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Design of Wellbore Trajectory Using Geomechanical Modeling for Improving Wellbore Stability: A Case Study

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ABSTRACT

In this research, geomechanical modeling was used to determine the optimum inclination angle and route/trajectory of drilling and to maximize wellbore stability during a drilling operation. In this regard, different data, including wave transit time, rock mechanical parameters, and in-situ stresses, were utilized, and the optimal inclination angle and trajectory of drilling were investigated in different zones of a given oil field. The modeling results indicated that from low angles toward high angles, the maximum fracture pressure changes and this change is more noticeable with increasing depth. Moreover, the minimum collapse pressure does not change significantly with the depth, and this pressure usually occurs at low angles. Pressure changes in all zones of this oil field except for zones 14 and 15 have similar trends and their drilling inclination angle is smaller than 45 degrees, which is the optimum angle for safe drilling in these zones. In lower zones, a drilling inclination angle of less than 60 degrees covers the maximum collapse pressure and an angle of less than 45 degrees covers the minimum collapse pressure. Without taking into account the temperature, the range of optimum inclination angle and range of optimum azimuth were determined to be 10-15 degrees and 65-115 degrees, respectively, and collapse pressure and fracture pressure were estimated to be 6324 psi and 8085 psi, respectively. Increasing temperature increases the collapse pressure and decreases the fracture pressure and this, in turn, results in narrowing the safe drilling window. However, the temperature does not significantly affect the optimal drilling trajectory, and it mainly limits the safe drilling mud window in the formation.

KEYWORDS

Wellbore stability, Azimuth, Inclination angle, Mud weight, Collapse pressure and fracture pressure

I. INTRODUCTION

Drilling operation in oil and gas wells is one of the most expensive and complex processes, so that the success or failure of this operation has a considerable impact on the total cost of a well operation. Therefore, performing accurate engineering calculations for optimizing drilling operation to advance predetermined operational goals and also to reduce operating costs is of significant importance.

Various parameters, such as the efficiency of the drill bit, the experience of the driller, and mud preparation, have an impact on the efficiency of a drilling operation, among which the determination of drilling mud parameters plays a significant role (Wang et al., 2022; Nwonodi et al., 2023; Zhang et al., 2023a, Zhang, et al., 2023b).

One of the most important factors that has a direct impact on the drilling operation is the optimization of the drilling mud design, determination of the appropriate weight of the drilling mud, and also determination of the angle of the well trajectory. In general, the creation of instability in the wellbore wall leads to disrupting the drilling operation and causing much damage to the well. The lack of stability of the wellbore wall gives rise to the collapse of the well opening, differential sticking, and drilling mud loss. Consequently, excess costs are imposed on the drilling operation. In some cases, the drilling operation is wholly stopped because of wellbore instability and collapse. Hence, the accurate determination of influencing parameters on wellbore stability is of paramount significance (Li et al., 2015; Dokhani and Bloys, 2016; Qiu et al., 2023). The state of stresses in the formation and the interaction of these stresses create many changes in the drilling operation, and ignoring these factors will cause irreparable damage. One of the ways to consider these stresses in the drilling operation is the use of geomechanics science. By using geomechanics as well as analytical and modeling methods, it is possible to optimize influencing parameters such as the weight of drilling mud, the role of

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azimuth and inclination angle, the penetration rate of the drill bit, and other influencing factors during the drilling operation (Yang et al., 2020; Luo et al., 2021; Qiu et al., 2023; Wang et al., 2022a; Wang et al., 2022b). One of the most important concerns of drilling engineers is the selection of an appropriate azimuth and a suitable inclination angle, which optimization of these factors results in the stability of the wellbore wall. On the other hand, the lack of appropriate design of the angle of the well trajectory leads to the instability of the wellbore wall. Carrying out detailed studies using analytical and simulation methods to determine the influencing parameters on the wellbore stability plays a vital role. These studies prevent excess costs from being imposed on the drilling operation. They also advance the drilling operation in the direction of optimization. Thus, the use of analytical and modeling methods to optimize influencing parameters on wellbore stability during a drilling operation is substantially needed (Fan et al., 2020; Lyu et al., 2021; Kim et al., 2022).

Oil reservoirs have unique characteristics, and these characteristics have many differences with each other from the point of view of geology, petrophysics, and reservoir. Moreover, it may not be possible to generalize a method to different cases. Therefore, the novelty of this research may be stated as determining the stability of a wellbore in a specific oil field affected by factors such as azimuth and drilling inclination angle, which has not already been carried out on this specific oil field and wellbore. In this research, at first, by using the pore pressure calculated by Eaton's method and by using the acoustic and density logs data, the in-situ stresses were investigated. Furthermore, to determine stability, analysis of drilling azimuth and drilling inclination angle was performed in different zones of a given oil field. The results of this modeling help us determine the appropriate drilling inclination angle and azimuth to maintain the stability of the wellbore wall.

