A STUDY OF DOWNHOLE CIRCULATING TEMPERATURE PREDICTION MODEL ANALYSIS AND ENHANCEMENT OF THE GEOTHERMAL DRILLING PRACTICES AND PERFORMANCE IN PUNA GEOTHERMAL VENTURE, HI

A Dissertation

by

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Submitted to the Office of Graduate and Professional Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

DOCTOR OF PHILOSOPHY

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August 2020

Major Subject: Petroleum Engineering

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ABSTRACT

Drilling complexity has been increasing over the years. With deeper targets, the oil and gas industry is reaching record high downhole temperatures. For these high temperature regions, a special and a careful consideration is needed during the well planning to choose proper drilling tools and fluids. This research investigates and improves the downhole temperature model prediction in a commercial software by reviewing the calculation steps and analyzing the source equations. In addition, a full analysis of the model's inputs is performed. Moreover, the research coupled the model's prediction with actual high temperature data from the Austin Chalk to test the model's accuracy. The study also provides a detailed sensitivity analysis for different drilling parameters and their effects on the downhole temperature with the model and the actual data. These parameters include the flow rate, type of drilling fluids, pipe rotation (RPM), and others.

An improved temperature model is developed and a new workflow in the commercial software is introduced based on this research. The new model eliminates the overestimation spikes in the downhole temperature profile by calculating the downhole torque of the motor based on the differential pressure. Also, the improved version utilizes the measured downhole torque data.

Geothermal drilling has increased in the recent years with the renewable energy initiatives. Geothermal plants provide more than 6% of California's electricity. A large sum from the development budget is consumed by the drilling. This research reviews the drilling activities and operations in Puna Geothermal Venture in Hawaii for more than twenty years. Six challenges were identified and analyzed. These challenges include: lost circulation, stuck pipe, cementing, low Rate of Penetration (ROP), logistics issues, and safety concerns. Then, the drilling performance of the field is compared with several oil and gas fields as well as geothermal drilling activities around the globe. The result shows that the drilling in Puna Venture can be enhanced significantly. A set of recommendations to improve the performance is presented as organizational and workflow changes, analysis and elimination of Non Productive Time (NPT), and engineering redesigns.

DEDICATION

To My Family:

My beloved Parents Reyad and Ekhlas.

My gorgeous wife Asma.

My adorable children Deem and Saud.

ACKNOWLEDGMENTS

First and foremost I would like to thank Allah who gave me the strength and power to continue this journey to the end. There were many obstacles in the research path that he eased on me and provided me with guidance to overcome.

I would like also to acknowledge my committee chair Dr. Samuel Noynaert who joined me in this journey and showed me the way of practical drilling projects and research. I am grateful for the tremendous time he spent answering my questions and concerns. I am also thankful for his guidance in this research. His way of supervising made this journey joyful.

Dr. Jerome Schubert who taught me most of my drilling classes during my studies. His wide range expertise in the drilling aspects is a treasure. Although his time was tight, and he is preparing for a relaxing retirement, he agreed to be a valuable committee member. His remarks are always interesting and brings a lot to the discussion. In addition, I would like to acknowledge Dr. Eduardo Gildin, his focus on the purpose and goals of the research project made the mission statement crystal clear. He also provided valuable input and remarks to this dissertation. I must also thank Dr. Mahmoud El-Halwagi who as an outside committee member from the chemical engineering department provided a fresh look into the research. I appreciate his valuable inputs.

Fred Dupriest, the professor of practice at the Petroleum Engineering Department, the PETE 639 course changed my way of looking at drilling engineering forever. Thank you for being there whenever I wanted to discuss an idea that crossed my mind and thanks for sharing your experience with me. I must also thank Eric Cogburn, the Technology Development Manager in K+M Technology Group. He played an essential role in the ERA communications.

Finally, I would like to thank Saudi Aramco who believed in me and sponsored my studies since my first year of college.

CONTRIBUTORS AND FUNDING SOURCES

Contributors

This work was supported by a dissertation committee consisting of Professor Sam Noynaert as an advisor, Dr. Jerome Schubert, Dr. Eduardo Gildin of the Department of Petroleum Engineering, and Dr. Mahmoud El-Halwagi of the Department of Chemical Engineering.

The data analyzed for Chapter 1 was provided by Navidad Operating, and the Extended Reach Architect (ERA) from K+M Technology Group was used in the modeling.

The second project, "Enhancement of the Geothermal Drilling Practices and Performance in Puna Geothermal Venture, HI" is part of a DOE project with FOA Number: DE-FOA-0001880. Ormat Technologies USA shared the data for the Puna Geothermal Venture.

Funding Sources

This graduate study was supported by a sponsorship from Saudi Arabian Oil Company (ARAMCO) for the student's entire years of the PhD degree.

NOMENCLATURE

BHA	Bottom Hole Assembly
BP	Bridge Plug
bph	barrel per hour
BOP	Blow Out Preventer
C_1, C_2	Integration constants defined by Eq. 1.5 and Eq. 1.6
C_P	Heat capacity of the drilling mud
CICB	Cast Iron Cement Plug
DHRPM	Downhole Rotation Per Minuit
DH Torque	DownHole Torque
DP	Drill Pipe
DC	Drill Collar
D_h	Hole diameter
D_i	Pipe inner flow diameter
D_o	Pipe Outer Diameter
$D_{wb.max}$	Maximum wellbore diameter
EDR	Electronic Drilling Recorder
ERA	Extended Reach Architect
ft.	Feet
FIT	Formation Integrity Test
g	Geothermal gradient

h_a	Forced convection coefficient in annulus
h_o	Heat- transfer coefficient near the wellbore
HTF	Heat Transfer Factor, calibration input
h_p	Forced convection coefficient in pipe
Hz	Hertz
I_r	Calibration Wellbore Insulation
$Kwb.item$	Wellbore item thermal conductivity
$Kformation$	formation thermal conductivity
k	Fluid thermal conductivity
lb/ft	Pound per foot
LCM	Loss Circulation Material
LOT	Leak of Test
MD	Measured Depth
MSE	Mechanical Specific Energy
MWD	Measurements While Drilling
NFS	National Science Foundation
NPT	Non Productive Time
N_u	Nusselt number , Ratio of convective to conductive heat transfer across boundary
$N_{ux.turbulent}$	Nusselt number for turbulent and transitional flow
OBM	Oil Based Mud
PDC	Polycrystalline Diamond Compact
PGV	Puna Geothermal Venture
POOH	Pull Out of Hole

ppg	Pound per gallon
q	Flow rate
q_a	Flow rate in annulus
q_p	Flow rate in drill pipe
Q_a	Heat sources in the annulus
Q_p	Heat sources in the drill string
$Q_{a.hyd}$	Heat from friction pressure loss in annulus
Q_{trq}	Heat from the friction torque
Q_{bit}	Total heat from the bit
$Q_{bit.hyd}$	Heat from hydraulic of the bit
$Q_{bit.mech}$	Heat from mechanical sources in the bit
Q_{BHA}	Heat from the BHA
r_1, r_2	Exponent coefficient defined by Eq. 1.4
R_F	Thermal resistance of formation
r_i	Inner radius of drillstring
RIH	Run In Hole
ROP	Rate of Penetration
RPM	Revolution Per Minutes
r_o	Outer radius of drillstring
r_w	Radius of the wellbore
R_{WB}	Linear thermal resistance of Wellbore
t	Time
T_a	Temperature of the drilling fluid in the annulus

T_f	Formation's temperature
T_p	Temperature of the drilling fluid in the annulus
TOC	Top of Cement
Tor	Torque
TD	Total Depth
U	Overall heat transfer coefficient across drill string
WOB	Weight On Bit
WOC	Wait On Cement
z	Depth
γ_w	Wall shear rate
ΔP_{af}	Change in annular friction
μ_w	Equivalent Dynamic Viscosity at wall
ρ	Fluid density
τ_w	Wall shear stress

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Study 1

Drilling complexity has been increasing over the years. With deeper targets and longer laterals, drilling operations need more planning than ever. When the first commercial well was drilled in 1859 in Pennsylvania, it was only 69 ft deep and was drilled by a salt well driller (Dickey, 1959). The first record of a horizontal well is dated back to 1929 in Texas (JPT, 2006). During the 1980s horizontal drilling flourished in the Bakken Shale and a shift toward horizontal wells started. The record for the longest horizontal well is 40,320 ft. and was drilled in Qatar in 2008 (Denney, 2009).

Drilling deeper and longer wells requires engineering and planning before the spud and during the drilling operations. One of the parameters that influences the drilling is the downhole circulating temperature. Knowing the circulating temperature profile has many benefits for the operator. First, it helps in preventing tool failures because of reaching the tool's temperature limit. Second, it helps in selecting the proper mud that would fit the downhole conditions especially because drilling fluid properties can deteriorate with the high temperature (Chang et al., 2018). Third, it gives an indication about the characteristics of the rocks in the formation. (Holmes and Swift, 1970)

The objective of this project is to analyze the temperature prediction model using Extended Reach Architect (ERA) software and perform a sensitivity analysis to study the effect of different parameters on the circulating temperature. These parameters include flow rate, pipe Rotation Per Minuit(RPM) , hole diameter, and friction factor.

This dissertation contains two studies, the first one is titled " A Study of Downhole Circulating Temperature Prediction Model Analysis"

Study 2

Drilling takes a large sum of the energy company's budget. This applies for petroleum and geothermal companies. Renting the rig can vary between $ 20K per day for an inland rig in North America (Daleel, 2019) to $ 250K per day for a drillship (IHS Markit, 2019). The geothermal rigs prices tend to be toward low end. The drilling operations in geothermal development can account for more than 50 % of the total project cost. (Tester et al., 2006). Thus, saving time during the drilling while maintaining a safe operation can affect the budget of the company in a positive way. It has been reported by Visser et al. (2014) that six major issues were identified as problems in the geothermal's drilling operations. These problems are related to lost circulation, cementing, efficient and consistent drilling programs, rate of penetration (ROP), and rig equipment selection. A holistic approach to analyzing the data of the drilling operations and finding areas to enhance the performance is essential for every operator.

The second study is titled "Enhancement of the Geothermal Drilling Practices and Performance in Puna Geothermal Venture, HI"

2. A STUDY OF DOWNHOLE CIRCULATING TEMPERATURE PREDICTION MODEL ANALYSIS

2.1 Introduction

Drilling complexity has been increasing over the years. With deeper targets and longer laterals, drilling operations need more planning than ever. When the first commercial well was drilled in 1859 in Pennsylvania, it was only 69 ft deep and was drilled by a salt well driller (Dickey, 1959). The first record of a horizontal well is dated back to 1929 in Texas (JPT, 2006). During the 1980s horizontal drilling flourished in the Bakken Shale and a shift toward horizontal wells started. The record for the longest horizontal well is 40,320 ft. and was drilled in Qatar in 2008 (Denney, 2009).

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2.2 Literature Review

Analytical Models

The interest in the downhole circulation temperature started early in the 1940's. Farris (1941) tried to resemble the downhole condition for his study of the performance of cementing at various depths. Edwardson et al. (1962) developed the first analytical solution to compute changes in temperature that results from the disturbance of the circulation of mud during the drilling operation. The solution was based on the differential equation of heat conduction. In order to develop the model, a historical data of the drilling operation was required to plot the graphs. Also, in 1962 Ramey developed an approximation to estimate the temperature of fluid as a function of time and depth. He assumed a steady-state heat transfer in the wellbore and an unsteady radial flow heat transfer in earth. These two papers have paved the road for the study of fluid circulation models.

Holmes and Swift (1970) developed an analytical solution by solving the steady-state equation that describes the heat transfer between the fluids in the annulus and in the drill pipe. The solution can calculate the temperature as a function of well depth. Arnold (1990) compared the different models and developed an analytical solution for the recirculation of fluid in the wellbore.

Kabir et al. (1996) presented an analytical model for the flowing temperature as a function of circulation time and well depth. They solved an energy balance between the formation and the fluid in the drill pipe and annulus. They also developed a new solution for the reversal flow in addition to the forward flow. Kumar and Samuel (2013) studied the influence of pipe friction on the downhole temperature of the drilling fluid. They studied two sources of friction. First, the friction generated by the contact between the pipe and the wellbore is calculated as the torque acting on the drillstring. Second, the frictional pressure losses in the drill pipe, across the bit, and in the annulus. Two cases were presented in the paper for validation, a deviated well and a horizontal well. Al Saedi et al. (2018) studied the effect of changing the boundary conditions for the solution of the energy balance and presented two new analytical solutions. Most of the previous studies solved the flow problem by using the first kind of boundary condition or the Dirichlet condition. The study tested two more boundary conditions which are the second kind, or Neumann condition, and the third kind, or Robin condition. The results were not definite in favor of the new models. Al Saedi et al. (2019) compared the frictional energy, the rotational kinetic , and their effect on the downhole temperature. The study presented a new analytical solution for the rotational kinetic energy.

Numerical Models

Raymond (1969) developed the first numerical model to predict the downhole temperature. He presented charts to predict the bottom hole temperature based on the simulation on 70 wells. The parameters that you need to use the charts are the mud weight, outlet temperature, circulating rate, and depth. Keller et al. (1973) presented a numerical transient solution to estimate the circulating mud temperature. They argued that the steady state solutions were good but the transient solution is giving a better match with the temperature logs. They also accounted for multiple casing strings in the design.

Marshall and Bentsen (1982) extended the work of Keller et al. (1973) with improved solution procedures that make the model more efficient to enable the use of it in the well site. They also included a parametric sensitivity analysis of drilling fluid heat capacity, fluid density, flow rate, and other parameters as well. Trichel and Fabian (2011) presented the results of a temperature simulation for a high temperature horizontal well that resulted in a model using drilling system energy balance. They included the contribution of the hydraulic and the mechanical sources to the heat generation, as well as the torque and drag. The study contains a sensitivity analysis for various drilling parameters and an optimization guideline for the operation in horizontal wells.

Chang et al. (2018) developed an integrated numerical model that predicts the temperature distribution of a horizontal well. They accounted for the drill pipe rotation, hydraulics, and mechanical friction in their model. They concluded that the mechanical friction had a great influence on the downhole temperature.

2.3 Research Objective

My research objective is to have a more well-rounded and robust prediction to the profile of the downhole circulating temperate. The research will be based on the Kumar and Samuel (2013) model and performs the analysis of the Trichel and Fabian (2011) methodology with clear steps. This combination will lead to a better understanding of the bottom hole circulating temperature. The research will be coupled with a case study of MWD and vibration logs for a horizontal well in the Austin Chalks to test the analysis.

2.4 Research Methodology

The research methodology is to start by designing the well in Extended Reach Architect (ERA) software and test the temperature prediction's model that it presents. Then, the field data will be imported for each run in the intermediate and the production holes. The changes in the model as more data is fed to it will be analyzed. Then, different parameters of the model will be calibrated to get a better match. Finally,a sensitivity analysis of various drilling parameters will be performed.

2.5 Kumar and Samuel (2013) Temperature Prediction Model

In order to solve the energy equilibrium's problem, a set of assumptions must be made:

- The temperature at the borehole is constant and the temperature gradient is linear.
- Fluid properties are independent of temperature.
- Heat generation within the fluid by viscous dissipation may be neglected.
- Heat transfer within the drilling fluid is by axial convection.
- The radial temperature gradient within the drilling fluid can be neglected.

The model starts with an energy equilibrium within the system in both the drill pipe and the annulus. Equation 2.1 describes the heat flow inside the drill string and can be written as:

$$\rho q C_p \frac{\partial t_p}{\partial z} + 2\pi r_p U(T_p - T_a) + \rho c_p \pi r_i^2 \frac{\partial t_p}{\partial t} = Q_p \tag{2.1}$$

In the left hand side of the equation, the first term represents the vertical convective heat transfer within the fluid. The second term is the radial convective heat transfer in the system and the third term is the accumulation of energy within the drill string. These three terms are equal to the total of all the energy sources in the drill pipe. The energy equilibrium in the annulus can be written as:

$$\rho q C_p \frac{\partial t_a}{\partial z} + 2\pi r_p U(T_p - T_a) + 2\pi r_w h_o(T_f - T_a) + Q_a = \rho c_p \pi (r_w^2 - r_o^2)\frac{\partial t_a}{\partial t} \quad (2.2)$$

The equation's left hand side have four terms. The first term is the vertical convective heat transfer within drilling fluid. The second one is the radial convective heat transfer between the drilling fluid and the drill pipe wall. The third term represents the radial convection between the drilling fluid and the formation. Then, Q_a is the sum of the heat sources terms in the annulus. The right hand side represents the accumulated heat energy in the annulus during a period of time.

The heat transfer is assumed to be steady state. This assumption will simplify the equations and the equilibrium will be independent of time. The final set of equations for Kumar and Samuel (2013) to calculate the temperature are: Drill pipe's temperature as a function of depth is given by: Eq.2.3

$$T_p = C_1 e^{r_1 z} + C_2 e^{r_2 z} + gz + T_s + \frac{(Q_a + Q_p)}{2\pi r_w h_o} + \frac{[Q_p - (\rho q C_p)g]}{2\pi r_p U} \quad (2.3)$$

Exponent coefficients are given by Eq. 2.4

$$r_1, r_2 = \frac{(2\pi r_w h_o) \pm \sqrt{(2\pi r_w h_o)^2 + 4(2\pi r_p U)(2\pi r_w h_o)}}{2\rho q C_p} \quad (2.4)$$

The differential equation is solved using the initial and the boundary conditionsand the constant C_1 and C_2 are calculated:

$T_p = T_{pi}$ at $z = 0$ and $T_p = T_a$ at $z = TD$

At z=z_1 ; $T_{p(zone1)}$ =$T_{p(zone2)}$; $T_{a(zone1)}$ = $T_{a(zone2)}$

At z=z_2 ; $T_{p(zone2)}$ =$T_{p(zone3)}$; $T_{a(zone2)}$ = $T_{a(zone3)}$

$$C_1 = \frac{[(T_{pi} - T_s - \frac{Q_p}{2\pi r_p U} - \frac{Q_a + Q_p}{2\pi r_w h_o} + Ag)Ar_2 e^{r_2 L} - \frac{Q_p}{2\pi r_p U} + Ag]}{Ar_2 e^{r_2 L} - Ar_1 e^{r_1 L}} \tag{2.5}$$

$$A = \frac{\rho q C_p}{2\pi r_p U} \tag{2.6}$$

$$C_2 = T_{pi} - T_s - \frac{Q_p}{2\pi r_p U} - \frac{Q_a + Q_p}{2\pi r_w h_o} + Ag - C_1 \tag{2.7}$$

2.6 Designing the Well in ERA

The commercial software that will be used is Extended Reach Architect (ERA) and was developed by K+M Technology Group. In order to build the model, several components of the model need to be built first. The first component to build is the drilling rig since it is the machine that will be used in the drilling and its components are responsible to carry the drilling operations. The hoist limit, pressure limit, rig pumps, cement pumps, and the top drive models are needed to be built in the system as in figure 2.1.

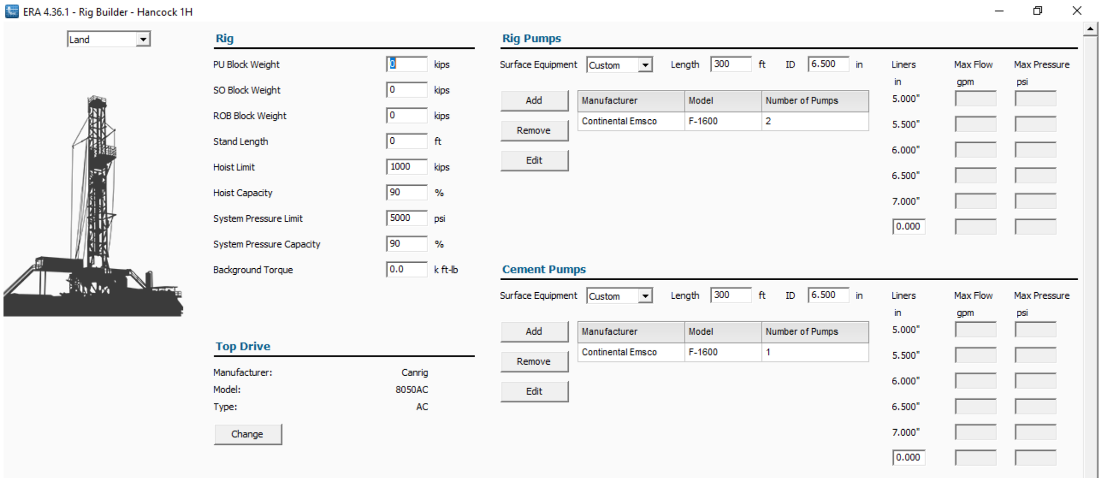


Figure 2.1: Rig Specification Window in ERA

The second component is the wellbore design, all the hole diameters and casing points have to be specified along with the casing grades and the connections specifications as in figure 2.2. The well in analysis had a 20 inch surface hole to 5125 ft. The hole was cased with J-55 45.5 lb/ft 10.75 inch casing. The well had one intermediate 9.875 inch hole to 13435 ft. that was cased with 33.7 lb/ft P-110 7.625 inch casing. The production hole was drilled with 6.5 inch bit to 20319 ft. and cased with a combination of 5 and 5.5 inch P-110 casings.

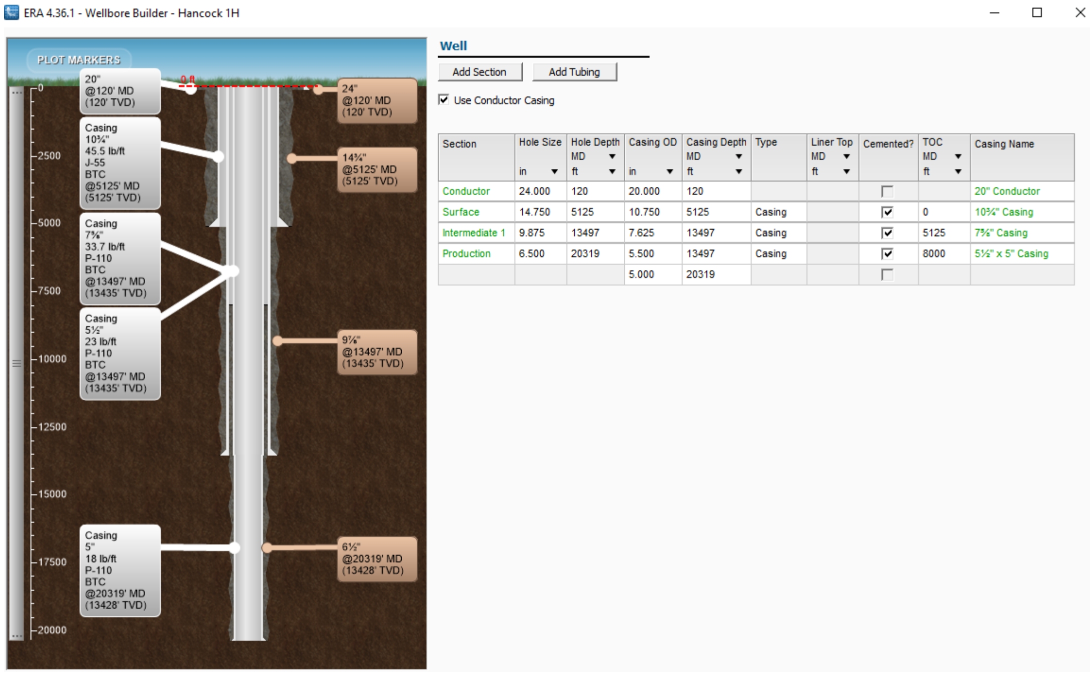


Figure 2.2: Wellbore Design Window

The third component of the model is the path of the well. Either a plan for the well path or surveys (if we have the actual data) are required to calculate the dog leg severity and to be used in the torque and drag calculations. The component needs the measured depth (MD) in ft, inclination and azimuth in degree. Figure 2.3 shows the window for the well path.

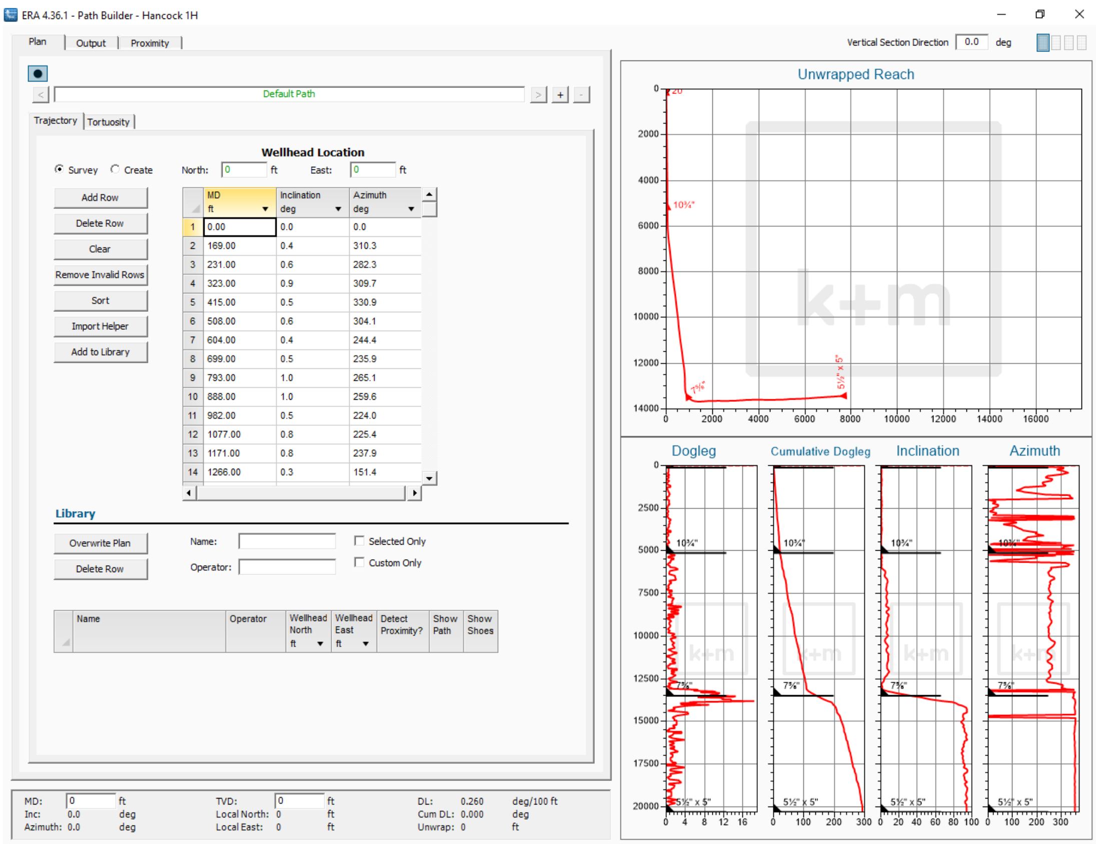


Figure 2.3: Wellbore Path Window

The fourth component to build is the Bottom Hole Assembly (BHA) assembly for all the hole sections. Each BHA assembly has a unique set up and has a great impact in the friction pressure losses and the torque and drag calculations. Figure 2.4 shows the window to build the BHA and the drill pipe specifications. For example, in the 6.5 inch hole the BHA had Wenzel 5:6 mud motor, Halliburton Gamma Ray and Pressure While Drilling sub along with Halliburton Telemetry followed by 4.5 inch drillpipe to surface.

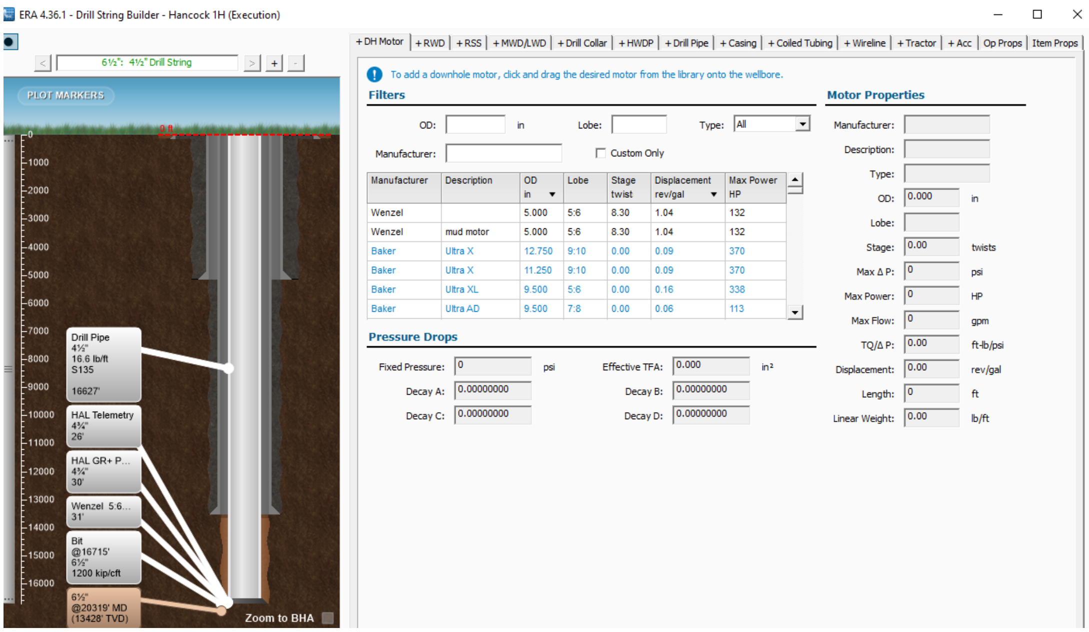
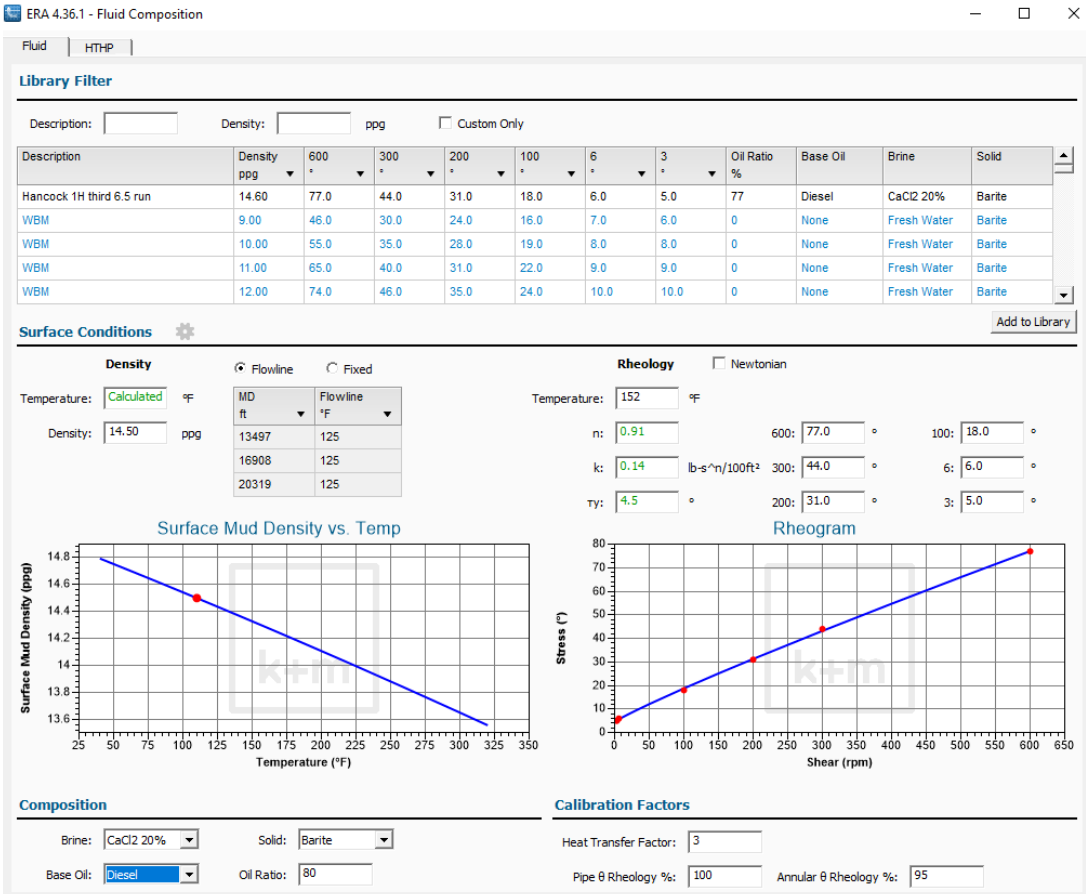


Figure 2.4: Drill String Builder Window

The last model component is to add the fluid rheology that is used in the operation. The composition of the drilling mud should be specified and the power law is used to plot the stress vs shear plot for the rheology. The well had a 14.5 ppg Oil Based Mud (OBM) system while drilling the production hole. Figure 2.5 shows the rheology window.



