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A Comprehensive Investigation of the Relationship between Fractures and Oil Production in a Giant Fractured Carbonate Field

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Abstract: This study examines the connections between various fracture indicators and production data with an example from one of the giant fields in the Middle East producing complex fractured carbonate lithologies. The field under study hosts two reservoirs with a long development and production history, including carbonates from the Asmari and Bangestan Formations. A fracture intensity map was generated based on the interpretation of image logs from 28 wells drilled within the field. Mud loss data were collected and mapped based on the geostatistical Gaussian Random Function Simulation (GRFS) algorithm. Maximum curvature maps were generated based on Asmari structural surface maps. Comparing the results shows a good agreement between the curvature map, fault distribution model, mud loss map, fracture intensity map, and productivity index. The results of image log interpretations led to the identification of four classes of open fractures, including major open fractures, medium open fractures, minor open fractures, and hairline fractures. Using the azimuth and dip data of the four fracture sets mentioned above, the fracture intensity log was generated as a continuous log for each well with available image log data. For this purpose, the fracture intensity log and a continuous fracture network (CFN) model were generated. The continuous fracture network model was used to generate a 3D discrete fracture network (DFN) for the Asmari Formation. Finally, a 3D upscaled model of fracture dip and azimuth, fracture porosity, fracture permeability, fracture length, fracture aperture, and the sigma parameter (the connectivity index between matrix and fracture) were obtained. The results of this study can illuminate the modeling of intricate reservoirs and the associated production challenges, providing insights not only during the initial production phase but also in the application of advanced oil recovery methods, such as thermal recovery.

Keywords: continuous fracture network CFN; discrete fracture network DFN; fractured reservoir; image logs; reservoir modeling; stress analysis



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1. Introduction

Unlike siliciclastic reservoirs, where permeability models derived from logging data typically exhibit reasonable accuracy, fractured reservoirs pose challenges due to their lithological heterogeneity. Analyzing fractured reservoirs, especially in the context of hydrocarbon production mechanisms, is particularly difficult [1,2]. The type and orientation of fractures notably impact enhanced oil recovery methods, especially in gas and thermal

applications, significantly influencing production mechanisms [3–5]. A significant complicating factor arises from the fact that the permeability of carbonates is influenced either by secondary dissolution porosity or by fractures that serve as pathways for fluid flow. Such features are typically hard to predict or describe in generalized models, as their spatial distribution within the reservoir and their impact on permeability often vary substantially at the field scale. Hence, a great heterogeneity in well production rates is commonly observed in naturally fractured carbonate reservoir systems. Different geological processes may cause further model uncertainty; examples are sedimentary discontinuities, thin-layered shale intervals acting as semi-permeable membranes, and local facies variations changing the matrix porosity characteristics of the carbonate strata. Nevertheless, the frequency and nature of fractures still play paramount roles in the production statistics of a fractured reservoir. Therefore, algorithm-based methods for detecting layer heterogeneity caused by fractures can provide a fast method to predict heterogeneity and production behavior and thereby help to maximize hydrocarbon recovery efficiency [6,7].

Extensive scientific research has been dedicated to advancing methods to achieve more precise characterization of fractured carbonate reservoirs. Many of these methods rely on seismic data, wireline logging, and geological borehole data [8–15]. An ideal characterization integrates all of these data sources. It incorporates additional information from outcrop analogues, drill core analysis, etc., to create a 3D model that can serve as a foundation for subsequent reservoir simulation [16–26]. Production data may then be applied to confirm fracture existence, aperture, and bulk reservoir properties such as permeability [27].

The fracture characterization and modeling task is a multi-step procedure involving several static and dynamic reservoir modeling disciplines [28,29]. Discrete Fracture Network (DFN) modeling can be used to represent hydraulically relevant fractures with specific characteristics [16,26]. In principle, the DFN is a set of planes representing fractures. Fractures that share similarities and genetic connections are grouped into a fracture set, and within each fracture network, there is usually more than one of these distinct sets. Fracture sets are created from the previously defined fracture based on image logs or seismic data interpretation. The main contributions of this paper are as follows:

- (i) Field stress regime analysis to identify the orientation of fractures into principal stresses.
- (ii) Classification of fractures in terms of their azimuths and apertures.
- (iii) Creating continuous and discrete fracture models based on formation image logs, including Micro-Imaging (FMI), Simultaneous Time and Resistivity (STAR), Ultrasonic Borehole Imager (UBI), and Circumferential Acoustic Scanning Tool (CAST).
- (iv) Comprehensively characterizing the influence of fractures on production by integration of fracture maps with production data, mud loss maps, and fault data.
- (v) Summarizing the benefits of a comprehensive and multi-analytical fracture modeling approach to enhance the accuracy of predicting productive zones in fractured carbonate reservoirs.

2. Geological Setting

The studied oilfield is one of the largest and most complex onshore fields in the Middle East, with over 400 wells and 90 years of production [30]. The field is located within the Zagros fold and thrust belt in the Khuzestan province of southern Iran. The field's NW-SE trending anticline is approximately 65 km long, with a maximum width of 9 km in its southeastern part. In 1998, it was proposed that the anticlinal structure is believed to arise from a detachment level deep beneath the surface, approximately 10 km down, and is associated with the Hurmuz salt [31]. The tectonic pattern is characterized by overlapping thrust folds with modest elevations between consecutive folds. The oilfield is subdivided into four reservoir zones and ten sub-zones of comparable properties, associated with two main carbonate reservoir horizons within the Oligo-Miocene Asmari and Bangestan Groups (the Santonian/Campanian Ilam and the Cenomanian/Turonian Sarvak Forma-

tions). The Asmari reservoir thickness is about 500 m in the west and 250 m in the east. It consists mainly of limestone and dolomite with minor siliciclastic intercalations [32]. The stratigraphic chart of Cretaceous-Tertiary sequences in Dezful Embayment illustrating the Oligo-Miocene Asmari Formation is shown in Figure 1. The upper and lower parts are mainly dolomitic limestone. Further elaboration on the stratigraphy of the Zagros region is available in references [33,34]. The Asmari reservoir in the field was discovered in 1937 by completing one of the exploration wells with about 44.5 billion Barrels [35]. The production of this reservoir has so far exceeded 10 billion barrels of oil. More than 10 trillion cubic feet of gas have been injected into the gas cap during the injection project since 1977 [30,36].

