Assessment of Fracture Density Distribution from Image Logs for Sensitivity Analysis in the Asmari Fractured Reservoir

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Abstract: Characterizing fracture properties in naturally fractured reservoirs poses a significant challenge. While well-testing remains valuable, it often fails to provide precise descriptions of these properties. Bridging this gap requires the integration of geological expertise to enhance fracture assessment. This study addresses the limitations of well-test analysis and explores the application of Conventional Image Logs in structural, fracture, and geomechanical analysis. However, effectively combining these applications with well-test analysis on a field scale reveals a substantial knowledge gap. A critical challenge in this context is the absence of a defined procedure for calculating the variable "σ," a crucial parameter for simulating fractured carbonate reservoirs using image log fracture density. Integrating geological knowledge is essential to reduce uncertainties associated with well-test analysis and provide more accurate characterizations of fracture properties. Image log data processing emerges as a valuable avenue for gaining insights into the static attributes of naturally fractured reservoirs. This study focuses on Characterizing fractures using data from ten image logs and Developing a more accurate simulation model through the interpretation of images, with a particular emphasis on OBM imaging. The main goals of this fracture study revolve around establishing correlations between fracture densities well by well within the simulation and enhancing the accuracy of the simulation model by incorporating fracture data from image logs. Borehole imaging tools such as FMI/FMS and OBMI-UBI play a pivotal role in identifying significant structural features, including faults, fractures, and bedding. Fine-tuning fracture parameters during the history matching process, while potentially time-consuming, significantly impacts other historical match parameters. Consequently, the reliability of reservoir simulation results, predictions, and recovery enhancement strategies hinges on the precision of fracture properties and their distribution within the model. Recent advances in interpretation techniques have expanded the horizons of image interpretation, enabling the creation of more accurate simulation models for fractured reservoirs using fracture data obtained from image logs. The overarching goal of this project is to comprehensively evaluate a fractured reservoir field by integrating data from ten individual wells.

Keywords: Well-testing, fracture evaluation, Image log data, fracture density, simulation sensitivity analysis.

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1 Introduction

The Zagros Mountains folded belt is distinguished by its concentrically folded geological formations [1]. The intricate character of the geological structures within the Zagros Mountain belt underscores the necessity for obtaining precise data on structural dip and subsurface fault patterns. This information is essential for the successful planning of development and infill wells. In certain wells, the observed thickness of formations exceeds what was originally anticipated. This can be attributed to varying factors, such as steeper bedding dips or the presence of reverse faults. In some instances, pinpointing the exact cause of these unpredictably greater thicknesses can be a challenging endeavor [2]. In this complex geological setting, borehole imaging logs played a critical role in detecting the structural and reservoir geometry[3]. Accurate reservoir description through the use of image logs, particularly in thinly laminated reservoirs, emerged as a key factor in facilitating effective field development [4]. Structural and reservoir geologists can readily identify fracture features and classify different types of fractures along the wellbore by directly utilizing the FMI (Formation MicroScanner) log, moreover, in situations where seismic data is unavailable, the FMI log serves as a valuable tool for these geologists, enabling them to provide essential information that can be used to develop dependable solutions for significant geological challenges[5][6]. Understanding the origins of fracture systems is a complex endeavor, often involving factors such as fracture angle, shape, orientation, abundance, and the relationships between different fracture sets. These factors are typically derived from sources like core samples, borehole imaging logs, and various logging tools. However, these sources may not always provide precise orientation data. To shed light on the genetic history of fracture systems, various fracture models, including tectonic and diagenetic origins, are employed [7] [8].

Interpreting the origins of fracture systems necessitates a multidisciplinary approach that combines geological insights with rock mechanics principles. It operates on the assumption that natural fracture patterns reflect the stress conditions that existed during the fracturing process, akin to laboratory tests conducted under similar conditions. Natural fracture patterns are then compared to laboratory-derived patterns and the inferred stress and strain fields at the time of fracturing. Essentially, any model capable of describing stress or strain fields can be utilized to elucidate fracture distribution [9] [10] [11].

A genetic classification system for natural fractures proves invaluable in breaking down complex fracture systems into distinct origin components. This approach plays a pivotal role in defining the structure and predicting reservoir quality enhancements based on fracture data, rendering it a more manageable task [12] [7].

The Gachsaran field, with its dimensions of 44 km in length and 5 km in width, exhibits an asymmetric structure. Located in the Dezful embayment to the south of Gachsaran city, a thrust along the southern flank resulted in the northern part being thrust over the southern part (Fig 1). The primary reservoirs in this field are the Asmari and Sarvak formations. The Asmari formation, situated above the Pabdeh, comprises shallow-water Oligocene-Miocene limestone and was the first reservoir to produce substantial quantities of oil in Iran. Notably, the Asmari formation boasts an exceptional production capacity due to its extensive fracturing [13].

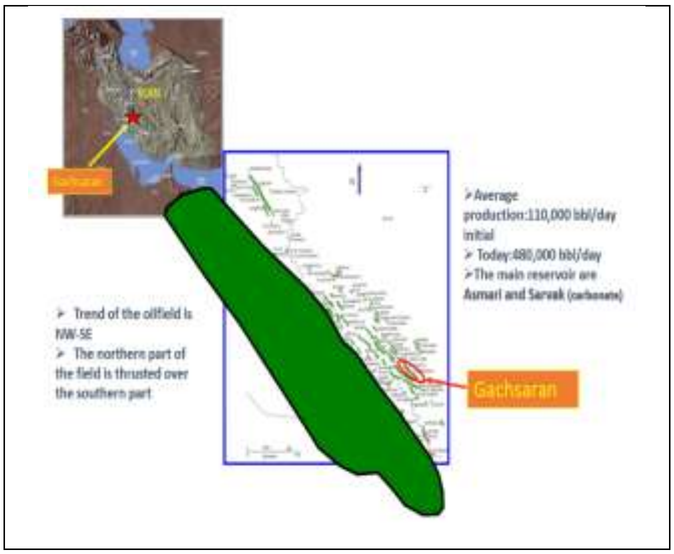


Fig 1: Geographic position of the Gachsaran field on the map of Iranian oilfields.

The dominant lithology within the Asmari formation is gray limestone, characterized by a well-developed network of fractures (Fig 2). The non-productive interval consists of rock with less than 5% porosity and less than 1md permeability. In contrast, the productive intervals typically exhibit porosities ranging from 5% to 25%, with an average of around 12%. Matrix permeability is generally low, but fractures within the pay intervals significantly enhance it, often exceeding 5 Darcies, resulting in remarkable flow rates.