Description	Density ppg	600 °	300 °	200 °	100 °	6 °	3 °	Oil Ratio %	Base Oil	Brine	Solid
Hancock 1H third 6.5 run	14.60	77.0	44.0	31.0	18.0	6.0	5.0	77	Diesel	CaCl2 20%	Barite
WBM	9.00	46.0	30.0	24.0	16.0	7.0	6.0	0	None	Fresh Water	Barite
WBM	10.00	55.0	35.0	28.0	19.0	8.0	8.0	0	None	Fresh Water	Barite
WBM	11.00	65.0	40.0	31.0	22.0	9.0	9.0	0	None	Fresh Water	Barite
WBM	12.00	74.0	46.0	35.0	24.0	10.0	10.0	0	None	Fresh Water	Barite

MD ft	Flowline °F
13497	125
16908	125
20319	125

Figure 2.5: Rheology Conditions Window

ERA accounts for the rheology changes in the Hight Temperature High Pressure (HTHP) conditions and plot the operational envelop as in Figure 2.6. The properties of the drilling fluid will change with the higher temperature an pressure and this effect the calculations of the downhole temperature.

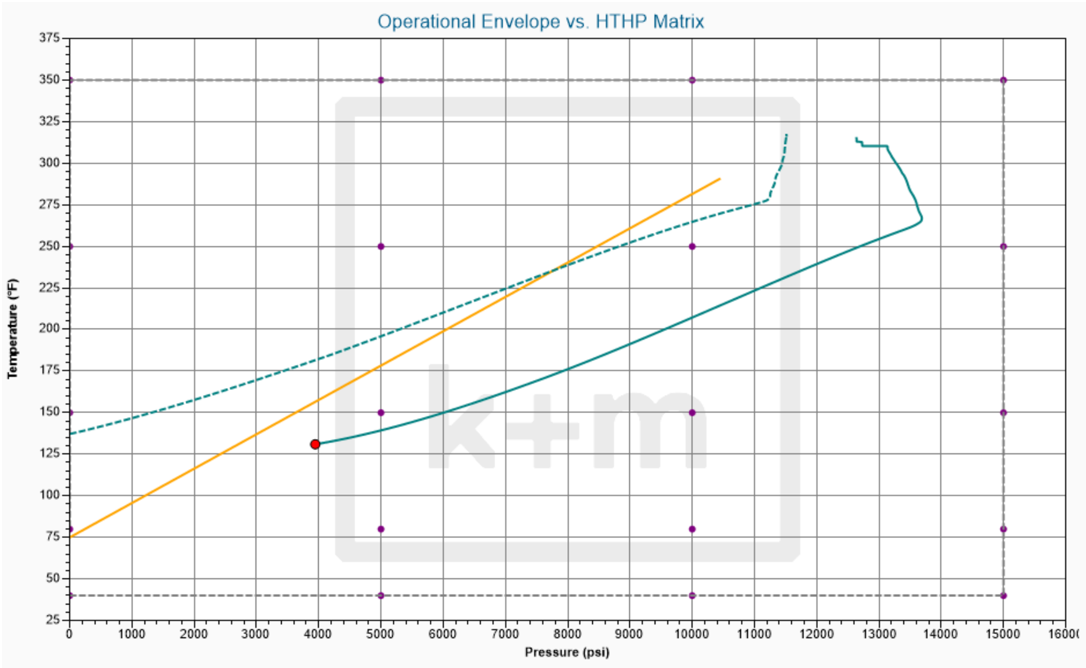


Figure 2.6: Operational envelop and the HTHP matrix. The yellow loine is the static downhole temperature. The dashed line is the annulus operational parameter and the solid blue line is for the pipe.

The previous five components were the foundation for the well design in ERA. After finishing them, the software will be able to calculate many drilling parameters and generate many plots to analyze the drilling operations. These plots include tension, torque, and down hole temperature which we need in our analysis. Nevertheless, more details and calibration must be performed for each hole section for better estimation.

2.6.1 Temperature Model Calculations in ERA

The downhole temperature's calculations that are done in the back end of ERA is described in this section. The heat transfer coefficients were derived from Nusselt's number for both turbulent and laminar flow.

Heat Transfer Coefficient

First, the equivalent dynamic viscosity at the wall is calculated μ_w

$$\mu_w = 0.4789 \frac{\tau_w}{\gamma_w} \tag{2.8}$$

Then, Prandtl number P_r by :

$$P_r = \frac{C_p \mu_w}{k} \tag{2.9}$$

After that, Generalized Reynolds's Number R_{eG} is calculated by:

$$R_{eG} = \frac{\rho u^{2-n'} d_i^{n'}}{8^{n'-1} K'} \tag{2.10}$$

Then, the local average forced convection coefficient

$$N_{ux\,turbulent} = 0.0152\, R_{eG}^{0.845}\, P_r^{\frac{1}{3}} \tag{2.11}$$

Then, the calculation of N_{ua} and N_{up}. Where $N_{ua\,laminar}$ and $N_{up\,laminar}$ are equal to 4.12 and 3.66 respectively.

$$N_{ua} = 4.12 FR_a + (1 - FR_a) N_{ua\,turbulent} \tag{2.12}$$

FR is the flow regime and it is equal to 0 if the flow is turbulent and 1 if the flow is laminar.

$$N_{up} = 3.66 FR_p + (1 - FR_p) N_{up\,turbulent} \tag{2.13}$$

After that, the calculation of the forced convection coefficient in annulus and in pipe h_a and h_p:

$$h_a = HTF \frac{N_{ua}k}{D_h - D_o} \tag{2.14}$$

$$h_p = \frac{Nupk}{D_i} \tag{2.15}$$

R_{WB} which is the thermal resistance of each wellbore item is computed next and applicable items are summed:

$$R_{WB} = \sum \frac{ln \frac{D_O}{D_i}}{2K_{wb.item}} \tag{2.16}$$

Then, the radial heat transfer coefficients at each depth is calculated:

$$R_F = \frac{ln(1 + D_h \frac{I_r}{D_{wb.max}})}{2k_{formation}} \tag{2.17}$$

$$U = \frac{12\pi}{39.37 \times 1.8} (\frac{1}{h_p D_i} + \frac{ln \frac{D_o}{D_i}}{2k_{string}} + \frac{1}{h_a D_o})^{-1} \tag{2.18}$$

$$h_o = \frac{12\pi}{39.37 \times 1.8} (R_{WB} + R_F + \frac{1}{h_a D_h})^{-1} \tag{2.19}$$

Heat Generation

Heat sources can be divided into two parts. The heat sources in the annulus Q_a and the heat sources in the drill string Q_p. The following set of equations shows the components of each:

Heat sources in the annulus are:

$$Q_a = Q_{a_hyd} + Q_{trq} + Q_{bit} \tag{2.20}$$

$$Q_{a.hyd} = |0.435 \Delta P_{af} q_p| \tag{2.21}$$

$$Q_{trq} = |0.00226 \tau_f 2\pi\omega| \tag{2.22}$$

$$Q_{bit} = Q_{bit.hyd} + Q_{bit.mech} \tag{2.23}$$

$$Q_{bit.hyd} = |0.435 \Delta P_{bit} q_{bit}| \tag{2.24}$$

$$Q_{bit.mech} = 0.0226(1-\epsilon) WOB\ ROP\ + \tau_{bit} 2\pi\omega \tag{2.25}$$

For the drill string the heat generation is calculated by:

$$Q_p = Q_{p.hyd} + Q_{BHA} \tag{2.26}$$

$$Q_{p.hyd} = |0.435 \Delta P_{pf} q_p| \tag{2.27}$$

$$Q_{BHA} = |0.435 \Delta P_{BHA} q_p| \tag{2.28}$$

ERA and Its Calculations

ERA is an excellent tool for analyzing the drilling operations and to visualize the different parameters and their effects on the operation. In this analysis, there is a close look to the back end calculations with a goal to improve the model. It is easy for the user to use the program and generate plots. However, the real challenge is to follow the calculation steps and give feed back to the developer in order have a better model. In the following section, the usage of the ERA will be explained.

2.7 Downhole Temperature Profile

ERA has two modes to work with. The first mode is the modeling mode where you can input your design and estimate several drilling parameters before drilling the well. The modeling mode allows the user to test different scenarios and perform sensitive analysis for different drilling parameters. The second mode is the execution mode which is used during the drilling operation with actual data as an input.

Modeling Mode

The focus of this research is on the temperature profile for the well's production section. After the building of all the components, the model is ready to be used to estimate the circulation temperature. The operational parameters of WOB, ROP, RPM, flow rate and mud weight are needed to initiate the first model and can be edited. Figure 2.7 is one of the early runs that was generated. The yellow line in the graph is the temperature gradient of the well and the solid blue line is the downhole circulating temperature profile in the driller view at the Total Depth (TD), which is 20319 ft. The model is estimating the temperature to be 314 °F.

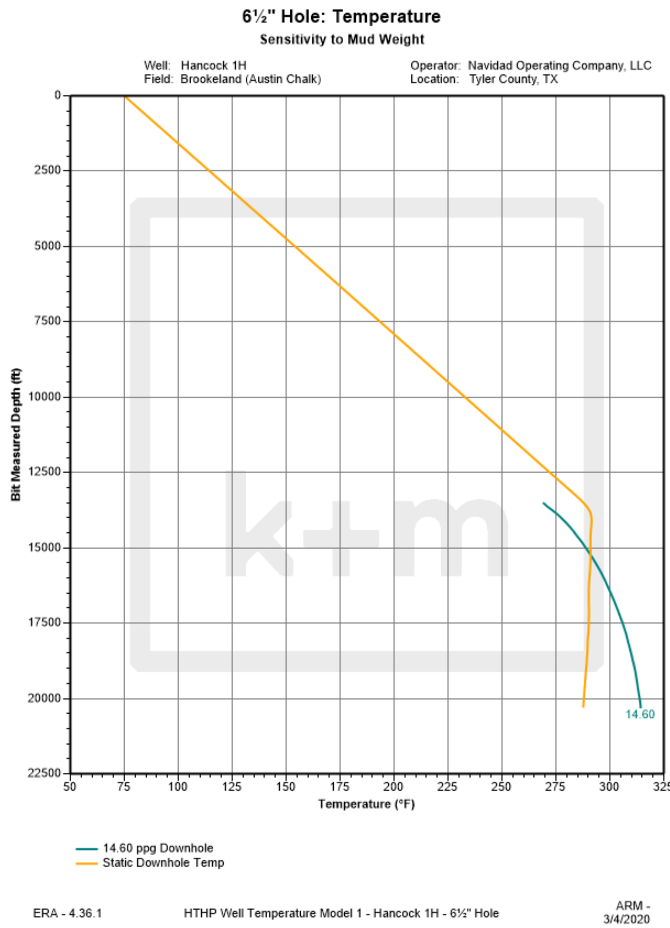


Figure 2.7: This is the temperature profile for the 6.5 inch hole (Model). The blue line is the estimated temperature for a given mud weight of 14.6 ppg

The modeling mode should be used before starting the drilling operation and is used to predict the downhole temperature. The model will help in choosing the proper equipment that can withstand high temperature. Also, it will guide in the drilling fluid choices. This model assumes that all drilling parameters such as WOB, RPM, and flow rate are constant throughout the drilling operation. However, this assumption is not accurate and shall be revised in the next section.

Execution Mode With Torque and Drag Method

In order to refine the model and to have a better understanding, time data for the actual drilling operation was imported to the software. The data includes many parameters that are summarized in Table 2.1

Parameter	Unit	Parameter	Unit
Depth	ft	Flow Rate (q)	GPM
Hook Load	Klbs	Differential Pressure	psi
ROP	ft/hr	DHWOB	Kips
Surface RPM	rpm	DH Temp	F
DHRPM	rpm	Stand Pipe Pressure (SPP)	psi
Surface Torque	lb-ft	Bit MSE	psi
DH Torque	lb-ft	Time	UTC

Table 2.1: The Imported Drilling Parameters for Time Data From the WellData database.

The First step was to export the data from NOV welldata base as in Figure 2.8 and then encode it into ASCII file to be used in ERA.

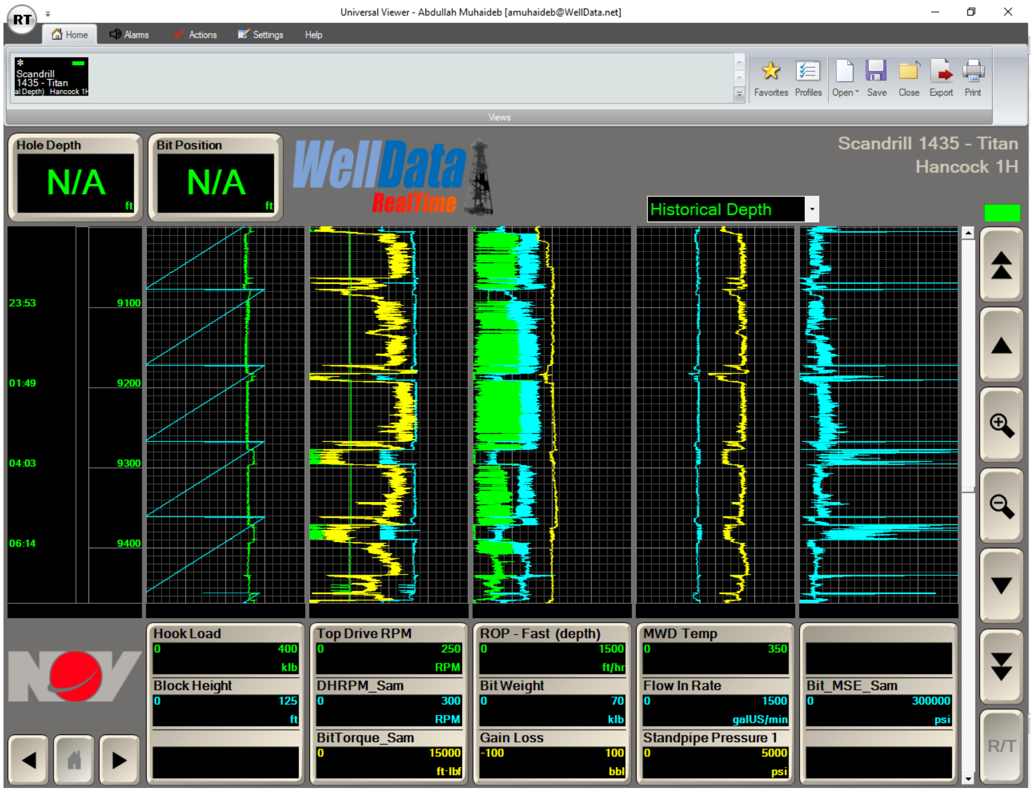


Figure 2.8: Snapshot of NOV WellData Software

The well had Electronic Drilling Recorder (EDR) data from August 15 2019 to October 15 2019. The data was recorded at a rate of 0.1 Hz using MWD in the 6.5 inch production section. The well had a total of 4 runs in the intermediate section and 3 runs for the production section. All the sub operations, which include tripping in the hole, drilling, and tripping out of the hole were timed and synchronized with the time data in the ERA software for better calculation as in Figures 2.9 and 2.10.

The time based data was converted to a depth based data for ERA to perform the calculations. It is important to note here that when there are several time data points for the same depth, ERA is taking the average for the data point. This might be a weak

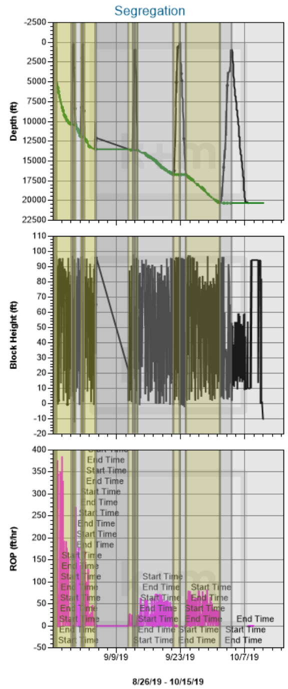


Figure 2.9: Time Data Segregation for Each Run. It has to be timed and synchronized.

point in the importing process. There are several ways of taking the average and a good statistics modeling will be helpful to figure out the best data point to be represented for each depth.

Subop

Subop	Start Time UTC mm/dd/yyyy hh:mm:ss	End Time UTC mm/dd/yyyy hh:mm:ss	Distance ft	Duration hh:mm:ss	Executed Subop
Drilling	09/12/2019 00:00:00	09/13/2019 00:31:15	148	24:31:10	Production → 6½" Hole Run 1 → ExeDrill
Tripping Out	09/13/2019 00:31:15	09/13/2019 08:32:30	12739	08:01:10	Production → 6½" Hole Run 1 → ExeDrillTripOut
Tripping In	09/13/2019 14:02:30	09/14/2019 00:21:15	12720	10:18:40	Production → 6½" Hole Run 2 → ExeDrillTripIn
Drilling	09/14/2019 00:21:15	09/21/2019 20:00:00	3074	187:38:40	Production → 6½" Hole Run 2 → ExeDrill
Tripping Out	09/21/2019 20:00:00	09/23/2019 06:04:51	16705	34:04:30	Production → 6½" Hole Run 2 → ExeDrillTripOut
Tripping In	09/23/2019 06:04:51	09/24/2019 13:54:36	16624	31:49:30	Production → 6½" Hole Run 3 → ExeDrillTripIn
Drilling	09/24/2019 13:54:36	10/01/2019 23:36:43	3659	177:41:30	Production → 6½" Hole Run 3 → ExeDrill
Tripping Out	10/02/2019 02:30:20	10/04/2019 13:49:27	19443	59:18:30	Production → 6½" Hole Run 3 → ExeDrillTripOut
Tripping In	08/26/2019 14:00:27	08/26/2019 19:07:32	4919	05:07:00	Intermediate 1 → 9⅞" Hole Run 1 → ExeDrillTrip
Drilling	08/26/2019 19:11:32	08/27/2019 00:18:47	147	05:06:30	Intermediate 1 → 9⅞" Hole Run 1 → ExeDrill
Tripping Out	08/27/2019 00:18:47	08/27/2019 03:28:06	5051	03:09:00	Intermediate 1 → 9⅞" Hole Run 1 → ExeDrillTrip
Tripping In	08/27/2019 03:28:06	08/27/2019 07:16:44	4992	03:48:00	Intermediate 1 → 9⅞" Hole Run 2 → ExeDrillTrip
Drilling	08/27/2019 07:16:44	08/30/2019 14:02:10	5289	78:45:00	Intermediate 1 → 9⅞" Hole Run 2 → ExeDrill
Tripping Out	08/30/2019 14:15:42	08/30/2019 20:07:17	9883	05:51:00	Intermediate 1 → 9⅞" Hole Run 2 → ExeDrillTrip
Tripping In	08/31/2019 01:44:56	08/31/2019 10:14:17	10008	08:29:00	Intermediate 1 → 9⅞" Hole Run 3 → ExeDrillTrip
Drilling	08/31/2019 10:14:17	09/01/2019 17:15:55	1721	31:01:00	Intermediate 1 → 9⅞" Hole Run 3 → ExeDrill
Tripping Out	09/01/2019 17:17:45	09/01/2019 22:17:45	11251	04:59:30	Intermediate 1 → 9⅞" Hole Run 3 → ExeDrillTrip
Tripping In	09/02/2019 01:59:45	09/02/2019 09:11:21	11480	07:11:00	Intermediate 1 → 9⅞" Hole Run 4 → ExeDrillTrip
Drilling	09/02/2019 09:11:21	09/04/2019 19:58:24	1716	58:46:30	Intermediate 1 → 9⅞" Hole Run 4 → ExeDrill
Tripping Out	09/04/2019 19:58:24	09/04/2019 23:41:16	3397	03:42:30	Intermediate 1 → 9⅞" Hole Run 4 → ExeDrillTrip

Figure 2.10: Time Data Segregation with the Sub operations

The production hole consists of three BHA runs. The first one was for a distance of 142 ft. to clean out the cement after running the previous casing. The second run was from 13680 ft. to 16715 ft. for a total drilling of 3035 ft. The cause for the trip out of the hole was to change MWD. The third BHA run was for 3604 ft. from 16715 ft. to the well total depth of 20319 ft.

First Run of Production Hole

Figure 2.11 shows the calculated downhole temperature in the solid red line, the geothermal gradient in the yellow solid line and the actual measured downhole temperature in the dark red dots. Nonetheless, the match between the model and the measured data was not accurate and needed calibration.

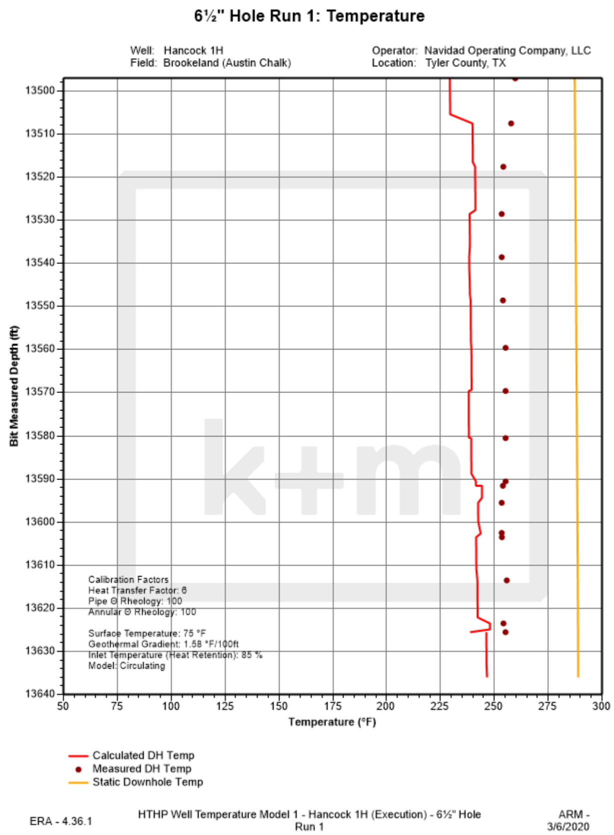


Figure 2.11: The Temperature Profile for the First Production Run with No Calibration. The model was underestimating the temperature

In order to calibrate the model, a closer look in the friction pressure losses was important. The BHA schematic can be seen in Figure 2.12 ,which is an essential part of the friction pressure losses analysis.

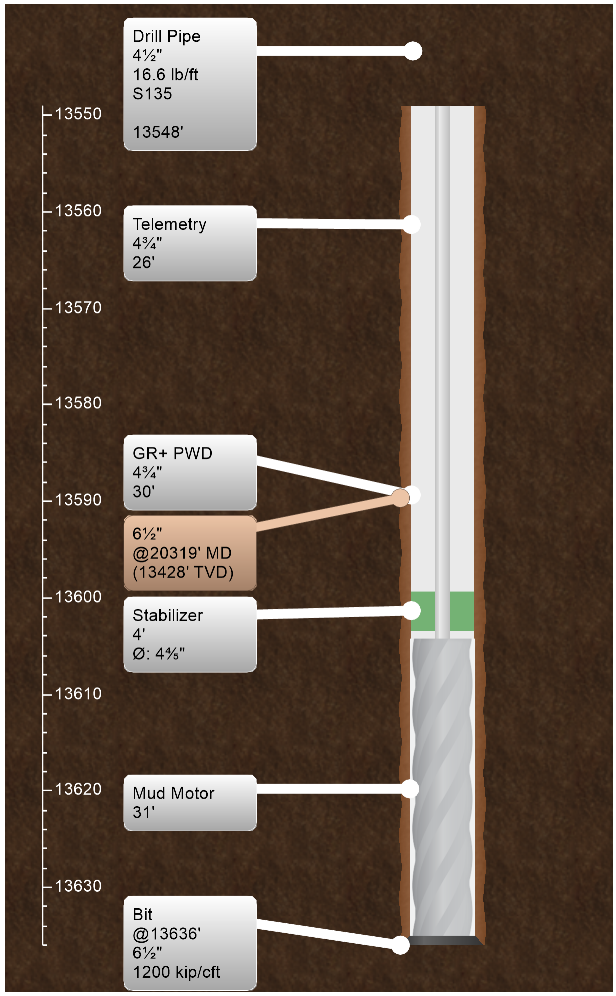


Figure 2.12: The BHA of the First Run. Bit, mud motor, stabilizer, GR followed by the Telemetery

The BHA consists of a 6.5 inch bit, and above it was the 5 inch mud motor, followed by 4.75 inch stabilizer, and then a combo of Halliburton PWD and MWD. The friction pressure losses in each part of the BHA was calibrated manually. This calibration includes the introduction of fixed pressure losses for some tools that didn't have effective Total Flow Area (TFA) such s the mud motor. Also, the heat retention in the inlet was changed to introduce a better model in Figure 2.13.

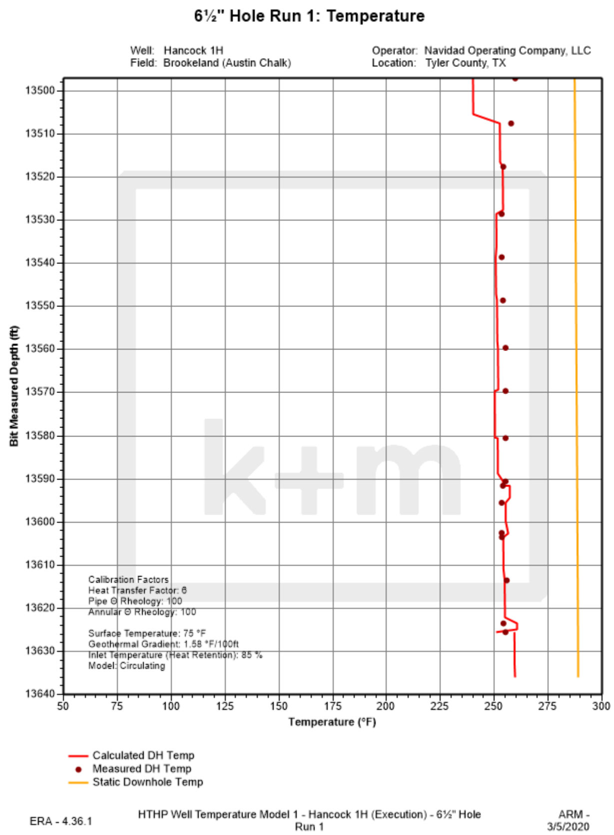


Figure 2.13: Temperature Profile for the First Production Run After Calibration. A better match is introduced.

Second Run of Production Hole

This run started after cleaning out the cement and drilling into the formation for around 180 ft. The BHA consists of a 6.5 inch bit, and above it was the 5 inch mud motor, followed by 4.75 inch stabilizer, and then a combo of Halliburton PWD and MWD. There were some operational incidents that occurred in this section of drilling. First, at 13983 ft., the well gained mud and 42 bbl kick was observed and circulated. This lead to an increase in the temperature by more than 20°F. The second operational difficulty was around 16,000 ft. where the data acquisition system had failures.

The friction pressure losses in each part of the BHA were calibrated manually along with the heat transfer factor and a better model was introduced in Figure 2.14. The solid yellow line represents the static downhole temperature. The filled dark red dots represents the measured downhole temperature and the solid red line represents the calculated temperature.

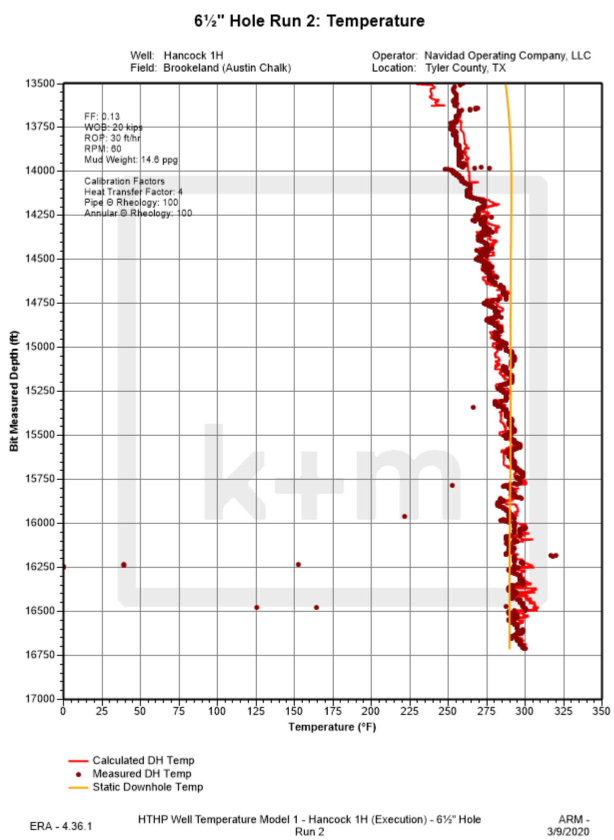


Figure 2.14: The Temperature Profile for the Second Production Run After Calibration. Good agreement between the model and the actual data.

Third Run of Production Hole

After a float failure in the last run at 16715 ft. , the well was killed with 18.2 ppg mud and then a new BHA was used for this run. The BHA consists of a 6.5 inch bit, and above it was the 5 inch mud motor, followed by 4.75 inch stabilizer, and then a combo of Halliburton PWD and MWD, and finally another 4.75 inch stabilizer. The drilling of this section had two gas kicks at 17,969 ft. and 18,375 ft. The measured downhole tempearture exceeded 320 F during the circulation of the gas kicks. Also, the model has some spikes at depths 19,213 ft., 19,479 ft., and 19,954 ft. that can be linked to spikes in surface torque. Overall, the performance of the model in this section is less accurate than the other two runs. Figure 2.15 shows the temperature profile in the third run. The filled dark red dots represents the measured downhole temperature and the solid red line represents the calculated temperature.

