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POST–DRILLING SIMULATION USING UTAH FORGE DATA ON THE DRILLING SIMULATOR AS WELL AS IN-DEPTH ANALYSIS OF DRILLING VIBRATION USING DRILLSCAN TECHNOLOGY

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SIMON L. AVINU

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POST–DRILLING SIMULATION USING UTAH FORGE DATA ON THE DRILLING SIMULATOR AS WELL AS IN-DEPTH ANALYSIS OF DRILLING VIBRATION USING DRILLSCAN TECHNOLOGY

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BY THE COMMITTEE CONSISTING OF

Dr. Catalin Teodoriu, Chair

Dr. Ramadan Ahmed

Dr. Ahmad Ghassemi

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Abstract

Geothermal energy extracted from the heat in the Earth's crust has emerged as one of the sustainable and reliable sources of power. Drilling for exploration and exploitation of Geothermal energy resources is key to affordable and independent energy. However, the inherent complexities of drilling in geothermal formations pose notable challenges to operational efficiency, safety, and cost-effectiveness. Drilling to exploit geothermal resources like all drilling activities is destructive and therefore problems such as equipment wear and tear, shorter tool life span, and Non-Performing Time (NPT) are inevitable. While there have been attempts to apply conventional oil and gas knowledge to geothermal drilling, it still poses unique challenges. Simulation of the drilling processes, challenges, and mitigating measures are required to ensure operational efficiency, cost-effectiveness, and safety in harnessing the resource. The study delves into a post-drilling simulation of Utah Forge data using a drilling simulator (DrillSim50) and DrillScan technology. This is to assess the drilling processes, the impact of drilling vibrations on equipment wear, and failure, and the mitigation of such vibrations in the drilling industry. By leveraging Utah Forge data, the study highlights the drilling difficulties in post-drilling simulations, providing valuable insights into real-world scenarios. The research will allow for a comprehensive investigation into vibration dynamics, shed light on potential challenges, and propose strategies for enhanced drilling efficiency. The major topics included in the study are:

A. Geothermal Drilling
B. Utah Forge well 16A-78-32 drilling overview
C. Post-drilling vibrations Analysis.

D. Categories of drilling and well control simulators
E. Strength, limitations, and future design opportunities
F. Vibration mitigation
G. Post-Drilling processes on DrillSim50
H. Impact of Conventional Well Control on Geothermal Drilling and Construction

With the above-mentioned topics, the study can comprehensively devise a tool for identifying a suitable simulator for specific training when embarking on challenging well operations. In addition, investigation into the drilling dynamics, and vibrations, may highlight the potential challenges, and propose strategies for enhanced drilling efficiency. One of the critical factors that impacts the success of geothermal well construction is the application of effective well control measures. Conventional well control principles, which encompass techniques for maintaining wellbore integrity and controlling formation fluid influx, are fundamental to ensuring safe and efficient drilling operations in geothermal reservoirs. However, the unique geological and operational challenges associated with geothermal drilling necessitate the adaptation and customization of conventional well control methodologies. By studying the impact of the application of conventional well control on geothermal, the techniques and technologies directed at managing subsurface pressures to prevent blowouts can be investigated. After successfully identifying the complexities of geothermal well control, appropriate well control measures unique to geothermal will be proffered.

- Overall, a comprehensive understanding of post-drilling processes, vibration analysis, and geothermal well control has been gained in this study which can be used in the field for better drilling process, effective well control, and mitigation of drilling vibrations

Chapter 1: Introduction

Geothermal energy is described as one of the cleanest, most reliable, safest, and most affordable energy being sought globally as a result of the Paris Accord. There is enough energy in the earth's crust, just a few miles down, to power all of humanity for ages, according to the US Advanced Research Projects Agency-Energy (estimated 0.1% of earth's heat content). The challenge is tapping into it safely, efficiently, and cost-effectively. Though, geothermal drilling dates back in time, the engineering design, safety, and construction were not straightforward. It has been described as an engineering problem that, when solved, provides clean, reliable, safe, and affordable energy globally (Feder 2021).

The drilling industry constantly seeks innovative approaches to improve drilling operations, enhance efficiency, and minimize risks associated with drilling vibrations since they form a major part of geothermal cost. In this context, post-drilling simulation and vibration analysis play a pivotal role in gaining a deeper understanding of drilling processes and challenges. The integration of Utah Forge data into drilling simulations offers a unique opportunity to replicate real-world conditions and assess the performance of drilling operations under various scenarios. Furthermore, the study extends its focus to the analysis of drilling vibrations, a critical aspect that significantly impacts drilling efficiency and tool longevity. The capabilities of DrillScan technology is used here to explore the complex dynamics of drilling vibrations and their correlation with drilling equipment wear and failure. By combining post-drilling vibration analysis with simulation on the DrillSIM50, this thesis aims to bridge the gap between theoretical understanding and practical application in drilling engineering. The subsequent chapters will delve into the methodology, data collection process, results, and discussions, ultimately culminating in a comprehensive exploration of the interplay between Utah Forge data, drilling simulations, and the analysis of drilling vibrations using Drillscan technology. The ultimate objective is to deliver better drilling performance for geothermal wells with fewer tool failures.

1.1 Purpose

The thesis aims to investigate and propose methodologies for enhancing geothermal drilling processes in future wells through post-drilling simulation, drilling vibration analysis, and applying unique geothermal well control principles. This addresses the major inherent complexities and challenges associated with drilling in geothermal formations. The simulation evaluates the efficiency of Drilling Simulators (DrillSim50) for a post-drilling replica of the actual well and diverse drilling scenarios specific to geothermal environments except with temperature variation. In addition, it devises a comprehensive post-drilling analysis, using real-time and historical data to evaluate drilling performance, identify operational inefficiencies, and optimize future drilling campaigns. Furthermore, apply DrillScan technology to investigate drilling-induced vibrations through post-drilling data analysis, identifying their causes and effects on drilling efficiency and tool wear with a focus on Utah Forge geothermal drilling operations. The study intends to modify Conventional Well Control methods to address the unique challenges of geothermal drilling.

Through these investigations, the thesis seeks to contribute to the advancement of geothermal drilling technology, enabling safer, more efficient, and cost-effective exploration and exploitation of geothermal resources for sustainable energy production.

1.2 Objectives

The proposed research aims to investigate the drilling vibrations and their impact on equipment wear, failure, and ROP for the Utah FORGE well 16A-78-32. The research involves investigating drilling-induced vibrations and identifying their causes and effects on drilling efficiency. In addition, the study modifies Conventional Well Control methods to address the unique challenges of geothermal drilling. In terms of effective geothermal drilling, the following research objectives have been proposed.

- Simulations were used to study drilling vibrations and processes for the Utah Forge Well 16A-78-32. Two simulators were available, namely DrillScan Technology and DrillSIM50
- The DrillScan Technology from H&P was used to determine the vibrations and analyze their impact on drilling performance. With this, the drilling parameters for the Utah Forge wells were modified in the drillScan to reduce the vibrations. To represent a practical drilling process, troubled sections of Utah Forge well 16A-78-32 were drilled on DrillSIM50 using the modified parameters. The aim was to determine and analyze the drilling process to ascertain whether the vibrations were mitigated and performance improved.
- The DrillSIM50 was used to run many scenarios of optimum WOBs and RPMs to study their effect on the post-drilling simulation performance.
- The well is drilled on drillsim50 with similar lithologies using similar BHAs to that of the Utah Forge wells. The data obtained at the troubled sections drilled on drillsim50 at specific depths were evaluated and compared to the field data to determine inefficiencies.
- The ideal parameters were applied to the sections where the drilling vibrations occurred to analyze the effects of key drilling performance indicators.

• The DrillSIM50 scenarios were configured to test Geothermal Well Control considering the unique geological and the fluid present within geothermal formation except for temperature variation.

• Data from simulations run on DrillSIM50 are analyzed to evaluate the performance of conventional well control methods in geothermal drilling. Results are analyzed to assess the effectiveness, identify failure points, and propose potential improvements.

• Review drilling and well control simulators based on current technologies to select the appropriate simulator for applicability and efficiency.

1.3 Scope

This thesis structure consists of seven chapters and sections. Chapter 1 is an introduction,

Chapter 2 reviews geothermal drilling, specifically Utah Forge well 16A-78-32, and the potential enhancement for future drilling activities. Chapter 3 provides a short overview of drilling vibrations., Chapter 4 reviews drilling and well control simulators, Chapter 5 presents two sections; post-drill vibration analysis, and a replica of the Utah Forge well 16A-78-32 drilling on DrillSIM50, Chapter 6 explores the impact of conventional Well control on geothermal drilling, Chapter 7 consists of Results and discussions, and Finally, Chapter 8 provides conclusions and suggests related future work that could be done.

