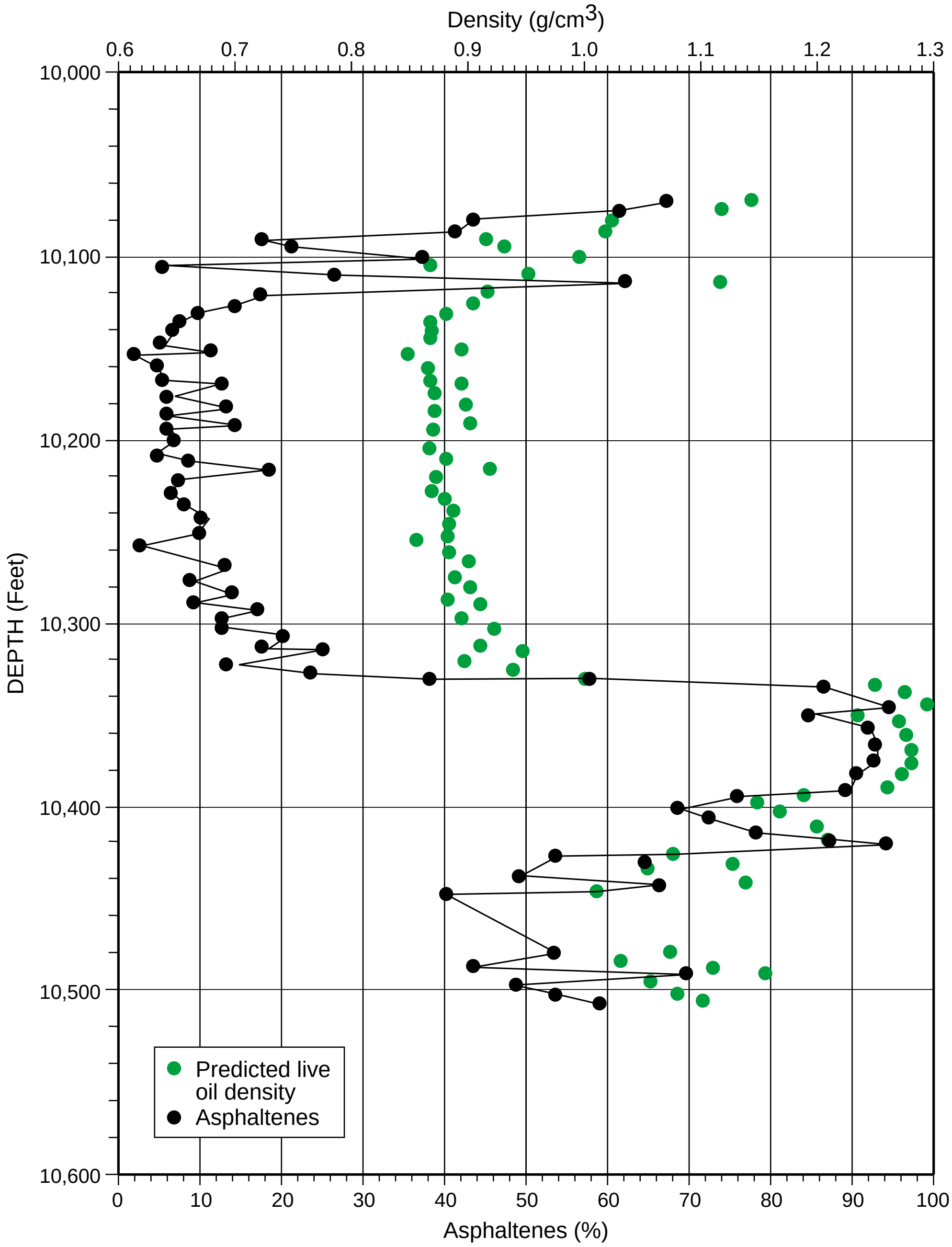

Figure 15: Well-A: Prediction of live oil density from Iatroscan data.