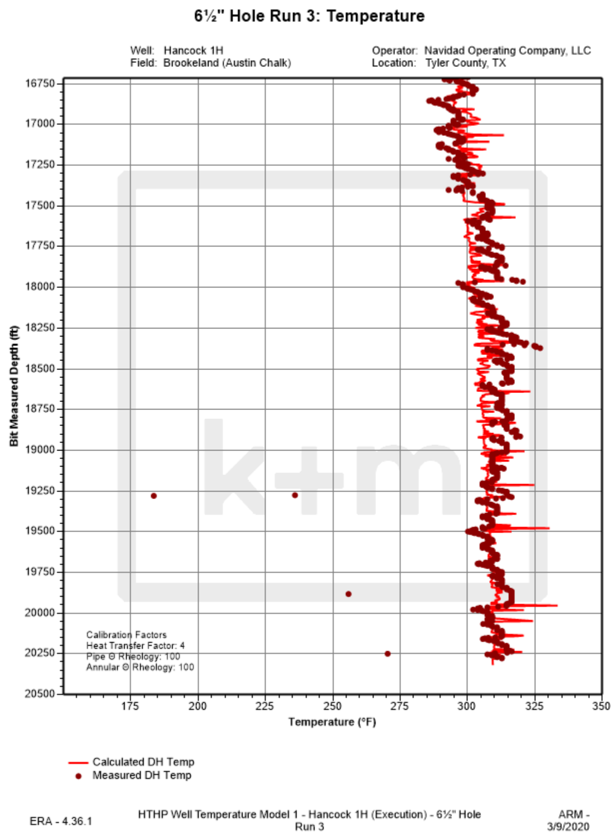


Figure 2.15: The Temperature Profile for the Third Production Run After Calibration. The model has a good estimation.

Model Calibration

First, it is important to make sure that the well has been designed correctly and all the needed data was imported. This step is critical in order to have an accurate base of the model then the calibration process can begin.

The calibration process can be done in many areas and parameters. We will focus on four coefficients and parameters. First the Heat Transfer Factor (HTF) which is basically a calibration factor that is a multiplier on the forced convection heat transfer coefficient for the annulus. In practice, it is used to adjust the spread between the flow line and downhole temp curves. The default HTF is 6 and ERA only accept integers. If HTF increases by 1 the whole plot will shift to the right due to the increase if the forced convection heat coefficient. In our calibration, we needed to decrease is to 4 to have a better match. The second calibration tool is the heat retention, which is part of the inlet temperature calculations. ERA uses it as a percentage of the heat retention that will be 100 % if no heat is lost from the fluid. We found that 90% heat retention had the best match.

The third parameter to calibrate was the friction pressure loss across the BHA. The BHA consists of five different main components: the drill collars, the Telemetry, the GR+ PWD, the stabilizers and the bit. The pressure drop across each component is different depending on the internal diameter of the tool. Calibrating the pressure drop of each component is necessary. Also, back calculating the stand pipe pressure helps in the calibration process. The last calibration that will be discussed here is the threshold set up for different parameters. ERA allows the user to set up threshold to be considered in the data importing process to eliminate some inaccurate data to be part of the calculations. In the case of the well in the analysis, the rig had RevIt, a CanRig rocking system that will keep an RPM reading even when the drilling is in the sliding mode. A threshold of 60 RPM was set to detect the sliding section, which would have lower temperature.

2.8 Drilling Parameters Effect on Downhole Circulating Temperature (Model)

In this section, sensitivity analysis of different drilling parameters on the downhole temperature profile will be presented. The focus is on the production section of the hole. For each drilling parameter, a range of operational values are tested to see the effect on the downhole temperature using the predictive model in ERA. All the other drilling parameters are set at the average operational value and one parameter is changed at a time to measure its effect. The goal will be to come up with a table for the personnel in the field to anticipate the change in the downhole temperature based on the change of the drilling parameter. The parameters that were tested are the follwing:

Flow Rate

Flow rates play an important role in the downhole temperature prediction. It affects the type of flow regimes in the drill pipe and in the annulus. As a result, it affects the frictional pressure loss of the whole system. Also, the flow rate changes the downhole pipe's rotational speed since the well was drilled with a mud motor. Figures 2.16 and 2.17 show the temperature profiles for different flow rates. At 17,000 ft., the model predicted an increase of 39 °F from 243 °F at 120 GPM to 282 °F at 180 GPM.

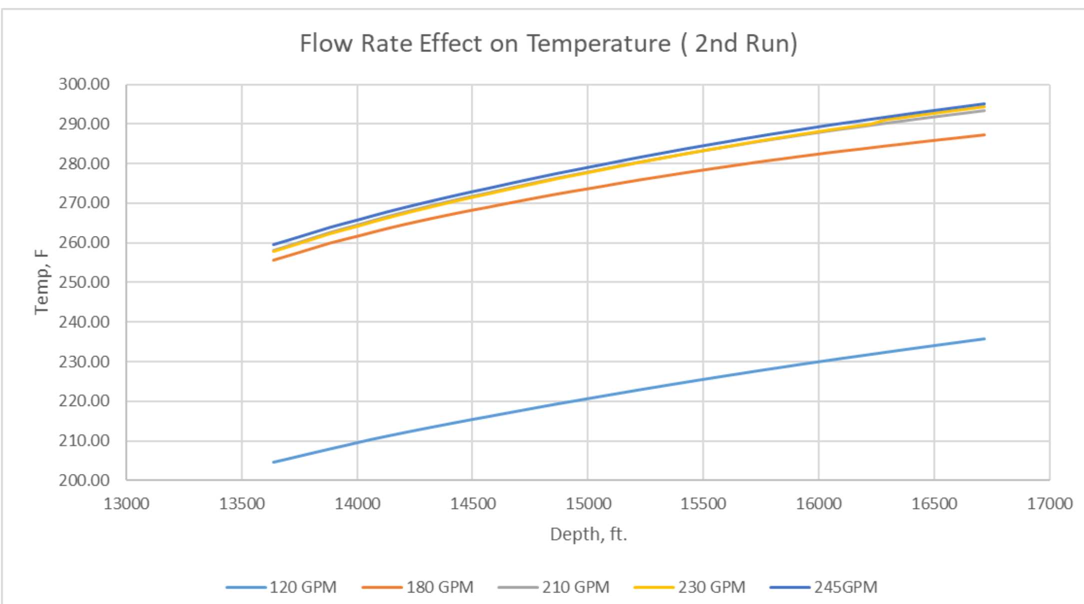


Figure 2.16: Flow Rate Effect on Downhole Temperature in the Second Run in the Production Hole. The blue line for 120 GPM and it is in the laminar flow regime that is why there is a drastic increase as we reached 200 GPM.

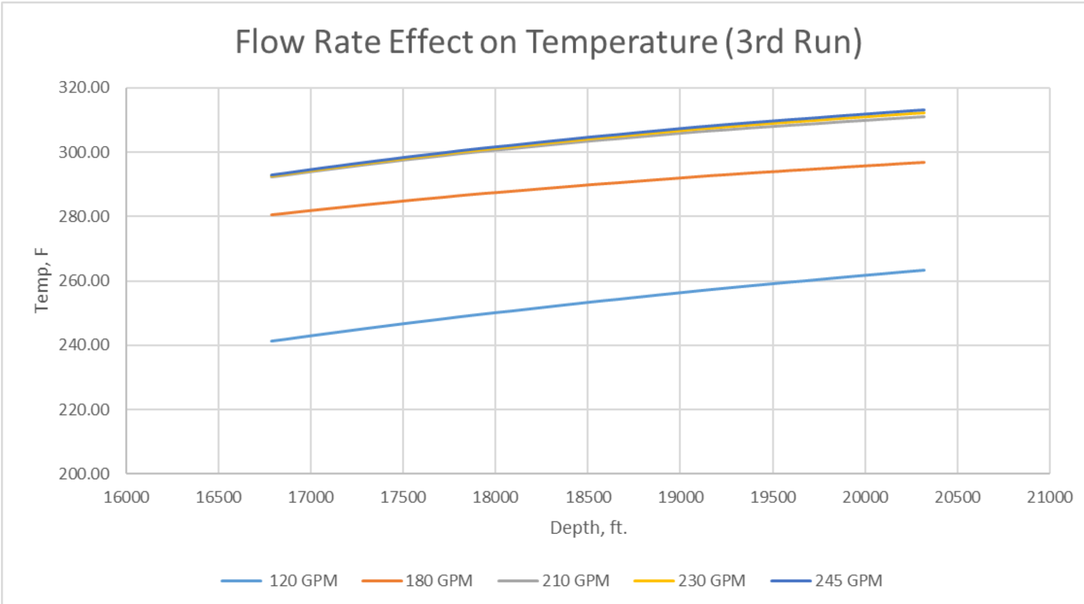


Figure 2.17: Flow Rate Effect on Downhole Temperature in the Third Run in the Production Hole. As the flow rate increases the downhole temperature increases. The high increase is due to flow regime change.

The effect of increasing the flow rate when pumping more than 200 GPM is not as drastic as the lower flow rate. The big difference in the temperature profile is linked to the type of flow regime in the drill pipe. Figure 2.18 shows the flow regimes in the drill pipe and in the annulus. The majority of the flow is in the laminar region. However, in Figure 2.19, the turbulent flow in the drill pipe is causing the steep increase in the temperature profile. In addition, once we are in the turbulent zone, the increase in the flow rate will no longer have a big effect on the temperature as we can see in the flow rates above 200 GPM.

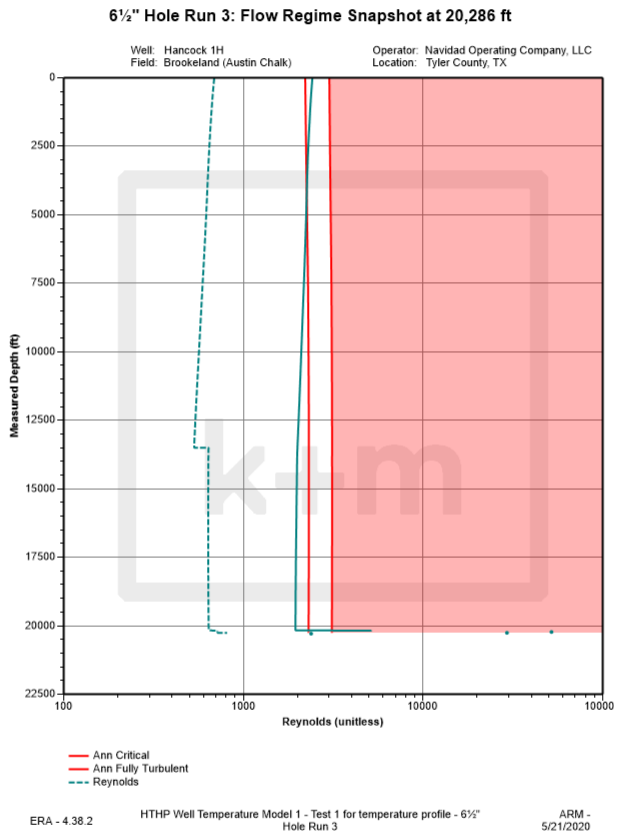


Figure 2.18: The flow regimes for the third production hole with 140 GPM. The annulus in the dashed line has full laminar flow and the drill pipe with the solid blue line has mainly laminar flow except for some turbulence above 7500 ft.

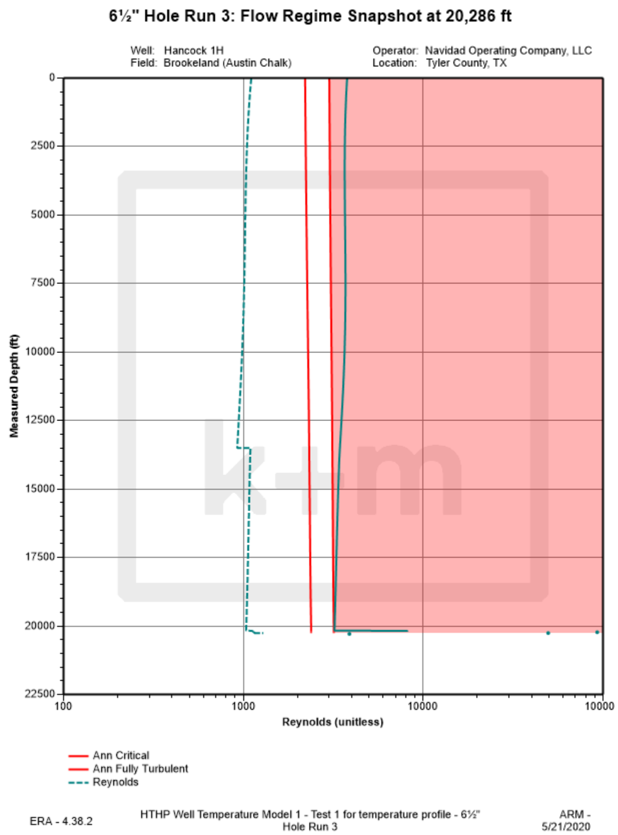


Figure 2.19: The flow regimes for the third production hole with 200 GPM. The annulus in the dashed line has full laminar flow and the drill pipe with the solid blue line has full turbulent flow.

Pipe Rotational Speed (RPM)

In the drilling operation, there are two rotational pipe speeds which are measured by the revolution per minute. The first one is the surface's pipe rotation, which is the rotational speed of the whole drill string. The second parameter is the downhole bit speed, which is generated by the mud motor. The focus is on the surface's pipe rotational speed since the key in the downhole speed is the flow rate, which will have greater impact on the temperature. Figure 2.20 shows the tempearature profile for different rotational speeds. At 19000 ft. , with 0 RPM the model estimates the downhole temperature to be 302 °F. The rotational speed can be zero in case of sliding in the formation. Increasing the rotation speed to 40 RPM will result in a rise of the downhole temperature by 2.4 °F to 304.7 °F. At higher speed the change in temperature is follwing the same trend.

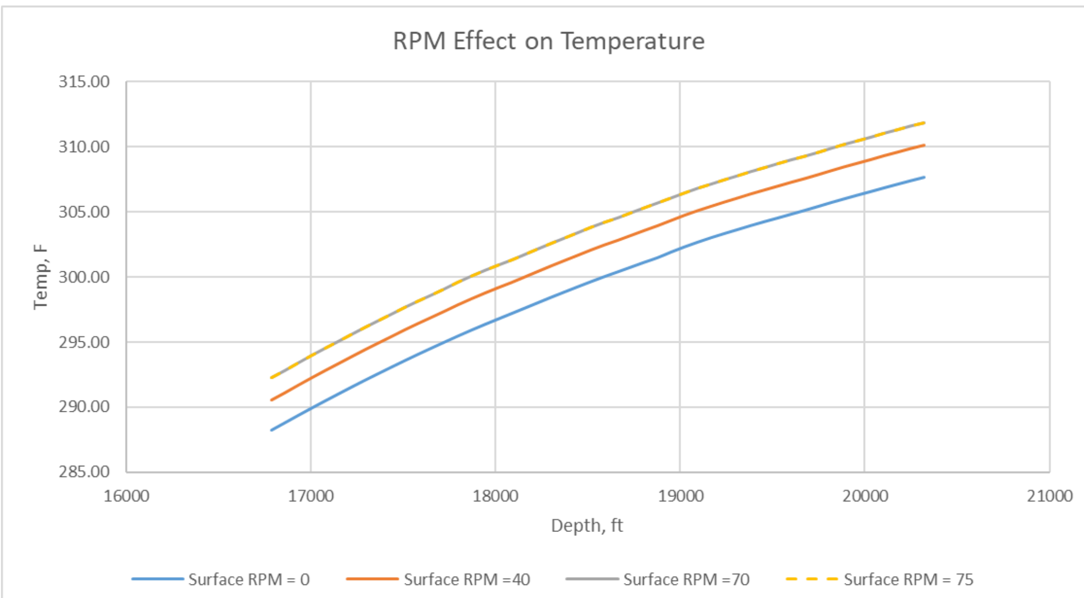


Figure 2.20: RPM Effect on Downhole Temperature in the Third Run in Production Hole, As the RPM increases, there is a slight temperature increase.

Weight On Bit (WOB)

Wieght on Bit (WOB) is the amount of downward force applied on the bit. Figure 2.21 expresses the effect of various WOB from 10 Kips to 40 Kips and the response from the downhole temperature is minimal.

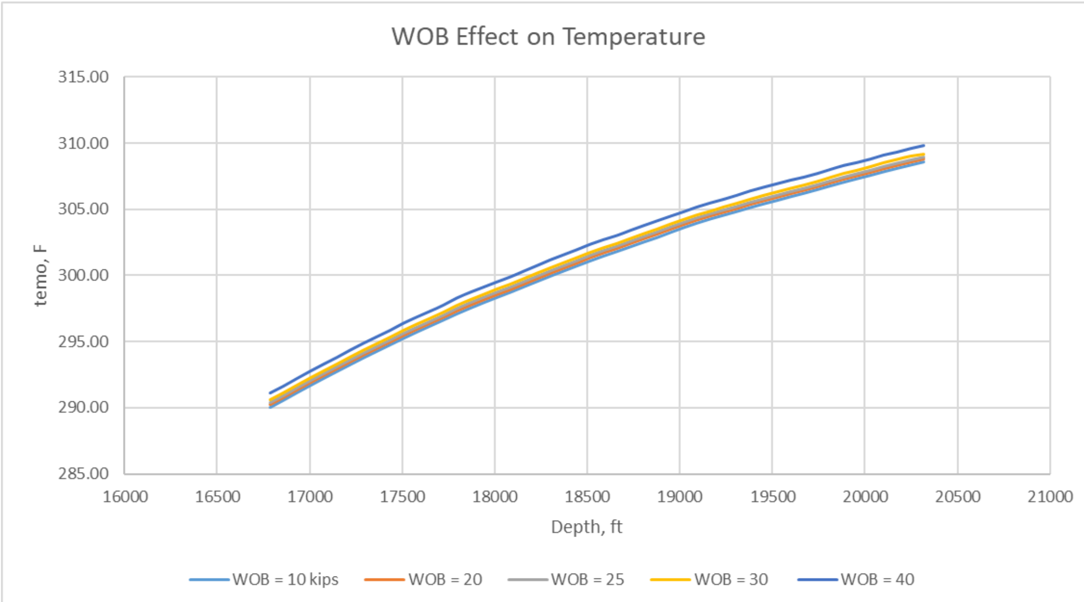


Figure 2.21: WOB Effect on Downhole Temperature in the Third Run in Production Hole. The effect is minimal.

Motor Torque

The motor torque is calculated using the theoretical performance curve from the motor provider. Figure 2.22 shows the performance curve for the Wenzel motor used in the well. The torque factor is equal to the slope of the torque line , which is equal to 2.58 ft-lbs/psi. In order to calculate the motor torque the motor pressure drop is multiplied by the motor torque factor.

$$Motor\ Torque = Torque\ Factor\ \times\ P_{Diff} \tag{2.29}$$

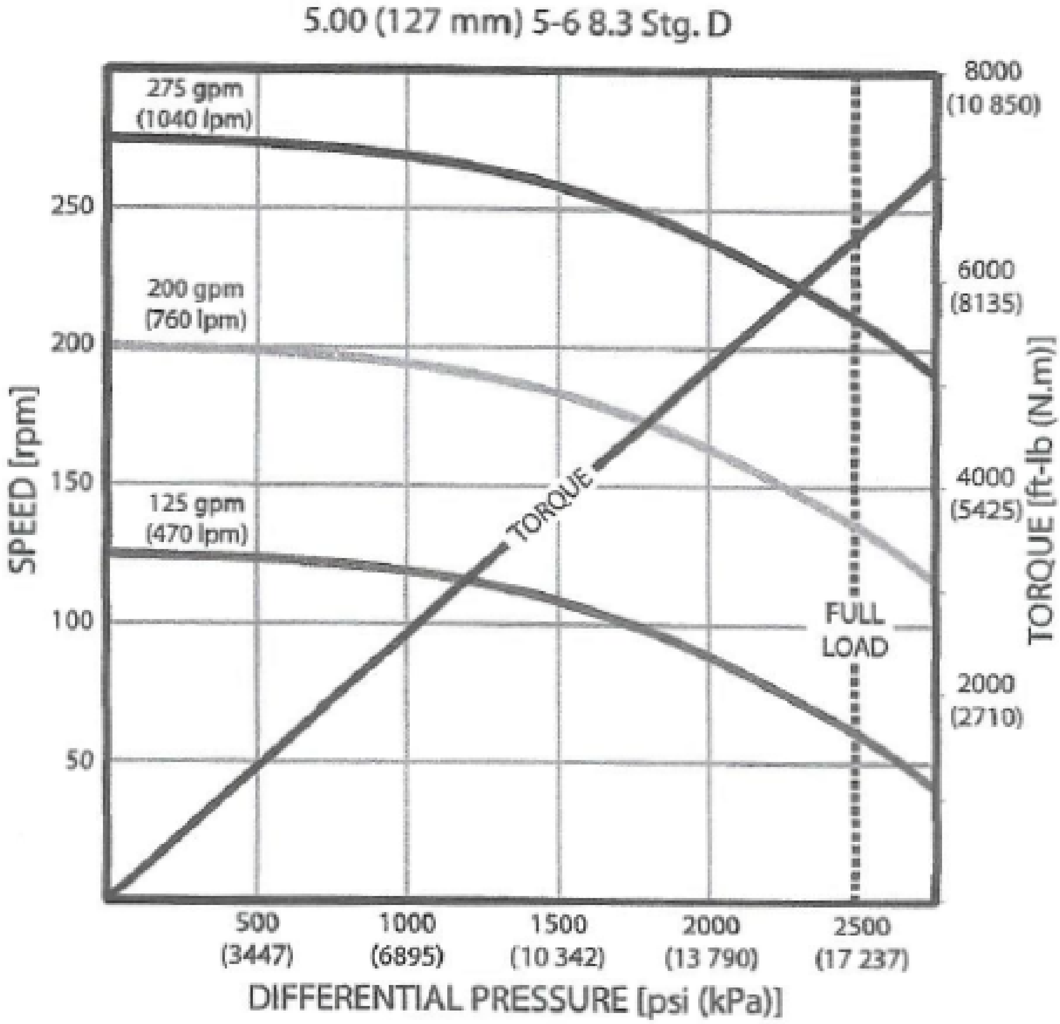


Figure 2.22: The Wenzel Motor Performance's Curve. It help in calculating the motor torque.

In Figure 2.23, the blue line represents the temperature if there was no bit torque. There is an increase of 2.4 °F if we add 500 lb-ft to the operation. In addition, increasing the bit torque to 1000 lb-ft will result in another increase of 2.3 °F. The effect of increasing the torque on the temperature is low. However, as we are operating in a high temperature zone, every degree is counted in order not to exceed the temperature limitation of the tools.

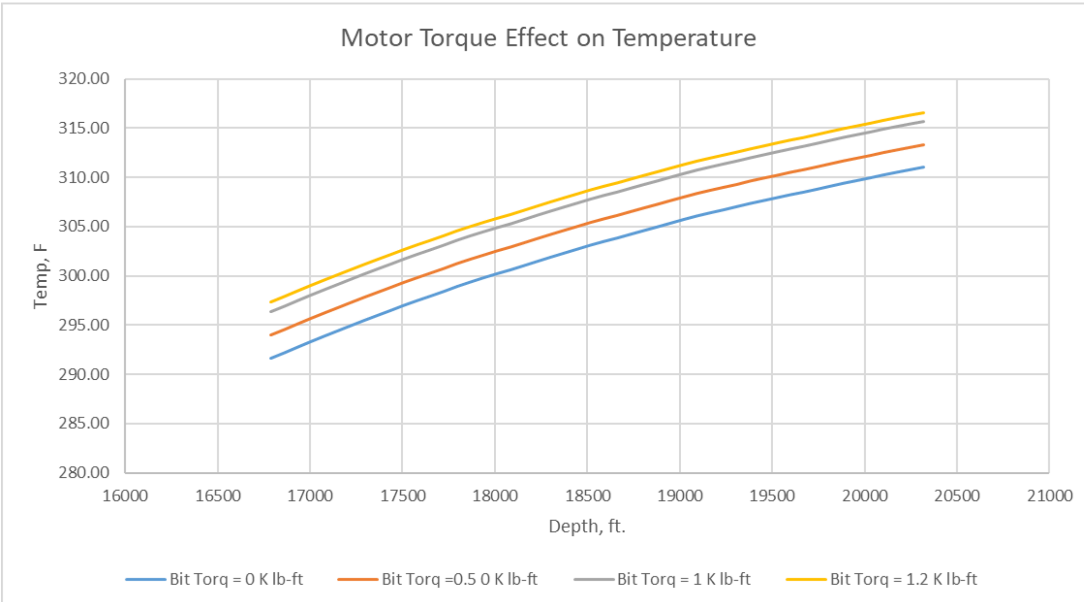


Figure 2.23: Motor Torque Effect on Downhole Temperature in the Third Run in Production Hole. As the motor torque increases the temperature increases slightly.

Vibrations

Vibrations can be defined as "any repeating oscillation about an equilibrium position"(Dupriest, 2017). In drilling, three types of vibrations can be encountered. The lateral vibration, which results in whirl, which can lead to wellbore instability (Khaled, 2017) (Khaled and Shokir, 2017). Also, the axial vibration that results in bit bounce, and the torsional vibration that causes stick slip. The well had vibration logs for the first and second run for the production 6.5 inch hole. Unfortunately, the data was lost for the last run. The logs recorded the lateral and axial vibrations. Figure 2.24 shows a sample of the log. The raw data was downloaded and then analyzed closely. More than

100 incidents of medium vibrations in x,y and z arises were recorded. The medium vibration threshold for x-axis and y-axis average vibrations was set between 3-6 (g). As for the z-axis vibration, the threshold was set between 2-4 (g). Vibrations can affect the drilling The analysis showed that most of the vibration happened either when we start the drilling after a trip or when we are pulling up to ream the hole. However, no significant temperature change can be linked to these medium vibration events. A vibration log containing high vibration events should be used to investigate the effect of the vibrations on downhole temperature.

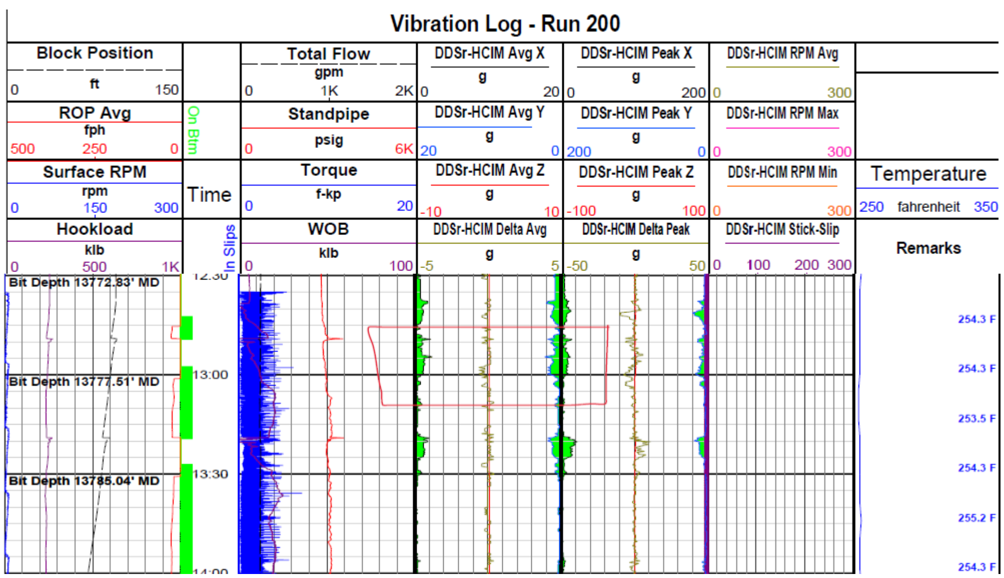


Figure 2.24: Vibration Logs for the Second Run of Production Hole

Type of Drilling Fluid

Drilling fluid plays an important role in the drilling operation. It cools the bit and transports the cuttings back to surface. There are two main types of drilling fluid base. Water Based Mud (WBM) where water is the continuous phase in the system. The second type is the Oil Based Mud (OBM) where deisel or mineral oil can be the continuous phase. Although there are other types of drilling fluid and many additive to achieve certain condition during the drilling, our focus here is on the effect of the drilling fluid type on the downhole temperature. Figure 2.25 shows two temperature profiles for OBM and WBM, where both fluids had the same mud weight of 14.6 ppg. At 18,000 ft., the downhole temperature is estimated to be 262.4°F with a WMB. On the other hand, with OBM the estimated downhole temperature is 305.3°F. The reason behind this difference is that water has higher heat capacity than oil.

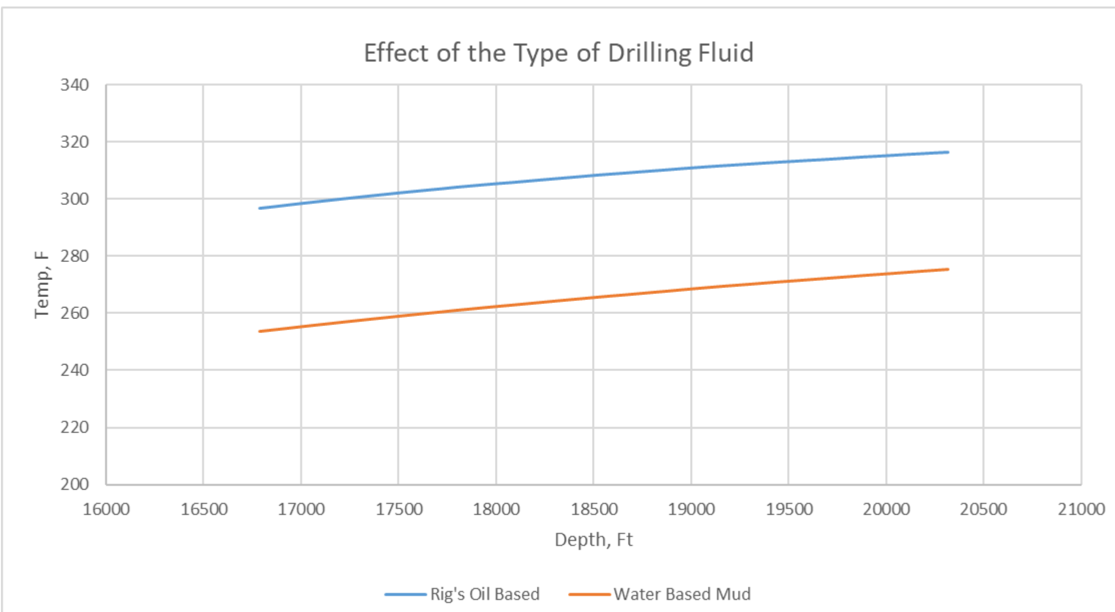


Figure 2.25: Type of Drilling Fluid Effect on Downhole Temperature in the Third Run in Production Hole. The effect on the downhole temperature is more than 30°F .

