SUMMARY AND CONCLUSION

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The primary objective of this research was to model a cyclic Upper Rudeis reservoir encountered in twelve key wells of thirty selected wells scattered in the study area, central Gulf of Suez in an integrated fashion involving geological, petrophysical, geostatistical, and fluid flow studies. The resultant reservoir description model could be used to better predict the reservoir performance of the Upper Rudeis, and also be adopted as a subsurface analogue for similar cyclic sandstone reservoirs.

The area under study is located in the west of July field, central Gulf of Suez restricted between latitudes 28° 24′ 58.1″ and 28° 32′ 35.9″ N and longitudes 33° 21′ 00.0″ and 33° 25′ 46.2″ E.

Structural Configuration

The Upper Rudeis reservoir of Early Miocene age represents a part of the syn-rift stratigraphic sequence of the Gulf of Suez rift basin. In the July field area; this reservoir was deposited on the slope of a large delta system and controlled by a major structural transfer zone and has been uplifted as a normal fault bounded, structurally high block forming a major oil field. Moreover, the Upper Rudeis records earlier structural deformation in the area represented by pulses of medium grained sediment progradation from the western shoulder of the rift during which episodic fault motion in the July field area resulted in dramatic lateral changes in thickness and facies.

Integrated Reservoir Characterization

Both the depositional and diagenetic models were prepared and the main features were retained. The large scale reservoir framework was defined to incorporate detailed reservoir layering and facies variation. Sequence stratigraphic analysis dramatically improved the understanding of the spatial variability of the reservoir properties. Spatial analysis of porosity and permeability were performed by considering heterogeneity in three dimensions. Core data was used to assess the heterogeneity of the permeability at different vertical and horizontal scales. Horizontal core plugs provided valuable spatial information at short lag distances and this is more powerful if the core itself was horizontal.

Depositional model

The principal source of data for the depositional model were produced by detailed examination and logging of cores penetrating the Upper Rudeis reservoir. Main core characteristics recorded on litho logs were lithology, the size of constituent grains and the depositional texture of the sediment, however, previous core descriptions were not performed in a manner suitable to be used in sequence stratigraphic analysis. The Asl and Hawara formations were deposited by a series of gravity flows indicated by a convulsive tectonic events, where rift margin alluvial fans become active, transporting large volumes of runoff and sediments down slope and offshore in a short period of time. These turbidite sediments model refers to the depositional mechanism as a submarine gravity flow rather than the classic Bouma sequence turbidite deposit. This interpretation is based on a combination of stratigraphic position, sedimentary structures observed and the paleoenvironmental analysis. The resulting depositional model is a rift margin shoreline supplying sediment each representing a pulse into an offshore bathymetric and structural low created by two similarly trending tilted fault blocks.

Sequence stratigraphy and reservoir quality

The Upper Rudeis rocks deposited during a low stand system tract (LST) exhibit an improvement in the reservoir quality towards land, the resultant effect is that the best rocks in terms of primary porosity are situated towards the palaeo shoreline. On the contrary, during the high stand system tract (HST), higher energy sediments are pushed away from shore during the progradation phase. This is the reason for the improvement in the primary porosity towards the basin in the direction of open marine environment. The progradation of the Upper Rudeis sandstone gave the origin to more heterogeneous facies, although with lateral continuity. The Upper Rudeis reservoir subdivided into two major units; the Lower Hawara Formation and the Upper Asl Formation.

The Hawara Formation is characterized by thickening upward cycles, while the Asl Formation is characterized by thinning upward cycles. The progradational cycles of the Upper Rudeis are dominated by carbonate sediments. Between the Asl and Hawara formations a maximum flooding surface (MFS) exists. This MFS is marked by a tight burrowed shale unit, which is an important flow barrier between the Asl and Hawara. The entire Upper Rudeis is bounded by two sequence boundaries which separate a thick succession of evaporites at the upper part and shale at the lower part from the reservoir rocks. These evaporites (anhydrites) are interpreted to be supratidal deposited in large hypersaline environment as part of a late high stand system track (HST).

