Abstract

Production Petrophysics plays a key role in reservoir surveillance and field management. This is particularly true for mature assets which present several challenges related to fluid contact movement, connectivity of reservoir layers and well productivity. Identification of infill targets therefore requires an integration of all sub-surface data. This paper presents examples from a mature North Sea field where cased-hole surveillance helped minimize risks in a high cost infill project. The Machar field, located in the UK Central North Sea is a fractured Cretaceous chalk and Palaeocene sandstone oil reservoir. The field development has been carried out in a phased manner due to a high degree of reservoir uncertainty, especially in the eastern flank. Enhancing the seismic sufficiently to fully assess prospects on the east became a priority, and ultimately led to drilling the east flank of the field in 2008.

Machar is a subsea field development and therefore petrophysical surveillance has been restricted due to limited well access and logistical challenges. During the infill drilling, it was therefore decided to use the opportunity and capture cased-hole saturation and production logs in existing wells. This data enabled the asset teams to understand fluid displacement mechanisms and upon integration with LWD and other logs provided the basis for the side track strategy. In particular, location of the imbibition flood front, fracture conduits and differentiation between formation and injection water were critical in the delivery of a successful producer.

Two wells have been drilled on the eastern flank, one in 2008 and another in 2010. Baseline petrophysical surveillance was part of the data acquisition program in both wells. The initial objective was to use such data in Time Lapse mode with later surveillance. However, in-depth work identified immediate use when integrating with LWD and Wireline data.

Field Introduction

The Machar field is located in UK block 23/26a in the central North Sea in 87m of water. It was discovered in 1976 and brought on stream in 1998. The reservoir is contained in a supra-diapir dome of Upper Cretaceous and Palaeocene strata that have been uplifted by the diapir and are sealed by Eocene mudstones. The field comprises two main reservoir units; the Upper Cretaceous and lowest Palaeocene chalks and Palaeocene turbidite sandstones. The Chalk Group is divided into the Hod, Tor and Ekofisk formations, the Tor being the dominant reservoir unit. The sands were deposited by NW-SE flowing turbidity currents that form many of the regional Palaeocene reservoirs.

The chalk reservoir has been the primary development target to date. Palaeocene turbidite sandstones account for ~25% of the STOIIP while the Chalk accounts for the remaining 75%. Communication around the field is normally good, with some key exceptions and there is evidence for pressure communication between the chalk and sand reservoirs.

The reservoir is currently under development using a voidage replacement water flood. However a ‘blow-down’ phase is planned in the future, when water injection will cease, to allow solution gas drive and gas cap advance to increase oil recovery. The structure has a vertical oil column of approximately 1300m TVDSS (Figure 1). The reservoirs are near flat at the crest but steepen to 45-60˚ on the flanks. The field performance is strongly influenced by a concentric fault geometry, evident in seismic data and drilled wells. Development wells cut numerous intensely fractured zones that aid well productivity and drainage in the low-permeability chalk matrix.

Recent reprocessing and reinterpretation of the seismic data has allowed mapping of the reservoir concentrically around the full extent of the diapir. The new interpretation resulted in an east-flank with significantly higher reservoir volumes and areal...
extent, allowing a well of sufficient length for an effective chalk producer, with considerable exposure to a highly fractured chalk reservoir, to be drilled.

Production Petrophysics

Production Petrophysics plays an important role in reservoir management during field life. It is not limited to petrophysical surveillance but includes understanding displacement mechanisms at various stages of field development. In Machar, reservoir performance prediction is a challenge because of the complexity of the fractured chalk reservoir under the combined processes of compaction, solution gas drive and gravity drainage. The current Machar development plan calls for a final phase of depressurisation and gas displacement following the present reservoir water-flood. Optimising recovery can only be achieved by the collection and integration of a wide variety of information. The Machar field has extensive core coverage with core available from 9 wells. The chalk section has been cored in 7 wells giving a total core length of ~750m, with recovery in the Ekofisk and Tor formations. No core was recovered in the Hod. The Palaeocene has been cored in 4 wells with a total core length of 95m. These cores are critical for the calibration of log calculated properties.