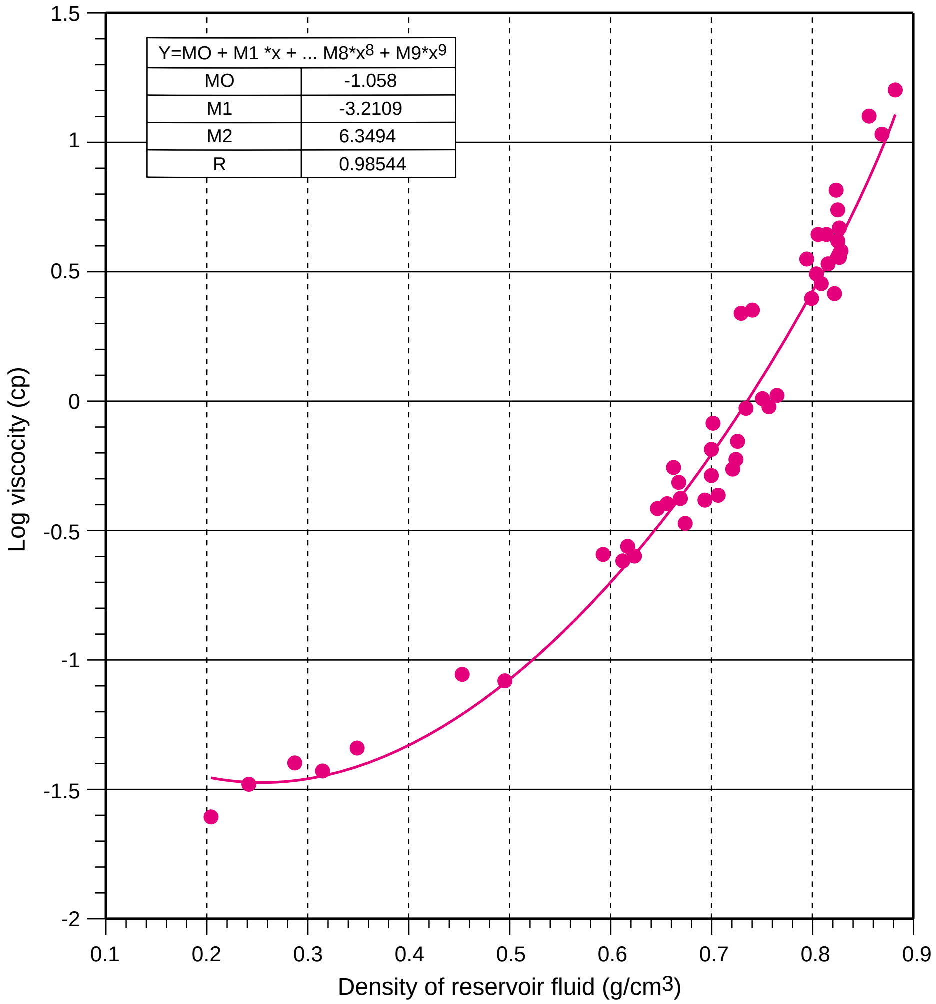

Figure 16: Relationship between live oil density and viscosity for black oils.

Live Oil Viscosity Prediction

Once live oil density has been predicted, the same can be done for the live oil viscosity using the correlations of Stevens (BP Exploration, written commun. 1997). Figure 16 shows the relationship between live oil density and viscosity for several black oils. The formula used to calculate the live oil viscosity is:

$$\mu = 10^{(-1.058 - 3.2109\rho + 6.3494\rho^2)}$$

where μ is viscosity in centipoises (cp) and ρ is live oil density in g/cm^3.

The above equation was used to predict live oil viscosity for Well-A, and the resulting prediction (Figure 17) shows that oil becomes immobile (less than 10 cp) in the reservoir at depths greater than 10,340 ft downhole depth (DD). The predicted Iatroscan viscosities are in close agreement with the measured live oil viscosities from PVT data for Well-A.

Inexpensive and rapid Iatroscan measurements can therefore be used to predict live oil viscosities from core measurements and they are in good agreement with the PVT data. Oil viscosity has an important control on the injection of water as when the asphaltene content reaches 80 percent (tar mat formation) no water can be injected.

