

1 INTRODUCTION

1.1 Background

Iran has a very long history as an oil producing country, following the first commercial find at Masjid Soleyman in 1908. Classically a geological structure has been identified, drilled, put into production and, when production declined, additional further drilling was then carried out to maintain production. Today much more emphasis is given to understanding reservoir character and to make a production plan for the lifetime of an oil field. This implies integration of many geoscientific disciplines. For oil fields with a complex history, also those affected by the Iran – Iraq war of 1980-1988, some of the parameters regarding production history may be missing. Modern reservoir model building and production simulation need a large set of data. When parts of the dataset are missing, or sparse, emphasis must be given to replacing the missing data in order to establish a working model. The present study of the Dehluran Field represents such a field with a complex history of exploration and exploitation with only fragmentary data access. A modern approach has been used herein to construct a viable geological model and to replace missing parameters, thus permitting the model to be tested by reservoir simulation.

The Dehluran Field is located 120 km northwest of the town of Ahwaz in the northwestern part of the Dezful Embayment. The Iran-Iraq border passes through the southwestern part of the field, in which the structure is a low relief dome exposing clastic deposits of Miocene-Pliocene age at the surface. Oil production commenced in 1978 and production estimated in 2001 was around $9.45 \times 10^6 \text{ Sm}^3$ (Sintef Report 2004). The production analysis from the Dehluran Field has shown that most of the wells seem to have asphaltene and/or salt problems or both. Twenty-two wells have been drilled in this field, but only 16 wells have penetrated the reservoir unit. Because of the low quality data, only partial information from 15 wells (a new well has been drilled but was not available for this study) has been used to build the

geological and reservoir models. Four wells are presently producing (DH02, DH03, DH04 and DH05). Wells DH07, DH08, DH09, DH10, and DH15 have been abandoned due to drilling problems above the reservoir. According to the production history of the wells in the Sarvak Formation, wells DH18, DH19 and DH21 are shut in due to asphaltene production. These wells have penetrated the lower Sarvak as well (upper Sarvak is only the target of this study). This may indicate that the oil has high density and therefore tends to give asphaltene problems. However, wells DH11, DH14 and DH16 are also shut in due to asphaltene and salt production, but after plugging all these three wells are perforated in the upper Sarvak. DH22 has currently drilled the Sarvak Formation, but the data was not available for this study. DH06 and DH17 have little production. Due to the salt and asphaltene problems, redevelopment of the Dehluran Field has been initiated in late 90's by NIOC to increase the oil production through introducing improved oil recovery mechanisms.

The Sarvak Formation in the Dehluran Field consists of two reservoir units; lower and upper. The upper Sarvak Formation (USF) is the main reservoir unit and is the target of this study (Fig. 1.1). The upper Sarvak Formation was deposited on a carbonate platform mainly in a ramp setting during Cenomanian to early Turonian. The lower boundary is characterized by a change in depositional regime from lagoonal deposits to overlying deep water basin sediments containing pelagic deposits and a significant increase in gamma ray content. The upper boundary is marked with a well known early Turonian regional unconformity which is characterized by karstification and overlain by Surgah Shale. The upper Sarvak Formation contains argillaceous limestone at the base, and is mainly dominated by limestone with occasionally partial or thin layers of dolomites and has been divided into three large scale transgressive-regressive sequences (Taghavi et al. 2006a).

Previous studies of the carbonate reservoir and reservoir modelling in Dehluran Field (Mohri 1982; Ghafori 1998; Sintef Report 2004) have used simple zonation models mainly based on gamma ray logs. Neither sequence stratigraphy nor stochastic models have been involved in these studies. In the earlier studies facies have been classified in terms of allochems, texture and energy in order to define the depositional environments and reservoir quality. Diagenesis features have briefly been interpreted to define their effects on the reservoir quality. No facies modelling has been incorporated and the petrophysical models have been constructed by simple deterministic modelling methods (Sintef Report 2004). Thus, neither heterogeneity of the reservoir nor uncertainty in the models has been evaluated.

This research study was planned to utilize the data which was available from the study by Sintef Petroleum Research after an agreement with NIOC, Sintef and NTNU. The Sintef study included seismic interpretation, geological study and reservoir characterization to be used as an input for reservoir simulation. The seismic interpretation by Sintef was only done to characterize the main surfaces (e.g. top Sarvak Formation) in order to tie the seismic to the well data. Thus it was later decided to incorporate more detailed seismic interpretations in this study. The Sintef study was done with Charisma software while NTNU at that time had changed to Landmark software for seismic interpretation. An old Charisma program at NTNU was not operative. Several attempts to use the Charisma programs in Sintef failed due to technical problems and lack of available supporting specialists. The difficulty to operate the

seismic interpretation tools within the timeframe of the thesis work was the main reason that a new complementary seismic study was not included in this work. With this background, it was decided to use the interpretations made by Sintef. Therefore, all the seismic related figures presented in this thesis have been imported directly from Sintef Report 2004. In addition, at the beginning of this study, it was expected to have access to more data, including high resolution data, than turned out to be possible. Unfortunately, due to a temporary stop in the consultancy work that Sintef Petroleum Research did for NIOC due to administrative reasons, data access for this thesis study was also hampered, both from Sintef and directly from Iran. The thesis study, thus, had to be done on the available data from the early part of the Sintef study.