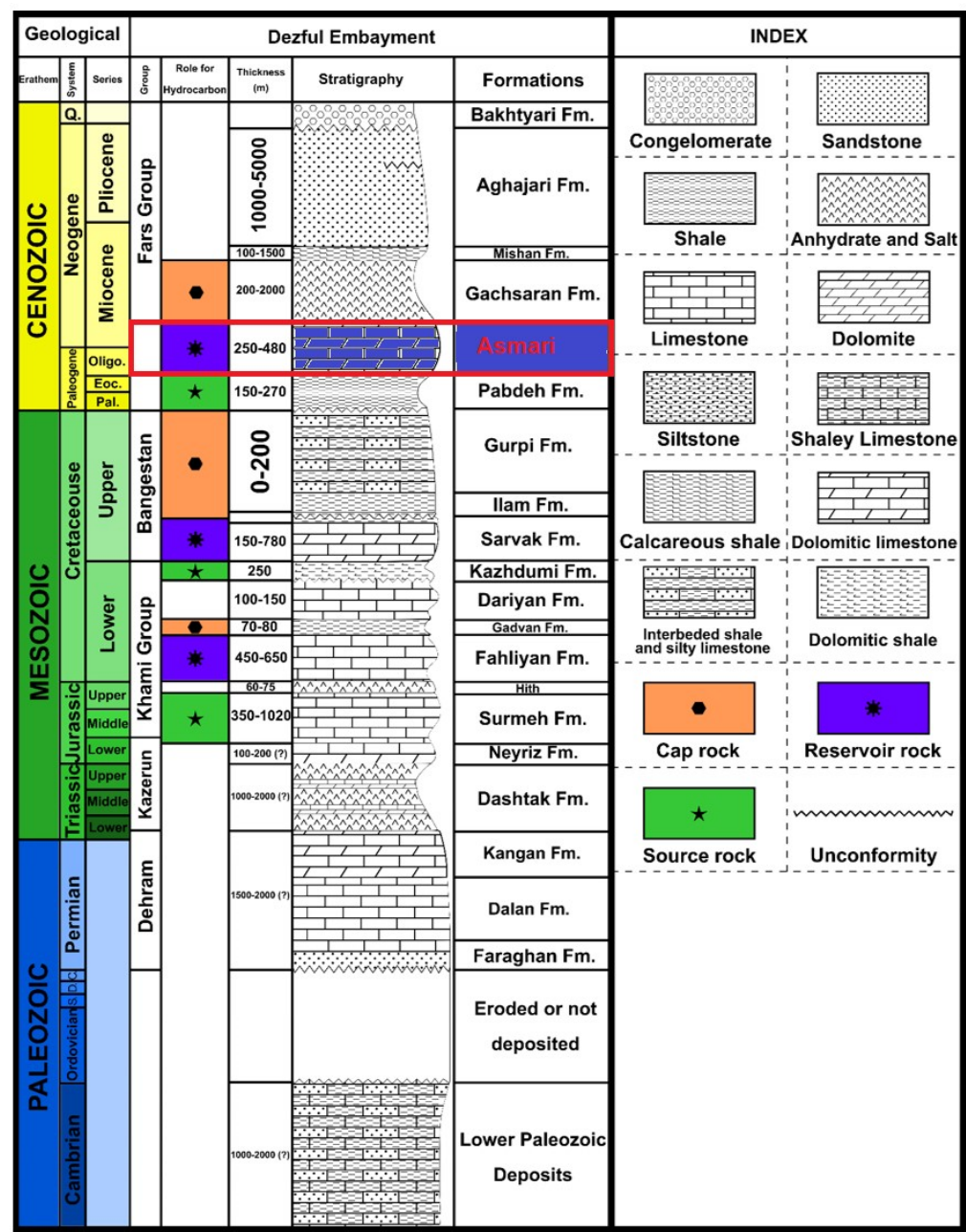


Figure 1. A stratigraphic chart of Cretaceous-Tertiary sequences in Dezful Embayment illustrates the Oligo-Miocene Asmari Formation as the main reservoir of the studied field.

Deformation History

The studied field is subjected to compressional stresses imposed by the northeastern movement of the Arabian plate pushing against the Zagros trust belt and local stress distribution in the Dezful embayment. Studying the field stress map can provide insights into the location of fractured zones and the formation orientation of fractures [37]. Fractures caused by induction appear in the direction of the highest horizontal stress (σ_H), while breakouts form parallel to the lowest horizontal stress (σ_h). The main stress paths run parallel and perpendicular to the free surface along the wellbore wall. When the maximum compressive stress trajectories converge, the stresses are more intense (at the direction of σ_H in the case of a vertical well). When the trajectories diverge, the stresses are less intense (at the azimuth of σ_H). Geologically, Asmari formation fractures have been generated in three generic steps, including pre-folding, syn-folding, and post-folding sets. Pre-folding fractures date back to the Late Oligocene and were formed during the collision of the Arabian and Central Iran plates. These fractures are distributed parallel to the maximum horizontal stress (maximum and medium open fractures). Syn-folding fractures have developed in the Early Miocene (Aquitania/Burdigalian) due to increased compressional stress and reactivation of basement faults, causing the opening of N-S, W-E, N020°, and N150° trending fracture sub-sets. Major and medium open fractures are hinge-perpendicular fractures (parallel to the maximum horizontal stress). In contrast, minor and hairline fractures are parallel to the hinge (parallel to the minimum horizontal stress). Due to their larger apertures, major and medium open fractures have the most influence on production.

3. Fracture Characterization of the Asmari Formation

Due to its reservoir lithology being mainly carbonate, the production from the Asmari Formation heavily relies on the presence of natural fractures [27]. Fractures are flat structures with no observable movement of blocks along their planes. In compressional stress regimes, they may dip at either high or low angles. The size of their openings may vary, being either wide open, narrow (closed), or filled with minerals such as calcite, clay, pyrite, or anhydrite. This section investigates various geological and reservoir data indicating the role of natural fractures in field production.

3.1. Curvature Map

By definition, each node of a gridded surface has a certain curvature value for a given azimuth. In practice, this curvature value corresponds to the second derivative of the surface topography in the respective orientation. Therefore, a curvature value as a function of azimuth (orientation) may be computed for any given point on a geological surface. Curvature analysis is a method to define anomalies in local surface curvature that may coincide with large-scale structural features such as fractures [38]. Generally, curvature analysis is performed for geological horizons picked from seismic data sets. Many authors have also described the relationships between folding and the generation of fractures on various scales [39,40]. Such features are known as ‘extrados’ fracture sets. The hypothesis is that fractures perpendicular to the hinge are pre-folding, while fractures parallel and oblique to the hinge are fold-related or due to post-folding reactions to the applied extensional stress. In such cases, fracturing is related to spatial variations of strain. Several researchers have noted a relationship between high fracture intensity and high curvature areas in the North Sea [39] and North America [40]. The curvature map (Top Asmari) indicating the location of faults/fractures is represented in Figure 2. High curvature areas correspond to the faulted and fractured areas, which appear as linear features along the map.

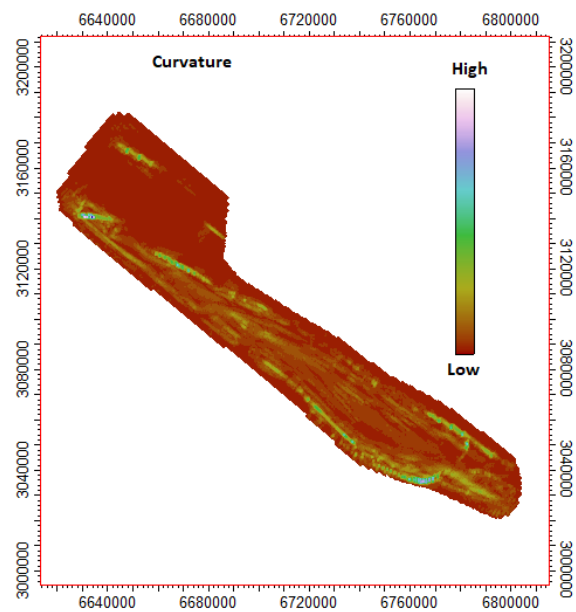


Figure 2. Curvature map (Top Asmari) indicating the location of faults/fractures.

3.2. Faults Distribution Map

To date, 13 large-scale faults have been picked in the field structure (Figure 3), dominantly distributed in the field's western and eastern sectors. The preferential orientation of the curvature patterns suggests that they represent structural directions. For the main orientation (N130), it is clear that this matches very well with the structural axis of the field. The most important fault in this field is trust fault F2, which separates the southeastern part from the main part. It resulted in dipping the southern flank of Asmari and Bangestan Group reservoirs up to 75 to 80 degrees. It has affected the communication of the reservoir's eastern and western sectors, separating the Asmari reservoir into two southeastern and main sectors. The eastern part is more complicated than the other sectors (same as Asmari) due to trust faults and the Kharg-Mish structure.

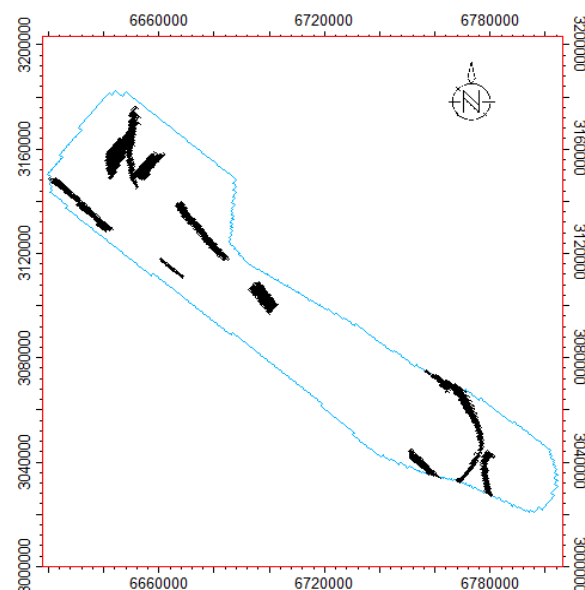


Figure 3. Location map of the faults of the studied field structure, Asmari top.