II. Geology of the Studied Oil Field

Field data from an oil field located in the north of Iran were used in this research. This oil field is located in the three countries of Iran, Azerbaijan, and Turkmenistan, and is controlled by the Caspian reverse fault. The field is related to Pliocene-Quaternary deposits, whose main reservoir rock has lower and middle Pliocene age, and its sub-reservoir rock consists of Apsheron Formation sand deposits of earlier Quaternary age.

Besides, this field is folded by the reverse fault located in its western part. This folding has continued in the Quaternary and Apsheron formations. Fig. 1 shows the geological characteristics of this field.

III. Geomechanical Model

Investigation of the geomechanical model is one of the practical factors in checking the state of stresses in the wellbore wall and reservoir rock. In this method, the determination of the state of existing stresses, as well as the analysis of the resultant stresses, which are primarily in-situ or induced stresses, are performed based on different models. In these models, the dynamic elastic properties of the reservoir are linked to the static elastic parameters of the reservoir, which are used to calculate and determine the formation strength and the in-situ stress state of the reservoir. Geomechanical models relate the dynamic elastic parameters of the reservoir to the static elastic parameters of the reservoir and use this approach as a method to determine the in-situ stresses of the reservoir. These models usually comprise rock strength, in-situ stresses of the formation, pore pressure of the formation, elastic parameters or plastic parameters, and direction of in-situ stresses. These parameters can be determined by both dynamic and static methods.

Overall, two sets of data are required to determine the geomechanical model of the formation. The first category includes Biot's coefficient, uniaxial compressive strength, moduli of elasticity, Poisson's ratio, and pore pressure. The second category includes horizontal and vertical stresses. The equations used in this study are summarized in Table 1.

Table 1. Equations used in this study

$\nu = 0.5\frac{V_p^2-2V_s^2}{(V_p^2-V_s^2)}$	(1)	Poisson's ratio
$E = \left(\frac{\rho b}{\Delta t_s^2}\right)\left(\frac{3(\Delta t_s^2)-4(\Delta t_p^2)}{\Delta t_s^2-\Delta t_p^2}\right) \times 1.34 \times 10^{10}$	(2)	Young's modulus
$G = (\frac{\rho_b}{\Delta t_S^2}) \times 1.34 \times 10^{10}$	(3)	Shear modulus
$k = \rho_b((\frac{1}{\Delta t_p^2}) - (\frac{4}{3\Delta t_s^2})) \times 1.34 \times 10^{10}$	(4)	Bulk modulus
$UCS = 7.1912Vp + 26.258$	(5)	Uniaxial compressive strength
$Sv = \rho_w g z_w + \rho g(z - Z_w)$	(6)	Vertical stress
$\sigma_H = \frac{v}{1-v}\sigma_v - \frac{v}{1-v}\alpha P_p + \alpha P_p + \frac{E}{1-v^2}\varepsilon_x + \frac{vE}{1-v^2}\varepsilon_y$	(7)	Maximum horizontal stress

First, the graphs related to density log and compressive and shear logs are evaluated by Geolog software and then the above equations are employed and the required parameters in each section are calculated and determined.