In order to characterize the reservoir quality and construct the geological and reservoir models of the upper Sarvak Formation in Dehloran Field, geological, petrophysical and, to lesser extent, seismic data have been used. The geological data include representative core and thin sections in two wells in the NW and central parts, and in addition there are discontinuous cored intervals of two other wells in the centre and the SE parts of the field. Thus, the depositional and diagenetic interpretations have mainly been made based on the wells in the NW segment, and have been correlated by gamma ray and effective porosity from well logs for other wells throughout the field. In addition, the wells have been drilled in a NW-SE direction along the crest of the field. Therefore, there is insufficient data from the flanks in the field, which makes it difficult to construct a reasonable geological section in a NE-SW direction.

The seismic data interpreted by Sintef as already explained, includes seven 2D lines, which only cover the SE part of the field. The seismic lines have been used in order to create the top Sarvak Formation-SB4- only in the SE part, and the top Sarvak in other areas has been obtained from two contour maps which have been digitized from the reports made by National Iranian Oil Company (NIOC). Because of the quality of the seismic lines, there is no possibility to interpret the internal geological and diagenetic structures and geometries at the reservoir scale of the upper Sarvak Formation. However, the seismic interpretation shows a layer-cake interval of the formations in the Dehloran Field, showing no complexity within the reservoir, while the petrophysical parameters interpreted from well logs shows high degrees of heterogeneity and complexity. In order to use the seismic data directly in petrophysical models, the data would have to be inverted to the acoustic impedance. But, such an analysis has been done, neither in this study nor in the Sintef studies.

The available pressure data (RFT data) has shown that there are two different pressure segments, and the reservoir has been divided into the NW and SE segments with different water-oil contacts. However, no influencing fault has been recognized, and the available geological data cannot explain the difference in pressure. One reason could be due to early depletion from the SE part, where DH02 has started to produce before other wells in the SE part of the field. In addition, no pressure changes have been recognized within the upper Sarvak Formation, and only pressure changes in a vertical direction can be seen between the units of upper and lower Sarvak reservoir units, which are separated by a thick interval of argillaceous limestone at the base of the upper Sarvak.

Due to limited and low quality production data and limited time, making a real history match became problematic. In addition, due to blow out during the war between Iran and Iraq, estimation of escaped oil is impossible and creates another problem for the history matching. Thus, no history matching has been included, and it has only been used to tune the production profile. The simulation of the reservoir performance has been done in only one of the geological models in order to evaluate the methods for improving oil recovery with available production data. The permeability data used in simulation from well tests have not been interpreted either by Sintef or in this study, the fracture permeability has only been constructed by using the mud loss data and creating the indices for values of mud loss. However, it should be noted that the production data and interpretations used by Sintef in the simulations have not been presented in detail in this study due to confidentiality reasons.

1.2 Research Objectives

The main goal of this study is to improve geological and reservoir modelling through an integrated approach in reservoir evaluation, using geological, petrophysical and reservoir engineering data and applying different geological scenarios as well as different modelling algorithms in order to capture the heterogeneity in the reservoir. Such integration can be useful in order to understand how the depositional facies and diagenesis can be combined to construct the sequence stratigraphy framework. In addition, it is intended to show how the sequence stratigraphic framework can influence the reservoir quality and how these techniques can be used to improve building geological models. In addition to building geologically constrained reservoir models, stochastic methods are used in order to capture heterogeneity and uncertainty in the reservoir. This is a wide and cross-disciplinary topic and the following sub-tasks have been selected for this thesis:

- Highlight a workflow for integrating geological, petrophysical and reservoir engineering data and finally production data (Fig. 1.2) by investigating a specific reservoir interval (upper Sarvak Formation) of a given field (Dehloran).
- Evaluate depositional facies and diagenetic features in order to classify flow units and to build a sequence stratigraphic framework and to characterize the reservoir quality.
- Distribute flow units through the sequence stratigraphic framework and apply different methods in order to make several scenarios and finally evaluate the advantages and limitations of the methods.
- Interpret porosity and saturation data from well logs and estimate permeability by different methods and evaluate the results to choose the probable best results for petrophysical modelling.
- Distribute petrophysical parameters through the flow units by stochastic methods and evaluate heterogeneity and uncertainty by applying different scenarios and realizations and finally evaluate the results.

- Test one of the petrophysical models in order to simulate reservoir performance and introduce the methods for enhancing oil recovery.

Similar integrated workflows to this presented here are currently applied within oil companies. However, independent methodical studies of an academic nature may help to test how such approaches can be used to improve carbonate reservoir characterization and building reservoir models. It will thereby assist in utilizing resources to determine the best way of managing data from different disciplines and to integrate them for use in carbonate reservoir projects.

1.3 Dissertation Outline

This dissertation is arranged based on a combination of a monograph and published and submitted papers. It contains nine chapters and four papers, two appendixes and one enclosure.