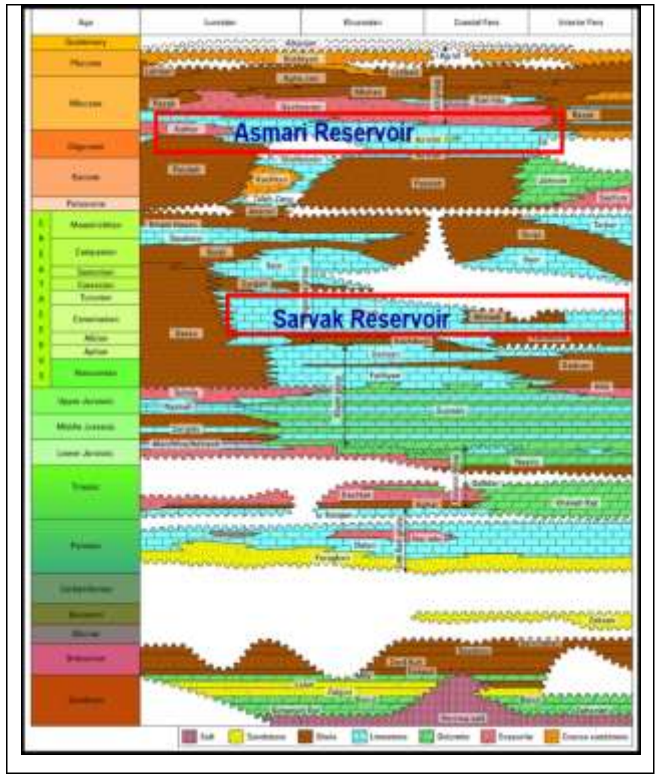


Fig 2: Illustrates the detailed lithology of the Asmari reservoir. This visualization provides a visual understanding of the reservoir's characteristics[14].

In naturally fractured reservoirs like Asmari, the identification and evaluation of fractures are of paramount importance for exploration, drilling, and well completion, as they have a profound impact on flow rates. Characterizing these fracture systems involves a multitude of methods that integrate geoscientific and engineering data.

By consolidating data from image logs, petrophysical data, well tests, production logs, formation tests, and core analyses, a comprehensive approach is established to estimate reliable fracture properties and their distribution. This work presents a workflow that focuses on precise sensitivity analysis by integrating diverse data types, ultimately enhancing well productivity, which addresses significant challenges encountered in naturally fractured reservoirs. In essence, the detection and characterization of fractures are pivotal in the ongoing quest to improve productivity.

2. Problem Formulation

This study leverages a comprehensive dataset of fracture properties, including fracture density, aperture, orientation, porosity, and permeability, derived from Formation Micro-Imager (FMI) and oriented Borehole Micro-Imager Ultrasonic Borehole Imager (OBMI-UBI) logs. Ten wells were extensively equipped with borehole imaging tools, such as FMI/FMS, OBMI-UBI, and conventional logs, to detect and map significant structural elements, including faults, fractures, and beddings(Fig 3).

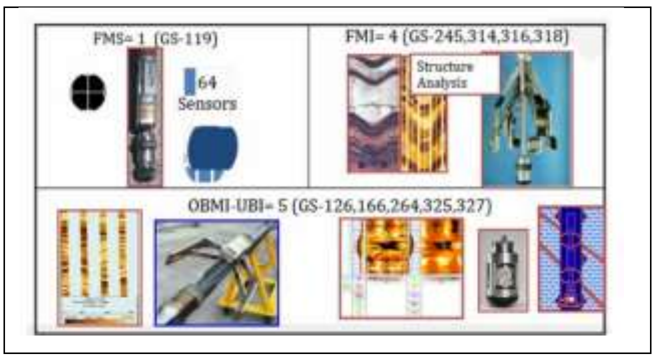


Fig 3: In this project, essential structural features, including faults, fractures, and beddings, are pinpointed using borehole imaging tools across the ten wells, encompassing FMI/FMS, OBMI-UBI, and conventional logging techniques.

These datasets serve as the foundational inputs for a dual porosity modeling approach, which is instrumental in enhancing the precision of subsurface fluid flow simulations.

The workflow unfolds as follows:

2.1.Characterization of Fractures Using Image Logs:

Fracture data are derived from the interpretation of image logs, encompassing attributes such as fracture density, aperture, orientation, porosity, and permeability. These insights are instrumental in understanding the fracture network within the reservoir.

2.2.Construction of a Static Model of the Fractured Reservoir:

The image interpretation results, which include fracture attributes, are integrated into a static reservoir model using COUGAR software. This model provides a visual representation of the fractured reservoir, offering a foundation for subsequent simulations.

2.3.Sensitivity Analysis in the Simulation Model with Emphasis on Fracture Density Data (σ):

The static model of the fractured reservoir serves as the basis for simulation experiments. The focus of these simulations is on sensitivity analysis, with a particular emphasis on fracture density data (σ). By varying fracture density parameters and examining their impact on fluid flow behavior, this analysis contributes to a deeper understanding of the reservoir's dynamics.

In summary, this workflow leverages fracture data extracted from image logs to construct a static reservoir model and subsequently conducts sensitivity analysis within the simulation model, with the primary objective of explaining the influence of fracture density on fluid flow characteristics in the subsurface reservoir(Fig 4).

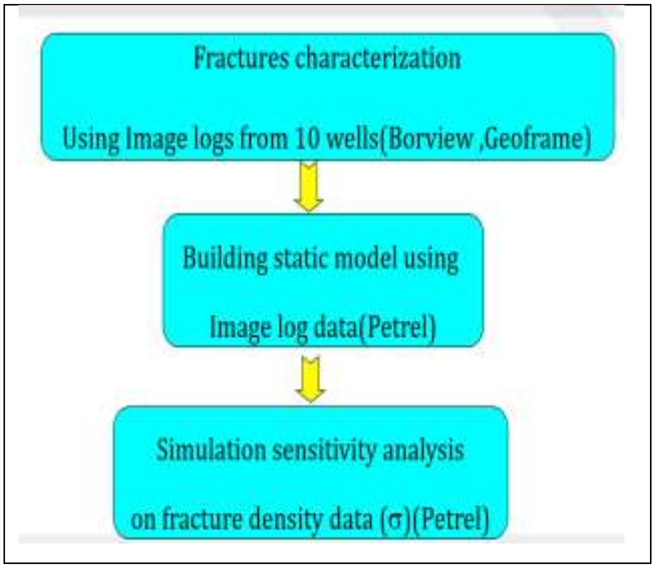


Fig 4: This workflow utilizes fracture data obtained from image logs to build a static reservoir model. It then proceeds to perform sensitivity analysis within the simulation model, primarily focusing on elucidating how fracture density impacts fluid flow dynamics in the subsurface reservoir.

3 Problem Solution

3.1. Characterizing Fractures through Borehole Imaging

Fractures play a pivotal role in reservoir characterization, profoundly impacting assessments of reservoir potential, production management, injection planning, and well design, regardless of well orientation—be it vertical, inclined, or horizontal. The role of fractures is multifaceted, contingent on several factors, including reservoir goals, quality, and their proximity to fluid interfaces (such as gas-oil, gas-water, or oil-water).