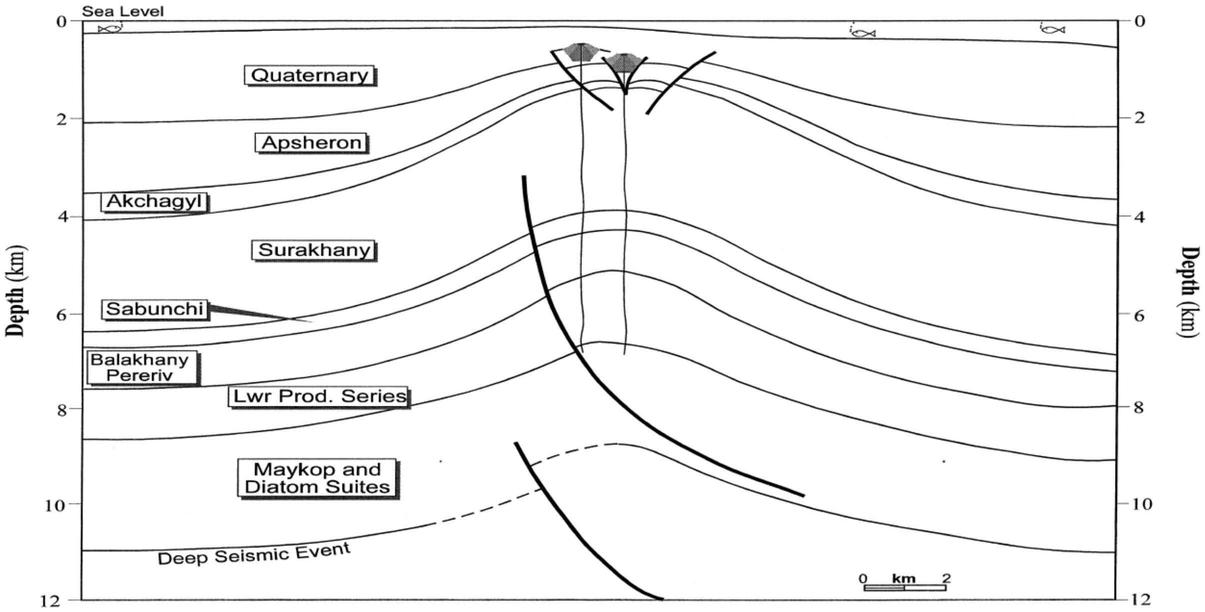

Fig. 1. Cross section of the studied oil field and its relationship with shallower layers (Cheraghsahar et al., 2020)

A. STABview Software

This software is practical software suitable for wellbore stability analysis. The results of this software determine the safe range of bottom hole pressure required to maintain wellbore stability. To use this software, the first part consists of input data, which is defined using the model properties and input data headers. In the model section, information such as the length of the well, the amount of mud loss during drilling, and wellbore collapse is expressed. In the input data section, information such as data related to the well and formation layers, data related to the mechanical properties of the reservoir rock, reservoir pressure, the in-situ stresses, and the type of model are provided. For this purpose, the gradient of in-situ stresses, the depth of layers, and the average elastic moduli in each formation are utilized. In the next section, using Analysis mode, the target graphs and tables are determined, and by specifying the collapse model, there is an option to determine the maximum amount of yielding around the wellbore wall. Through the failure models used in this software, the onset of wellbore wall failure can be predicted.

B. Numerical Modeling

Modeling was performed using the implicit finite difference numerical method. For this purpose, the concepts of forward and backward derivatives of time and location were used and the finite difference grid network is displayed in Fig. 2. Also, the data shown in Table 2 were utilized for modeling and input data. The parameters of this Table were extracted from the daily drilling reports in the oil field.

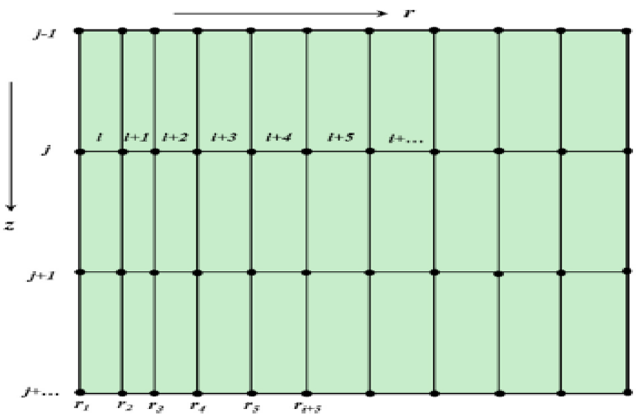

Fig. 2. Finite difference grid network in the wellbore

Table 2. Field data of wave transit time and rock porosity (obtained through daily drilling reports)

Rock type	Compressional wave transit time (μs/ft)	Shear wave transit time (μs/ft)	Rock density (g/cc)	Rock Porosity (%)
Cement	51.3	87.2	3.15	30
Fossil	50	87	1.4	65
Chert	44.8	71.7	2.3	10
Basalt	49.6	76.9	3.33	6
Gypsum	52.5	128.3	2.35	25
Asphalt	33.8	60.5	2.09	9
Bituminous	26.2	48.6	1.67	2
Anhydrite	50	122.4	2.97	2
Gravel	51.3	82.3	2	4
Sandstone	51.3	82.3	2.5	24
Dolomite	40	80.1	2.84	11
Limestone	44.3	90.4	2.78	17
Siltstone	43.6	109.3	2.68	17
Claystone	47.9	78.2	2.5	16
Mudstone	47.6	99.9	2.5	9
Shale	51.3	88.1	1.28	70
Marl	50	95	2.08	6