Parameter	Base Case	Change Made	Change in Downhole Temperature	Cause
Higher Flow Rate	180 GPM	+ 40 GPM	+ 13 F	The increase in frictional pressure losses causes the temperature to rise and fully turbulent flow is reached
Lower Flow Rate	180 GPM	- 40 GPM	- 36 F	Decrease in frictional pressure losses causes the temperature to decrease and flow regime changed to laminar
WOB	20 Kips	+ 10 Kips	+ 0.4 F	The effect is minimal
Type of Drilling Fluid	OBM	WBM	- 42 F	Water has higher heat capacity than oil
Pipe Rotational Speed (RPM)	40 RPM	+30 RPM	+ 1.7 F	More friction between the pipe and the wellbore
Hole ID and Previous Casing	6.5" and 7.625"	+ 1 inch for each	- 23.4 F	Decrease in frictional pressure losses causes the temperature to decrease and leaving the critical turbulent in the drill pipe
Motor Torque	500 lb-ft	+ 500 lb-ft	+ 2.3 F	Extra work dissipate more heat from the motor

Table 2.2: Summary of Drilling Parameters Effect on Downhole Temperature

2.9 Drilling Parameters Effect on Downhole Circulating Temperature (Actual Data)

The previous sensitivity analysis tested the model's ability to predict the change in the downhole temperature with a minimal amount of data provided. However, in order to test the sensitivity of each parameter with actual depth data, the actual data was imported and then converted from the time based data to a depth data for the third run in the production hole. In addition, the model was edited with threshold to identify the sliding sections. This threshold is determined to be 60 RPM. The rig was using RevIt, a CanRig rocking system that gives surface RPM readings. As a result, the actual data did not have 0 surface RPM while sliding and ERA was not able to detect the sliding intervals. The method used in this section for the sensitivity is similar to the previous one. One parameter will be changed at a time with all the other parameters being actual drilling data.

Figures 2.26 to 2.28 show the effect of different drilling parameters on the downhole temperature. For the flow rate, the effect of the flow regime change from laminar to turbulent is clear at 140 GPM and 180 GPM. There is 48 °F increase in the temperature between 140 GMP and 180 GPM. However, once the flow is fully turbulent in the drill pipe, the effect of the flow rate in the temperature is less than 1°F between 200 GPM and 220 GPM. In addition, the flow rate plays an important role in the friction pressure loss calculations that effect the temperature profile.

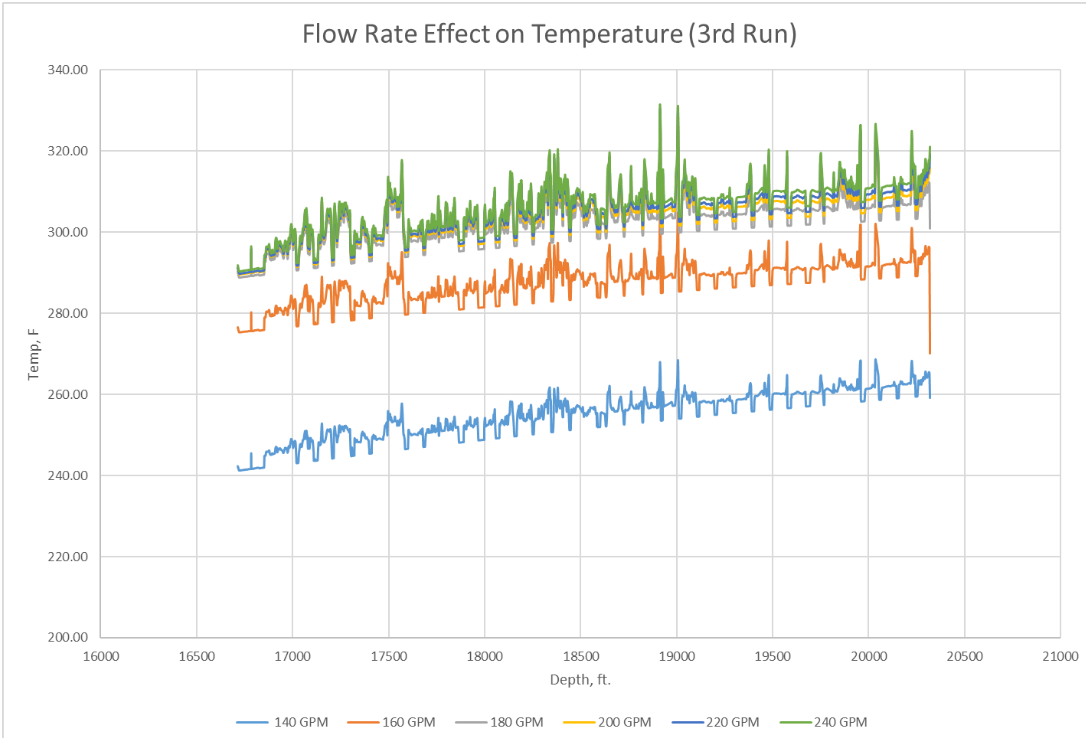
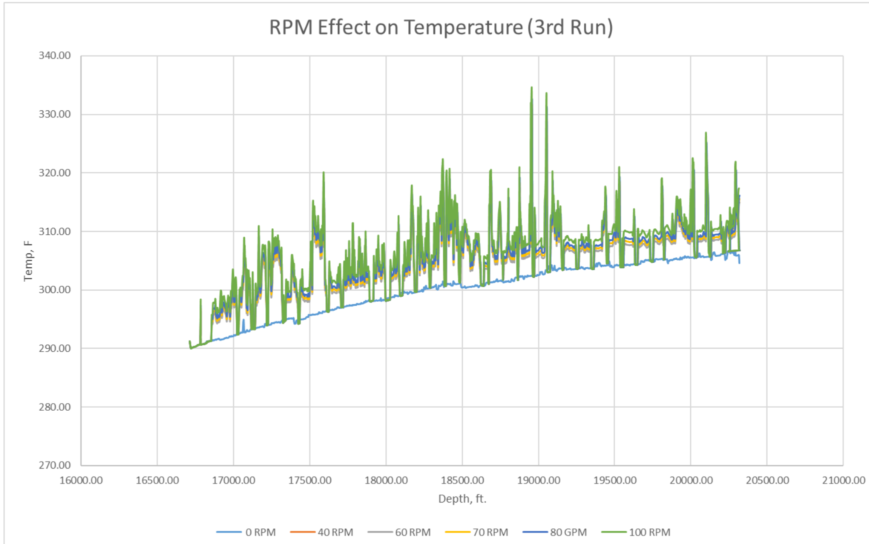
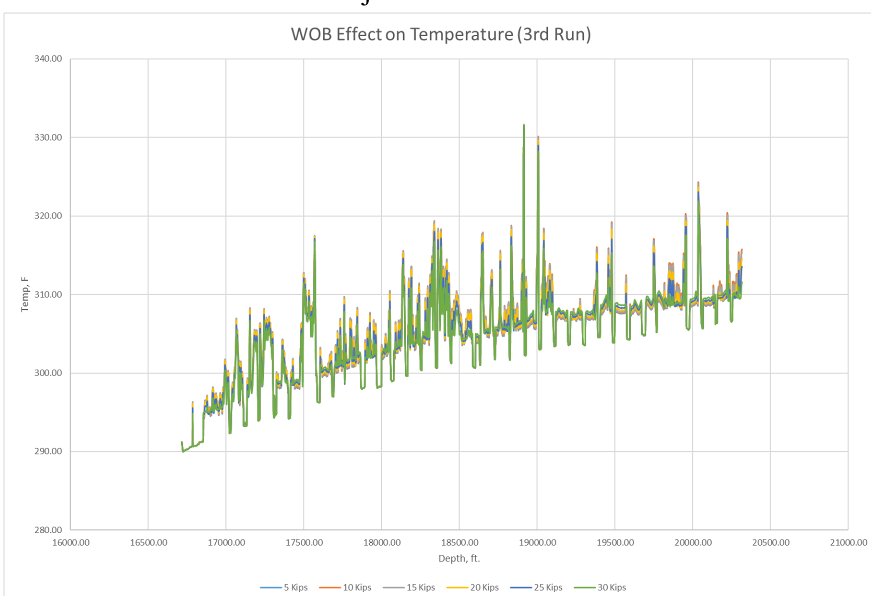


Figure 2.26: The flow rate effect on the temperature with actual data. Once we are in the turbulent flow regime above 200 GPM the effect is low.

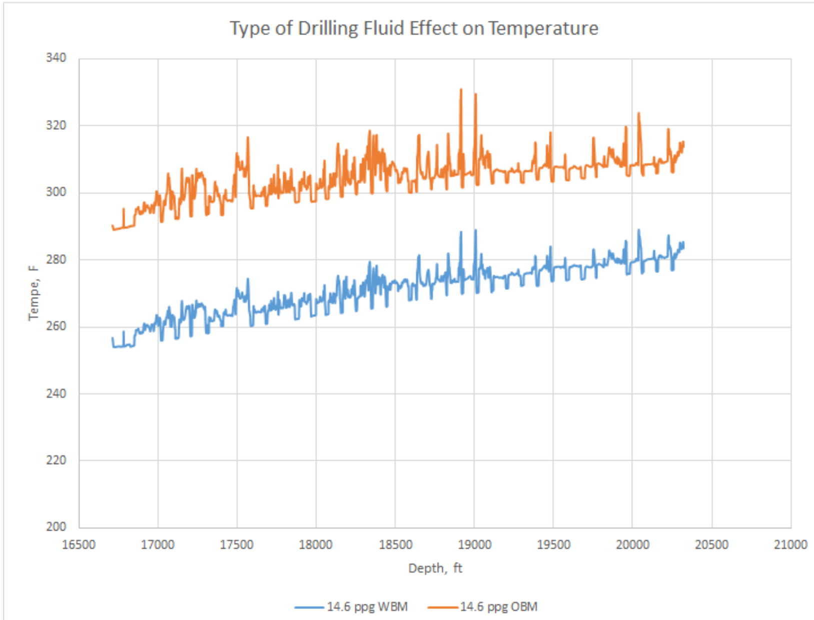


(a) The RPM effect on the temperature with actual data. 0 RPM will reduce the temperature since the pipe is not rotating and the friction with the hole side is minimal. However, once there is a rotation the temperature difference with an increase of 10 RPM is just 0.4 °F

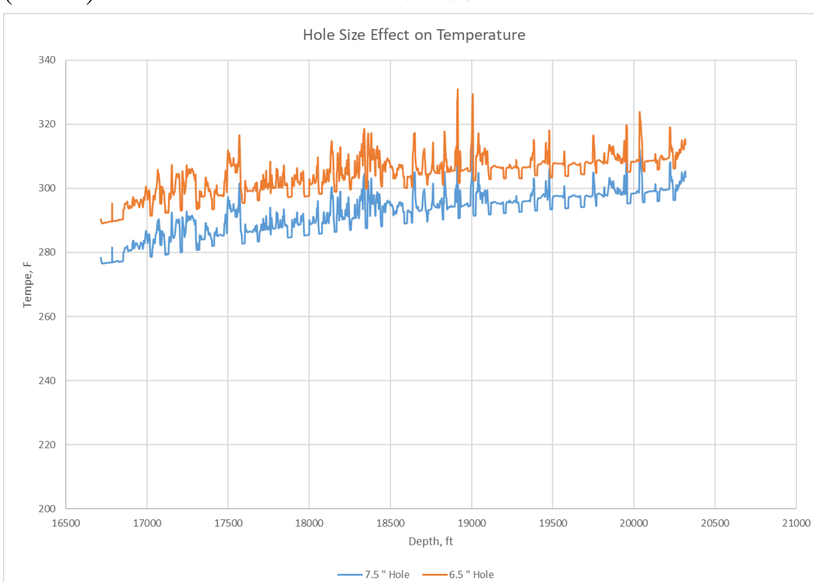


(b) The WOB effect on the temperature with actual data. The change in temperature is minimal.

Figure 2.27: RPM and WOB effect on temperature model



(a) The type of drilling fluid effect on the temperature with actual data. The difference between Oil Based Mud (OBM) and Water Based Mud (WBM) with the same MW of 14.6 is 33 °F.



(b) This shows the hole size effect on the temperature with actual data. Increasing the previous casing size from 7.625 inches to 8.625 inches and the hole size from 6.5 inches to 7.5 inches results in 12 °F decrease in the downhole temperature.

Figure 2.28: Hole size and drilling fluid effect on temperature model

BHA Pressure Drop

When we study the friction pressure loss profile in Figure 2.29, it is clear that the BHA accounts for a large pressure loss in the system. This pressure loss causes higher downhole temperature. In this test, the MWD and the motor pressure drops were lowered by 300 psi and Figure 2.30 shows the effect on the dowbhole temperature.

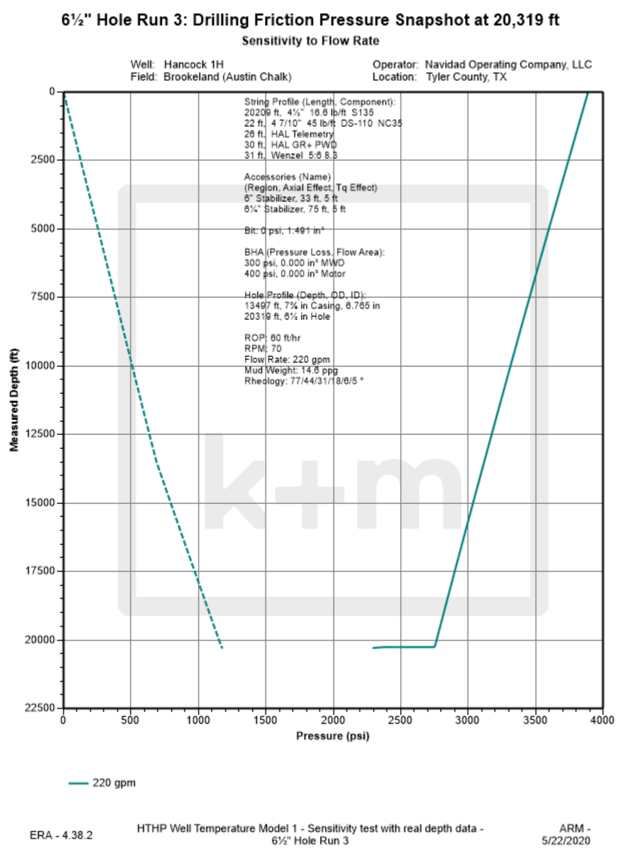


Figure 2.29: This plot shows the BHA friction pressure drop in system. It is clear the the BHA accounts for a large amount of pressure that is effecting the downhole temperature.

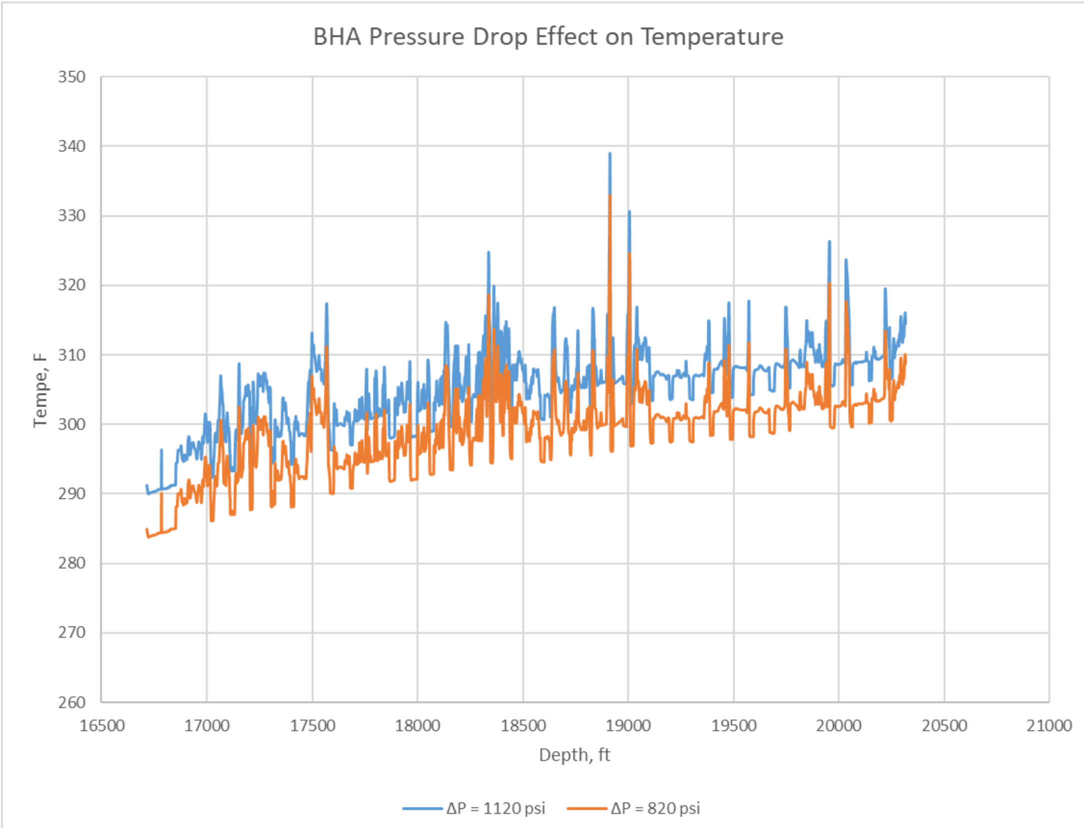


Figure 2.30: This shows the BHA pressure drop effect on downhole temperature. Lowering BHA pressure drop by 300 psi by 6 °F.

Sliding vs Rotation

Slide Drilling means that the surface rotary speed is equal to zero and the pipe is not rotating. The only rotation comes from mud motor bit rotation powered by the mud flow. This mood of drilling is used during the geosteering in the reservoir or while building an angle of drilling. The second mode is rotation drilling where the whole drilling string is rotating along with the mud motor bit rotation. Most of the drilling is rotation drilling since it is faster. Figure 2.31 shows five sliding intervals in the 6.5 inch hole. The temperature decreases in the sliding mode compared to the rotation mode by 3 °F . This decrease in temperature is linked to the loss of pipe frictional heat.

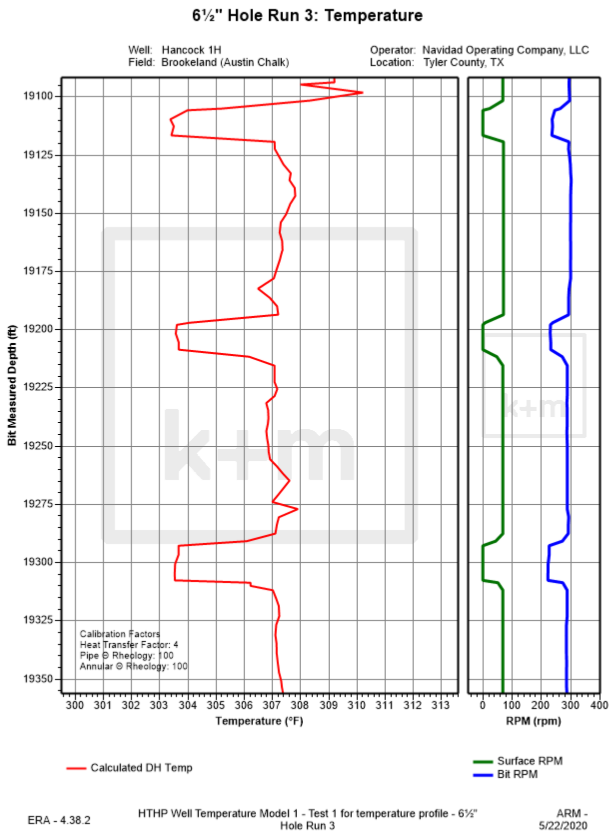


Figure 2.31: Rotation vs. sliding effect on downhole temperature in the third run in production hole. The sliding decrease the downhole temperature by 3-5 °F.

Parameter	Base Case	Change Made	Change in Downhole Temperature	Cause
Higher Flow Rate	220	+20 GPM	+ 1°F	Increase in frictional pressure losses causes the temperature to rise
Lower Flow Rate	220	-20 GPM	- 0.75°F	Decrease in frictional pressure losses causes the temperature to decrease
Type of Drilling Fluid	OBM	WBM	- 33°F	Water has higher heat capacity than oil
Pipe Rotational Speed (RPM)	70 RPM	+10 RPM	+ 0.44 °F	More friction between the pipe and the wellbore
Larger Hole ID and Previous Casing	6.5" and 7.625"	+ 1 inch for each	- 12°F	Decrease in frictional pressure losses causes the temperature to decrease
BHA Pressure Drop	700 psi	-300 psi	-6.2°F	Decrease in frictional pressure losses causes the temperature to decrease
Rotate vs Slide	Rotate	Slide	- 5°F	Rotation causes more heat due to more work being done and the friction between the pipe and the wellbore increase

Table 2.3: The summary of a sensitivity analysis for different drilling parameters with actual data

2.10 Improving ERA Model

In the process of modeling the temperature in ERA and performing the sensitivity analysis. There were certain behaviors in the model that were not matching the measured data. On the other hand, there were behaviors in the measured data that were abnormal. Some of these regions were discussed in the results. For example, at 17,967 ft the measured temperature increased from 313°F to 323°F and then returned to 297°F T 17,975 ft. The model did not follow this increase in the temperature. What happened in the rig in that depth range was that the circulated gas and the back pressure increased to 1600 psi. The same situation happened at 18,375 ft. and the measured temperature increased to 327°F and then dropped to 18,377 ft.

One model's behavior in particular is causing clear inaccuracy. This behavior is resulting in the spikes in the temperature that can be seen in Figure 2.32. While investigating this behavior, all the drilling reports and the drilling parameters were examined and there was no explanation for this sudden increase in the downhole temperature. The next step was to revisit and analyze the calculation steps in ERA and to test different drilling parameters and to measure their impact on the model's temperature spikes.

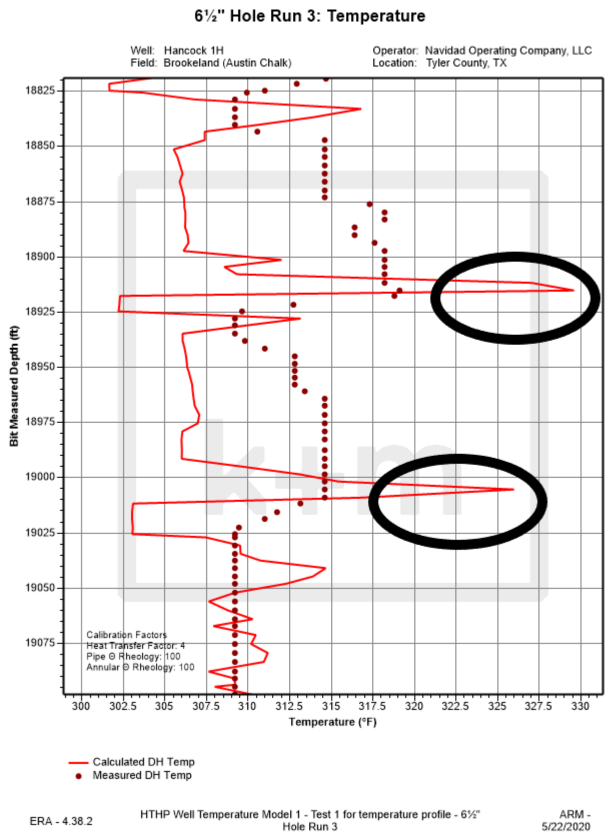


Figure 2.32: A zoom in the model to show the spikes in the temperature model

There are two types of heat sources in the system. The heat sources in the annulus Q_a and the drill string Q_p. Let us revisit Equations 1.20 and 1.26 and study the drilling parameters the can affect the dowbhole temperature model. The parameters are listed in Table 2.4.

$$Q_a = Q_{a_hyd} + Q_{trq} + Q_{bit} \tag{2.20}$$

$$Q_p = Q_{p.hyd} + Q_{BHA} \tag{2.26}$$

The sensitivity analysis that was performed in the previous section presented the

Flow Rate (q)	Friction Pressure Loss
ROP	Friction Torque
WOB	Bit Torque

Table 2.4: The parameters that affect the calculations of the temperature model

effect of flow rate, WOB and friction pressure loss. However, the other parameters in Table 2.4 were not tested. I started by changing the bit torque for the whole run to 500 lb-ft to measure the effect. However, the temperature profile did not change. Then, I tested changing the surface torque to a uniform 3000 lb-ft. The result of the model run is in Figure 2.33. There are no temperature spikes in this test.

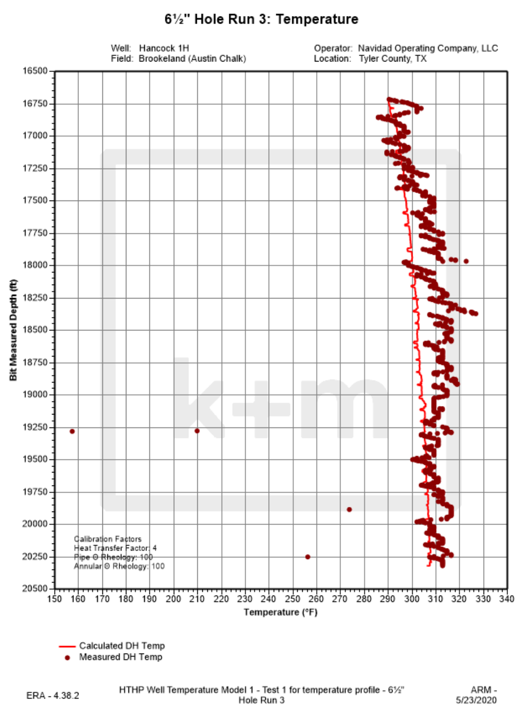


Figure 2.33: Temperature model run with a uniform 3000 lb-ft surface torque. There are no spikes in temperature profile.

For a deeper investigation, I plotted the original temperature profile with a zoom in a temperature spike region and plotted the measured and the calculated bit torque to analyze the correlation in Figure 2.34. The plot shows a good match between the calculated bit torque by the ERA torque and drag (tnd) engine and the model's temperature. However, the measured bit torque, which is the differential bit torque, has a closer trend to the measured temperature. The measured bit torque is calculated by Equation 1.29 :

$$Motor\ Torque = Torque\ Factor\ \times\ P_{Diff} \tag{2.29}$$

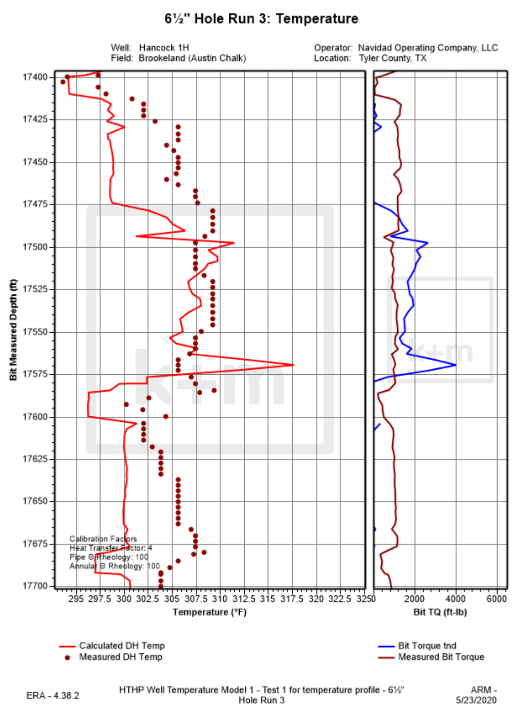


Figure 2.34: This is a zoom in a temperature spike. The plot in the right has the calculated bit torque in the blue line using the torque and drag engine in ERA. The blue line has a good trending match with the temperature model.

During this process, I shared these findings with the software developers and got their input in several meetings calls. The result was a promise to review the model for the suggestion provided and to release an update to with an improved model.

2.11 The Improved Temperature Model with Differential Downhole Torque Calculation Method

The improved model will change the way of the bit torque calculations and the use of it in the model. If we recall Equation 1.25 :

$$Q_{bit.mech} = 0.0226(1-\epsilon)WOB\ ROP\ + \tau_{bit}2\pi\omega \tag{2.25}$$

The bit torque here (τ_{bit}) is calculated based on the TnD engine and is linked with the spikes in the temperature model. The improved model will use the measured downhole torque data if available. This will ensure that the model is based on the most accurate data. Then, if no measured DH torque data available, the model will use the calculated bit torque based on the differential pressure as in Equation 1.29 if there is a motor in the BHA. If there is no motor, it will use the calculated DH torque from the TnD model. Figure 2.35 shows the new work flow that has been implemented.

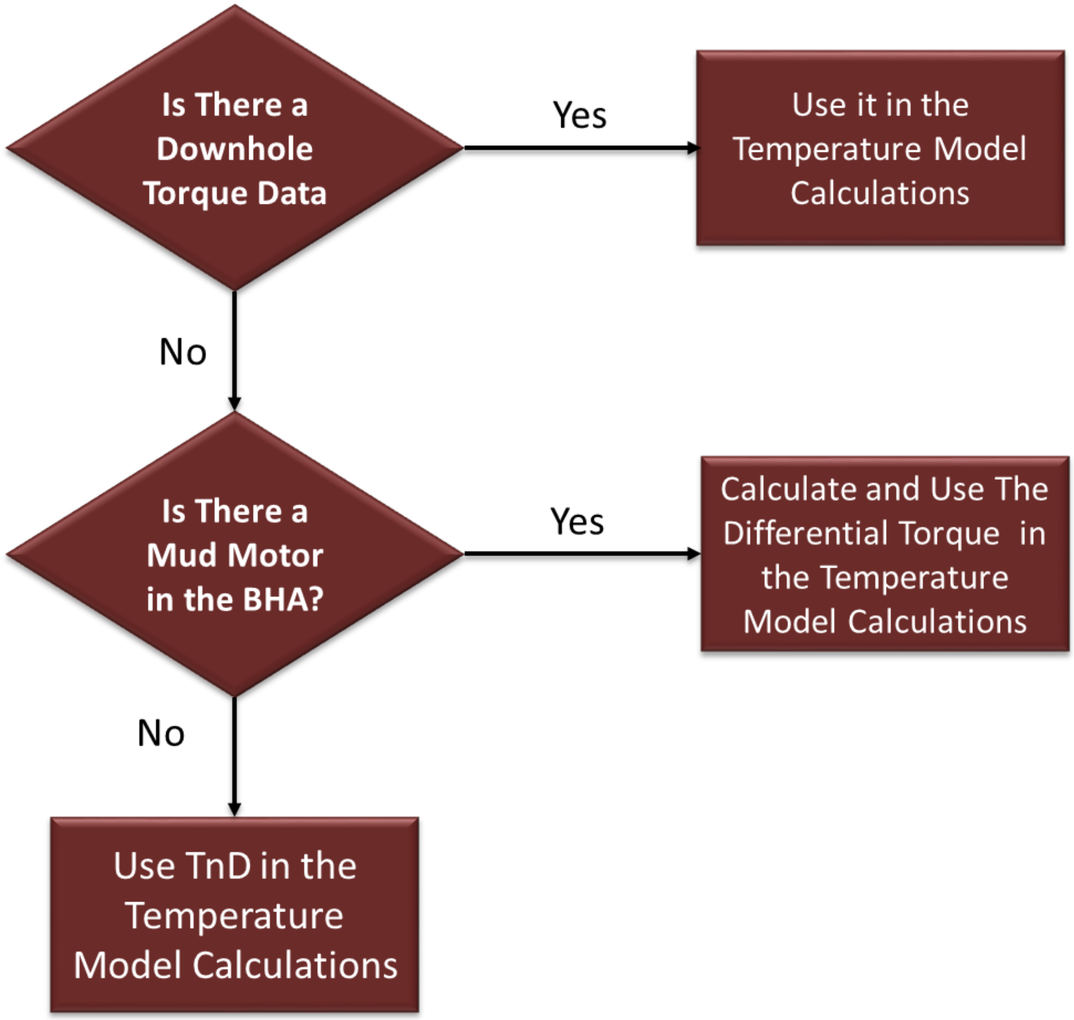


Figure 2.35: The new workflow to be used in the case of the temperature prediction for the BHA with motors.

