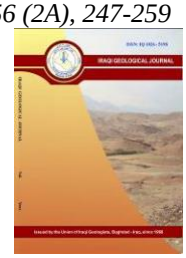
**Iraqi Geological Journal**

Journal homepage: https://www.igj-iraq.org



# Estimation of the Fracturing Parameters and Reservoir Permeability Using Diagnostic Fracturing Injection Test

**Hiba A. Hasan[1, *] and Sameera Hamd-Allah[1]**

1 Department of Petroleum Engineering, College of Engineering, University of Baghdad, Baghdad, Iraq

* **Correspondence**: hiba.hasan2008m@coeng.uobaghdad.edu.iq

Received:
18 October 2022

Accepted:
2 February 2023

Published:
31 July 2023

## Abstract

The term "tight reservoir" is commonly used to refer to reservoirs with low permeability. Tight oil reservoirs have caused worry owing to its considerable influence upon oil output throughout the petroleum sector. As a result of its low permeability, producing from tight reservoirs presents numerous challenges. Because of their low permeability, producing from tight reservoirs is faced with a variety of difficulties. The research aim is to performing hydraulic fracturing treatment in single vertical well in order to study the possibility of fracking in the Saady reservoir. Iraq's Halfaya oil field's Saady B reservoir is the most important tight reservoir. The diagnostic fracture injection test is determined for HF55using GOHFER software. Models for petrophysics and geology were calibrated using the diagnostic fracture injection test results after the petrophysical and geomechanical parameters of the rock have been determined. The HF55 vertical well, which penetrates the Saady reservoir, has well logs that have been used to evaluate the petrophysical and geomechanical parameters. These estimates have been supported by findings from the diagnostic fracture injection test through the utilization of standard equations and correlations. The findings of the diagnostic fracture injection test, often known as the diagnostic fracture injection test, are very compatible with the findings of the well logs. The diagnostic fracture injection test pre-falloff test event was examined to determine the instantaneous shut-in pressure and fracture gradient. In the meantime, Closure pressure, process zone stress, fracturing fluid efficiency, closure gradient, critical fissure opening pressure, storage correction factor, permeability, and pressure-dependent leak-off coefficient were all determined using the G function on plot. With the help of a specific software, the petrophysical and geomechanical properties of a single vertical well [HF55] was found. Saady B reservoir's upper and lower sections, along with it are therefore predicted to have the full range of petrophysical and geomechanical features. With the use of DFIT analysis, these features serve as the foundation for developing fracturing models.

**Keywords:** Diagnostic fracturing injection test; Saady reservoir; G-function; Hydraulic fracturing; Halfaya oil field.

## 1.Introduction

diagnostic fracture injection test (DFITs) are used for a variety of purposes, including estimation of the amount of the min principal stress in a formation. A small to moderate amount of fluid, typical water, is injected into the well for a brief period to create a hydraulic fracture, and then the well is sealed off. To determine the closure pressure, which is the fluid pressure at which the fracture walls come into contact, the pressure transient following shut-in is examined (McClure Mark et al., 2016)

DOI: 10.46717/igj.56.2A.19ms-2023-7-28

Step-rate injection testing can be used to determine the formation's closure pressure. In a step rate test, every injection is done at the same rate and over the same period (Economides and Nolte, 1989). To evaluate pressure responses during fracture treatment and identify times of fracture propagation with various methods of height increase, Nolte (1979) suggested a pressure diagnostic approach. Step-rate injection testing can be used to determine the formation's closure pressure. The effectiveness of the mini frac test can be improved by calculating the dimensionless closure time from the shut-in time and the pumping time (Tinker et al., 1997). The time of injection and the volume of injection are two crucial factors in the study of a DFIT, hence the injection schedule must be accurately recorded (Barree, 1998).

Tali and Farman, (2021) employing both traditional and statistical techniques, determine Iraq's southern region's carbonate reservoir's porosity. A highly permeable reservoir's petrophysical characteristics were investigated by Al-Majid (2021). The process of a typical DFIT is depicted in Fig 1. The rate is plotted in black, with surface pressure in red. The initial breakdown is achieved at point1; a constant rate is held for 3 to 5 minutes, indicated by point 2; Point3 shows a rapid stepdown; Point4 indicates ISIP, and Point 5 shows falloff (Barree et al., 2014).

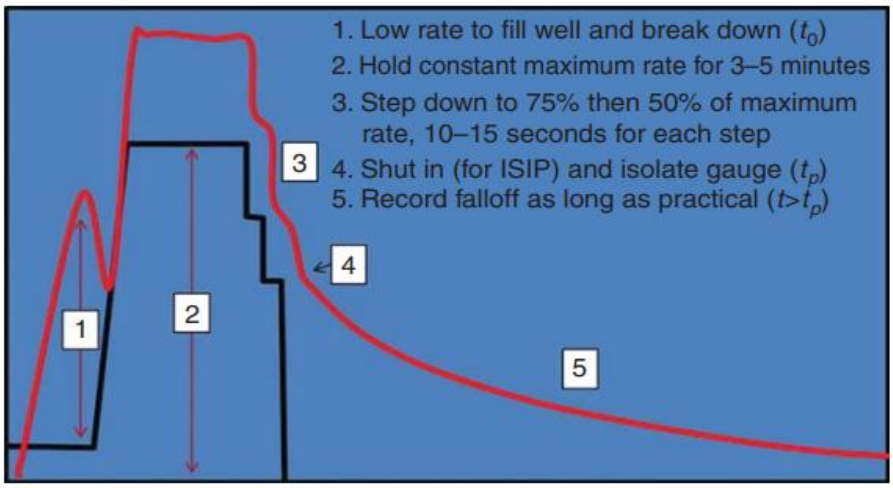



**Fig. 1.** Typical DFIT (Mehana et al., 2015)

This research has been done to properly apply the petrophysical and geomechanical attributes to assess the capacity and simplicity of fracture the formation underneath investigation. Well-log and results from diagnostic fracture injection test have been utilized to assess these features.

The goal of this research is to develop the Saady B reservoir's petrophysical and geomechanical features for discovering how easy the reservoir rocks can breakdown, showing the orientation as well as the path of fracture propagation.

