Predictive Characterization of Fracture and Absorption Tests in Halite Formations: an integrated approach of numerical modeling and field data

Themisson dos Santos Vasconcelos[1], Catarina N. A. Fernandes[1], João Paulo Lima Santos[1], Luis Philipe Ribeiro Almeida[1], Antonio P. A. Ferro[1], João Fyllipy de Lima Nunes[1], Rafael Dias[2], Bruno Sergio Pimentel de Souza[2], Fabio Sawada Cutrim[2]

[1]*Laboratory of Scientific Computing and Visualization, Federal University of Alagoas*
Av. Lourival Melo Mota- Tabuleiro do Martins, 57072-900, Maceió/Alagoas, Brazil
themisson.vasconcelos@lccv.ufal.br, catarina@lccv.ufal.br, jpls@lccv.ufal.br, luisphilipealmeida@usp.br, antonio.ferro@lccv.ufal.br, joao.nunes@lccv.ufal.br
[2]*CENPES, Petrobras*
Av. Horácio Macedo, 950 - Cidade Universitária, 21941-915, Rio de Janeiro/Rio de Janeiro, Brazil
rafael_dias@petrobras.com.br, brunosergio@petrobras.com.br, fabiosawada@petrobras.com.br

Abstract. This study introduces a predictive model based on field data from oil wells in the pre-salt region, focusing on the analysis of fractures in saline rocks and the simulation of leak-off tests through integration with the finite element method. The analysis utilized a variety of techniques, including the construction of a correlation matrix, statistical testing, linear adjustment methods, and numerical modeling. Utilizing specific field data from halite formations, the study identified overburden stress and sediment depth as the most critical variables for minimum stress. Three linear adjustment methods—least squares, genetic algorithms, and Bayesian methods—were employed. All methods demonstrated a strong correlation among the variables, with Bayesian methods exhibiting the lowest percentage error relative to experimental data. Residual analysis showed that the regression models provided accurate predictions, with most points closely matching the actual values. Numerical modeling was developed based on existing studies, allowing for the assessment of rock behavior and providing more realistic results that adhere to field data expectations. The results affirm the efficacy of the proposed models, particularly highlighting the use of Bayesian methods and mathematical modeling integrated with the finite element method in predicting the dynamics of fractures and fluid absorption in saline formations, with the latter yielding more precise results. This model significantly enhances the characterization of LOT, improving its utility in predicting behaviors in formations associated with pre-salt fields.

Keywords: fracture, oil wells, leak-off test, salt rocks.

1 Introduction

In the context of petroleum drilling operations, maintaining wellbore pressure within a safe range is fundamental to ensure the integrity of the drilling process and avoid costly complications, such as lost circulation. The Leak-Off Test (LOT) is a verification method employed to estimate the fracture pressure of exposed formations [1, 2]. Conducted after the cementing of the casing string, a LOT verifies if the formation below the casing shoe can withstand the wellbore pressure necessary to drill safely to the depth of the next casing setting. The fracture pressure determined from this test is used as the maximum pressure that can be applied to that formation, forming the basis for drilling decisions, casing design, and subsequent operations [1, 2].

Despite the simplicity and cost-effectiveness of the LOT, its interpretation can be challenging, particularly in formations that exhibit nonlinear relationships between the pumped volume and the observed pressure. Ideally, a LOT generates a linear response reflecting the total system compressibility, including the drilling fluid, the casing expansion, and the formation expansion [3]. However, nonlinear LOT behavior may arise due to the presence of gas, borehole failure, resulting in lost circulation, and the presence of rocks that exhibit anomalous deformations [3]. Currently, no mathematical model comprehensively explains this nonlinear behavior, especially when saline rocks and their associated behavior are involved in the analysis.

