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Petroleum & Petrochemical Engineering Journal
ISSN: 2578-4846

Offset Wells Data Analysis and Thermal Simulations Improve the Performance of Drilling HPHT Well

Ivan R, Halafawi M* and Avram L

Petroleum-Gas University of Ploiesti, Romania

***Corresponding author:** Mohamed Halafawi, Petroleum-Gas University of Ploiesti, B-dul Bucureşti, nr. 39, cod 100680, Ploieşti, Romania, Tel: 0040799641954; Email: halafawi@upg-ploiesti.ro

Research Article
Volume 6 Issue 1
Received Date: February 11, 2022
Published Date: March 18, 2022
DOI: 10.23880/ppej-16000298

Abstract

To drill new HPHT development wells safely, an exact estimate of their stability is essential. Analyzing previously drilled offset wells can assist in this determination, eliminating any stratigraphic column issues and saving nonproductive time. The challenges found with offset wellbores, their consequences on well design, possible remedies, and preventative measures are discussed in this paper. It examines drilling data from offset wells in order to discover, diagnose, and treat serious issues. Furthermore, thermal simulation was done in order to study the temperature distribution of the wellbore, annuli and fluids during drilling, tripping, circulation, logging, casing and cementing in HPHT zone.

Keywords: HPHT wells; Offset data; Field studies; Thermal simulation

Introduction

HPHT wells refers to high pressure and high temperature boreholes. They are an inescapable byproduct of the world's never-ending hunt for new hydrocarbon resources. The high pressures and temperatures are bigger challenges during designing, drilling, and doing operations in these wells. When constructing such wells, each string design influences the design of other strings due to the unusual encountered stresses, unlike the traditional well design, such as annular pressure accumulation connect numerous strings. HPHT circumstances result in a variety of non-standard load situations, necessitating the use of non-standard fluids and materials, advanced design techniques, and innovative processes. The design of these wells frequently need material or equipment which are difficult to meet at the current technology [1].

In order to define HPHT wells**,** a common definition of these wells has not been developed; in any event, most administrators regard a well with a formation temperature in excess of 300 °F and a surface closing pressure more than 10000 psi to be an HPHT application [2]. Wells with layer temperatures above 425 °F and pressures over 15000 psi are commonly referred to as ultra-HPHT or extreme-HPHT (X-HPHT) wells [3]. The UK Heath and Security Executive has recommended that for an application to be classified as HPHT, the undistributed bottomhole temperature must exceed 300 °F and have a formation pressure gradient in excess of 0.8 psi/ft or require the utilization of controlling equipment rating in excess of 10000 psi working pressure [4].

It is critical to note that bottomhole temperature and zone pressure are critical. Borehole temperature and formation pressure are not, in and of themselves, indicators of HPHT conditions. The geothermal change is a third factor that will be used to identify situations in which hot issues demand special attention. Warm impacts became genuine enough to need remarkable thought amongst planning after a geothermal gradient of 0.014 °F/ft [1].

In this paper, we review the HPHT circumstances that are considered in plan all through the world. In this portion, we endeavor to characterize the term HPHT as well as distinguish the worldwide dissemination of HPHT indications. The study examines strategies and methods for assessing temperature and pressure, which are clearly basic within the plan of HPHT wells. The effect of HPHT on the characteristics and execution of liquids and materials, as well as non-standard stresses put on wells, are investigated. The operational results of HPHT circumstances, especially as they relate to well control, are inspected.

Previous Studies

Drilling in HPHT fields and regions is highly difficult and required a lot of circumstances, technologies, strategies and plans in order to do the trajectory and reach target safely and cost effectively. There are several authors who studied those area and cover main researches. Table 1 shows a survey study of published researches regarding the HPHT wells' problems and their solutions, pressure and temperature estimation methods, thermal analysis, and wellhead movement.

Author (s)	Publication Year	Study/ or Technique Developed
HP/HT Wells Problems and Pressure Estimation Methods		
Maury and Idelovici [5]	1995	Studying the effect of transient thermal regime, which comprises alternating cooling and heating of the wellbore, and causes a loss of well stability while drilling under HP/HT circumstances.
Kelley, et al. [6], Sweatman, et al. [7], and Webb, et al. [8]	2001	Presenting HP/HT well pore pressure integrity and treatments to avoid problems
Skomedal, et al. [9]	2002	A study of the reservoir rock's mechanical behavior when uncovered to varieties in stress and formation pressure
Swarbick [10]	2002	The limits of porosity-based prediction tools and popular ways of predicting formation pressure
Shaughnessy, et al. [11]	2003	Issues involved with ultradeep HP/HT wells and their solutions
Esmersoy and Mallick [12]	2004	A novel approach/ or technique for predicting pressures ahead of the bit using vertical seismic profile (VSP)
Wellbore thermal problem and temperature estimation methods		
Marshal and Bentsen [13] Hasan and Kabir [14]	1982 2002	Studying typical thermal characteristics of formation and borehole materials.
Prensky [15]	1992	Geothermal temperature estimation techniques
Sathuvalli, et al. [16]	2001	Investigating the significant geothermal gradients seen in offshore oil and gas fields
Beardsmore and Cull [17]	2001	Errors in the estimate of the geothermal gradient due to geologic noise
Hasan and Kabir [14]	2002	Investigating the borehole thermal problem and the numerous situations that arise during drilling fluid circulation and formation fluid generation.
Wellbore thermal analysis and measurement techniques		
Ramey's [18] Raymond [19] Willhite [20]	1962 1967 1969	Building semi-analytical models for borehole thermal analysis and predicting injection and production temperatures
Vidick and Acock [21]	1991	highlighting some of the flaws in some of the flow temperature measuring methodologies
Impact of High temperatures on material characteristics		
Berckenhoff and Wendt [22]	2005	Examining the impact of high temperatures on material features such as elastomers and how they affect the system's sealing integrity
Brownlee, et al. [23]	2005	Offering a thorough examination of the industry's materials selection techniques for sour HP/HT wells

