A Full Field Static Model of the RG-oil Field, Central Sirte Basin, Libya

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Summary

Cambrian-Ordovician and Upper Cretaceous reservoir formations are found in the central western Sirte Basin, the main oil producing region in the Sirte Basin, Libya. As a result of changes in sedimentary environments and structural activities, a number of irregularities in reservoir continuity have developed, which negatively affected the overall performance of the reservoir. Effective simulation of such complex reservoirs can be achieved by integrating geophysical, geological, and petrophysical data to construct a reliable full-field static model, which has the potential to simulate the vertical and lateral variations in the reservoir formations. In this study, 2D and 3D seismic data acquired in central western Sirte Basin are used to construct a fault and structural model which is an important component of the static model. Well data are incorporated with core data to construct a property model that integrates a range of reservoir properties including facies, porosity, permeability, and net-to-gross ratio. A fine-scale geo-cellular model is created by integrating the fault, structural, and property models for the entire field. The model consists of three main zones, which are subdivided into 23 lithologically and petrophysically distinct subzones and are further divided by adding layers to prepare for property distribution. This results in the development of a static model that contains 30.6 million cells. A total of ten facies are identified using well-log and core data and are distributed through the model using sequential index simulation method. Porosity, permeability, and net-to-gross ratio are estimated and distributed through the model using sequential Gaussian simulation method. The total original oil in place for the full field is estimated to be 2.548×10^9 STB.

Introduction

The Sirte Basin is one of the most prolific oil producing fields in the world. Because of its complex structure, it is essential to understand detailed relationships between fault networks and stratigraphy of the area for future field development. Integration of geophysical, geological, and petrophysical data provide the best tool for a future developing plan of the field.

The Sirte Basin, located in the north central part of Libya, is one of four known sedimentary basins in Libya. It covers an area of 600,000 km² and is the richest and youngest of basin in Libya. The basin developed from the late Paleozoic through much of the Early Cretaceous, with continuous uplift that created the Sirte Arch. From the beginning of the Late Cretaceous, extensional tectonics caused a partial collapse of the arch that resulted in the development of a system of horsts and grabens (Anketell et al., 1996; Baird et al., 1996; Rusk et al., 2001). Subsidence in the basin occurred at different rates, showing four phases of extensions that affect the deposition through the basin (Gumati and Nairn, 1991). The RG-oil Field is located on the Beda Platform with a surface area of 4,708 km² (Figures 1). It is approximately 135 km south of the Mediterranean Sea. Sediments in the study area consist of Lower Paleozoic Gargaf Formation, Upper Cretaceous Bahi and Waha formations. The degree of connection between different layers of the Waha and Gargaf reservoirs are still debated. The main objective of this study is to create a new full field static model for the Cambrian-Ordovician and Upper Cretaceous reservoir formations in the RG-oil Field to aid in predicting the future performance of the field.
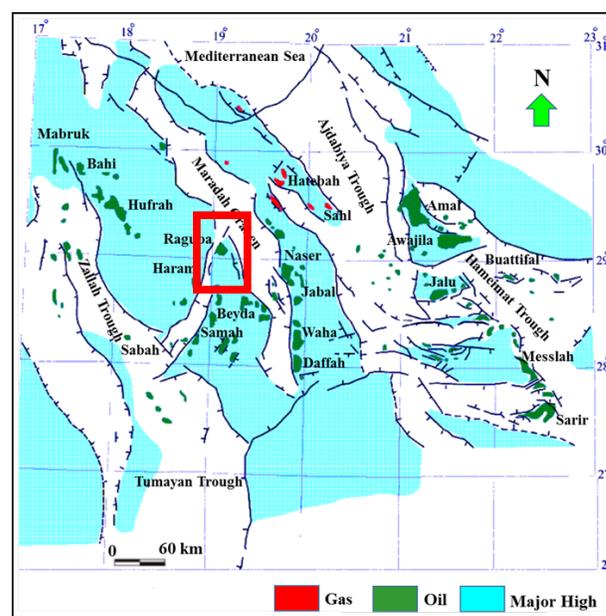
Figure 1. A map showing the main structural features affected the sedimentation pattern in the study area. The red rectangle outlines the location of the study area. Blue represents major highs; red represents gas fields, and green represents oil fields (modified after Rusk, 2001).