To address this gap, this study introduces a predictive model based on field data from oil wells in the pre-salt region, focusing on the analysis of fractures in saline rocks, particularly halite formations, and the simulation of leak-off tests through integration with the finite element method. The analysis incorporates a variety of techniques, including the linear adjustment methods, and numerical modeling. Key variables, such as overburden stress and sediment depth, are identified as critical for obtaining minimum stress, with the study employing linear adjustment methods such as least squares, genetic algorithms, and Bayesian methods.

This study emphasize the effectiveness of the proposed models in accurately characterizing fractures and fluid absorption pressures in saline formations, and associate them with the results of the developed mathematical modeling. The integration of numerical modeling with finite element methods allows for a detailed assessment of rock behavior under various fluid conditions, closely aligning with both theoretical expectations and field data. By enhancing the understanding and prediction of the dynamics of fractures and fluid absorption in pre-salt formations, this research significantly contributes to the safe and efficient planning of drilling operations in challenging environments.

2 LOT mathematical modeling

Direct methods like the classic leak-off test (LOT) provide precise data on rock formation strength under pressure. In a LOT, drilling fluid is pumped into the well at a constant rate, pressurizing exposed rock. Pressure and volume are recorded to identify the leak-off pressure, where the rock begins to fracture. This, combined with mud hydrostatic pressure, determines the formation breakdown pressure, offering valuable insights into rock properties and pressure responses.

Hydrostatic pressure refers to the expected pressure at a given true vertical depth (TVD), defined as the vertical distance from the formation's endpoint to the surface [1, 2]. Lithostatic pressure is the cumulative pressure from the weight of the overburden or overlying rock on the rock formation.

During the LOT, once the leak-off point is identified, pumping is stopped to prevent excessive fracturing that could compromise the rock's structural integrity. The test also determines the Equivalent Mud Weight (EMW), similar to the leak-off pressure. The pressure is monitored in both the drill string and annular space, with the latter potentially showing a delay. The pressure data from the annular space are vital for directly determining the leak-off pressure without additional corrections for fluid compression loss. If annular pressure data are unavailable, the leak-off pressure can still be calculated from the pump pressure, accounting for any load loss observed after stopping the pump. This load loss is seen as the immediate pressure drop following the cessation of pumping.

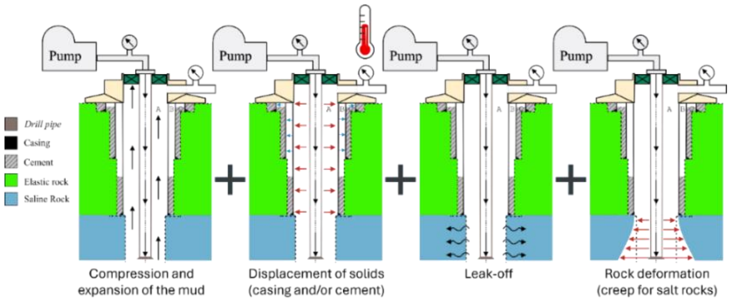
2.1 LOT mathematical modeling

To develop the mathematical model, this study builds upon the work [4], which explored the phenomenon of Annular Pressure Build-up (APB) in deep and ultra-deepwater pre-salt oil exploration contexts [4]. The objective is to expand these findings and apply them to the Leak-off Test (LOT), by enhancing and implementing a multilayer axisymmetric thermomechanical model originally developed by these authors. This study adapts and integrates the approach, focusing on the pressure increase resulting from the injection of drilling fluid into the annular space.

According to Fig. 1, the modeling uses four subsystems: fluid compression, displacement of solids (casing and/or cementing), rock displacement, and fluid leakage (filtration). It is noted that the pressure increase can lead to the displacement of salt rocks and the formation or expansion of fractures and microfractures, allowing the drilling fluid to escape into these fissures, characterizing the absorption point expected in a LOT. Each subsystem is investigated independently to understand its specific behavior, and the results are then combined to illustrate the overall behavior of the total system.

Figure 1. Sub-systems of mathematical modeling.

