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Model-Based Temperature Distribution Assessment in Geothermal Well during Underbalanced and Overbalanced Drilling

Olatunji Olayiwola[1], Opeyemi Bello[2], Catalin Teodoriu[2], Mostafa Abdelhafiz[3], Joachim Oppelt[13] and Olusegun Osundare[4]

[1]Institute of Petroleum Engineering, Clausthal University of Technology, Germany
[2]Mewbourne School of Petroleum and Geological Engineering, University of Oklahoma, USA
[3]Drilling Simulator Celle, Clausthal University of Technology, Germany
[4]School of Engineering. University of Glasgow, Glasgow G12 8QQ, United Kingdom

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ABSTRACT

The understanding of downhole and surrounding wellbore formation temperature plays a very significant role during the geothermal drilling operations. Its knowledge is essential in the understanding of the borehole temperature recovery process which affects the operations. In a case of drilling through salt formations, the composition of the annular fluid and rheological properties change and influence the fluid temperature in the annular space in underbalanced drilling (UBD) and overbalanced drilling (OBD) conditions. Thus, it is hereby necessary to establish a simplified model that can predict accurate temperature distribution in geothermal wells during different drilling conditions and establish the controlled parameters which can be tuned to realize the desired result.

The study presents a simplified user-friendly computational system that analyses the influencing parameters for drilling fluid systems performance evaluation and selection optimization in a geothermal well drilling operation using a deterministic quantitative method known as Distance-Based Approach Model and Python® (SALib open library). The effect of salts concentration and compaction effect which affects the porosity values was also incorporated.

An overview of existing models for fluid temperature distribution in both OBD and UBD conditions was studied. Furthermore, identifications and screening of parameters that influence fluid temperature distribution with emphasis on geothermal well exploration were examined. The sensitive analysis performance was carried out with Python® (SALib open library) to generate the model inputs. Among some of the established parameters, circulation rate, temperature drop across the bit, influx rate and thermal conductivity of the cement are the main parameters observed during the sensitivity analysis. The selected model was later modified to accommodate the effect of salt concentration in the annular column when drilling through a salt formation. The modified model was used to establish the main governing parameters that influence the estimation of drilling fluid temperature during drilling conditions. The outcome of the modified model is compared with the existing model and the percentage variance was recorded.

The accuracy of this developed modified model was later used to predict the PET-1 Geothermal Field fluid temperature values with an error output of 2% - 3% against 5% - 15% observed for the base model. The modified model was validated with MWD field data to estimate and predict the fluid temperature values.

The modified computational support system will aid operators or drillers to identify, evaluate, select and control the main parameters that govern the accurate performance prediction of fluid temperature profile in geothermal drilling conditions.

1. INTRODUCTION

Overbalanced drilling is always regarded as the conventional way of drilling a well. It is usually employed by most drilling companies. In overbalanced drilling, the bottom hole wellbore pressure is kept higher than the formation fluid pressure during drilling operation. This also involves the adjustment of mud weight to keep the well overbalanced at all times. The designed mud weight must be kept so that it will be lower than the formation fracture pressure and above formation pore pressure.

The design of the mud weight is so important in overbalanced drilling because it forms a good filter cake around the wellbore wall and hence prevents the mud invasion into the formation. With this identified reason, it becomes necessary to know the actual temperature in this drilling region so that the mud weight does not fail its intending properties.

On the other hand, an underbalanced drilling approach entails a rotary drilling mode where bottom hole pressure is kept lower than the formation pore pressure. Some technological advancement such as improved planning and enhanced crew training have made it possible for underbalanced drilling technique to be in competition with overbalance method (Akdeniz, 2012). In underbalanced drilling, pressure is often expressed as Equivalent mud weight (EMW). The relationship between depth and pressure actually governs the drilling operations under UBO, MPD and Convectional drilling Operations.

The underbalanced drilling is also achieved when drilling fluid provides a hydrostatic pressure in the column which is held lower than the formation pore pressure. The rotating blowout preventer (RBOP) is one of the most important equipment during underbalanced drilling because the process requires safety precautions than the overbalance method. Well control operation is also like UBD in its mode of operation. The control of well against wellbore pressure is achieved with the use of choke.

The importance of underbalanced drilling can be seen in the areas of increased drilling rate, avoidance of lost circulation, limiting reservoir damage and reducing costs of completion enhancement. All these applications are extensively used in geothermal well drilling.

For safe, economic and efficient drilling operation, it is highly important to accurately predict the fluid temperature at the wellbore and annular conditions. This helps to understand the changes in rheological properties of drilling fluid as drilling progresses because of downhole temperature in the pipe, wellbore and annular space. If this is not accurately estimated, the influx of oil from the pay-zone during drilling operation can increase the temperature at the wellbore region and hence causes borehole complications. However, it is also quite challenging for the drilling industry to accurately employ a suitable model for estimating fluid temperature in both underbalanced and overbalanced drilling conditions. Therefore, efforts are made to review some existing models with respect to their best areas of application. Several governing parameters are also analyzed, and their understanding helps the drilling operators to achieve a proper tuning method when a desirable result is required.

The main objective of this study is to investigate some existing fluid temperature models for drilling operations adapted to geothermal wells. In investigating the models, governing parameters are established and analyzed for optimization using software's application.

2. FLUID TEMPERATURE DISTRIBUTION IN GEOTHERMAL WELLS

The methods of estimating an accurate fluid temperature in geothermal wells have been majorly segmented into distinct categories; the Analytical and Numerical models (Yang et al., 2013). The classical analytical method deals with conductive heat flow in cylindrical coordinates and the numerical model deals with the transient heat transfer process based on an energy balanced principle. These two methods try to focus majorly on the wellbore and formation temperatures during drilling conditions. Figure 1 illustrates the stages for the heat flows pattern in a typical geothermal wellbore.

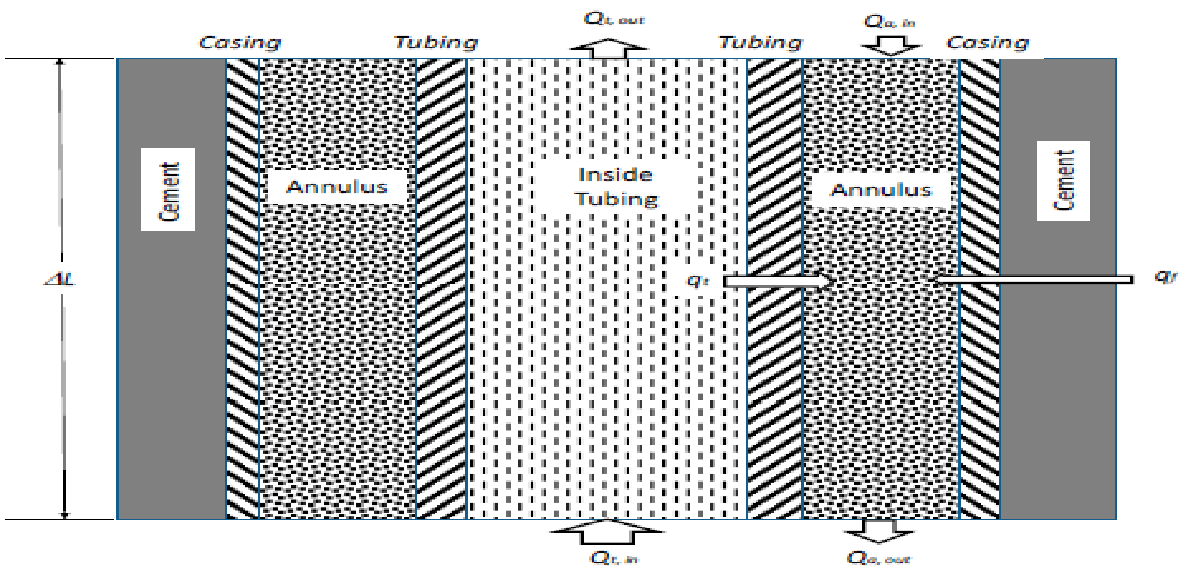

Figure 1: Stages of Heat Transfer in Geothermal drilling Operation ((Yang et al., 2013)

The stages at which heat transfers between the formation and the drilling fluid are itemized thus;

i. across the cementing section
ii. across the casing section
iii. across the rock section
iv. across the drilling string / drilling bit section
v. across the Annulus section
vi. across the surface section

There is always a need for energy balance equation before the heat transfer around the wellbore can be modelled. During the exchange of heat around the wellbore which leads to loss of temperature, several factors govern this transfer mechanism. These factors are;

i. Formation temperature distribution in the presence of heat source or sink (Sharifian (2016)
ii. The resistance to heat transfer within the wellbore elements

This interaction mechanism can be observed during the production operation where the hot reservoir fluids enter the wellbore and flows towards the surface. As the flows continue to the surface, they begin to lose heat to the cooler surrounding. This heat exchange between the wellbore fluid and the formation leads to heating up of surrounding rock and thereby reduces the temperature difference and heat transfer between the fluids and the rock. This phenomenon is called FLUID-ROCK INTERACTION (Sharifian (2016). However, at a constant mass flow rate, the surrounding region reaches a steady state temperature distribution. The depth and time function can however be used to predict the fluid physical properties and pressure gradient calculation (Brill and Mukherjee 1999). The heat transfer during the fluid flow in the wellbore is always considered as a steady state phenomenon because of high thermal conductivity and small radial distance between the fluid and the borehole wall. However, because of the high thermal mass of rock, the heat transfer in the formation never reaches a steady state level. The unsteady state radial conduction is then incorporated into the steady state wellbore model by means of a log-linear time function. The analytical and numerical wellbore model can also be coupled with the transient model to compute pressure, temperature and velocity values. The reservoir/wellbore heat transfer mechanism system can be categorized into, conduction; convection; and radiation heat transfer.