### 1.1. Area of Study

One of the leading oil fields in Iraq's southeast, the governorate of Meyssan, is Halfaya oil field. It is situated 35 kilometers from downtown Amara City (Noori et al., 2019). A series of oil-bearing reservoirs from the Cretaceous to Miocene are present in the field, which has an anticline structure that runs from NW- SE. The Saady Formation, the reservoir under investigation, has two layers within it: SA and SB. Section SA is a water zone, whereas Layer SB, which includes Layers B1, B2, and B3, is a constantly dispersed reservoir and oil-bearing layer. SB3 is divided longitudinally into SB3U1, SB3U2, SB3U3, and SB3U4 layers based on changes in lithology, electrical, and petro-physical parameters. The Saady formation's thickness ranges from 120 to 130 meters on average. Each layer's thickness values are around 51 m for Saady-A, 28 m for Saady-B1, 30 m for Saady-B2, and 20 m for

Saady-B3 (Al-Ameri et al., 2020). The principal tight oil reservoir for the Halfaya Oil field has been identified as the 77 m- thick Saady B tight oil reservoir. It is a carbonate petroleum reservoir that has poor petrophysical characteristics, moderate pores, and limited pore throats. Limestone dominates the Saady Formation's anticlinal composition. Saady Formation's permeability (k) is 0.02-5 millidarcy, whereas its porosity is 0.08-0.25 (Farouk and Al-Haleem, 2022). Fig. 2 shows the digitized depth structural map for the top of Saady B.

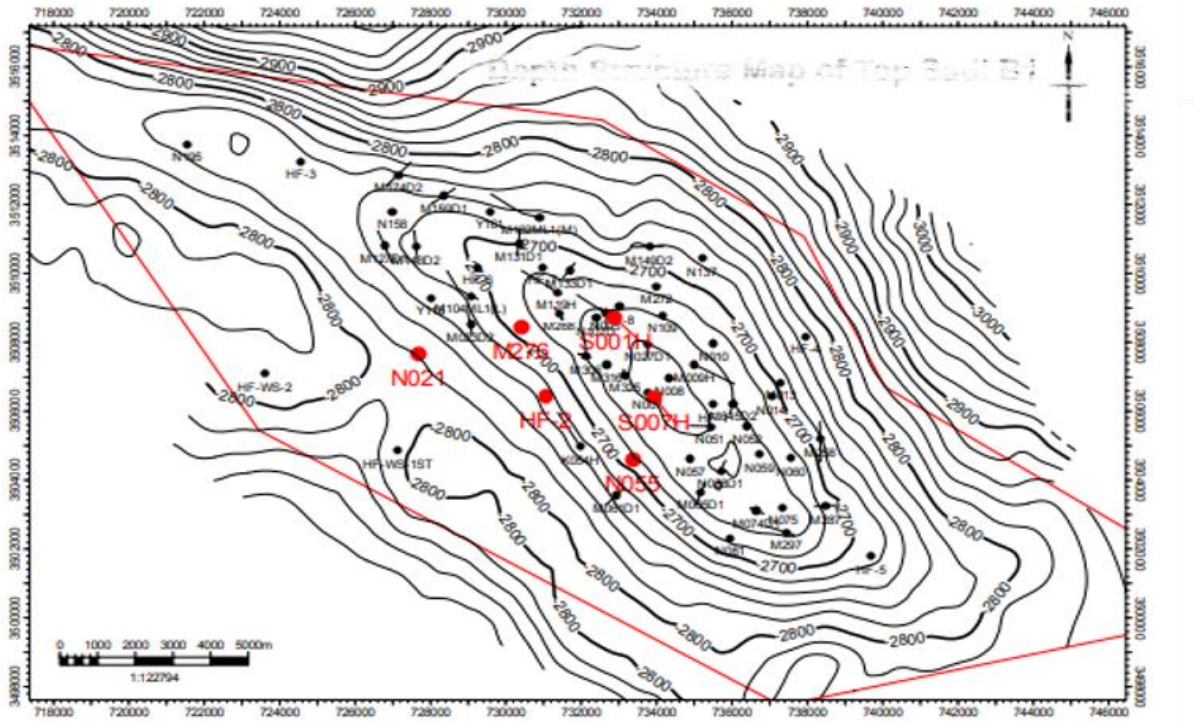



**Fig. 2.** Digitized Depth Structure Map for Top Saady B

The Saady Formation lies below the Hartha Formation, above the Tanuma Formation. The four primary microfacies (S1, S2, S3, and S4) that make up the Saady Formation represent the formation's surroundings, Planktonic Foraminiferal Lime Mudstone Microfacies (S1) The, Bioclastic Lime Mudstone Microfacies (S2) The, Planktonic Foraminiferal (Globigerinid) Lime Wackestone Microfacies (S 3) and Globigerinid - Bioclastic Lime Wackestone Microfacies (S4)(Al-Fandi et al., 2020). Fig. 3 illustrates the study area's stratigraphy and lithology.