The original model by Vasconcelos, Escarpini Filho, and Lages (2024) incorporates the thermomechanical



numerical analysis of APB, coupling the thermal increment to the nodal displacements of the well elements and the creep mechanism of salt rocks [4]. This approach will be replicated using constitutive models such as linear elastic and the dual deformation mechanism, which are effective in representing the experimental responses of the rock formation. The application of the finite element model enriches the analysis, allowing detailed integration between heat transfer and the deformation mechanism.

For practical representation, the model uses the geometry of a fictitious pre-salt well as a platform for computational simulations. This allows for a detailed exploration of the pressure increment phenomenon associated with the LOT, providing a better understanding of the interactions between pressure, temperature, and the mechanics of salt rocks.

2.2 Adaptation of constitutive fluid equation for LOT Study

To predict the LOT, it is considered that the annular space is filled with drilling fluid, which can be oil, water, or other mixtures. The fluid pressure (p) depends on the relationship between the annular volume (V_f), the amount of trapped fluid (m), and the temperature (T).

In situations where the annular space is completely sealed, the problem is conditioned by the isobaric ratio of thermal expansion and the isothermal compressibility of the fluid. Additionally, when considering fluid influx or efflux in the annular region, the equation can be further simplified and reformulated, as shown in previous studies [5, 6]:

$$\Delta p = \frac{1}{k_T}\left(\alpha \Delta T - \frac{\Delta V_f}{V_f} + \frac{\Delta V_l}{V_l}\right) \tag{1}$$

where α represents the thermal expansion coefficient, k_T is the isothermal coefficient of compressibility, and ΔV_l is the variation in the fluid volume that can occur by inflow (ΔV_l positive) or efflux (ΔV_l negative) of fluid between the annular space and the formation or adjacent layers. Additionally, when considering fluid influx or efflux in the annulus, Eq. 1 simplifies and accounts for three main factors contributing to the pressure increase in the annulus. These factors are associated with the thermal expansion of the fluid, volume changes due to the "ballooning effect" (deformation or radial distension resulting from additional radial stress imposed internally on the casing), and the inflow or outflow of fluids from the annulus [5].

To adapt the study to the specifics of the LOT, fluid influx at the bottom of the well and fluid efflux when the formation is fractured are considered. Thus, Eq. 1 can be reformulated to:

$$\Delta p = \frac{1}{k}\left(\alpha \Delta T - \frac{\Delta V}{V} + \frac{\Delta M_l}{\rho_l V} - \frac{\Delta V_e}{V} + \frac{\Delta V_q}{V}\right) \tag{2}$$

According to Eq. 2, the term related to influx and efflux (ΔV_l) is characterized as follows:

$$\frac{\Delta V_l}{V_l} = \frac{\Delta M_l}{\rho_l V} - \frac{\Delta V_e}{V} + \frac{\Delta V_q}{V} \tag{3}$$

where the first term after the equality considers the variation in fluid density (ρ_l) due to changes in temperature and pressure, a concept introduced by [4]; the second term is related to efflux; and the third term pertains to influx, determined by the flow rate of fluids into the well.

2.3 Fracture modeling and methodology for salt rocks

The proposed model for the leak-off test assumes that during the test execution, the well shoe should be open, allowing the drilling fluid to come into direct contact with the surrounding rock. Consequently, when the fluid is injected, the pressure in the well increases, causing the rock to displace until the point where fluid drainage into the adjacent rock formation occurs. For the initial representation of the fluid flow process, which occurs after the leak-off test reaches the minimum principal stress, the tangential stress was used as the fracture opening parameter. This was calculated based on the stress and deformation conditions of the salt rock under geostatic stress and the fluid pressure inside the well.