C. Elastic Parameters of Reservoir Rock

In the studied wellbore, dynamic Poisson's ratio is in the range of 0.252 to 0.411 and dynamic Young's modulus is 48 to 127 MPa. Using these values and the empirical relationships, static Young's modulus was calculated in the range of 8 to 64 MPa and static Poisson's ratio in the range of 0.162 to 0.254, smaller than their dynamic values. The changes in the cohesion coefficient of the reservoir rock are in the range of 612 to 1894 psi and the internal friction angle is in the range of 38 to 51 degrees. The minimum vertical stress gradient, equal to 1 psi/ft, is located at the surface, and the maximum value, equal to 2.5 psi/ft, is located at a depth of 3200 m. A summary of the ratios of the minimum and maximum horizontal stress to the vertical stress, as well as the maximum horizontal stress angle relative to the north direction, are presented in Table 3 for reservoir layers. As observed, the value of the horizontal stress angle is in the range of 9 to 152 degrees, the ratio of the maximum horizontal stress to the vertical stress is in the range of 0.6791 to 0.8633, and the ratio of the minimum horizontal stress to the vertical stress is in the range of 0.6042 to 0.7395.

Table 3. Ratio values of minimum and maximum horizontal stress to vertical stress, and maximum horizontal stress angle relative to the north direction, for reservoir layers

Zone	Ratio of maximum horizontal stress to vertical stress	Ratio of minimum horizontal stress to vertical stress	Angle of maximum horizontal stress relative to north
1	0.6791	0.6517	9
2	0.7416	0.6801	100
3	0.8012	0.6963	42
4	0.8144	0.6889	46
5	0.8186	0.7138	152
6	0.8576	0.7395	51
7	0.8626	0.6543	45
8	0.8633	0.6042	48

IV. FACTURE PRESSURE AND COLLAPSE PRESSURE

To determine the stability of the wellbore wall, the Mogi-Columb failure criterion was employed. The data shown in Table 4 (rock mechanical parameters) were used for this purpose. Using the data in this Table, the optimal drilling inclination angle and the safe pressure range were calculated separately in each zone.

Fig. 3 exhibits the changes in collapse pressure and formation fracture pressure in Zone 1. As it is noticeable, the collapse pressure in this Zone is equal to 469 psi, and the fracture pressure of the formation is 689 psi. To determine the optimal drilling inclination angle and azimuth in each of the studied formations, the optimal angle is determined when the difference between the collapse pressure and the fracture pressure of the formation is at its highest value. Fig. 4 depicts the changes in collapse pressure and formation fracture pressure in Zone 2, where the collapse pressure is equal to 1188 psi and the formation fracture pressure is equal to 1806 psi. The collapse pressure in zones 3-7 is equal to 1636, 1700, 1770, 1858, and 1971 psi, respectively, and the formation fracture pressure in these zones is equal to 2573, 2676, 2755, 2878, and 3043 psi, respectively.

Fig. 5 shows the changes in formation fracture pressure and collapse pressure in Zone 8. According to Fig. 5, collapse pressure and formation fracture pressure in this Zone are equal to 2144 and 3427 psi, respectively. To prevent the paper from becoming voluminous, the other related Figs. are not shown and a summary of the collapse pressure and fracture pressure in different zones of the studied oil field is presented in Table 5.

Table 4. Rock mechanical parameters in different zones of the oil field

Zone	Top depth (m)	Vertical stress (psi)	Maximum horizontal stress (psi)	Minimum horizontal stress (psi)	Pore pressure (psi)	Cohesion (psi)	Angle of internal friction (deg)	Poison ratio
1	100	883	600	576	469	610	41	0.22
2	540	2567	1964	1762	1188	1500	39	0.19
3	1080	3755	3009	2615	1636	880	40	0.19
4	1150	3908	3131	2721	1698	710	43	0.23
5	1165	4067	3258	2832	1768	710	42	0.22
6	1245	4273	3423	2975	1856	640	45	0.22
7	1285	4541	3638	3162	1969	815	40	0.20
8	1400	4880	3975	3362	2112	710	41	0.23
9	1480	5329	4340	3671	2328	855	40	0.20
10	1650	5796	4720	3993	2609	675	49	0.25
11	1720	7131	5572	5090	3159	950	40	0.21
12	2360	8297	6792	5922	3888	775	40	0.21
13	2380	9103	7807	6732	4793	745	44	0.22
14	2795	10287	9014	6838	5202	935	42	0.20
15	2960	11115	9826	6877	5276	965	40	0.20