Data

The seismic data employed in this study consist of twenty-three 2D migrated lines and one 3D seismic cube, covering an area of approximately 350 km^2. Check shots used to tie the well tops to the seismic data are available from eight wells. In addition to the seismic data, well data from 109 wells are also used for the study. Seismic to well ties are evaluated by constructing synthetic seismograms at well locations where sufficient sonic log data are available. We also examined a total of 104 wells for the petrophysical study for the construction of property modeling. Core description data from 30 wells are used in the determination and the distribution of reservoir properties in the models.

Methodology and Results

Fault and Structural Interpretation. The horizons interpreted from the seismic data include main producing formations which are Upper Cretaceous, Waha, Bahi, and Cambrian-Ordovician Gargaf formations. Well tops are utilized to control the interpretation of the horizons. The seismic data quality deteriorates with increasing depth, and as a result, uncertainty of the interpretation of the deep formations is increased. Fortunately, there is enough well control to constrain the interpretation and produce a valid time and depth structural maps of the main producing formation. We delineated 20 faults, which are connected to reservoir network and imported as fault polygon in the geological model (Figure 2). The major fault (F1) located to the west side of the field is effectively seals the structure on this flank. The other major fault (F2) with an exhibited throw of 130 m also seems to seal the reservoir on the east side of the field.

Structural surfaces made from 3D seismic and well-top data are used to construct the structural model of the main reservoir formation zones. Isochore maps are used to make horizons and zones in the geocellular model. Reservoir zones are created by adding interval isochore thickness values to the structural horizons (Figure 3).

Property Modeling. The subzones of the reservoir formations are further divided by adding layers to prepare the model for property distribution. We choose the layer thickness that best capture the vertical heterogeneity that the petrophysical properties exhibit. In order to construct an accurate property model, we apply upscale wireline log data into the 3D grid and populate the 3D model with basic properties by utilizing sequential index simulation (SIS) for discrete data (e.g., facies) and sequential Gaussian simulation (SGS) for continuous property data (e.g., porosity and permeability) (Goovaert, 2006; Journel and Ying, 2008).

The first step in the property modeling process is the construction of the facies model. Using well log and core description data, we have identified a total of ten facies and distributed them spatially using the SIS statistical method. The resulting model suggests that the Upper Cretaceous Waha Formation contains calcareous sandstone, limestone, and thin shale. Sideritic limestone and Argillaceous are only present in a few wells with significant thicknesses. The Cambrian-Ordovician Gargaf Formation containing quartzite, scattered shale, and mafic intrusive igneous rocks is found in a few wells. We also found that the Bahi Formation contains siliceous sand, conglomerate, and rare shale (Figure 4).
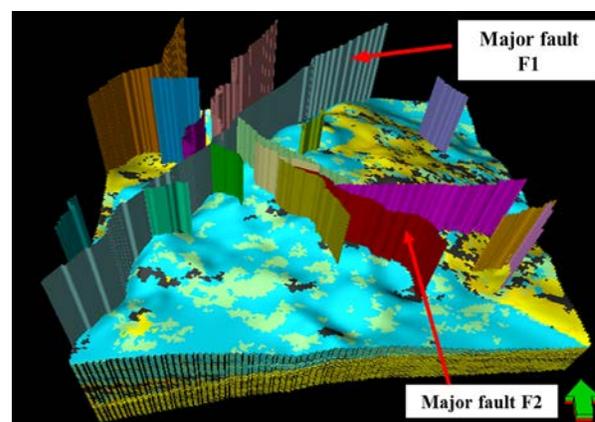
Figure 2. A fault model showing twenty faults identified from seismic data.
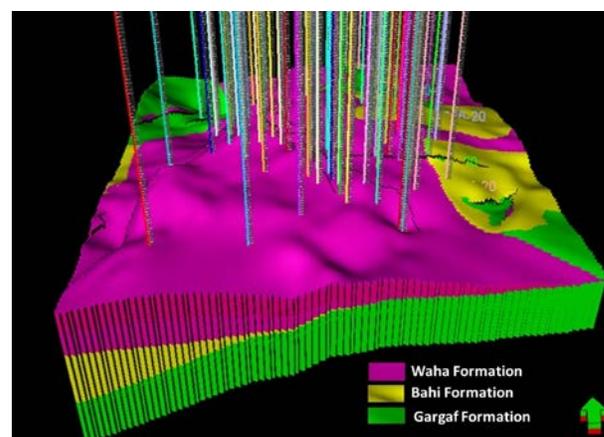
Figure 3. 3D structural model showing the major reservoir formations in the RG-oil Field.