2.1 Estimating the Fluid Temperature Distribution in Geothermal Wells using an Analytical Approach – Model Formulation

Between the tubing and the annulus, the heat transfer is governed primarily by a convection mechanism. The heat transfer through tubing, casing walls and down to a cemented filled annulus between casing and borehole wall is governed by conduction mechanism. The analytical method selected for this study is Shan and Guo model (Shan and Guo, 2016; Shan et al., 2016). The model was chosen based on its simplicity, range of application, error range in terms of accuracy, and reality of the model assumptions.

The model considered the effect of fluid influx from the pay-zones which creates hot temperature fluid stream during underbalanced drilling in geothermal well. This heat transfer process can cause downhole complications if no accurate temperature model is developed. In this research work, three important parameters were greatly considered by the researcher namely; Temperature drop at the bit, fluid influx rate at the formation and thermal conductivity of the cement sheath. The following assumptions are considered in their study:

i. Annular fluid temperature is always affected by influx of formation fluid during underbalanced drilling of a geothermal well.

ii. Drill cuttings entrainment at the bottom hole affects the annular fluid temperature because of their heat capacity and thermal conductivities.

iii. The fluid Temperature is reduced at the drill bit nozzle due to Joule Thomasson cooling effect.

The main model equations for estimating the fluid temperature distributions in both tubing and annulus sections of a geothermal well are written below. Further derivation of these model equations can be made available on request by the author. During UBD, drilling fluid is injected into the drill string with a heat in the string which is proportional to the product of fluid heat capacity C_p, and the mass flowrate m_p. The mass flowrate is mathematically expressed as:

$$\boldsymbol{m_p} = \boldsymbol{\rho_p Q_p} \tag{1}$$

Where ρ_p is the drilling fluid density and $Q_p$is the volumetric flowrate.

During drilling, the drilling fluid flows down the drill strings and the heat transfer rate is proportional to the string thermal conductivity K_p. As the drilling fluid flows down the bit nozzles, it expands, and its temperature drops by a value called ΔT_b due to joule Thomasson cooling effect. At the bottom hole, the drilling fluid temperature is further increased with the entrained drill cuttings and formation oil influx.

The annulus heat at the bottom hole is proportional to the product of mixture heat capacity C_a and mixture mass flowrate m_a.

$$\boldsymbol{C_a m_a} = \boldsymbol{C_p m_p} + \boldsymbol{C_s m_s} + \boldsymbol{C_f m_f} \tag{2}$$

Where C_s and m_s are solid cuttings heat capacity and mass flowrate respectively. C_f is the heat capacity of the formation influx fluid (oil).

$$\boldsymbol{C_s m_s} = \boldsymbol{C_h m_h} + \boldsymbol{C_r m_r} \tag{3}$$

C_h and m_h are heat capacity and mass flowrate of the hydrocarbon respectively, while C_r and m_r are heat capacity and mass flowrate of the rock in the cuttings.

The hydrocarbon and rock mass flowrates can be calculated as;

$$\boldsymbol{m_h} = \frac{\pi}{4} \boldsymbol{D_b}^2 \boldsymbol{R_p} \, \Phi \, \boldsymbol{\rho_h} \tag{4}$$

$$\boldsymbol{m_r} = \frac{\pi}{4}\boldsymbol{D_b}^2\,\boldsymbol{R_p}(\,1\text{-}\,\Phi)\,\boldsymbol{\rho_r} \tag{5}$$

Where D_b is the diameter of the drill bit, R_p is the rate of penetration, Φ is the rock porosity, ρ_h is the hydrocarbon density, and ρ_r is the density of rock. The mass flowrate of the fluid is calculated as;

$$\boldsymbol{m_f} = \boldsymbol{Q_f}\,\boldsymbol{\rho_f} \tag{6}$$

ρ_f is the density of the fluid influx and Q_f is the flowrate of the fluid influx.

The fluid mixture flows up in the annulus and the heat transfer rates of drill string and cement sheath are proportional to thermal conductivity of drill string K_p and cement sheath K_c respectively. The thermal conductivity of the drill string is always assumed to be bigger than that of cement sheath. The fluid temperature in the drill string is then calculated using equation 7 below;

$$\boldsymbol{T_p} = \boldsymbol{C_1}\mathrm{A}\boldsymbol{e^{r_1L}} + \boldsymbol{C_2}\mathrm{A}\boldsymbol{e^{r_2L}} + \mathrm{GL} + \frac{\boldsymbol{AG+\,ABT_{go}-G(B+E)}}{\boldsymbol{AB}} \tag{7}$$

And that of the fluid temperature in the annulus is calculated using equation 8;

$$\boldsymbol{T_a} = \boldsymbol{C_1}(\mathrm{A}+\boldsymbol{r_1})\boldsymbol{e^{r_1L}} + \boldsymbol{C_2}(\mathrm{A}+\boldsymbol{r_2})\boldsymbol{e^{r_2L}} + \mathrm{GL} + \frac{\boldsymbol{AG+\,ABT_{go}-EG}}{\boldsymbol{AB}} \tag{8}$$

Where

$$\boldsymbol{C_1} = \frac{\boldsymbol{AB(A\Delta T_b\,-G)-[\,ABT_{po}-ABT_{go}-AG+G(B+E)r_2e^{r_2Lmax}]}}{\boldsymbol{A^2B(r_1e^{r_1Lmax}-r_2e^{r_2Lmax})}} \tag{9}$$

$$\boldsymbol{C_2} = \frac{\boldsymbol{-AB(A\Delta T_b\,-G)+[\,ABT_{po}-ABT_{go}-AG+G(B+E)r_1e^{r_1Lmax}]}}{\boldsymbol{A^2B(r_1e^{r_1Lmax}-r_2e^{r_2Lmax})}} \tag{10}$$

$$\boldsymbol{r_2} = \frac{\boldsymbol{B-E-A+\sqrt{[(B+E-A)^2+4AB]}}}{\boldsymbol{2}} \tag{11}$$

$$\mathrm{A} = \frac{\pi d_p K_p}{C_p m_p t_p},\ \mathrm{B} = \frac{\pi d_c K_c}{C_a m_a t_c}\ \text{and}\ \mathrm{E} = \frac{\pi d_p K_p}{C_a m_a t_p}$$

2.1.1 The Governing parameters

Having analyzed the model equations for the fluid temperature distribution, the governing parameters that can influence the temperature distribution are enumerated as thus;

i. Temperature drops at the bit
ii. Formation influx rate
iii. Drill bit size
iv. Thermal conductivities of the cement sheath
v. Thermal conductivities of the drill pipe
vi. Mass flowrates (Annulus, formation fluid influx, hydrocarbon cuttings and the rock)
vii. Porosity
viii. Densities (Injected fluid and rock)

2.1.2 Incorporating the Salt concentration effect on Geothermal Fluid Temperature Model

In drilling through a saline formation, an emphasis needs to be placed on the effect of salt content on the fluid temperature estimation. During the drilling operation, the salt content does not have any effect on the temperature inside the drill pipe section but does affect the fluid temperature in the annular space region. This is a reason why mixture rule needs to be employed while considering the salt effect. Further analysis shows that salt content affects the overall heat capacity of the fluid in the annulus and hence considerably affects the thermal conductivity properties.

The real value of thermal conductivity is evaluated from the density, heat capacity and thermal diffusivity of any selected samples at a drilling depth (Teodoriu and Falcone, 2016).

$$\curlywedge(\boldsymbol{T}) = \mathrm{a(T)} * \boldsymbol{C_v}(\mathrm{T}) * \rho\,(\mathrm{T}) \tag{12}$$

where a is the thermal diffusivity, C_v is the heat capacity and ρ is the density of the fluid. All these parameters are temperature dependent. In salt dominated drilling region, the thermal conductivity of an aqueous electrolyte solution becomes important for variety of applications. Several experimental studies have shown that the salt / electrolyte composition have profound consequences on the thermal conductivity of the drilling fluid and medium, hence affects the temperature distribution.

A model developed by Wang and Anderko (2012) was used to calculate the thermal conductivity on aqueous, non-aqueous and mixed solvent ranging from fused, pure salts and mixture solutions. The relevance of this method is then integrated into the temperature model for drilling operations. The effects and interaction of the salt's contents are expressed as function of ionic strength and temperature.

2.1.3 Thermal Conductivity Model with Salt Content

A general framework was developed and derived for evaluating the thermal conductivity model of an electrolyte system in a mixed solution. This mixed solution is assumed to be mixture of water, drilling fluid and salts component. The thermal conductivity of an electrolyte solution is expressed as sum of three dependent variables;

$$\curlywedge = \curlywedge_{water} + \Delta H^S + \Delta H^{S-S} \tag{13}$$

Where $\curlywedge_{water}$ is the thermal conductivity of water, ΔH^S is the individual contribution and ΔH^{S-S} is the contribution of interaction between pairs of species. Δ_{water} can be calculated with simple formulation from 2011 IAPWS for thermal conductivity of pure water, ΔH^S is also characterized by ion specific coefficients using Riedel additive generalized rules for ions where mole fractions are used (El-Shari, 2017).

$$\Delta H^S = \sum_i^n x_i \alpha_i \tag{14}$$

Where x_i is the mole fraction and α_i is the mole fraction-based Riedel coefficient. The α_i is then expressed as;

$$\alpha = \alpha_1 + \alpha_2 \exp\,[-k\,(T - T_O)] \tag{15}$$

Where T is the temperature in kelvin, T_O = 273.15k, K is the universal constant equal to 0.023. The α_1 and α_2 are then determined through experimental data.

$$\curlywedge - \curlywedge_{water} = X_c \alpha_C + X_a \alpha_a \tag{16}$$

The interaction between the species is then expressed as;

$$\Delta H^{S-S} = \sum_i^k \sum_k^n f_i f_k \beta_{ik} \tag{17}$$

where β_{ik} is the binary parameter, f_i and f_k are mole fractions of I and k species. These are then adjusted for species charges.

$$f_i = \frac{x_i / \max(l, Zi)}{\sum m\, X_m / \max(i, Zm)} \tag{18}$$

$$\beta_{ik} = \beta_{ik}^{(1)} + \beta_{ik}^{(2)} + \beta_{ik}^{(3)} \exp\,(\beta_{ik}^{(0)} I_x) \tag{19}$$

The parameter I_x is the extended ionic strength that accounts for ions pair.

$$I_x = \frac{1}{2} \sum_{ion}^{i} Z_i^2 + \sum_{ion\ pair}^{i} x_n \tag{20}$$

The temperature dependent of the three parameters m (1,2,3) is then expressed as;

$$\beta_{ik}^{(m)} = \beta_{ik}^{(mo)} \exp\,[\beta_{ik}^{(mT)} (T - T_o)] \tag{21}$$

$\beta_{ik}^{(mo)}$ and $\beta_{ik}^{(mT)}$ are all adjustable parameters.