Reservoir rock types

Reservoir rock typing is a set of techniques aimed at classifying rocks from their constituents, texture and porous network properties. Core data are the only directly measured reservoir petrophysical data, thus are often considered as hard data. Core analysis data are often used as the basic data for reservoir characterization and special core analysis (SCAL) data are critical for modeling reservoir fluid flow and distribution in reservoir rocks. Understanding permeability controlling factors and predicting permeability distribution was recognized at an early stage of the reservoir characterization as the pivot point of the Upper Rudeis integrated reservoir characterization study. Describing, quantifying and predicting permeability ranges and variations inside a clastic reservoir requires understanding of porous network properties through direct rock observation and petrophysical analyses.

In this study, we recognized more detailed subdivisions during the integrated reservoir characterization, while the previous workers were subdividing the Upper Rudeis into general sedimentological facies correlatable field wide, based on the abundance of accessory minerals, cementation and on the proportion of lime mudstone.

Capillary pressure curves measure for reservoir quality

In the Upper Rudeis heterogeneous reservoir, one single capillary curve can not describe the reservoir, because the shape and position of the capillary curve is mainly dependent on the permeability and porosity of the rock. When a reservoir consists of alternating permeable and impermeable layers, several oil-water contacts can be found in one well. Since the free water level (FWL) is horizontal in a single reservoir, the position of a fluid contact may change throughout the field.

The capillary of pore systems in J37-37A core plugs of Hawara Formation is highly variable. Rocks with a preponderance of large well connected pore throats have low capillarity. Rocks containing only very small pores have high capillarity, where the degree of size affects the curve. Well sorted pores display prominent plateaus, while poorly sorted pores have more linear curves. The pores size distribution are dominated by micropores with macroporosity and very little megaporosity present. Thin section photomicrographs confirm that matrix microporosity is the typical pore type. The porosity system is strongly unimodal pore throat size of 0.1 μ to 15 μ. Samples exhibit differing modal pore sizes due to the widely varying degrees of cementation that yield a wide range of porosities (0 - 15%).

Fracture analysis and implication to reservoir permeability

Fracture analysis was conducted using core images, modular dynamics formation tester and dipmeter processed data. The fractures encountered were classified into two main classes, based on their morphology: a conductive class representing open fractures, and a resistive class representing asphaltine filled fractures. In general, open and asphaltine filled fractures can occur with similar directional trends. However, the most directional trend and distribution of open and asphaltine fractures is dominantly NW-SE. Fractures are interpreted to develop as a result of faulting. However, certain layers of the Upper Rudeis reservoir, such as Layers (L14 and L15 at SG310-5A and L11 and L12 at J37-37A), exhibit the best developed fractures and fracture enhanced permeability, whereas in other layers such as mud supported rocks fractures' are absent. Thus, both deformation (structural position) and lithology playa are responsible in rock fracturing, occurrence, and distribution. The fractures were not dynamically modelled in the flow studies, since the aim of this research was to establish the relationship between fluid flow, layer cyclicity, variogram models and methods of description. Since fractures do not dominate the flow in the Upper Rudeis (stratigraphic layering and associated permeability contrasts are more important) a structural analogue was not developed further. Further work would be required in order to find ways of incorporating fractures into the modelling procedure.

Diagenetic model at megascopic and macroscopic scales

The diagenetic model of the Upper Rudeis was confirmed and progressed in three stages:

1- Very early diagenetic stages

Precipitation of chlorite, pyrite, and alteration of fecal pellets to glauconite results from reducing conditions in marine pore fluids; this occurs soon after burial. Accumulation of bacterial end products in pore fluids often results in precipitation of carbonate minerals and iron sulfides. The earliest diagenetic event is compaction. This is most significant for sediments with a high mud content; sand sized grains floating in the mudstone matrix exhibit few and minor diagenetic changes. This results from isolation of these grains from pore fluids that affected cementation and dissolution. Rate of compaction of sediments decreases through time; later diagenetic cementation of sandstones by calcite and quartz stabilizes the grain framework; this decreases porosity and permeability loss through rearrangement of grains.