Tectonic and Geological Settings. Chapter 2 presents the background and discusses the tectonic and geological setting of the Dehluran Field and geological interpretation of the Bangestan Group. The Bangestan Group includes the Kazhdumi, Sarvak, Surgah and Ilam formations and is of Cretaceous age. Dehluran is located in the northwestern part of the Dezful Embayment and is characterized by a complex geological and tectonic setting. The upper Sarvak Formation with an average of 330 m thickness, is the main reservoir unit in this field.

Facies Associations. Chapter 3 presents the classification of depositional environment and facies associations by using information from cores (700 m) and thin sections (2000 slices). The main goal of studying facies is to construct depositional models to be used in sequence stratigraphic analysis and evaluation of reservoir quality. The facies associations have been classified based on texture, depositional energy and fauna content. The facies analysis has resulted in understanding the high heterogeneity in the reservoir with different textures and pore types (mainly intergranular pores and micropores) which is useful to characterize the reservoir quality.

Diagenesis. Chapter 4 discusses the diagenetic processes which have taken place in the upper Sarvak Formation. The effect of the diagenetic processes in destroying and enhancing porosity are discussed. Among them cementation and compaction have destroyed porosity and occluded the original pores while dissolution and dolomitization, as well as fracturing, have enhanced the porosity. The diagenetic processes have resulted in heterogeneity of the pores with filling and redistribution of pores as well as creation of vuggy pores. Diagenetic processes have a direct impact on reservoir quality. Dissolution and associated dolomitization, occurring as a result of meteoric waters during sea level fall, can be seen in the upper part of the sequence in the early to late regression with high intensity below sequence boundaries. This has resulted in improvement of reservoir quality. Cementation, however, decreases the reservoir quality in some intervals of the regressive part.

Sequence Stratigraphy. Chapter 5 presents the sequence stratigraphic analysis. The main reason for working with sequence stratigraphy is to construct a framework which is used for creating geological and petrophysical models. Core description and thin sections are the basis for defining depositional environment, facies, and diagenesis as well as main surfaces. These are basic elements for sequence stratigraphic studies. The sequences recognized from the core data are tied to the well logs and are correlated throughout the field. Sequence stratigraphy has resulted in defining three large scale transgressive-regressive sequences that have been further divided into eight medium to small scale sub-sequences which are used as the basis for constructing the geological framework of the field.

Paper 1. *Sequence stratigraphically controlled diagenesis governs the reservoir quality of a carbonate reservoir from southwest Iran. 2006. Taghavi, A.A., Mørk, A., and Emadi, M.A. Petroleum Geoscience, 12, 2, p. 115-126.*

This paper discusses the sequence stratigraphic analysis and diagenetic processes associated with sea level fluctuations. In addition, the effect of diagenesis on reservoir quality is discussed.

Characterization of Petrophysical Properties. Chapter 6 gives a short introduction to how petrophysical parameters have been obtained from well log interpretation. The lithology has been interpreted from GR, density, neutron and sonic logs. The porosity has been interpreted from density and occasionally from neutron logs in the case of bad hole conditions. Saturation has been interpreted from effective porosity and resistivity logs using the Archie equation. The permeability estimation has briefly been discussed in Paper 2.

Paper 2. *Improved permeability estimation through use of fuzzy logic in a carbonate reservoir from southwest, Iran. 2005. Taghavi, A.A. Paper SPE 93269, presented at the 14th SPE Middle East Oil & Gas Show and Conference held in Bahrain International Exhibition Centre, Bahrain, 12–15 March.*

This paper discusses the methods used for estimating permeability. Prediction of permeability is one of the main challenges in the carbonates, thus three alternative methods have been used in this study to see the differences and to choose the probably most accurate results for reservoir modelling. Permeability has thus been estimated by three methods: from effective porosity, by multilinear regression and by fuzzy logic. The fuzzy logic method has shown the best results of permeability prediction after being cross validated with core permeability.

Paper 3. *Flow unit classification for geological modelling of a heterogeneous carbonate reservoir: Cretaceous Sarvak Formation, Dehluran Field, SW IRAN. 2006. Taghavi, A.A., Mørk, A. and Kazemzadeh, E. Accepted by Journal of Petroleum Geology.*

This paper discusses the flow unit classification by combining facies, porosity-permeability data and quantification of diagenesis. Capillary pressure data as well as pore throat size have been used to confirm such classification. Dissolution has

resulted in establishment of flow units in mud-dominated facies and cementation has resulted in constructing several flow units in grain-dominated facies.

Geological and Petrophysical Modelling. Chapter 7 discusses on how the geological and petrophysical modelling of the upper Sarvak Formation has been constructed. Geological models are built based on a sequence stratigraphic framework and geological-petrophysical rock types. Rock types are defined by depositional environment, diagenesis and porosity-permeability relationships. Different algorithms and alternative scenarios as well as several realizations have been run to show geological heterogeneity. The reservoir modelling is the second step which is used to infill geological models. Complementary results have been derived by applying deterministic and stochastic methods to model porosity, permeability and saturation. In addition to determine different continuity and heterogeneity, several alternative models of stochastic methods were run based on variograms. Uncertainty in petrophysical parameters were characterized by running four realizations. The modelling results have shown that the stochastic methods, using the variogram model for each rock type with single zone, led to the best distribution of petrophysical properties in the reservoir.