2.2 Determining the overall Specific Heat Capacity of the Annular Mixture

In the annular space of a geothermal well, during the drilling of a saline formation, the returned fluid goes through the annulus to the surface. The total component in the annulus becomes;

Annular Component = Drilling fluid + Solid + Influx + Salt Content (22)

The equation 21 valid for an underbalanced drilling operation. To modify it for an Overbalanced method, the influx value is fixed to be zero and the equation becomes;

Annular Component = Drilling fluid + Solid + Salt Content **(**23)

To calculate the overall specific capacity of the mixture in the annular section, the mixture rule is employed. The overall heat capacity of the annular mixture during UBD is expressed as follows;

$$\boldsymbol{C_a m_a} = \boldsymbol{C_p m_p} + \boldsymbol{C_s m_s} + \boldsymbol{C_f m_f} + \boldsymbol{C_{SC} m_{SC}} \quad (24)$$

And that of the overbalanced expression is written as;

$$\boldsymbol{C_a m_a} = \boldsymbol{C_p m_p} + \boldsymbol{C_s m_s} + \boldsymbol{C_{SC} m_{SC}} \quad (25)$$

Where C_{SC} and m_{SC} denote the heat capacity and mass flowrate of the salt content respectively while the remaining abbreviations retain their usual expressions.

2.3 Incorporating the Compaction effect on Geothermal Fluid Temperature Model

Compaction effect affects the porosity value and hereby contradicts the believe that porosity remains same throughout the depth. Porosity is an important physical property of a sedimentary rock (El-Shari, 2017). It is governed by the grains interlocking pattern within the pores. The depth at which rock is buried determines the porosity value, the thickness reduction in sedimentary rock formed as a result of the compaction effect. The compaction effect can be caused either by physical or chemical means. Schmoker and Halley (1982) presented the outcome of an investigative observation of depth- porosity relationship of limestone and dolomite reservoirs in form of chart.

Furthermore, estimating the porosity value at each depth involves the use of Hubbert-Rubey equation formulated in 1959 for normally compacted rocks. The expression is written as thus;

$$\Phi_n = \Phi_o e^{-CZ} \quad (26)$$

Φ_n represents the porosity at any depth of burial, Z is the depth, Φ_o is the original / initial porosity and C is called the compaction coefficient, which can be primarily be determined as the slope of porosity versus depth cross plot during the porosity measurement (El-Shari, 2017). The compaction coefficient C is determined also by the type of lithology.

3. RESULT AND DICUSSIONS

3.1 Model Application and Prediction

To demonstrate the geothermal fluid temperature trend for both UBD and OBD operations, the input data of PET-I field is used as shown in Table 2. The model equations are used to generate T_p and T_a for the PET-1 geothermal field.

The Python program is then used to generate temperature profile for fluid in both pipe and the annulus under UBD and OBD conditions. However, the only difference that exists between the two drilling operations (UBD and OBD) is presented in Table .

Table 1: Difference in OBD and UBD Parameters

Parameter	Underbalanced (UBD)	Overbalanced (OBD)
Liquid influx flowrate	0.1 m^3/s	0, i.e. no liquid influx

Table 2: Data Set for PET-1 Well in China (Liquin shan 2016)

DATA SET FOR PET-1 WELL	
Depth	**5190m**
Bit diameter	**0.152m**
Inner diameter of cement	**0.178m**
Outer diameter of the drill pipe	**0.127m**
Inner diameter of drill pipe	**0.108m**
Geothermal temp at surface	**20 Deg. C**
Geothermal gradient	**0.025C/m**

Thermal conductivity of cement sheath	**0.85W/m-C**
Thermal conductivity of drill pipe	**43 W/m-C**
Fluid Injection rate	**0.026 m³/s**
Temp of the injected fluid	**37 Deg C**
Heat Capacity of the fluid inside pipe	**4210 J/kg C**
Heat Capacity of the rock	**920 J/kg C**
Heat Capacity of the oil	**1880 J/kg C**
Porosity	**0.3**
Rate of penetration	**2.1m/h**
Temperature drop at bit	**-0.45**
Rock density	**2650kg/m³**
Fluid density	**800kg/m³**
injected fluid density	**990kg/m³**
Liquid influx rate	**0.1m³/s**

The model equations are then used to generate and predict the values for fluid temperature both in the pipe and in the annulus under OBD and UBD conditions as estimated in Table 3.

Table 3: Fluid Temperature profile for PET-1 Field in both OBD and UBD Conditions

Depth(m)	Tp_UBD(deg C)	Ta_UBD (deg C)	Tp_OBD (deg C)	Ta_OBD (deg C)	GT (deg C)
0	37	64.87164223	37	35.67040655	20
1000	96.49172907	97.59054323	45.08050416	46.54704183	45
2000	110.5240404	111.3977877	68.45315766	70.188117	70
3000	120.9220308	121.5015146	93.27358008	95.02976568	95
4000	126.4925527	126.6804892	117.8780183	119.5617281	120
5000	125.6396318	125.3065745	136.669505	137.130831	145
6000	116.2396591	115.2133658	60.42630269	40.9455509	170

As presented in Figure 2 and Table 3, the fluid temperatures, both in the annulus and in the drill pipe increase with depth under the two drilling conditions. The geothermal temperature also increases linearly with depth. Between the drilling depths, 0m to 4000m, the fluid temperature profile in UBD shows an acute increase which is also greater than the geothermal temperature at any point within the stipulated depth. The reason could be that the high temperature from the surrounding rock, transfer heat into the formation and increases the temperature of the drilling fluid. This then makes the fluid temperature to be greater than the geothermal temperature.

At depth 4400m, the fluid temperatures in the annulus and the pipe, under the two drilling conditions approximately equal to geothermal temperature. Above 4400m, there is a sharp decrease in fluid temperature trend of UBD with respect to the geothermal temperature while the OBD fluid temperature distribution continues to increase until the drilling depth reaches 5000m, The decline in temperature trend under OBD is sharp while a slight decrease is noticed in UBD condition at 5000m. The reason for the sharp decrease in fluid temperature of UBD could be due to Joule Thomasson cooling effect, which accounts for temperature drop across the bit due to the influx experienced during underbalanced drilling.

One distinguished observation is also that the temperature in the pipe and the annulus relatively remain the same from depth 1000m to 6000m under UBD condition but the case only the same for OBD condition from depth 500m to 5100m.

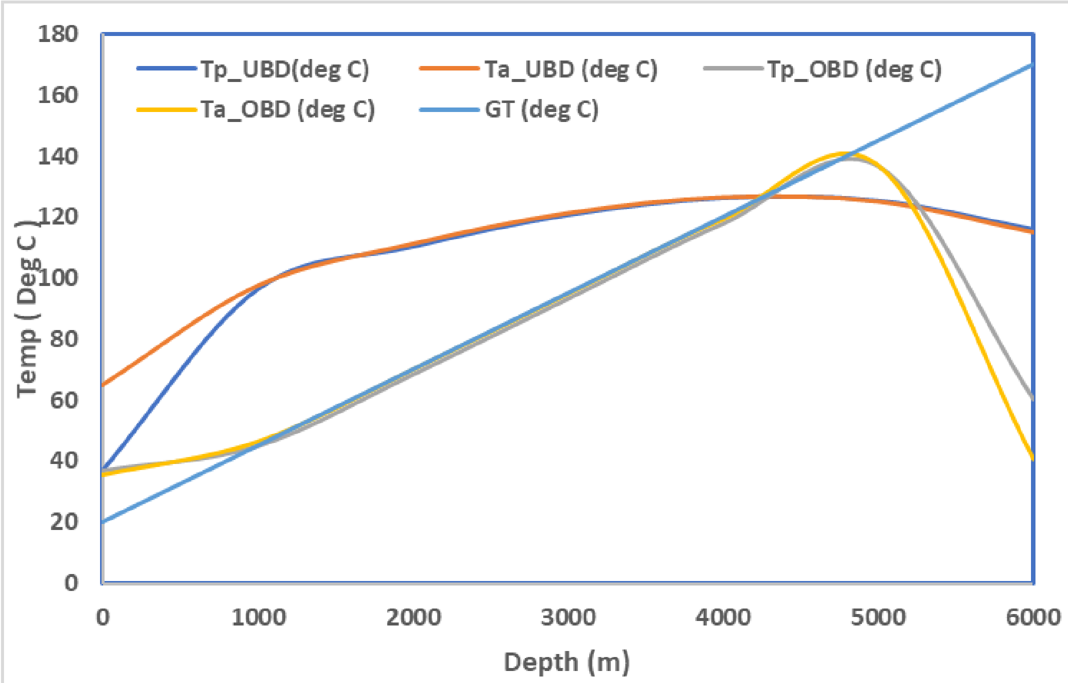

Figure 2: Temperature Distribution of PET-1 Field, China

In a separate analysis, Figure 3 shows the fluid temperature trend under the underbalance drilling condition using the PET-1 Field data. It can be deduced from the trend that the fluid temperature both in the annulus and inside the pipe differs with a positive value between the depth of 0 to 1000 meters. In this trend, the annular temperature is leading the fluid temperature in the pipe. Between 1000 meters to 4000 meters, the temperature in the annulus and pipe continue to increase non-linearly with depth, with no noticeable difference between the temperature in the pipe and annulus. At this point, both the temperature in the annulus and pipe higher than the geothermal temperature. Above 4000 meters drilling depth, the temperature profile both in the annulus and the pipe starts to decline below the geothermal temperature.