Chapter 2

Geothermal Drilling

Geothermal drilling is vital to harnessing geothermal energy, a renewable energy source derived from the earth’s crust, as shown in Figure 2:1-1 The process comprises drilling wells into the Earth to access steam (Hydrothermal) or Hot Dry Rock (Enhance Geothermal energy) that can be used to generate electricity or provide direct heating. Hydrothermal is a naturally occurring geothermal system that requires three key elements to generate electricity: heat, fluid, and permeability, by which fluid can move freely through the underground rock. Even without water and permeability, thermal energy (heat) exists everywhere beneath the Earth's surface and increases with depth. Research in the 1970s, partially funded by the U.S. Department of Energy (DOE), expanded the potential of geothermal resources through the study of Enhanced Geothermal Systems (EGS). At the most basic level, EGS are manmade geothermal reservoirs. In areas where the subsurface is hot but lacks sufficient permeability and/or fluid, water can be injected into the well to stimulate the creation of a geothermal system as shown in Figure 1.1.1.1. An enhanced geothermal system (EGS) is therefore a commercially viable thermal reservoir where two wells are interconnected by some form of hydraulic stimulation (Sugiura et al. 2021). The U.S National Renewable Energy Laboratory (NREL) discovered that there is significant potential for geothermal resources in the form of conventional hydrothermal or Enhanced Geothermal Systems (EGS) in the United States, particularly in the western part of the country (Glassley 2014). In 2020, the global geothermal power capacity was estimated to be 14,050 megawatts (MW) (IRENA 2021) . Of this, the United States contributed 2,587 MW. The U.S. remains the world leader in both geothermal power production and installed capacity (IRENA 2021) . According to DOE 2010, EGS holds the potential to power more than 65 million American homes and businesses and is the next frontier for renewable energy deployment. However, drilling to exploit geothermal resources is complex and challenging. This is due to the presence of harder igneous and metamorphic rocks and higher temperatures ((Dusseault 2011); (Jefferson W Tester et al. 2007)). Compared to the sedimentary formations of most oil and gas reservoirs, Geothermal production zones often experience temperatures ranging from 160°C to over 300°C, which far exceed those typically found in oil and gas operations. This requires the use of specialized materials and equipment that can endure these high temperatures. The rock formations in geothermal reservoirs are usually very hard, with compressive strengths greater than 240 MPa. Additionally, their high quartz content (over 50%) makes them particularly abrasive, causing rapid wear on drilling tools and equipment (Blankenship 2010). These challenging conditions often result in difficult drilling operations, characterized by low rates of penetration and reduced bit life (Macini and Mesini 1994). Geothermal formations are frequently highly fractured, with fracture apertures that can be several centimeters wide. Unlike many oil and gas reservoirs, geothermal formations are often under-pressured (Blankenship 2010). These challenges include issues with long-term casing and cement integrity due to elevated temperatures, significant severe and frequent circulation losses in natural fractures, and very low penetration rates. Over 40% of drilled depth each year is estimated to be affected by drilling vibrations, and ROP improvements are observed when they are mitigated ((Bailey et al. 2008) (Rahman et al. 2012)). Geothermal drilling techniques, however, have evolved significantly over the years, benefiting heavily from the oil and gas industry (Tomasz Sliwa et. al 2021). The next section gives a brief overview of the drilling process.

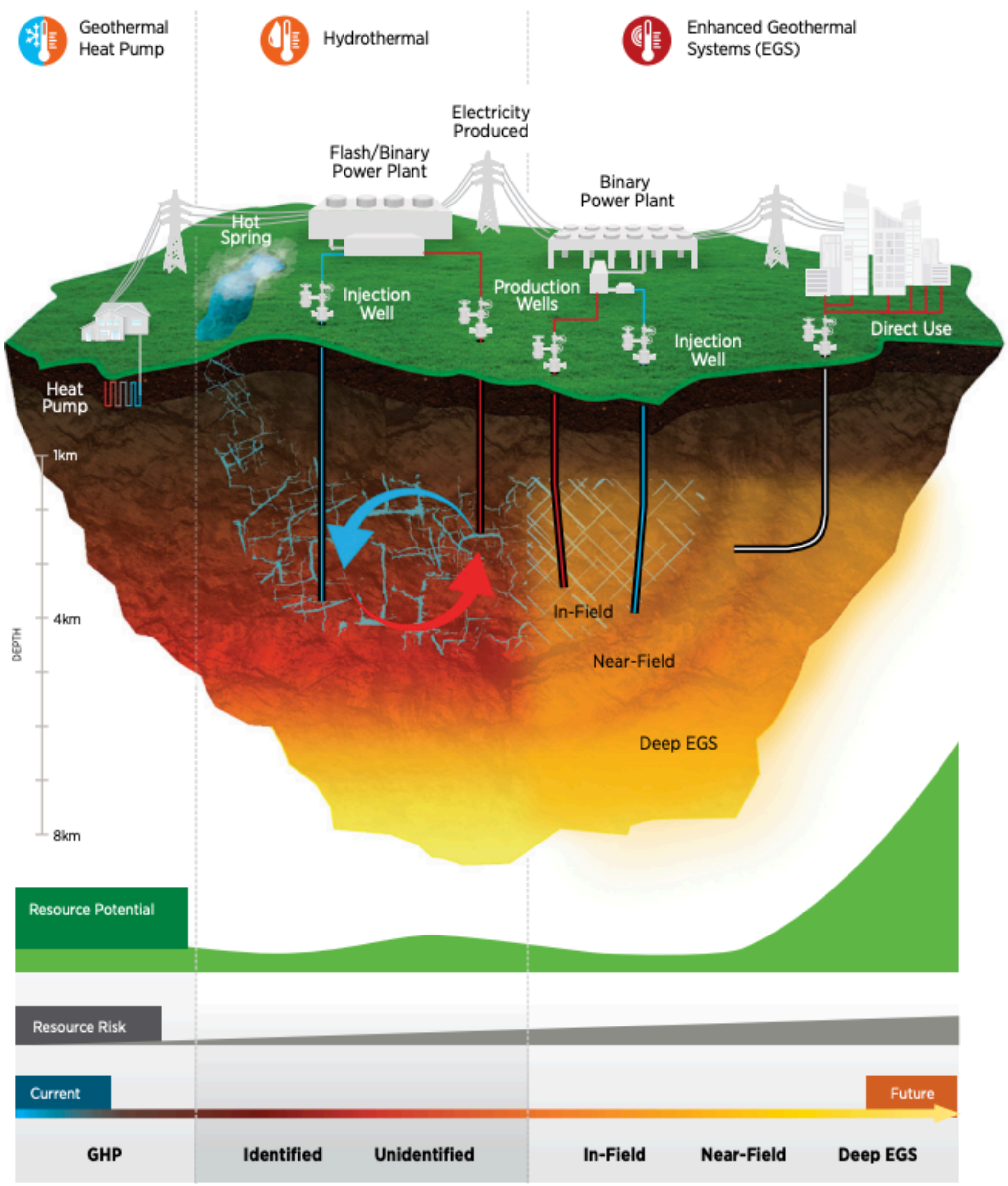

Figure 2:1-1 The Geothermal resources and applications are categorized into three main types: geothermal heat pumps, hydrothermal systems, and enhanced geothermal systems (EGS) (US 2019)

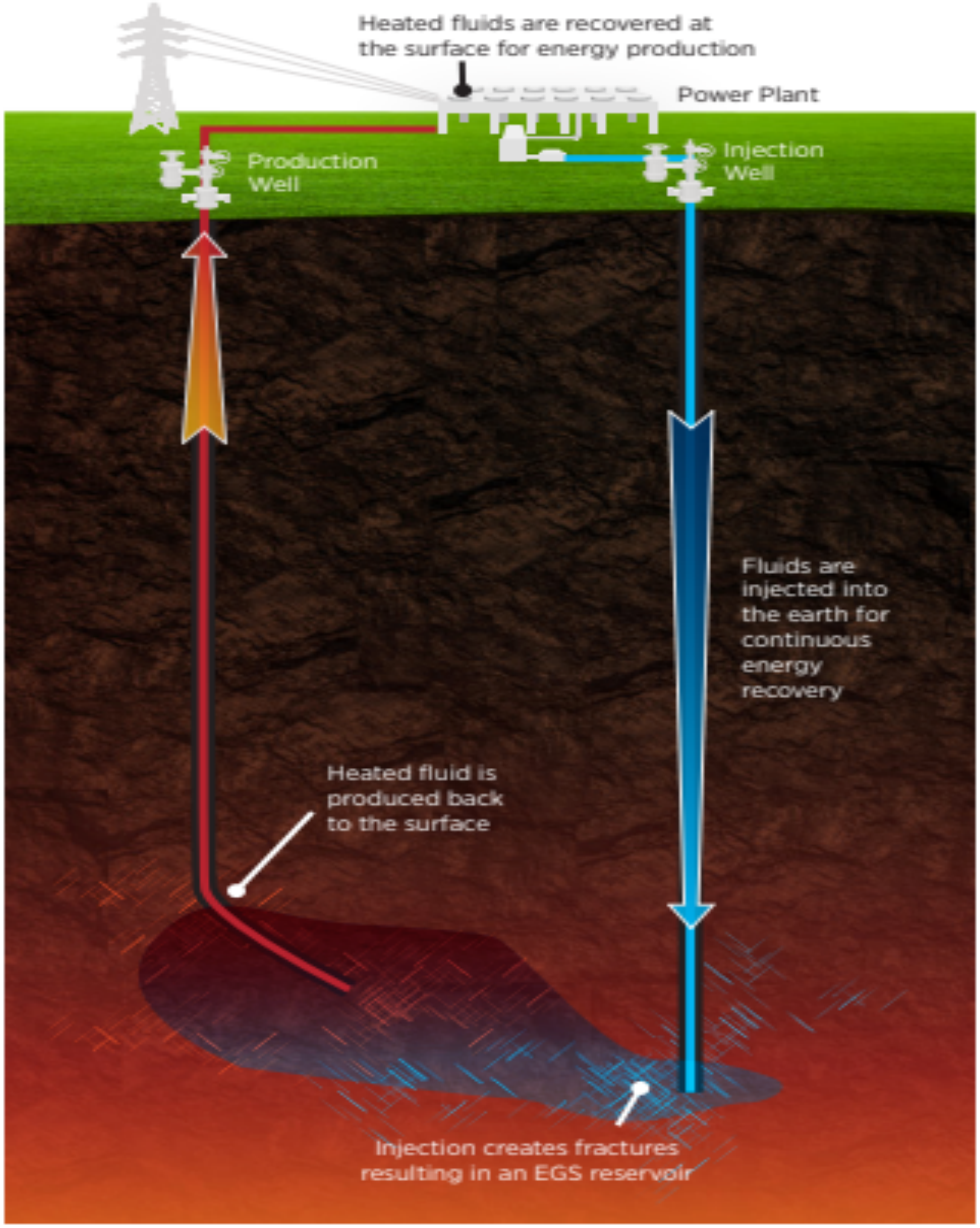

Figure 2:1-2 Simplified cross-section of EGS wells, courtesy of GeoVision (US 2019).