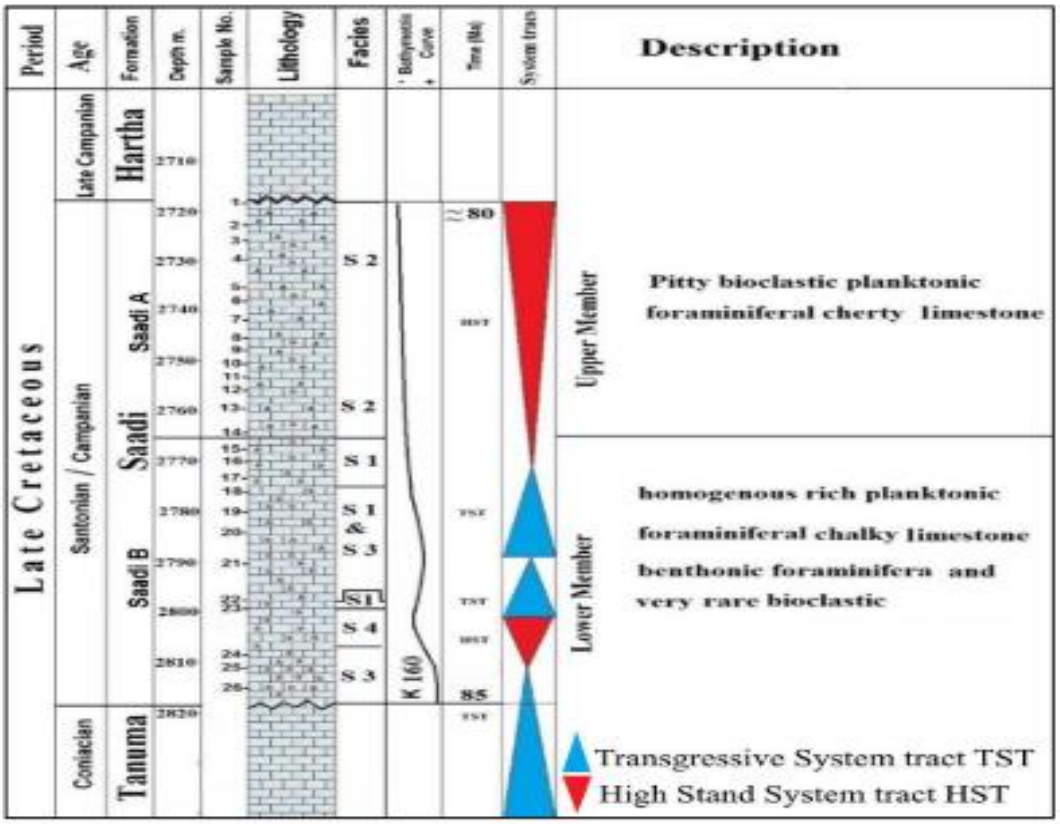



**Fig. 3.** Lithological description of Saady formation in Halfaya (Al-Fandi et al., 2020)

## 2. Methodology

### 2.1. Petrophysical Properties

Petrophysical variables such as porosity, permeability, water saturation, and net pay thickness were all incorporated into the model.

Calculating the volume of shale and the average porosity will yield effective porosity (Bateman, 1986) using equations 1, 2 and 3, respectively. One can estimate the average porosity using the root mean square averages which obtained from PHID, PHIN given in equation 4. With a matrix density of 2.71 g/cm$^3$ and a fluid density of 1 g/cm$^3$, $PHI_D$ is calculated using equation 5 (Kilgore et al., 1972). The Gamma-ray index is estimated by equation 6 (Thomas and Stieber, 1975). The model's averaged porosity ($PHI_A$) seems to be the arithmetic mean of ($ø_{avg}$) and ($ø_{RMS}$), as per equation 7.

$$Vshale = IGR/(3 - 2IGR) \quad (1)$$

Where, Vshale is volume of shale, deg, IGR is Gamma ray index, dimensionless.

$$\emptyset avg = (\emptyset N + \emptyset D)/2 \quad (2)$$

Øavg, average porosity, deg, $\emptyset_N$, $\emptyset_D$ are neutron and density porosity

$$\emptyset\, Eff = \emptyset avg * (1 - Vshale) \quad (3)$$

Øeff is effective porosity, deg.

$$\emptyset sq\ avg = \sqrt{((\emptyset N\text{^}2 + \emptyset D\text{^}2)/2)} \quad (4)$$

Ø sq avg is average square root porosity, deg.

$$\emptyset D = (\rho M - \rho b)/(\rho m - \rho f) \quad (5)$$

D is density porosity, $\rho_M$ is matrix density, gm/cm$^3$; ρb is bulk density gm/cm$^3$and ρf is drilling fluid density, gm/cm$^3$.

$$IGR = (GRlog - GRmin)/(GRmax - GRmin) \quad (6)$$

$$\emptyset A = (\emptyset avg + \emptyset RMS)/2 \quad (7)$$

$\emptyset A$ is average porosity, deg, $\emptyset_{RMS}$ is root mean square porosity.

Equation (8) displays the correlation to calculate the matrix permeability.

Since the reservoir is very tight and has a very low permeability calculated using the determined effective porosity, the permeability multiplier was set to 20, and the permeability exponent was set at three, respectively. According to equation 9)Archie, 1952), the Archie equation is used to compute the water saturation. Formation water resistivity (Rw) estimated in the Saady reservoir using the Schlumberger table for regulating resistivity is determined as being 0.040 ohms at190 °F. in carbonate reservoir, the cementation factor is 1.80–2.0 and the deformation coefficient (a) is one (Petrochina, 2016). It will be averaged and only used in the production simulator. Three cutoff conditions are used to determine the reservoir's net pay. Cutoffs for porosity are 0.04, resistivity is 10 ohm.m, and Vsh is set at 0.5, respectively. A better knowledge of reservoir heterogeneity and texture is given by the petrophysical features model (Jasim et al., 2020).

$$kEST = Kmult * \varphi Eff\hat{}kexp \quad (8)$$

KEST is estimated reservoir permeability, md; Kmult is permeability multiplier, dimensionless, K exponent is permeability exponent, dimensionless.

$$SW = \sqrt{((a * RW)/(\varphi\hat{}m * Rt))} \quad (9)$$

SW is water saturation, deg; a is a formation resistivity factor, dimension less, m is cementation exponent, RW is formation water resistivity, ohm.m; Rt is formation true resistivity, ohm.m.

### 2.2. Diagnostic Fracture Injection Test (DFIT)

The mini-frac job was implemented before the main frac job and a total of 101 cubic meters of fluid was injected into the formation. this job could be divided into 2 stages: As shown in Fig. 4.