3.3. Image Log-Based Fracture Intensity Map

Image logs serve as advanced logs for imaging a borehole's physical properties (electrical resistivity or acoustic impedance). They can be used to interpret different types of fractures in the formation based on resistivity or acoustic contrasts. Fracture information such as open and filled fractures, fracture dip and azimuth, fracture spacing, and fracture intensity is derived from the interpretation of image logs. There are 28 wells in the field with good-quality image interpretation results. An example of continuous open fractures from the middle part of the Asmari Formation on FMI logs of the field is shown in Figure 4. Each fracture is represented spatially as a plane with its azimuth and dip attributes. The intensity of open fractures was computed as the area of fractures per unit volume (1/ft), represented by P32 (3 refers to a unit volume of rock, and 2 refers to a 2D fracture area). The fracture intensity map (P32) of the Asmari reservoir in the oilfield is shown in Figure 5. As is seen, high fracture intensity areas correspond to fault locations and high curvature intensity.

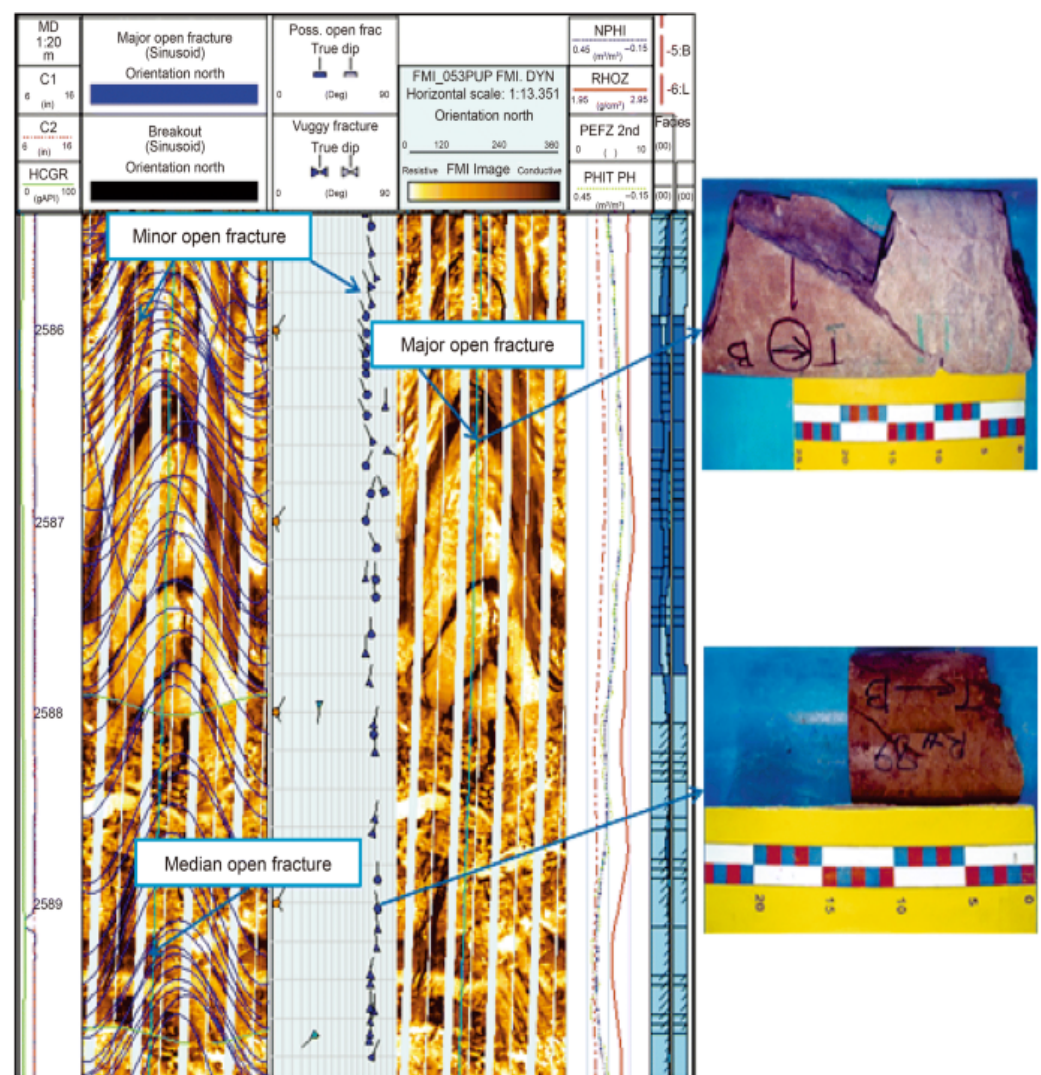


Figure 4. Representation of major and medium open fractures on core samples and FMI log [27].

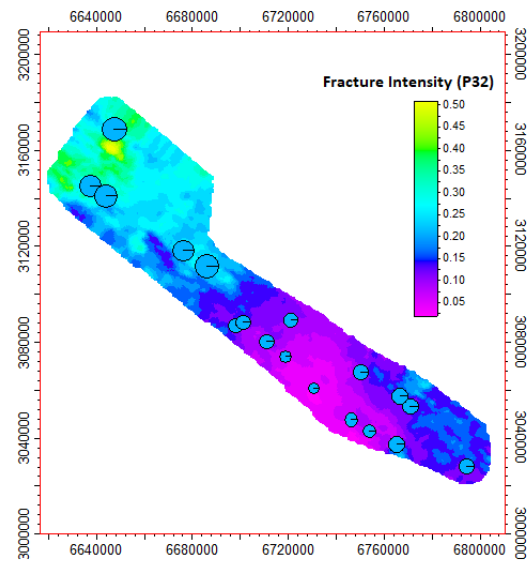


Figure 5. Average fracture intensity map (P32) in Asmari reservoir.

3.4. Mud Loss Map

Mud loss data provide very useful proxies for the fracture characterization of carbonate reservoirs. Wells with high mud loss are usually correlated to fractured zones. This study used mud loss data from 261 wells to generate the mud loss map. In some cases, mud loss rates were given in inconsistent units. In other cases, only the bulk volume of the mud loss was given. The first step in our efforts was to obtain unit consistency. The second step was to estimate the mud loss duration from drilling reports to convert the volumes into rates. The mud loss rate for complete loss was reported as 100 STB/hour, equivalent to 2400 STB/D. However, while searching the drilling records, it was seen that the circulation rate, in some cases, could go up to 5000 STB/D, which is more than 200 STB/hour. The Gaussian random function simulation (GRFS) algorithm generated a mud loss map for the Asmari Formation (Figure 6). It should be noted that the source of “complete losses” could be either fractures or localized cavities, and they tend to occur in geological formations that have pre-existing fractures [32,34].

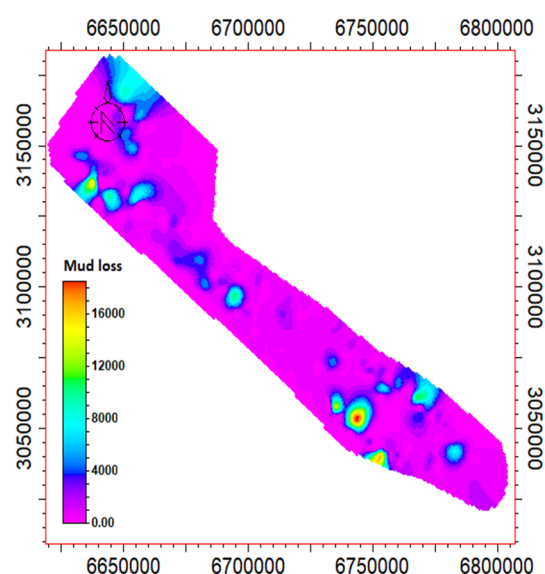


Figure 6. Mud loss map in the Asmari reservoir.