Accurately identifying and comprehending fractures is of paramount practical significance for the following reasons:

- **Orientation**: Different fracture types appear in various orientations in response to the geological stresses during fracturing. Precise identification of these types is crucial for predicting the orientations of entire fracture populations, enabling optimal drilling directions and reservoir model development.
- **Fluid Flow**: Each fracture type possesses unique fluid-flow properties, directly influencing reservoir performance.
- **Rock and Geological Context**: Specific fracture types are associated with distinct rock types and geological settings.
- **Shape and Density**: Individual fractures exhibit characteristic shape and size distributions and adhere to specific density patterns, which are essential for constructing comprehensive 3D reservoir models.

Fractures are essentially planar features with no noticeable displacement of blocks along their planes. Their dip can vary, featuring steeper dips in tensional and wrench regimes and high to low-angle dips in compressional regimes.

Fractures may present either open or tight (closed) apertures, or they could be filled with minerals like clays, calcite, anhydrite, pyrite, and others. In image logs, fractures typically manifest as linear features with dips steeper than the structural dip.

Appreciating fracture information is paramount due to the enhanced permeability these features offer in fractured reservoirs, significantly influencing reservoir productivity.

Key questions arise: Is the reservoir fractured or unfractured? If fractured, what are the fracture types (open or closed), and how extensive are they? Do fractures occur as a single set or multiple sets, and what is their dominant strike orientation? Answers to these inquiries are invaluable for geologists and reservoir engineers in assessing reservoir size, identifying optimal well locations, and formulating well completion plans. Production engineers also rely on this data to optimize production and well-completion strategies.

While reservoir cores provide the most precise information, coring highly fractured zones or unconsolidated sandstone formations is not always practical.

Furthermore, coring the entire reservoir length in each well is both cost-intensive and time-consuming. Borehole images offer a valuable alternative to cores, particularly when in-depth information on geological, structural, and sedimentological features is necessary.

Schlumberger provides high-quality borehole images for wells drilled with diverse drilling mud types, including water-based, oil-based, or synthetic-based mud. These images are obtained in wells with various geometries, spanning from vertical wells to highly deviated ones.

The primary goal of image log surveys is to analyze fractures. Interpretation of images is conducted in conjunction with open-hole logs, enabling correlations between observed fractures in the images and responses recorded in logs such as sonic, nuclear, and resistivity. The subsequent discussion delves into numerous fracture attributes.

3.1.1 Evaluating Fracture Aperture

Assessing fracture aperture is of utmost significance due to its direct impact on fracture network permeability. This influence escalates exponentially with the cubic size of the aperture.

Moreover, fracture aperture determines the available space within the fractures, thereby governing the storage volume, often referred to as fracture porosity, within the fracture system.

When aperture plays a role in fluid flow and storage, it becomes essential to consider not only the width of the fracture but also to estimate the volume of cement fill, quantify the percentage of contact area between fracture walls—commonly termed "asperities," and measure the surface roughness of these walls. The quantification of surface roughness is often accomplished using the Joint Roughness Coefficient (JRC) method [15].

It's important to note that measuring aperture is inapplicable for closed fractures lacking an open aperture. Instead, measurements are focused on open fractures, categorized in various ways, with a priority on areas where data confidence is higher. Typically, these results are presented in centimeters within the combined display.

Calculating fracture aperture is based on a well-established equation developed through modeling conducted at the Schlumberger Research Center in France. According to this equation, fracture aperture is determined as a function of two primary factors: the resistivity of the drilling mud (Rm) and the resistivity of the invaded zone within the formation (Rxo)(Fig. 5).

$$W = c.A.Rm^{b}.Rxo^{1-b}$$

(Where 'W' represents fracture aperture, 'A' indicates an excess flow of current through the FMI/FMS electrode, 'Rm' denotes the resistivity of the drilling mud, 'Rxo' stands for the resistivity of the invaded zone, while 'c' and 'b' are constants derived from the model).

3.1.2 Quantifying Fracture Density

To quantify fracture density, we conducted a comprehensive analysis that involved counting both open and closed fractures per meter. Through this examination, we pinpointed specific areas or intervals characterized by heightened densities of both open and closed fractures.

The identification of open-fracture zones within these intervals was based on various factors, including fracture density and their spatial arrangement, often forming clusters.

Our analysis revealed varying fracture densities among the wells, with GS-119 and the Thrust zone showing the highest number of fractures, while GS-318 exhibited the lowest fracture density (Fig. 5, Fig. 6, Fig. 7, Fig. 8, and Fig. 9). Notably, we observed a strong correlation between fracture density and cumulative production data.

Furthermore, it has become increasingly apparent that Production Logging Tools (PLT) possess substantial potential for evaluating flow characteristics in both fractured and non-fractured sections of the reservoirs.

These findings, particularly the maps illustrating fracture strike patterns, have empowered NISOC to make well-informed decisions regarding placement for development, ultimately leading to increased productivity and the achievement of production targets for future wells.

The enthusiastic reception and endorsement of this data and methodology by geologists and reservoir engineers have been a significant highlight of this project (Fig. 5).

Significantly, our findings underscore the substantial potential of Production Logging Tools (PLT) in assessing flow characteristics within both fractured and non-fractured segments of the reservoir. Leveraging these insights, particularly through the application of Fracture Strike maps, has empowered NISOC to make well-informed decisions concerning well-placement for development.

As a result, this advancement has notably boosted productivity, facilitating substantial progress toward meeting future production goals. The enthusiastic reception and endorsement of this data and methodology by both geologists and reservoir engineers stand out as key highlights of this project's success.