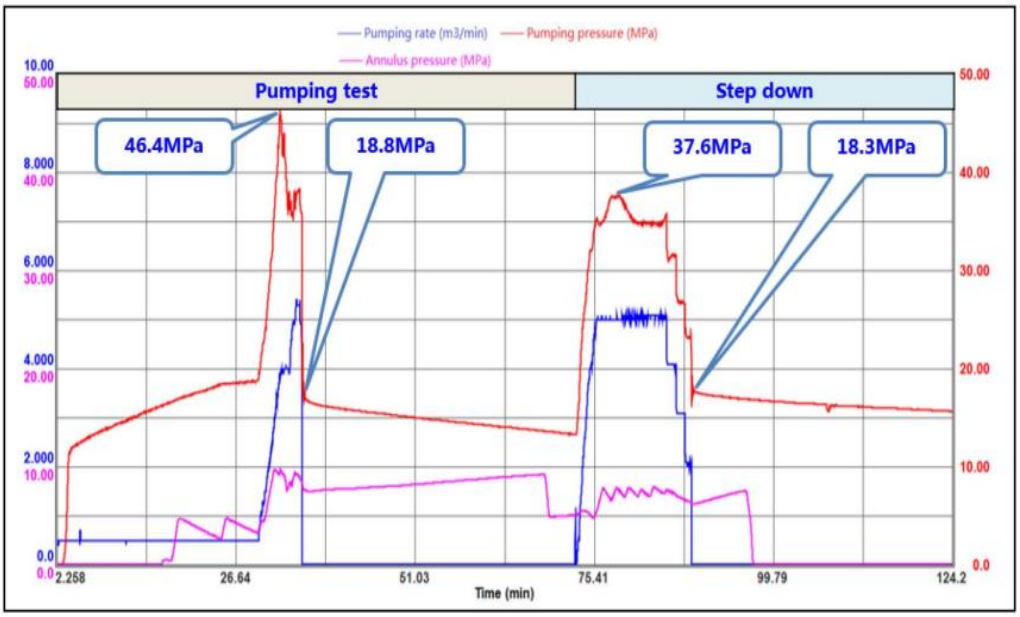



**Fig. 4.** Mini fracturing operation pressure chart (Syed et al., 2018)

Injection test: Active water was injected first, then displaced with linear gel. The formation was fractured at a flow rate of 5$m^3$/min.

Step down test: After injection of cross-linking fluid, the flow rate was reduced step by step to measure perforation and tortuosity friction near the wellbore.

DFIT is used to confirm and calibrate petrophysical results prior to the initiation of hydraulic fracturing. The mini-frac, reservoir data, and fluid type were utilized as essential input to analyze it. It consists of three analyses, and be analyzed by several techniques.

*2.2.1. Pre-fall off*

It has test events used to estimate surface and bottom hole ISIP and fracture gradient as shown in table 1, step rate may be used to determine pipe, nd blowdown can be used to estimate the wellbore compression at the beginning of pumping which provides a good value for the decompression at shut down. This can be used to estimate the amount of tortuosity required to match blowdown and determine a more accurate ISIP.

*2.2.2. Closure*

It has G Function, square root and log-log analysis can be used to determine closure pressure, net extension pressure (PZS), efficiency, CFOP, fracture gradient, permeability and rp area ratio as shown in Tables 2 and 3.

PZS pressure required over closure pressure to extend a fracture.

$$\mathrm{PZS} = \mathrm{ISIP} - \mathrm{PC} \quad (10)$$

Where, PZS is process zone stress, psi; ISIP is instantaneous shut- in pressure, psi; PC is closure pressure, psi.

Fluid efficiency: is the percentage of fluid that is still in the fracture at any point in time, when compared to the total volume injected at the same point in time.

$$Fluid\ effiecency = Gc/(Gc + 2) \quad (11)$$

GC is G-function time at closure.

*2.2.3. After closure analysis*

Can be used to define the reservoir flow capacity such as pore pressure and permeability. rp is storage coefficient factor that indicates the excess time it takes to leak off the stored fluid to get to closure based on the derivative's deviation from the straight line.

$$rp = \frac{\int_0^{Gc} G * \frac{\partial P}{\partial G}}{0.5 * Gc^2 * \left(\frac{\partial P}{\partial G}\right)} \quad (12)$$

Where rp is storage correction factor, ratio; GC is G-function time at closure, dimensionless; and subscript c is closure time, dimensionless

$$K = (0.07\mu\sqrt{0.01 * Pzs})/(\varphi * ct(Gc * YME * rp(Pc - Pp)\text{^}1.4\ )\text{^}1.75) \quad (13)$$

Where k is permeability, md; $\mu$ is viscosity of injected fluid, cp; and ct is total compressibity, 1/psi.

## 3. Results

### 3.1. Lithology Identification

Figure 4 is an illustration of the lithology identification scatter cross-plots for well HF-55. The Saady Formation has a ΔTC of 47.60 g/cm$^3$ and a matrix density of 2.715 sec/ft, according to the sonic-neutron scatter plot. These numbers suggest that the limestone in Saady B reservoir is relatively unpolluted (clean). The Saady B reservoir does, however, contain some shale sections, as shown in Fig. 5.