For the displacement of salt rock, the study considers the viscoelastic properties of the salt rock. To this end, it uses the enhancements developed in the study by Vasconcelos, Escarpini Filho, and Lages (2024) to Araújo's (2012) one-dimensional axisymmetric mechanical model, incorporating thermal conduction and mild thermomechanical coupling. Araújo's (2012) introduced a simplified axisymmetric model employing the Finite Element Method (FEM) to estimate the closure rate of vertical wells in salt rocks [7]. The model adopted a double deformation mechanism and focused on a single layer of salt rocks, using one-dimensional elements of unit thickness [7]. This approach allowed the representation of state variables with exclusively radial variations, optimizing the use of FEM and reducing processing time.

To calculate the initiation of hydraulic fracture opening, it is established that when the internal pressure exceeds the tangential stress, hydraulic fracturing models are used. These include the PKN (Perkins-Kern-Nordgren) model; the KGD (Khristianovic-Geertsma-de Klerk) model, including both circular and elliptical variations; and the Penny-shaped model, widely referenced in technical literature on hydraulic fracturing [8] [9].

2.4 Analysis of minimum stress based on experimental data

For this research, data on halite were provided by an operator, covering essential variables such as true vertical depth (TVD), waterline (LDA), minimum stress, rock failure stress, propagation stress, and overburden stress. The minimum stress, initially assumed to be the absorption stress, plays a central role in understanding rock fracture behavior. The provided data, related to tests in pre-salt regions with depths between 4,433 and 5,724 m and LDA between 1,903 and 2,302 m, were analyzed using a correlation matrix to identify interdependencies, resulting in a subsequent linear adjustment.

The statistical analysis included the application of the Akaike Information Criterion (AIC), Kolmogorov-Smirnov (K-S) test, and Anderson-Darling test to associate minimum stresses with different probabilistic distributions. The results indicated that the normal distribution was the most suitable for representing the minimum stress data.

In the parameter calibration phase, three distinct methods were used: the least squares method, genetic algorithms, and Bayesian methods, implemented in Python with specialized libraries such as TensorFlow, deap, and scipy. One form of linear adjustment was considered that has overburden stress and sediment depth as independent variables. The equation for this adjustment was as follows:

$$\sigma_{min} = a \cdot \log(\sigma_{Sobrecarga}) + b \cdot Prof_{sed} + c \tag{4}$$

The parameters resulting from the adjustment for Eq. are detailed in Tab. 1. This table includes the maximum percentage comparison between the values obtained from the adjustments and the experimental field data obtained during the leak-off test in the pre-salt region, allowing for a direct assessment of the model's accuracy in relation to real conditions.

Table 1. Calibration of the Parameters for Eq. 4 and Eq. 5

Coefficients	Least Squares	Genetic Algorithms	Bayesian Methods
a (Eq. 5)	$3{,}01946224 \cdot 10^3$	$25{,}264350687581012$	$3{,}0194783 \cdot 10^3$
b (Eq. 5)	$1{,}98202652$	$3{,}925093142691278377$	$2{,}001034$
c (Eq. 5)	$-2{,}24210344 \cdot 10^4$	$8{,}3705123572384545$	$-2{,}2421006 \cdot 10^4$
Difference (%) compared to field data (Eq. 4)	$-0{,}748\%$	$-19{,}252\%$	$-0{,}370\%$

The percentage differences predicted by the three adjustment methods to the experimental data, according to calculation model presented, suggest that both calculation models are valid for modeling the relationship between minimum stress and overburden. According to the results, the adjustments associated with Eq. 4 align well with the experimental data, especially for the least squares and Bayesian methods. However, the genetic algorithms show some prediction points that deviate from the experimental data, implying that this method may have limitations or may need further adjustments to improve model accuracy. Overall, the least squares and Bayesian methods are effective for predicting the minimum stress from the analyzed data, with these methods standing out for having the smallest percentage difference when compared to the experimental data from the leak-off test.

3 Results and discussion

3.1 Description of the properties applied to the scenario

For this research, data on halite were provided by an operator, covering essential variables such as true vertical depth (TVD), waterline (LDA), minimum stress, rock failure stress, propagation stress, and overburden stress. The minimum stress, initially assumed to be the absorption stress, plays a central role in understanding rock fracture behavior. The provided data, related to tests in pre-salt regions with depths between 4,433 and 5,724 m and LDA between 1,903 and 2,302 m, were analyzed using a correlation matrix to identify interdependencies, resulting in a subsequent linear adjustment.