A preview update release for ERA was developed based on the improved model and was shared with us to test. Figure 2.36 shows the temperature profile for the third run in the production hole. With the improved mode, there are no spikes in the temperature compared with Figure 2.15. Also, after an initial statistical analysis,the improved model has a Mean Absolute Error (MAE) of 1.46 %, which is less than the

1.61% MAE of previous model.

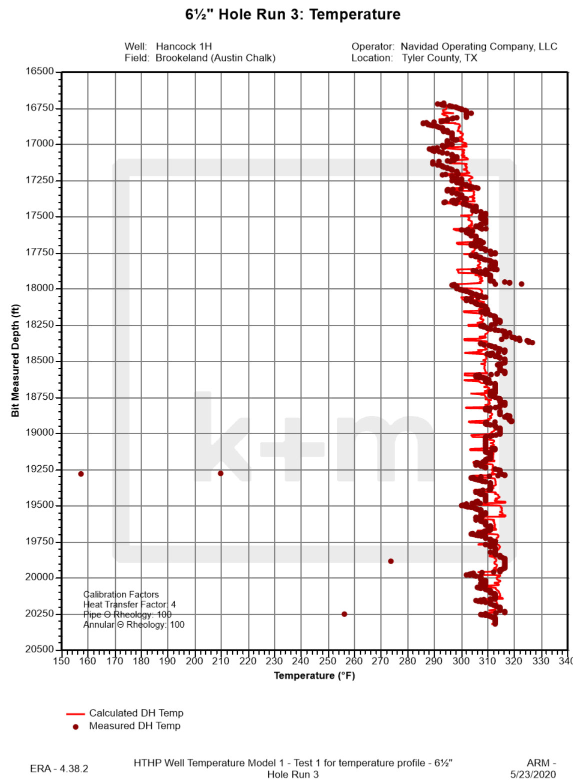


Figure 2.36: This is the temperature profile for the third production hole run using the improved model with the differential pressure to calculate bit torque. There are no spikes in the temperature model.

The improved model is more stable in the temperature calculation and Figure 2.37 shows the same range that had temperature spikes in Figure 2.32. It is clear that there are no temperature spikes in the improved calculation method.

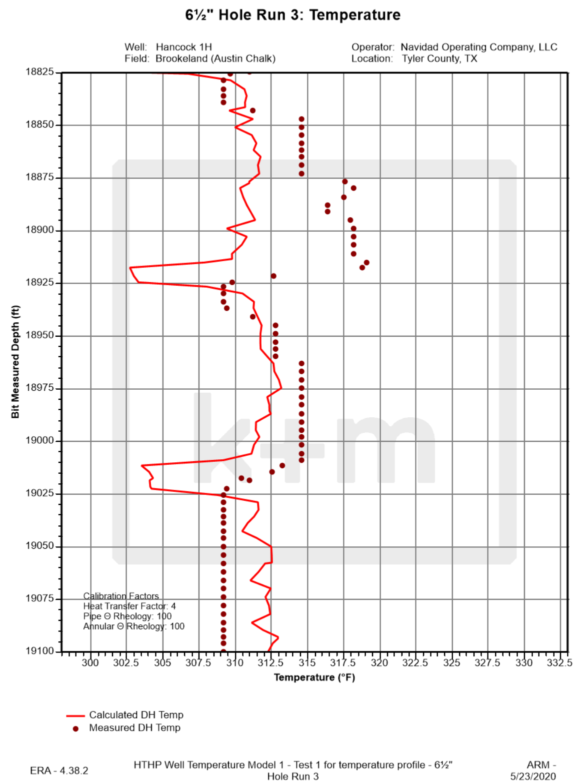
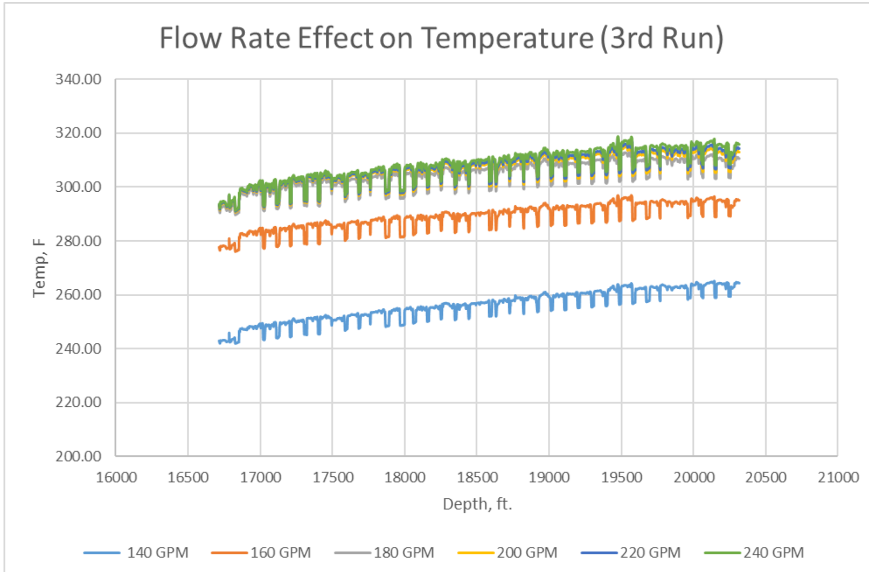


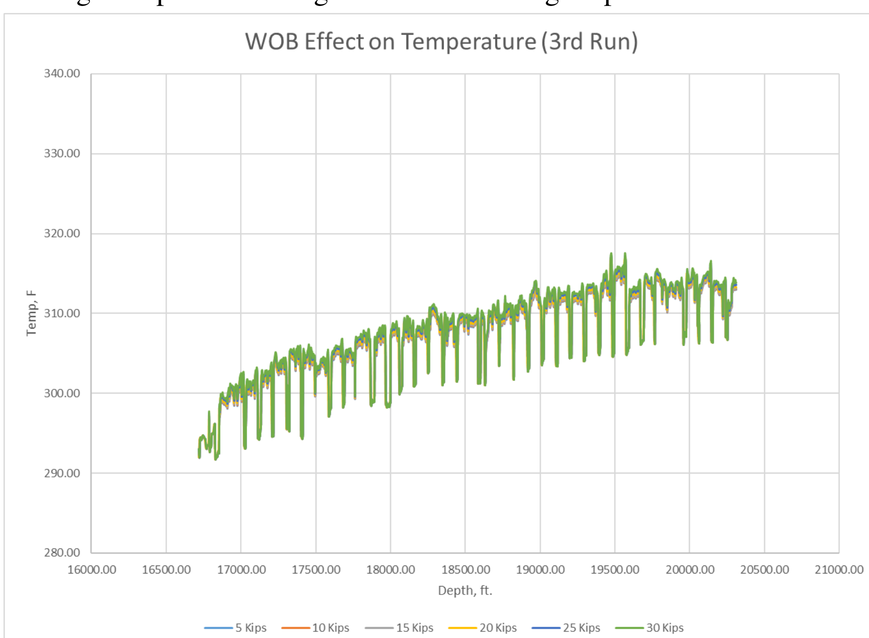
Figure 2.37: A zoom in the region that had temperature spikes in the old model. There are no spikes in the improved temperature model.

2.12 Drilling Parameters Effect on Downhole Circulating Temperature (Improved Model)

The improved model has more stable results and in order to test further a sensitivity analysis for major drilling parameters was performed. Figures 2.38 to 2.40 show the effect of the flow rate, RPM, WOB, BHA pressure drop, and the type of drilling fluid on the downhole temperature using the improved model.

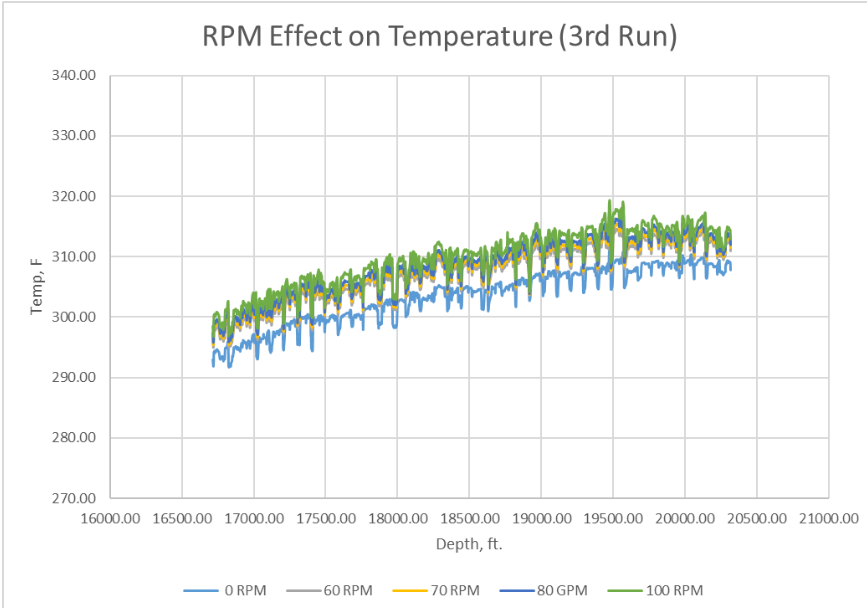


(a) The flow rate effect on the temperature with the improved model and actual data. In low rates the temperature is low since the flow is laminar. The increase of the flow rate to the turbulent flow regime region will result in a high temperature change because of the higher pressure loss.

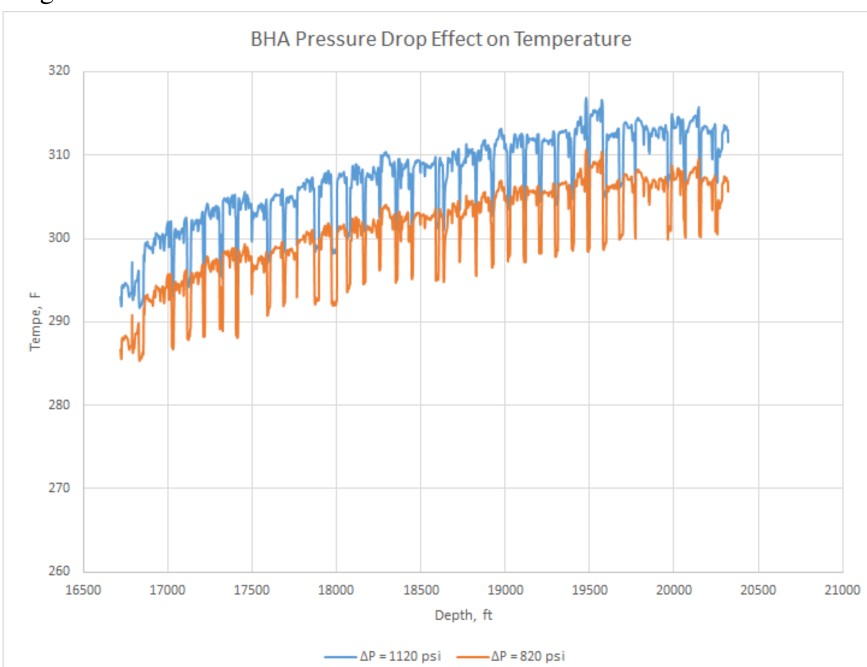


(b) WOB effect on the temperature model is minimal. The drop is temperature is in the sliding regions.

Figure 2.38: Flow rate and WOB effects on the improved temperature model



(a) This plot shows the RPM effect on the improved model temperature. As long as there is RPM the effect is minimal.



(b) This plot shows the effect of lowering the BHA pressure drop by 300 psi. There is a difference of 6 5°F

Figure 2.39: RPM and BHA pressure drop effects on the improved temperature model

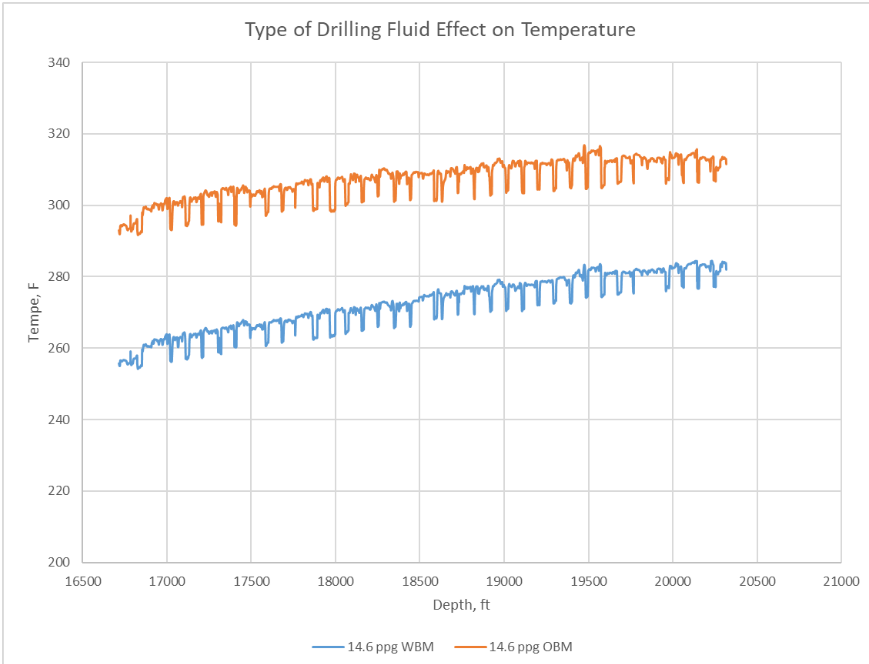


Figure 2.40: This plot shows that the system using WMB would have lower temperature compared to OBM with the improved temperature model

The trends of the effect of the drilling parameters on the downhole temperature match the trends in the original model. There is no clear difference that can be pointed out. These results show that the spikes in the previous model did not have a big impact on the overall effect of the drilling parameters. There is a slight increase in the RPM and the rotation drilling effects on the downhole temperature. Table 2.5 summarizes the effect of each drilling parameter on the improved temperature model.

Parameter	Base Case	Change Made	Change in Downhole Temperature	Cause
Type of Drilling Fluid	OBM	WBM	- 33°F	Water has a higher heat capacity than oil
Larger Hole ID and Previous Casing	6.5 in and 7.625 in	+ 1 inch for each	- 12°F	Decrease in frictional pressure loss causes the temperature to decrease
BHA Pressure Drop	1617 psi	-300 psi	-6.2°F	Decrease in frictional pressure loss causes the temperature to decrease
Rotate vs Slide	Rotate	Slide	- 6°F	Rotation causes more heat due to more work being done and the friction between the pipe and the wellbore increase
Higher Flow Rate	220 GPM	+20 GPM	+ 1°F	Increase in frictional pressure loss causes the temperature to rise slightly if the flow regime type does not change.
Lower Flow Rate	220 GPM	-20 GPM	- 0.73°F	Decrease in frictional pressure loss causes the temperature to decrease slightly
Pipe Rotational Speed (RPM)	70 RPM	+10 RPM	+ 0.6°F	More friction between the pipe and the wellbore
WOB	15 Kips	+ 10 Kips	+ 0.4°F	The effect is minimal

Table 2.5: The summary of a sensitivity analysis for different drilling parameters with the improved model

Hole Size Sensitivity

In this sensitivity analysis, operational bit sizes are tested. The original 6.5" bit can be replaced with different bits that can drift the 7.625" casing. Three sizes are tested to see their effect on the downhole temperature, 6", 6.25", and 6.75" hole sizes. Figure 2.41 shows the downhole temperature for the third production hole run for different hole sizes. As the hole size decreases, the downhole temperature increases. This increase in the temperature is due to the rise of the frictional pressure loss in the annulus. Table 2.6 summaries the effect of changing the hole size.

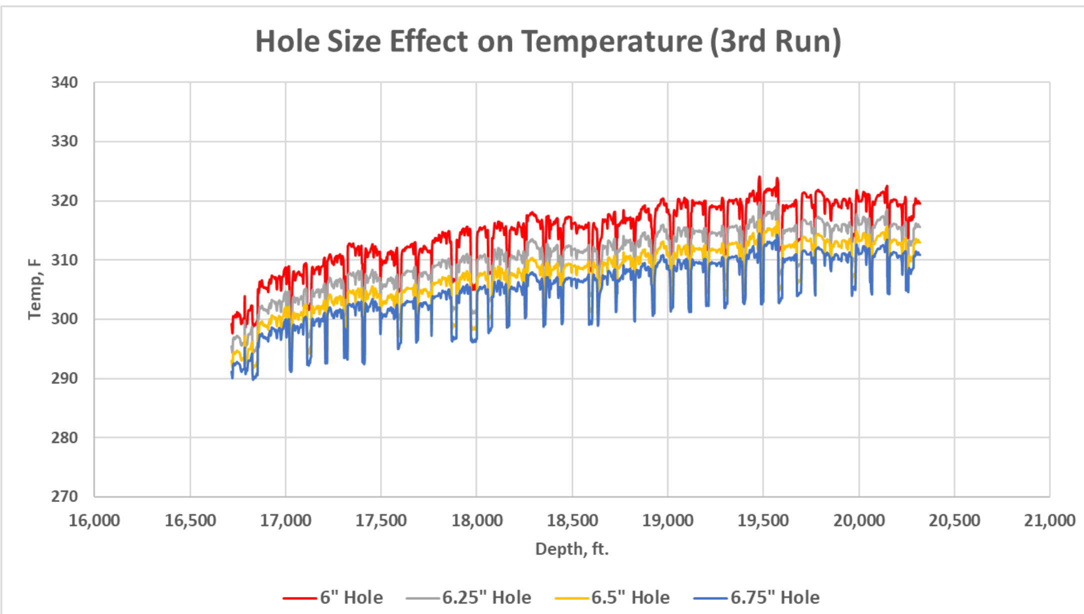


Figure 2.41: This plot shows the effect of different operational hole sized on the temperature with the improved temperature model. As the hole size decreases the downhole temperature increases.

Hole Size	Change from Base Case	Δ Temp	Cause
6"	- 0.5"	+ 7.1 °F	Increase in the annular friction pressure loss
6.25"	- 0.25 "	+ 2.8 °F	Increase in the annular friction pressure loss
6.75"	+ 0.25 "	- 2.2 °F	Decrease in the annular friction pressure loss

Table 2.6: Summary of the hole size effect on the downhole temperature.

Oil Content in the Drilling Fluid

It is typical in the Oil Based Mud (OBM) to have oil and water mixed in a certain ratio in order to have the optimum combination for the fluid properties and cost. The well used an oil ratio of 77. In the sensitivity analysis this ratio is changed to 70 , 85, and 90. Figure 2.42 shows the effect of changing the oil content on the downhole temperature. As the oil ratio increases, the downhole temperature increases. This can be linked to the lower heat capacity that the oil has. Table 2.7 shows the summary of the findings.

Oil Ratio	Change from Base Case	Δ Temp	Cause
70	- 7	- 3.2°F	Water has higher heat capacity
85	+ 8	+ 3.9°F	Oil has lower heat capacity
90	+ 13	+ 6.3°F	Oil has lower heat capacity

Table 2.7: Summary of the effect of the oil content in the drilling fluid on the downhole temperature

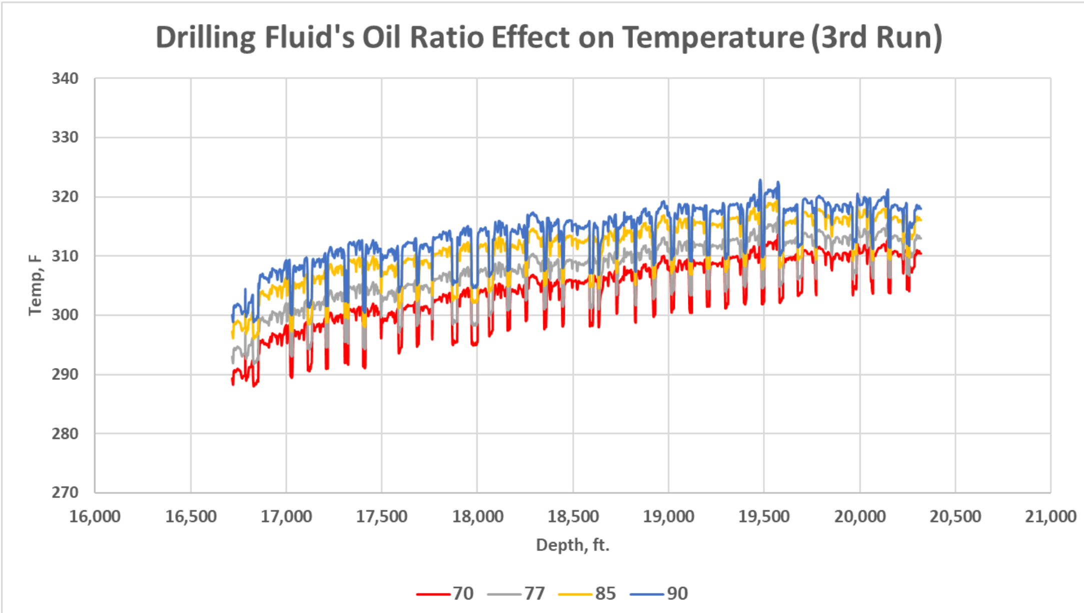


Figure 2.42: This plot shows the effect of different drilling fluid's oil ratio on the downhole temperature with the improved temperature model. As the oil ratio increases the downhole temperature increases.

How to Use the Sensitivity Table?

The summary table of the sensitivity analysis for different drilling parameters is helpful for the operations and the designing engineers. For the operation engineer, it can be a guideline for some parameters during the drilling operations especially in high temperature zones, such as parts of the Austin Chalk in Texas and Haynesville in Louisiana where the temperature can exceed 320°F, which is more than the static bottom hole temperature. This higher circulation temperature is due to the heat build up in the lateral in the high temperature zone and the increase in the friction between the pipe and the wellbore. On the other hand, in the vertical wells, the drilling fluid is not contacting the high temperature zone for long and the circulation temperature will be lower than the static bottom hole temperature. Depending on the limit of the tools in the hole, the operation engineers can find some guidance in controlling the downhole temperature by changing some drilling parameters. On the other hand, the designing engineer can change the drilling program and design based on the table to reach to the desired outcome. For example, if the only tool available is near the temperature limit, there will be two options. First, to change the mud system to oil based mud given that all the additives needed are available to prevent swelling and other hole problems. This change in the mud system will grant about 30°F below the temperature limit. If it is a series of well, the hole design can be changed to a larger size to reduce the annulus temperature given that the casing design can be carried out or a change in the wellbore design is needed. There are a lot of tweaks in the design that can be performed based on the table to achieve the desired downhole temperature. However, we must take into consideration other drilling challenges while making these changes to avoid any complication in the operation.

2.13 Discussion

It is important to understand the effect of different drilling parameters on the downhole temperature especially in high temperature wells. The MWD and the downhole sensors can have failures in high temperature, and the service company could charge the operator the tool's price once a certain temperature is exceeded.

Trichel and Fabian (2011) presented their temperature sensitivity for eight scenarios in drilling a well in Haynesville. Thier work was the trigger that initiated this research to have a better understanding and a holistic approach to predict the downhole temperature. Our results match the trends in results presented in their paper and in Table 2.8. However, there are differences in the specifics of the temperature changes. These differences in the specifics in the temperature can be linked to the different op-

Paremeter	Base Case	Change Made	Change in Downhole Temperature
Higher Flow Rate	200	+10 GPM	+ 1 °F
Lower Flow Rate	200	-20 GPM	- 2 °F
Type of Drilling Fluid	OBM	WBM	- 37 °F
Reduce bit TFA	1.0354 in^2	to 0.69 in^2	+2 °F
Increase hole size by 1"	6.5 in	+ 1 inch	- 9 °F
BHA Pressure Drop	1815 psi	-200 psi	-6 °F
Rotate vs Slide	Rotate	Slide	- 3 °F

Table 2.8: Trichel and Fabian (2011) results for the sensitivity analysis of the downhole temperature

erational parameters.

Trichel and Fabian (2011) did not present the full temperature profile for the well. There is a three hours log data with a channel for the temperature and the match has more than 15 °F difference in most of the plot. In addition, the match with the downhole temperature was in two points only. However, we tried in this research to present the whole temperature profile and the average error was 1.61 %. Also, we tried to show the calculation method for the downhole temperatuer in detail so it can be used for any future analysis. In addition, new parameters were tested such as RPM, WOB, and motor torque. Moreover, our study analyzed the flow regimes in the system, which showed that a special consideration is needed once we move from laminar flow to turbulent flow and vice versa.

Kumar and Samuel (2013) presented the general analytical model that is used in ERA. In their paper, they did a sensitivity for the flow rate, the wellnore friction, and the rotational speed in RPM. The trends of the study match our results. However, the changes made to test the sensitivity seem large compared to the actual drilling parameters. Also, it was performed in a well with normal downhole temperature.

My research should build on the previous work and consolidate the findings of Trichel and Fabian (2011) on the drilling parameters effect on the downhole temperature. In addition, the research's findings should also add to our understanding of the effects of some parameters that were not tested before such as RPM and WOB.

2.14 Conclusions

This research explored the perdition and modeling the dowbhole circulation temperature in high temperature land wells. It utilizes ERA software and investigates the temperature model built by Kumar and Samuel (2013). In addition, the study replicates Trichel and Fabian (2011) investigation of the effect of different drilling parameters on the temperature profile with the utilization of the more recent model.

One of the important goals of this research is to understand and follow the calculations steps for the temperature prediction in order to improve the model in ERA. In this process, spikes in the temperature were investigated and linked to an increase in the surface torque that resulted in an overestimation of the downhole temperature because of the usage of the ERA's torque and drag (TnD) engine in the temperature modeling. Not only was this overestimation found but also the software did not account for the measured torque data in the calculations when it was available. Moreover, in a deeper analysis, it was found that the temperature profile was following the trend of the differential pressure and the downhole torque should be calculated using the differential pressure method instead of the TnD method if the BHA has a motor. After several meetings and investigation, a new preview release of ERA was developed with an improved temperature model and a new workflow based on this research. The new model eliminates the overestimation spikes in the temperature profile and utilizes the measured downhole data.

The last part of this study focused on the a sensitivity analysis of different drilling parameters and their effect on the downhole temperature in order to give a tool for the people in the field to anticipate the change in the downhole temperature based on the change in the parameter. The parameters can be divided into three categories. First, the operational parameters that has small to negligible effect such RPM, WOB,and flow rate. RPM and WOB rate did not show a big impact on the temperature profile. However, the flow rate should have a special consideration. If the flow regime does not change in the change of the flow rate. The impact on the temperature is small. On the other hand, if the change of the flow rate resulted in a change in the flow regime from laminar flow to turbulent flow and vice versa, the impact on the down hole temperature is huge. This huge impact can be link to the increase of the fiction pressure loss. The second set of parameters are the ones with a medium impact on the downhole temperature. This set includes BHA pressure drop and the sliding effect. The temperature change was 6 °F. The last category is for the parameter with a high impact on the downhole temperature. The set include using the type of the drilling fluid and change of the hole size. Changing the drilling fluid from OBM to WBM resulted in more than 30 °F difference in the downhole temperature because of the higher heat capacity for the water compared to oil. Moreover, the increase in the hole size will result in less friction pressure loss because of the partial change of flow regime to laminar and will reduce the downhole temperature by 12°F.

2.15 Future Work

While performing the study and the analysis, several future research possibilities can be identified and will be addressed in this section. The first one would be to study the effect of a kick in the downhole temperature. The model does not account for the heat from a flow from the wellbore. In the plotted measured temperature data, there was a clear increase of the temperature at the depths that had gas kicks or when the gas accumulated in the system. This phenomena can be studied and analyzed.

In this study, the data was originally in time based form and was transformed to depth based. ERA does this by taking the average of the data for each depth. Several methods of calculating the average are available in statistics, and applying them in ERA data conversion will grant more accurate prediction calculations. Moreover, another way is to prepare the data before importing it to ERA. Also, with the increase in the frequency of data gathering such modification in the data conversion from time to depth based is necessary.

Another area of interest that can be explored is the effect of downhole vibrations on the downhole temperature. The measured data set that was used in this research had a few medium vibrations that cannot be linked to an increase in the downhole temperature. Wells with medium to high downhole vibrations should be studied to analyze the effect of high vibrations on the downhole temperature. Finally, more actual high temperature well data can be used to test the model and an analysis between the WBM, and the OBM with actual data will be an interesting subject.

3. ENHANCEMENT OF THE GEOTHERMAL DRILLING PRACTICES AND PERFORMANCE IN PUNA GEOTHERMAL VENTURE, HI

3.1 Introduction

Drilling takes a large sum of the energy company's budget. This applies for petroleum and geothermal companies. Renting the rig can vary between $ 20K per day for an inland rig in North America (Daleel, 2019) to $ 250K per day for a drillship (IHS Markit, 2019). The geothermal rigs prices tend to be toward low end. The drilling operations in geothermal development can account for more than 50 % of the total project cost. (Tester et al., 2006). Thus, saving time during the drilling while maintaining a safe operation can affect the budget of the company in a positive way. It has been reported by Visser et al. (2014) that six major issues were identified as problems in the geothermal's drilling operations. These problems are related to lost circulation, cementing, efficient and consistent drilling programs, rate of penetration (ROP), and rig equipment selection. A holistic approach to analyzing the data of the drilling operations and finding areas to enhance the performance is essential for every operator.

Background on the Geothermal Industry

The term "goethermal" is a combination of two Greek words. Geo which means earth and therme which means heat. The result would be the term " Earth Heat". Humans have used the earth's heat since the early days for cooking and bathing. It has been reported by Mink (2017) that the city of Boise in Idaho used geothermal sources to heat commercial and residential buildings in the 1890s. The usage of geothermal energy evolved in the United States in 1960, when the commercial geothermal electric power production started in the Geysers geothermal field in California. The attention on the geothermal industry has increased in the recent years and 6 % of California's electricity is produced by geothermal plants (EIA, 2016). The budget for the Geothermal Technologies Office in the Department of Energy was $ 84 Million in 2019 (Hamm, 2019).

3.2 Literature Review

Drilling performance enhancement is important for all energy companies. Using the physics based approach will help to look into the root causes of the bit's dysfunctions that are causing the operations to be inefficient. There are many drilling parameters that are recorded and in many times transmitted real-time to the surface while a rig is drilling a well. These parameters include Rate of Penetration (ROP), Weight On Bit (WOB), pipe Revolution Per Minutes (RPM), differential pressure , torque, and many others. Monitoring and analyzing these parameters enable the detection of many inefficiencies in the drilling operation.

Pierce et al. (1994) reported that the geothermal energy had a decade of growth in the 1980s to produce electricity. However, it slowed down in 1990 because of the depletion of the resources. They also reported the prediction that the geothermal energy would become the most cost effective resources for Southern California Edison in the next decade. Many interviews were conducted to evaluate the state of the geothermal industry in that time. The authors stated that lost circulation was the most costly problem that has been encountered in the past and it remained so. Lost circulation would cost rig's time and can lead to severe problems during the cementing operation.

Tester et al. (2006) studied the geothermal drilling technologies and predicted the well cost as part of an assessment titled "The Future of Geothermal Energy". They discussed the available technologies at that time such as high temperature instrumentation, drilling fluids coolers, and new bit designs. The authors presented a model to predict the geothermal well costs. Finally, they discussed emerging drilling technologies. These technologies were expandable tubular casing, under-reamers, drilling with casing, and multilateral completions.