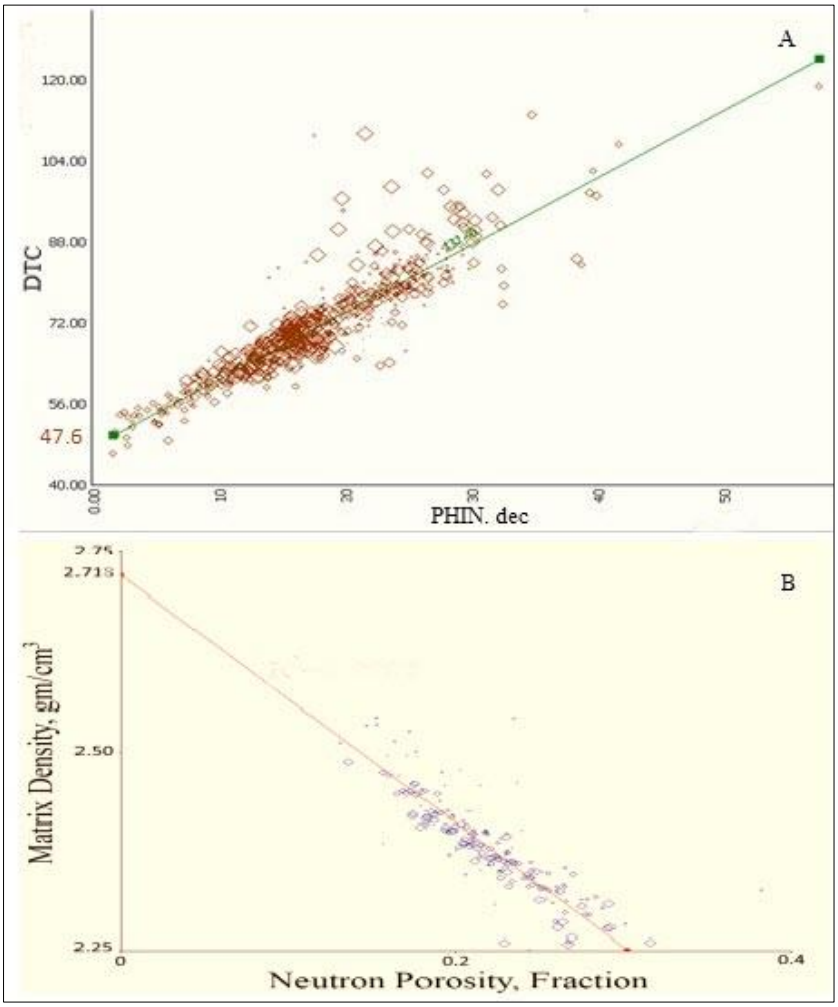



**Fig. 5.** Lithology Identification Scatter-Plots (a) Sonic-Neutron (b) Density-Neutron

### 3.2 Petrophysical properties

Figs. 6 and 7 demonstrate the calculated petrophysical and geomechanical parameters of rocks, accordingly. Fig. 6 shows that the Saady Formation contains a tight oil reservoir due to its exceptionally low permeability, high porosity, and low-quality reservoir. On the other hand, encouraging water saturation readings range from 18.20 percent to 47.40 percent, indicating a better oil zone. It is a fragile formation due to the fact that it has a lower passion ratio value and higher YME value than the layers that are above it. And that indicates rocks break more easily. Regardless of the presence of flexible rock layers beneath and above the Saady B reservoir, BRF findings suggest that the Saady B aquifer has stiff rock exactly next to the wellbore, this aids in the transmitting of fractures, as seen in Fig. 7. CFOP, Pc, PZS, and pp values are crucial for determining the breakdown pressure.

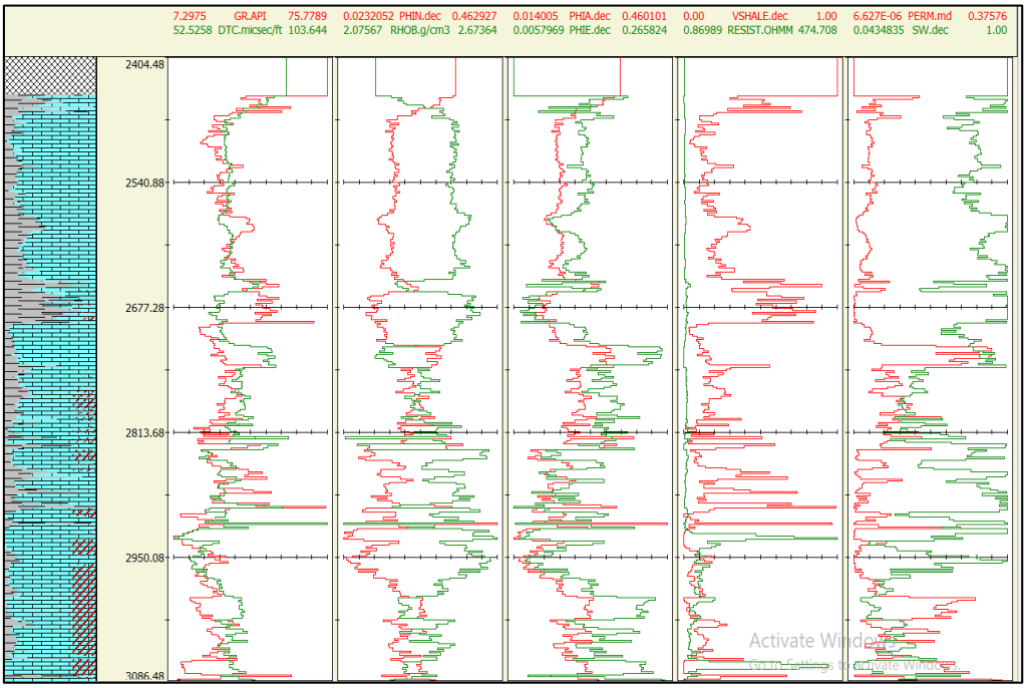



**Fig. 6.** Input petro-physical data for grids- well HF55-N55

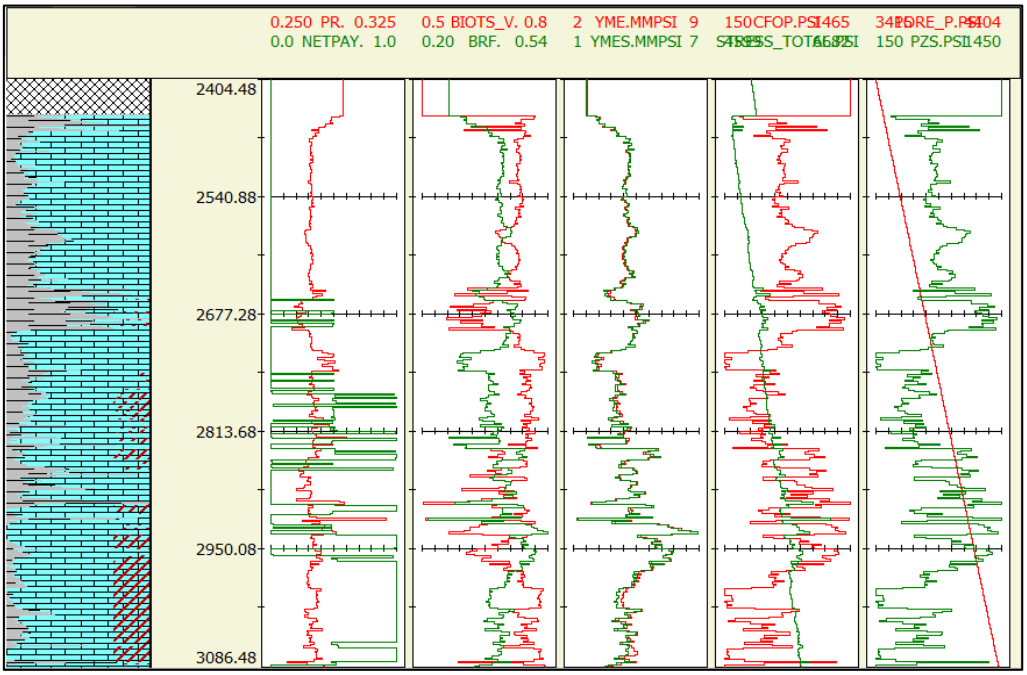



**Fig. 7.** Input geomechanically Data for Grids - Well HF55-N55

### 3.3 DFIT Analysis

Data preparation for the DFIT analyses began with uploading the data. The figure displays the entire data set that was generated by DFIT. Injection of slick water at 180 F was carried out for 9.6943 minutes, in the procedure, we control the seconds, not its fractures. 46 minutes were spent observing a decrease in pressure. During the period of the test, the lowest pressure that was measured was 2247.32 psi as shown in Fig. 8**.**

Fig. 8 shows pretest, fracture extension, and falloff periods for Well HF55. The pressure falloff lasted for 46 min. After gathering the data, the instantaneous shut-in pressure (ISIP) for well HF55 was calculated by doing a regression analysis on the pressure data and examining the falloff period as shown in Fig. 8. The obtained surface and bottom hole ISIP for Well HF55 are 2560.09 and 6450.65 psi, accordingly.