3.5. Productivity Index (PI) Map

The productivity index is a significant measure that indicates the ability of an oil or gas well to produce. It is calculated by dividing the total liquid flow rate at the surface by the pressure drawdown at the midpoint of the productive depth range. In essence, it represents the thickness of the formation responsible for production. Therefore, it is important to determine this thickness to characterize a given well's deliverability appropriately. The PI is usually expressed in STB/D/psi. Reservoirs may be classified as cross-flow and commingled systems from the standpoint of reservoir dynamics. In the latter case, the production is commingled only in the common wellbore, and the reservoir layers have no vertical communication. In commingled systems, the PI of each layer depends on its characteristics. The overall PI of the reservoir depends on the sum of the PI's of the layers exposed to the wellbore. In the cross-flow system, the PI is unique due to interlayer communication. The system behaves like one, even when partially penetrated [32,34]. Since the field is a fractured reservoir, the PI estimates represent the whole Asmari interval and a combination of layers from Asmari to the Bangestan Group, where appropriate. The PI database included 177 digitized build-up data from 55 wells and 196 PI tests. A bubble map showing the productivity index (PI) in the field/Asmari is presented in Figure 7. Assuming the poor and good reservoir quality zones are directly linked to PI distribution, the most productive areas are located in the central and northwestern parts of the structure.

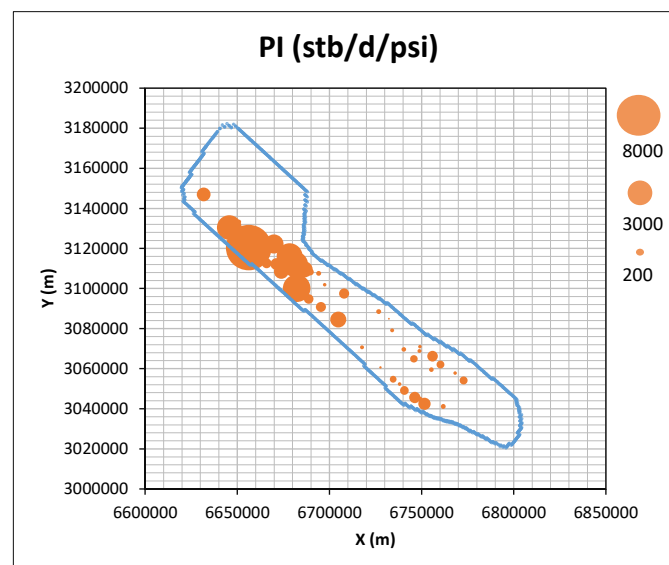


Figure 7. The bubble map shows the productivity index (PI) in the Asmari reservoir.

4. Classification of Fracture Types

On the FMI images, fractures are seen as linear features with a steeper dip than the structural dip. Open fractures have a conductive appearance on the images of a clay-free formation as their aperture is invaded with conductive drilling fluid. Mineralized or sealed fractures, such as anhydrite or calcite, seem resistive if their filling material is dense. The fractures containing a pyrite or clay filling show a conductive response. To differentiate between pyrite/clay-filled conductive fractures and mud-filled fractures, knowing the depositional setting of the study area is necessary. Open-hole logs can also be highly beneficial for this kind of differentiation.

In specific zones of the field formations, the FMI log revealed the presence of either a limited or extensive number of fractures. Generally, fractures can be classified into closed or continuous/discontinuous conductive traces, called open fractures. Mud invasion into the open parts of the fractures' apertures makes them conductive. Water-based mud invasion into fractures causes a decrease in the reading of resistivity buttons that appeared as black-colored sinusoids in the FMI logs.

Open fractures can further be grouped into more classes regarding their continuity and appearance within the wellbore. This study classified open fractures into four categories based on image log interpretation results: major open, medium open, minor open, and hairline. Other open fractures, such as vuggy, partially closed, and partially open fractures, were also considered when interpreting image logs.

Based on FMI log interpretations, induced fractures occur in two opposite directions. Most induced fractures indicate a NE-SW strike (N015 to N030), while the minority represent an NWW-SEE strike (N285 to N300). Such stress behavior indicates the rotation of maximum horizontal stress from the original NE-SW (parallel to the direction of the Arabian plate push against the Zagros Trust Belt) to the recent NW-SE trends [41].

Figure 8 represents the rose diagram of all open fractures in the studied oilfield. Open fractures propagate in all directions, parallel or perpendicular to the maximum horizontal stress. Rose diagrams of major open fractures, medium open fractures, minor open fractures, and hairline fractures are shown in Figure 9a–d. The important understanding of the extracted rose diagrams is the bipolarity of different fracture sets. Major open and medium open fractures are developed parallel to maximum horizontal stress. In contrast, minor open and hairline fractures are perpendicular to maximum horizontal stress (or parallel to minimum horizontal stress). It is important to note that caution must be exercised when making blanket statements about the correlation between fracture types and stress directions for all wells in the field. Due to the local stress variation, some stress rotations may occur.

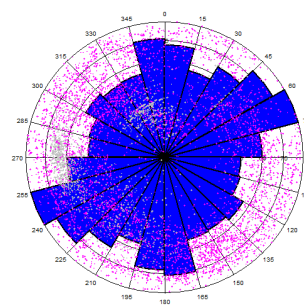


Figure 8. Rose diagram of all open fractures (Asmari reservoir).

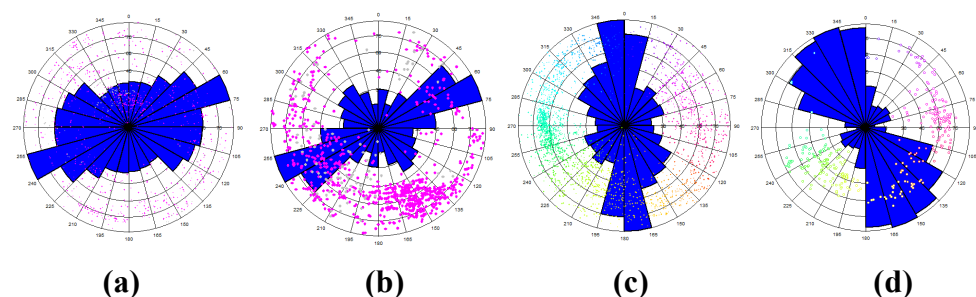


Figure 9. Rose diagram of (a) major, (b) medium, (c) minor, and (d) hairline fractures (Asmari reservoir).

5. Results and Discussion

5.1. The Relationship between Fractures and Production Data

This section investigates the relationship between fractures and actual production data. Figure 10 shows a generally good agreement between fracture intensity, mud loss, and the PI in the Asmari reservoir parts of the studied field. Notably, the highest values of the PI in the northwestern part of the study area do not correlate well with the other available data. This means other geological complexities probably control high mud losses in this zone. Irrespective of the northwestern part of the field, the areas with high production rates almost correspond to those with high mud losses and high curvature in the structural map,

indicative of faulted zones with high fracture intensity in their surroundings. Two mud loss clusters can be detected in the field structure, one in the central and northwestern parts of the field (high mud flow rates) and the other in the southeastern area (minor losses). The most productive areas are distributed in the central and northwestern parts of the field, where high mud loss and fracture intensity coincide. The results show that the mud loss zones match reasonably well with the major fractured zones, likely to show the most intense deformation and, consequently, high fracture intensity. Although the relationship between the mud loss map and productivity index is scattered, it can generally be seen as a direct correlation between the PI and mud losses (Figure 11a). Fractures enhance reservoir permeability in horizontal and vertical directions. Studying the relationship between horizontal permeability (Kh) and productivity index (PI) for the Asmari reservoir in the studied field confirms the strong dependence of the productivity index on horizontal permeability (Figure 11b). Permeability is highly correlated with fracture aperture and spacing. The fractures' presence is directly related to interval permeability data (mD-ft) derived from formation tests (e.g., Drill Stem Test, DST). Care must be taken not to use matrix permeability for calibration with fracture data, as it does not have intrinsic fracture information. Wells with a high PI are expected to produce from both the matrix and fractures. Accordingly, higher productivity index values are directly correlated to horizontal permeability and the direct role of fractures in field production.