Simulation. Chapter 8 introduces the simulation study which is presented in more detail in Paper 4.

Paper 4. A full field simulation study of a heterogeneous mid-Cretaceous carbonate reservoir in SW Iran. 2006. Taghavi, A.A. and Georgescu, S.

This paper gives a discussion on how the geological framework and petrophysical properties have been used for simulating the reservoir performance and the results of different scenarios for enhanced oil recovery. The simulation has shown that infill drilling with injecting water has led to the highest oil production rate in this reservoir.

Suggestions. Chapter 9 gives a very short discussion on the suggestions which are essential for developing the Dehluran Field and other similar oil fields.

Appendix 1. Thin section photomicrographs that have been arranged from bottom to the top of the reservoir.

Appendix 2. Abstracts from conference presentations.

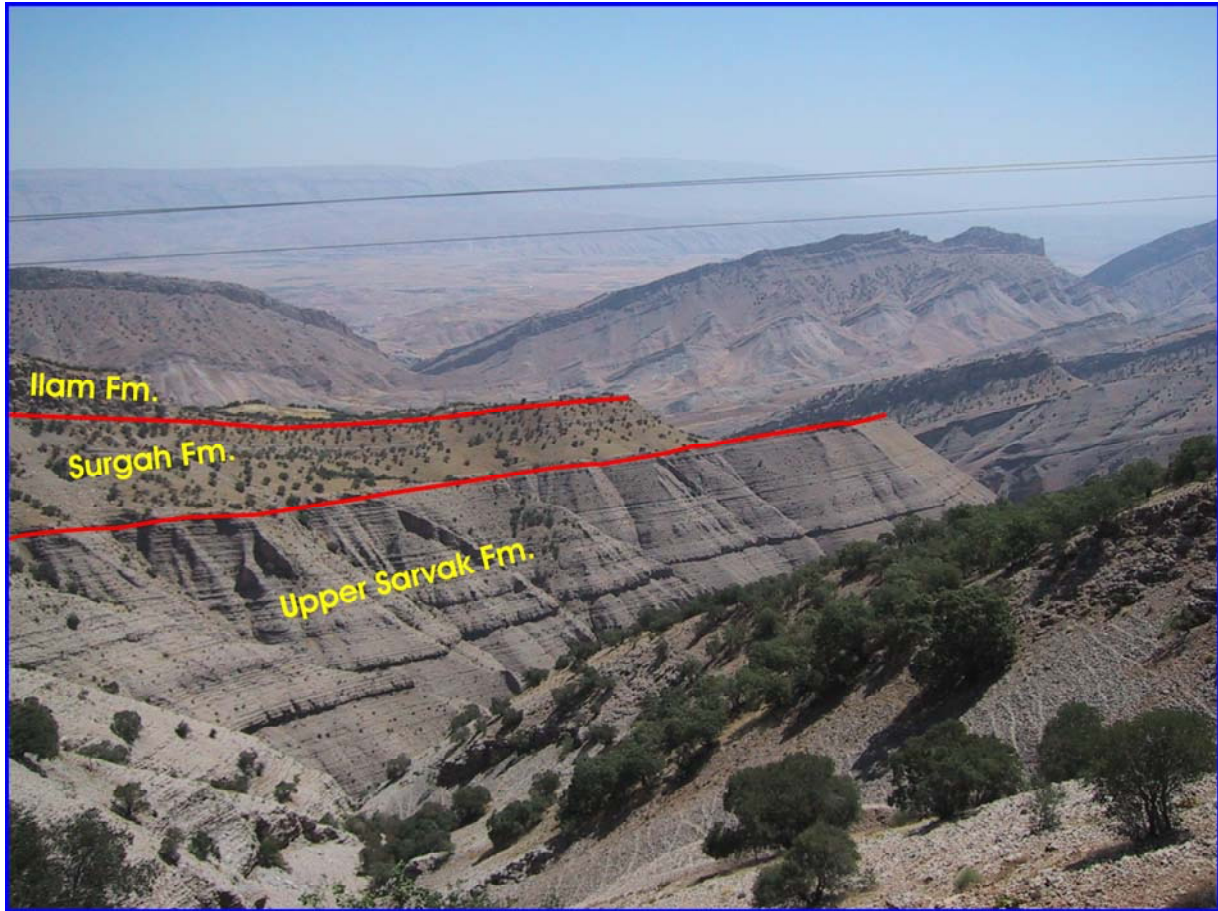


Fig. 1.1. A succession of the upper part of the Bangestan Group in Kabir-Kuh located in SW Iran close to Dehluran. Upper Sarvak, Surgah and Ilam formations can be seen in the figure.