As illustrated in Fig. 2, for the analysis of the reference well, defined as the base well, a scenario was established that explores the stratigraphic alternation between halite and carnallite, simulating a more complex geological variation. This stratification represents geological variations that can directly influence the behavior of the leak-off test (LOT).

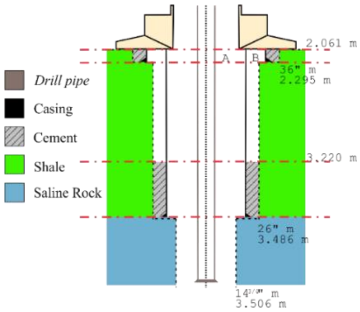


Figure 2. Sub-systems of mathematical modeling.

As shown in Tab. 2, 3, and 4, the basic well specifications, casing details, thermomechanical properties of the materials, and the constants of the double deformation mechanism model are sequentially presented.

Table 2. Well Characteristics and Geometric Configuration

Casing	Outer Diameter (in)	Inner Diameter (in)	Well Diameter (in)	Weight (lb/ft)	Casing Depth Top (m)	Casing Depth Base (m)
Conductor	30	28	36	456.4	2061	2158
Surface	20	17.813	26	203	2061	3313
Intermediate	-	-	16.5	88.2	-	-
Drill pipe	7297	5791	-	20	2061	-

Table 3. Thermomechanical Properties of Materials

Material	E (GPa)	Poisson	Thermal Expansion Coefficient $(1/°C)$	Density (kg/m^3)	Thermal Conductivity $(W/m°C)$

Iron	206.84	0.30	$1.24 \cdot 10^{-5}$	7849.0470	0.45
Cement	10.3421	0.21	$1.00 \cdot 10^{-6}$	1890.1787	0.837

Table 4. Constants of Rocks and the Double Deformation Mechanism Model

Rock Type	E (GPa)	Poisson	Density (kg/m^3)	ε_0 (h^{-1})	σ_0 (MPa)	T_0 (°C)	n_1	n_2
Halite	20.4	0.36	2200	$1.888 \cdot 10^{-6}$	9.91	86.00	3.36	7.55
Shale	20	0.29	2240	-	-	-	-	-

It is important to highlight that the constitutive equations adopted in this study consider the influence of the geological formation in the simulation. Thus, the burial or overburden stress, corresponding to the vertical stress generated by the weight of the overlying layers, was incorporated. This stress can be estimated through the combined calculation of the weight of the water column and the rock formations above the point of interest. For simulation purposes, seawater was assigned a density of 1,030 kg/m^3. The drilling phase, water-based fluids were selected with the following properties: for phases 1 and 2, the fluids had a density of $8.60\ lb/gal$, isothermal compressibility is $6.67 \cdot 10^{-10} Pa$, thermal expansion coefficient is $8 \cdot 10^{-4}$°C^{-1}; in phase 3, the fluid's density is $11.00\ lb/gal$, with the same compressibility and thermal expansion coefficients, and viscosity of $3.00\ cP$. These data were compared with field LOT tests from a similar geological setting to enrich the analysis.

3.2 Results

The analysis of this scenario focuses on the study of the stratigraphic properties of halite, simulating rock behavior under more realistic absorption test conditions. The modeling considered lithological variation and incorporated comparative analysis with field data from an analogous well, allowing an in-depth evaluation of the accuracy and applicability of the proposed numerical model.