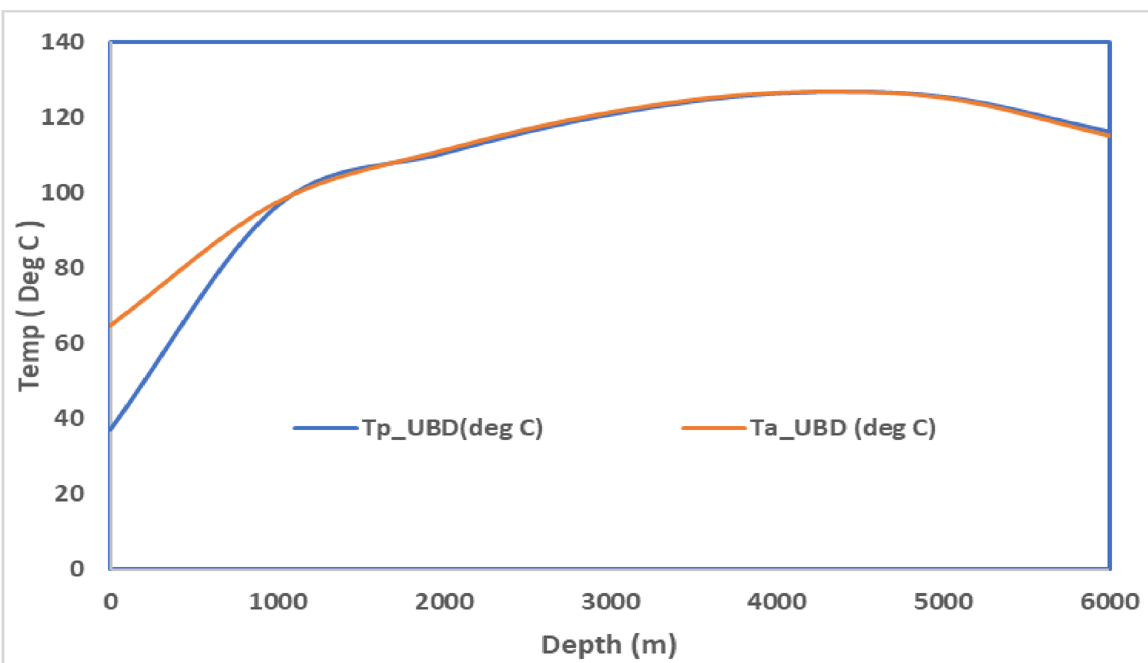

Figure 3: Fluid Temperature Profile of PET-1 Geothermal Field under Underbalanced Drilling Condition

But from Figure 4, the whole process under overbalanced drilling differs with what is discussed in underbalanced drilling. From figure 4, the temperature profile in the annulus, drill pipe and the geothermal temperature approximate remains same and increases with depth until 4800m when the geothermal temperature goes above the annular and drill pipe temperature with some values. Above 5000 meters, the temperature in the annular and drill pipe starts to decline with depth.

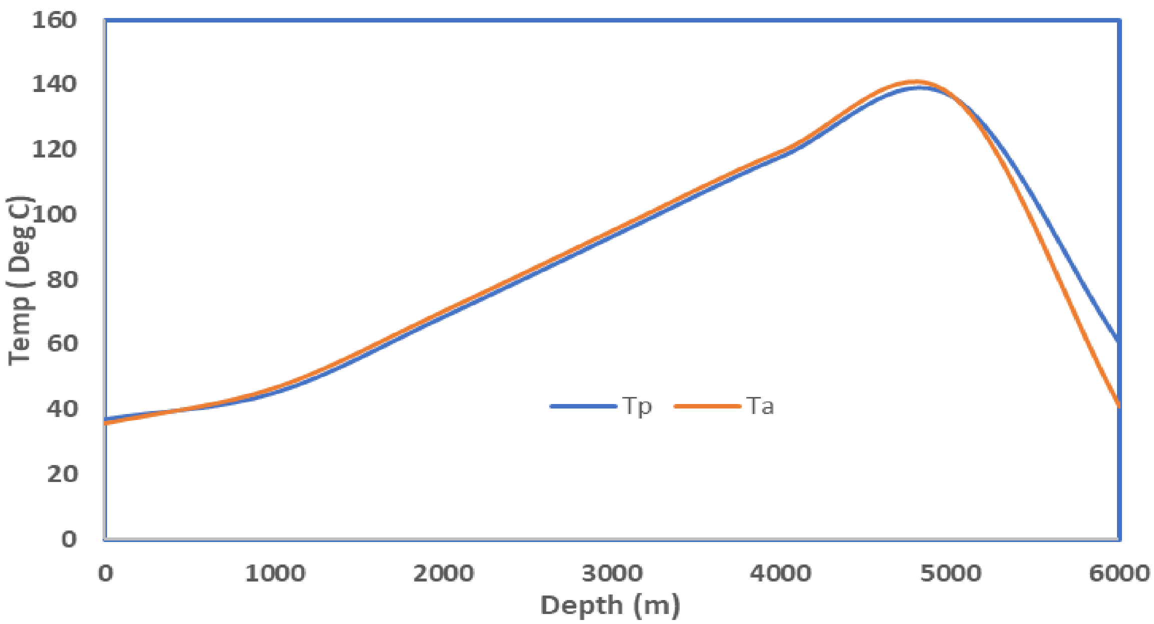

Figure 4: Fluid Temperature Profile of PET-1 Geothermal Field under Overbalanced Drilling Condition

3.2 Sensitivity Analysis

In this regard, several parameters are selected for sensitivity analysis. The sensitivity analysis is carried out on the selected parameters under the base case scenario and the observation is made based on the effect of varying the parameters on the geothermal fluid temperature estimation. The basic sensitive values for all the selected parameters in this study are shown in Table 4 below.

Table 4: Sensitive Parameters Values

S/No	Parameter	Condition	Value		
			Low	High	Average
1	Temperature drop across the bit (ΔTb) , Deg C	UBD, OBD	0	1	0.5
2	**Rate of Penetration (ROP) m/s**	**UBD, OBD**	**2.1**	**5**	**3.55**
3	Cement Thermal Conductivity (W/m C), Kc	UBD, OBD	0.85	3	1.93
4	**Fluid Density (ρf) , Kg/m³**	**UBD, OBD**	**900**	**1100**	**1000**
5	Porosity (φ) , Frac	UBD, OBD	0	1	0.5
6	**Influx rate (Qf) , m³/s**	**UBD**	**0.1**	**0.4**	**0.25**
7	Circulation rate, m³/s	UBD, OBD	0.1	0.4	0.25

3.2.1 Effect of Temperature drop across the bit on Fluid Temperature Profile

The temperature drop across the bit is an important parameter that governs the fluid temperature flow profile both in underbalanced and overbalanced drilling conditions. The drop in the temperature is caused by the expansion of drilling fluid below the bit nozzles. The phenomenon that happens in this process is called Joule-Thompson cooling effect. The temperature drop at the base case is set at 0.45 and in performing the sensitivity analysis, the value is set to range from 0 to 1 and the result is estimated and tabulated as shown in Table 5.

Table 5: Fluid Temperature values versus Temperature drop at the bit

Depth (m)	Tp @ Dtb=0	Ta @ Dtb=0	Tp @ Dtb=0.45	Ta @ Dtb=0.45	Tp @ Dtb=1	Ta @ Dtb=1
0	37.00	68.13	37.00	64.87	37.00	60.89
1000	103.24	104.47	96.49	97.59	88.25	89.18
2000	119.50	120.56	110.52	111.40	99.55	100.20
3000	132.87	133.69	120.92	121.50	106.32	106.61
4000	142.39	142.90	126.49	126.68	107.06	106.86
5000	146.79	146.88	125.64	125.31	99.79	98.94
6000	144.38	143.92	116.24	115.21	81.84	80.12

As displayed in Table 5, as the temperature drop across the bit increases, the estimated values of fluid temperature both in the pipe and the annulus decrease. Though this does not affect the fluid temperature in the pipe at the surface level (depth of zero), since the values remain unchanged. The corresponding inverse relationship increases as the drilling depth increases. This is due to the large influence of Joule Thomasson cooling effect on the bit which considerably lowers the temperature value. The sensitivity analysis carried out on temperature drop across the bit parameter shows that the accurate value of the parameter is highly needed when estimating fluid temperature during drilling condition. This is evident in the outcome of wide range of positive values with respect to a slight adjustment from 0 to 1 sensitive value. The clearer explanation is shown in Figure 5.