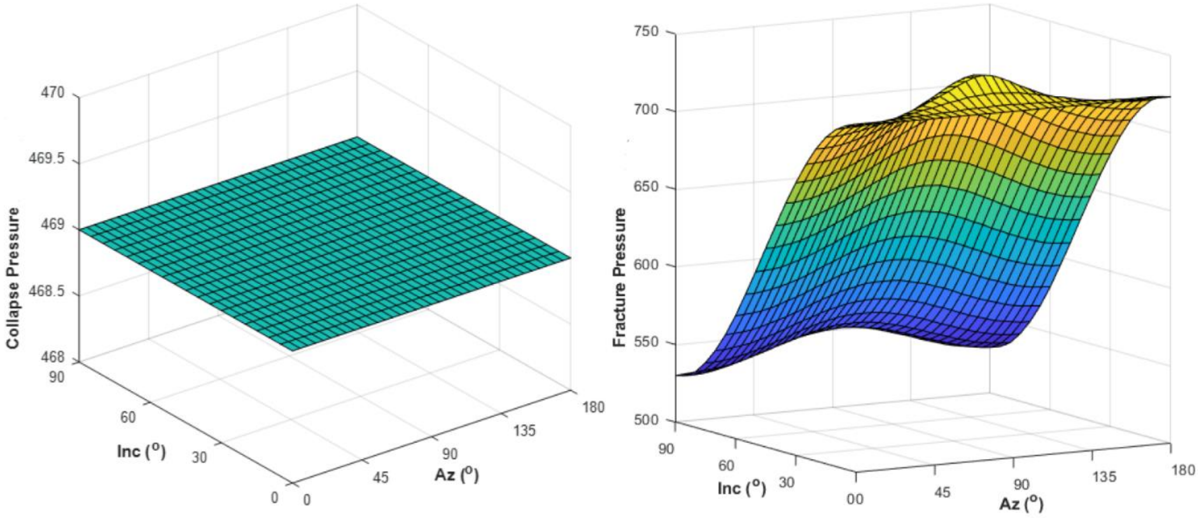

Fig. 3. Changes in collapse and fracture pressures in Zone 1

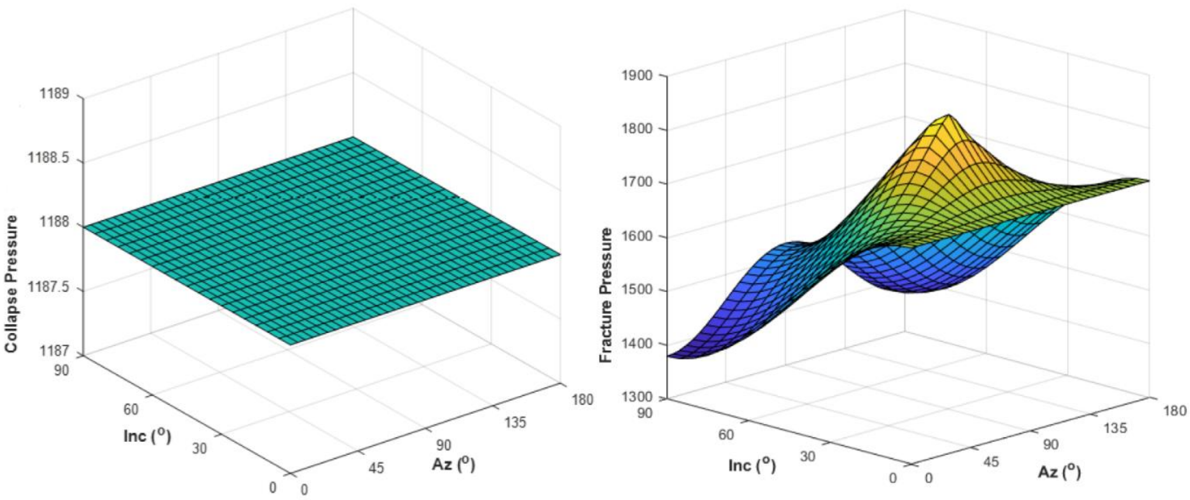

Fig. 4. Changes in collapse and fracture pressures in Zone 2

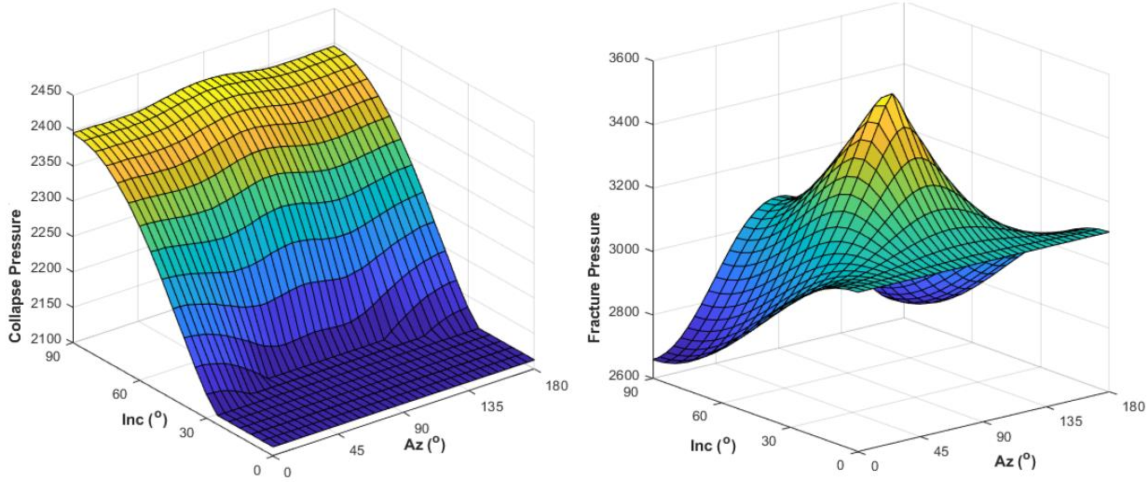

Fig. 5. Changes in collapse and fracture pressures in Zone 8

Table 5. Collapse and fracture pressures in different zones of the studied oil field

Zone	Collapse pressure (psi)	Fracture pressure (psi)
1	469	689
2	1188	1806
3	1636	2573
4	1700	2676
5	1770	2755
6	1858	2878
7	1971	3043
8	2144	3427
9	2379	3726
10	2611	4047
11	3227	4978
12	4347	5934
13	5125	6985
14	5937	7524
15	6324	8085

V. Investigation of Wellbore Stability Using Drilling Angle and Azimuth

To determine the optimal drilling inclination angle and azimuth in each of the studied zones, the optimal angle is determined when the difference between the collapse pressure and the fracture pressure of the formation is at its highest value. Table 6 presents a summary of the results in different zones.

In general, the purpose of using collapse pressure and fracture pressure data is that the use of these data in the points that have the lowest value of azimuth and optimal angle results in the determination of the optimal points. Therefore, determining the optimal range occurs at the points where the lowest collapse pressure and fracture pressure have occurred. Hence, the optimal point is the lowest collapse pressure and fracture pressure have occurred, leading to an improvement in the performance of the drilling operation. It should be noted that determining the optimal value of azimuth and inclination angle is based on the values extracted from the