1.4 Results and Conclusions

Integrated Workflow. The present study presents an integrated workflow in order to improve the reservoir characterization analysis and building reservoir models (Fig. 1.2). The workflow includes: (1) integration of core and thin section interpretations in order to characterize the facies associations and diagenetic features which control the heterogeneity of the reservoir, (2) using geological results and well logs to develop the sequence stratigraphic framework that is used to construct the geological models, (3) using the well logs to obtain the petrophysical parameters, (4) integration of core, thin section, petrophysical and reservoir engineering data to define the reservoir rock types for porosity-permeability modelling within the sequence stratigraphic framework, (5) integration of static models, reservoir engineering and production data to build 3D dynamic reservoir models for simulating reservoir performance. The lack of high resolution seismic data in this study prevents any possibility to use seismic data for reservoir characterization analysis. The only use of seismic data has been to interpret the top Sarvak surface which has been used as the reference for the geological framework.

Using such an integrated workflow with different types of datasets and interpretations as well as using powerful softwares with stochastic applications can generate images of the reservoir

properties that are geologically more meaningful than the well logs alone and can provide better description of interwell variability than when using simple correlation through the reservoir.

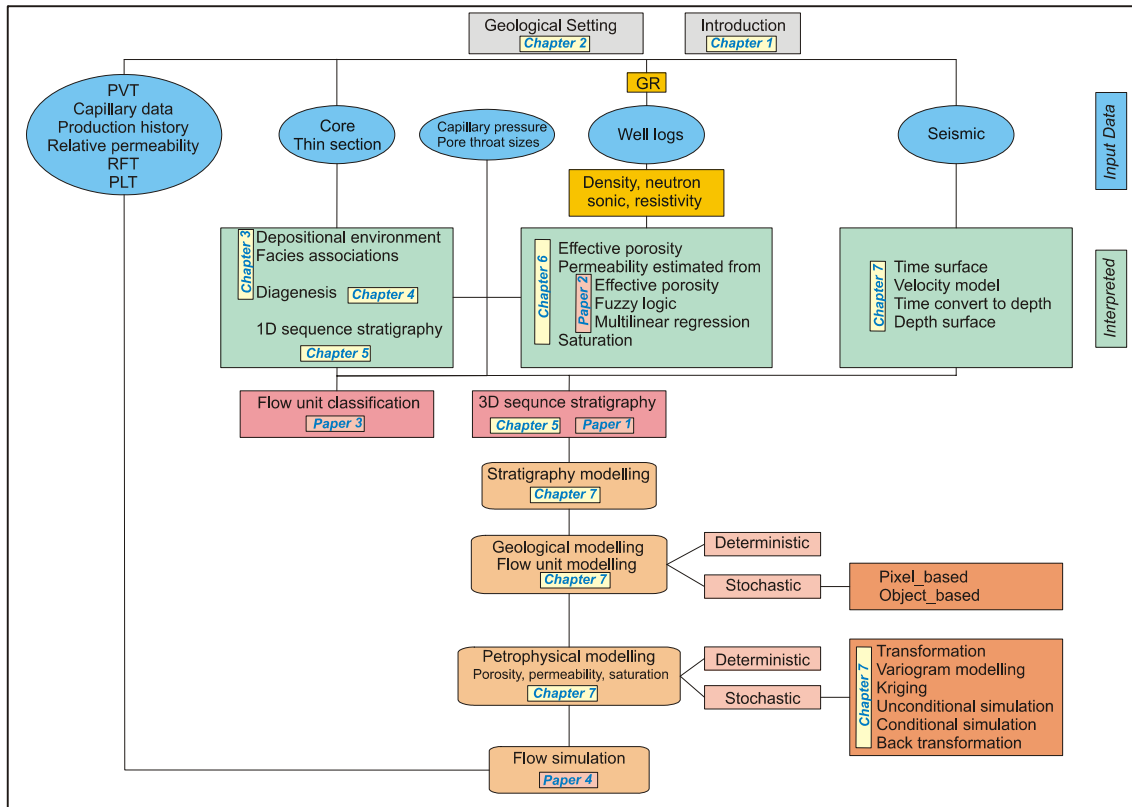


Fig. 1.2. Flow chart of this study showing the analysis procedures of core and well logs which have been used by different interpretations and processes to aid the simulation of the reservoir performance.

Deposition and Diagenesis. The effects of both deposition and diagenesis cause the heterogeneity of the reservoir. Ascertaining and predicting these heterogeneities within carbonate reservoirs are strategic to field development and optimum production (Pomar and Ward 1999). To characterize reservoir heterogeneity, an integration of core and thin section analyses has been carried out. The textural heterogeneity of the deposition gives rise to extreme permeability variation that is the controlling factor in reservoir production. The upper Sarvak Formation ranges from mud-supported to grain-supported limestones, which are grouped into different facies associations dependent on depositional environment. The mud-dominated textures commonly show micropores, while grain-dominated textures show intergranular porosity, which has led to different reservoir quality in the reservoir. The depositional model characterizes a ramp setting (Burchette and Wright 1992; Aqrabi et al. 1998; van Buchem et al. 2002), which has led to understanding the geometry and dimensions of the geological heterogeneity in the reservoir used as input values for geological modelling parameters. In addition, facies analysis displays a necessary step in analysing sequence stratigraphy by recognizing the changes in vertical and horizontal directions and the deepening and shallowing of the depositional basin. It is used for characterizing the original reservoir quality and to determine the small scale heterogeneity in the reservoir.