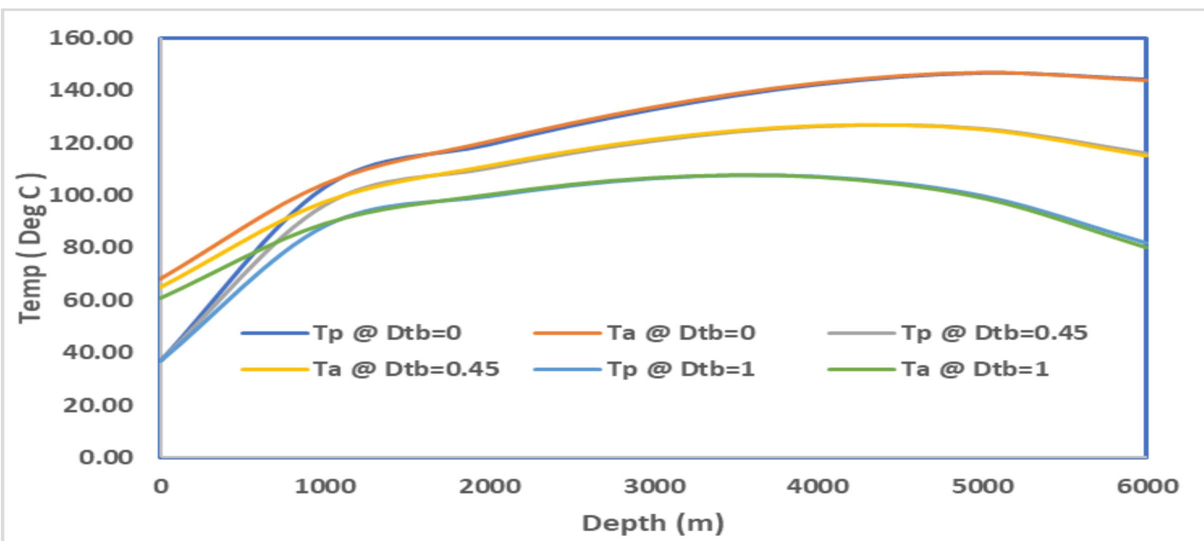

Figure 5: Effect of varying Temperature drop across the bit on fluid temperature profile in the annulus and pipe

3.2.2 Effect of rate of penetration (ROP) on Fluid Temperature Profile

The rate of penetration (ROP) is one of the established parameters that govern the temperature distribution of the drilling fluid during the drilling conditions. In order to determine the sensitivity of varying the parameter, the value is varied from an initial set of 2.1 m/s to 5.0 m/s. The outcome of this sensitivity analysis is presented in Table 6.

Table 6: ROP values against Fluid Temperatures

L	Tp @ RP=2.1	Ta @RP=2.1	Tp @RP=3.0	Ta @ RP=3.0	Tp @RP=5.0	Ta @ RP=5.0
0	37.00	64.87	37.00	64.88	37.00	64.89
1000	96.49	97.59	96.50	97.59	96.50	97.60
2000	110.52	111.40	110.52	111.40	110.53	111.40
3000	120.92	121.50	120.92	121.50	120.92	121.50
4000	126.49	126.68	126.49	126.68	126.48	126.67
5000	125.64	125.31	125.63	125.30	125.62	125.29
6000	116.24	115.21	116.24	115.21	116.23	115.20

From the result obtained, it is seen that no significant effect is observed when the rate of penetration is increased from initial value of 2.1 m/s to 5.0 m/s. This make the values of fluid temperature in both the annular space and drill pipe to remain the same throughout the period of increment. This actually depicts that effort to increase the rate of penetration (ROP) while drilling yield no positive significance in fluid temperature control. This finally implies that the ROP parameter is not the main governing parameter that can be manipulated while realizing a specific fluid temperature profile. This is diagrammatically explained in Figure 6.

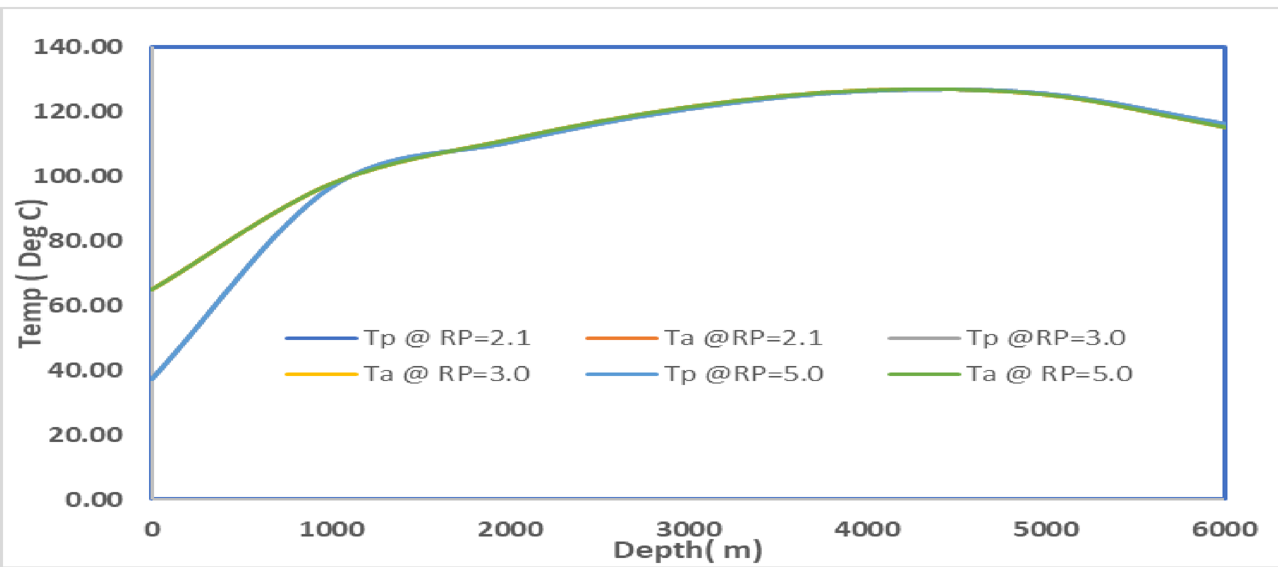

Figure 6: Effect of varying ROP on Fluid Temperature Distribution

3.2.3 Effect of Thermal Conductivities on Fluid Temperature Profile

Thermal conductivity is an important parameter that determines the ability or property of any selected materials to conduct heat. In the course of this analysis, two principal thermal conductivity properties are analyzed, namely; the thermal conductivity of the cement (Kc) and that of the drill pipe (Kp). The initial values for Kc and Kp are fixed as 0.85 W/m-C and 43 W/m-C respectively. For the sake of sensitivity analysis, the value for Kc is varied from the initial value of 0.85 W/m-C to 3 W/m-C, and the result is generated using the python software. The same approach can be employed with Kp by varying it for the analysis, but this will not be carried out in this research work. The outcome of the sensitivity analysis on Kc is presented in Table 7 and Figure 7.

Table 7: Conductivity values of the Cement (Kc} versus Temperature

Depth (m)	Tp @Kc = 0.85	Ta @Kc = 0.85	Tp @Kc = 2.0	Ta @ Kc = 2.0	Tp @ Kc = 3.0	Ta @ Kc = 3.0
0	37.00	64.87	37.00	49.09	37.00	42.29
1000	96.49	97.59	77.02	78.64	67.21	68.93
2000	110.52	111.40	99.24	100.74	91.33	93.00
3000	120.92	121.50	118.85	120.10	114.00	115.50
4000	126.49	126.68	133.41	134.17	132.77	133.85
5000	125.64	125.31	138.18	137.99	141.18	141.11
6000	116.24	115.21	123.94	121.92	121.93	118.79

In Table 7, it can be deduced that at an initial depth of 0 meter, which means at the surface level, the thermal conductivities value of the cement (Kc) do not have any considerable effect on fluid temperature profile in the drill pipe but affects the fluid temperature in the annulus. It is also observed that as the drilling depth increases from 1000 meters to 3000 meters, the increase in the value of thermal conductivity of the cement (Kc) leads to decrease in the values of fluid temperature both in the pipe and the annular space. This shows that at this drilling depth, an inverse relationship exists between the Kc parameter and the fluid temperature values as it can be seen in Figure 9. But the reverse case is observed at the drilling depth of 4000 meters down to 6000 meters. In this case, the fluid temperature at both the annular and in the pipe, increases as the thermal conductivities value of cement increases. This shows the direct relationship exists between cement thermal conductivity parameter and the fluid temperature.

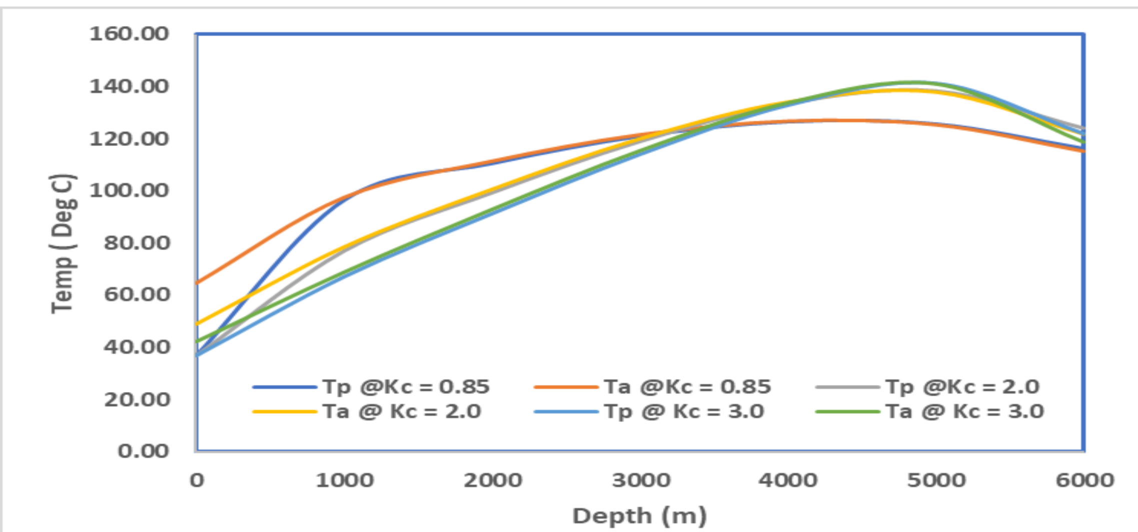

Figure 7. Effect of varying Cement Thermal Conductivity (Kc) values on Fluid Temperature Distribution

<u>3.2.4 Effect of drilling fluid density on Fluid Temperature Profile</u>

The density of any parameter plays an important role in determining how consistent material is under temperature and pressure influence. The density of drilling fluid is designed to perform the safety of the operation while drilling, this is because abnormally over-pressured zone or influx can be encountered. The type of drilling fluid selected (oil or water-based mud) determines its density value. Like the normal practice, the density of the drilling fluid used for this model analysis is 990 kg/m³. For the sensitivity purpose, the density of the drilling fluid is varied from 900kg/m³ to 1100kg/m³ and the observed effect is tabulated and recorded as shown in Table 8 and Figure 8 respectively. From Table 8, it is initially observed that at the depth of 0 meter, i.e. at the surface, the temperature of fluid in the drill pipe remains unchanged and that of the annular space decreases as the fluid density increases. But as from 1000m depth up till final depth of 6000m, the fluid temperature starts to increase as the density of the fluid increases from 900kg/m³ to1100kg/m³. The reason for this trend could be as a result of geothermal temperature in the formation which considerably increases the temperature of the fluid through heat transfer mechanism (conduction and convection effects).