fracture pressure and collapse pressure in each zone (Table 5). Therefore, these data were used and the optimal values were obtained. As an example, Figs. 6-7, which respectively display the graph of the pressure difference in zones 4-5 to determine the optimal drilling inclination angle, are presented. These diagrams were employed to determine the optimal range of azimuth and drilling inclination angle, as well as to determine the optimal points of these two parameters. The optimal range includes the range with the lowest collapse pressure and fracture pressure in the diagram, and the optimal point includes the point where the lowest collapse pressure and fracture pressure are obtained. Thus, these Figs. were utilized to determine the optimal range as well as the optimal drilling point. The calculation of the optimal values of azimuth and angle of inclination is based on the values of the difference between the fracture pressure and the collapse pressure, in which the optimal values of these parameters are calculated.

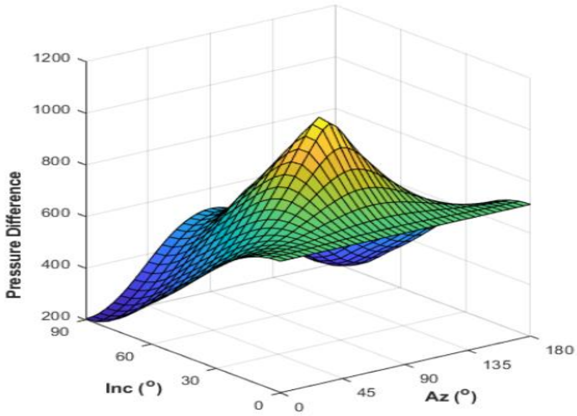

Fig. 6. Difference in fracture and collapse pressures in Zone 4

Table 6. Optimum drilling inclination angle and azimuth in different zones of the oil field

Zone	Optimum inclination angle (deg)	Optimum azimuth (deg)	Range of optimum inclination angle (deg)	Range of Optimum azimuth (deg)
1	15	90	5-25	80-100
2	30	90	30-35	80-100
3	40	90	35-40	85-95
4	40	90	35-40	85-95
5	40	90	35-40	80-100
6	40	90	35-40	80-100
7	40	90	35-45	80-100
8	40	90	35-40	85-95
9	40	90	35-45	90
10	40	90	40-45	90
11	30	90	25-30	80-100
12	30	90	20-40	75-105
13	40	90	25-45	80-100
14	25	80	20-35	60-120
15	60	90	10-15	65-115