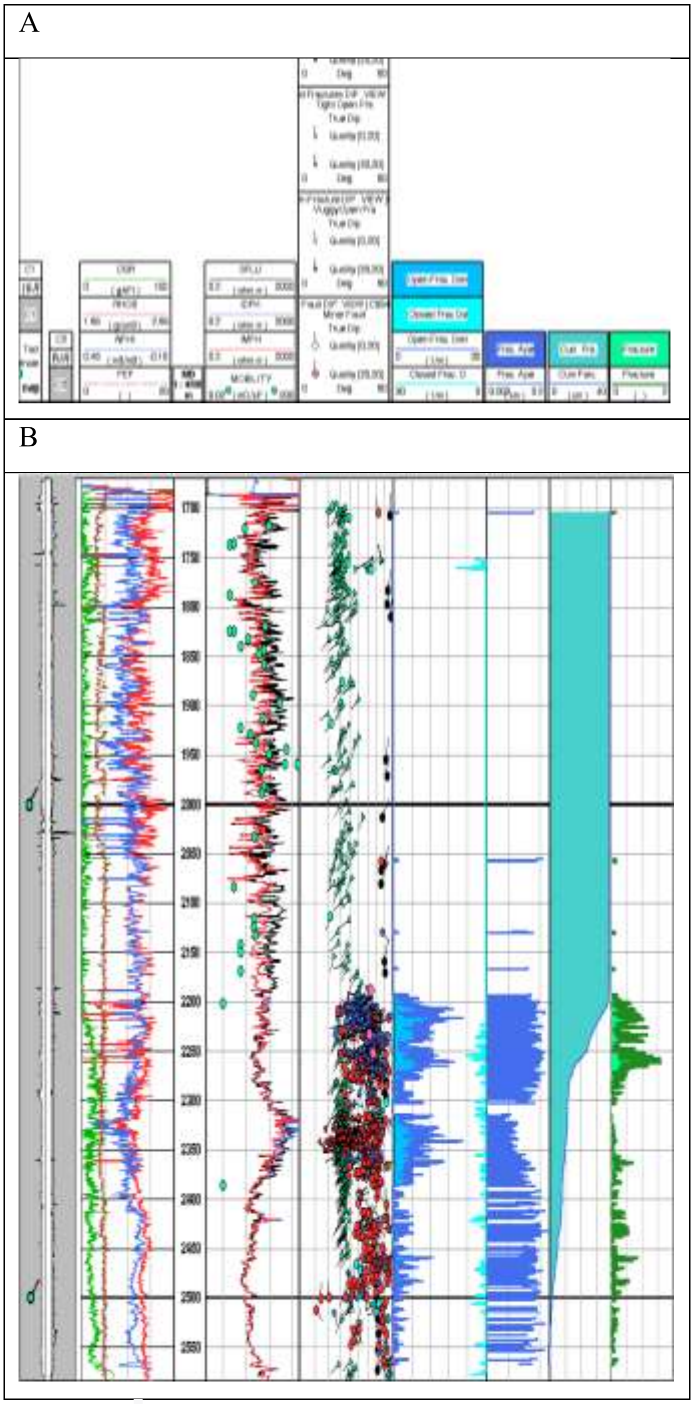


Fig. 5: A) Header details and B) Summary Log showcasing crucial data on Resistivity, Density, Porosity, Dips, Fracture Density, and Apertures within the Asmari, Pabdeh, and Gurpi Formations. This comprehensive summary provides a consolidated view of key parameters across these formations, aiding in a thorough analysis and understanding of their geological characteristics.

3.1.3 Determining Fracture Orientation

Determining the orientation of fractures involved reading the azimuth by observing the sinusoidal troughs visible on the directional scale located at the top of the image. These fractures often presented a more pronounced contrast anomaly compared to other porosity features.

This heightened contrast arose from fractures being saturated with conductive borehole fluid, with the exaggeration of the anomaly attributed to wellbore breakout along the fracture. In certain cases, these fractures could be obscured by highly conductive vugs. Consequently, we conducted a meticulous examination of both grayscale images and electrical wiggle-trace data to identify fractures.

The micro-scanner boasts an impressive resolution of approximately 10 mm, enabling the detection of even finer features, some as small as a few microns. Micro-scanner images offered an excellent visual correlation with core samples, aiding in the interpretation of sedimentary characteristics at various scales within the rock formations. This approach facilitated the precise identification of fractures and their orientation, distinguishing them from high-angle bedding features.

Upon analyzing these fractures about the dip of the bedding data, it becomes evident that open fractures tend to exhibit oblique, longitudinal, or transverse orientations concerning the bedding strike, categorizing them into these specific types.

An examination of statistical plots concerning the dip angles of open fractures in the Asmari formation fracture zones revealed a broad range of dip angles and azimuths. This variability suggests the potential development of faults within this geological area. This visual depiction provides an extensive overview, outlining the distribution and orientation of natural fractures alongside the bedding dip characteristics within this specific geological formation. Such detailed mapping serves as a valuable resource for understanding the structural complexities and orientations critical for reservoir characterization and exploration endeavors in the Asmari Formation (Fig. 6).

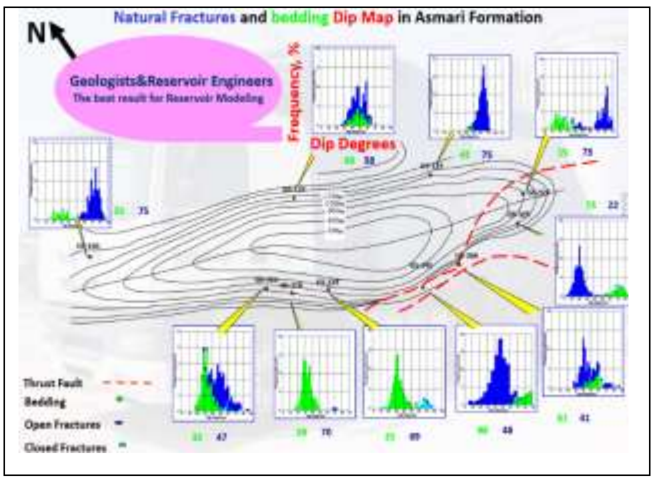


Fig. 6: Shows a comprehensive map detailing the natural fractures and bedding dip within the Asmari Formation.

The detailed azimuth map of natural fractures and bedding in the Asmari Formation provides extensive insight into the directional orientations of natural fractures and bedding characteristics within this geological layer. This intricate map stands as a crucial resource, aiding in the comprehension of structural complexities, directional patterns, and geological intricacies essential for reservoir evaluation and strategic exploration endeavors within the Asmari Formation(Fig. 7).

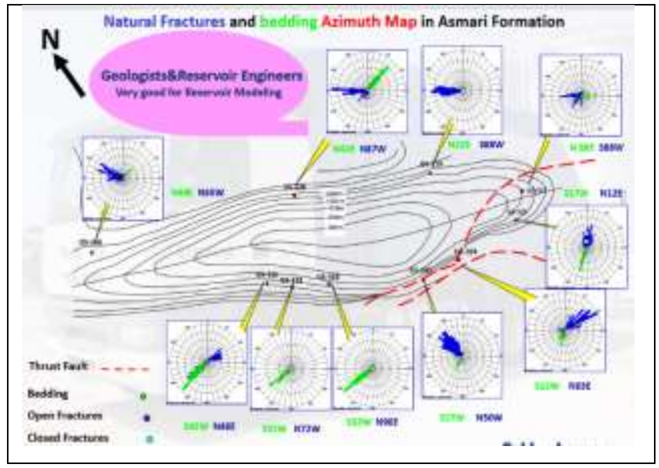


Fig. 7: presents a detailed cartographic representation delineating the azimuthal orientation of natural fractures alongside bedding within the Asmari Formation.

The fracture orientation and fracture density map in the Gachsaran field provides a thorough overview, illustrating the directional alignments of fractures as well as variations in their density across this specific field. Such a meticulous mapping representation serves as a fundamental resource, facilitating a deeper understanding of fracture orientations and densities critical for optimizing reservoir performance and guiding extraction strategies within the Gachsaran field.

The use of fracture strike maps proved instrumental for NISOC in optimizing well placement for development wells, leading to increased productivity and setting them on the path to achieving production targets for the future (Fig. 8).