The facies model created for the three formations is used as a reference to assign porosity and permeability values (Figure 4). We use four distinct porosity log technologies and three distinct deep-reading resistivity log technologies in addition to quantitative analyzes of the petrophysical properties of core samples to determine porosity and permeability values (Figures 5 and 6). The resulting porosity of the Upper Cretaceous Waha Formation ranges from 25% in the north part of the field to 15% in the south part, and the permeability ranges from 10 MD to 350 MD. We estimated hydrocarbon pore volume and original oil in place (OOIP) for each formation in the full field static model. The resulting model suggests that the porosity of the Bahi conglomeratic sandstone decreases with depth and thickness in all directions. The porosity of the Bahi Formation ranges from 30% in the south and southwest of the field to 5% in the southeastern part, an area in which the formation thickness exceeds 150 feet. The porosity model indicates that the average porosity of the basal fractured Gargaf quartzites Formation, excluding the fracture, is 2% and the average permeability is less than 0.1 MD. However, in the center of the field, the Gargaf Formation exhibits relativity high porosity and permeability, where the porosity reaches 9% and permeability reaches 0.54 MD.

Net-to-Gross Ratio. The final grid for the 3D geological model is the net-to-gross (NTG) ratio. NTG values may theoretically range from zero to one in a reservoir interval. Our data suggest that the NTG ratio of the Cambrian-Ordovician and Upper Cretaceous reservoir formations of the study area is 1.0 over large volumes of rock. At the wells, most of the drilled rock is a net reservoir and, for geostatistical purposes, this entails that the vertical and lateral variations observed in terms of the NTG ratio are very limited, making it impossible to generate separate variograms for the description of these minimal variations in NTG ratio (Dashti et al., 2013). We develop the NTG model in accordance with a net and pay flag which consists of ones and zeros. Zeros imply failed cut-offs and are treated as non-reservoir layers while ones represent a reservoir layer. After experimentation, we decide that the same variograms employed to populate the porosity grid can be successfully used to populate the NTG grid (Figure 7).

Conclusions

Integrated geophysical, geological, and pertophysical interpretations are employed to construct a full field static model of the Cambrian-Ordovician and Upper Cretaceous reservoir formations in the Sirte Basin, Libya, using a variety of analyses and connectivity of various modules that we extracted from seismic and well data. The geophysical interpretation of the data is primarily used to construct a fault and structural model, and petrophysical analyses incorporated core data are employed to identify and construct the reservoir properties model. The full-field static model created includes fault and structural interpretations, facies, porosity, permeability distribution models, and net-to-gross ratio calculation. The original oil in a place is calculated for the field by examining the reservoir layers, using reservoir properties cut-offs, and estimated to be 2.548 billels. Our results suggest that over 50% of the estimated oil locate in the Upper Cretaceous Waha Formation. The resulting fine-scale geological model clearly defines the vertical and lateral heterogeneities of the reservoir and can be used with confidence for the future development of plans in the field. The established model is unique to the study area and for the entire Sirte Basin. It is applicable to any field in the Sirte Basin and can be updated at any time with new data acquired following production and drilling activities.