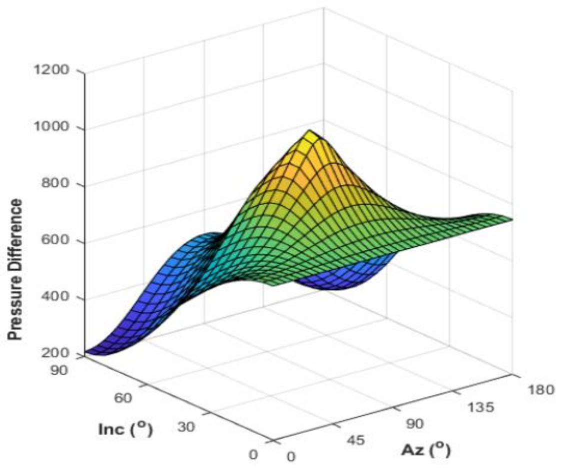

Fig. 7. Difference in fracture and collapse pressures in Zone 5

The data analysis indicates that pressure changes in all zones of this oil field except for zones 14 and 15 have a similar trend. The inclination angle in them is smaller than 45 degrees, which is the optimal mode of drilling in these zones. In the lower zones of the field, an angle of 60 degrees includes the range of the highest fracture pressure, and an angle of smaller than 45 degrees includes the range of the lowest collapse pressure. Fig. 8 illustrates the safe range of drilling in this oil field based on the pressure gradient, where the pressure gradient increases with increasing depth.

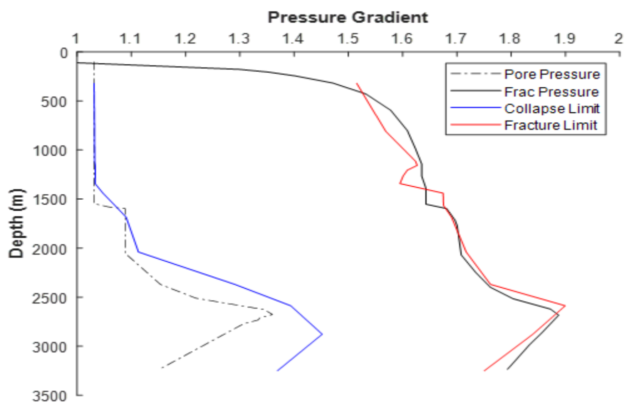

Fig. 8. Safe range of drilling in the oil field based on the pressure gradient

VI. Investigation of Wellbore Stability in Different Temperatures

To investigate the effect of temperature on wellbore stability, temperature changes in the range of 30°C to 120°C were evaluated. Fig. 9 exhibits the temperature of the fluid inside the annular space, where the temperature has increased with the increase in depth. The temperature difference between the fluid inside the annular space and that in the wellbore wall is shown in Fig. 10, which shows the most significant positive temperature difference in the lower parts of the annular space due to a more significant temperature decrease in these areas. Considering the induced stresses in the wellbore and also the temperature profile in the wellbore, the fracture pressure and collapse pressure in Zone 15 of this oil field were evaluated (Fig. 11). According to this diagram, the effect of temperature has increased the collapse pressure and decreased the fracture pressure, and this, in turn, has limited the safe window of the drilling mud. Therefore, temperature does not have a significant effect on determining the optimal drilling trajectory, and its chief effect is on narrowing the safe window of drilling mud in the formation. Table 7 provides a summary of the range of drilling optimal inclination angle and azimuth without considering the effect of temperature and with considering the effect of temperature. Due to the limitation of the safe window of the drilling mud, the range of the optimal inclination angle also becomes more limited.