Finger and Blankenship (2010) developed a handbook for the best practices for geothermal drilling. They discussed the well cost drivers such as the well design and the drilling hazards. The authors have several chapters and in each one they presented different aspects of the drilling operation starting from the well design and the rig selection. Followed by the casing design, cementing and drilling fluid selection. Finally they presented potential drilling problems, well control, instrumentation and logging, and emerging technologies. Dumas et al. (2013) published a report on the geothermal drilling in Europe. They analyzed the geothermal drilling market in Europe and suggested enhancing the competition between drilling contractors. Also, they outlined some different drilling practices between the geothermal industry and the oil and gas.

Okwiri (2013) analyzed the drilling time for 15 geothermal wells in Kenya and 19 wells in Iceland. She reported that the average well depth in Iceland was 7648 ft. while in Kenya it was 6427 ft. However, it took 43.1 days in average to complete the well in Iceland compared to 95.9 days in Kenya. She concluded that there are two reasons behind the difference. First, the crew in Kenya was new and they had to establish their work dynamics. Second, they faced lost circulation that leads to bigger problems such as a stuck pipe in eight out of fifteen the wells.

Visser et al. (2014) compared the daily drilling operations of 42 wells. Half of them were geothermal wells while the other half were petroleum drilling operation wells. The geothermal drilling operations averaged 56.4 days longer than comparable petroleum wells. It is important to look closely at these differences and transfer the knowledge and practices from the petroleum industry to the geothermal to enhance the performance and bridge the gap.

Lowry et al. (2017) studied the cost factors of the drilling operations and developed drilling cost curves with different scenarios. Then, the authors discussed three focus research areas. First, the bit design and they reported the differences between the roller cone bits and the PDC bits in the geothermal industry. They presented several studies for the usage of PDC bits in hard rocks. Second, the high temperature environment, and they discussed the issues of the failure of downhole components because of the high temperature. Third, the non drilling time, and they reported that the most common causes were lost circulation and stuck pipes.

Knudsen et al. (2014) used MSE surveillance and changed the design of the Bottom Hole Assembly (BHA) for a geothermal well in the McGinness Hill field in Nevada. The drilling was through hard metamorphic and crystalline formations. The BHA design was changed from pendulum to packed assembly. In pendulum assemblies, the stabilizer just above the bit is removed while retaining the upper ones and was used to maintain the inclination angle below 2 degrees. On the other hand, the packed assembly contains three to five stabilizers properly spaced allowing for more WOB. The result was that the packed assembly drilled 87% faster than the original pendulum assembly.

Mechanical Specific Energy (MSE)

MSE is defined in Schlumberger oil field glossary as "the energy required to remove a unit of volume of rock". Teale (1965) was the first to introduce the concept of MSE. He divided the work that is done to crush the rock into two components. The thrust, which is the force acting on the area and the rotary component. Another approach that the paper discussed was to take the penetration rate in inch per revolution. The relationship between torque and penetration rate might be useful index of MSE. The author noted that the specific energy at low thrust will be high and this can be related to the Depth of Cut (DOC). The author also noted that the minimum energy found was equal to the compressive strength of the material drilled. All Teale's experiments were performed in the lab under the atmospheric conditions.

Pessier and Fear (1992) built on Teale's work and introduced the bit specific coefficient of sliding friction to express torque as a function of WOB. They performed a full scale simulator to validate the energy balance model under hydrostatic pressure conditions. As a result, they were able to extend the concept of the MSE to the oilfield drilling. Their final form of the MSE equation is the general MSE that is used today.

$$MSE = \frac{480 \times Tor \times RPM}{D_h^2 \times ROP} + \frac{4 \times WOB}{D_h^2 \times \pi} \tag{3.1}$$

Waughman et al. (2003) used MSE to assess the dull grading of the bit and when it should be pulled out of the hole. They suggested that a comparison between the bench mark new MSE and the calculated current reading of MSE should provide an indication about the dull condition of the bit. The authors noted that bit balling can mask the bit's dull condition if water based mud is used. They added that an operator was able to successfully follow the methodology in water based mud with antiballing chemicals. A guideline to apply the technique was presented in the paper.

Dupriest and Koederitz (2005) applied the real time surveillance of MSE to maximize the drill rates. They introduced the use of MSE as an indicator to the inefficiencies in field operations. Also, they reported a linear relationship between the ROP and WOB if there is no founder. The authors reported an increase in the average ROP for six rigs by 133 % in the period of three months. They also suggested that the MSE should be adjusted by an efficiency factor since bits cannot reach 100 % efficiency. The paper includes many field data examples of the use of MSE to detect foundering bit's inefficiencies.Three main bit's foundering points were discussed; bit balling, bit bouncing, and vibrations.

Vibrations:

Vibrations can be defined as "any repeating oscillation about an equilibrium position"(Dupriest, 2017). In drilling, three types of vibrations can be encountered. The lateral vibration which results in whirl, the axial vibration that results in bit bounce, and the torsional vibration that caused stick slip.

Whirl

Whirl is the most common type of vibrations that can be experienced in the field. The main cause of whirl is that the center of the rotation movement is moved by dynamic forces as the bit rotates (Brett et al., 1990).There are two types of whirl, forward and backward whirl. All BHAs develop sine waves that caused forward whirl. The forward whirl is in the direction of the pipe rotation. The second type of whirl is the backward whirl and it can result in high impact events. Backward whirl can lead to damaged bit teeth identified by beach marks and a non uniform wear as a result of an impact (Dupriest, 2005).

Stick Slip

The torsional vibration during the drilling operation can cause stick slip which starts with a torque oscillation that leads to string twist. The twists can lead to the full stop of the bit followed by a fast rotation since the top drive is still rotating. It is usually observed at low RPM and high WOB (Kovalyshen, 2014). Stick slip can lead to severe damage to the bit in the form of chipped teeth.

3.3 Research Objective

To review and analyze the drilling data of Puna Geothermal Venture in Hawaii and provide recommendations to adopt the best drilling practices in order to enhance the drilling performance.

3.4 Research Methodology

First, monitor and analyze the drilling data and operations to identify areas of improvement. Second, provide recommendations and suggest changes in workflows and operations to enhance the drilling performance.

3.5 Puna Geothermal Venture, Hawaii

Background

The first well was drilled in the East Rift Zone of the active Kilauea volcano in 1961 by Richard Lyman (Schroeder, 2015). He thought about the project to transport the electricity between Hawaii islands during a trip to Japan where he learned about a Japanese Company called "Sumitomo Electric Cable Company", which was "Note" in Japan. In Hawaii, the source of electricity would be a geothermal plant in Puna. Several shallow wells were drilled but with no success (Szvetecz, 2001). In 1972, a research proposal was submitted to the National Science Foundation (NFS) by an engineer at the University of Hawaii for $ 2.7 million geothermal project. This was a seed to the discovery of the Kapoho Geothermal Reservoir in the East Rift Zone in 1976 after drilling the well HGP-A (Boyd et al., 2002). The drilling of HGP-A lead to the construction of the first 3 MW wellhead generator that was completed in 1981. In

1993, the first commercial geothermal power plant was completed with 25 MW facility (Schroeder, 2015).

3.5.1 Puna Geothermal Venture Overview

Puna Geothermal Venture is located in the lower right corner of the Big Island in Hawaii, USA as can be seen in Figure 3.1 (HCCDA, 2018). It is an active volacano zone. Figure 3.2 (Schroeder,2016) shows an aerial view of the plant and its surroundings. There are two road accesses to the venture and two power plants that is generating 36 MW. Also, the venture has five well pads A, B, D, E and F pads.

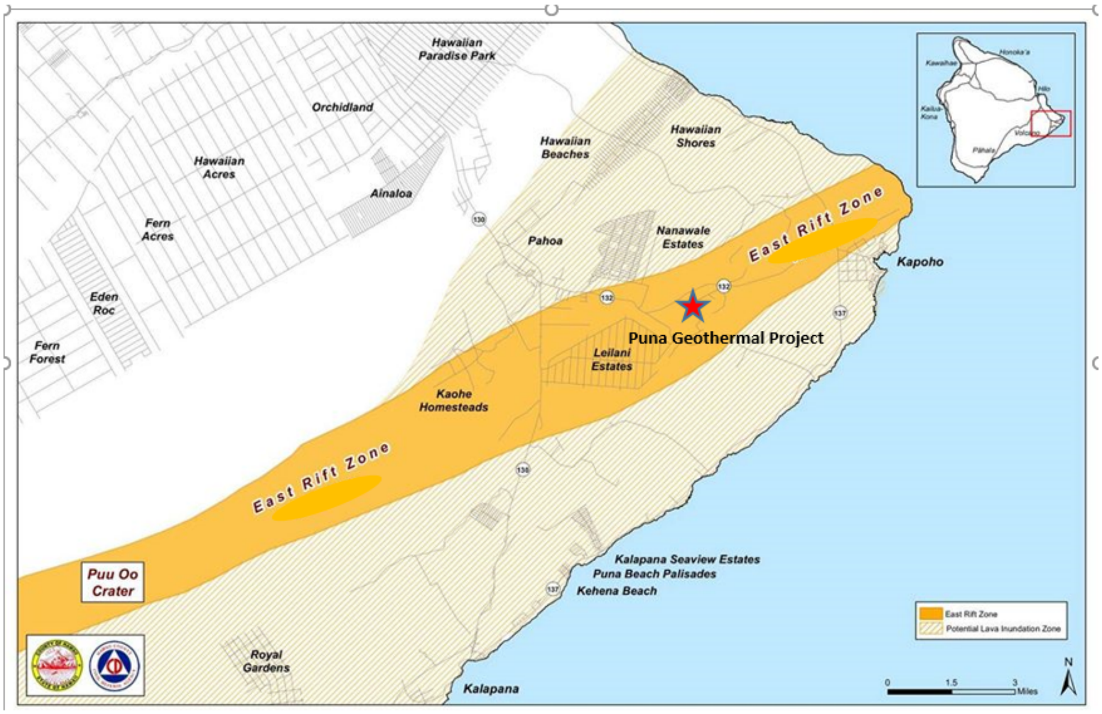


Figure 3.1: Location of the Puna Geothermal Venture, Big Island Hawaii (adapted from Hawaii County Civil Defense)

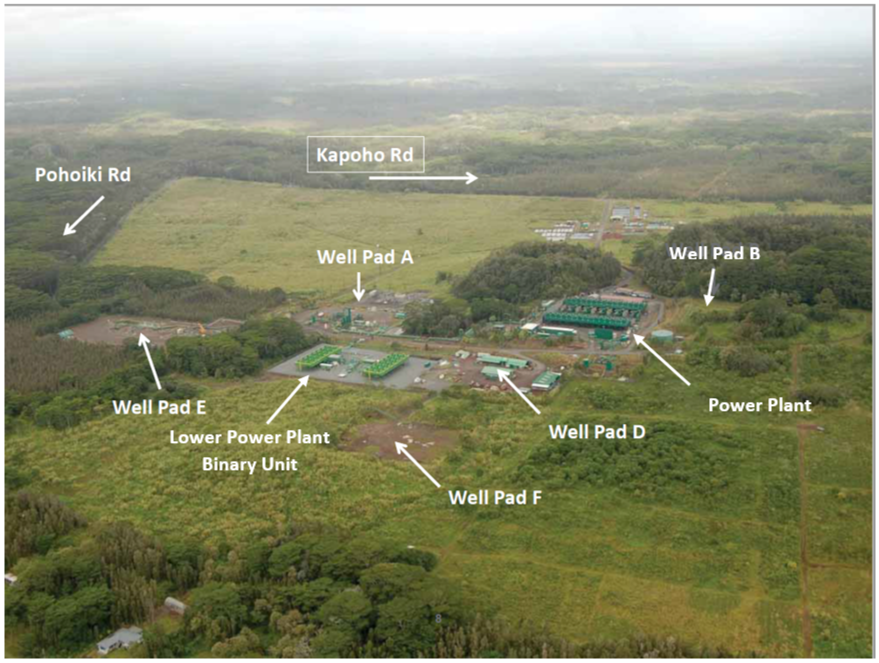


Figure 3.2: Areal View of the Puna Venture Power Plant (adapted from ORMAT)

Figure 3.3 (HGGRC, 2015) in the next page shows a diagram for the Puna Geothermal Venture. It shows the production and injection wells in each pad along with the bottom hole locations. There are more than 14 wells that were drilled over the years. 11 wells were active before the lava flow incident in May 2018. Five wells were for injection and six wells were for production. The power plant was shut down after the lava flow and some wells were covered in lava. ORMAT is working very hard to bring the power plant back in service in 2020 (ORMAT,Company Release,2020). According to a permit review summary that was filed by the venture in 2014, Pad A has three production wells KS-9, KS-10 and KS-16. Pad A also has three injection wells KS-1A, KS-11 and KS-13. Pad B has one injection well which is KS-15. Pad E has four pro-

Table 3.1: Wells in the Puna Geothermal Venture

Well Name	Pad	Well Type	Depth (ft)
KS-1A	Pad A	Injection	7216
KS-3	Pad E	Injection	6835
KS-5	Pad E	Production	6386
KS-6	Pad E	Production	6532
KS-9	Pad A	Production	4584
KS-10	Pad A	Production	5210
KS-11	Pad A	Injection	6500
KS-13	Pad A	Injection	8262
KS-14	Pad E	Production	5727
KS-15	Pad B	Injection	8020
KS-16	Pad A	Production	5745
KS-18	Pad E	Production	5690
KS-17	Pad B	Injection	n/a

duction wells KS-5, KS-6, and KS-14. Pad E also has one injection well that is KS-3. ORMAT started drilling KS-18 at the end of 2019 and is planning to drill KS-17. Table 3.1 summarizes the wells in Puna Geothermal venture.

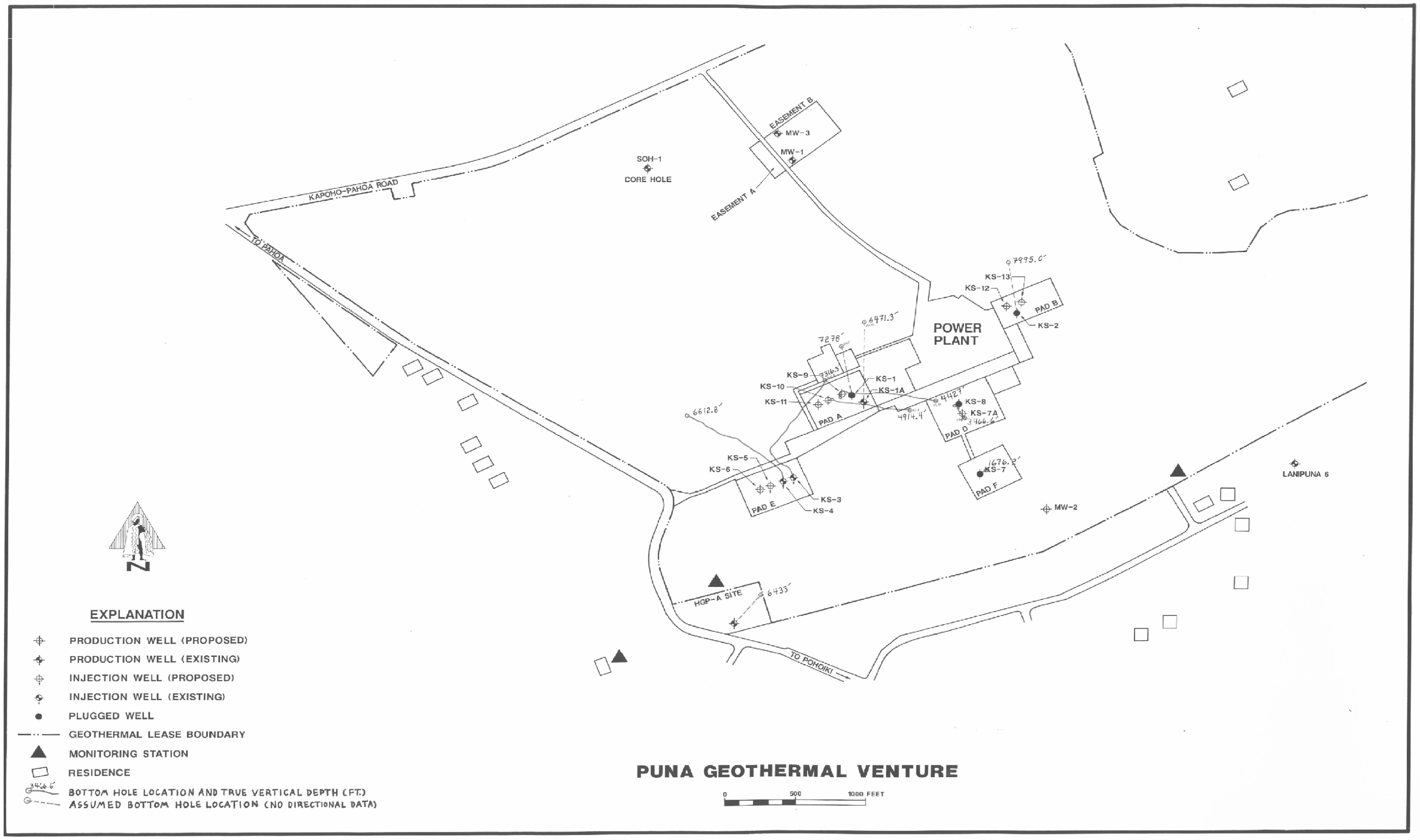


Figure 3.3: Map of Puna Geothermal Venture

3.5.2 Geology

Kilauea is located in the southeastern corner of the Island of Hawaii and is an active volcano. The Island was formed from five volcanoes Kohala, Mauana Kea, Hualali Muana Loa and Kilauea. All their shields are composed of tholeiitic basalt (Moore and Kauahikaua, 1993). The main surface rock that is covering the Lower East Rim Zone (LERZ) is Puna Basalt and 75% of it is less than 400 years old (Moore and Trusdell, 1993). There are multiple fractures in the Puna Geothermal venture that are a result of the large fault in the southern flank. The fault is down-dropping and sliding into the ocean (Fitch and Maltlick, 2008).

Basalt is the only lithology that is forming Puna. The formation of basalt below 1000 ft. was in a sub-aqueous environment. The basalt stratigraphy was divided into five divisions by Puna geologists: basalt dikes, which are encountered in deeper drilling, pillow, hyaloclastite, lavas and cinder basalt (Fitch and Maltlick, 2008).

3.6 Summary of ORMAT's Drilling Activities

This section summarizes the drilling operations of ORMAT Technologies in Kilauea East Rift Zone, Hawaii, USA. The operations took place between September 1999 and February 2020. We had a total of 21 daily drilling reports from 9 different wells. There were three types of operations described in the reports. First, the original hole report describes the operations of drilling the well from the surface to the target for the first time. Second, the Re drill report describes the daily drilling operations for re drilling a well either to side track it or deepen the original hole. Third, the clean out report describes the operation of a workover for the well, cleaning out casing or replacing it. We had a total of 7 original hole drilling reports, 7 re drill reports and 4 clean out reports. Table 3.2 summarizes the report types that we had for each well:

Table 3.2: Summary of Available Reports and Their Type

Well Name	Original Hole Report	Re Drill Report	Clean Out Report
KS 4	N/A	Re drill Report	Clean out #1 Report and Clean out #2 Report
KS 5	Original Hole Report	N/A	N/A
KS 10	N/A	Re drill Report	Clean out Report
KS 11	Original Hole Report	Re drill #1 Report, Re drill #2 Report and Re drill #3 Report	N/A
KS 13	Original Hole Report	N/A	Clean out Report
KS 14	Original Hole Report	Re drill Report	N/A
KS 15	Original Hole Report	N/A	N/A
KS 16	Original Hole Report	ST#1 Report	N/A
KS 18	Original Hole Report	N/A	N/A

Well Design

Most of the wells had a design of five sections as in Figure 3.4. These sections are :

- 30" conductor to ≈ 90'.

- 26" hole to ≈1050' and 22" casing.

- 20" hole to ≈2100'and 16" casing.

- 14.75" hole to ≈ 4800'and 11.75" casing.

- 10.625" hole to 6000'+ and 8.625" Liner.

There is one well which is KS-16 that had slimmer wellbore design. It had 17.5", 12.25" and 8.25" hole sections instead of the 20", 14.75", and 10.625".

3.7 Summary of Drilling Performance

The time needed to complete a well in Puna Geothermal Venture ranges from 58 days to complete KS-14 which had a depth of 5727 ft. to 127 days for KS-5 which had

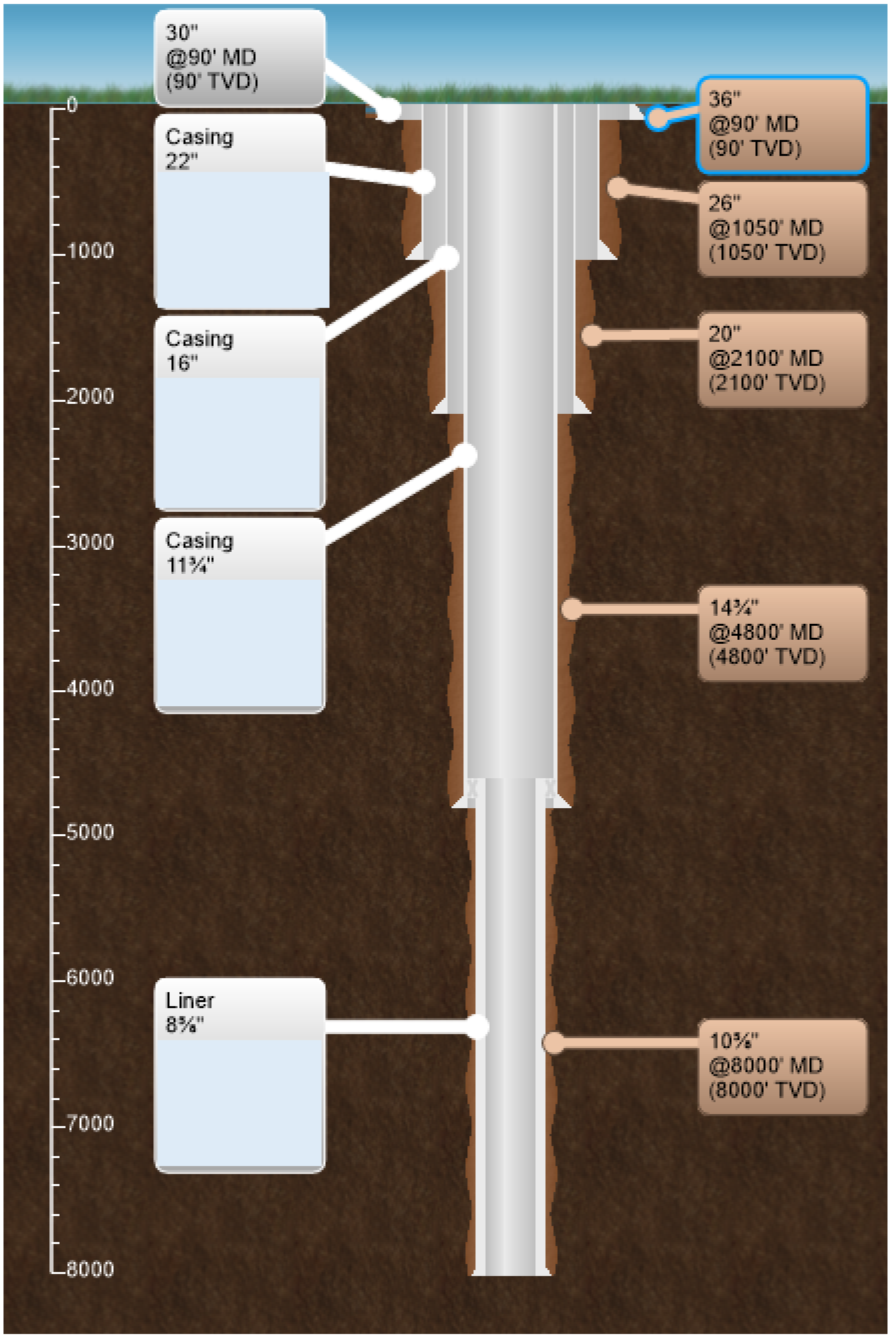
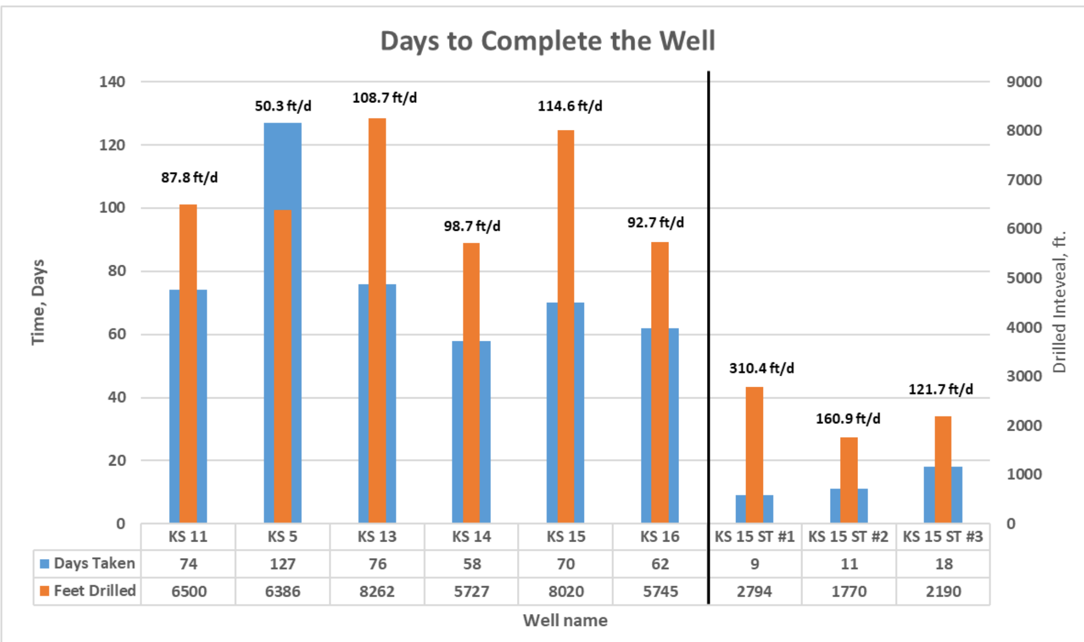


Figure 3.4: Generic Wellbore Diagram for a Well in Puna Geothermal Venture

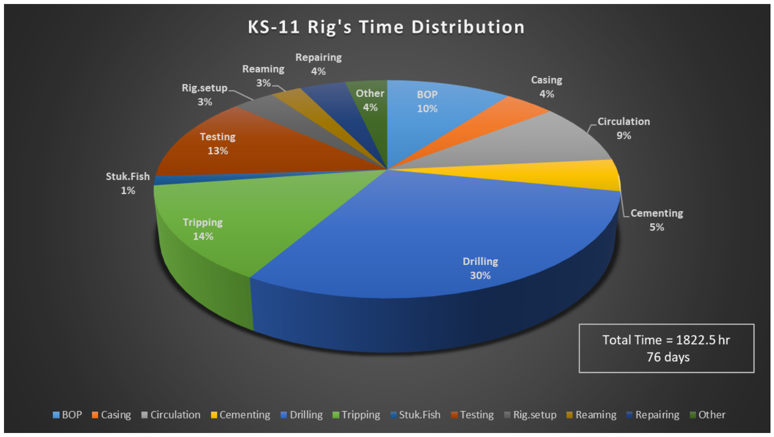
a depth of 6386 ft. This wide range can be explained when we look at the details of the drilling operations (Appendix A) and the challenges encountered at each well. Figure 3.5 shows the time it took drilling KS-5, KS-11, KS-13, KS-14, KS-15, and KS-16. The blue columns show the days taken to complete the well with the days in the left vertical axis. The orange columns show the drilled interval in feet (right vertical axis) during that period of time. The average time was 77 days per well and the average feet drilled was 6773 ft. per well.



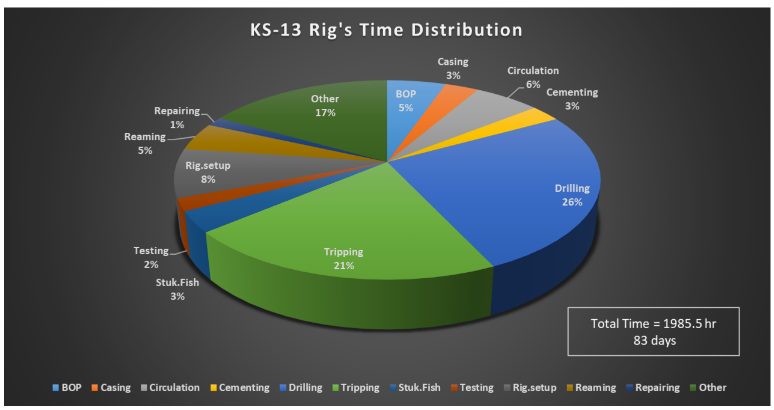
	KS 11	KS 5	KS 13	KS 14	KS 15	KS 16	KS 15 ST #1	KS 15 ST #2	KS 15 ST #3
Days Taken	74	127	76	58	70	62	9	11	18
Feet Drilled	6500	6386	8262	5727	8020	5745	2794	1770	2190

Figure 3.5: This figure shows time in days to complete the wells in Puna Geothermal Venture. It is arranged chronically from KS-11 to KS-16. The far right represents the side track performance in KS-15

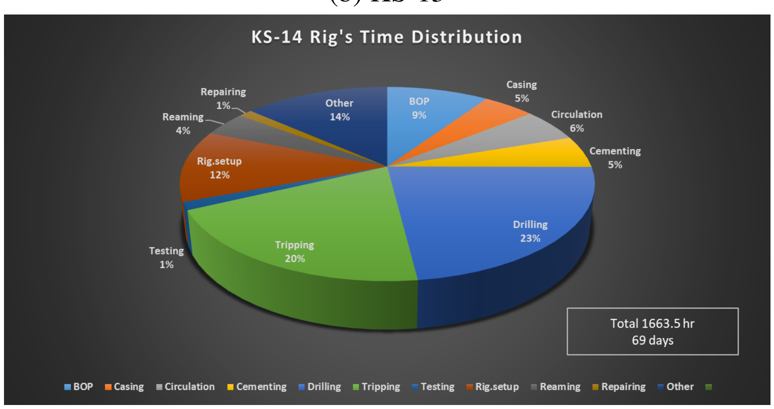
In order to look deeper into the drilling performance, we had to look into the time spent in each operation to detect areas of improvement. The daily drilling report summarizes the operations of the drilling activities. Each activity would have an operation code. All the operation codes were extracted from the reports for each well using R software script. As a result, more than 40 different codes were identified. Then, these codes were categorized into 13 operations which are BOP, Casing, circulation, cementing, drilling, tripping, stuck and fishing, testing, rig setup, reaming, repairing, and other. Figures 3.6 and 3.7 show pie charts for the time spent for each drilling activity in each well.