2- Early to middle diagenetic stages

Rims of chlorite coating quartz grains and intergrown with the well developed quartz overgrowths. Porosity and permeability exhibit general upward increase, which correlates with increase in depositional energy (trough crossbedded sandstone), and decrease in amounts of calcite cements. Early diagenetic alteration is indicated by presence of the competent siderite clasts on Upper Rudeis trough crossbedded sandstones. The initial stage of calcite cementation in is probably contemporaneous with alteration to siderite of foraminiferal tests.

3- Middle to late diagenetic stages

These late diagenetic pyrite crystals are commonly associated with the dolomite and may result from changes in chemical composition of pore fluids resulting from migration of hydrocarbons into the Upper Rudeis sandstone. Quartz and feldspar grains in the thin section display well developed overgrowths. Overgrowth formation was followed by precipitation of optically continuous, calcite cement. This was followed by filling of the secondary pore by dolomite and pyrite. Also visible are a glauconite pellet that has been slightly altered to illite and plagioclase feldspar that underwent extensive late diagenetic dissolution and recrystallization.

Original grain outline is indicated by brown dead oil (latest diagenetic emplacement). Dissolution of the calcite cements resulted mainly from changes in pore fluid chemistry, primarily organic and carbonic acids associated with hydrocarbon generation and migration into the reservoir. This created secondary porosity, and provided the primary source of chemically reduced iron for pyrite and dolomite. Migration also resulted in dissolution of feldspar and subsequent precipitation of kaolinite in pores. Primary intergranular porosity is the dominant porosity type in the Upper Rudeis reservoir. The size and shape of the intergranular pores has been modified by diagenetic processes (compaction and cementation). Cementation is by far the most important factor affecting the size, morphology and interconnection of primary intergranular porosity. Secondary dissolution porosity is also present as a porosity enhancement due to leaching of chemically unstable allochemical grains. Interagranular porosity is best developed within moderately to coarsely grained fabrics and more poorly developed within fine grained fabrics.

The diagenesis in the Upper Rudeis is fabric selective, enhancing the depositional contrasts. The dolomitization is also fabric selective as it is established in the top and bottom layers of the reservoir. After review of the large scale reservoir depositional and diagenetic framework, the main features were retained, but the large scale reservoir model was refined to incorporate detailed reservoir layering and facies variation. In this context, emphasis was given to sequence stratigraphy, bearing in mind the broad objectives of improving oil recovery and developing an analogue model in the process. These sequence stratigraphic analyses dramatically improved understanding of the spatial variability of the reservoir properties. For example, in the case of the Asl Formation, the improvement of reservoir properties towards land is the result of a transgression; while for the Hawara Formation, the improvement of reservoir quality towards the sea (opposite direction) is the result of a progradation of sediments towards a more open marine environment located in the east-southeast. This asymmetrical behaviour in the reservoir property trends between the Asl and the Hawara formations is a direct consequence of the different sequence stratigraphic settings during the deposition of the reservoir. This model had significant implications for the spatial analysis (variograms) and subsequent modelling of petrophysical data.

Well Logging Analysis

The graphical well log analyses have provided the means to distinguish patterns typical of complex pore types (size and connectedness), occurrence of irreducible water saturation and presence of transition zones. The analysis is based on the Pickett plot and delineation of depth based trends and patterns in porosity, resistiviy, water saturation and bulk volume water (BVW). Thousands of analyses have demonstrated the fact that porosity varies considerably due to varying pore type and capillarity. While porosity may vary little, saturations and productivity can be considerably different when pore types change. Alternatively, changes in water saturation and bulk volume water (BVW) may vary closely with elevation of the reservoir, suggesting fluid continuity, as well as serving as an additional tool in evaluating lateral reservoir continuity. The result has been an improved means to evaluate potential production and to assess zonation and continuity of the reservoir and ensuring fit reservoir modeling.