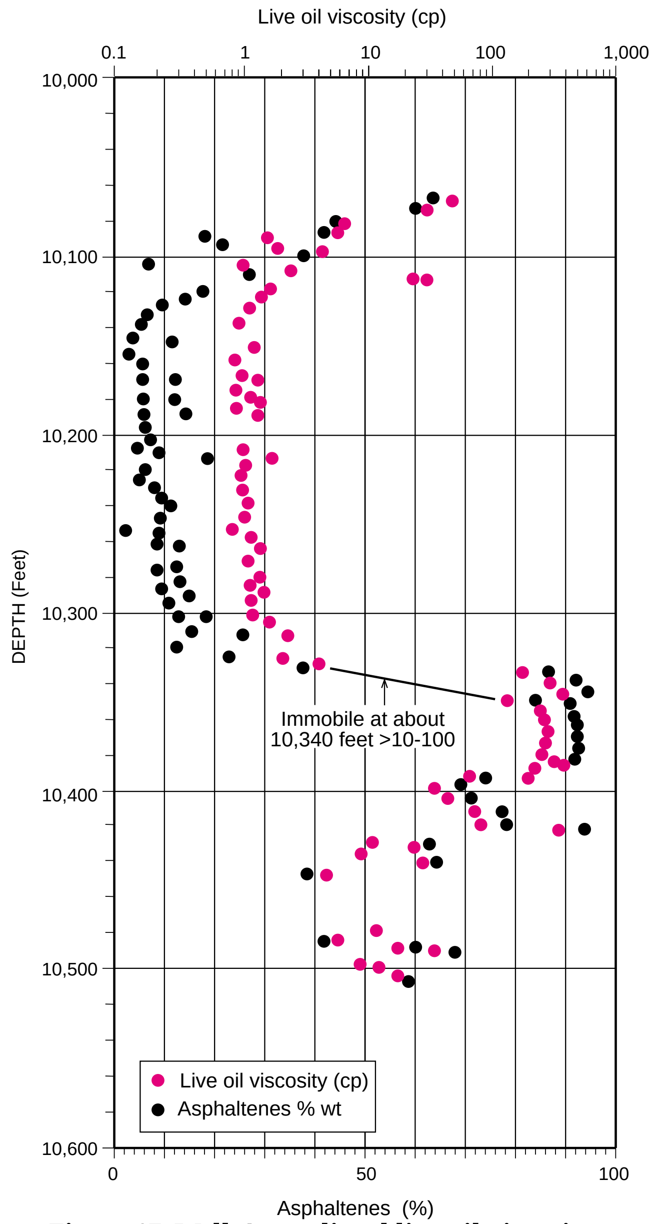

Figure 17: Well-A: predicted live oil viscosity from Iatroscan data.