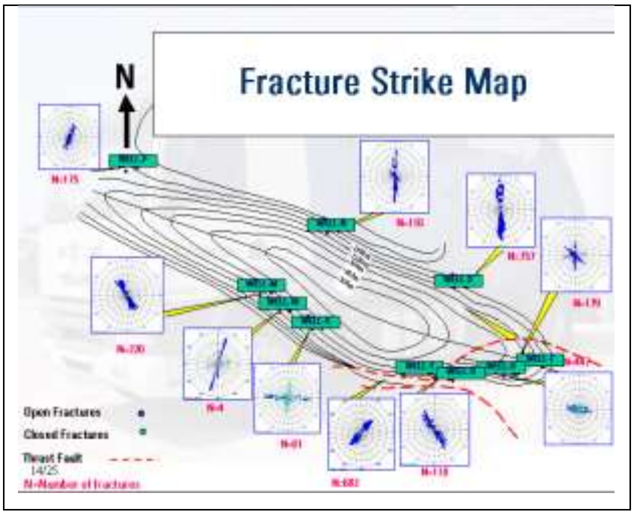


Fig. 8: Provides an extensive overview detailing the spatial distribution of fracture orientation and fracture density specifically within the Gachsaran Field. This map offers a comprehensive visualization, illustrating the directional alignment and density variations of fractures within this specific field.

Tectonic fractures and fracture density map offers an extensive overview, showcasing the spatial arrangement of tectonic fractures and variations in fracture density specific to this field. The intricate mapping serves as a fundamental resource, providing insights into the structural intricacies and density patterns of tectonic fractures essential for reservoir assessment and strategic planning within the Gachsaran field. Most fractures identified in this study are associated with folding and display oblique orientations, with thrust faults influencing the strike of fractures in GS-245 (resulting in transverse fractures) as depicted in Fig. 9.

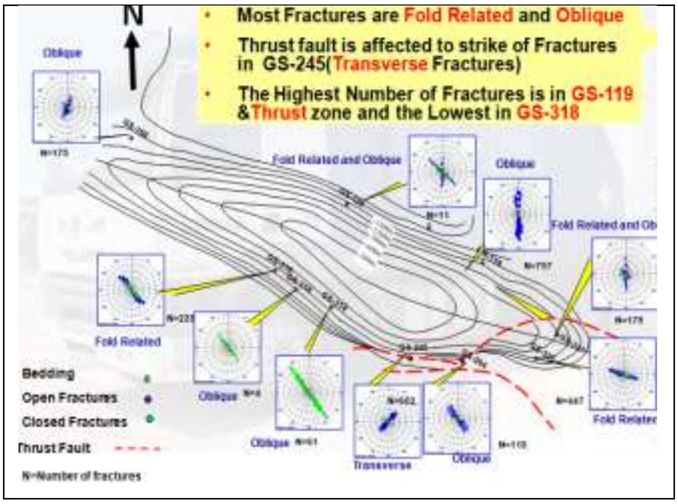


Fig. 9: presents an elaborate map delineating the distribution of tectonic fractures and fracture density within the Gachsaran Field.

The correlation between fracture density and production logs shows a compelling and intricate link between fracture density and the data extracted from production logs. This representation vividly portrays a noteworthy harmony between the density of fractures within a reservoir and the detailed information logged during the production phase. This correlation serves as a tangible testament to the profound connection between these two critical parameters.

The coherence observed between fracture density and production logs signifies a deep interdependence, underscoring their mutual reliance. This revelation strongly implies that regions displaying heightened fracture density are intricately linked to augmented levels of production. The alignment between these facets not only substantiates their correlation but also accentuates the pivotal role they play in reservoir management.

This robust correlation becomes an invaluable indicator for making informed strategic decisions in managing reservoirs. It illuminates a pathway toward optimizing production efficiency by pinpointing areas characterized by higher fracture density for refined extraction outcomes. Such strategic decisions based on this alignment can greatly influence the effectiveness of extraction methodologies and resource allocation.

Ultimately, this visual representation offers a clear and tangible demonstration of the substantial correlation between fracture density and production logs. It underscores their intrinsic relationship, establishing a foundation for informed decision-making in reservoir management to elevate production yields by strategically targeting areas rich in fracture density. The strong correlation between fracture density and cumulative production data underscores the success of the project. This study is well on its way to becoming a standard workflow for the assessment of other fractured reservoirs, solidifying its enduring influence on reservoir analysis and development. The enthusiastic reception and endorsement of this data and methodology by geologists and reservoir engineers are significant highlights of this project(Fig. 10).

This enhanced understanding has contributed to the optimization of well placement for development, resulting in increased productivity and progress toward achieving future production targets. Furthermore, this project has shifted NISOC's focus toward understanding reservoir performance within fractured reservoirs, highlighting the importance of formation pressure data and revealing the substantial potential of Production Logging Tools (PLT) for comprehensive flow analysis. Notably, our findings highlight the substantial potential of Production Logging Tools (PLT) for evaluating flow characteristics in both fractured and non-fractured segments of the reservoir. The application of these insights, particularly the use of Fracture Strike maps, has empowered NISOC to make well-informed decisions regarding well placement for development, ultimately leading to increased productivity and the achievement of production targets for future wells.

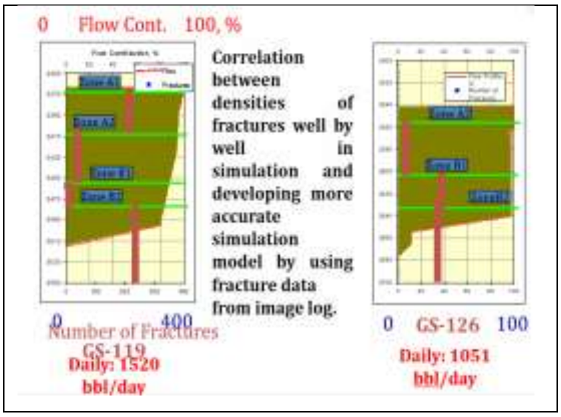


Fig. 10: Demonstrates a compelling correlation between fracture density and production logs.

3.2. Simulation Sensitivity Analysis

3.2.1.Sigma Computation

In the past two decades, reservoir simulation has emerged as a pivotal tool for guiding decision-making in reservoir development. This significance is particularly pronounced when dealing with fractured carbonate reservoirs, which account for a significant portion of the world's proven oil reserves. Reservoir simulation encompasses a variety of techniques, which can be broadly classified into four groups: sequential simulation, p-field simulation, object simulation, and optimization-based techniques. In our study, we specifically concentrate on the category of sequential simulation algorithms.

This group stands out for its versatility and applicability to a wide range of problems. Moreover, specifically, we employ the sequential Gaussian simulation algorithm, which assumes that the variable follows a Gaussian distribution.

Even in cases where this assumption doesn't hold, it is possible to transform the variable's marginal distribution into a Gaussian form. This transformation allows us to work with the variable, even when it doesn't meet the Gaussian distribution assumption.

A diagram depicting the theory of sequential simulation offers a thorough depiction of the sequential simulation theory, elucidating the sequential modeling process and its application within the specified context.

The diagram provides a valuable visual aid, outlining the sequential simulation methodology and its implications, serving as a critical reference for understanding the sequential simulation process as discussed in the cited source [16](Fig. 11).