Acknowledgments
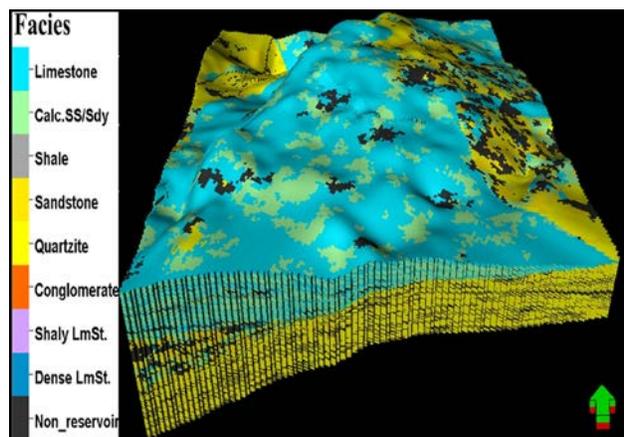
Figure 4. 3D facies distribution of the main reservoir formations from the sequential indicator simulation method.
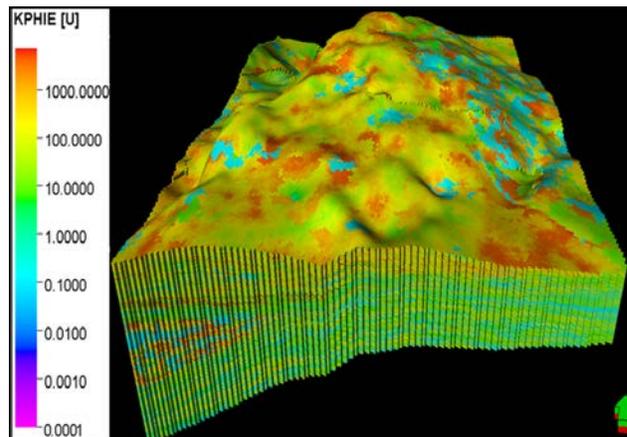
Figure 6. 3D permeability distribution of the main reservoir formations from the sequential Gaussian simulation method.
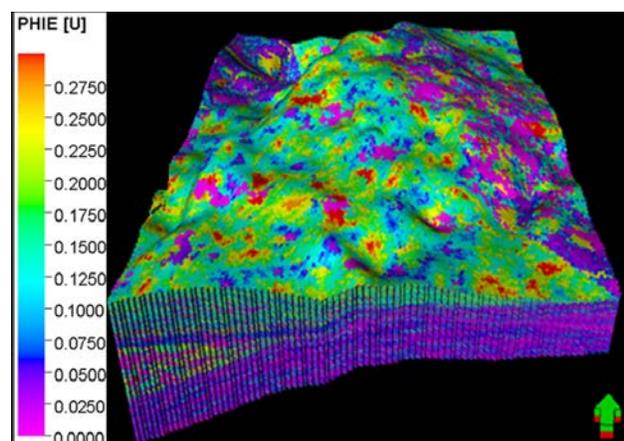
Figure 5. 3D porosity distribution of the main reservoir formations from the sequential Gaussian simulation method.
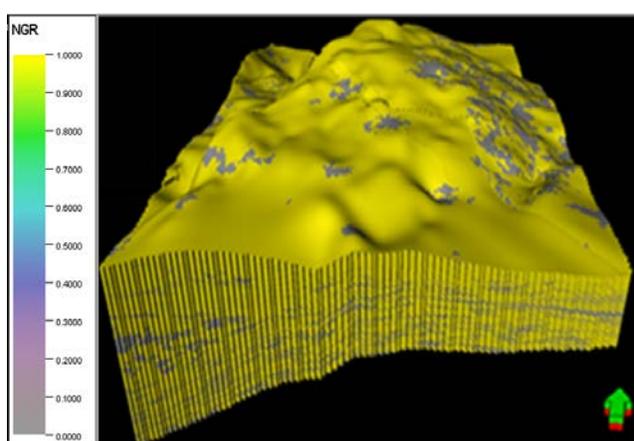
Figure 7. 3D net-to-gross ratio distribution of the main reservoir formations from the sequential Gaussian simulation method.

EDITED REFERENCES
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