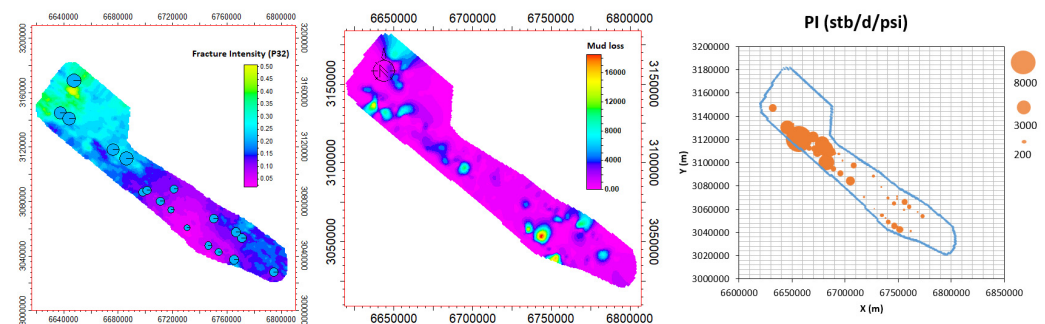


Figure 10. A good agreement between fracture intensity, mud loss map, and productivity index (PI) in the Asmari reservoir.

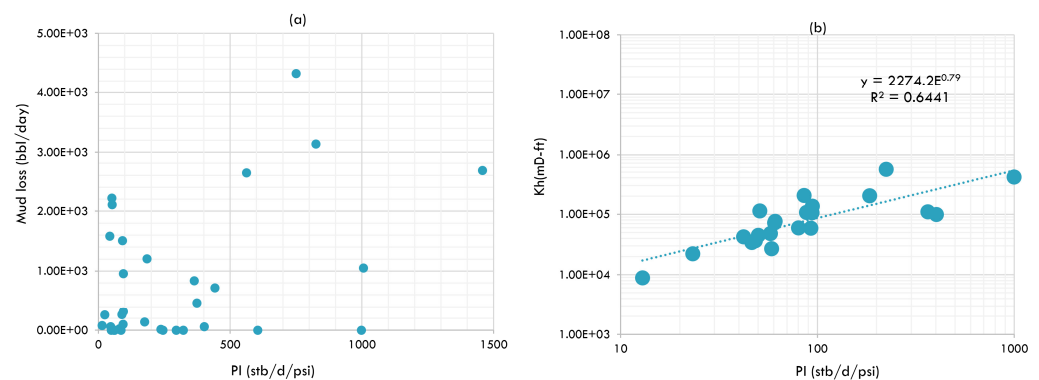


Figure 11. (a) Cross plot showing the relationship between mud loss and PI (b) Cross plot showing the relationship between Kh and PI in Asmari reservoir.

5.2. Field Stress Analysis & Geomechanical Sectors Classification

The field is exposed to compressional forces imposed by the NW movement of the Arabian plate pushing against the Zagros thrust belt (ZTB) and the distribution of local stress in the Dezful embayment. According to the field's reverse and thrust faults system reported [42], the magnitude of maximum horizontal stress (σ_H) is greater than minimum horizontal stress (σ_h) and vertical stress, respectively ($\sigma_H > \sigma_h > \sigma_v$). As is seen in Figure 12a, the northwestern and southeastern main fault zones of the field structure have created

three geomechanical sectors, including the northwestern (geomechanical sector 1), central (geomechanical sector 2), and southeastern sectors (geomechanical sector 3). To perform a more in-depth analysis of the stress conditions, wells 337, 316, and 325 were selected as the representative wells for geomechanical sectors 1, 2, and 3, respectively, as shown in Figure 12b. Major open fractures in geomechanical sectors 1 and 3 have a similar azimuth, while the stress regime in the middle sector (geomechanical sector 2) differs. The strike of maximum horizontal stress in sector 2 is NW-SE (Figure 13). The field stress analysis used more wells from the mentioned sectors to validate the geomechanical sectors identified in this study.

The classification scheme, including four classes of open fracture sets used in this study, is consistent with Price's classification of natural fractures [43,44]. Major and medium open fractures are aligned with the maximum horizontal stress (σ_H), while minor and hairline fractures form parallel to the minimum horizontal stress (σ_h). This shows that two generations of fractures, syn-folding and post-folding, occur in the studied structure.

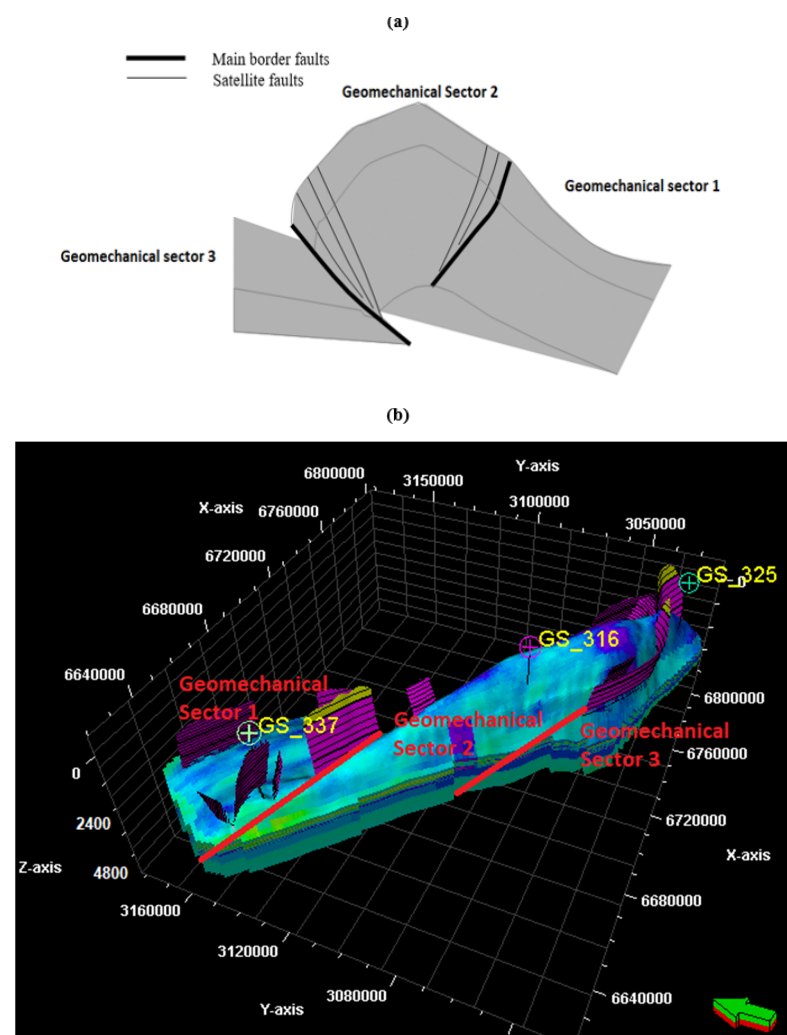


Figure 12. (a) Three geomechanical sectors were identified in this study based on the field structure's NW and SE main faults. (b) Wells 337, 316, and 325 were chosen as the representative wells corresponding to geomechanical sectors 1, 2, and 3, respectively. The red lines are the two major faults in the field.