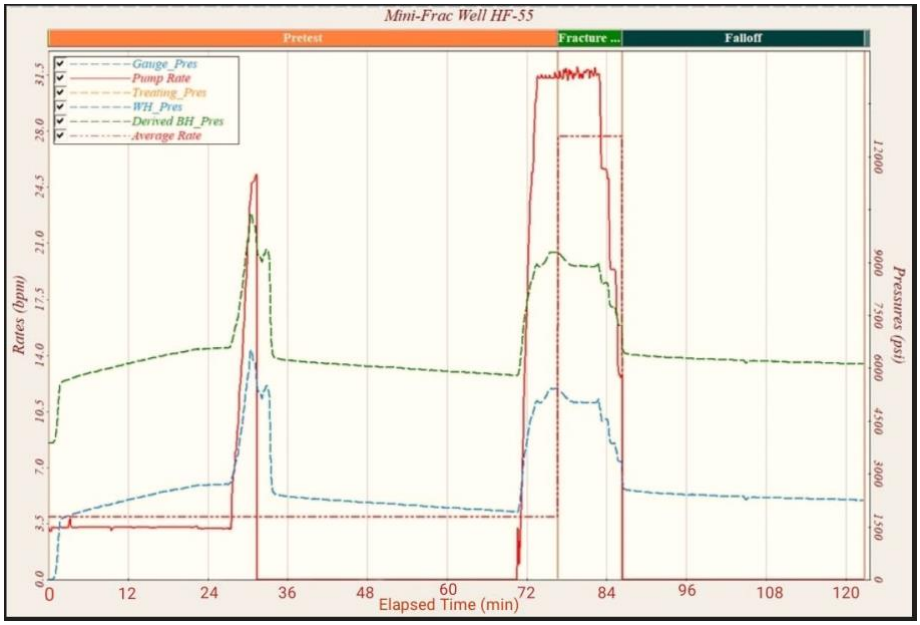



**Fig. 8.** DFIT analysis diagnostics including pump rate, wellhead pressure, bottom hole pressure, and gauge pressure for Well HF55

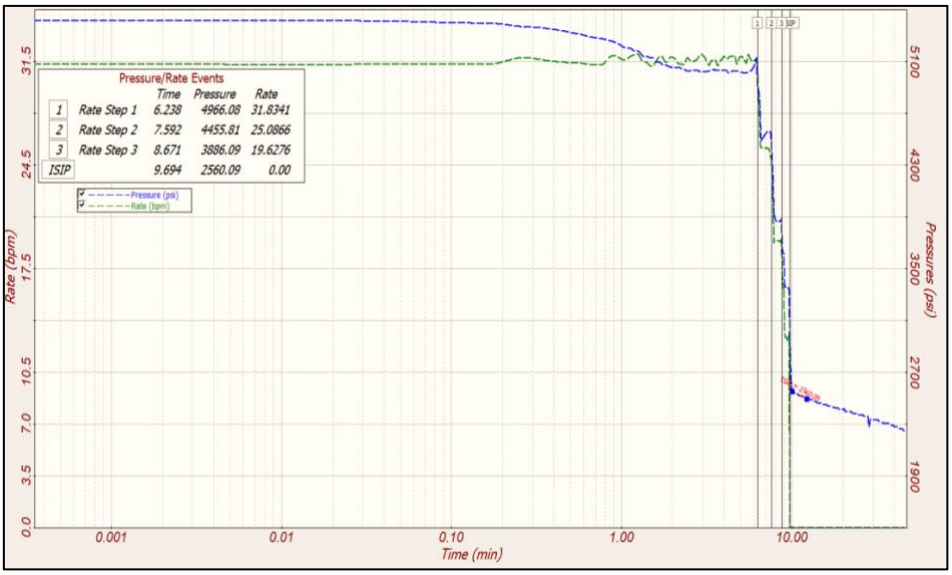



**Fig. 9.** ISIP estimation for Well HF55

Figs. 10 to 12 display the G function is a dimensionless function of shut-in time normalized to pumping time, square root of time, and log-log analyses for the well. The analyses are done in order to determine the reservoir pressure, effective permeability, and closure pressure. The estimated closure pressures from the analyses were 6251 psi with closure gradients of 0.695899 psi/ft, and the permeability at the time of closure is 0.056 md which was consistent in the G-function, square root of

time and log-log. The analyses indicated that the Well has pressure-dependent leak-off (PDL) with a coefficient of 0.00752 1/psi, as per Fig. 12.

**Table 1.** Inputs and Outputs of the test event

| Test Event Inputs | Test Events Results |
|---|---|
| Hydrostatic head(psi):3890.56<br>Avg. perforation TVD (halfway between the first and the last perforation) :2738.00<br>Pump stop time(min):9.7 | ISIP time(min):9.69<br>ISIP (surface)(psi):2560.09<br>ISIP (bottom hole) (psi):6450.65<br>Fracture gradient(psi/ft):0.7181 |

**Table 2.** Inputs and Outputs of Sqrt(T)

| Sqrt(T) Inputs | Sqrt(T) Results |
|---|---|
| ISIP (surface)(psi): 2560<br>ISIP (bottom hole) (psi)= 6450 | Total closure stress=6251<br>Process zone stress=199.428<br>Fluid efficiency (%) =52.4197<br>Permeability from G closure time(md)=0.056 |