Integrating core analysis, with existing petrophysical surveillance and residual water saturation from new wells gave a new insight into displacement efficiency. The goal is to understand spontaneous imbibition and gravity drainage in the flooded matrix. This will help determine if options such as the extension of water flood into the attic of the field may offer an alternative to depressurisation. Characteristics of the chalk reservoir are that oil is recovered through solution gas drive with secondary recovery from water injection. Recovery could be further enhanced through depressurisation. Initial reservoir pressure was 3812 psi with an oil column of 1330m of 0.3cp 41deg API oil.

Core Measurements

Accurate definition of residual oil saturation under gas gravity drainage (Sorg) and water injection (Sorw) are essential for reservoir performance optimization. The main uncertainties are related to wettability and matrix/fracture interactions. The initial centrifuge based capillary pressure measurements focused on a direct comparison of experimental Sorg’s and Sorw’s in the high porosity/permeability Tor Chalk core samples. Sorw from the centrifuge experiments appeared to be related to the permeability with the highest permeability sample having a Sorw of 37.3su while the lowest permeability sample had a Sorw of 51.7su. Sorw’s derived from the centrifuge tests exhibited similar behaviour with the highest permeability sample measuring a Sorg of 24.8su and the lowest permeability sample a Sorg of 35.8su.

Sorw from the centrifuge experiments were on average 44.3su which is 13.8su higher than the average Sorg of 30.5su when the rock is displaced with gas. The wide range in the initial displacement studies data prompted further core work focused on defining the waterflood displacement characteristics of the low porosity / low permeability Tor Chalk. The low rate reservoir condition waterflood yielded residual oil saturation Sorw of 30su. There was very limited post breakthrough oil production, with an average oil saturation at breakthrough of 39su reducing to 30su after 35 pore volumes throughput. The differences in Sor appear to be due to the differences in sample permeability and porosity, with the high permeability / high porosity samples showing the best matrix oil recovery.

Petrophysical Surveillance

Reservoir surveillance is a key component of field management and optimization. The ability to monitor changes in reservoir performance, fluid contacts and well productivity becomes even more significant towards the end of field life. Being a subsea development, well access is the main challenge to data acquisition. The available cased-hole data comprises of various vintages of Pulsed Neutron Capture logs and Production Logs (Figure 2). Most of the data were acquired with rigs during infill drilling campaigns and lately data gathering was associated with well work from light intervention vessels (2006, 2008 and 2010). Although lower cost than rigs, surveillance it is still prohibitive using light intervention vessels. Interpretation of the data also poses challenges related to reservoir, completion and facilities complexity. The main interpretational uncertainties relate to:

- Water salinity variation
- Changes in Porosity
- Presence of Fracture Conduits
- Cement Quality
Formation water salinity is 135kppm (from core data) while injected water has a salinity of 32.8kppm. Some water samples ranged between 190 and 230kppm, indicating that formation or injected water is leaching the salt diapir. A change in salinity with time can be observed by monitoring the field tracer data measured from surface flowline samples (Figure 3). Note the change in chlorides values (decrease) as a result of sea water injection followed by a stable period, and then increasing as wells are SI, and again “stabilized” around 80kppm following pressure support and the introduction of gas lift. Tracer data plays an important role in understanding water movement around the field and should be corroborated with the fluid information obtained from cased hole saturation and PL data.

Changes in porosity occur around perforated intervals due to the use of acid frac stimulation. No proppant is used in the stimulation. Figure 4 represents the Sigma change as a result of porosity enhancement in well A01. Mud losses and the Stoneley response are the main fracture indicators and are used for initial perforation selection. The difference between 2002 and 2001 Sigma’s is related to an add perf / acid frac job. The length of perforations is 3 to 5 meters and the 2002 Sigma response corresponds to strong acid effects. In this example, the difference between 2001 and 2002 Sigma is related to the efficiency of acid frac stimulation rather than any change in saturation. The effect propagates between perforations and even above the top perforation.