2.1 Drilling process

The general drilling process for oil and gas wells shares similarities with geothermal well drilling. As noted by (Purba et al. 2022), the standard drilling procedures for both types of wells are comparable, as illustrated in Figure 2:1-3.

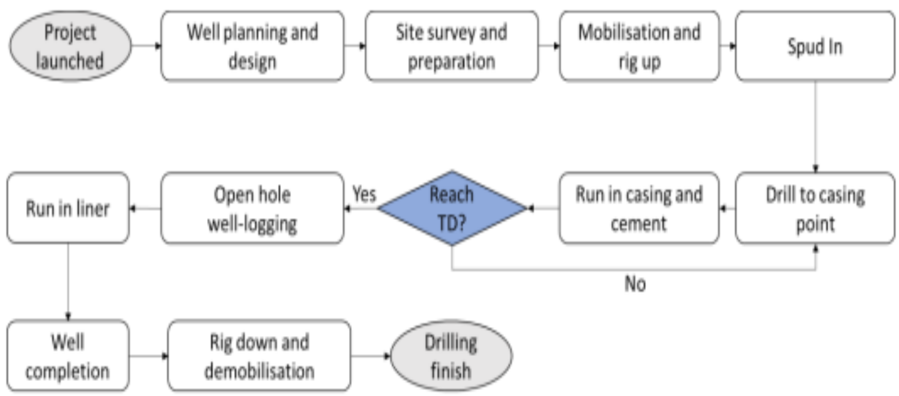

Figure 2:1-3 Simplified Drilling Project Activities (Purba et al. 2022)

Well Planning and Design: After the launch of the Geothermal project, the next phase is the well planning and design which are two separate but closely related parts of a geothermal drilling project. The planning aspect deals with the definition of the potential target, list, schedule, and budget for the multitude of individual activities required to drill the well. The Design part means to specify all the physical parameters (depth, diameter, pressure profile etc.) that define the well itself to reach the subsurface target effectively. However, the Design of a geothermal well is a "bottom-up" process (Blankenship 2010). The location of the production zone dictates the total length of the well, while the desired flow rate determines the diameter at the bottom of the hole. The well's profile above the production zone is then set by iteration of the successively larger casing strings required by drilling or geological considerations.

Site Survey and Preparation: Once management approves the drilling proposal, a site survey and preparation phase follow. This step involves setting up the necessary drilling infrastructure, such as the well pad, access roads, water supply, staging areas, and disposal areas. In high-altitude areas, preparation is more complex than in flat terrain due to the challenges posed by steep slopes, making it difficult to create a level surface for the well pad. Following site preparation, the conductor casing (ranging from 18 inches to 36 inches) can be installed using an auger unit to isolate the upper soil layers and prevent loose material from contaminating the wellbore during the initial drilling operations (this is for onshore. Drilling).

Rig Selection, Mobilization, and Rig-Up: This phase involves the selection of the appropriate rig based on the design parameters of the well followed by the transportation of the Drilling equipment from the drilling yard to the site. For land-based operations, equipment is often shipped to the nearest port and then transported by heavy-duty trucks to the well pad. Upon arrival, the equipment is set up and secured before rig-up operations commence.

Spud-In: This marks the official start of drilling operations. This step is initiated once the rig has been thoroughly inspected and deemed safe for operation.

Drilling to Casing Point Depth: Drilling operations commence from the surface and continue until reaching the planned depth for the surface casing. This casing is essential for isolating surface aquifers and gas zones, ensuring safe drilling into deeper formations. It's crucial to use environmentally safe drilling materials to prevent contamination. As the drilling progresses deeper, smaller bit sizes are typically used. Once the casing point is reached, the drill pipe is tripped out of the hole.

Casing and Cementing: Once the target depth is achieved, the casing is run, set in place, and secured with cement, which is pumped to fill the annular space between the outer casing and the formation. This process isolates the casing from the formation, preventing issues like corrosion, blowouts, and casing collapse.

Drilling to Total Depth (TD): continues to total depth after completing the first section. The next phase involves drilling to the next casing setting depth, which may present more challenging conditions due to the hazardous environment, such as Possible Causes of Kick. A common challenge is lost circulation, which can be caused naturally or induced by human activity. Lost circulation reduces the hydrostatic pressure in the wellbore, potentially leading to a formation influx, known as a kick, which could escalate to a blowout. Once the next casing point is reached, the well is secured with casing and cement. In the final section (reservoir zone), a perforated liner is used without cement to minimize formation damage (depending on the formation integrity), allowing for data acquisition activities.

Open hole well-logging: This is typically performed in the reservoir section using logging tools that make direct contact with the formation. The collected data assists the subsurface team in formation evaluation. After open-hole logging, a perforated liner is run into the hole to secure the wellbore. This liner permits formation fluids to flow, enabling well testing or production.

Rig down and demobilization: This occurs after all drilling operations are completed. The rig is disassembled and moved to the next drilling location.

2.2 Overview of Utah Forge Well 16A-78-32

Here, we review the oil and gas drilling technology, benefits, challenges, and prospects as applied successfully to Forge Well 16A-78-32 (Junichi Sugiura et al. 2021).

The Utah FORGE project, supported by the US Department of Energy (DOE), aims to develop and demonstrate EGS technologies. Well 16A (78)-32, is the first deviated geothermal well drilled by Utah FORGE that highlights the technical challenges faced, such as drilling accurate vertical sections and long tangent sections in hard granitic formations at high temperatures (Duane Winkler, Leroy Swearingen 2021). The drilling summary for well 16A (78)-32, prepared by Duane Winkler and Leroy Swearingen in March 2021, provides a comprehensive account of the drilling activities undertaken as part of the Utah FORGE project, which the U.S. Department of Energy funds. This well was spud on October 30, 2020, and the rig was released on January 12, 2021, after reaching a measured depth of 10,987 feet.

Location

The well 16A(78)-32 is located on the Utah School and Institutional Trust Lands (SITLA) property. The surface coordinates are:

-Latitude:38° 30’ 14.447” N

- Longitude:112° 53’ 47.066” W

- Ground Level Elevation: 5,414.00 ft

- Rotary Table Elevation 30.00 ft

The true vertical depth (TVD) from the rotary table elevation is 8,560.61 ft. The well plan azimuth is 105°, and the measured depth at the total depth (TD) is 10,987 ft. Figure 2:1-4 shows the directional trajectory plot.

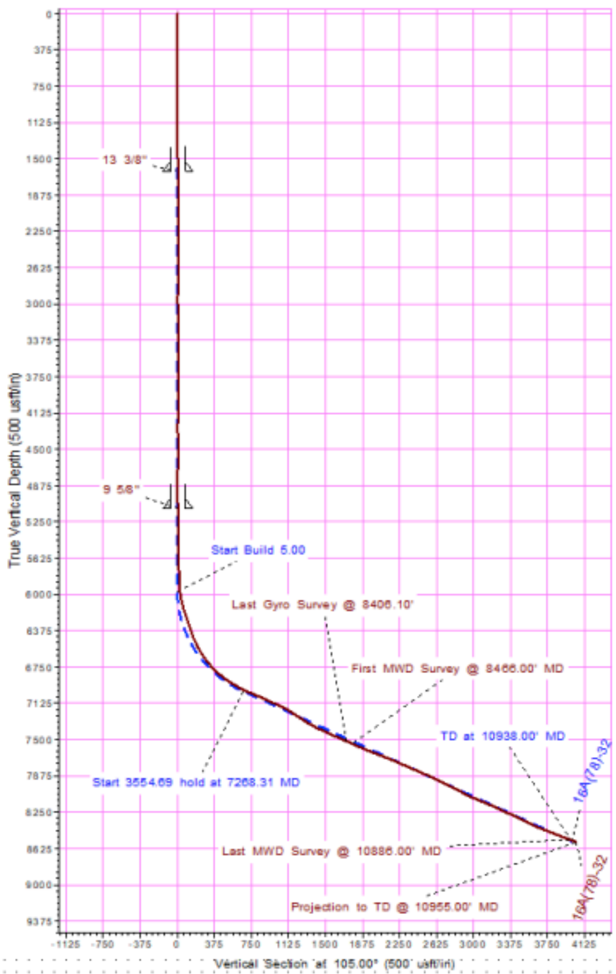

Figure 2:1-4 Directional profile of 16A-78-32 (Duane Winkler, Leroy Swearingen 2021)

Drilling Operations

Before drilling the Utah Forge 16A-78-32 comprehensive downhole temperature simulations were conducted to ensure the selection of appropriate drilling equipment, including mechanical vertical drilling tools, instrumented steerable motors, measurement-while-drilling (MWD) tools, and high-frequency drilling dynamics recorders. Data collected from both downhole and surface drilling dynamics were utilized to refine bit designs, optimize motor power sections, and continuously enhance equipment durability, drilling efficiency, and footage drilled (Sugiura et al. 2021).