Diagenesis is another parameter which has caused a high degree of heterogeneity in the reservoir under study. Diagenesis typically reduces porosity, redistributes the pore space and alters permeability and capillary characteristics (Lucia 1999), and is commonly used to characterize the reservoir quality. Thus, an understanding of diagenetic processes and the patterns of their products is essential for carbonate reservoir description and the construction of reservoir models. Evaluation of diagenetic overprint in this study has shown that the heterogeneity in horizontal direction is mainly due to diagenesis where no variation of facies has been recognized. In addition, the diagenesis helped to construct the sequence stratigraphy framework, thus led to capture the flow units within the sequences. The result of diagenetic analysis has shown that cementation, dolomitization associated with dissolution and fracturing have improved the reservoir quality by enhancing the original porosity, while cementation and compaction have destroyed porosity and have led to diminished reservoir quality.

Rock Types/Flow Units. In order to link the geological parameters to petrophysical properties, rock types have been classified. The rock types have been synonymously used as flow units in this study, as the capillary pressure curves and pore throat sizes have been involved in defining the rock types. In addition, the productivity of each rock type has been evaluated in the reservoir, which thus acts as the flow units and their production in well locations has been investigated. Incorporating depositional facies, quantification of diagenetic features and investigation of porosity-permeability, capillary pressure and pore throat size have resulted in defining eight rock types in the upper Sarvak Formation. Using dissolution as the main diagenetic feature in mud-dominated lagoon and open marine facies associations has resulted in defining four rock types, while cementation in grain-dominated facies association of shoal deposits has resulted in three rock types, and intrashelf basin deposits indicate one rock type which act as a barrier in the reservoir (Taghavi et al. 2006b). The flow unit definition in this study is different from flow unit concepts accepted by reservoir engineers. They use petrophysical flow unit defined as an interval of sediments with similar petrophysical properties, such as porosity, permeability, water saturation, pore throat radius, storage and flow capacity, that are different from the intervals immediately above and below (Lucia et al. 1992). Flow units are appropriately based on the definition and mapping of depositional sequences, and facies boundaries, thus flow units are controlled by sequences. Flow units are assumed to do not cross the sequence boundaries. This is because, when properly defined and correlated, depositional sequences represent the best available indicator of original depositional surfaces. The results have shown that the main flow units that participated in production are located in the regressive part of the sequences due to high intergranular and vuggy porosities in grain-and mud-dominated textures, respectively.

Sequence Stratigraphy. The geological framework of the reservoir has been constructed in order to represent the small and large scale heterogeneities within the package of sediments bounded by chronostratigraphic surfaces. The framework therefore has been based on a sequence stratigraphical analysis and used to build the reservoir models. Such a sequence stratigraphy based framework characterizes the dynamic nature of the deposition in the basin, in comparison with traditional lithostratigraphical analysis (Lucia 1999). The sequence stratigraphy analyses have been obtained through interpretation of depositional facies and diagenesis. Depositional and diagenetic processes at the scale of sequence stratigraphy have a strong effect on reservoir flow units and their petrophysical properties (Lucia et al. 1995; Loucks et al. 2004). The Transgressive-Regressive (T-R) sequence stratigraphic model of Embry (1993, 1995) has been used in this sequence stratigraphic analysis. This model works well in this carbonate reservoir with the available data. The reservoir shows layer cake intervals with no significant change in thicknesses as well as no facies variations in horizontal direction. Lack of high resolution seismic data makes it difficult to characterize the depositional pattern which is mainly used in the Exxon sequence stratigraphy model (Vail et al. 1977). There is no evidence of preserved lowstand systems tracts which is commonly used in the Exxon model (Vail et al. 1977). The lowstand, which corresponds to a large sea level fall is mainly characterized by exposure in carbonates (Sarg 1988), as it has been identified by dissolution and early cementation in this reservoir. Furthermore, identifying the sequence boundaries by maximum regression surfaces is another benefit of using the T-R model (Embry 1993; 1995), where no significant exposure can be seen in the boundary of the sequences, whilst large variations in depositional regime can be identified in the reservoir.

The sequence boundaries in this study are identified based on facies and diagenetic features as well as well log characteristics. Sequence boundary 1 (SB1) separates the lower and upper Sarvak reservoir units and is assigned to a drowned surface following Schlager (1999) where the lagoonal deposits are overlain by pelagic deposits. SB2 and SB4 characterize facies variation and sea level fall with related diagenetic parameters like dissolution and cementation. SB4 refers to the top Sarvak surface which characterizes exposure of the deposits to meteoric waters with large scale karstification and indicates a regional unconformity. Such an unconformity, at this stratigraphical level, has been reported in several studies in the Middle East (Aqrabi et al. 1998; Sharland et al. 2001; van Buchem et al. 2002). At this surface the lagoonal deposits are overlain by the Surgah Formation. The pelagic deposits of Surgah Formation have partly influenced the deposits below the sequence boundary and have filled vuggy pores that resulted from dissolution, thus indicating a tight interval below the sequence boundary in the southeastern part of the field. The maximum flooding surfaces can be correlated with the regional studies in the Middle East (Sharland et al. 2001). They are characterized by high degree of bioturbation, pelagic and open marine deposits as well as high gamma ray log responses.