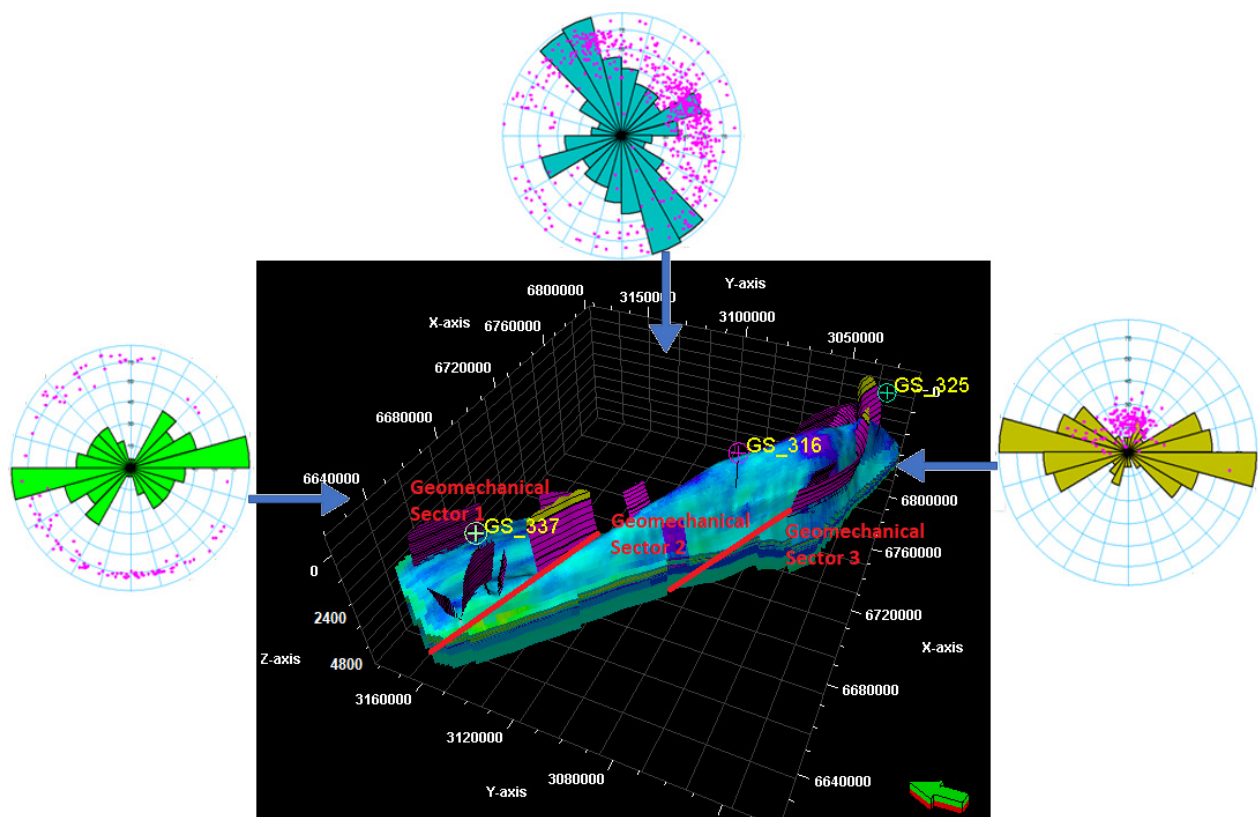


Figure 13. Strike of open fractures in representative wells from geomechanical sector 1 (337), sector 2 (316), and sector 3 (325). The red lines are the two major faults in the field.

5.3. Continuous Fracture Network Modeling

The fracture dip and azimuth values derived from image log interpretation were used to build a plane in 3D space for each fracture. Fracture intensity was calculated using the fracture plane data (fracture dip and azimuth) for each well as a P32 log, the fracture area per rock unit volume. Accordingly, P32 logs were generated as fracture intensity logs for all 28 wells of the field with image log interpretation results. Using the Gaussian Random Function Simulation (GRFS) algorithm, a 3D continuous fracture model for all types of fractures was prepared (Figure 14a). A longitudinal and transverse section through the fracture intensity model is illustrated in Figure 14b,c. Fracture intensity maps of Asmari A1 (a), C2 (b), and D2 (c) zones are shown in Figure 15a–c. The generated fracture intensity volume indicates a higher stress concentration in areas corresponding to the main fault zones. The generated CFN was employed as an input for the discrete fracture modeling process.

5.4. Discrete Fracture Network Modeling for a Prototype Sector

A model of the fractures in a prototype area was created using available data to examine the impact of different fracture types on production. The southeastern sector of the field has good coverage of both image logs and production data. Therefore, a small sector within the southeastern flank of the field structure was chosen for the prototype modeling (Figure 16). The modeling area includes wells 245, 347, and 363 with image logs and wells 033 and 041 with production data (Figure 16). When constructing the model, a static model was trimmed to fit the designated fracture modeling region, which encompasses the oil-water contact (OWC) and gas-oil contact (GOC) of the reservoir. Afterward, a continuous and discrete fracture model of the prototype area was built. The DFN model was created for the prototype model based on the CFN model. The maximum and minimum fracture aperture was set to 0.005 mm and 0.000075 mm, respectively. The fracture porosity and

permeability parameters are listed in Tables 1 and 2, respectively. Considering moderate to relatively high fracture porosity and permeability, the Asmari Formation falls in Class I and II of the Nelson classification of fractured reservoirs [45].

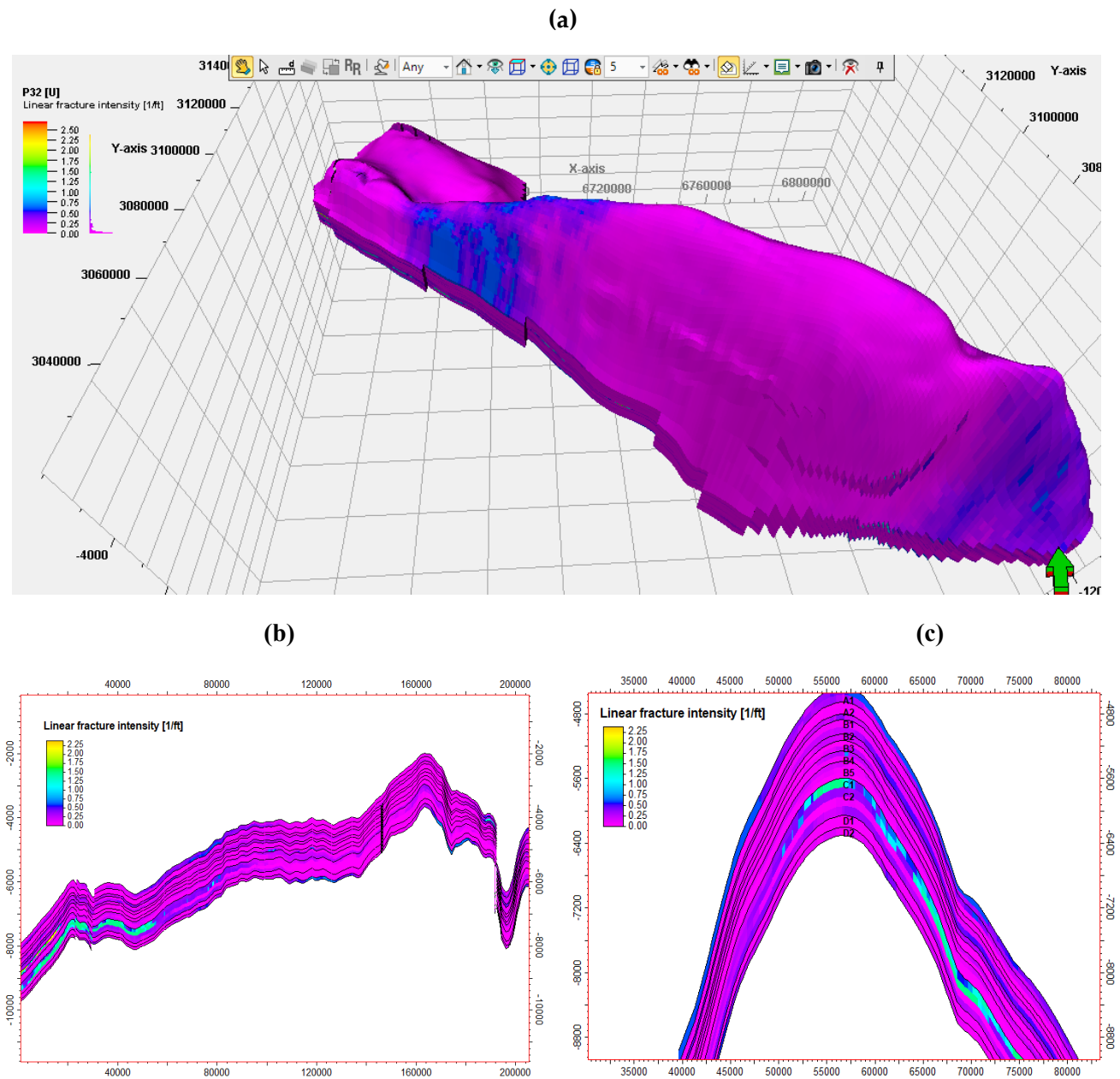


Figure 14. Fracture Intensity Model Analysis; (a) Asmari Reservoir: (b) Sections of Fracture Intensity Model in Longitudinal (c) and Transverse Directions. Higher fracture intensities highlighted in blue and green represent A1, C2, and D2 reservoir zones.