Table 8: Fluid density values versus Fluid Temperature

Depth	Tp @ ρp = 900	Ta @ ρp = 900	Tp @ ρp = 1000	Ta @ ρp = 1000	Tp @ ρp = 1100	Ta @ ρp = 1100
0	37.00	65.52	37.00	64.80	37.00	64.08
1000	96.14	97.12	96.52	97.63	96.76	98.00
2000	109.97	110.75	110.58	111.46	110.99	111.98
3000	120.09	120.60	121.00	121.59	121.66	122.33
4000	125.29	125.43	126.61	126.80	127.60	127.84
5000	123.92	123.58	125.81	125.47	127.26	126.94
6000	113.81	112.83	116.48	115.45	118.57	117.49

The understanding of this trend can be well digested by looking through the temperature profile in figure 18. This confirms that the fluid density also plays an important role in the fluid temperature profile, both in annulus and drill pipe sections.

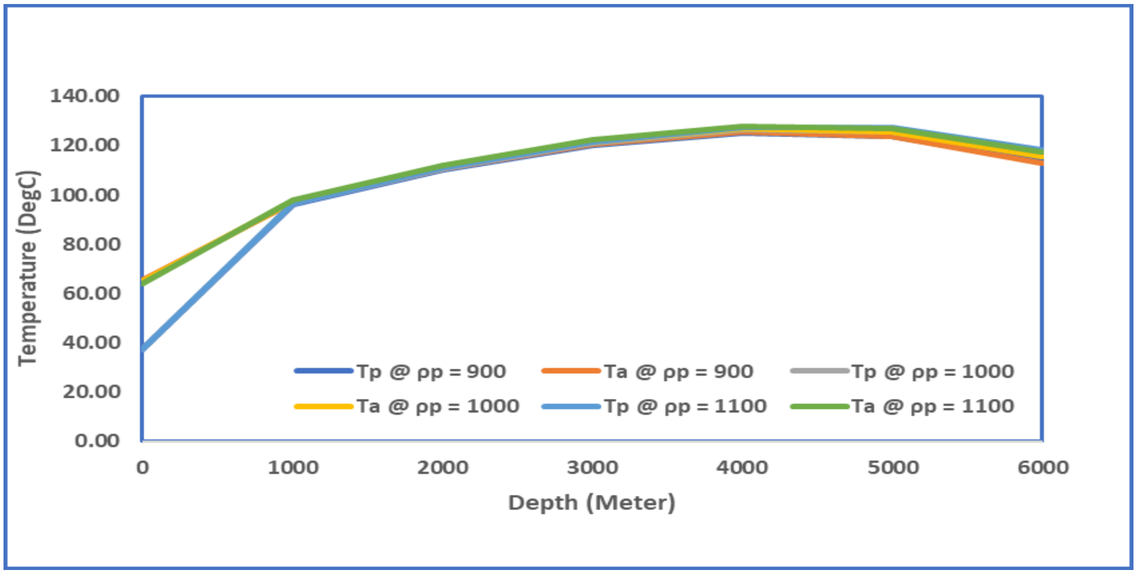

Figure 8: Effect of varying drilling fluid density on fluid temperature profile

3.2.5 Effect of the Porosity on Fluid Temperature Profile

The porosity is a parameter that governs the interconnectivity of the pores in the reservoir rock. This may be as a result of effective porosity influence within the grains. It measures the fraction of voids over the total volume of rock. In this thesis report, it is established that porosity is one of the parameters that govern the fluid temperature profile during the drilling operation. In this regard, sensitivity analysis is carried out on the porosity effect by varying its value from 0 to 100 percent using the base case data. The outcome is presented and analyzed as shown in table 9 and figure 11 below.

Table 9: Porosity values versus Fluid Temperature

Depth	Tp @ ϕ = 0	Ta @ ϕ = 0	Tp @ ϕ = 0.3	Ta @ ϕ = 0.3	Tp @ ϕ = 0.6	Ta @ ϕ = 0.6	Tp @ ϕ = 1.0	Ta @ ϕ = 1.0
0	37.00	64.87	37.00	64.87	37.00	64.87	37.00	64.87
1000	96.49	97.59	96.49	97.59	96.49	97.59	96.49	97.59
2000	110.52	111.40	110.52	111.40	110.52	111.40	110.52	111.40
3000	120.92	121.50	120.92	121.50	120.92	121.50	120.92	121.50
4000	126.49	126.68	126.49	126.68	126.49	126.68	126.50	126.68
5000	125.64	125.31	125.64	125.31	125.64	125.31	125.64	125.31
6000	116.24	115.21	116.24	115.21	116.24	115.21	116.24	115.22

In Table 9, it is observed that as the porosity value is varied from 0 percent to 100 percent, the effect on the fluid temperature distribution, both on the annular space and pipe remains approximately unchanged. This is also reflected in figure 9 as there are no significant changes in the fluid temperature trend as the value of porosity changes. It is hereby concluded that porosity is not a main parameter that actually controlled the fluid temperature profile during drilling operations. The reason being that porosity deals with pore connection in the grains and have nothing to do with the temperature / thermal property of a given reservoir. It is unlike permeability parameter which governs the flow of reservoir fluid within the pores.

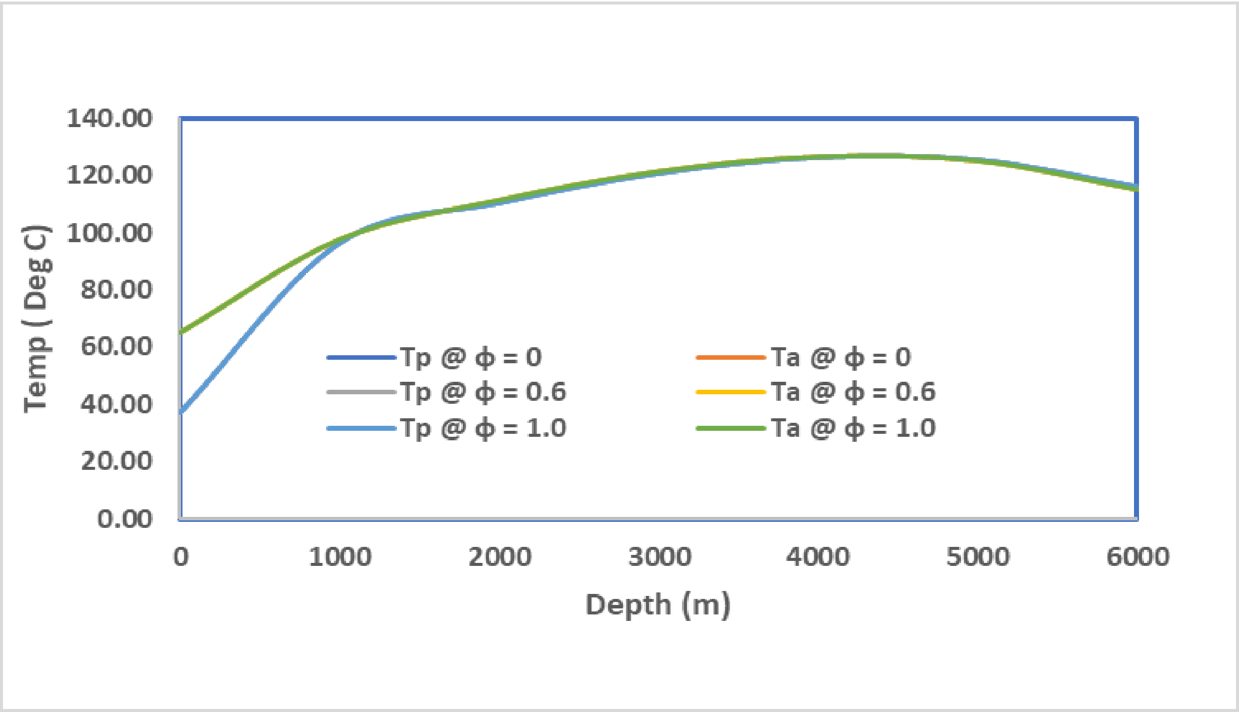

Figure 9: The effect of varying porosity on Fluid Temperature Distribution

3.2.6 Effect of the Influx rate on Fluid Temperature Profile

The flowing of reservoir fluid into the formation is usually encountered during underbalanced drilling condition. The reason for this is attributed to the fact that the pressure difference during drilling condition gives room for the fluid to infiltrate into the formation i.e. the drilling pressure which is lesser than the formation pressure. The formation pressure then has an edge in pushing the formation fluid into the wellbore region. This flowing fluid can be oil, gas, liquid or condensates. For the sensitivity analysis, the fluid influx rate is varied from the initial value of 0.1 m^3/s to 0.4 m^3/s with 0.1 interval values and the result is as shown in Table 10.