Drilling optimization techniques typically employed in oil and gas operations were effectively applied to this well (Sugiura et al. 2021). These included analyzing data from drilling dynamics sensors embedded in steerable motors and vertical drilling tools, monitoring surface mechanical specific energy (MSE), and implementing a drilling parameter roadmap to reduce drilling dysfunctions and equipment failures. By employing these optimization strategies, the instrumented steerable motors paired with the appropriate bits achieved an average penetration rate of over 40 feet per hour, doubling the rate of penetration (ROP), footage, and run lengths compared to prior granite well drilling operations (Sugiura et al. 2021). The next section gives the drilling overview of the surface section, intermediate, production, vertical production, curve, tangent, and Final TD sections.

Run Summary

The following Table 2.1 shows the run summary for bottom hole assemblies (BHAs) 5-42 from 1419m (around the top of the basement) to the TD at 3415m MD.

BHA Number	Hole Size (in)	Bit Vendor	Depth In (ft)	Depth Out (ft)	Footage (ft)	On-Bottom Hours	On-Bottom ROP (fph)	Angle In (deg)	Angle Out (deg)	Comments	Grading
5	12-1/4	A	4552	4964	412	24.7	16.7	1.5	1.6	Pulled due to deteriorating ROP	6-2-CR-N-X-I-CT-PR
6	12-1/4	A	4964	5113	149	15.6	9.5	1.6	1.5	Pulled due to low ROP. Casing point called.	0-0-NO-A-X-I-NO-PR
9	8-3/4	A	5113	5345	232	27.1	13.6	1.5	0.8	16 mm cutters	0-1-WT-S-X-I-BT-PR
10	8-3/4	B	5345	5473	128	9.0	14.2	0.8	0.2	16 mm cutters, Reached core point	0-1-WT-S-X-I-NO-CP
14	8-3/4	C	5504	5846	341	36.8	9.3	0.2	2.8	Reached core point	8-3-CR-C-X-I-CT-CP
18	8-3/4	C	5892	6360	468	11.6	40.4	2.8	18.2	Curve, first 13 mm cutters	1-2-WT-A-X-I-CT-PR
21	8-3/4	C	6360	6526	166	4.6	36.2	18.2	21.1	Curve, geometrically stuck	1-1-WT-A-X-I-NO-BHA
22	8-3/4	C	6526	6945	419	17.5	23.9	21.1	42.0	Curve	2-2-CT-S-X-I-WT-BHA
23	8-3/4	C	6945	7390	445	14.6	30.4	42.0	66.6	Land curve and log	1-1-WT-A-X-I-NO-LOG
30	8-3/4	C	7390	8024	634	18.0	35.3	66.6	60.8	Tangent	4-8-RO-S-X-I-BT-PR
34	8-3/4	C	8026	8241	215	4.9	44.1	60.8	65.4	Tangent, Cored out bit	8-1-CR-C-X-I-WT-PP
35	8-3/4	C	8241	8391	150	3.0	20.2	65.4	66.8	Tangent	
35A	8-3/4	C	8391	8535	144	2.0	70.6	66.8	65.6	Tangent	2-1-CT-C-X-I-CT-LOG
38	8-3/4	C	8535	9064	529	10.3	51.4	65.6	66.3	Tangent, Ring out bit	3-6-RO-N-X-I-WT-PR
39	8-3/4	C	9064	9748	684	15.5	44.1	66.3	62.9	Tangent, Ring out bit	2-7-RO-S-X-I-CT-PR
41	8-3/4	C	9748	10490	742	14.8	52.3	62.9	64.9	Tangent	1-3-CT-S-X-I-WT-PR
42	8-3/4	C	10490	10955	465	8.1	57.4	64.9	68.6	Tangent	1-1-WT-A-X-I-NO-TD

Table 2:1—The run summary for BHAs 5-42 (vertical, curve, and tangent sections). (Sugiura et al. 2021)

Drilling Surface Section

BHA Detail								
#	Description	Mfg.	Serial #	O.D.	I.D.	Length	Sum	Top Conn
1	TKC76 Bit	NOV	A275580	17 1/2		2	2	7 5/8 REG
2	14" Vertical Scout RSS	Scout	SDI-1400-VS08-002	14		21.11	23.11	7 5/8 REG
3	7 5/8 Reg Pin X 6 5/8 Reg Pin X-Over	Scout	SDI-950-XO-010	9 1/2	2 3/4	2.15	25.26	7 5/8 REG
4	9 5/8" Scout 7/8 5.9 stg Straight Fixed 17 3/8" Stab	Scout	TDI-OSA-962-01-	9 5/8		41.08	66.34	6 5/8 REG
5	8" Shock Sub	NOV	160-80692	8 3/8	2 3/4	13.52	79.86	6 5/8 REG
6	17 3/8" Steel Stabalizer	Stabildrill	SD24282	8 3/8	2 7/8	7.96	87.82	6 5/8 REG
7	8" NMDC	Stabildrill	SD55421	8 1/4	3 1/4	29.52	117.34	6 5/8 REG
8	8" Hang off Sub	Scout	SDI-825-OSTM-008	8 1/4	3 1/4	5.09	122.43	6 5/8 REG
9	4 Stands of 8" DC					378	500.43	6 5/8 REG
10	6 5/8 Reg Pin X 4 1/2IF Box X-Over	Rig	111111	8	2 3/4	2.8	503.23	4 1/2 IF
11	3 Stands of HWDP						503.23	4 1/2 IF

Table 2:2 BHA 01 (Duane Winkler, Leroy Swearingen 2021)

The BHA01 in Table 2:2 drilled a 17.5-inch hole from 28 ft to 1,629 ft MD with an average ROP of 134 ft/hr. Verticality was maintained without any issue, and the (13 3/8” x 68 ppf, L80, BTC) surface casing was run and cemented to the surface. Mild bit balling was encountered, as shown in Figure 2:1-5 and highlighted red in Figure 2:1-6. The rig pumps were limited to 800 gpm due to rig pressure limitations. The report captured in the lessons learned that bit-balling affected course stability, which required the availability of products to eliminate bit-balling. Also, a bigger

Rig pump capacity was required. It was therefore recommended that a rig pump capable of pumping 900 gpm should be used and the bit nozzle size reduced to improve hole cleaning.

Figure 2:1-5 Bit balled (Duane Winkler, Leroy Swearingen 2021)

Figure 2:1-6 highlights the damage in the red circle (Duane Winkler, Leroy Swearingen 2021)

Drilling the Intermediate Casing Section

BHA Detail								
#	Description	Mfg.	Serial #	O.D.	I.D.	Length	Sum	Top Conn
1	Z713S Smith 2x18's 4x20' 1x16	Smith	JP4755	12 1/4		2	2	6 5/8 REG
2	9 5/8" Vertical Scout RSS	Scout	SDI-962-VS08-027	9 5/8		20.65	22.65	6 5/8 REG
3	6 5/8 Reg Pin X 6 5/8 Reg Pin X-Over	Scout	SDI-800-XO-046	8	2 3/4	2.16	24.81	6 5/8 REG
4	HT 9 5/8" Scout 7/8 5.9 stg Straight Fixed 12 1/8" Stab	Scout	OSA-962-01-031C	9 5/8		41.18	65.99	6 5/8 REG
5	8" Shock Sub	NOV	160-80692	8 3/8	2 3/4	13.52	79.51	6 5/8 REG
6	12 1/8" Steel Stabalizer	Stabildrill	SD25600	8 3/8	2 3/4	5.8	85.31	6 5/8 REG
7	8" NMDC	Stabildrill	SD55421	8 1/4	3 1/4	29.52	114.83	6 5/8 REG
8	8" Hang off Sub	Scout	SDI-825-OSTM-008	8 1/4	3 1/4	5.09	119.92	6 5/8 REG
9	4 Stands of 8" DC					366.49	486.41	6 5/8 REG
10	6 5/8 Reg Pin X 4 1/2IF Box X-Over	Rig	Rig	8	2 3/4	2.8	489.21	4 1/2 IF
11	3 Stands of HWDP					276.35	765.56	4 1/2 IF

Table 2.3 BHA 06 (Duane Winkler, Leroy Swearingen 2021)