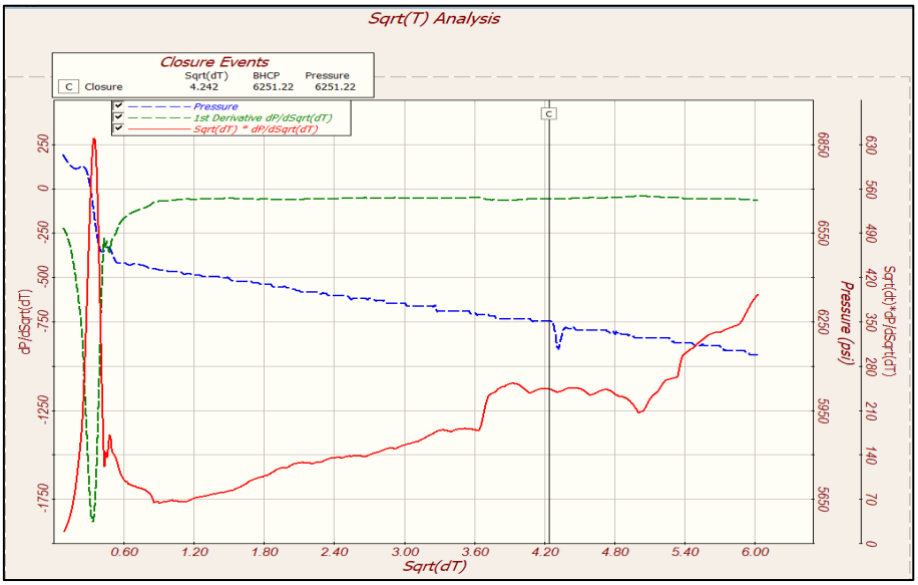



**Fig. 10.** The square root of time analysis

**Table 3.** outputs of G-function

| G-Function Inputs | G-Function Results |
|---|---|
| G time at closure: | 2.203 |
| Time at closure(min): | 27.6 |
| BHP at closure(psi): | 6251 |
| dp at closure (psi): | 199.42 |
| Fluid efficiency (%): | 52.4196 |
| Rp area ratio: | 0.79718 |
| Permeability from G- | 0.056 |

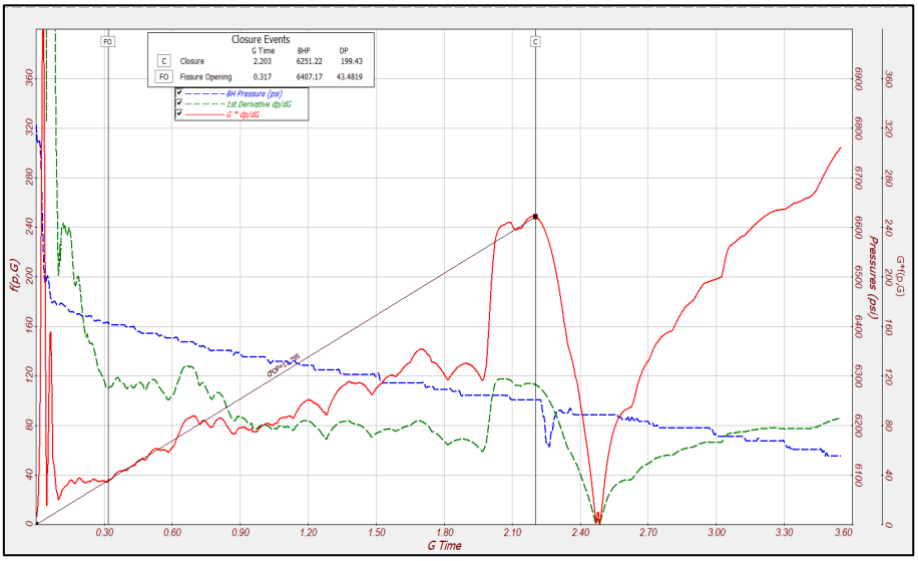



**Fig. 11.** G-Function Analysis

The closure pressure was estimated to be 6251.22 psi at a square of ti me of 4.242 (unitless). The total closure stress is 6251pounds per square inch, the G time is 2.203, and the shut occurs once a total of 27.68 minutes has elapsed. The work further found the natural cracks must be opened through introducing added pressure of 155.96 psi above the closure stress, or CFOP, creating a pore pressure gradient of 0.684855 psi/ft. It is expected that its permeability was 0.056 md at the time of closure. The well-log results and the DFIT results match.

The closure pressure was estimated to be 6251.22 psi at log of time 17.991(unitless)

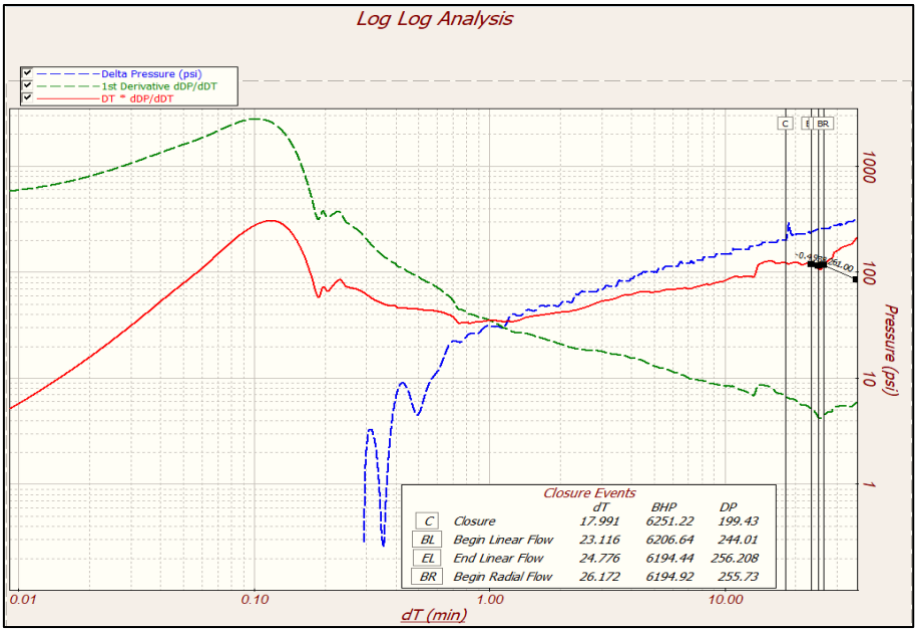



**Fig. 12.** log-log analysis

## 4. Discussion

Well logs are used as input data to obtain additional information related to the research area, like sw, permeability, the net pay zone, and geomechanical characteristics, which are shown in Figs. 5 and 6. Petrophysical characteristics shown in Fig. 5 demonstrate that the Saady Formation is a tight oil

reservoir because of its extremely low permeability, high porosity, and low-quality reservoir. However, promising water saturation values range from 18.20% to 47.40%, marking a better oil zone. These findings imply that increasing the permeability and conductivity of such pores would be good. The Saady B reservoir needs to be fractured.