Table 10: Influx flow rate versus fluid temperature

Depth (m)	Tp Qf = 0.1	Ta Qf = 0.1	Tp Qf = 0.2	Ta Qf = 0.2	Tp Qf = 0.3	Ta Qf = 0.3	Tp Qf = 0.4	Ta Qf = 0.4
0	37.00	64.87	37.00	76.76	37.00	72.88	37.00	61.90
1000	96.49	97.59	97.13	97.69	84.82	85.10	68.13	68.26
2000	110.52	111.40	103.69	104.05	87.81	87.95	69.09	69.10
3000	120.92	121.50	107.38	107.53	88.59	88.56	68.25	68.13
4000	126.49	126.68	107.76	107.66	86.91	86.70	65.48	65.21
5000	125.64	125.31	104.33	103.94	82.54	82.13	60.62	60.20
6000	116.24	115.21	96.49	95.77	75.20	74.57	53.52	52.94

From Figure 10, it is observed that the fluid temperature in drill pipe and annular sections initially increased as the influx flowrate changes from 0.1 m³/s to 0.2 m³/s, at depth of 0 to 1000 meter. After this, there is an anomalous decrease in the fluid temperature profile, both in the annulus and drill pipe, as the influx flowrate increases to 0.4 m³/s, down the drilling depth of 6000m. The reason for this change could be as a result of relaxation time which affects the dominance of influx temperature on the entire drilling fluid temperature. This explanation could be well pictured in Figure 12 shown below.

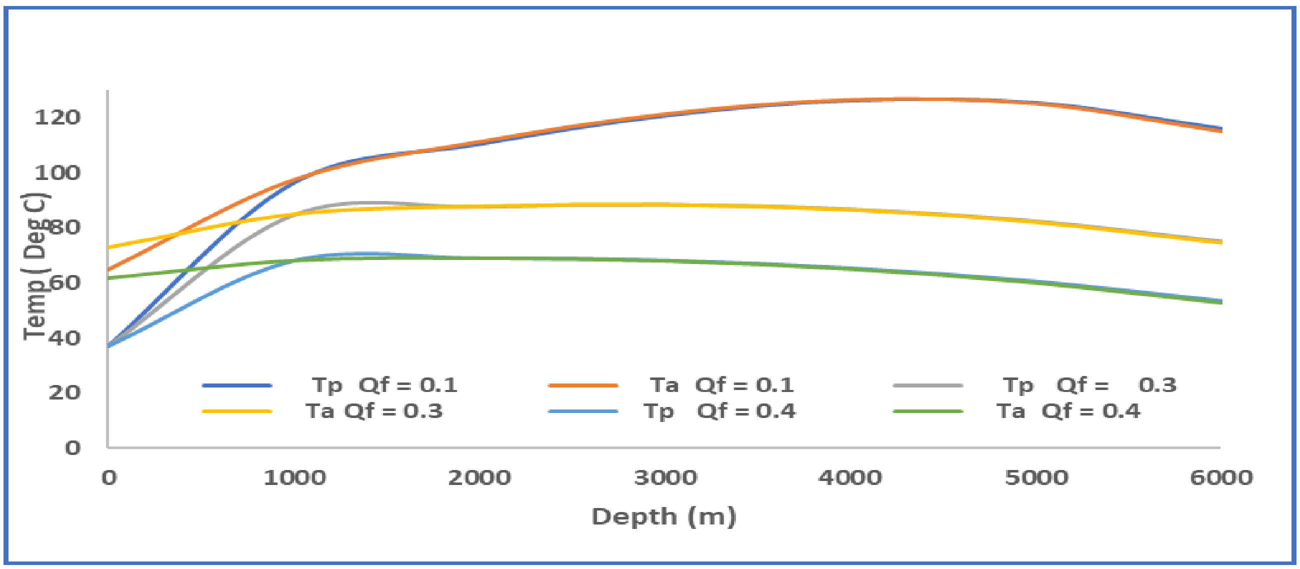

Figure 10: Effect of Influx rate on fluid temperature distribution

3.2.7 Effect of the Circulation rate on Fluid Temperature Profile

The drilling fluid circulation rate is also an important parameter that governs the trend of fluid temperature during drilling operation. The circulation rate is varied from 0.01m³/s to 0.4m³/s and the result is presented in Table 11.

Table 11 Circulation rate vs Fluid Temperature

Depth (m)	Tp @ CR = 0.01	Ta @ CR = 0.01	Tp @ CR = 0.02	Ta @ CR = 0.02	Tp @ CR = 0.03	Ta @ CR = 0.03	Tp @ CR = 0.04	Ta @ CR = 0.04
0	37.00	66.95	37.00	66.47	37.00	63.79	37.00	61.32
1000	87.79	88.13	95.26	96.07	96.82	98.11	96.48	98.40
2000	98.40	98.63	108.68	109.31	111.13	112.16	111.46	112.88
3000	104.21	104.28	118.24	118.64	121.88	122.58	122.73	123.74
4000	103.58	103.46	122.68	122.75	127.94	128.20	129.55	130.00
5000	94.39	94.00	120.27	119.92	127.77	127.45	130.47	130.18
6000	73.76	73.01	108.76	107.84	119.31	118.22	123.56	122.30

From Table 11, it is observed that the fluid temperature in the drill pipe and annular sections have a direct relationship with the drilling fluid circulation rate. As the circulation rate is increased from 0.01m³/s to 0.04m³/s, an increment in the fluid temperature values (both in the pipe and the annulus) is observed from depth 1000 meter to the final drilling depth. The major reason for this could be as a result of thermal conductivity property of the drilling fluid, which also increase as a result of increase in the volume circulated downhole during the drilling condition and this can be seen in Figure 11.

On the other hand, the reverse trend is observed at the surface condition, where the increase in the circulation rate leads to decrease in the temperature values in both annular and pipe sections. The main reason that could be suspected may be the effect of environmental factor (cooling effect), which considerably lowers the temperature value.

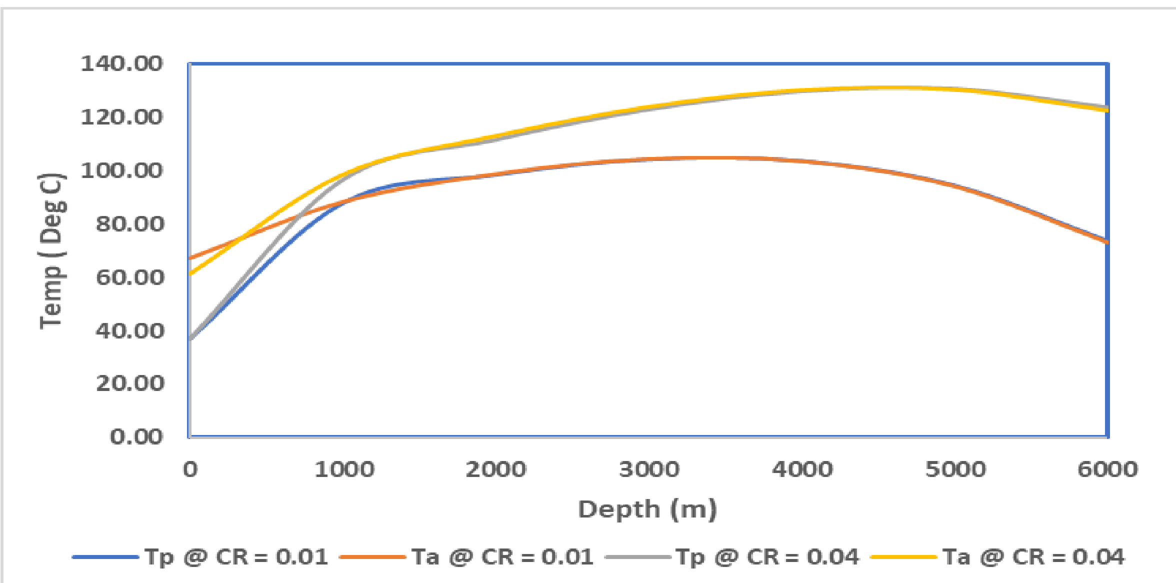

Figure 11: Effect of Circulation rate on Fluid Temperature Distribution

3.3 Result of the Sensitivity Analysis

The summary of the sensitivity task performed is presented in Table 12. The average percent variation is determined for each parameter by calculating the variation of the sensitized parameter (under low and high sensitive values) with that of base case result, using PET-1 Field data inputs. It is inferred from the results obtained in Table 12 that influx rate, the temperature drop across the bit, fluid circulation rate and thermal conductivity of cement are the major parameters that influence the fluid temperature trend with average percent variation of 39% , 23% ,17% and 15% respectively under the sensitivity studies. Other parameters like porosity, the rate of penetration (ROP) and fluid density are considered minor parameters because their variation effect is negligible (0%, 1%).

Table 12: Result of the Sensitivity Analysis

S/N	Parameter	Sensitive value	Avg. % Variation	
			Tubing	Annulus
1	Temp Drop across the bit (Deg C)	0	23	12
		1	14	15
2	**Rate of Penetration, ROP, (m/s)**	**2.1**	**0**	**0**
		5	**0**	**0**
3	Thermal conductivity of cement Kc, (W/m C)	0.85	0	0
		3	11	15
4	**Fluid density, (Kg/m³)**	**900**	**1**	**1**
		1100	**1**	**1**
5	Porosity, (Frac)	0	0	0
		1	0	0
6	**Influx rate, (m³/s)**	**0.1**	**0**	**0**
		0.4	**38**	**39**
7	Circulation rate, (m³/s)	0.1	16	17
		0.4	2	3

The established parameters that govern the distribution of fluid temperature in the annulus and pipe sections, under overbalanced and underbalanced drilling conditions are also itemized and grouped according to their influence on the outcome of the analysis. The Table 13 below shows the summary of the task in this sub-chapter.