Nice, et al. [24]	2005	Discussing the development of a moderate sour benefit, 125-ksi high-strength low-alloy steel study for the Kristin production casing
The impact of HP/HT circumstances on PVT behavior of reservoir fluids		
Fisk and Jamison [25], Oakley, et al. [26], Zamora, et al. [27]	1989 2000	Examining the impact of high temperatures on mud characteristics
MacAndrew, et al. [28], Mansour, et al.[29], Rotmero and Loizzo [30],	1993 1999 2000	Providing research on the loss of cement mechanical properties under the impact of temperature
Rommetveit and Bjørkevoll [31], Harris and Osisanya [32].	1997 2005	Building a simulator to forecast the pressure and temperature dependency of mud density and rheological parameters
Wang and Su [33]	2000	Presenting a pressure-temperature model for estimating equivalent static density (ESD) in HPHT circumstances
Danesh [34]	2002	Doing experiments to demonstrate that increasing water content enhances the viscosity of formation fluids
Saasen, et al. [35]	2002	Presenting benefits of cesium formate for the Huldra field in the North Sea, which had a kick owing to barite sag in the OBM utilized
Griffith, et al. [36]	2004	Investigating the use of foamed cement systems to lessen the influence of temperature
Gozalpour, et al. [37]	2005	Demonstrating the impact of temperature on the volatility of heavy elements in HP/HT fluids
Developed thermal loads due to higher temperatures		
Handelman [38], Lubinski [39], Lubinski, et al. [40], Hammerlindl [41], Sparks [42], Mitchell [43], Paslay [44], He and Kyl-lingstad [45], Lea ,et al. [46]	1946, 1951, 1962, 1980, 1984, 1986, 1994, 1995, 1995	Addressing the problem of buckling in restricted tubulars caused by high thermal loads
Handelman [38], Lubinski [39], Lubinski, et al. [40], Hammerlindl [41], Sparks [42]	1946, 1951, 1962, 1984	Presenting the equations and theory needed to calculate effective forces for buckling and post-buckling analyses
Suryanarayana and McCann [47]	1995	Presenting buckling theory and experimental findings
ISO 13679 [48]	2002	Recommendation of using premium connections for HP/HT wells designing utilizing severe testing techniques.
Bradley, et al. [49], Carcagno [50]	2005	Addressing the issue of increased thermal loads created by higher temperatures
Wellhead movement (WHM) and annular pressure buildup APB		
Adams [51]	1991	Provides the formulas for calculating WHM and thermal stresses resulted from the elastic spring model's thermal expansion of the strings.
Halal and Mitchell [52]	1993	Highlighting the multistring casing design, which addresses the elastic response of the casing system.
Samuel and Gonzales [53]	1999	Describing the optimizing of multi-string casing design for annuli fluid expansion and wellhead increase

Table 1: Literature review study of HPHT wells.

Field Case Study, Results and Discussion

Field Description

A gas field located in Arab Gulf is classified as HPHT field because of appearing pressure in excess of 10000 psi and temperature over 300 °F during drilling its stratigraphic column (Figure 1). The drilling program is issued to drill 3 wells among between the previous drilled wells. The wells are proposed as a vertical S-shape well with Pre-Khuff as primary and Khuff-C as secondary objective in the gas field. Also, Offset and planned wells map is shown in Figure 2.The well is designed as a special well due depleted pressures in Khuff-C and high pressure in Pre-Khuff. The well is designed as a S-shape because of the surface location issues.

Otherwise, Hydrocarbon potential are:

1. Zones of primary hydrocarbon potential Pre-Khuff.
2. Other Known accumulations of hydrocarbons include:

- Oil in carbonates of the Arab-D Reservoir.
- Gas in Khuff Reservoir.
- Shallow gas is not expected in this location.

Furthermore, the pressure and temperature profiles of this region are plotted in Figures 3 and 4. Additionally, the future planned selected mud weights are constructed in Figure 3. So as to improve the future drilling performance, offset data analysis is done for previously drilled offset wells.

Offset Data Analysis

For the production section - 5 7/8 inch hole with 4 1/2 inch liner, 5 7/8 inch hole where the problem of HPHT appears, is drilled with the performance BHA bottom assembly from 4204 meters to +/- 4505 meters MD / 4411 m TVD (60 m - 200 ft in layer) with KCl type drilling mud polymers with ideal density 1553 kg/m^3 (97 pcf). A volume of cleaning fluid is circulated before the introduction of the casing. Investigations (mud logging and wireline logging) are done for this section. Potential hazards and information from neighboring or similar wells are also detected. Based on information from offset wells, the following risks are considered relevant for this section (Table 2 & Figure 5)

- Slow ROP and bit wear due to abrasive Unay and Jauf formations.
- Possible sloughing shale and tight spots in Tawil formation.
- Possible high pressure in Unay and Jauf reservoirs.
- Hole washout in Jauf formation

Based on offset data analysis, the drilling parameters are optimized and selected for the 5 7/8 inch borehole section until the 4-1 / 2 inch liner is landed at 4505 meters MD / 4411 m TVD, as follows:

- WOB: 15 – 22 klbs
- Flow Rate: 160 – 200 gpm
- RPM: 60 – 90

Expected ROP: 15 – 40 ft/hr

Due to the overpressure in the Jauf layer, a risk of differential clamping is estimated. In this regard, it is necessary to minimize the time to make a connection or any time in which the gasket is stationary. Additionally, the optimum mud weights are selected and plotted in Figure 3. Finally, the planned depth-time graph is constructed and shown in Figure 6. The required days for drilling the next HPHT well are 71 days of drilling, conditioning, logging, casing, cementing, and completion.