Thus identifying the sequence boundaries and maximum flooding surfaces, as well as accommodation space, has resulted in defining three large scale sequences which contain eight medium-scale sub-sequences. Thereafter the sub-sequences have been correlated throughout the reservoir to capture the heterogeneity and to construct the framework. The benefit of such a sequence stratigraphic framework in this study is that the sequence

stratigraphy controls the flow units (Kerans and Tinker 1997) and can capture the small and large scale heterogeneities resulted from deposition and diagenesis. That is, the flow units are bounded by sequences. In other words, flow units do not cross the sequence boundaries. Thus constructing reservoir models constrained by the sequence stratigraphic framework has resulted in capturing the flow units, understanding the fluid flow and identifying the production zones in the reservoir.

Petrophysical Properties. The main petrophysical properties, which are incorporated in building reservoir models, include effective porosity, permeability and saturation. The porosity is commonly used in order to calculate the pore volume, while saturation is used to calculate oil in place in the reservoir. The permeability controls the fluid flow in the reservoir and directly affects the production of the oil from the reservoir. Density logs have been used to interpret effective porosity, whereas, in the bad hole conditions due to low reading, of density, the neutron porosity has been used. The water saturation has been interpreted from porosity and resistivity well logs using Archie equation. One of the main challenges in saturation interpretation which has been faced in this study was using an acceptable value for cementation exponent (m) where there has not been a core analysis. The value of 2, that commonly has been measured for carbonates with intergranular/intercrystalline porosity (Focke and Mumm 1987), which is dominant in the upper Sarvak Formation has been used.

Permeability is probably the most important petrophysical property of the reservoir. However, one of the big challenges in the carbonates is how to predict the permeability (Jennings and Lucia 2003; Babadagli and Al-salmi 2004; Nelson 1994). Direct measurement of the permeability in this study has been obtained from core plugs. But core data is limited to only four wells within small intervals throughout the reservoir. Therefore, three different methods have been used in order to predict the permeability in the reservoir under study. The results are then compared with the core permeability to select the best results for using in reservoir models. The first method is to interpret the permeability from effective porosity. This can be obtained by making a linear equation between core porosity and permeability relationship. Due to the effect of depositional and diagenetic heterogeneities, there is no good linearity between core porosity and permeability. Thus, the results have shown that these estimated values are commonly too low where the core permeability is very high. The same results have been obtained using multilinear regression methods (Wendet et al. 1986) that underestimate permeability for high values. Using these two methods may result in ignoring the high permeable intervals which generally are very important in oil production in the reservoir. Probably more realistic results have been obtained using the fuzzy logic method (Cuddy 1998; Taghavi 2005) in this reservoir, where both very low and high permeable intervals have been captured. In other word, the results of fuzzy logic show more consistency with core permeability values and are thus used to build the permeability models in the reservoir and are further used for predicting the reservoir performance.

Modelling and Simulation. In order to construct the 3D geological and petrophysical models the sequence stratigraphic framework has been divided into vertical layers and horizontal cells to create the geological grid cells. The gridding is mainly done to honour the heterogeneity in the reservoir. The heterogeneity can be seen by different thickness of rock types and also

large variation of porosity-permeability values in vertical and horizontal directions. Small thicknesses of the rock types, as well as large variation of porosity-permeability values, have resulted in defining very fine vertical layers. The horizontal grid cells in both X and Y direction has been defined to be 200 m which capture the small scale heterogeneities in horizontal direction, which is smaller than the smallest well distances in the reservoir. The aim of geological gridding is to preserve the horizontal and vertical resolution provided by one dimensional log and core data, to mimic accurate and detailed 3D geologic framework, and ultimately a more accurate 3D geologic model (Kerans and Tinker 1997). Fine scale heterogeneities may have a significant effect on flow performance in the reservoir, thus a large number of grid cells are required to capture the effect of such heterogeneities on flow responses.

Due to the difference in scale between well data and the geological grids, the data have been blocked/upscaled from well data to geological grids. The well data generally are on a scale of several centimeters while the geological grids in this study vary between 0.5 to 5 meters in vertical direction and 200 m in horizontal direction. Upscaling of highly heterogeneous reservoir models is a very challenging process, despite much research that has been carried out over the past few decades (Zhang et al. 2005). The biggest challenge of upscaling is to reduce model size without losing the heterogeneity level of the original geological model (Ates et al. 2005). Several algorithms can be used in order to upscale the petrophysical data (Irap RMS Userguide 2005) and, in this study, the arithmetic averaging method has been used for porosity and saturation. The upscaling of the permeability is also challenging in reservoir modelling. The main challenge in upscaling of permeability is due to different ideas and practice between geologists and reservoir engineers. The geologists often regard permeability data to be log-normally distributed and, therefore, the geometric mean should be used according to the statistical theorem; while reservoir engineers argue that permeability controls the fluid flow through porous media, while the geometric mean indicates a statistical averaging (Lucia 1999). In this study the geological approach has been used by applying the geometric mean.