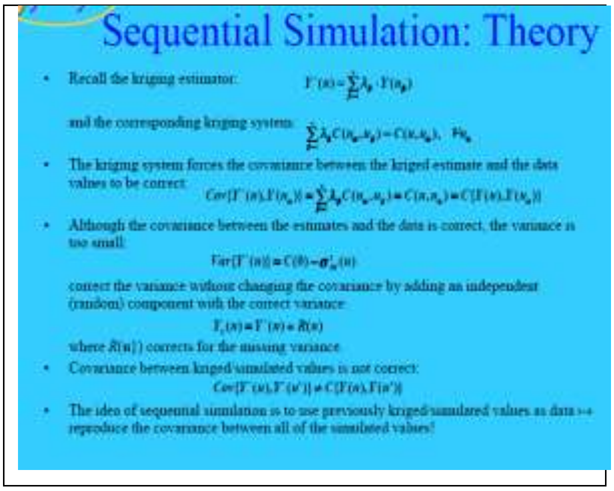


Fig. 11: Shows a comprehensive diagram detailing the theory of sequential simulation, as referenced in [16].

Oda (1985) introduced an analytical equation for computing the fracture-permeability tensor, while Lough et al. (1997) proposed an approach using the boundary-element method. Oda's method involves numerical integration based on statistical parameters of fracture sets, where equivalent permeabilities are assumed to be linearly dependent on density variations. Notably, Oda's solution allows for efficient calculations without the need for flow simulation. However, it is most suitable for well-connected, high-density Discrete Fracture Networks (DFNs) [10] [17].

In contrast, the second approach is numerically driven. It necessitates solving a steady-state flow problem within the discrete fractured network under specified boundary conditions, utilizing Poiseuille's formula for fracture flows.

This method takes into account the entire system geometry but requires more computational time, making it typically applicable to scenarios with lower fracture density. Moreover, the Dual-Porosity (DP) formulation assumes perpendicular fractures oriented along grid axes.

When it comes to simulating fluid flow in naturally fractured carbonate reservoirs while preserving their inherent heterogeneity and computational efficiency, specific challenges arise. The range of fracture scales spans from small-scale diffuse fractures to intermediate-scale sub-seismic faults and large-scale seismic faults. Due to computational limitations, incorporating the Discrete Fracture Network (DFN) model into field-scale models is not feasible, given the potential presence of billions of fractures within each cubic kilometer of reservoir rock. As a result, upscaling becomes necessary for flow simulation [18].

In these simulations, dual-porosity reservoir simulation tools are commonly employed. These tools implicitly represent the geological model of fault and fracture networks, as well as matrix media, using larger grid blocks. The transition from DFN models or implicit fracture models to dual-porosity reservoir simulation parameters is achieved through upscaling procedures.

These parameters include equivalent fracture permeability and equivalent matrix-block dimensions or shape factors. The upscaling of fracture permeability can be performed using either analytical or numerical techniques.

To effectively model fractured reservoirs, comprehensive fracture network information is essential. Fig. 12 offers a comprehensive exploration of the distinct categories of fractures resulting from folding processes. The diagram provides detailed insights into the diverse fracture types arising from folding phenomena, elucidating their characteristics and implications within the context of the referenced source [16].

This illustration serves as a valuable reference, aiding in the understanding of fracture formations attributed to folding processes as described in the cited literature. Once this data is available, simulations can be conducted with the dual-porosity option incorporated into conventional simulators.

Fig. 13 suggests an inclusive view of the methodology employed in dual porosity modeling, elucidating the process, steps, and parameters involved in this modeling approach. The diagram serves as a valuable reference, detailing the intricacies of the dual porosity modeling methodology discussed in the cited source [16].

Its comprehensive portrayal aids in understanding the complexities and applications of dual porosity modeling within the specified context.

This approach requires the preparation of engineering parameters for both the matrix and the flow through them, which can be sourced from well-testing, core analysis, log data, and geophysical studies.

Well-log data, in particular, plays a pivotal role in improving fluid flow modeling in the media. Parameters such as fracture density, aperture, orientation, porosity, and permeability, obtained through logging, are invaluable for dual-porosity modeling.

Fracture density assists in estimating the dimensions of matrix blocks within the model, which is crucial for estimating the sigma parameter representing transmissibility between the matrix and fractures. The inclusion of aperture information enables the estimation of fracture permeability and porosity. Meanwhile, fracture orientation is essential for aligning grid coordinates with the flow direction [16].

In this section of the study, we emphasize the significant enhancement in reservoir modeling, especially in estimating the sigma parameter based on well log fracture density data obtained from various wells.

To begin the calculation of essential engineering parameters for simulation, we start with log data as the foundation.

The primary parameters of focus include fracture density, fracture aperture, and fracture orientation. Fracture density (FD) is determined by taking the inverse of the block dimension, with a representing the block dimension and 'b' representing the fracture aperture.

The parameter 'Sigma' plays a crucial role as a transfer function that bridges the matrix and fractures within the model. Its calculation is based on the formula Sigma = 12 * (FD^2). In this study, we utilize the average values of 'b' and 'a' to estimate the permeability and porosity of fractures within the model, as depicted in Fig. 14.

This figure offers a comprehensive view, showcasing the utilization of image log-derived data as input for the simulation model, along with the representation of specific parameters, denoted as "a" and "b," within the reservoir model.

The visual depiction aids in understanding the integration of image log data into simulation models and the representation of crucial parameters within the reservoir model for accurate and detailed analysis.

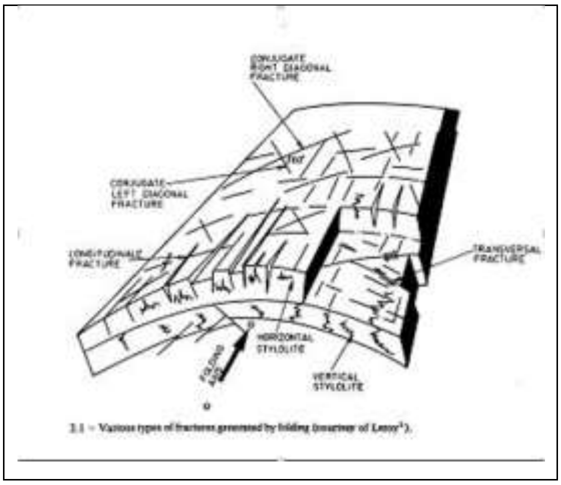


Fig. 12: Defines various types of fractures induced by folding, as discussed in [16].