Prior to 2006 there have been some attempts to look at the cased hole saturation logs (Sigma data), but the approach was to use standalone log analysis rather than integrating the data from multiple sources. A more integrated approach results in a change to the work flow and information sources used to converge on a solution. Steps in this process include:
1. We correlate chronologically the cased hole logs with the phase of development (ie primary vs secondary recovery). A major milestone is the start of water injection. Timing is important in Production Petrophysics, as logs respond to specific conditions at a given time. We have to consider all aspects, from appraisal to late field developments. Although we can relate dynamic changes to a specific point in time, ideally they should reference measurements to initial reservoir state and to achieve this, a robust initial porosity and saturation model (height function) is required in any subsequent surveillance work.
2. Understand the displacement mechanism and limitations of the Sigma model. As a stand alone measurement, Sigma is limited due to high uncertainty related to water salinity.
3. Generate a synthetic Sigma using a material balance equation.
4. An estimation of Sorw is a critical input into simulation modelling. Log Inject Log was not considered viable as the core scale experiments took 24 days to achieve maximum matrix imbibition and at the well scale water will preferentially flow through the major fractures. In one instance (well 128) we have been able to calculate the Sorw in chalk. Well 128 was planned as a Palaeocene Sand producer with an updip pilot hole to ensure an optimal trajectory for the mainbore down the steeply dipping flanks of the Machar diapir. Opportunistic data acquisition allowed the pilot hole to be deepened into the potentially swept chalk to determine residual oil saturation. The well encountered updip swept Palaeocene sands and Chalk close to an anticipated water ‘highway’ between an injector and producer.

Formation tester water samples showed formation water rather than an assumed ‘mixed’ or seawater composition. This data reduced the uncertainty in Sor determination from wireline logs due to known water resistivity in swept zones. Figure 5 shows significant matrix water imbibition rather than minor water imbibition associated with just the chalk fractures, with a Sorw value of 45s.

Machar East

Most of the field development has historically been in the western side of the field where seismic quality could define the structure leaving the eastern part of the field an undrilled target. Machar East was drilled in October 2008 and encountered a full reservoir section both in the Palaeocene Sands and in fractured Cretaceous chalk. Reservoir depths and thicknesses were within the predicted range even though the target was seismically less well defined. The initial penetration (B1z on Figure 6) encountered water-imbibed chalk in the latter part of the well, suggesting that the modelled matrix water front was further advanced than base-case modelling had suggested (Figure 7). Complexity of drilling called only for LWD data acquisition with a contingency for pipe conveyed fluid sampling. However water samples could not be taken in the well which left a large uncertainty in the water salinity across the imbibed zone. The use of formation water along the entire section would have generated pessimistic water saturations from resistivity data and been detrimental for future production from the area. A sidetrack from the original well location (B1y on Figure 6) increased significantly the interval of oil bearing chalk. LWD, open hole and cased hole wireline data integrated with geological and seismic information provided the basis for the side track and completion strategy. The baseline Sigma taken in the sidetrack (B1y hole) before perforation and acid frac stimulation confirmed the presence of sea water in the imbibed zone (Figure 8 and 9).

An understanding of fluid displacement through the integration of core displacement studies backed up by petrophysical surveillance enabled immediate action to be taken to sidetrack the original well. Key elements of production petrophysics work have been used to design the completion and perforation strategy, especially the vertical and lateral standoff from the imbibed zone.

The Machar East 2 well was drilled in 2010 and also encountered reservoir sections in the Palaeocene sands and in the fractured Cretaceous chalk. As part of a surveillance plan, pulsed neutron logs were acquired in both sigma and carbon-oxygen.
modes during the logging operations. As explained earlier, sigma measurement alone would not be adequate to meet the diagnostic and surveillance requirements due to variations in formation water salinity. Multiple approaches were utilized to address the conditions. One of these uses a simultaneous solution for resistivity and sigma data (Figure 10) to obtain water saturation at every depth level using a minimization routine that such that looks for the minimum of the square of difference between Sw Res and Sw Sigma using a range of salinity inputs. In addition to water saturation, this method provides a continuous output of water salinity (Figure 11). Variations in computed water salinity are observed and these can be explained by the heterogeneity of the reservoir in the logged section.