Table 13: Summary of the influencing parameters for fluid temperature distribution

S/N	Parameter	Unit	Category	Influence	Remark
1	Thermal Conductivity of the Cement (Kc)	W/m Deg. C	Major	OBD & UBD	Has a direct influence on fluid temperature and it is a controllable parameter
2	Temp. drop across the bit (Δtb)	Deg. C	Major	UBD & OBD	Has a direct influence on fluid temperature in UBD and OBD Operations and it cannot also be controlled
3	Fluid density (ρf)	Kg/m³	Minor	UBD & OBD	Affect directly both fluid temperature estimation in UBD and OBD Operation. It is a controllable parameter
4	Rate of Penetration (ROP)	m/s	Minor	UBD & OBD	This parameter has little or no effect on fluid temperature distribution. Though it can be controlled

5	Porosity (φ)	Fraction	Minor	UBD & OBD	Little or no effect on the fluid temperature estimation. It is also an uncontrollable parameter.
6	Fluid influx rate (Qf)	m³/s	Major	UBD	Affect directly the fluid temperature estimation in UBD Operation only
7	Circulation rate (CR)	m³/s	Major	UBD & OBD	Very important parameter that affect the fluid temperature distribution. It is very easy to influence as it can be controlled from the surface

3.4 Error Function Analysis of the Main Parameters

In this section, the outcome of the sensitive analysis is used to enumerate the main parameters for the fluid temperature estimation. From this outcome, four main parameters are established, namely-

- Temperature drop across the bit (ΔTb)
- Fluid influx rate (Qf)
- Thermal conductivity of the cement (Kc)
- Circulation rate (CR)

The error function analysis is carried out on each parameter with ± 0.3 error values at 0.1 step interval and the result obtained is shown in Table 14

Table 14: Error Analysis result for the main parameters

Error range	Main Parameters							
	Temp drop across the bit (ΔTb)		Oil influx rate (Qo)		Cement Thermal Conductivity (Kc)		Circulation rate (CR)	
	Etp	ETa	ETp	ETa	Etp	ETa	ETp	Eta
-0.3	0.044	0.068	0.008	-0.008	-0.047	-0.060	-0.052	-0.073
-0.2	0.030	0.045	0.008	0.000	-0.024	-0.030	-0.030	-0.041
-0.1	0.015	0.023	0.005	0.002	-0.010	-0.011	-0.013	-0.017
0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
0.1	-0.015	-0.023	-0.008	-0.006	0.006	0.006	0.010	0.013
0.2	-0.030	-0.045	-0.017	-0.015	0.010	0.008	0.017	0.022
0.3	-0.044	-0.068	-0.028	-0.027	0.012	0.008	0.022	0.029

3.5 Estimating the temperature distribution with Salt content effects

Using the model equations (Equation 24, 25 and 26) to modify the base case data gives an outcome that is presented in Table 15 and Figure 16. The application of the modified equations works with some basic assumptions which are stated thus;

1. The lithology is assumed to be normally compacted with coefficient factor of 0.0005/m.
2. 10% of the salt content effect is applied in the annular fluid composition since direct measurement cannot be obtained.
3. One phase fluid influx into the formation is assumed.

The modification is carried out on porosity and Annular specific heat capacity under UBD condition as it is seen in the result.

Table 15: Modified and the Base Case Values of Porosity and Annular Specific Heat Capacity

Depth (m)	Porosity (frac)		Specific Heat Capacity of the annular fluid (J/kg C)		
	Base Case	Modified Case	Base Case	Modified Case	Modified Case + 10% S.C
0	0.30	0.30	281416.77	281416.77	309558.45
1000	0.30	0.18	281416.77	281421.44	309563.59
2000	0.30	0.11	281416.77	281424.27	309566.70
3000	0.30	0.07	281416.77	281425.99	309568.59
4000	0.30	0.04	281416.77	281427.03	309569.74
5000	0.30	0.02	281416.77	281427.67	309570.43
6000	0.30	0.01	281416.77	281428.05	309570.85

Table 16: Base Case and Modified Fluid Temperature Results of PET-1 Field, China

Depth(m)	$T_{p\,modified}$	$T_{a\,modified}$	$T_{p\,modified+10\%SC}$	$T_{a\,modified+10\%SC}$
0.000	37.000	64.872	37.000	68.529
1000.000	96.492	97.591	98.412	99.390
2000.000	110.524	111.398	110.746	111.501
3000.000	120.922	121.501	119.535	120.008
4000.000	126.492	126.680	123.792	123.905
5000.000	125.638	125.305	122.254	121.905
6000.000	116.239	115.212	113.299	112.360

Based on the extracted results presented in Table 15 and 16, it can be deduced from Figure 12 that the annular specific heat capacity increases with depth when the compaction factor is incorporated. The values change from the initial constant value of 281416 J/kg-C to 281428 J/kg-C at the bottom hole condition. When 10% Salt content effect is included in the analysis, the annular specific heat capacity changes to 309570 J/kg-C in the wellbore region.

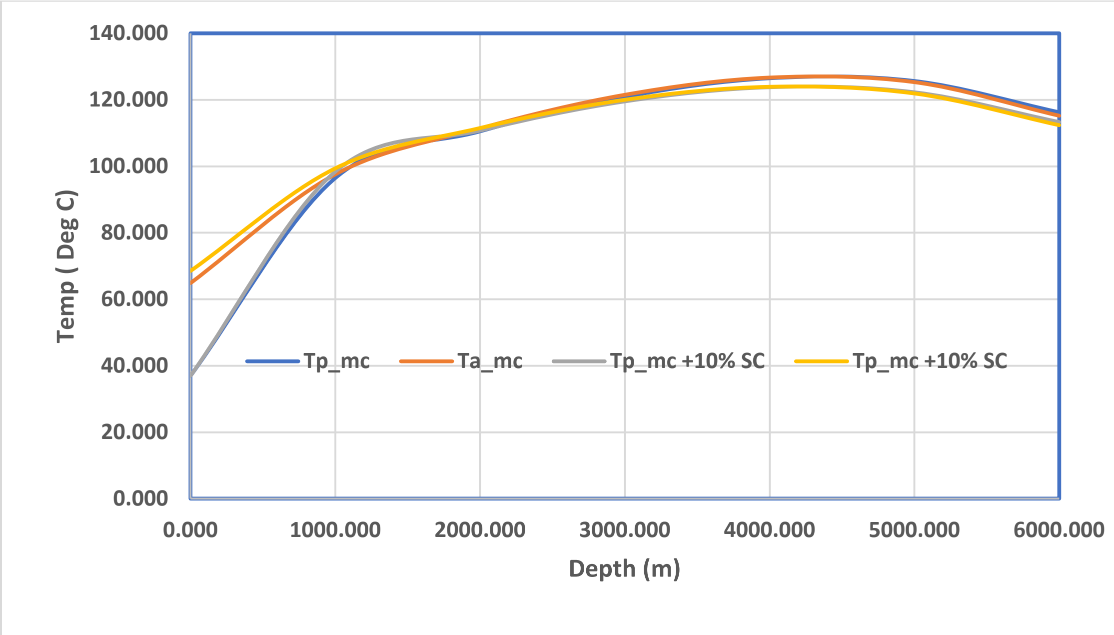

Figure 12: Base case versus Modified case result of PET-1 Field

These modified data are then used to predict the fluid temperature distribution in the field and the result is presented in Table 17. Further analysis is also performed on the annular fluid temperature predictions for both modified and base case scenarios and the result is compared with the measured data obtained from the field.

Table 17: Base and modified cases prediction results for Annular Fluid Temperature

Parameter	Measured Value (Deg C)	Model Value (Deg C)	Modified Value (Deg C)	Modified+ 10% SC Value (Deg C)
Reservoir Temp	155	NA	NA	NA
Bottom hole Annular Fluid Temp	112	106	115	112
Surface Annular Fluid Temp	67	56	65	68.5
Degree of variation for bottomhole annular temperature estimation		5%	3%	0%
Degree of Variation for surface annular temperature estimation		16%	3%	2%

From the result obtained in Table 17, the following underlisted observations can be made.

i. The selected mathematical model accurately predicted the bottom hole annular fluid temperature of the field with a 5% degree of variation.
ii. The selected mathematical model accurately predicted the surface annular fluid temperature of the field with a 16% degree of variation.
iii. The modified model without salt content accurately predicted the bottom hole annular fluid temperature of the field with 3% degree of variation.
iv. The modified model without salt content accurately predicted the surface annular fluid temperature of the field with a 3% degree of accuracy.
v. The modified model with salt content accurately predicted the bottom hole annular fluid temperature of the field with 0% degree of variation.
vi. The modified model with salt content accurately predicted the surface annular fluid temperature of the field with a 2% degree of accuracy.

From these inferences, it can be seen that the modification of the mathematical model yields an accurate prediction of the annular fluid temperature of the Geothermal field both in the wellbore and the surface conditions. This hereby helps in eliminating or minimizing any form of errors that may arise as a result of the mathematical prediction.

4. CONCLUSIONS

The following conclusions can be drawn from this study:

1. It is established that mathematical models can be effectively used to accurately predict fluid temperature profile in geothermal well under underbalanced and overbalanced drilling conditions
2. Several parameters such as porosity, circulation rate, the rate of penetration (ROP), the cement thermal conductivity, temperature drop across the bit, influx flowrate, and fluid density are identified as the influencing factors that govern the fluid temperature trend in geothermal well during drilling conditions. Out of all these parameters, circulation rate, influx rate, cement thermal conductivity and the temperature drop across the bit are the main parameters that are sensitive to the fluid temperature distribution in UBD and OBD Conditions.
3. The four identified main parameters can be tuned to model an accurate fluid temperature value.
4. The only parameter that distinguishes between the underbalanced and overbalanced fluid temperature estimate is the influx rate.
5. The sensitivity analysis result shows that the temperature profile in UBD and OBD is sensitive to all the four main parameters i.e. cement thermal conductivity, circulation rate, influx rate and temperature drop across the bit.
6. The error function analysis conducted on the four main parameters also shows that the influx rate is the most sensitive parameter in underbalanced drilling section as it is shown in its error pattern.
7. The modification of Liqun Shan model with compaction and salt concentration effects accurately predicted the temperature profile of the PET-1 field with an average error of 2% against 5% error value attributed to the base model.
8. Finally, I hereby conclude that this analytical model should be employed in the Geothermal drilling industry to reduce drilling complication and thus cost of operations.

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