Formations	Depth (ft)			Estimated Pressure (Low) (psi)	Estimated Pressure (High) (psi)	Balance MW (Low) (pcf)	Balance MW (High) (pcf)	Program MW (pcf)	Over Balance (Low) (psi)	Over Balance (High) (psi)	TEMP (°F)
	MD	TVD	SS								
	10,654	10,390	-9,387	± 30' into Base Jilh Dolomite							
MDJR	10,914	10,634	-9,631					104			250
SUDR	11,768	11,460	-10,457								263
SDDM	12,078	11,769	-10,766								268
KHFF	12,443	12,134	-11,131								274
KFAC	12,652	12,156	-11,153								274
KHUFFA1	12,514	12,205	-11,202								275
KHUFFA2	12,557	12,248	-11,245								276
KFBC	12,586	12,277	-11,274								276
KFB1	12,646	12,337	-11,334	7,639	7,639	89.2	89.2	104	1271	1271	277
KFB2	12,725	12,416	-11,413								279
KFB3	12,786	12,477	-11,474								280
KFB4	12,828	12,519	-11,516								280
KFB5	12,864	12,555	-11,552								281
KFB6	12,926	12,617	-11,614								282
KFB7	13,002	12,693	-11,690								283
KFCC	13,066	12,757	-11,754								284
	13,071	12,762	-11,759	± 5' TVD into Khuff-C Carbonate							
KC01	13,084	12,775	-11,772	3,112	4,112	35.1	46.3	75	3542	2542	284
KC02	13,104	12,795	-11,792								285
KC03	13,121	12,812	-11,809								285
KC04	13,139	12,830	-11,827								285
KC05	13,154	12,845	-11,842								286
KC06	13,168	12,859	-11,856								286
KC07	13,188	12,879	-11,876								286
KC08	13,210	12,901	-11,898								286
KC09	13,241	12,932	-11,929								287
KC10	13,255	12,946	-11,943								287
KC11	13,287	12,978	-11,975								288
KC12	13,324	13,015	-12,012								288
KFDA	13,343	13,034	-12,031								289
	13,793	13,484	-12,481	± 450' into Khuff D Anhydrite							
BKDC	13,960	13,651	-12,648					97			298
PKFU/UNYZ	14,002	13,693	-12,690								299
UNYZ	14,002	13,693	-12,690	8,725	8,725	90.4	90.4	97	640	640	299
PUZU/JUBH	14,212	13,903	-12,900								302
JAUF	14,212	13,903	-12,900	5,434	8,634	56.3	89.4	97	3931	731	302
JFB3	14,307	13,998	-12,995								304
Lower JAF	14,413	14,104	-13,101								306
TWLF	14,580	14,271	-13,268								308
	14,780	14,471	-13,468	At Well TD (±200' into TAWIL)							

Figure 1: Geological column of area.

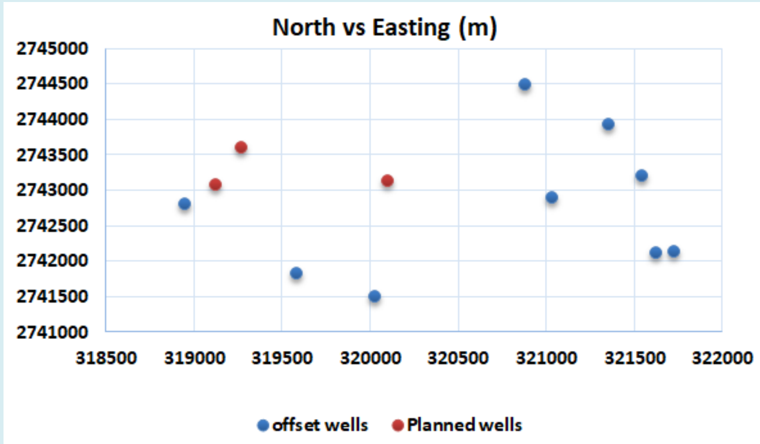

Figure 2: Offset and planned wells map.

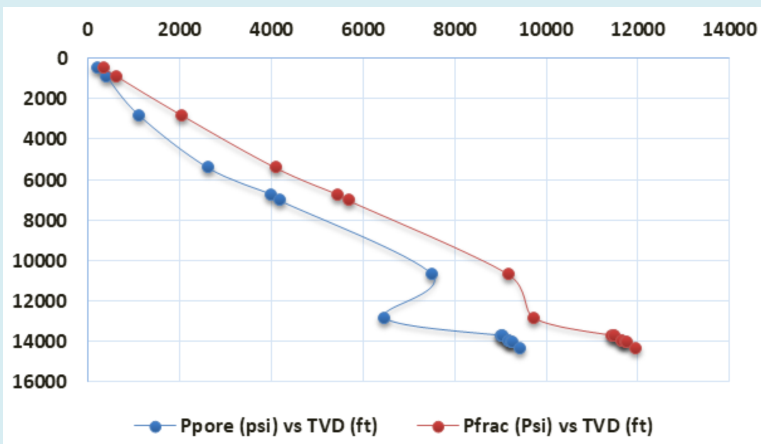

Figure 3: Formation and fracture pressure distribution for case #1.

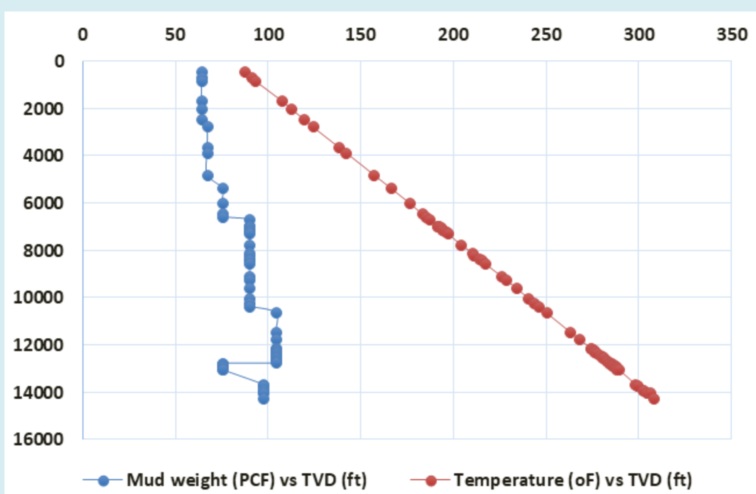

Figure 4: Mud density and temperature distribution for case #1.