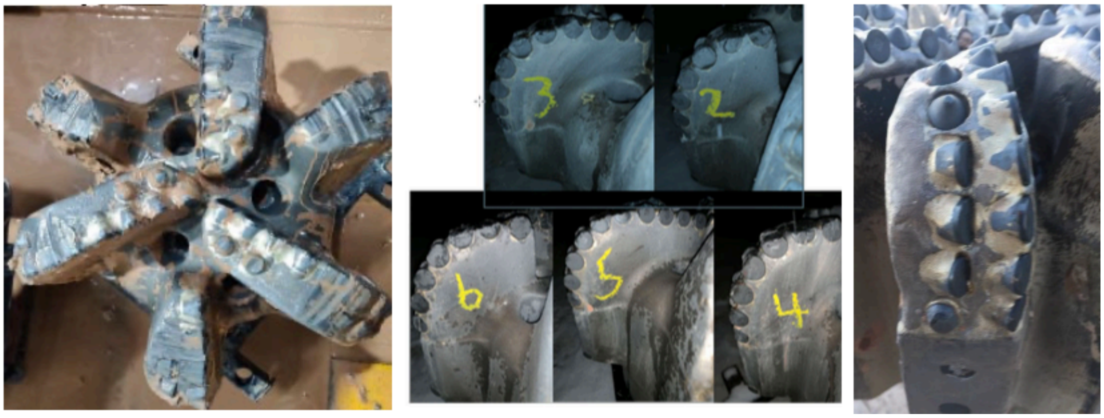

Figure 2:1-7 Smith Z713 with a degraded ROP (Duane Winkler, Leroy Swearingen 2021)

Figure 2:1-8. This is a ReedHycalog TKC 66R1 that drilled 2908 feet in 59.58 hours at 48.8 ft/hr but was pulled because of low ROP (Duane Winkler, Leroy Swearingen 2021).

The BHA in Table 2.3 is similar to BHA 03 to BHA 06 except for the different bit types used to Drill the 12-1/4-inch hole from the surface shoe to 5,113ft. The various BHAs faced challenges, including failed attempts to drill out the shoe track with a PDC bit in BHA 02 and low ROP in granite sections in the case of BHA 04 and BHA 05. While BHA 04 with the bit in Figure 2:1-8 drilled just past the approximate top of the granite, as shown in Figure 2:1-9, and performed adequately, drilling 2,908 ft with an average ROP of 49 fph, it was pulled because of low ROP. Notable observation showed that the BHA 05 bit exhibited a similar trend for all the bits in the granite region, but the failure may have been compounded by torsional and axial vibrations. The rig pumps and motor speeds were also limiting factors. As part of the lessons learned, Motor speed and bit selection were identified as critical for optimal performance. Higher WOB and faster motors were also recommended for improved ROP. The report recommends the use of 13 mm cutters instead of the 16 mm in granite and confirms float equipment is PDC drillable.

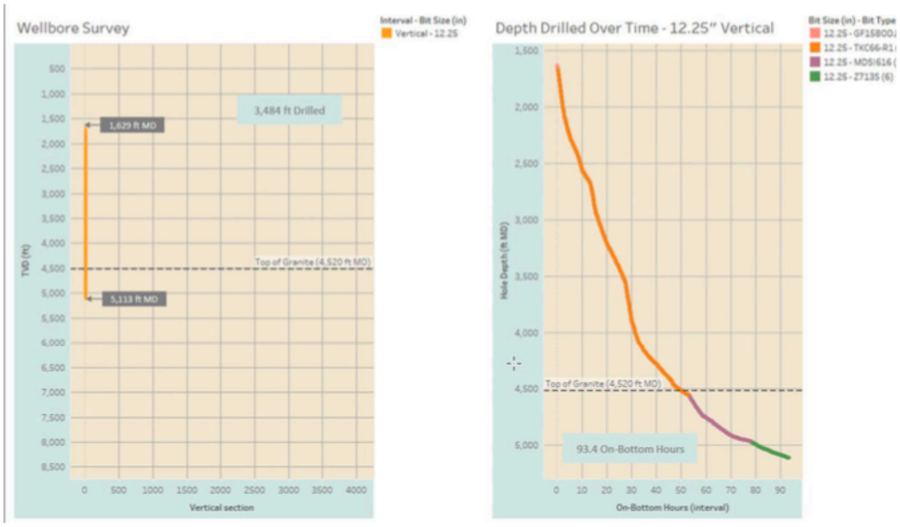

Figure 2:1-9 Intermediate casing section wellbore survey trajectory (Duane Winkler, Leroy Swearingen 2021)

Drilling the Vertical Portion of 8-3/4" Production Hole

BHA 09 to BHA 17 similar to the one in Table 2.5 were used to Drill from 5,113 ft to 7,262 ft with an average on-bottom ROP of 12.7ft/hr and included coring operations and temperature surveys. This bit, as with all others, showed a characteristic rapid ROP drop in the first 100 feet or so that was drilled. The run showed the inefficiency of 16 mm cutters. Schlumberger Smith's maximum allowable weight on bit was 45,000 lbf, and, at the time, it was felt that one needs at least 50,000 lbf to engage all the cutters and prevent bit whirl. The VRSS was having difficulties holding the angle, and therefore, a lower weight on the bit was mandated (Duane Winkler, Leroy Swearingen 2021). The coring bits faced slow ROP, and several BHAs encountered difficulties with weight transfer and maintaining verticality. Having applied some measures to overcome the difficulties, efficient core catching mechanisms and optimized motor parameters were identified as necessary in the lesson learned. The report recommends the use of higher torque motors and monitor MSE for trend changes.

BHA Detail								
#	Description	Mfg.	Serial #	O.D.	I.D.	Length	Sum	Top Conn
1	XS 616 Smith Bits	Smith	JV2705	8 3/4		0.85	0.85	4 1/2 REG
2	712 Vertical Scout RSS	Scout	712-VS08-011	7 1/8		19.6	20.45	4 1/2 IF
3	6 1/2 Scout 7/8 3.0 Straight Fixed 8 15/16 Stab Pin	Scout	650-05-433	6 1/2		28.48	48.93	4 1/2 IF
4	6 1/2" Shock Sub NOV	NOV	147-0009	6 3/4	2 1/4	10.81	59.74	4 1/2 IF
5	6 3/4 Stabil Drill NM Stabilizer	Stabil	SD 610501	6 3/4		6.87	66.61	4 1/2 IF
6	6 1/2" Scout UBHO	Scout	650-UBHO-083	6 1/2	2 3/4	3.11	69.72	4 1/2 IF
7	6 3/4 NMDC	Stabil Drill	SD 55831	6 3/4		30.35	100.07	4 1/2 IF
8	7 Stands of DC's		Rig	6 1/2	3	644.15	744.22	4 1/2 IF
9	3 Stands of HWDP					276.35	1020.57	4 1/2 IF

Table 2.4 BHA 09 used to drill from 5113' to 5,345'

Drilling Curve Section of the 8 ¾'' hole

Table 2.6 shows BHA 18 to BHA 23, except the bit drilled the curve section from 5,892 ft to 7,262 ft with an average build rate of 5° per 100 ft. Various BHAs were used to manage the curve, with attention to maintaining azimuth and inclination. No issues were reported about vibrations, however, the lessons learned were that the effective use of a fixed 1.50° motor and real-time MSE monitoring were crucial. And this was the contributing factor to why the curve landing was achieved ahead of plan. The report subsequently recommends that the curve be started at the planned depth, avoid using string stabilizers, and use roller reamers in granite formations.

BHA Detail								
#	Description	Mfg.	Serial #	O.D.	I.D.	Length	Sum	Top Conn
1	Reed Hycalog TKC63 PDC bit	Reed Hycalog	A255857	8 3/4		1	1	4 1/2 REG
2	6 1/2" Scout 7/8 5.7, Fixed 1.50, 8 1/4" Stab, valve	Scout	650-05-376	6 1/2	1 1/4	33.56	34.56	4 1/2 IF
3	6 1/2 Scout String Sub with PUK sensor	Scout	650-CSS-005	6 1/2	3 1/4	2.34	36.9	4 1/2 IF
4	6 3/4 NM Pony Collar	Stabildrill	SD 55005	6 3/4	3 1/4	9.22	46.12	4 1/2 IF
5	6 1/2" NM UBHO	Scout	650-UBHO-083	6 1/2	2 3/4	3.11	49.23	4 1/2 IF
6	6 3/4" NMDC with MWD	Stabil Drill	SD 55831	6 3/4	3 1/4	30.35	79.58	4 1/2 IF
7	6 3/4" NMDC (2 joints)	Stabildrill	SD56089 SD49788	6 3/4	3 1/4	60.66	140.24	4 1/2 IF
8	6 1/2" DC's (2 stands)		RIG	6 1/2	3	183.22	323.46	4 1/2 IF
9	5" HWDP (15 stands)		RIG	5	3 1/4	1384.33	1707.79	4 1/2 IF
10	5" Drill Pipe to surface		RIG	5	4 1/4		1707.79	I.F.

BHA highlights:
Bit TKC63 C-7; TFA = 0.84
Motor 7/8 5.7; Fixed 1.50, Single 8 ¼'' Stab
No String Stabilizers nor Roller reamers

Table 2.5 BHA 18 used to drill the curved section

Drilling the Tangent Section of the 8 ¾'' hole

BHAs (23-30), similar to BHA in Table 2:7, drilled the tangent section from 7,262 ft to 8,024 ft. Various BHAs encountered issues with weight transfer and sliding difficulty. The use of roller reamers and high-torque motors improved performance. The lessons learned were that longer gauge bits and double-stabilized motors enhanced drilling efficiency. The report recommends the use of agitators for better weight transfer and monitoring MSE and vibration data closely.