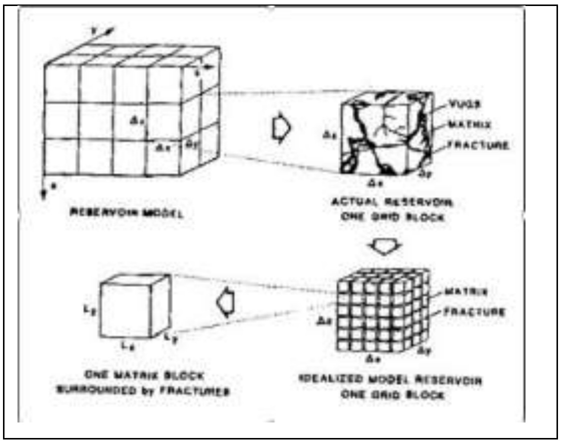
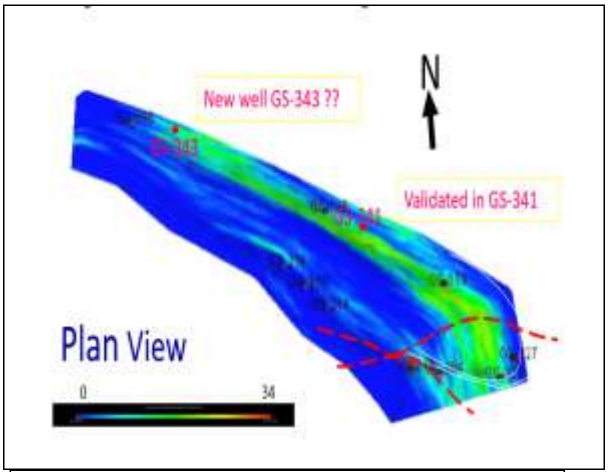
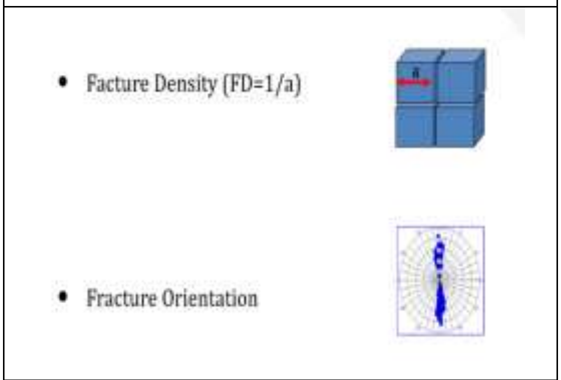


Fig. 13: Presents an in-depth depiction of the dual porosity modeling methodology as outlined in [16].



A



B

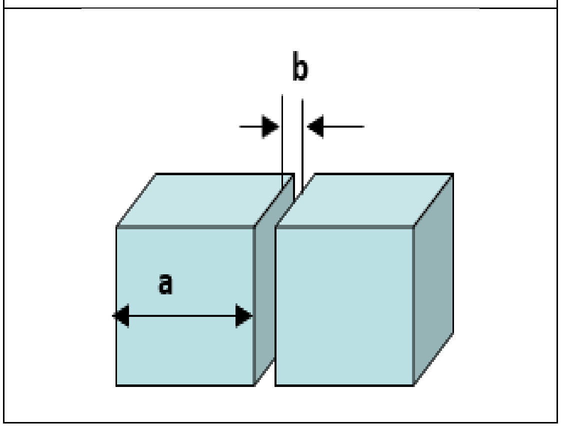


Fig. 14: A) Input Data derived from Image Logs for the Simulation Model. B) Illustration and Depiction of Parameters "a" and "b" within the Reservoir Model.

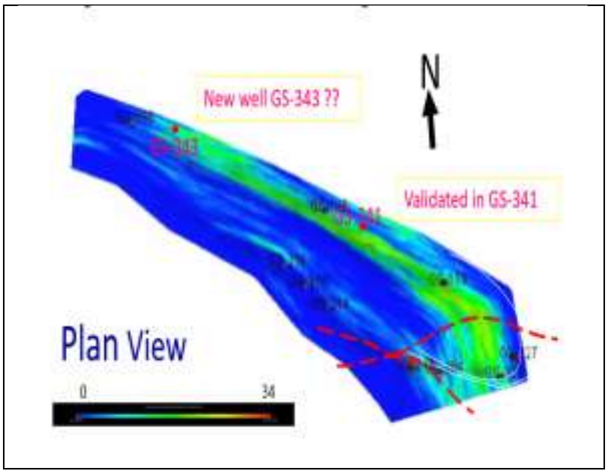
The computation of Sigma involves the incorporation of all fracture density data derived from the logs, as illustrated. The primary focus of this study is to assess the simulation's sensitivity to Sigma.

To accomplish this, a comparative analysis is conducted, contrasting scenarios in which Sigma is determined from log-derived fracture parameters with cases in which Sigma is assumed as a fixed value across the entire reservoir.

COUGAR software is employed for this analysis, providing valuable insights into the impact of Sigma on the simulation's results. The fracture density and orientation data are integrated into the simulation model, enabling the development of a more precise simulation model for the fractured reservoir by utilizing fracture data from the image logs.

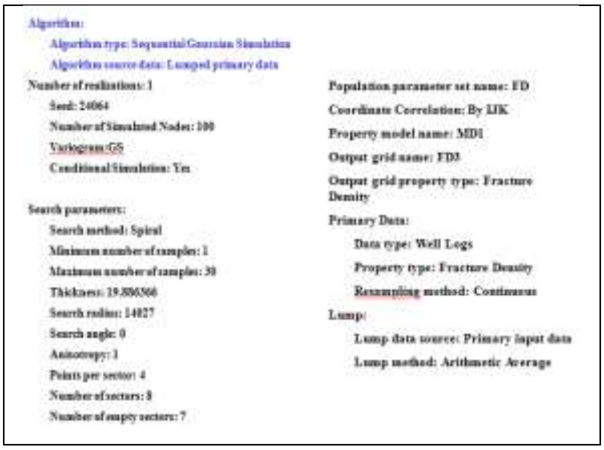
Fig. 15 focuses on illustrating a key factor employed in the computation or determination of population fracture density. The figure serves as a pivotal reference point, elucidating the essentiality and significance of this particular parameter within the context of calculating fracture density within a given population or dataset.

Fig. 16 provides a comprehensive view of the spatial arrangement and variation in fracture density across the field. The figure provides a detailed depiction, presenting the distribution pattern of fracture density, enabling a deeper understanding of the density variations and their significance within the Gachsaran Field.



This project combines data from ten individual wells to create a comprehensive model for evaluating fractured reservoir fields. The results of the simulated fracture density distribution are validated in GS-341(Fig. 16).

In circumstances where 3D seismic data is either lacking or of subpar quality, our study emphasizes the critical importance of borehole image data. It has become evident that a heightened focus on acquiring more image logs is essential for comprehensive fracture characterization and enhanced fracture modeling. In conclusion, we stress the need for additional image logs to facilitate comprehensive fracture characterization and robust modeling.


Algorithm:
Algorithm type: Sequential Gaussian Simulation
Algorithm source data: Lumped primary data
Number of realizations: 1
Seed: 24064
Number of Simulated Nodes: 100
Variogram: GS
Conditional Simulation: Yes

Search parameters:
Search method: Spiral
Minimum number of samples: 1
Maximum number of samples: 30
Thickness: 19.806560
Search radius: 14027
Search angle: 0
Anisotropy: 1
Points per sector: 4
Number of sectors: 8
Number of empty sectors: 7

Population parameter set name: FD
Coordinate Correlation: By IJK
Property model name: MD1
Output grid name: FD3
Output grid property type: Fracture Density
Primary Data:
Data type: Well Logs
Property type: Fracture Density
Resampling method: Continuous
Lump:
Lump data source: Primary input data
Lump method: Arithmetic Average

Fig. 15: Represents a specific parameter crucial in calculating population fracture density.