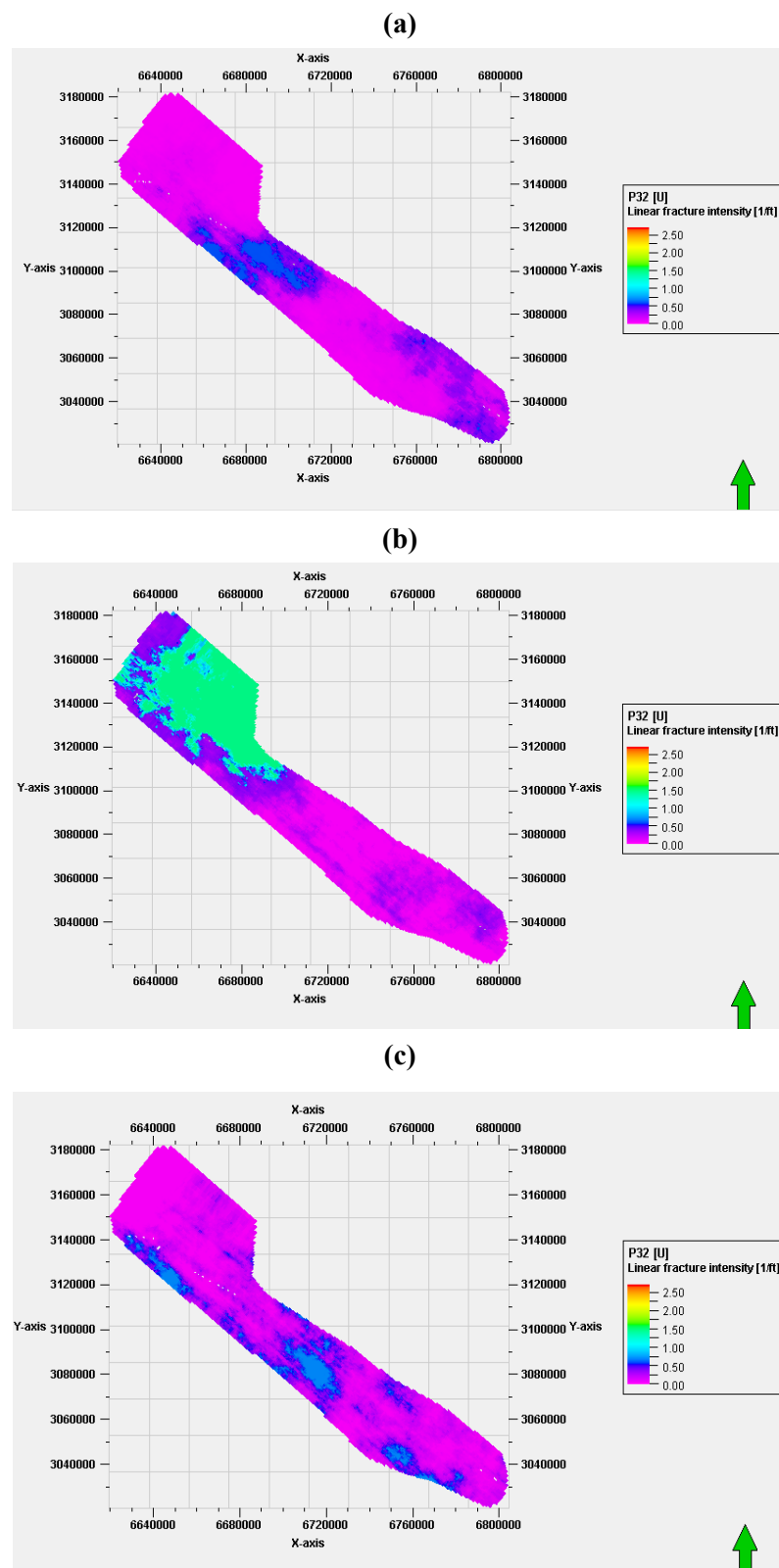


Figure 15. Fracture intensity map, Asmari A1 (a), C2 (b), and D2 reservoir zones (c).

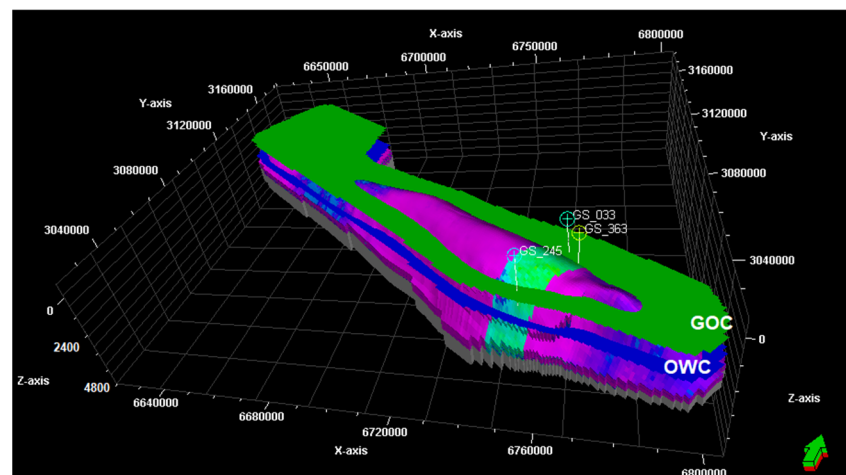


Figure 16. 3D visualization of the prototype area of the field structure. The yellow and blue surfaces show oil-water and gas-oil contact, respectively.

Table 1. Modeled fracture porosity derived from image logs for different sectors before the history match.

Sector	1	2	3	4	5	6
Maximum porosity (fr)	0.0091	0.00678	0.00499	0.007317	0.01321	0.00461
Mean porosity (fr)	0.00117	0.000971	0.000879	0.00115	0.001494	0.001157
Minimum porosity (fr)	0.000027	0.0000418	0.000077	0.000028	0.000011	0.000087

Table 2. Modeled fracture permeability was derived from DST data for different sectors before the history match.

Sector		Kx (md)	Ky (md)	Kz (md)
1	Max	2307	5000	2380.9
	Mean	391	486.4	659.8
	Min	17.44	8.95	7.9
2	Max	1618.6	5000	3653.4
	Mean	345.6	415.8	445.8
	Min	3.97	14	10
3	Max	1338.6	4030	1767.6
	Mean	335.97	434	411.3
	Min	32	32.8	34.3
4	Max	3058	5000	3043.2
	Mean	404.8	538.8	543.4
	Min	6	5.96	12.16
5	Max	3675.8	5000	4499.5
	Mean	500	672.7	664.8
	Min	4.8	4	3.75
6	Max	1347	1521	3318.4
	Mean	423.7	398.9	500.8
	Min	22.7	35.5	30

By upscaling the DFN to the simulation grid, fracture porosity, permeability, sigma, and block height models were generated. The fracture permeability model for major open fractures before (a) and after (b) upscaling is shown in Figure 17 for illustration. The permeability decreases from major open fractures to hairline fractures (Figure 18). However, as permeability is a vector parameter showing variations in the simulation cell's i, j, and k directions, the minor and hairline fractures contribute to fluid flow perpendicular to the direction of major open fracture sets.