Petrofacies Analysis

Petrofacies analysis is used in Upper Rudeis reservoir characterization study to extend an initial stratigraphic analysis of a sandstone reservoir in an attempt to define flow units and to conduct a reservoir simulation of the field to help evaluate future production options. Volumetric properties of pore space and fluid saturation were calculated from porosity logs (density, neutron and sonic) and resistivty logs using Pickett plots and found to be a useful technique for capturing the heterogeneity of the reservoir and determining the main flow units and provide reliable analysis of pore types, abundance, and shapes and fluid saturations that pinpoint flow units by geological origin, and compare pore origins with reservoir quality rankings of individual flow units. When the data points are connected in order of depth within reservoir, the characteristic patterns reflect reservoir rock character and its interplay with the hydrocarbon column. Contrasts between reservoir pore types and fluid saturations are reflected in changing patterns on the cross plot and used to discriminate and characterize reservoir heterogeneity. The zonation of the reservoir was based, primarily, on gamma ray, sonic and the neutron-density logs. Zones with low, but existent connectivity are classified as baffles, and zones with high capillary resistance to flow are classified as barriers. Porosity and permeability may have formed as results of depositional or diagenetic processes, as fractures, or as composites of end member pore types.

RFT identify Pressure Gradients and Permeability anisotropy

The use of wire line repeat formation tester (RFT) to get vertical pressure profiles, mobilities, in situ fluid samples and vertical permeabilities is achieved.

Pressure changes are continuously recorded throughout the test. The limitation of the using of mobility, k/μ, because this is a measurement in the damaged zone and influenced by mud filterate. The modular formation dynamics tester (MDT) allows pumping of reservoir fluid and real time measurements of fluid properties to ensure in situ quality fluids before securing samples. In development wells of the study area, the measured pressure profile reflects the response of the reservoir to production and the pressure information interpreted in terms of reservoir structure and fluid distribution.

Pretests were performed to determine the formation pressure within several intervals of interest at the selected wells J37-37A, J37-43A, SG310-4 and formation fluid samples at well SG310-5A. As well, fluid gradients and contacts determined to interpret the hydrocarbon producing potential of these wells. The pressure depth plot indicates that oil and water intervals are present. The calculated pressure values at vertical depths and formation pressure indicating a constant pressure gradients for Asl Formation equals 0.425 (water bearing) in SG310-5A, while for Hawara Formation is equal to 0.313 (oil bearing). In addition, the intercept of the pressure gradients, corresponding to oil and water, is representative of the oil-water contact at in well SG310-5A. The formation pressure profile, Hawara Formation shows a very distinct gradient change at 10174 feet in SG310-5A well. The fluid density above can be calculated to be 0.97 g/cm3 which fits closely with would expect for water at this depth. The gradient above corresponds to a fluid density of 0.31 g/cm3 in good agreement with the expected value for oil. Hence, the oil-water contact can be put at 10174 feet. This confirmed by open hole log interpretation and MDT fluid sample at that depth which indicates a resistivity value of 0.8 Ωm. Asl Formation, on the other hand, showed a pressure gradient corresponds to a fluid density of 0.97 g/cm3 of water and also confirmed by open hole log interpretation. Asl was water flooded in such location due to penetration of Asl Formation at the wedged thin sand down dip of a faulted block.

A similar application in the rest of the selected wells was conducted, where the formation pressure plot indicates a large gradient change within Hawara

Formation at well SG310-4 at 9590 feet. The slightly higher pressure differences of Hawara would indicate an imperfect vertical communication within Hawara and between Hawara and Asl formations clearly identify them as being separate reservoir units unconnected with each other, while laterally were connected. By comparing pressure variation from well to well in the study area, the discontinuities among wells are indicative of faults and the same result was confirmed by seismic interpretation and 3D reservoir geological model. The non uniform reservoir pressure distribution indicates reservoir layers and permeability barriers.

CMR logs identify flow units and fluid properties

Combinable magnetic resonance (CMR) logs helped identify the pay intervals. The zones were not initially promising because conventional logs did not show a crossover of neutron and density curves in the sand interval. Combinable magnetic resonance (CMR) measurements on Upper Rudeis reservoir Asl and Hawara formations were calibrated with core samples at SG310-5A well to improve interpretation of CMR log data to obtain porosity and correlate pore size distribution, bound water and permeability with T1 and T2 spectra. CMR also provided information about the pore structure and pore neck and thus the saturation height profile, the amount of fluid in-situ and the interactions between the pore fluids and the rock..