BHA Detail								
#	Description	Mfg.	Serial #	O.D.	I.D.	Length	Sum	Top Conn
1	Reed Hycalog FTKC63-01	Reed Hycalog	A276121	8 3/4		0.85	0.85	4 1/2 REG
2	6 1/2 Scout 7/8 5.7 Fixed 1.50 8 1/4" Stab. valve	Scout	650-05-211	6 1/2	1 1/4	33.92	34.77	4 1/2 IF
3	6 1/2 Scout String Sub with PUK sensor	Scout	650-CSS-005	6 1/2	3 1/4	2.34	37.11	4 1/2 IF
4	6 3/4 NM Pony Collar	Stabildrill	SD 55005	6 3/4	3 1/4	9.22	46.33	4 1/2 IF
5	6 1/2" NM UBHO	Scout	650-UBHO-076	6 1/2	2 3/4	3.08	49.41	4 1/2 IF
6	6 3/4" NMDC with MWD	Stabil Drill	SD 55831	6 3/4	3 1/4	30.35	79.76	4 1/2 IF
7	6 3/4" NMDC (2 joints)	Stabildrill	SD56089 SD49788	6 3/4	3 1/4	60.66	140.42	4 1/2 IF
8	6 1/2" DC's (2 stands)		RIG	6 1/2	3	183.22	323.64	4 1/2 IF
9	5" HWDP (15 stands)		RIG	5	3 1/4	1384.33	1707.97	4 1/2 IF
10	5" Drill Pipe to surface		RIG	5	3 1/4		1707.97	4 1/2 REG

Table 2.6 BHA 23 used to drill the tangent section

Drilling to Total Depth (TD)

BHA 34 to BHA 39: Drilled from 8,024 ft to 10,987 ft. Included operations to cool down the hole and logging runs. BHAs were optimized to manage high temperatures and maintain drilling efficiency. The lessons learned reported effective temperature management and bit selection as critical factors for high-temperature drilling. It was therefore recommended to use double-stabilized motors and under-gauge roller reamers in high-temperature environments. The summary of the drilling performance in terms of ROP, as depicted in Figure 2:1-10, showed that in the vertical section (BHAs 5-14), the average on-bottom ROP is approximately 12.7 ft/hr. The average-on-bottom ROP in the curve section (BHAs 18-23) is close to 32.7 ft/hr. In the tangent section (BHAs 30-42), however, the average on-bottom ROP is improved to 46.9 ft/hr. The drill bits and BHAs were progressively optimized to improve the ROP for subsequent sections.

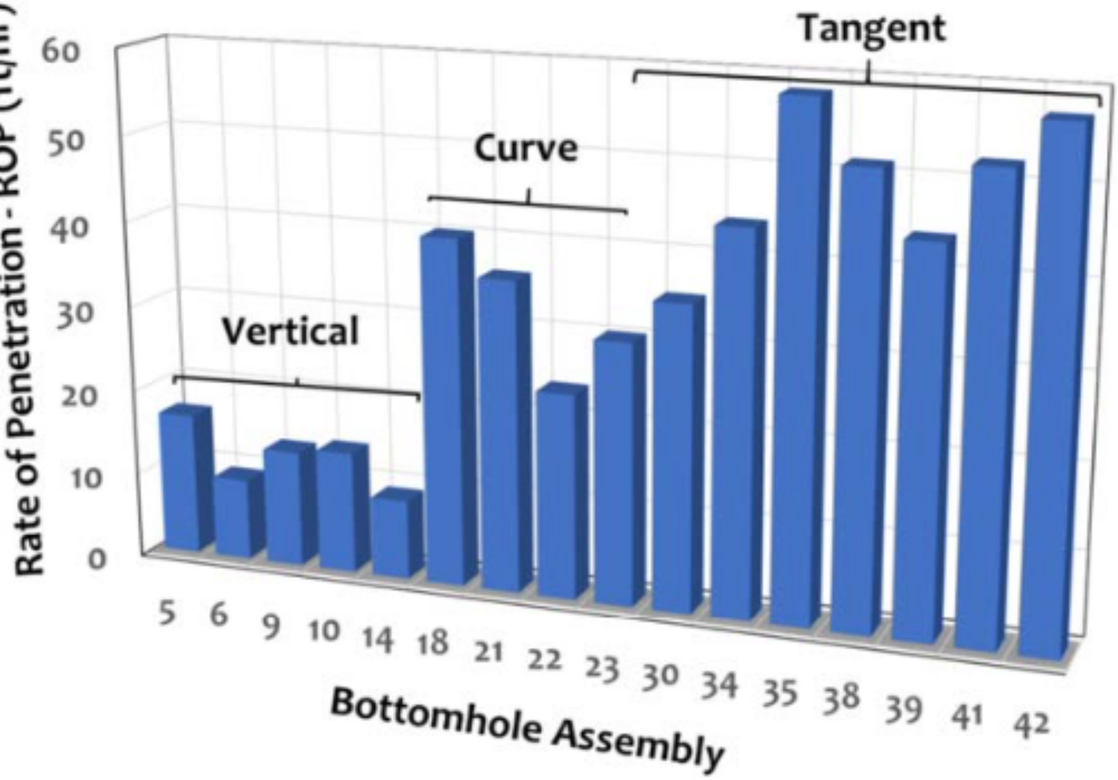

Figure 2:1-10 —On-bottom ROP for each BHA [Vertical, Curve, and Tangent] (US 2019) .

Though the drilling of well 16A (78)-32 demonstrated the successful application of advanced drilling techniques and equipment optimization to address the challenges of geothermal drilling, the lessons learned suggest there is more room for improvement. Apart from the key takeaways such as the importance of real-time monitoring, proper bit and motor selection, and effective temperature management which were largely implemented, vibration monitoring and mitigation were not fully explored. The next sections of this thesis will cover an overview of drilling vibrations, post-drilling simulation, and vibration analysis for the Utah Forge well 16A-78-32 and mitigation that may further enhance drilling performance for subsequent geothermal systems

(EGS) wells. Table 2.7 shows the summary of the average ROP (ft/hr) per Drilling Phase for Utah Forge Well 16A-78-32.

Drilling Phase	Utah Forge Average ROP (ft/hr)
Surface Hole	134
Intermediate Hole	49
Vertical portion of Production Hole	12.7
Curved Section of the Production Hole	32.7

Table 2.7 Summary of Drilling Phase Performance in Terms of ROP (ft/hr) Utah Forge 16A-78-32

Chapter 3

Drilling Vibrations

3. Overview of Drilling Vibrations

Many works of literature and experiments established that drilling vibration is the cause of much of the equipment wear, failure, non-productive time, and inefficiency. For instance, the drilling summary of the Utah Forge Well 16A-78-32 indicated that the Non-Productive Time (NPT) recorded was because of torsional and axial vibrations suffered by the bit. Drill string vibration and its effect on the drilling component has been a subject of interest due to its negative effects, as stated above. The main sources of drill string vibration are the non-linear friction along the string length and the cutting action by the drill bit on the formation (Parimal Arjun Patil 2013). The drill string exhibits three different vibration modes: axial, torsional, and lateral as depicted in (Figure

4). In severe cases of axial, lateral, and torsional vibrations, the drill string may encounter bit bounce, backward/forward whirl, and stick-slip associated with each mode respectively (Yaser Alsaffar 2017). It is established that drill string vibrations may lead to fatigue failures and abrasive wear of the tubular, damaging the drill bit and the wellbore (Hamid Ahmadian 2007). Each vibration mode has its destructive nature, affecting the drill string's overall performance.