Offset Well No.	Mud weight (pcf)	Risk / Event / Prevention / Mitigation
1	88	1. Drilled interval: 13,000' to 15,135' starting from 73 till 100 pcf.
		2. Well flow at 14,944' (TWIL), killed with 88 pcf.
2	94	1. Drilled interval: 12,040' (KHUFF B base) to 13,775'.
		2. Unable to complete coring due to abrasive sands in UNNZC.
3	89	1. Drilled interval: 12,560'to 14,052' starting from 74 till 89 pcf.
		2. Well flow at 12,865 killed with 89 pcf.
4	92	1. Drilled interval: 12,560 (JAUF TOP) to 14,550' (450' below JAUF).
5	94	1. Drilled interval: 12,438' (KHUFF-B top) to 14,597' (TAWIL).
6	97	Drilled 5-7/8" hole from 13,552' to well TD at 14,481' (180' into TWIL).
		Ran and cemented 4-1/2" liner.
		1. Drilled interval: 13,552' (450' into KFDA) to 14,052' (180' intoTWIL).
7	68-74/94	1. Drilled interval: 13,937' (KFCC) to 5,807' MD / 14,989' (200into TAWIL).
		2. Well flow at 14,183' MD / 13,380' TVD (KFC-10), killed with 74 pcf mud.
		3. Reaming BHA stuck at bottom.
		4. MDT on TLC got stuck at 15,369' MD /14,520 TVD (JAUF).
8	96	1. Drilled interval: 13,435' to 14,350' (TWIL).
		2. String stuck at 14,350' (TWIL).
9	95	1. Drilled interval: 13,885' (UNZA) to 14,350' (TWIL).
		2. Wireline held up on 2 occasions at 14,48 (JAUF) and 14,806 (TWIL), performed logging on TLC.

Table 2: Offset wells data analysis.

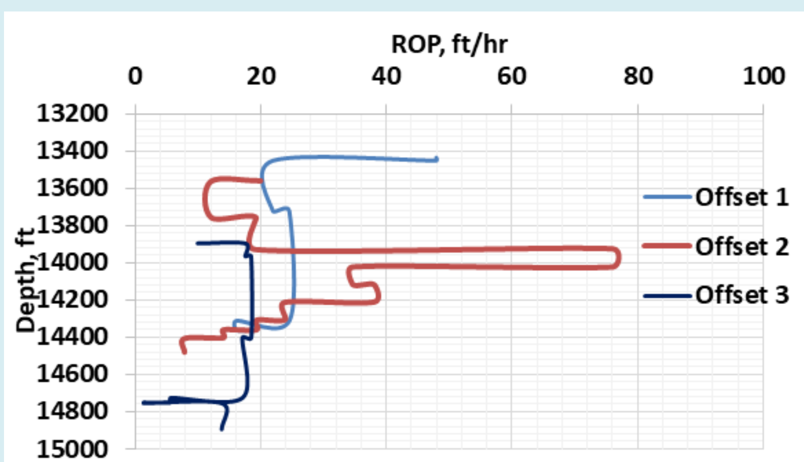

Figure 5: ROP data analysis.

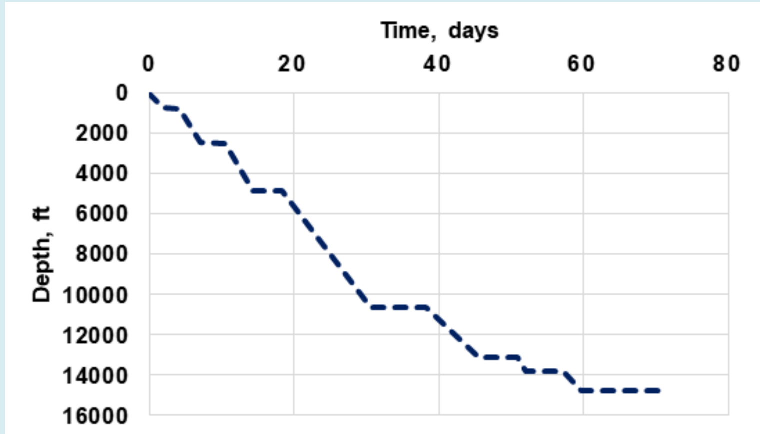

Figure 6: Depth-time curve for future wells.

Simulations Results and Analysis

A simulation study is done using landmark software in order to show the effect of HPHT on future wells. For the production section - 5 7/8 inch wellbore with 4 1/2 inch liner, HPHT appears. The temperature simulation and design would be done and performed in this section with Landmark software. Figure 7-9 show the geothermal gradient and temperature of the drill string and at the annular space. It is noted that the temperature of the drill string also increases at the annular space, and reaches the geothermal gradient despite the cooling caused by the mud. Simulations and modeling studies were performed for HPHT well pressures and dynamic conditions.

The entire circulation system has been optimized to determine and predict pressure losses, pump flow rates, flow pressure, pressure loss distribution, ECD and circulation pressure. During the modeling, the effect of temperature, change operations, cuttings loading and DFG hydraulic model was taken into account. Figures 10-15 shows the simulation results including various effects such as temperature, change operations, cuttings loading and DFG. It found that the HT increases the pressure distribution and losses in the hydraulic system during drilling HPHT section than normal case (Figures 11 & 12). Further, the variations of ECD during drilling operation causing swab and surge problems are appeared in Figure 12. Now, we can overcome the future surge and swab problem during drilling this zone.

Additionally, the HT induces the increasing of annulus and string pressure during circulation making them moving towards fracture pressure and super passing it (Figure 14). However, this effect does not exist in case of lower temperature or without taking the effect of temperature (Figure 15). Therefore, HPHT well can effectively be drilled based on offset data analysis and simulation so that the best drilling parameters can be optimized and selected carefully.

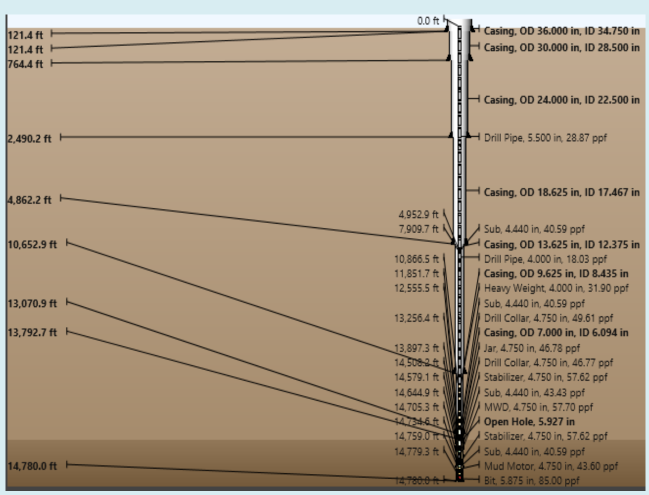

Figure 7: Well Profile.