**Fig. 13.** Fissure Leak-off Analysis

The Saady B reservoir is brittle because it has a PR than PR of layer above it, and higher YME value than YME of the layer above it as shown in Fig. 6. However, compared to the Saady B reservoir, Tanuma and Hartha have higher YME values and lower PR. values; the formations above and below these layers are more fragile. Additionally, BRF (Brittleness factor) show that there is brittle rock right next to the wellbore in the Saady B reservoir, it aids the transmission of fractures, though the Saady B reservoir has deformable rock layers over and beneath it. Additionally, incredibly fragile rocks exist above and below the ductile rock.

## 5. Conclusions

The used research's analysis methods such as (G-function, log-log, square root, test events, and fissure leak off analysis) over three periods (before, during, and after fracturing) have shown their ability to estimate the necessary fracturing parameters and reservoir permeability using the mini frac well HF55 that lasts for two hours, instead of prolonged transient tests. The results also show that the formation's stress is less than 7000psi, and the closure pressure gradient is below 0.72 psi per foot. Thus, the necessary pumping pressure, pumping rates, and fracturing materials to breakdown the Saady formation can be determined. Also, it has been shown that DFIT results are consistence with well logs results.

**Acknowledgments:** I wish to express my deep sense of gratitude to my supervisor Dr. Sameera Hamad-Allah, for her outstanding guidance and support which helped me in completing my thesis work. I would like to express my sincere gratitude and thank to director, department of geology and reservoir engineering, M.r Alaa Abdul Malik to provide me set of data

## 7. Nomenclature

| Symbol | Description |
|---|---|
| CFOP | Critical fissure opening pressure |
| DFIT | Diagnostic fracture injection test |
| ISIP | Instantaneous shut-in pressure |
| ATC | Compressional travel time |
| ATS | Shear travel time |
| rp | Storage correction factor |
| PC | Closure pressure, |

## References

Al-Ameri, N.J., Hamd-Allah, S.M., Abass, H.H., 2020. Stress-Dependent Petrophysical Properties of High Heterogeneous Carbonate Tight Oil Reservoirs. In Abu Dhabi International Petroleum Exhibition & Conference. OnePetro.

Al-Fandi, E.I., Hadid, N.A., 2020. Sequence stratigraphy, depositional environments and reservoir characterization of Sa'di Formation in East Baghdad and Halfaya oilfields. Iraqi Geological Journal, 53(1C), 21–35.

Al-Majid, M.H.A., 2021. Petrophysical Properties Estimation of Euphrates Reservoir in Qayyarah Oil Field Using Core and Well Log Data. Iraqi Geological Journal, 54(2E), 186–197.

Barree, R.D., 1998. Applications of Pre-frac Tests in Fissured Reservoirs – Field Examples. Presented at the SPE Rocky Mountain Regional/Low Permeability Reservoirs Symposium.

Barree, R.D., 2017. GOHFER 3D Training Course: Principles of Hydraulic Fracturing. Retrieved from Barree and Associates.

Barree, R.D., Barree, V.L., Craig, D., 2009. Holistic fracture diagnostics: consistent interpretation of prefrac injection tests using multiple analysis methods. SPE Production and Operations, 24, 396–406

Economides, M.J., Nolte, K.G., 1989. Reservoir stimulation. Prentice Hall Englewood Cliffs, NJ.

Farouk, A.K., Al-Haleem, A.A., 2022. Integrating Petrophysical and Geomechanical Rock Properties for Determination of Fracability of the Iraqi Tight Oil Reservoir. Iraqi Geological Journal, 55(1F), 81–94.

Archie, G.E., 1952. Classification of Carbonate Reservoir Rocks and Petrophysical Considerations. AAPG Bulletin, 36(2), 278–298.

Jasim, N., Hamd-Allah, S.M., Abass, H., 2020. Specifying quality of a tight oil reservoir through 3-d reservoir modeling. Iraqi Journal of Science, 61(12), 3252–3265.

Kilgore, E.C., Land, A.G., Schmidt, A.W., Yunker, J.D., 1972. Applications of the Coriband Technique to Complex Lithologies. The Log Analyst, 13 (01), 24–35.

Mehana, M., & Bashir, M.O., 2015. Diagnostic Fracture Injection Test (DFIT). Petroleum Today.

McClure Mark, W., Jung, H., Cramer, D.D., Sharma, M.M., 2016. The fracture-compliance method for picking closure pressure from diagnostic fracture-injection tests. SPE Journal, 21(4), 1321–1339.

Nolte, K.G., 1979. Determination of fracture parameters from fracturing pressure decline. In SPE Annual Technical Conference and Exhibition. OnePetro.

Noori, A.K., Lazim, S.A., Ramadhan, A.A., 2019. Geological Model of the Tight Reservoir (Sadi Reservoir-Southern of Iraq). Journal of Engineering, 25(6), 30–43.

Petrochina Co., 2016. Fracturing Operation Post Job Report.

Syed, I.H., Ahmed, A.R., Abd Hatem, R., Alabdali, S.A., Yandong, C., Winxin, C., Ab Murad, M., 2018. Pioneering the First Hydraulic Fracturing in Iraq's Complex Reservoir. SPE / IADC-189336

Tali, A.H., Farman, G.M., 2021. Use Conventional and Statistical Methods for Porosity Estimating in Carbonate Reservoir in Southern Iraq, Case Study. Iraqi Geological Journal, 54(2D), 30–38.

Tinker, S.J., Baycroft, P.D., Ellis, R.C., and Fitzhugh, E., 1997. Mini-Frac Tests and Bottomhole Treating Pressure Analysis Improve Design and Execution of Fracture Stimulations. paper SPE 37431 presented at SPE Production Operations Symposium, Oklahoma City, Oklahoma

Thomas, E.C., Stieber, S.J., 1975. The distribution of shale in sandstones and its effect upon porosity. In SPWLA 16th annual logging symposium. One Petro.