(a) KS-11

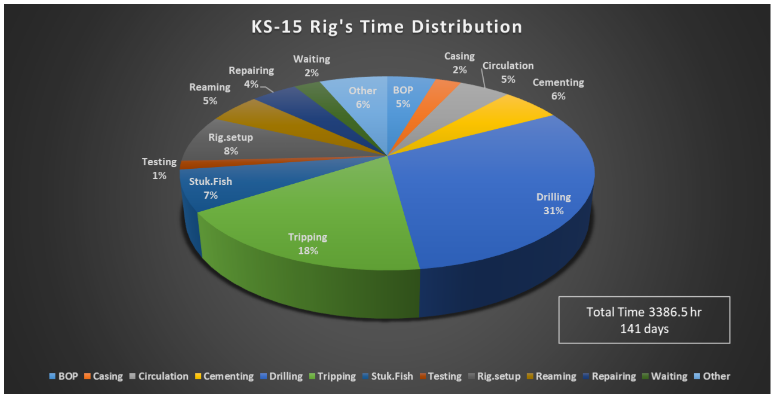


(b) KS-13

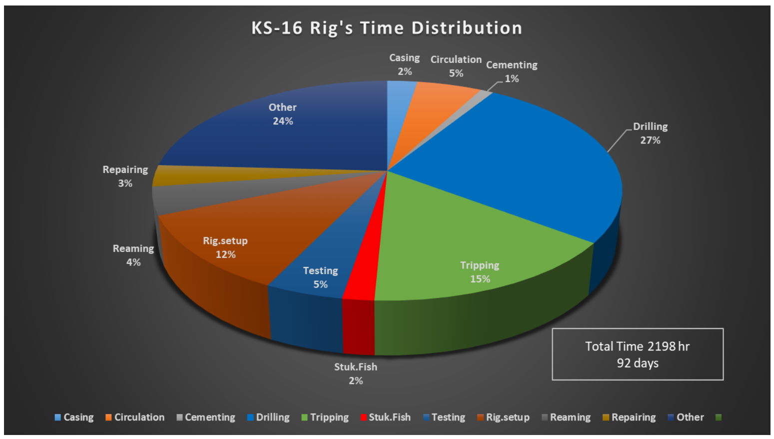


(c) KS-14

Figure 3.6: The Rig's Time Distribution for KS-11, KS-13, and KS-14. Drilling and tripping account for more than 40% but other activities are taking long time.



(a) KS-15



(b) KS-16

Figure 3.7: The Rig's Time Distribution for KS-15 and KS-16

In the well KS-11 , the rig's time distribution during the operation was the following: 30 % of the total time which was 76 days was in drilling. Next. 14% was in tripping and 13% was in testing. Then, BOP operations took 10% of the total time and 9% was in circulation. Cementing and casing accounted for 9% and the last five activities which are rig set up, reaming, repairing, other, and stuck and fishing took 3%, 3%, 4%, 4%, and 1% respectively.

For the other wells, the time took each operation varies depending on challenges faced. Drilling took between 25-30 % of the time and tripping took between 15-20 %. Rig setup which includes rig up and rig move accounted for about 10 %. The rest of the operations took less than 10% each in most of the wells. KS-18 was excluded from this analysis since it hasn't been completed yet.

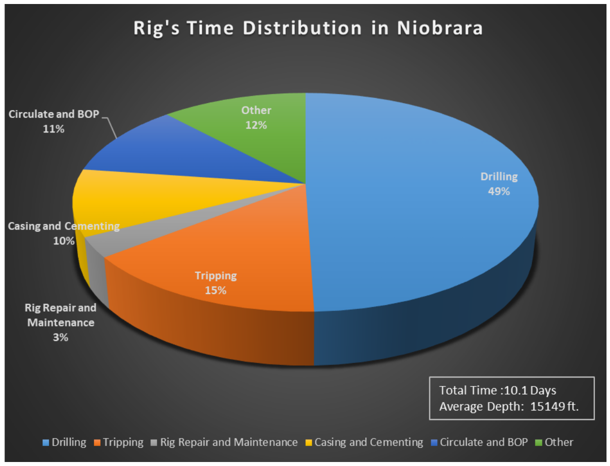
How Does This Performance Compare To Others?

After analyzing the time spent on the operations in Puna Venture, it was important to compare the performance with operators around the world to identify the areas of improvement and to set benchmarks for each operation. We researched both oil and geothermal industries' performance in five oil and gas basins in the United States. Also, we looked in the Gulf of Mexico drilling performance. In addition, we looked into the geothermal drilling in Kenya and Iceland.

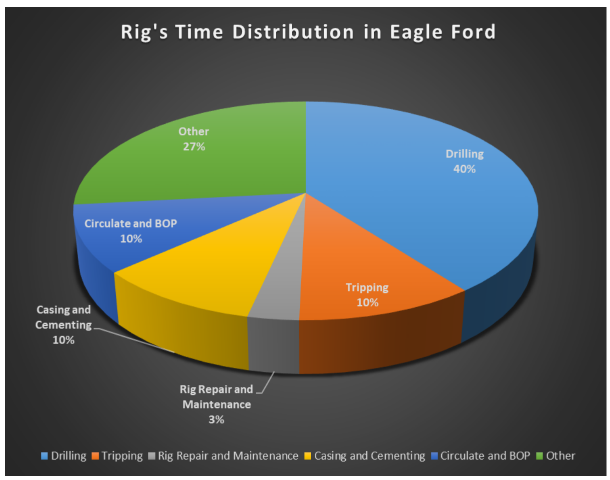
Oil and Gas Land Drilling in USA

A report by NABORS (2017) provided the drilling performance data for the Permian, Eagle Ford, Bakken, Niobrara, and Haynesville for the second quarter of 2017. The data set consists of 2746 wells: 1384 wells in the Permian, 540 in Eagle Ford, 422 in Niobrara, 266 in Bakken, and 134 in Haynseville basins. In addition, the report shows the average time to drill a well, average depth of the wells, drilling and tripping speeds, and connection time for each basin.

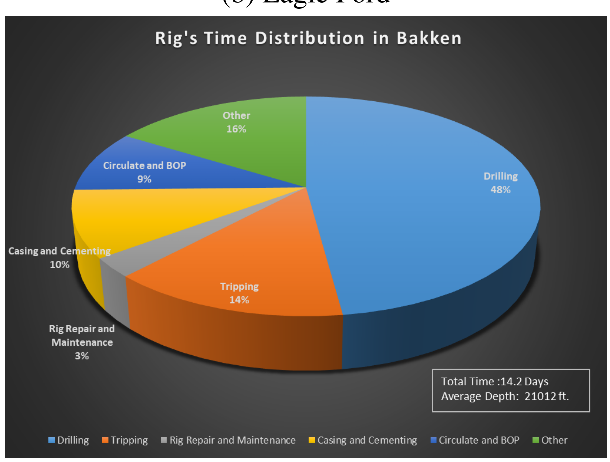
Figure 3.8 shows the rigs time distribution for three basins in the United States. Starting with the fastest basin which was Niobrara, the rig spent only 10.1 days to drill 15000 ft. well. Almost half of the rig's time was in drilling. Then, 15% of the rig's time was in tripping. Circulation and BOP set up took 11% of the rig's time. In addition,casing and cementing accounted for 10% of the time. Finally, the rig repair and maintenance was minimal at 3%.



(a) Niobrara



(b) Eagle Ford



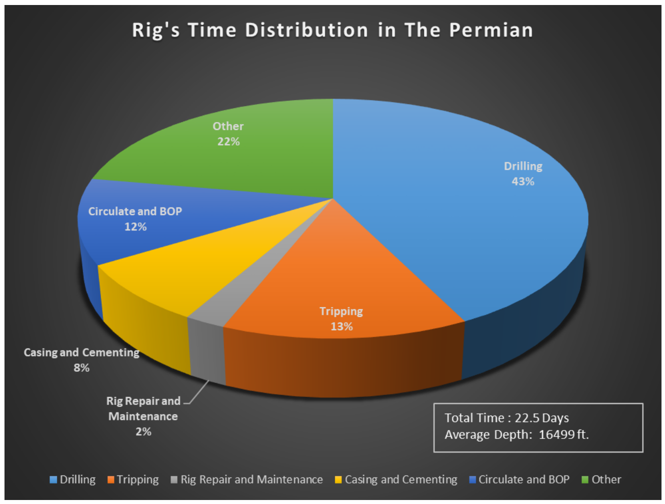
(c) Bakken

Figure 3.8: The Rig's Time Distribution in Niobrara, Eagle Ford, and Bakken Basins

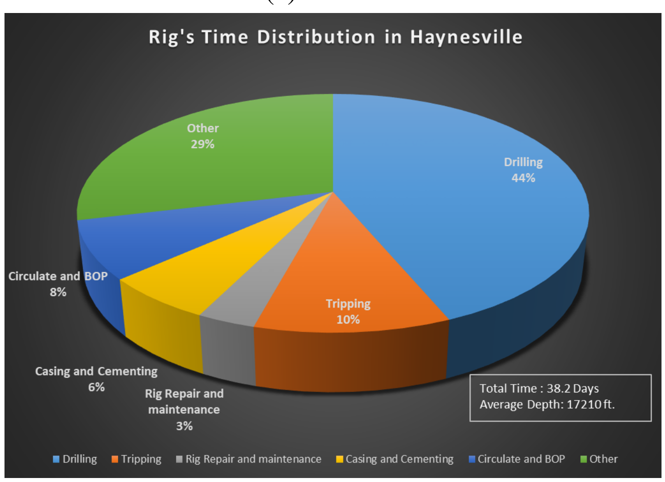
Moving to the Eagle Ford basin, drilling accounted for 40% of the 13.1 days that took the rig to complete a well. Tripping, circulation and setting up BOP, and casing and cementing each used 10% of the rig's time. Tripping was faster in the Eagle Ford due to the usage of RSS and Electromagnetic MWD. Finally, rig repairs and maintenance accounted for 3% of the rig's time. In another Basin, Bakken rigs spent 14.2 days to complete a 21000 ft. well. Drilling and tripping accounted for 48% and 14% respectively of the rig's time. All the other operations were similar to the Eagle Ford time distribution.

In the Permian, the rig's time distribution is in Figure 3.9. Drilling and tripping accounted for more than 50% of the total operation time which was 22.5 days. Circulation and BOP set up took 12% of the rig's time. Then, casing and cementing spent 8% of the rig's time. Finally, the rig repair and maintenance accounted for 2% only. Moving to the slowest drilling basin in this report which was Hayneaville, drilling accounted for 44% of the rig's time and tripping used 10%. Circulation and BOP set up took 8% of the rig's time. Then casing and cementing accounted to 6%. Lastly, rig repair and maintenance didn't take more than 3%.

Comparing the performance of these basins with the performance of Puna Venture, it is clear that they have better performance that can be learned from to enhance the efficiency in the Puna venture operations. Starting with the drilling which should account for more than of 40% compared to 20-30% in Puna operation. Also, Tripping should take between 10-15% of the rig's time compared to 15-20 % in the current situation in Puna. Moreover, the entire operation in Puna venture is taking more time to drill the well at this depth compared to the operations at these five basins.



(a) Permian



(b) Haynesville

Figure 3.9: The Rig's Time Distribution in the Permian and Haynesville Basins

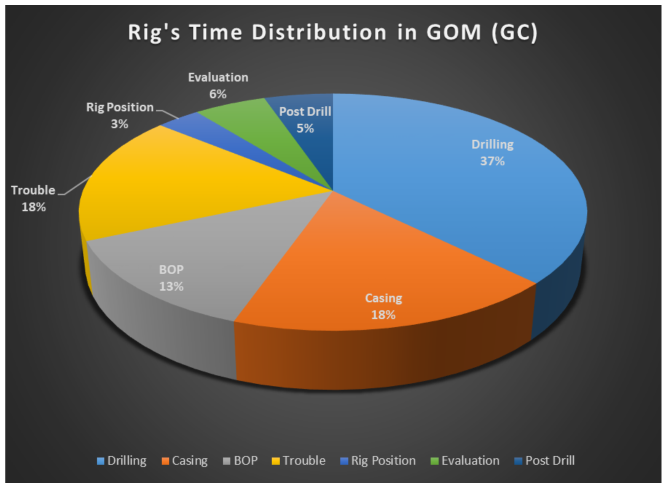
Gulf of Mexico

To have a wider comparison, we looked into the offshore operations in the Gulf of Mexico (GOM). Iyoho et al. (2005) reported the drilling performance in the GOM. The rig's time distribution in Green Canyon (GC) and South Timbalier is in Figure 3.10. In the deep Green Canyon, drilling and tripping accounted for 37% of the 27 days to drill the well. Casing and BOP took 18% and 13% respectively. These percentages are higher than the land operations due to the extra requirements for the offshore operations. In the ultra deep South Timbalier, drilling and tripping took 42% of the total time which averaged at 104 days. Casing and BOP accounted for 12% and 6 % respectively. Finally, we are not going to look at the trouble time here since it will be mentioned in the next section of NPT.

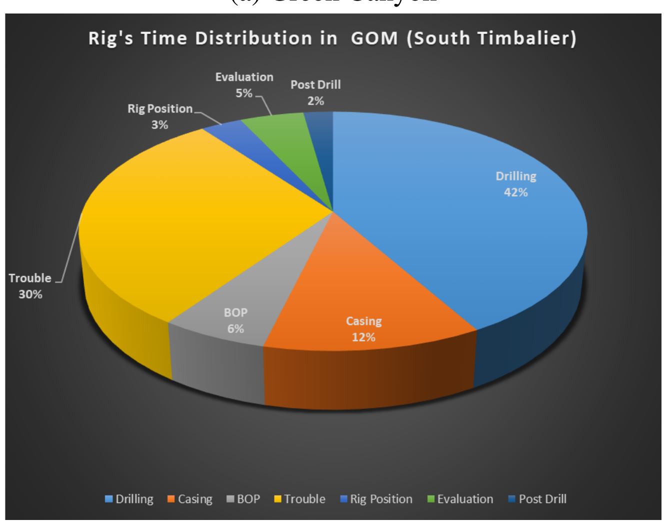
Kenya and Iceland Geothermal Drilling

Nyota and Murigu (2016) reported the geothermal drilling performance in Olkaria, Kenya. Figure 3.11 a. shows the time distribution for the operations. Drilling accounted for 55% of the average total time which was 61 days. Waiting On Cement (WOC) and tripping took 13% each. All the other operations used less than 5% of the time each.

Okwiri (2013) reported a case study for geothermal drilling in Menengai, Kenya and Hengil Iceland. Figures 3.11 b. and c. show the rigs' time distribution. In Menengai, the drilling and tripping used 41% of the total time which was 95.9 days. In addition, cementing and repair accounted for 8% and 7% of the time respectively. All the other categories were 5% or less each. On the other hand, Hengill's rigs spent more than 50% of the time in drilling and tripping. Casing and cementing accounted for 10% and 8% respectively. Logging took 13% of the 43.1 days total time.

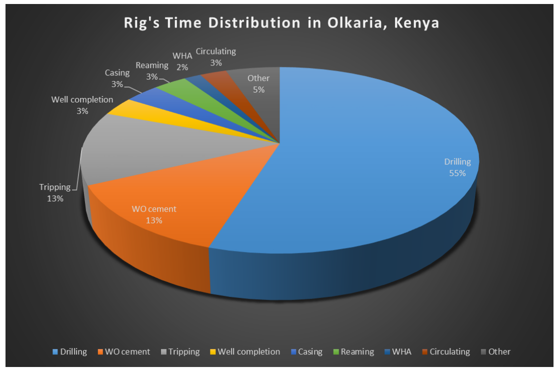


(a) Green Canyon

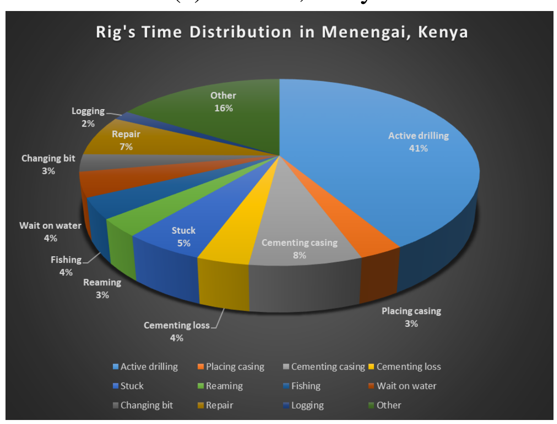


(b) South Timbalier

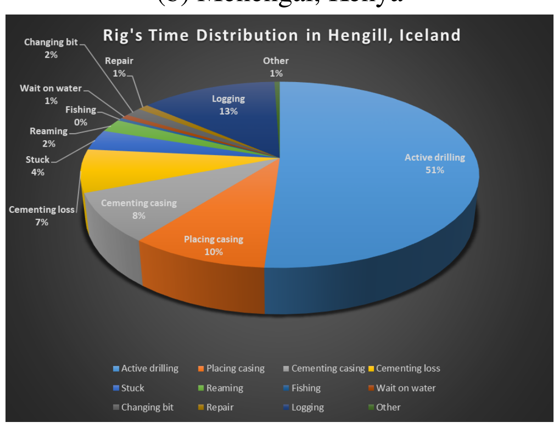
Figure 3.10: The Rig's Time Distribution in the Green Canyon and South Timbalier in GOM



(a) Olkaria, Kenya



(b) Menengai, Kenya



(c) Hengill, Iceland

Figure 3.11: The Rig's Time Distribution in the Olkaria and Menengai , Kenya and Iceland

It is important to note here that the way to categorize the operations was different from an operator to another. For example, in Menengai, Kenya, tripping was not mentioned as a solo operation and instead it was embedded in the drilling part of the operation. Also, most of the operators didn't list the rig set up as part of their time reporting. Moreover, not all the wells needed testing or logging which can take more than 10% as in Hengill, Iceland. The purpose of reporting all these time distributions for different parts of the world is to compare the total time to carry an operation and where does the rig time was being spent. Also, it can be as a guideline and an indication of low performance or an invisible lost time. So it is important to look into the trends not the exact percentages. The trends of drilling and other operations and the time spent in each is much less than the time spent Puna venture operation. This difference is an indication that the drilling in Puna is not as efficient as it should be and there are multiple areas of improvement that should be considered.

3.8 Non-Productive Time (NPT)

Non-Productive Time (NPT) is one of the phrases that oil and gas industry does not have a standard definition for. International Association of Drilling Contractors (IADC) (2019) defines NPT as "the reported time spent on activities that don't contribute to drilling the well". IADC left the specific definition to the company's policies. In the literature, there is a wide range of NPT definitions. Cochener (2010) in an Energy Information Administration (EIA) paper defines NTP as "time the drill bit is not turning to the right". However, this definition is extreme since there are numerous activities in the rig that is leading to completing the well beside turning the bit.

Adams et al. (2010) defines NPT as "any unplanned operation". They divide the rig's time into Trouble Free Time (TFT) and NPT. TFT is the time of planned trouble free operation activity at Approved For Expenditure(AFE) stage. They also discussed the status quo which was that NPT is subjective since it tends to vary by drilling supervisor or the engineer who is inputting it. They also provided a table with a list of drilling activities with a characterization as NPT or TFT. Rabia (2001) defines NPT as the net time between the starting of a problem to the time the operation is back to its state prior to the problem occurring. Hsieh (2010) reported a definition from Mr. Keene, the drilling manager with Occidental Petroleum, as "anything that happens outside the original well plan". It is important to note that there is hidden NPT or Invisible Lost Time (ILT) that is usually embedded in the under performance of some activities in the rig such as tripping or running a casing. ILT and hidden NPT have been discussed and explained by (VanOort et. el, 2008) , (Maidla and Maidla, 2010), and (Eren, 2018).

NPT ranges between 10% to 25% of the well delivery time (Van Oort et. el, 2008). In a report by the Oil and Gas Authority in UK (2018), NPT accounted for greater than 15% of the well cost. The report also confirmed that NPT reduction is a great opportunity for cost reduction. In order to look deeper into NPT and quantify it for different operators in the world, we looked into the publications and extracted the time analysis. It is important here to note that there is a subjectivity in the definition of NPT by each company. However, it is the only source available for the comparison.

For the oil and gas industry in North America, NPT for 41 wells drilled in the Wild River field in Canada was 24% in the first wells. However, NPT dropped to 7% in two years as the learning curve progressed. Many of the NPT was due to well control issues (Adeleye et al.,2004). Moreover, in a study by Visser et.al (2014) the NPT for 21 inland wells in Colorado,Wyoming and Louisiana was reported to be 6%.

The NPT for the offshore field tends to be higher because of the harsh weather and environment. Iyoho et al. (2005) reported the average NPT deep water wells, which had 4000 ft water depth and the ultra deep wells, which had a water depth of 9000 ft. The study had six deep water wells in Green Canyon with an average NPT of 18%. In addition, NPT for the ultra deep wells in Timbalier was 30%. Most of the NPT was caused by troubles with tight holes and fishing operations. Moving to the North Sea operations, a study by Adams and Smith (2010) for 118 wells in central North Sea found that the reported NPT was 28.6 %. The main drilling problem that they had was stuck pipe.

In North Africa, the NPT reported by Emhanna (2019) for five wells in Ghahames Basin in Libya was 18%. Almost half of the NPT was waiting on service, equipment, or orders. In addition, the NPT for five wells in the Azar oil field in Iran, which is part of the Middle East, was reported by Rahmati and Shadizadeh (2017) to be 32.8 %. Fishing operations and slow ROP were the main reasons of NPT.

For the Geothermal Industry, the NPT for drilling twenty one wells in Western USA was reported by Visser et al. (2014) to be 21%. Lost circulation contributed the most to NPT. Moreover, Nyota and Murigu (2016) studied NPT for twenty wells in Olkaria region in Kenyan and reported it to be 6%. However, the percentage reported here seems to be low. A closer look in the data will reveal that the depth for these wells was around 11500 ft. and it took an average of 65 days to complete a well. This number is high and there might be invisible NPT or the way NPT was calculated was not accurate.

The drilling operation in Puna Venture has tremendous NPT and the reporting of it was not accurate in the reports. There were many stuck pipe incedints, fishing operations and waiting on materials or orders. All these are clear NPT and should be labeled as NPT. Also, as mentioned in the pervious section, the operations in Puna Venture is not efficient and there is Invisible Lost Time (ILT) that should be traced by setting up benchmark numbers in tripping, placing casing, ROP, and connection.

3.9 Challenges in the Drilling Operation

The drilling operation in the Puna Geothermal Venture (PGV) is not a typical drilling. There were many associated challenges with the drilling. These challenges are discussed in this section. The first challenge is the loss of circulation which might lead to hole cleaning problems that caused stuck pipe incidents. Some of these incidents ended up in lengthy fishing operation or even an abandon of the hole and a side track. In addition, the cementing operations in most of the wells were not easy and had to be repeated several times. Then, the logistics must be examined since Puna is in Hawaii, which is far from drilling hubs. Finally, the safety of the operations and some environmental challenges are discussed.

3.9.1 Lost Circulation

Lost circulation has been cited in many studies (Goodman, 1981) (Pierce and Livesay, 1994) (Finger and Blankenship, 2010) (Lowry et al., 2017) (Cole et al., 2017) and others to be one of the most common and expensive problem during drilling in general and in the geothermal drilling specifically. Lost circulation is universal problem that is encountered in many places around the world. Lost circulation can be initiated due an overbalance drilling that would induce fracture on the formation and cause the fluid to infiltrate the formation. Another way to encounter lost circulation is drilling in highly naturally fractured formation that will cause the drilling fluids to enter the fractures.

Looking at the drilling data of seven wells which are KS-5, KS-11, KS-13, KS-14, KS-15, and KS-16 loss of circulation was encountered in all of them. It is true that loss of circulation is desired in the production and injection zones so that the geothermal process can be established. However, in the sections prior to the production section, lost circulation would cause serious drilling problems such as stuck pipe and would cost in drilling fluids. In all the seven wells the returns were lost in the surface hole section which was mostly 26 inch. In most of the wells the lost circulation started right after the bit leaves the conductor and starts the drilling around 100 ft. except for KS-15 where the losses started at 430 ft. In the 20" intermediate section, partial losses ranging from minor seepage to 40 bph losses in all the wells. Moving to the second intermediate section which is 14.75 inch hole, most of the wells carried the operations with full returns to the casing point around 4800 ft. Some wells experienced partial losses up to 60 bph but regained the full return after pumping LCM. Finally, in the production section which is 10.625 inch hole, most of the wells had full returns until the well hits the fractures where it is expected to lose the return.

3.9.2 Stuck Pipe

The second most common drilling problem in Puna Venture was stuck pipe. There are two types of stuck pipe. The first is differential sticking and it happens after the pipe has been sitting still for some time. Most of the time, it happens after a connection. It is usually experienced in permeable formation with thick filter cake. This sticking can’t be eliminated but by having available force to pull the pipe, it is possible to get free (Dupriest, 2017). This type of stuck pipe was encountered in Puna Venture operations in KS-13, KS-14, and KS-15. The rigs spent more than 10 days collectively trying to free the pipe. Dupreist (2017) provided a real time responses that should be helpful in this situation:

• Minimize still pipe time on connection.

• Use stabilizer to ream and condition the cake in the permeable zones.

• Seal the zone if the overbalance is more than 2000-3000 psi.

• Reduce the Mud Weight in order to reduce the cake shear strength.

• If stuck, apply high right hand torque and slack off most of the string weight. Then , pick up and reapply weight periodically.

Mechanical sticking is the second type of pipe sticking. It occurs while the pipe is moving and this is how it is distinguished from the differential sticking in order to have the adequate response to the stuck pipe. To get in a mechanical sticking, the top stabilizer shears into the filter cake that is undergauged. If the pulling continues, the area and the shear resistance will be equal to the pulling capacity and then the pipe will not move (Dupriest, 2017). All the Puna Venture wells had mechanical sticking except KS-11. The rigs spend more than 8 days in battling mechanical sticking and that is an extra cost for the operations.

3.9.3 Cementing

The cementing operation in Puna Venture wells was not an easy task. The high temperature and the existent fractures need extra consideration while planning. In many hole sections, the cementing needed to be redone more than once because of the failure to pass the Leak of Test (LOT) or Formation Integrity Test (FIT). The analysis covered an extended period of time for Ormat activities in Puna Venture from 1999 to 2018. The methods used in these operations can be different from one well to another. However, there was a trend for repeating the cementing job after failures in LOT. 20" casing cementing failed LOT or FIT in KS-13, KS-14, KS-15, and KS-16 wells. As a result, squeeze cement jobs were needed in all of them. Also, KS-14 needed a squeeze job for the 16" casing after a failed FIT. Several solutions were introduced such as the nitrogen foam cement in KS-11 and KS-13 for the 14.75" hole section. Also, Peters et al. (2013) discussed the successful reverse cementing technique was used in KS-15 along with spotting Latex cement in the suspected corrosive interval. Adopting this technique and trying to apply the reverse cementing in other hole sections should be considered.

3.9.4 Rate of Penetration (ROP)

The Rate of Penetration (ROP) in the Puna Venture operation varies by the hole section and well. ROP tends to be very low in the beginning of drilling at a around the depth of 150 ft. with rates of 5-10 ft/hr. This low ROP can be related to the fact that we are still building the BHA and WOB and we want the hole to start straight. However, KS-13 continued having ROP in the range of 8-11 ft/ht throughout the first hole section which had a casing point around 1000 ft. Also, KS-14 had low ROP in the first hole section ranging between 7 ft/hr to 14 ft/hr with an average at about 10 ft/hr. Moreover, KS-15 ROP was averaging at 12 ft/hr. These calculated ROP numbers are low and increasing them will enhance the operation. For the 14.75" hole section, the average ROP was about 17 ft/hr in KS-14 and 11 ft/hr in KS-15. In addition, for the 10.625" section, the ROP was 21 ft/hr in KS-13, 18 ft/hr in KS-14, and 18.5 ft/hr in KS-15. One note here is that all the drilling reports were analyzed and the ROP was calculated manually from the reported time spend in the operation and the drilled depth during that time. This way of calculation of ROP was not efficient and it is important to enhance the reporting of the ROP. One way to do that is to list the average ROP in each drilling interval in the daily drilling report and then store it in the database in a daily basis. The practice now is to report the average ROP in the database for random periods that can reach to more than 100 hours. This makes it difficult to trace the ROP performance and detect any inefficiency. Also, installing an EDR system will help in storing all the data and provide the operator with a better picture of the overall performance and where it can be enhanced.

ROP is an important metric for the drilling performance and it has to be increases from the current levels in Puna Venture operations. One way that will help in achieving that is replacing the tricone bits with the PDC bits. PDC bits nowadays are very strong and can withstand harsh environments. The difference in the price should be justified by the increase in ROP. Moreover, there are some special PDC bits that can be used in geothermal drilling and might even provide a better performance such as the Kymera bit (Van Oort,2020).

3.9.5 Logistics

Puna Venture is located in Hawaii, USA, which is an isolated island in the middle of the Pacific Ocean. While logistics can be difficult, challenges can be overcome by careful and proactive planning. Here are some examples for the waiting on tools in several wells: KS-16 crew waited two days for a new bit. Also, KS-15 crew waited for three days for a power breaker and waited on tools for two days. Finally, KS-14 crew waited for swivel replacement for 4 days. Moreover, some wells waited on personnel such as KS-13 waiting for pipe recovery personnel. The solution for this problem is being proactive and anticipating some needed equipment or personnel based upon previous experiences. Also, if the budget permits and there is a storage, parts that are being needed regularly such as drill bits should have replacements. This will save time and make the operation more efficient.

Rig Move and Setup

The time reported for the rig move, rig mobilization, and rigging up was very long compared to similar operations. KS-11 daily report showed the rig up operation took two days. On the hand, KS-15 and KS-16 spent 18 days in the rig move and rig up. Other wells such as KS-13 took 7 days and KS-14 took 12 days. These numbers are high and need to be revised and actions must be taken to increase the efficiency. One way to shorten the time is to work 24 hours. Most rigs worked for 12 hours only during the rig up and waited for daylight to complete the operation. Another possibility explaining the long rig up time is the inaccurate reporting where the rig was on repair or the operations could not be started for some other reason beside the rig up. The drilling report should be accurate and report all the details of the operations. In addition, all the wells were in the same area and located close to each other in the same perimeter so the move should have been local and fast.

3.9.6 Safety

Puna Venture is in proximity to a residential area on the Big island. Also, it is located in a rift zone with an active volcano. As a result, conducting safe operation should be a priority to the operator. After a deep analysis to the drilling reports and researching previous incidents and the safety concerns in the operation, three main issues were identified. The first concern is the poisonous H_2S gas, the second is kicks flowing from the well in drilling, and the third is the lava flow over the location and the magma encounter while drilling.

For H_2S emission, ORMAT is committed to reporting the emission levels and to calculate the expected emission in each permit application. It has also installed Emergency Steam Release Facility (ESRF). However, there were several incidents for uncontrolled H_2S emission such as the one in August 7th 2014. There was a civil defense alert issued to the residents close to the Puna venture.(Big Island News, 2014) In addition, in a workover operation for KS-14 the alarm sounded off and the H_2S concentration was 8 ppm and the CO_2 was at 1800 ppm.

In the drilling of Puna Venture wells, several kicks were encountered and controlled. For example, in KS-11, the well got a CO_2 kick and bullheaded it with water successfully. It is important to keep the well plans updated and to have an emergency plan for such incidents. Updating the well plans and review them regularly will help in preventing blowouts such as the KS-8 blowout in 1991. Thomas et al. (1991) reported a technical investigation on the KS-8 blowout incident which found ORMAT was responsible for the blowout. Also, it recommended updating the plan regularly and modifying some equipment.

Puna Venture experienced a lave flow in May 2018 that caused the plant to shut down. The plant is still closed and several wells were covered in lava. It is important to consider safety measures and emergency plans for similar incidents. ORMAT started cleaning out the wells in 2019 and is drilling new wells and planning to reopen the plant in the second quarter in 2020 (ORMAT, 2020). Moreover, in the drilling of KS-13. Magma was encountered at the depth 8162 ft. and high string torque was observed. Also, the crew lost 42' of the hole when the BHA was picked up. Updating the geological model and avoiding this depth should be considered in the new wells.