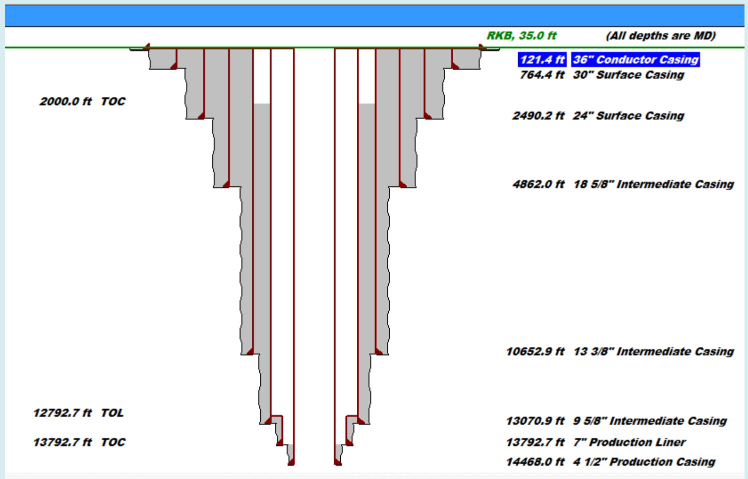

Figure 8: Well schematic.

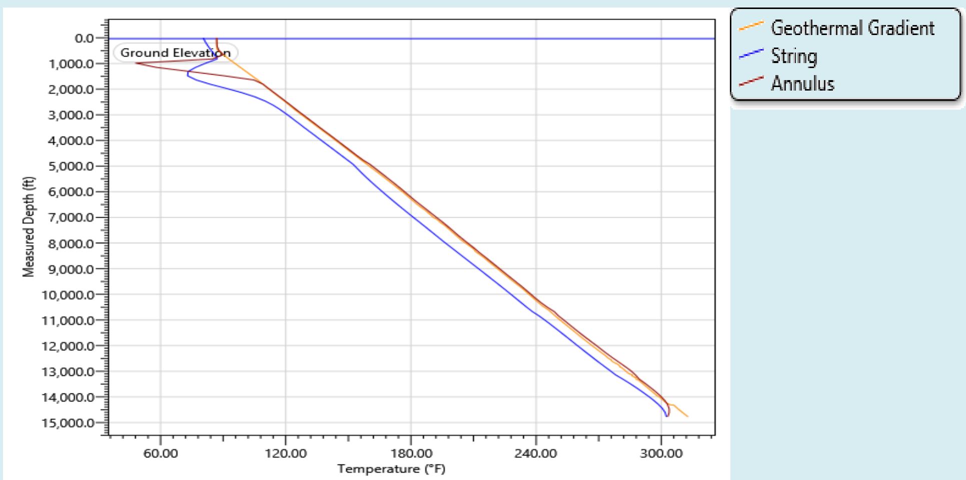

Figure 9: Temperature variation in the wellbore with depth.

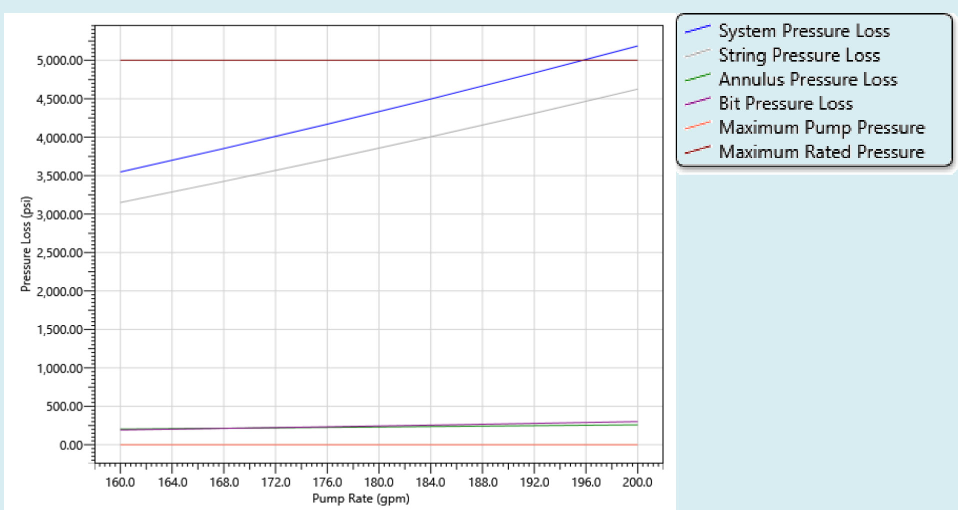

Figure 10: Pressure losses variation with flow rates including temperature effect.

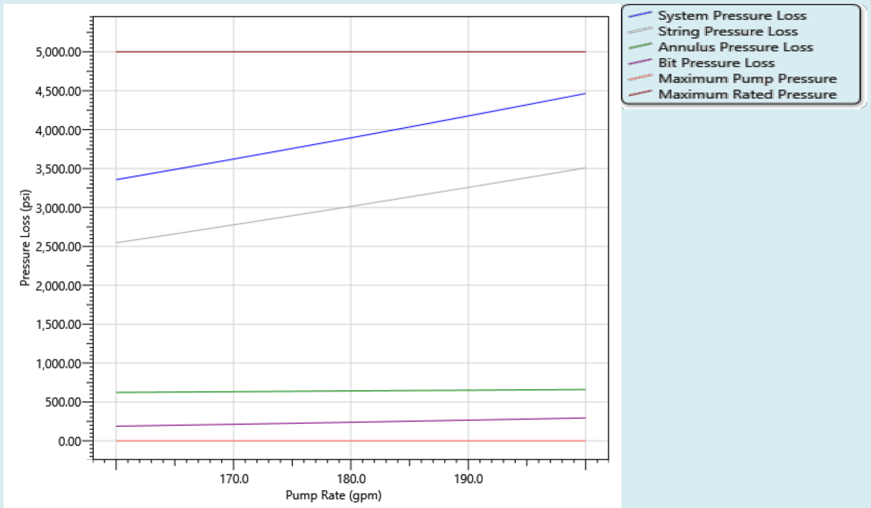

Figure 11: Pressure losses variation with flow rates including DFG Model.