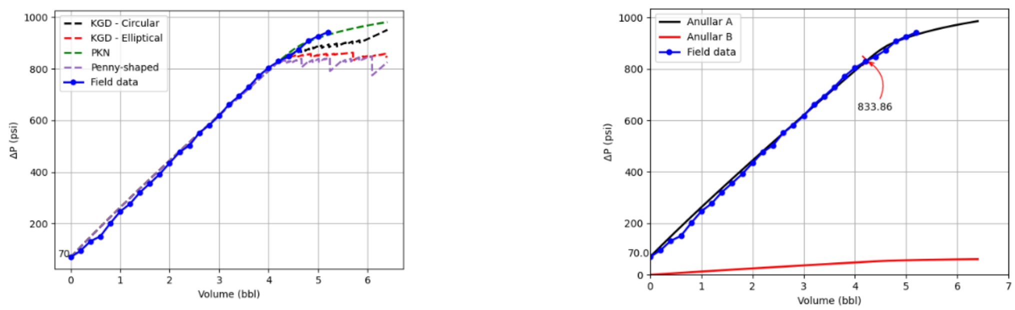
As depicted in Fig. 3 (a) and (b), the absorption point is marked by a break in the curve, indicating the onset of fractures in the salt rock. The first figure compares different hydraulic fracturing models with field data from absorption tests, while the second focuses on the PKN model, which best matches the field data. This critical point shows a direct influence on fluid absorption dynamics, where the rock begins to fracture and absorb the injected fluid more significantly.

The results demonstrate that the break point corresponds to fracture initiation, confirming the effectiveness of the adopted model in predicting rock behavior under pressure during absorption tests. This emphasizes the importance of including microfracturing and temporal creep in numerical models for accurate prediction of the salt rock's response to fluid injection in LOT tests.

The compared models include the PKN model, the KGD model (in both circular and elliptical forms), and the Penny-shaped model. The PKN model aligns closely with the field data, accurately predicting fracturing pressure based on the injected volume. Although similar break points were observed across models, Fig. 3 (a) highlights the PKN model's response due to its superior data fit. Fig. 3 (b) illustrates fluid behavior under specific conditions, excluding variations in the fluid's physical properties due to temperature and pressure changes. Notably, the characteristic break in the absorption test curve appears after 10.5, corresponding to the injection of $4.2\ bbl$ into the annular space.

A slight increase in pressure observed in annular B during injection in annular A is included to illustrate an important mechanical interaction. This pressure increase in the adjacent annular space suggests a casing displacement towards annular B, demonstrating how the LOT in one annular can affect the surrounding well structure. Including annular B in the figure helps visualize this interconnected behavior of the well system during pressure testing.

The pressure values in this scenario, calculated using Eq. 4 and the data from Tab. 1, predicted a theoretical breakdown pressure of approximately 7,343.67 psi at the top of the salt layer. Field data indicated the absorption point occurred at 829.00 psi, totaling, along with the hydrostatic pressure, a final pressure of approximately 7,370.97 psi. The result associated with Eq. 4 showed a percentage error of -0.370%. With the developed modeling, a breakdown pressure of 833.87 psi was observed, which, added to the hydrostatic pressure values, corresponds to a final pressure of approximately 7,375.84 psi, representing a relative error of approximately 0.066%.



(a) (b)

Figure 3. a) comparison of fracturing model results with field data; e b) PKN model adjusted to field data.

4 Conclusions

The analysis of the pressure values in the described scenario demonstrates that the developed model shows excellent accuracy in predicting the breakdown pressure at the upper end of the salt layer. The expected theoretical breakdown pressure of approximately 7,343.67 psi is very close to the values observed in the field. According to the field data, the final pressure was approximately 7,370.97 psi, with a percentage error of -0.370% in relation to Eq. 4, for the Bayesian Methods. The developed modeling indicated a final pressure of 7,375.84 psi, with a relative error of only 0.066%. These results suggest that the proposed model is highly effective in predicting the breakdown pressure under real field conditions, demonstrating remarkable accuracy and a small relative error.

Therefore, the developed modeling can be considered a reliable tool for analyzing of LOT in salt formations, providing precise predictions that are essential for optimizing and ensuring the safety of operations.

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