3.10 Conclusions, Future Work, and Recommendations to Enhance the Drilling Performance and Efficiency

The scope of this project was to review and analyze ORMAT's operations in the Puna Venture. Based on the analysis it was clear that there are multiple areas in the operations that need improvements. This section will provide recommendations and guidance for future work in organizational changes, NPT, and engineering redesigns.

3.10.1 Organizational and Workflows Changes

ORMAT is a massive company and it operates in 25 countries around the world. Puna Venture is one of the locations and there are changes that need to be established. The first recommendation is to change the Access database that stores the data. This database started from the well KS-13 which was drilled in 2005 and covered the wells onward. There are wells that were drilled before that date and it is recommended to combine their data with the current database. The new database should be organized in a better way with a user-friendly interface and many analysis tools. Second, the source for the current database is mainly the daily drilling report. The current daily report forms lack unity in the acronyms and the abbreviations used for each activity. The organization should use universal language and all the personnel should be aware of it. IADC DDR plus reporting system is widely used and is considered as a standard in the daily drilling report. DDR Plus version 2.0 has been released and adopting it will help the organization in having a uniform way of reporting the activities. In addition, the way of writing the daily operations should have a standard. Some engineers were expanding in the activities and providing details while others were writing the absolute minimum and missed some important information. Also, the current daily report is missing key operational parameters such as WOB, torque, RPM, and flow rates. As a result, a guideline for the reporting style should be developed for the organization.

We did not have a chance to look into the drilling programs for the wells. However, it is important to have clear instructions for the objectives of the well in order to avoid any NPT in waiting for orders. Also, the drilling report should have a guideline on the required tools for completing the wells and name the standby personnel for any emergency maintenance needs. Puna Venture is in a remote location so proper planning and resources allocation is very important to avoid any logistics delays. A closer look is needed in the materials required to drill the well such as backup drill bits and some key spare parts for the rigs. Also, the possibility of storing them in a nearby location if the budget allows.

3.10.2 NPT Analysis and Elimination

The reporting of NPT in the daily drilling report was not accurate and some NPT was missed especially in the case of stuck pipe and fishing operations. As discussed in the NPT section, there is no universal definition of NPT. As a result, ORMAT should develop a definition for what is considered NPT and include a list of all the operations that the rig performs with a categorization of what is considered NPT. The second step is ensuring accurate reporting in the daily drilling report in order to have a good track of NPT and the operations that are causing it. Then, a closer look into the causes NPT and the leading activities of NPT should be studied. For example, it is clear that stuck pipe is a challenge that Puna venture operations have. The crew should look for the signs causing such an incident before it happens and cause NPT. These signs can be higher torque or pull and accumulation of cuttings. Being proactive will help in eliminating NPT. In addition, the cementing operation should be revised in order to eliminate re cementing after failed LOT. The next step will be setting up a target benchmark for the operation and investigating Invisible Lost Time (ILT). These benchmarks should be revised quarterly and should not be the ultimate goal.

3.10.3 Engineering Redesigns and Performance Enhancement

Even with 0 NPT the drilling performance can be enhanced and more efficiency can be achieved. However, time and money should be invested by installing equipment in the rig and redesign others. First, installing Electronic Drilling Recorder (EDR) such as Pason or Tocto in the rig will help in gathering more data and providing a better picture of the operation that will lead to better analysis and recommendations. This data will be realtime and the engineer can detect inefficiencies in drilling by tracking MSE and other drilling parameters. Second, the redesign of the BHA and the use of the modern PDC bits will enhance the performance in drilling and a pilot run should be run. Third, lost circulation is a big challenge in Puna Venture and choosing a proper LCM can help in mitigating some losses. Finally, redesigning cementing operation and introducing the reveres latex foam cementing in other hole sections will ensure better cementing jobs and successful LOT and eliminate additional need to a squeeze job.

4. SUMMARY

Study 1

This research explored the perdition and modeling the dowbhole circulation temperature in high temperature land wells. It utilizes ERA software and investigates the temperature model built by Kumar and Samuel (2013). In addition, the study replicates Trichel and Fabian (2011) investigation of the effect of different drilling parameters on the temperature profile with the utilization of the more recent model.

One of the important goals of this research is to understand and follow the calculations steps for the temperature prediction in order to improve the model in ERA. In this process, spikes in the temperature were investigated and linked to an increase in the surface torque that resulted in an overestimation of the downhole temperature because of the usage of the ERA's torque and drag (TnD) engine in the temperature modeling. Not only was this overestimation found but also the software did not account for the measured torque data in the calculations when it was available. Moreover, in a deeper analysis, it was found that the temperature profile was following the trend of the differential pressure and the downhole torque should be calculated using the differential pressure method instead of the TnD method if the BHA has a motor. After several meetings and investigation, a new preview release of ERA was developed with an improved temperature model and a new workflow based on this research. The new model eliminates the overestimation spikes in the temperature profile and utilizes the measured downhole data.

The last part of this study focused on the a sensitivity analysis of different drilling parameters and their effect on the downhole temperature in order to give a tool for the people in the field to anticipate the change in the downhole temperature based on the change in the parameter. The parameters can be divided into three categories. First, the operational parameters that has small to negligible effect such RPM, WOB,and flow rate. RPM and WOB rate did not show a big impact on the temperature profile. However, the flow rate should have a special consideration. If the flow regime does not change in the change of the flow rate. The impact on the temperature is small. On the other hand, if the change of the flow rate resulted in a change in the flow regime from laminar flow to turbulent flow and vice versa, the impact on the down hole temperature is huge. This huge impact can be link to the increase of the fiction pressure loss. The second set of parameters are the ones with a medium impact on the downhole temperature. This set includes BHA pressure drop and the sliding effect. The temperature change was 6 °F. The last category is for the parameter with a high impact on the downhole temperature. The set include using the type of the drilling fluid and change of the hole size. Changing the drilling fluid from OBM to WBM resulted in more than 30 °F difference in the downhole temperature because of the higher heat capacity for the water compared to oil. Moreover, the increase in the hole size will result in less friction pressure loss because of the partial change of flow regime to laminar and will reduce the downhole temperature by 12°F.

Study 2

The scope of this project was to review and analyze ORMAT's operations in the Puna Venture. Based on the analysis it was clear that there are multiple areas in the operations that need improvements. This section will provide recommendations and guidance for future work in organizational changes, NPT, and engineering redesigns.

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APPENDIX A

SUMMARY OF ORMAT'S DRILLING OPERATIONS

A.1 Well KS-11

Operations started in September 1999. Rig up took two days only.

26" Hole

Drilled 26" hole to 673' with no return. POOH and then RIH with pump to take a sample. Continued drilling to 1040' and then cleaned out fill. Ran 22" casing and cement it. Nipple up BOP and tested it.

20" Hole

Drilled out cement to 1040' and performed LOT. Drilled 20" to 1150'. POOH and RIH with open ended pipe and pumped loss circulation plug. Continued drilling to 2122' and got twist off. RIH with fishing tool and fished BHA. Continued drilling to casing point at 2151'. Reamed hole and then ran 16" casing and cemented it.

14.75" Hole

RIH with 14.75" BHA and drilled out cement from 890' to 1366' then RIH to 2102'. Tested BOP and then drilled out float collar and shoe and drilled formation to 2153'. Performed LOT successfully. Drilled 14.75" hole to 3450' with full return. Continued drilling to 4626' and POOH to change mud motor. RIH and continued drilling to 5070' and then circulated and conditioned the hole for casing. Ran 11.75" casing to 5061' and cemented it with N2 foamed cement.

10.625" Hole

RIH and drilled out the cement at the shoe and performed LOT and detected leak. Pumped cement plug. Ran 10.625" BHA and tagged TOC at 4854'. Drilled out cement to 5000' and tested the casing. Drilled 10.625" hole with full return to 5318' and then POOH. Left one cone in the hole and fished it. Made up bit # 8 and RIH then drilled to 6211'. POOH for BHA change. RIH and continued drilling through two fractures and one void to 6500'. Ran permeability test and PT log. Well kicked CO2. Ran 8.625" perforated production liner with bottom at 6470' and top at 4803'. Test the well.
Rig down on Nov 30 1999

A.2 Well KS-5

No information about rig up. Operations took place in August 2002

36" Hole

There was no conductor in place, and they drilled a pilot hole to 88' followed by a hole opener of 36" to 88' and ran down conductor. Got stuck once with hole opener for 2.5 hours. Cemented the conductor

26" Hole

Drilled 26" hole to 99' and lost return. Continued drilling to 230' and worked a tight hole. Worked another tight hole at 239'. POOH and changed bit. Waited on water for 7 hours. RIH then washed and reamed. Then drilled to 422' and waited. Pulled two stands and waited on water for 8 hours. Drilled to 599' and got a stuck pipe Spent two days trying to work the stuck pipe and eventually ran the free point. Backed off at 406' and POOH. RIH with fishing tool and fish the DP. RIH and tried to jar on remaining fish. No success. Ran free point back off @ 483'. 49' of fish still in hole. Tried to jar on fish. No success. Tried for 5 more days to jar on fish and circulate with different fluid (foam, Lax rig Halliburton) but no success. Pumped a cement plug @ 521'. Tagged TOC at 506' wait on order for 10 hours. RIH and washed over fish at 527' and then jarred on fish. Milled on stab spent 6 days washing and jarring and trying to mill. Rebuilt mill tooth and milled stabilizer to 531'. RIH with spear to attempt spearing fish. No success. Baker Atlas and all personnel in location. Performed shot in hole and jarred on fish. No success. Set a cement plug. (Spent 24 days on the incident).

26" Hole Side Track

Prepared for a side track. Drilled out cement from 77' to 85'. Drilled 26" hole to 1005' then reamed and washed multiple times. Ran 22" welded casing to 900'. Circulated casing with no return. Cemented casing. Tagged cement on annuals at 500'. Performed a top cement job. Ran 1" pipe and tag TOC at 460'. Pulled pipe to 186' for second job. Then 126' for third job and 76' for a forth job. Nipple up BOP and tested it. RIH and tagged TOC at 894'. Cleaned out cement to shoe at 900' and then to 1005' then lost 125 bbl. of mud. Performed a squeeze cement job. WOC and then tag TOC @ 964' circulated and checked for mud loss at 852'. Performed another cement job. No circulation. Tried it 4 more times and test shoe. Test was no good. Pumped LCM and then cemented. Tested shoe to 120 psi for 15 min and got verbal pass.

20" Hole

Cleaned out cement to 1005' and drilled 20" hole to 1841' and Kelly up, twisted off on bottom. RIH with grapple and chained out fish. RIH with magnet and then POOH and made up BHA then RIH with washing and reaming. Continued drilling to 2064' and got a twist off. POOH with the twisted off 10" DC. Made up overshot and pulled fish free. RIH and got plugged bit. POOH and unplugged it. RIH and continued drilling to 2232'. POOH. Ran 16" casing with the shoe at 2205' and cemented it. Installed and welded the wellhead. Tested BOP and casing.

14.75" Hole

RIH to TOC at 2155'. Cleaned out cement to 2233' and drilled 1 ft. of new hole. Performed LOT with no success at 11.5 ppg. Squeezed cement at 2329' with no success in LOT at 11.5 ppg. Squeezed cement at 2249'. Cleaned out cement and performed LOT at 10 ppg. with verbal ok. Cleaned out cement to 2333'. Ran with 14.75" directional BHA and drilled to 3067' with no information about returns. POOH and ran with new bit. Drilled to 4832' and decided to drill 30' and circulate to decide casing point. Drilled to 5100' and POOH laid down directional tool and RIH to ream. Circulated and conditioned the hole for 4 days and waited for Halliburton shoe and float collar. Ran 11.75" casing to 5077' and cemented it two times.

10.625" Hole

Ran with 10.625" BHA and drilled out cement stringers from 4788' to 5075'. They waited on choke manifold for 34 hours. Cleaned out cement and shoe and tested shoe to 10.3 ppg (approved). Drilled from 5100' to 5128' and got directional tool failure. POOH. Dropped MWD probe but no communication. Retrieved MWD with slick line. Worked on probe and dropped it. Worked OK. Continued drilling 10.625" hole to 6230' with small losses. Continued drilling to 6375' and lost circulation at 6356' didn't touch bottom of fracture. POOH. Nipple down BOP and set up flow equipment for two days. Ran P and T survey for 6 times BHT is 639 F and P is 2022 psi and at 3000' T is 322F. Tested BOP with packer at 500'. RIH and tagged obstruction at 1975' POOH and ran camera observed collapse casing at 1981'. Waited for milling

tool for 3 days. RIH with concaved mill to 1960' and milled 6'. RIH with skirted mill and milled. Alternating milling and camera evaluation 4 times. Bad Spot casing between 1960' and 1965'. Ran packer and tested casing with no success in different depths. Ran cast iron bridge plug and squeeze cement. Tagged TOC at 1924' drilled out cement to 1975' then tested casing to 2500 psi and got approved. RIH and drilled out cement and bridge plug. RIH and tagged bridge plug at 6144'. Cleaned out BP and washed hole. RIH and tagged BP again and reamed. Then drilled hole to 6418' and worked tight hole. POOH to 4200' and monitored. RIH and tagged bridge at 6164' reamed and circulated. Tried several times and got tagged. Pumped LCM and cement plug at 6110'. RIH and tagged TOC plug at 6119'. Cleaned out cement to 6343'. RIH and tagged fill at 6106'. Spotted #2 cement plug at 6093' and then plug #3 at 6033' , and finally plug #4 at 5909'. RIH and cleaned out cement to 6386'. RIH and tagged top of fill at 6386'. Ran 8.625" blank and perforated liners. Bottom of liner at 6385' and hanger at 4925'. Ran P/T survey and got tagged at 6235'. Performed injection test but hole was hot at 6329' and tool quit working. Evaluated the well with 6 survey runs T was 636 F at 6370'. Ran liner between 1882' and 2058'
Rig down

A.3 Well KS-13

Operations started in August 2005. Rig up took 7 days.

26" Hole

Conductor was set at 90'. Started drilling 26" hole and lost total returns at 109'. Drilled blindly to 246' with back reaming every 10' and got partial return to no return at 299'. Continued drilling to 489' and got stuck pipe while making a connection. Got free and POOH and change jars. RIH and drilled with no return then got the bit stuck again at 581’ while making a connection. Got free and continued drilling to 738’ and got stuck. Worked free and POOH. RIH and tagged fill at 679’. Cleaned out fill with air and foam. Continued drilling and got stuck and worked free. Drilled to 1005’. Reamed the hole with 26" hole opener. Ran 22" welded casing to 225’ and stopped. POOH and reamed the hole. Ran casing again to 954’ and cemented it.

20" Hole

Nipple up BOP and tested it. Tested the casing to 650 psi. Cleaned out cement and shoe. Performed LOT and failed. Set cement plug # 1 at 1005’. ROC at 813’. Cleaned out cement to 955’ and tested the shoe to 11.43 ppg. RIH and Drilled 20" hole to 2079’ the casing point. Spent three days in rig maintenance. RIH and filled the hole. Then spent 5 days in rig maintenance. Ran and cement 16" casing

14.75" Hole

Nipple up and tested BOP. RIH with 14.75" BHA and tagged TOC at 2018’. Drilled the shoe and performed LOT to 441 psi. Drilled 14.75” hole to 3125’. POOH and ran with 1.6 degree bent sub. RIH and could not survey. POOH and safety sub backed off. Left 241’ of BHA in hole. Fished BHA and saw break out bit (pinched). RIH with magnet and recovered drift but no wire. RIH with 14.75" mill. POOH and ran with 14.75" directional and drilled with full return to 3655’. Continued drilling and started having losses at the rate of 50 bph at 3955’ to 4097’. POOH and then RIH with locked rotary assembly. Reamed the hole and then lost 50K of weight. POOH and had a back off at safety sub. Fished the drill pipe and BHA. RIH and reamed. Continued drilling with partial losses to 4886’. Ran temperature test with flow. Ran 11.75” casing and cemented it with foam nitrogen cement then did a top cement job. Tested casing at 2589’ and shoe integrity test to 14.5 ppg.

10.625" Hole

Drilled 10.625" hole to 5901’ with partial losses. No response from MWD. Tripped to casing shoe and retrieved MWD probe through wireline and installed a new MWD. Drilled to 6457’ with no return. POOH and RIH with BHA # 9 and drilled to 7698’ with no returns. MWD failed. Attempted to recover the probe. POOH and ran with bit #10 and drilled to 8297’, with 90 % return. Torqued up and lost 5’ of hole. Circulated and tripped out. RIH and reamed at 8262’ with losses. Got stuck. Backed off at 4100’. Bit was at 8139’. Wait for pipe recovery personnel. Temp is 632 F. perforate pipe at 7992’ and start pumping to cool the well. Ran free point and worked pipe until free at 7279’. Ran 8.625" perforated liner to 6970’ and top of liner at 4647’. Ran hydrostatic bailer and then performed injection test. Ran 8.625" casing and place nitrogen blanket. Rig down.

KS-13 Clean Out

Operations started in November 2019. Move and Rig up took 14 days. Set a bridge plug and tested it. Then tested BOP, Pulled out 9.625" liner. RIH with 10.5" bit and tagged top of fish at 4610’. Ran with 7.5" bit and tagged top of 8.625" liner at 4460’. Washed and cleaned liner to 8001’. And then drilled new hole to 8020’. Performed injection test. Tried to in ML1 window at 4396’. Enter the window and drill with 7.5" hole from 8020’ to 8127’ and got stuck. Spent 9 days to free the pipe and fish. Performed injection test.

A.4 Well KS-4 Re Drill

The operations started in October 2006. The well was drilled before to 4200 ft. and the hole seems to be vertical. They had a 7" liner in the hole with hanger @ 3837’.

They pumped 4 cement plugs and tagged the top of cement at 2317'. They tested the casing to 650 psi and it bled. Then tested it to 625 psi and held steady at 620 psi then they pumped plug # 5 and tagged top of cement at 1950'. They drilled the cement and placed the whip stock at 2094' with top ramp and 2111' bottom of the ramp.

8.5" Hole

Drilled the 8.5" hole with MWD and motor directionally. They had an incident with one smashed his middle finger between tongs. Drilled to 3909' and placed 7" liner then cemented it. Tagged TOC at 1340". Drilled the cement to the top of liner hanger @ 1702. Performed formation integrity test to 505 psi.

6" Hole

Drilled 6" hole to 5456' and then tripped out and changed MWD battery and made up a new bit #4. Drilled 6" hole to 7317' with low MWD battery. Ran caving surge tool and permeability test. Filled the hole with mud and then RIH and tagged top of cement at 4039'. Then pumped a plug # 7. Drilled out cement. Ran with motor and bit and drilled to 5760' when they tripped out. Trip in and continued drilling to 6516' and encountered losses at 6532' total fluid was lost. Drilled with losses to 6767'. Performed a permeability test and got 11 gpm per psi permeability rate

A.5 Well KS-14

The operations started in January 2010.

26" Hole

Spudded with 26" bit on Feb 7. Conductor was already set at 110'. Started drilling with mud motor to 123' and lost return at 113' and lost water supply! Continued drilling with motor and no return to 140' with ROP of 8.7 ft/hr. waited to repair water line which was packed of cement! Continued drilling with motor and air with partial return to 175’. Continued drilling with motor and air and lost return at 321’. Continued drilling with motor and air foam to 692’ where they got partial return. Used submersible pump at 640’. Continued drilling to 845’ and lost return at 800’. Got stuck at 970’ and got free. Drilled to 1000’ then started cleaning and reaming the hole. Ran and welded 22" casing to 954’. Cemented the casing.

20" Hole

Ran with 20" and tested casing to 680 psi. Drilled to 1000’ and performed a leak of test to 45 psi and it dropped to 0. Set a cement plug and performed a LOT to 0.63 gradient. Drilled 20" hole to 1175’ with losses. Continued drilling with full return to 1364’. Continued drilling and had jet plugged in the bit at 2139’ that they unplugged. Ran 16" casing but couldn’t circulate. POOH and then reran it to 2201’. Cemented it with Haliburton. Tried Integrity test it wouldn’t hold 75 psi. Set a cement plug and performed integrity test and it was approved.

14.75" Hole

Drilled with a 14.75” directional assembly to 2532’ with full return. Continued drilling with full return to 4417’ and had pressure loss in the pump with 500 psi. Changed heads in pumps. Continued drilling to casing point at 4890’. Ran 11.75” casing and cemented it with Haliburton. Tested BOP 500/1500 psi. RIH and performed a LOT to 10.8 ppg.

10.625" Hole

Made up 10.625" BHA with 1.2 deg motor bend and MWD drilled to 5191’ with some losses. Continued drilling and sliding to 5603’. Got stuck at 5603’ and worked the pipe also increased the torque limit in top drive. Continued drilling to 5717' blindly after total loss at 5626'. Performed a 2 stage permeability test.Ran 8.625" liner and had the liner hanger at 4713' and the bottom at 5688'.

Workover in February 2019

Spent more than 40 days in the rig move and rigging up! RIH and set a packer at 80 ft. and tested casing to 500 psi. Then tested the BOP. Test good. Made up 10.5" BHA and ran in hole to 77'. H2S and CO2 alarm H2S was at 8ppm and CO2 at 1800 ppm. Got a stuck pipe at 760'. Continued RIH and cleaned out the hole to 2297'. Then was unable to clean out due to high torque. RIH with open ended drill pipe and couldn't pass 2301 ft. possible parted casing. Ran a camera and then prepared a new BHA for milling. Milled from 2296' to 2303'. Ran with open ended drill pipe and then ran the camera again and saw parted casing. Made up 7.625" and RIH to 2330' had a tight hole. Got a kick and bullhead it with water. Changed BHA to 9.825" and RIH. Well flow after a pit gain of 35 bbl. Ran PT log and got 235 F at 2196' and 575 F at 2214'. Then decision was made to kill the well. Ran Cast Iron Cement plug to 2010'. Tested and failed. Put sand and waited. Then ran baker hurricane packer to 40 ft. and finished the operation. Came back in July 2019. Tested BOP and then RIH to 1770 ft. continued to 2011' and drilled the CICB. RIH to 4729' then POOH. Ran with 7.5" BHA then POOH and changed to 10.5" BHA. RIH and then did PT log set a cement plug. Milled casing and then set 6 cement plugs. Ran 10.5 " clean out assembly and ran it to 4625'. Ran 8.625" liner and cemented it. Made up 6.75" BHA and RIH to 1881' cleaned out cement. POOH and tested casing above packer. Continued workover and finally waited on tools for 5 days.

A.6 Well KS-15

26" Hole

Conductor was set at 90’. Started drilling 26" hole with mud motor to 171’ and lost return at 168’. Bit’s jet was plugged and motor quit working. POOH and ran with a new motor to 346’ and got a stuck pipe at 314’. Freed the pipe after 10 hours then RIH and reamed. Continued drilling to 800’ with partial return. Reamed and swept hole and then ran submersible pump to test water sample. RIH and drilled to 848’ then got a stuck pipe at 828’. Got free and continued drilling blindly to 1006’. POOH and then RIH to ream the hole with no return. Got a stuck pipe at 898’. Took two days to work the pipe and then the decision was made to attempt back off the safety sub. Recovered 702’ of the DP, DC and jars. Then spent two days in fishing. RIH and reamed but got stuck again at 862’ then got free. Washed and reamed the hole between 788’ and 883’. Back up tongs slipped and unscrewed the string in the hole. Top of fish is at 587’ then pulled free. P/U hole opener and bit and continued drilling to 1048’ which is the casing point. Ran 22" casing and landed it at 1040’. Did a top job and RIH. Tagged TOC at 953’. Failed FIT test. Perfumed a squeeze cement job.

20" Hole

RIH with 20" BHA and tagged TOC at 946’. Performed LOT and passed. Drilled 20" hole to 1177’ with full return then lost the return at 1177’. Continued drilling and pumped LCM to 1185’. Set a cement plug and continued drilling to 1396’ with minor losses. Waited for power breaker for three days. Repaired electricity breaker and continued drilling to casing point at 2300’ with minor losses. Ran 16" casing to 2293’. Set up BOP. RIH and drilled out cement and performed a LOT to 431 psi

14.75" Hole

Drilled 14.75" hole with mud motor and full return to 2596'. Started having losses at 2644' pumped LCM and regained full return.Continued drilling to 3945' and got high torque.POOH to check the bit and MWD. RIH and continued drilling to 4238' and started the kick off. POOH at 4705' and inspected motor. RIH with new BHA. Drilled to casing point at 4709'. Ran 11.75" casing to 4709'. Reverse foam cement operation. Installed well head and nipple up BOP.

10.625" Hole

RIH with 10.625" BHA and drilled out cement. Performed LOT to 10.5 ppg. Drilled directionally with full return to 5532'. Continued drilling with full return to minor losses to 6629' and then changed MWD. POOH and changed bit and MWD. RIH to 6171' and got a stuck pipe. Spent 5 days in freeing stuck pipe and fishing with 100% fish out of hole. RIH and continued drilling with full return to 7827'. Had minor losses at 7931' to 8020'. Performed injection test. RIH and got tagged at 7574' attempted to wash 10.625" hole but started to have hole problems. Set a cement plug.

Tagged TOC at 7334'. Pumped 4 more cement plugs last one at 4843'. RIH and found the cement is soft and all pipes where full of cement. Pumped a cement kick off plug at 4870'. RIH with 10.625" BHA and drilled out cement. POOH and ran with directional assembly to 4706' and started slide drilling. Changed the motor from a 3 degree to 1.2 degrees bend. RIH and started drilling with minor losses to 5261'. Got the full return and continued drilling to 6669' with minor losses. POOH and drilled with BHA#8 to TD at 7500'. Performed injection test and ran P/T. Ran another injection test. Decided to plug the hole. Pumped cement plug through open end drill pipe at 6625'. Got a stuck pipe and set free point. Spent 2 days. Fished the tool and left 428’ of pipe and set 2 abandonment plugs. Last one at 5619’.

Made up 10.625 " BHA and tagged cement at 5289’. Cleaned out cement to 5404’. Set Kick off plug #3 and POOH. RIH with reamers and tagged TOC at 5001’. Drilled out cement to kick off point at 5217’. POOH and RIH with directional tool and 3 degrees bend motor and drilled to 5258’. POOH and picked up 1.2 degree bend motor. RIH and drilled to 6569’ and encountered losses of 150 bbl/hr and had a stock pipe at 6560’. Freed the pipe in 12 hours and POOH. Made up bit #10 and RIH tagged at 6546’ and pumped high viscous fluid with no return. Got differentially stuck at 6501’ while making a connection. Spent 10 hours. Freed the pipe and POOH. RIH and rabbit drill pipe. Pumped down thorough annulus and it was at vacuum. Made up new BHA and RIH. Got Tagged at 6552’. Reamed with no return. Drill the hole to 6635’. Made up diffuser and Kuster PT tool and tripped to 2500’. Conducted water loss test. Drilled to 6987’ with no return. Conducted water loss test at 2518’. Then they waited on sand for 12 hours. Dumped gravel down the wellbore. Set cement plugs. Waited on tools for two days.

10.625" Hole Side Track #1

Made up the whip stock and milling assembly and tripped to 2988’. Milled a window from 3001’ to 3035’. Made up bit #11 and RIH and drilled to 3901’. Ran 8.625" liner at 2789’ as a top of liner. Cemented the liner. Tested the liner lap to 500 psi.

7.625" Hole Side Track #1

Made up 7.625" bit and RIH. Tested the liner and did an LOT to 754 psi. Drilled with directional tool to 4804’ with almost full return and 15-30 bbl losses at the end ran the diffuser with MRT to 4804’ max reading was 358 F. Continued drilling to 4944’ where 50% losses. Continue drilling to 5182’ with no return. Made up diffuser and performed injection test. RIH and reamed it and then ran 6.625" liner with hanger at 3755" and bottom at 5155’.

Start rigging down

Clean Out Operation

The operations started in July 2019. RIH and pulled out 51 joints of 7" casing and 21 joints of 6.625" liner. Ran with 5.5" BHA and cleaned scale out of casing. To 5104’. Ran static PT and did an injection the well and ran a caliper log. Ran liner and casing.

Started rigging down

A.7 Well KS-16

The operations started in February 2015 and the drilling reports were short with minimal data ! Crew spent 18 days to rig up with no details of the operations.

26" Hole

Started drilling 26" hole on Feb 15 2015 with ROP of 3.7 ft/hr. It seems that they had issues with top drive they worked on it several times. Continued drilling to 830’. Casing point was at 1042’. Ran 20" casing. TOC was at 911 ft. didn’t provide information about the FIT but they squeezed cement this might indicated that the FIT failed.

17.5" Hole

Drilled 17.5" hole and had 20.3 ft/hr ROP to 1461 ft. They had bad data in readout in several runs at 2301’. They fished something at 2474 ft. maybe related to survey. Casing point was 2555’ and they ran 13 3/8 " casing and cemented it.

12.25" Hole

RIH with 12.25 " bit and drilled to 2620' then performed FIT test. Drilled to 2776' with ROP of 7.8 ft/hr. continued drilling 12.25" hole to 5008 ft. They were using directional BHA. They ran liner. TOC was 2255'. They waited two days for a new 8.25" bit!

8.25" Hole

Drilled 8.25" hole to 5289' with ROP of 11.7 ft/hr. They drilled to 5745' and did an injection test. Got a stuck pipe while reaming for 4 hours. They drilled a side track from 5262' to 5277'. They plugged the hole with two cement plugs and cleaned out the cement to 5155 ft. then waited on order.

The well took 68 days to drill!

KS-16 Side Track #1

Operations started in April 2015. They had two MWD failures within two days.They drilled a side track to 5762' and ran 7" liner and performed injection test.

Then the report stopped.

A.8 Well KS-18

Operations Started in October 2019

Conductor

They started by drilling the conductor to 98.5 ft. KB. The ROP was 1 ft/hr. The rig was moved after the completion of this operation.

Then after three weeks the rig up took more than 10 days

26" Hole Part 1

Spudded on Oct 19 2019 at 1300 hrs with drilling 26" hole. The ROP was very low at 0.5 ft/hr. started having losses at 122' at the rate of 100 bph and then at 131' they had a total loss of fluid. Drilled blindly to 138' regained 50% return at 142'. Continued drilling with total loss to 407'. ROP was getting better to 5 ft/hr at 533'. They pulled out because they are using water supply and KS-14 lost circulation and waited on water for 5 days. Got a stuck pipe at 515' and jarred it. Got a tight connection and waited on welder for two days. Had issues with bushing. Ran submersible pump and had issue with the cable and reran it again. Had issues with mud pump #2. Repaired it and continued drilling to 817' with total loss. While making a connection, they had pack off at 817'.

Rigged down and moved for 40 days to KS13ML! Nov 11 2019

Rigged up the new rig in 8 days and weld several parts Dec 31 2019

26" Hole Part 2

Tagged fill at 769' Cleaned it out and then drilled to 1003' with ROP 5-7 ft/hr. Ran 22" casing to 1095' but faced tight hole at 762'. Pulled up casing and reran 26" bit and reamed the hole then reran the casing to 1056' and cement it in two stages. WOC and then performed FIT but bled 200 psi in minutes. Performed a squeeze cement job. Performed FIT but wasn't successful. Did another cement job and then tested the pressure and was successful.

20" Hole

Drilled a new 20" hole with ROP of 5 ft./hr. At the end of January, they were still drilling the 20" hole to 1465'. This was the last drilling report that we had.