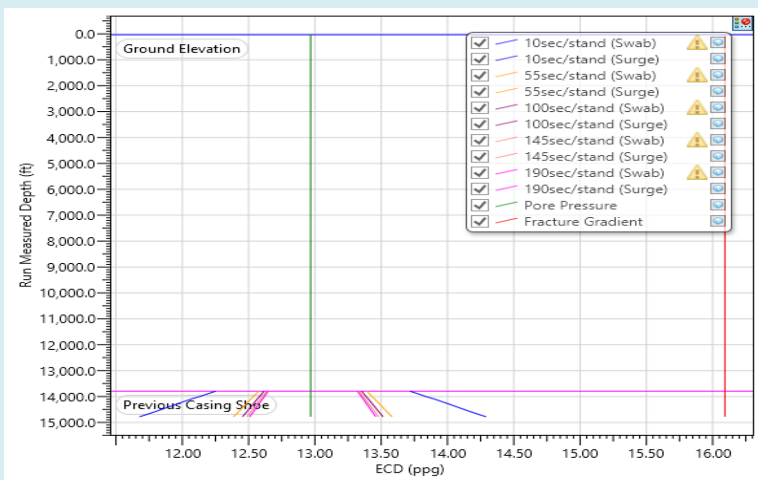

Figure 12: ECD of swab and surge during drilling HPHT section including the effect of HT and DFG model.

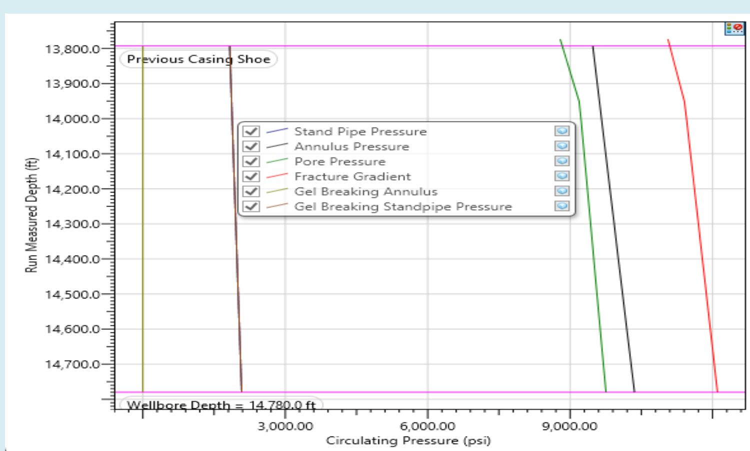

Figure 13: Circulation pressure per run for drilling HPHT section including the effect of HT and DFG model.

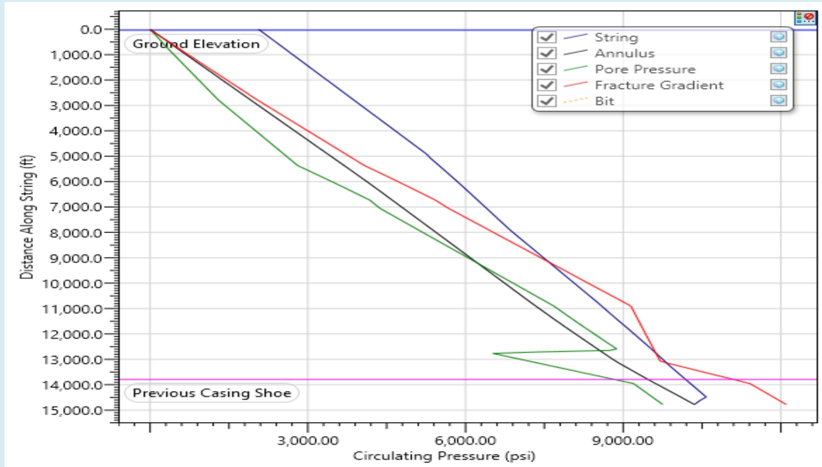

Figure 14: Circulation pressure for drilling HPHT section including temperature effect and DFG model.

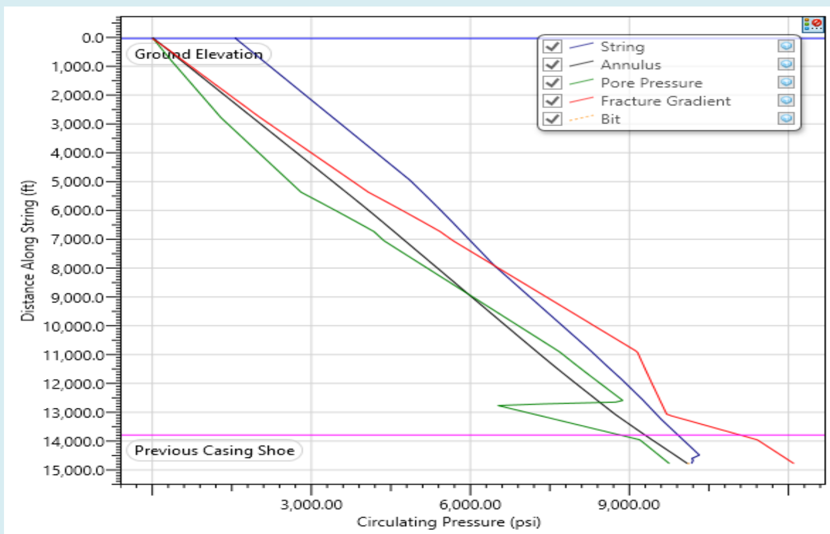

Figure 15: Circulation pressure for drilling HPHT section without temperature effect.

Thermal simulation study was also done as shown in Figures 16 through 22 in order to study the temperature distribution in the wellbore and around it. During drilling operations, fluid temperature increases. The more period of the operation, the higher fluid temperature acquires (Figure 16). The same situation repeats for the wellbore to be drilled in HPHT section (Figure 17).