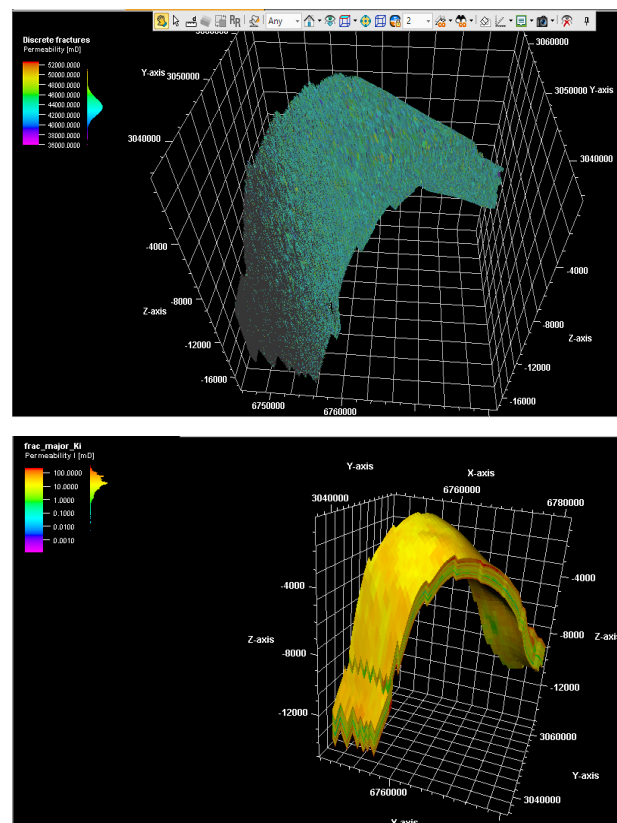


Figure 17. Fracture permeability model for major open fractures before (top) and after (bottom) upscaling.

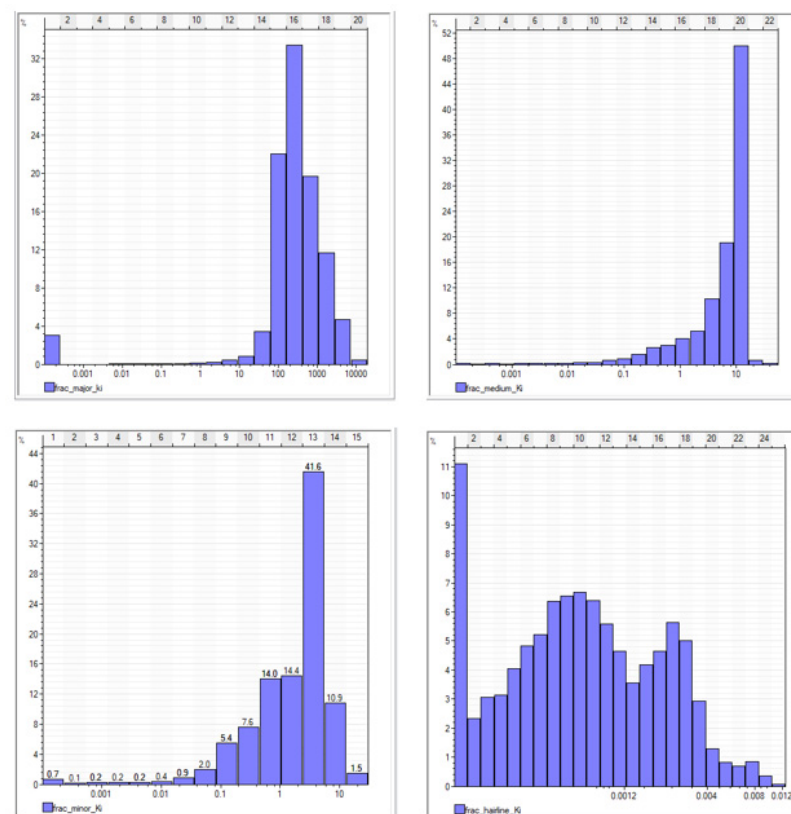


Figure 18. Fracture permeability histograms for major open, medium open, minor, and hairline fractures. Permeability shows a clear decreasing trend from major open to hairline fractures.

On the other hand, Price's classification scheme was used for field fracture classification. Accordingly, major and medium open fractures form parallel to the maximum horizontal stress direction, while minor and hairline fractures are aligned with the minimum horizontal stress. Such good agreement between the proposed open fracture classification and modeled permeability proves the reliability of the image log interpretation and resulting fracture network modeling. Hence, the prototype model results shown for the studied part of the Asmari reservoir in the field may be used to promote a more realistic and less uncertain dynamic reservoir model. Furthermore, the integrated fracture study workflow outlined in this research could greatly increase the predictive power of future fractured reservoir models.

5.5. Limitations of the Methodology

Although the integrated methodology adopted in this study shows an advantageous workflow for fracture characterization and modeling, it has some limitations, as follows:

- (i) The CFN and DFN models heavily rely on the interpretation results of image logs such as FMI, CAST, and UBI. An adequate number of wells should have image logs that are geologically well distributed on the structure. Without adequate, good-quality image logs, fracture models based on geological data will be highly uncertain.
- (ii) The image log interpreter should have sufficient experience interpreting complex and heterogeneous carbonate reservoirs. Otherwise, some important fracture information may be misinterpreted, causing uncertainty in the fracture model.
- (iii) Field observation data must be incorporated into the fracture modeling software. For example, if the maximum fracture length is 100 m based on field observations, then the outputs of fracture models can be validated. Otherwise, the wrong parameter setting of a fracture model will not honor production data.
- (iv) The fracture modeler must be familiar with geological, petrophysical, and reservoir simulation disciplines. For example, a fracture modeler can be a geologist with a good background in reservoir dynamic model parameters.

6. Conclusions

This study investigated the correlation between fractures and oil production in a giant, fractured carbonate field using image logs, curvature maps, stress maps, mud loss data, and production data. Four fracture sets were identified based on the interpretation of the image logs of the studied field, including major open fractures, medium open fractures, minor open fractures, and hairline fractures. Using the UGC maps, a curvature map was generated for the reservoir units in the Asmari Formation. Subsequently, an investigation was conducted to analyze the correlation between fracture characteristics and production data. A relatively good correlation was found between the fracture model, curvature map, mud loss map, fracture intensity, and productivity index. Studying the stress regime showed that three individual geomechanical sectors occur in the field structure, showing different stress directions. Major open and medium open fractures align well with the maximum horizontal stress direction. In contrast, minor open fractures and hairline fractures are parallel to the direction of minimum horizontal stress. A small sector in the southeastern part of the field was selected to build a prototype fracture model. Both continuous fracture network (CFN) and discrete fracture network (DFN) models were developed for the prototype model. Fracture length was modeled by a normal distribution function. Fracture orientation was modeled by using the Fisher probability distribution model. Finally, 3D models of fracture dip and azimuth, fracture porosity, fracture permeability, fracture length, fracture aperture, and the sigma parameter were computed for the prototype model. The DFN model established for the prototype area could serve as a baseline to investigate the impact of various fracture types on the dynamic simulation model and to address the frequent production challenges encountered in the field under examination.

The results show a good agreement between high fracture intensity zones and productivity index maps. Mud loss data also confirms the fracture model results. The methodology

adopted in this study can be applied to other complex carbonate reservoirs to address the heterogeneities resulting from variations in fracture parameters such as aperture, length, density, and continuity. The prototype model performs well in only one sector of the field. Following the same methodology in all sectors and feeding the outputs to the dynamic model will provide a more realistic dynamic model. This is compared to the case in which only a constant value for fracture porosity, permeability, and sigma is assumed within each sector.

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