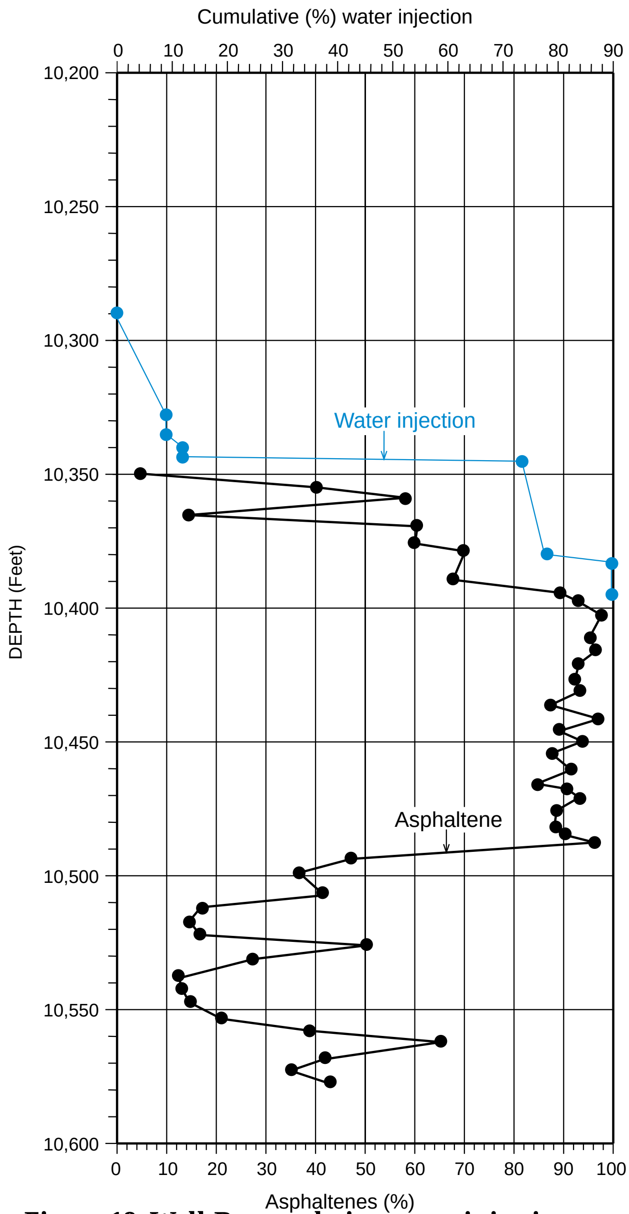

Figure 18: Well-B: cumulative water injection versus asphaltene content.

IMPACT OF TAR MAT ON WATER INJECTIVITY

Well-B has a much thicker tar mat as determined by Iatroscan measurements from the core than was originally estimated from log data. The top of the tar mat was previously estimated to be at 10,420 ft core depth. The Iatroscan data (Figure 18) show that the tar mat is effectively present (asphaltene content greater than 80 percent) at depths of about 10,390 ft DD. Well-B is an injector on the eastern flank of the Minagish field in which recent injectivity tests have been undertaken. A comparison of asphaltene content against cumulative water injection is shown in Figure 18.

Injectivity is greatest in the main section of the reservoir, whereas closer to the tar mat less water can be injected. It was not possible to inject water at depths greater than 10,394 ft. This closely matches the zone of very high asphaltene content, as determined by Iatroscan, and shows that oil viscosity plays a key role in determining injectivity. At this depth, the oil has greater than 80 percent asphaltenes, and corresponds to an in-reservoir viscosity of about 10 to100 cp. Some injection of water was achieved in the zone above the tar mat where the asphaltene contents are between 20 to 80%, although the amount of injected water in this interval was small. The predicted live oil viscosity data, combined with production logging tool results from operating injection wells, indicate that water injection into the tar mat of the Minagish field is not possible.

Earlier work in the Minagish field had led to the suggestion of breaking up the tar mat by injecting water into or below it, so as to create better communication between the aquifer and oil leg. However, it was concluded that it was not possible to determine if the tar mat could be ‘broken’. In addition, water injection with the tar mat broken might cause a loss of energy to the aquifer that would ultimately require even more water injection to provide the same pressure support as with the tar mat intact.

In terms of pressure support, this study has shown that the tar mat is not continuous between the aquifer and the oil leg. The lack of continuity of the tar mat allows water to percolate from the aquifer into the reservoir and for attendant pressure transmission. However, because the areas where the tar mat is not present are of poorer rock quality, it is unclear whether perforating beneath the tar mat would permit a rapid enough pressure communication by means of water support.

CONCLUSIONS

The Iatroscan technique works well on Minagish rocks, and is able to detect marked changes in extract yields and compositional changes in the vertical oil column. The tar mat is characterized by high residual oil saturation (high extract yields), high proportions of asphaltenes, and low amounts of saturates, polars and aromatics. There is a strong relationship between the occurrence of the tar mat and high-permeability layers within the reservoir so that the tar mat is present in layers where permeability is greater than about 100 md. Tar mat formation is related to processes that lower the solubility of asphaltenes, thus causing them to precipitate. Asphaltene solubility may have been lowered either by a late light-oil or gas migration into the reservoir or by a pressure drop as petroleum migrated into the oil column. Live oil viscosity has been predicted from a relationship between oil density and asphaltene content.

At asphaltene proportions in excess of 80 percent (typical of the tar mat zone) live oil viscosity ranges from 10 to 100 cp. Water injection against the tar mat will not occur at these viscosities but as the tar mat has been shown not to be present throughout the reservoir, injection below the tar mat may be beneficial in maximizing the water sweep. However, it is not known whether pressure transmittal through the lower permeability rocks where the tar mat is absent will be efficient. An improved understanding of tar mat occurrence and its distribution within the Minagish reservoir has allowed future injector well locations and perforation intervals to be optimized.

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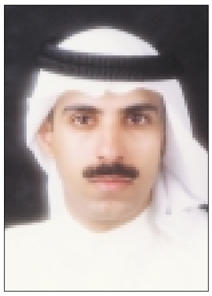

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