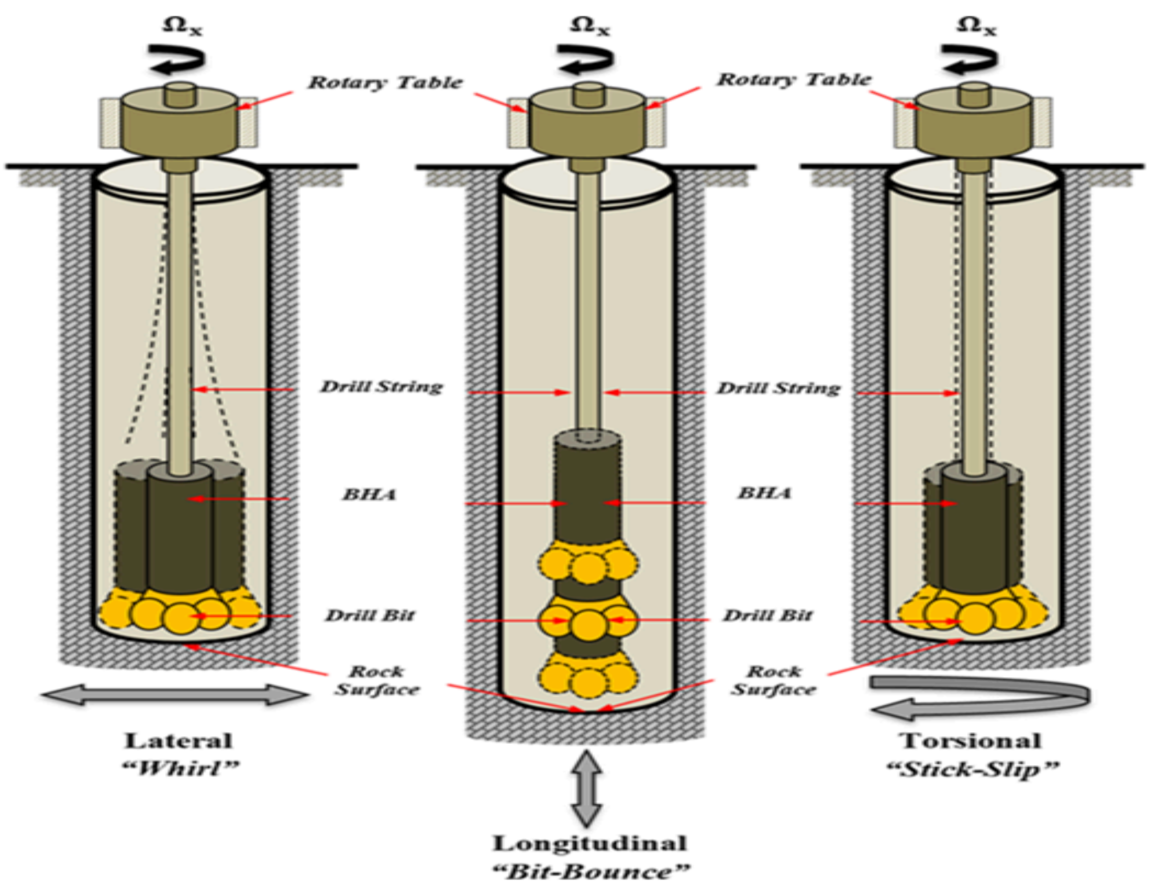

Figure 3.1.1 shows the drill string the different vibration modes, axial, torsional, and lateral (Yaser Alsaffar 2017)

The next section will discuss the modes briefly and their impact on the drilling process and equipment failure.

3.1 Lateral Vibrations

Lateral vibration is a side-to-side oscillatory motion that causes the bending of the drill string. The eccentric rotation of the bottom-hole assembly (BHA) around a point other than its geometric center is a phenomenon known as a whirl (Yaser Alsaffar 2017). This vibration mode is widely recognized as the most damaging stress form in drilling assemblies and a leading cause of BHA failure. Also, Lateral vibrations of the drill string severely damage the wellbore wall and affect the overall drilling trajectory (Hamid Ahmadian 2007). Lateral vibrations are difficult to identify at the surface, but with sophisticated downhole tools, forward and backward whirl conditions can be identified with greater accuracy (Parimal Arjun Patil 2013).

3.2 Axial Vibrations

Drill string axial vibration creates a motion in a direction parallel to its axis. This mode of vibration is caused by a phenomenon known as a bit-bounce. When it happens, this instability causes the drill bit to lose contact with the rock surface intermittently. Consequently, the bit bounce phenomenon strongly influences the drill string response to the applied weight-on-bit (WOB) and severely damages the drill bit cutting structure such as bearings and seals (P. D. Spanos 1995). The use of a tri-cone bit has always been related to the occurrence of axial vibrations due to the erratic interaction of the bit and formation with tri-cone bits((Idir Kessai et al. 2020); (Parimal Arjun Patil 2013)). Axial vibrations may easily be detected at shallower depths; however, they mostly get coupled with other vibration modes downhole. (Idir Kessai et al. 2020) research has shown that axial vibrations cause lateral vibrations of the string.

3.3 Torsional Vibrations (stick-slip)

Torsional vibrations are considered the most dangerous form of vibrations which cause drilling dysfunction and make drilling inefficient (Fear et. al 1997). This special form of drilling vibration results from contact between the drill bit and the formation which prevents normal rotation of the drill string and the BHA (Khulief et al. 2007).. The stick-slip phenomenon associated with the torsional mode is irregular drill string rotation, as the bit stops rotating shortly at regular intervals causing the drill string to periodically torque up and spin free as high as ten times the rotary table speed (Jansen J.D. 1995). Stick-slip is most associated with Polycrystalline Diamond Compact (PDC) bits which drill through rock with sheer rotary force (Mohammed F Al Dushaishi et al. 2022) . The nonlinear relationship between the frictional torque and the angular velocity at the bit results in extensive bit wear, severe shock loading, fatigue, and eventually, equipment failure. According to (Xianping Wu 2010), (Warren and Oster 1998), stick-slip vibration not only shortens the tool life but also increases the non-productive time that increases the drilling cost. However, this is determined by the severity of the vibrations. Stick-slip severity is therefore classified into Normal, Moderate, and Severe. Table 3.1 helps distinguish the low and moderate (0.5 – 1g) vibrations from severe (>1 g) vibrations.

Lateral Acc		Lateral RMS Acc		Stick-Slip	
(g's)	Severity Level	(g's)	Severity Level	(-)	Severity Level
0-15	Normal	0-2.5	Normal	0-0.5	Low
15-35	Moderate			0.5-1	Moderate
35+	Severe	2.5+	Severe	1+	Severe

Table 3.1 The severity level for different vibration modes (M.F. Al Dushaishi et. 2015)

Stick-Slip Severity Index (SSI) is another industry-standard method that normalizes the RPM fluctuations over time ((Parimal Arjun Patil n 2013), (Ertas, et al. 2014)):

SSI = (Bit RPM_{max}-Bit RPM_{min})/2xBit RPM_{avg}………..Equation 1 is a measure of the intensity of torsional vibration.

An SSI value of less than unity indicates that the bit always turns to some degree. In contrast, at SSI = 1, the full stick/slip condition is reached, and the bit periodically stops turning for a moment before a slip face is reached at RPM greater than the set surface RPM. At higher values of SSI, the bit stops turning for longer periods of "stuck time. Maintaining a Stick-Slip Index (SSI) below 1 is recommended to prevent drilling dysfunction, as suggested by (Arevalo et al. 2012). Furthermore, the application of SSI as a tool to minimize excessive vibrations has been shown to enhance drilling operations significantly in field applications ((Payette et al. 2015); (Sanderson et al. 2017)). To solve this problem different drilling vibration models, predict and avoid resonance regions by optimizing the selection of drill string components and operating parameters such as weight on bit, and surface RPM (Mohammed F Al Dushaishi et al. 2022). (Sean et al. 2010) observed a relation between WOB and RPM that highlights drilling dysfunctions and suggested a theoretical optimum drilling zone where drill string vibrations were minimal. Besides, the resonance regions, specialized tools have been developed to reduce vibrations. However, post-drilling analysis of the vibrations and their effect on drilling performance and mitigation measures are much needed in future adjacent wells. The next chapter outlines the post-drilling data simulation and vibration analysis to determine the cause of drilling vibrations, its effect on equipment wear and failure, and the reduction in ROP reported in the drilling report of Utah Forge well 16A-78-32 drilled in Utah. The simulation is structured in two main parts. The first part will simulate the drilling data using DrillScan Technology to determine the cause of vibrations and optimum operating parameters zone as shown in Figure 3.2.1 that mitigates the vibrations. In the second part, optimum operating parameters are replicated on drillSIM50 to assess the performance against field data.

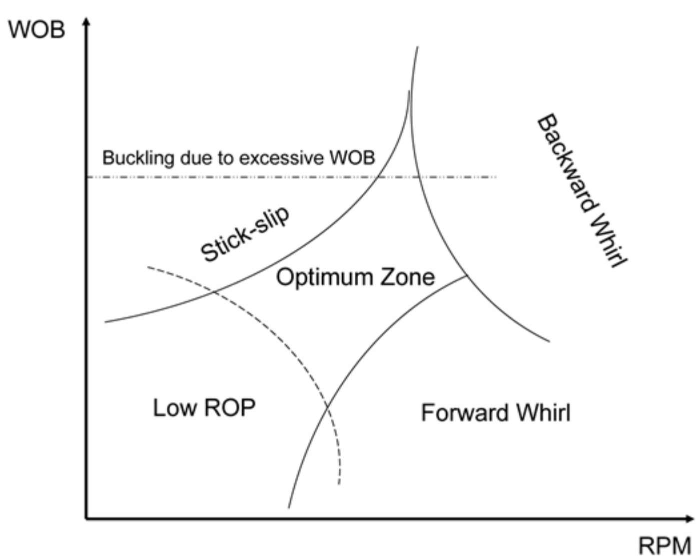

Figure 3.2.1 Schematic description of optimum zone (Sean et al. 2010)

Chapter 4

Overview of Drilling and Well Control Simulator

4.1 Importance of Drilling and well Control Simulators

Drilling and well control simulators have traditionally been employed in simulation exercises for well control and to train crews on operating new-generation automated drilling equipment (D. Santoro and K. Lahou 2023). These advanced simulators play a crucial role in minimizing the learning curve for drilling operations and accelerating expertise acquisition, particularly when developing innovative well programs or handling challenging well operations (R. Hodgson 2006). The demand for ultra-deepwater, unconventional, and high-pressure, high-temperature (HPHT) wells has driven the design and manufacturing of new, innovative simulators tailored to meet the rigorous requirements of these operations. The Software Pressure Upon Rig Simulator (SPURS), for example, was created to provide realistic, rig-based well control training. Its primary objective is to enhance communication among crew members, ensure competency in real-life working environments, and comply with international standards (A.S. Bamford and Zhihua Wang 1994). The aim of using these simulators is to ensure efficiency, safety, and cost-cutting while maximizing production (Placeholder1). The introduction of digital simulations has further revolutionized training and operations by creating virtual environments capable of delivering years of practical experience within weeks (Forrester 2021). This innovation gained increased relevance during the COVID-19 pandemic, where remote or virtual training became essential to maintain crew certification and competency (Kim 2021). In this context, tools like Virtual Experience

Simulation (VES) emerged, utilizing heuristic computer technologies to enable hands-on training while retaining field knowledge and expertise (Millheim and Gaebler 1999).