This is due to increasing the geothermal temperature with depth during drilling as seen in Figure 18. As a result of that, all the wellbore including boreholes, casings, pipes, annuli, cementing, equipment, strings and devices landed or will be landed would be subjected to be heated during drilling those zones of HPHT (Figures 19-21). Thus, it is recommend to be careful with all material landed if they are suitable or not).

Finally, the required ECD during various operations is shown in Figure 22. It appeared that there are some shallower depths/ zones would be subjected to ECD problems but those would be cased during drilling HPHT section. Consequently, there would not be problems with those areas.

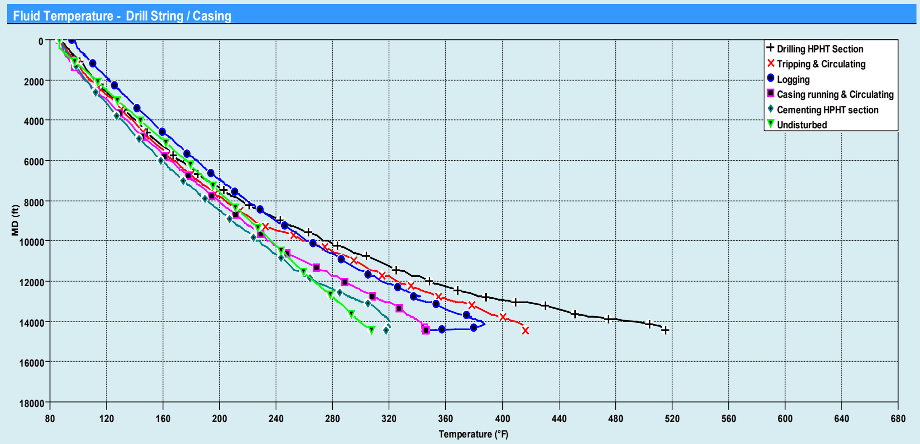

Figure 16: Fluid temperature during drilling operations.

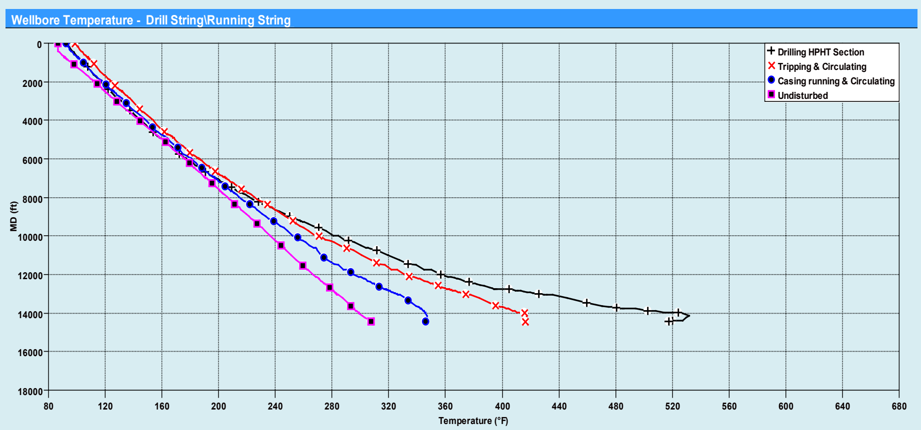

Figure 17: Wellbore temperature during drilling operations.

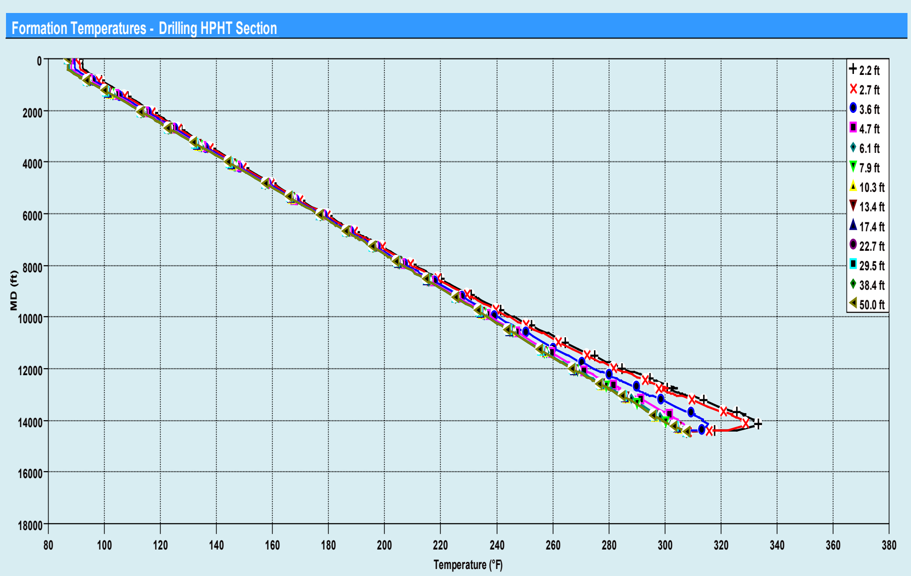

Figure 18: Formation temperature variation during drilling.

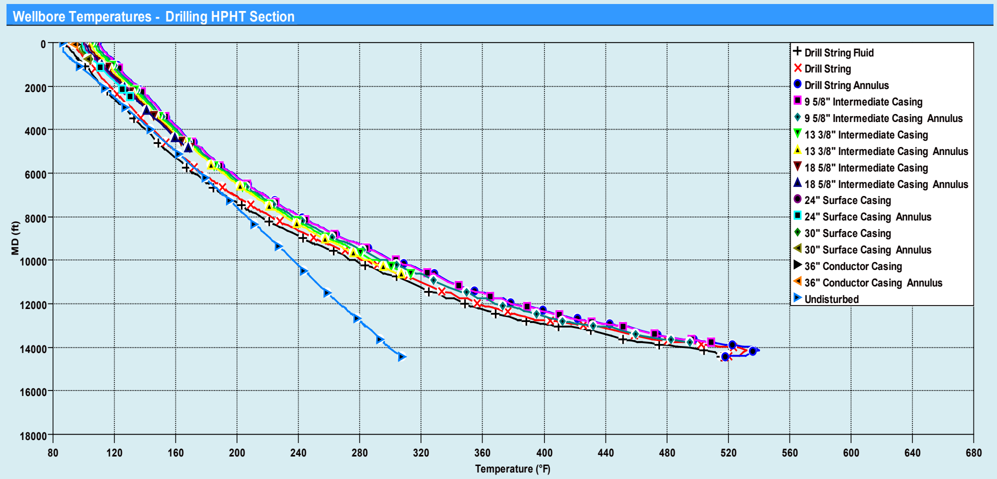

Figure 19: Wellbore temperature variations during drilling.