The wellbore environment was within the conditions of the characterized data base for pulsed neutron log measurements in this well and high confidence logs were obtained. The sigma and carbon-oxygen evaluation (Figure 12) shows two zones of interest. The difference between synthetic computed sigma and measured log sigma at 2625m shows an inhibition effect since the computed sigma uses a formation water salinity (135000ppm) where as the actual log is lower indicating a fresher water salinity in that zone. In the Ekofisk and Maureen sandstone sections round 2900m, another effect comes into play. There are variations in matrix and sigma therefore also responds to lithology changes in addition any saturation variations. To resolve this, an additional processing was carried out using the spectral lithology methodology which de-convolves the gamma ray spectrum into its constituent elements in terms of relative yields (Figure13). These are then converted to dry weight elements and eventually into lithology fractions. The model is built from geochemical studies and a core data base using infra red mineralogy, x ray fluorescence and mass spectrometry. The bottom section in Figure 14 highlights the variations in calcite and limestone in the Maureen and Ekofisk zones. Inability to account for these would introduce errors in both sigma and carbon-oxygen evaluation.

Conclusions

Resolving dynamic displacement within Machar is complex due to the influences of sea water injection, fracture network, diapir proximity, primary gas cap as well as secondary gas caps. Production petrophysics can help better understand the driving mechanisms and narrow the parameter uncertainties within the dynamic model.

Unlike conventional open hole petrophysics where multiple calibration points are available from conventional and special core analysis, in production petrophysics we are dealing with a limited number of calibration points that might not be representative of the entire reservoir. Careful consideration should be taken when reconciling dynamic measurements from core with cased hole logs and reservoir models. Ideally they should converge towards the same answer.

In the absence of a coring program, formation evaluation programs in new wells drilled behind the imbibition front should target key information to reduce the uncertainty around of key parameters such as Sorw, and Sorg.

The use of baseline cased hole nuclear logs should be promoted to help characterise and capture changes at the formation-well interface. A dual baseline should be considered for wells consisting of a baseline immediately after setting the casing and another after perforation and acid frac stimulation. With this configuration there will be continuity between OH data and subsequent time lapse data, accounting for both changes in porosity / water saturation due to stimulation and real changes in saturation due to fluid displacement processes.

Acknowledgements

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References

Zett A, Mukerji P, 2008, Subsea Logging and Intervention – Challenges and Solutions on Machar Field, 14th SPE ICoTA European Well Intervention Round Table, Aberdeen, Scotland.
Machar Oil Column
1330m (tvd)

OWC – 2500m

Figure 1 – Machar Structure

Mapping from PSDM finalised 2007

Figure 2 – Petrophysical Surveillance in Machar Field
Figure 3 – Flowline Field tracer data

Figure 4 – Stimulation Porosity Enhancement
Figure 5 – Water imbibed matrix chalk
Figure 6 – Machar East cross section

Figure 7 - Water thickness difference map between Jan 2009 & Jun 1994 (initial conditions) Chalk reservoir

Figure 8 – Distribution of Resistivity derived Sw and corresponding Sigma values in the sidetrack chalk (B1z hole)
Figure 9 – Baseline Sigma in Machar East sidetrack (B1y hole)

Figure 10 – Resistivity–Sigma Cross-plot (interval 2650-2350m) method in Machar East sidetrack (B1y hole)
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Figure 11 – Resistivity–Sigma Cross-plot method solution in Machar East sidetrack (B1y hole)
Figure 12 – Baseline Sigma & Carbon-Oxygen log evaluation in Machar East 2

Figure 13 – Spectral Lithology Methodology
Figure 14 – Spectral lithology evaluation from pulsed neutron logs in Machar East 2