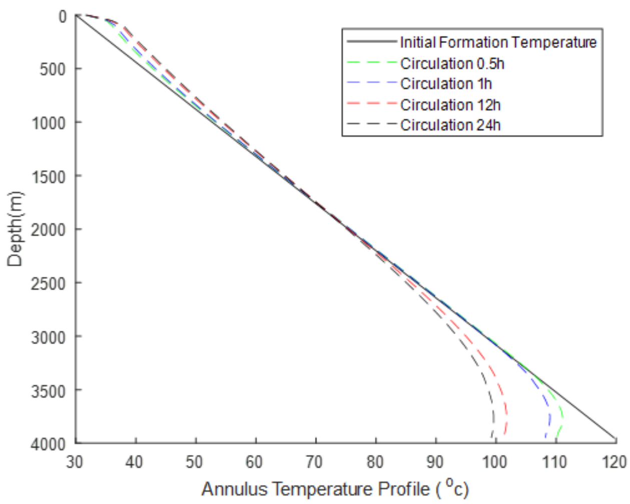

Fig. 9. Temperature of fluid inside the annular space

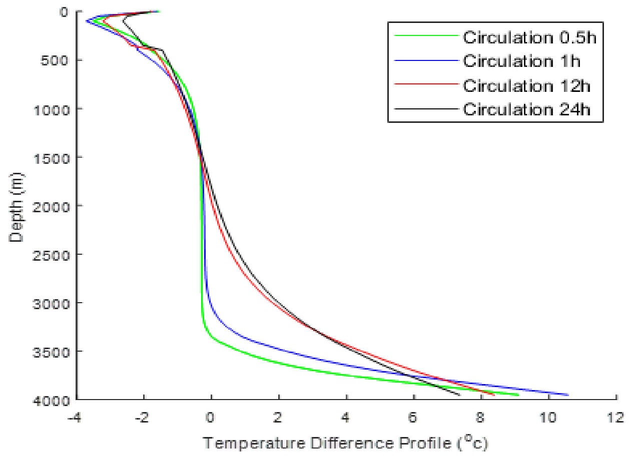

Fig. 10. Temperature difference between the fluid inside the annular space and wellbore wall

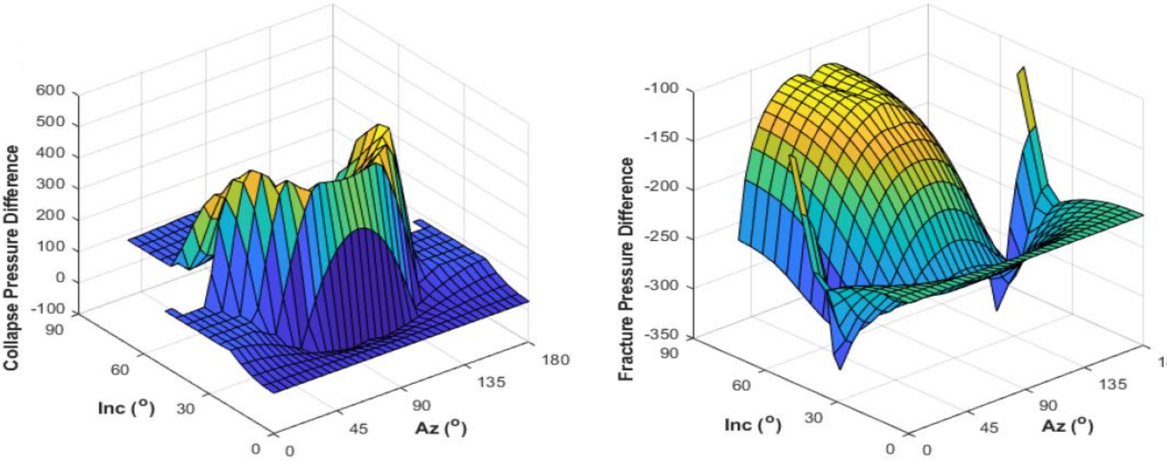

Fig. 11. Difference between fracture and collapse pressures in Zone 15 after considering temperature effect

Table 7. Optimal inclination angle and azimuth with and without temperature effect

Case	Range of optimum inclination angle (deg)	Range of Optimum azimuth (deg)	Collapse pressure (psi)	Fracture pressure (psi)
Without temperature	10-15	65-115	6324	8085
With temperature	20-30	105-120	6501	7855

VII. CONCLUSION

Geomechanical modeling was carried out to determine the optimal drilling inclination angle and trajectory and to increase the stability of the wellbore wall during the drilling operation. To achieve this goal, well logging data such as compressional wave velocity data, rock mechanical parameters, and induced stresses were employed, and the optimal drilling trajectory and inclination angle were evaluated in different zones of this oil field. A summary of our research results is as follows:

• The maximum fracture pressure changes from the range of low inclination angles to higher inclination angles, and this becomes more intense with increasing depth. However, the minimum collapse pressure does not change substantially with increasing depth and occurs at low inclination angles.

• The pressure changes in all zones of this oil field except for zones 14 and 15 have a similar trend, and the inclination angle is smaller than 45 degrees, which is the optimal mode of drilling in these zones.

• In the lower zones of the oil field, the inclination angle of 60 degrees includes the range of the highest fracture pressure of the formation, and the inclination angle of less than 45 degrees includes the range of the lowest collapse pressure.

• The effect of temperature has increased the collapse pressure, and decreased the fracture pressure, and this has narrowed the safe window of the drilling mud. Hence, temperature does not have a considerable impact on determining the optimal drilling trajectory and its main effect is on narrowing the safe window of drilling mud.

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