In Asl and Hawara reservoirs, the highly variable grain sizes lead to a considerable variation in rock permeability. Over the interval depicted, the log shows clean sandstone in Asl Formation, shaly sandstone in Hawara Formation and intervening shale between the two sandstones. Agreement between CMR porosity and permeability with core porosity and permeability is good. The T2 distributions are indicative of a clean permeable sand of Asl Formation with almost all of ØCMR derived from relaxation times greater than 10 msec. The T2, log and permeability logs also indicated clean permeable sand with predominantly medium pores. A bout 80% of the porosity in the clean sand of Asl Formation is free fluid porosity and the remaining 20% is capillary bound fluid porosity. This shale free zone makes relatively little contribution to the relaxation time distribution below the 3-msec detection limit of the early pulse-echo CMR tools. Below the clean sand of Asl Formation is a long shaly sand interval of Hawara Formation.

There was a strong correlation between the gamma ray log and the bound fluid porosity measurements, the porosity associated with short T2 components provided a good shale indicator that is independent of natural radioactivity in the formation. This is significant because there are many important logging environments with clean sands that contain radioactive minerals. The sands of Asl and Hawara formations show that T2 lengthens in the oil zone because this is light oil which has long bulk relaxation time. The T2 distribution correlate with the resistivity log curves. The low resistivity sand at the lowermost part of Hawara Formation will produce only water probably from the flood drive. However, it is consistent with the petrophysical interpretation and MDT samples. The rest of the sand contains oil with only little free water. The low permeability is due to clay and carbonates seen in these intervals.

3D static geological models

Before establishing a reservoir model, research into the stochastic modelling techniques and methods which would best fit the heterogeneity of the Upper Rudeis reservoir was undertaken. Spatial analysis of the Upper Rudeis was performed by considering heterogeneity in three dimensions. Variograms of porosity and permeability were generated at different orientations for determination of anisotropy. This was the best way to account for the three dimensional heterogeneity of the reservoir. Horizontal cores provided valuable spatial information at short lag distances.

Analysis of variograms from horizontal cores showed that the porosity and permeability variograms exhibit different correlation structures. Geostatistical analyses of measured permeability and porosity indicated that correlation lengths decreased with decreasing sample spacing and that different rock fabrics exhibited different mean permeabilities.

The stochastic models

The stochastic model has tremendous potential, because it allows the quantitative integration of different datasets, and the provision of a numerical model that is in agreement with the different datasets, for subsequent flow simulation. As a result, different scenarios of the static model were embedded into the larger coarse model without the need to re-create a new coarse model for each detailed description. The reservoir description models validated partial hydraulic isolation between the upper Asl Formation and the lower Hawara Formation. The contrast in permeability between Asl and Hawara layers is the main driving force controlling the hydraulic isolation. Fluid flow response in the Hawara Formation will be more uniform and have improved performance relative to the more highly stratified Asl Formation. Most of the bypassed oil is present in the Asl Formation only.

Stochastic models showing better results and more realistic compared to deterministic models of 3D effective porosity, permeability and water saturation of Asl and Hawara reservoirs and performed identical and proportional spatial trend. The higher porosity and permeability the lower water saturation and vice versa. The better quality and properties are distributed in the reservoir crestal part trending relatively south west to south east direction. Poor quality reflected by low porosity, low permeability and high water saturation are distributed in north and north east parts of the study area. In general, Hawara Formation is better developed than Asl Formation, reflected by improved property distributions.

Uncertainty of the calculation was affected by (from high – least) water saturation, porosity and depth structure as well as oil water contact.

3D porosity models

The 3 D distribution of porosity in Upper Rudeis reservoir reveals that the sand exhibits the greatest porosity close to the westward margin of the field with porosity decreasing, seaward (eastern). These sandstone bodies separate further and pinch out entirely to the north, and the lowest porosity intervals are basal facies of most sandstone bodies. These low porosity intervals compartmentalize the reservoir and across much of the field. Core porosity represents point sources, whereas well log porosity is commonly smoothed over intervals of a few feet.

Illustrating the high variability in porosity and permeability over short horizontal and vertical distances requires 3D images of core data, rather than porosity and permeability calculated from well logs. The high values of porosity (>0.18) are trending relatively north to south direction, distributed in the crestal part of the reservoir and the best reservoir interval is found in layer 20. Low porosity values (<0.1) are distributed in north eastern part adjacent to GS302-1 well and in the northern part adjacent to EGJ-1 and J3 wells.