The aim of reservoir modelling in 3D space is to integrate all available data in order to maintain geologic integrity. This is difficult without an accurate stratigraphic framework, which has a major effect on the accuracy of a 3D model. The techniques for distribution of log, core, seismic and production data within the 3D framework also have a significant impact on model accuracy. The new developed programs which have currently opened a new era in carbonate studies are used in order to integrate the data and to apply different alternative scenarios for building reservoir models. Thus, comparing the results of the alternative methods and validation by geological understanding of the reservoir can help to choose the best methods and the results which are then used for predicting the reservoir performance.

The Irap RMS program has been used in this study in order to build the geological and petrophysical modelling and the terminology used in this study has been taken from Irap RMS userguide. The reservoir models have been built in two steps. In the first step the rock types/flow units have been populated within the geological grids, while in the second step the petrophysical parameters have been distributed both with and without using the rock types. To

model the rock types two methods have been used; pixel-based and object-based (Irap RMS Userguide 2005). Both models use the volume fraction for each rock type within each subgrid/zone. The goal of an object-based model is to fill the 3D space with objects that represent geologic bodies. Such bodies can be assigned to the diagenetic volumes in the reservoir which are in this study referred to the rock types. The results of this method are relatively inaccurate because it does not correspond to the geology of the reservoir, thus it is only used as a test to be compared with the results of other methods. The pixel-based model can be used for transitional environments where the depositional patterns can be easily defined in the reservoir. In this method the rock types as a diagenetic volume can be modelled both by deterministic and stochastic methods. The deterministic process is one where there is an exact mathematical relationship between the independent variables, whereas a stochastic process is one in which the dependent variables is random, and the prediction of their values depends on a set of probabilities (Irap RMS Userguide 2005). When run with the same input parameters and equations, deterministic models achieve the same results every time, whereas stochastic models (Isaaks and Srivastava 1989; Haldorsen and Damsleth 1990; Srivastava 1992; Yarus and Chambers 1994) achieve equi-probable but different results after each model run leading to different realizations (Sahin and Al-Salem 2001). In general, as the space between wells increases, the confidence in the 3D model results decreases (Lucia 1999). This is because there is no data control between well locations to capture small scale heterogeneities in carbonate reservoirs resulting from diagenesis and different pore types. In such cases information from outcrops (Grammer et al. 2004) can be very helpful, but unfortunately such data was not available for this study.

In order to build the petrophysical models, two different geological scenarios have been used. In the first scenario, it is assumed that the petrophysical parameters are controlled by the sequences, that is, no incorporation of rock types have been used. In the second scenario it has been assumed that rock types control the petrophysical parameters, as they have been defined by integration of facies, diagenesis and petrophysical parameters. In both cases the deterministic methods, as well as different variograms for stochastic methods, have been used. The variograms show the variability of the data when their distance increases (Bahar et al. 2001; Gringarten and Deutsch 2001). The variograms have been constructed for porosity, while the saturation and permeability are modelled through co-simulation after being correlated with porosity. Therefore, each rock type within each subgrid can lead to different types of variograms due to different heterogeneity. Indeed, stochastic methods used in this study have some limitations; the greatest is to create the horizontal variogram and to obtain the correlation range. The correlation ranges are used to understand the continuity of the petrophysical parameters. Collecting data in a horizontal direction is very difficult in the subsurface, thus vertical wells have limitations because well spacing almost always exceeds the horizontal range of variability. The data in horizontal and vertical direction must be collected for the same facies/flow unit, if not, then the correlation range and direction provided by the variogram can be misleading. If horizontal data is not available, the data can be collected from outcrop analogues and 3D seismic. However, in this study it has not been possible to use either outcrop or high resolution seismic data. Thus testing, different variograms helped to understand the continuity of the petrophysical parameters as well as to understand more corresponding models to the conceptual geological models. The results of

the petrophysical modelling have shown that use of rock types and large correlation ranges by stochastic methods, where the data are conditioned to the well locations, can lead to most accurate results. This accuracy can be estimated by comparing with the geology of the reservoir.

Reservoir simulation has already helped oil and gas producers to increase predicted ultimate recovery and further development of the carbonate reservoirs (Bouska et al. 1999). Reservoir optimization requires carefully constructing a reservoir model and performing of simulations. The reservoir simulation can optimize the field development strategies accordingly, and is a tool for reservoir management and risk evaluation (Adamson et al. 1996; Gharbi 2004). Reservoir simulation has been done in this study in order to evaluate different completion techniques as well as deciding whether to maximize production rate or ultimate recovery. Both water and gas injections have been tested in the simulation after suggesting infill drilling by adding new horizontal wells in the reservoir. The result of water injection has shown an increase in oil production rate and optimistic total oil production after the reservoir pressure has been kept high. Gas injection, however, resulted in low production rate. Running 30 years simulation with water injection has improved the recovery factor up to 28 % in the reservoir. The result of the simulation may be used for future development plans of the field.

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