Fig. 16: Showcases the resulting distribution of fracture density within the Gachsaran Field.

3.2.2.Sensitivity Analysis and Pressure Profile Assessment

Following a sensitivity analysis involving a constant production rate of 2000 barrels per day across ten wells, our study delved into the assessment of pressure changes within the field under three distinct scenarios:

- **Scenario 1:** In this case, we assigned a fixed value of 0.001 ($1/ft^2$) to Sigma throughout the entire reservoir.
- **Scenario 2:** Sigma was maintained at a constant value of 100 ($1/ft^2$) across the entire reservoir.
- **Scenario 3:** Sigma was determined from the fracture density distribution within the reservoir, utilizing fracture density logs, as illustrated in (Fig. 17).

The examination of pressure profiles yielded compelling insights. In Scenario 1, where the distribution of fracture density in the reservoir was considered, the pressure remained relatively stable due to the heterogeneity in Sigma distribution.

Conversely, in both Scenario 2 and Scenario 3, where Sigma was evenly distributed, the pressure exhibited a more significant decline within the reservoir. In conclusion, our study has emphasized the pivotal role of fracture density, volume, and conductivity in driving field recovery rates.

Accurate representation of the fracture network across the field, with a particular focus on fracture density, proves crucial in approximating the dimensions of matrix blocks within our modeling framework.

The spatial distribution of fractures exerts a direct and substantial influence on production from distinct regions, underlining the need for meticulous consideration when modeling both individual wells and the entire field.

It offers a comprehensive representation, illustrating both the simulated performance of fractured reservoirs and the outcomes of sensitivity analysis. These components serve as fundamental aspects for understanding the behavior, performance, and variability of fractured reservoirs under varying conditions, aiding in informed decision-making and strategic planning within reservoir management

The integration of data from image logs and other fracture information collection methods has proven invaluable for achieving precise reservoir modeling and enhancing recovery outcomes.

Our project has significantly advanced our understanding of the utilization of Formation MicroScanner (FMS), Formation MicroImager (FMI), Oil-Based MicroImager (OBMI), and Ultrasonic Borehole Imager (UBI) data, both at the individual well level and on a field scale.

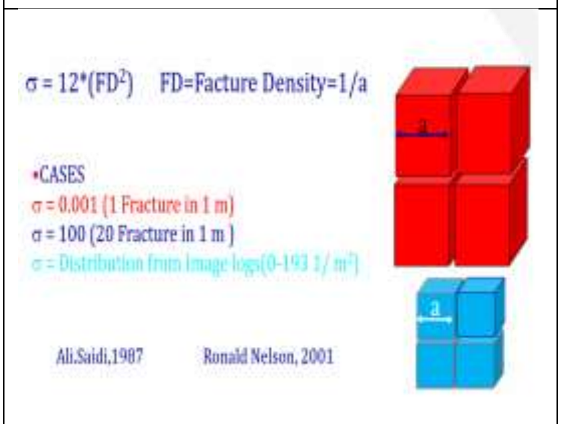
Furthermore, this project has highlighted persistent challenges within the oil field, including issues related to the conventional application of image logs on a field-wide scale, potential pitfalls associated with drilling wells in high fracture density areas, and the absence of established procedures for calculating sigma within simulation models for fractured reservoirs.

Our study has revealed the pivotal role played by fracture density, volume, and conductivity in driving field recovery rates. Accurate representation of the fracture network across the field, with a specific emphasis on fracture density, is imperative for accurately approximating the dimensions of matrix blocks within our modeling framework. The spatial distribution of fractures exerts a direct and substantial impact on production from distinct regions, necessitating meticulous consideration when modeling both individual wells and the entire field.

Moreover, this endeavor has enriched our understanding of the reservoir's fracture system and its direct impact on production. We have achieved precise verification of fracture properties on a field scale and have introduced a novel approach to compute Sigma in the simulation model based on image logs.

Additionally, this project has redirected NISOC's focus toward understanding reservoir performance within fractured reservoirs, underlining the importance of enhanced formation pressure assessment and the need for additional wireline formation testing.

A



B

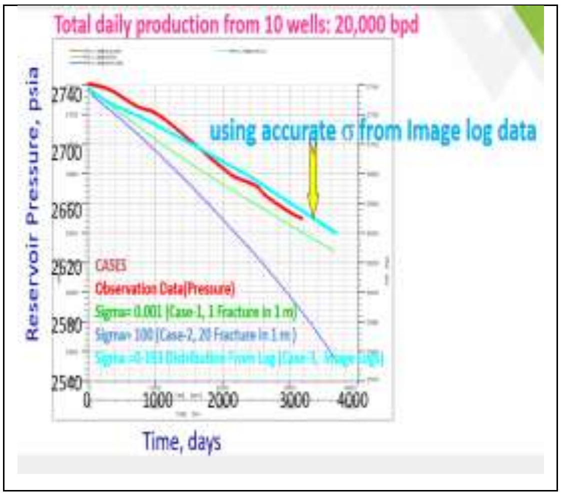


Fig. 17: A) Simulation depicting Fractured Reservoir Performance. B) Presentation of Sensitivity Analysis Results. This figure provides an intricate view, showcasing the simulation of fractured reservoir performance alongside the results derived from sensitivity analysis.

4. Conclusion

The study underscores the vital role of borehole image data, especially when 3D seismic data is insufficient. It emphasizes the necessity for more image logs to understand fractures thoroughly and create robust models. The research significantly advances comprehension of borehole imaging technologies and addresses challenges in oil fields such as effectively using image logs, drilling in high-fracture-density zones, and lacking standardized procedures for fractured reservoir simulation models.

Establishing a strong link between fracture density and cumulative production marks a major success, potentially becoming a standard assessment method for similar fractured reservoirs, influencing reservoir analysis and development. Positive feedback from experts adds weight to its significance.

The findings emphasize fracture properties' critical role in field recovery rates. Accurate representation of fractures, particularly density, is crucial for the modeling framework, impacting production in various areas. This study deepens understanding of fractures' impact on production, validating fracture properties at a field scale and introducing a new approach for sigma computation based on image logs.

Additionally, the project highlights the importance of understanding fractured reservoir performance, advocating for improved formation pressure assessment and wireline formation testing. This deeper insight optimizes well placement, enhancing productivity to meet future production targets.

By focusing on fractured reservoir performance, the study stresses the significance of formation pressure data and Production Logging Tools (PLT) for comprehensive flow analysis. Utilizing Fracture Strike maps aids informed decisions on well placement, thereby boosting productivity and achieving production targets for future wells.

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