3D permeability models

The 3 D stochastic models of permeability using in Upper Rudeis reservoir show obvious alternating permeability trends. The high values of permeability (>0. 64 md) are trending relatively south to north direction, distributed in the crestal part of the reservoir. The best properties are found in layer 20 in line with the porosity model. The various streaks of low through high porosity and permeability illustrate the interbedding of thin beds of reservoir and non reservoir grade sandstone and mudstone. Low permeability values (<0.01 md) are distributed in the southwestern part around SG310-1B well, and also in the north and northeastern part around EGJ-1 well and GS302-1 well respectively. Spatial distribution of best permeability values shows that the best permeability values are distributed in the reservoir crestal part and trending relatively south to north direction identically following the 3D porosity model.

3D water saturation model

The 3 D stochastic models of water saturation model in Upper Rudeis reservoir show the lowest values are concentrated in the crest of the reservoir and trending higher to the flank. Value of 100% water saturation from simulation is relatively the same with previously assumed fluid contacts. However, local differences between modeled and previously assumed fluid contact/boundaries are still being found reflecting reservoir heterogeneities. Water saturation model shows local anomalies. These anomalies confirm lateral heterogeneities of rock quality within the reservoir and are in agreement to low porosity and low permeability values. Very high water saturation values are found in southwestern part of the field adjacent to SG310-1B well, in the northern part of the field adjacent to EGJ-1 and J3 wells, and in northeastern part of the field adjacent to GS302-1 well.

Model uncertainty

Model uncertainty is related to geostatistic based process. A probabilistic case, where uncertainties linked to the bad quality of seismic and structural data and to the lack of production behaviour of the field, was quantified and translated in term of volumes within a consistent model. The data analysis and the geostatistical model controlled by geological concept tempt to make the model more realistic. Stochastic simulations will reproduce input parameters "on average". This is done by construction variability in responses from geostatistical simulation and simply due to stochastic fluctuations around the input parameters. The uncertainty related to model parameters is one that is very rarely dealt with in practice, yet it may be one of paramount influence on the global uncertainty. What is essential is to model and what the exact values of the modeling parameters are.

Uncertainties still remain especially associated with depth surfaces, water saturation data and the assumption of unbiased parameter estimates. For a given set of input data, the geostatistical method of conditional simulation produces a series of grids which are consistent with the input data in terms of statistics (mean and standard deviation) and texture (variogram) in addition to honoring the same set of control data. If the reservoir is well defined (lots of data with a high degree of reservoir continuity), then there will not be much uncertainty in the reservoir description and all of the grids produced by conditional simulation will look similar. If the reservoir is not well defined, then there will be a substantial degree of uncertainty, and the grids produced will look quite different.

RECOMMENDATIONS

The introduction of a new static modeling system, based on detailed reservoir characterization has improved modeling fluid flow units of the Upper Rudeis reservoir. As a result, recovery could be increased in the west July area. The next manifestation of the reservoir model would benefit from attention in the following areas:

1- **Structural information**: The uncertainties around the positioning and the relationship of fault models will be a key part of this structural revision.

2- **Lithology and fluid information:** If reservoir properties are derived from the seismic data and suitably reconciled to the well data, it may provide inter-well control beneficial to the reservoir characterization.

3- **Increase model resolution:** The reservoir static model grids were founded on a 250 meter square grid cell size. Seismic information is available at 12.5 meter lateral spacing. Reduction of cell size will mean more model cells to cover the reservoir, but this will not be significant for modeling software in both static and dynamic model gridding schemes.

4- **Increase control on rock type:** Since reservoir rock type is the foundation of permeability modeling in the current approach, better rock type control help to reduce model uncertainty. Rock types had been derived at cored wells only. Techniques to infer rock type from well log data explored but found immature during this study.

5- **Review core plug sampling:** A review of core plug sampling obtained from non friable rocks that often have the highest permeabilities resulted in an under-sampling of the best quality rocks and introduced a bias in the permeability dataset.

6- **Investigate uncertainty:** All elements of a reservoir model carry uncertainty. Detailed consideration should be given to each to determine which uncertainties have the most impact on the model's prime purpose.