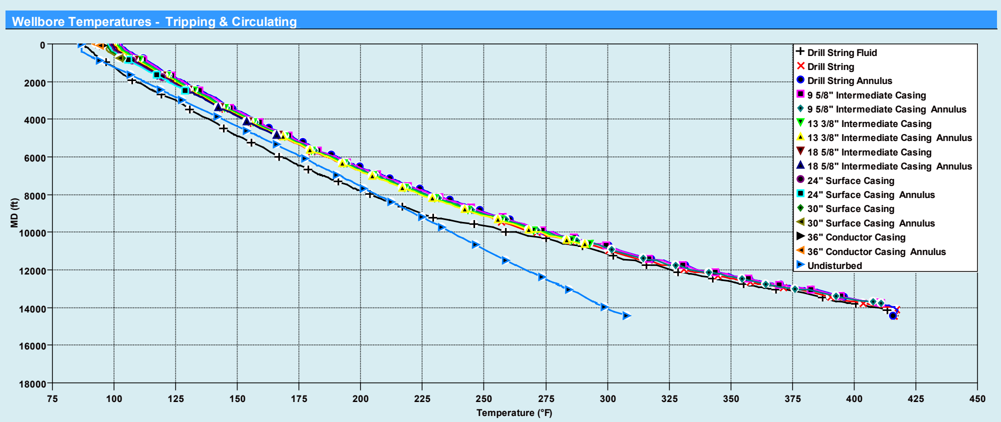

Figure 20: Wellbore temperature variations during tripping and circulation.

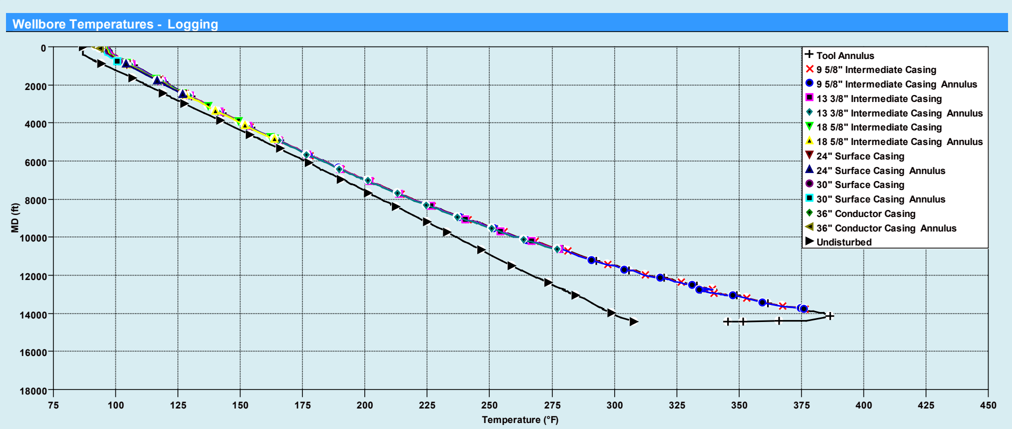

Figure 21: Wellbore temperature variations during logging.

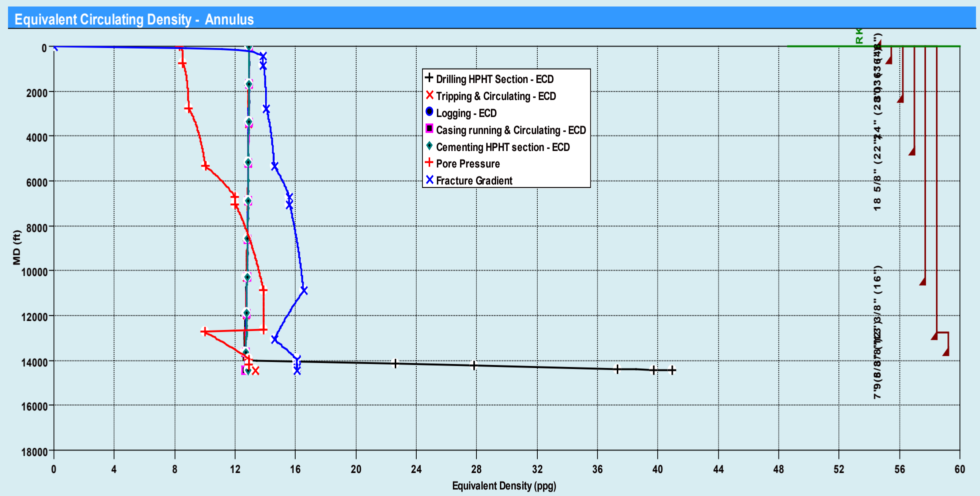

Figure 22: ECD variations during drilling operations.

Conclusion and Recommendations

HPHT well is a big a challenge, and needs several studies and advanced technologies. In our case, the HPHT zone has a little bit pressure of less than 10000 psi but the temperature of more than 300 °F. However, this zone can be considered as an HPHT region based on the definitions previously presented. Although our simulations and study contain a lot of details regarding HPHT well, the conclusions will include the only part presented in this paper, which is about offset data analysis, and simulation with landmark to show the effect of HPHT on circulation system, as follows:

1. HPHT zone changes most of the drilling parameters during operations.
2. HT has a great effect on pressures' profiles and fluids composition.
3. Offset data analysis plays a great role in future development plans.
4. Thermal simulation is a key-element to study temperature distribution in HPHT wells.
5. HPHT increases the swab and surge problems.
6. It is recommended to be careful for all material used in HPHT well if there are suitable or not.
7. HPHT Technologies, materials, fluids and standards are often your requirements without thinking.
8. Wellhead movement (WHM) and annular pressure buildup (APB) will be a challenge due to annuli pressurizing and multistring interaction.

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