Modern trends in simulator development emphasize increasing fidelity, cost-effectiveness, and sustainability. Fidelity, defined as the degree to which simulators replicate actual field equipment and environments (Hays, 1981), remains a critical component of simulator training. Enhanced fidelity and virtual reality technologies are shaping simulators to better accommodate drilling crews' evolving roles. Simulators now range from portable devices connected to laptops to full-mission systems featuring cyber chairs and dedicated video walls (Forrester 2021). While portable simulators are suited for limited training scenarios, full-mission systems are designed for more complex and immersive training (Drilling systems 2022). Significant advancements have been made in creating realistic operational environments. However, there is a growing need for remote training options utilizing media such as portable, virtual, augmented, hybrid reality, software-based, and cloud-based simulators without losing the aspect of feel and touch (Forrester 2021). Hardware-in-the-loop (HIL) simulators represent a hybrid platform, addressing challenges like scalability limitations and the inexactness of mathematical models (Wilson 2015). HIL simulators allow hardware testing in laboratory settings before deployment, enabling software updates, troubleshooting, and safe testing of potentially hazardous scenarios (Pedersen and Smogeli 2013). Digital twin technology further enhances training by providing opportunities to practice real-world interactions in virtual configurations, creating realistic learning environments, and enabling students to familiarize themselves with operational scenarios (Francesco Curina 2021).

A comprehensive review of simulator types, their features, advantages, and limitations reveals how these systems can support novel applications, especially in the post-COVID-19 era.

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4.2 Simulator Types

A simulator is defined as a device or piece of equipment that replicates some physical process or operation to some level of fidelity (K. K. Millheim 1986). There are four basic types of simulators: a)-partial-tasks, b) procedural training, c) full-fidelity, and d) engineering, (K. K. Millheim 1986). These simulators are developed, manufactured, and used by various industries and the military According to Mulheim (1986). The oil and gas industry has yet to develop a full-fidelity type of simulator and only uses partial-task and procedural training types. The same observation was presented by (VINCENT 2021), who concluded that the petroleum industry needs to develop a simulator that depicts the full fidelity concept. Nevertheless, there are many types of simulators related to the operation they replicate, such as drilling, well control, well design, cementing, crane operation, well intervention, work-over, rig simulators, etc. However, this study focuses on drilling and well control simulators, which can be broadly classified into hardware-based, software-based, and cloud-based systems. These simulators employ computer-based technologies to replicate real-world operations in controlled environments (ESIMTECH 2022).

4.3 Drilling Simulators

Drilling Simulators are designed to apply state-of-the-art technology that uses actual mathematical models for realistic simulation of drilling operations in the oil and gas industry (ESIMTECH 2022). A Reliable drilling simulator software should replicate the drilling process with a close level of fidelity (SAFE 2004). A drilling Optimization Simulator (DROPS) simulator is one such type designed to reduce the drilling cost of future wells based on the capability to simulate the drilling performance as a function of the rock strength (R. Nygaard and G. Hareland 2002). The improved simulator determines optimum conditions for drilling new wells by simulation using WOB, RPM, flow, survey, and lithology data from offset wells (Vassilios C. Kelessidis and Alexandros Koulidis 2015). Before full rig deployment, the automated Well Control system was tested using drilling simulators with real drillers which showed that the technology enables shut-in times faster than conventional human interface methods (B. W. Atchison 2021). (Jelena Skenderija and Alexis Koulidis, Vassilios Kelessidis and Shehab Ahmed 2012), concluded in their study that a combination of an accurate hydraulic model and a real-time simulator can assist in training students

or professionals to drill a well most effectively before the actual drilling process. They can also be used to simulate challenging wells and train personnel on how to drill a well, how to handle drilling fluids, and how to deal with drilling problems such as stuck pipes, differential sticking, pipe washout, lost circulation, etc. Drilling simulators may be used to train crew on how to optimize drilling parameters such as weight on bit, rotary speed, mud flow rate, and Managed Pressure Drilling. For instance, the use of advanced drilling simulators provides a new environment where drilling crews can train in how to react and implement the well control procedures, as well as allow the implementation of new technologies such as Managed Pressure Drilling (MPD) in highly sensitive environments. The MPD simulator as part of personnel benefits builds a strong MPD foundation for crews to carry back to the rig through simulation exercises (Carpenter 2020). The Advanced Dynamic Training Simulator can verify and train crew on identified risk elements before drilling a well, as well as retrain during the operation on a “true” virtual copy of the well (Ødegård, et al. 2013). (Ali Karimi Vajargah 2015) numerical simulator compares the actual well response with simulated results during an influx event, and following the proposed algorithm allows the best MPD-CBHP(Constant Bottom Hole Pressure) response to be taken in a quick, convenient, and accurate manner. (Kwang-Phil Park a 2022) developed a virtual offshore drilling platform that simulates drilling operation, well control, and ROV control. It also included dynamic analysis of results such as the heave compensation system and DPS. The NOV Drilling HIL is another, in addition to representing operational rig models, the HIL can also be used to generate extremely accurate renditions of rig models currently undergoing development (App 2014). Figure 4.1.1 shows the OU NOV drilling and pipe handling simulator designed to simulate drilling, tripping, and stand-building processes by providing an efficient and intuitive rig floor command.

Figure 4.1.1 OU NOV-HIL Simulation Room

4.4 Well Control Simulators

Well control simulators are valuable tools used to simulate kick detection and kill methods such as the driller's method (engineers' method), wait & weight method, bullheading, volumetric method, and reverse circulation in well control operations. They are used to train drillers and drilling engineers in the decision-making process during well control operations and kick situations. (Fred Ng, 2005) presented the "Drillbench" suite of drilling simulation software, a fully time transient, two-phase flow simulator that provides several technology improvements over conventional steady-state models. The need for these simulation tools cannot be over-emphasized post-Macondo Spill 2010. As a result, the new edition of IOGP Report 476 recommends enhancements to well control training, examination, and certification that address appropriate role-specific training, continuous online knowledge assessment, magnified use of software simulations, and frequent competent instruction (IOGP 2023). (Fritz Golding, John Spath and Bob Newhouse 2016) concluded that Simulation increases operational safety and efficiency by promoting teamwork between key individuals while they are experiencing simulated system faults, failures, and well control problems. In addition to uncovering possible technical issues, information may be used to analyze and modify current and future operations. An advanced dynamic drilling simulator is used in challenging High-Pressure High-Temperature (HPHT) wells drilled with Managed Pressure Drilling (MPD) by the operator to test and verify operational procedures as well as the HPHT & MPD well control manual (Harald Blikra and Giancarlo Pia, Just Sverre Wessel and Morten Svendsen 2014). The Transient Well Control simulator is another very powerful tool developed for well control evaluations relevant to HPHT and other wells with small operating margins (Rommetveit et al. 2003). The advanced modeling approach and new software package simulator are capable of simulating complex multi-phase flow phenomena that can occur during

MPD and regular drilling operations (Z. Ma and R. May 2016). This may offer the potential to improve rig safety and reduce non-productive time during well control events. Advanced well control and temperature simulators when used to simulate the wellbore can detect and understand abnormal failures which in the conventional practices could not be detected and explained. This improved well control, safety, rig performance, and effective application of resources. The drilling and well control simulators can replicate well control and drilling operations conducted on the rig (B. W. Atchison 2021). Automated well control technology was first successfully simulated on a rig simulator to demonstrate and verify the integration and functionality of both systems before deployment (B. Atchison 2022). However, Well-control schools all over the world use the different compositions of simulators which are dependent on among other factors, the simulator provider, training purpose, and available resources. They may be classified into two different types based on their capabilities and fidelity: Half-Task simulator (HTS) and Procedural simulators (PS)— (K. K. Millheim 1986). They can also be classified and discussed according to the main features, hardware, software, and cloud technology applications. They can be deployed in different forms such as digital virtual, cloud, and hardware-based. (Robert Howell and Isabel Poletzky 2019) concluded that Advancements in high-fidelity training are a gateway to efficient and safe operations in the field. Crews trained both technically and non-technically with modern techniques using advanced drilling simulators and integrated Crew Resource Management (CRM) will produce better results in the field. In this study, we expound on three categories of simulators i.e.: Hardware-based, Cloud-based, and Software-based.

4.5 Categorization of Drilling and Well Control Simulators

4.5.1 Hardware-Based

Under this category, are the portable drilling well control, the" on-the-rig" and the full-size mission cyber/manual drilling well control simulators. These are the types of simulators in which there is an actual physical connection between people and equipment, and the feedback is acted upon based on the knowledge of the process (ESIMTECH 2022). Advanced Drilling Simulation Environment is a simulation tool that uses hardware in the loop (HIL) simulation to test and validate new drilling technologies, to study their impact on the working conditions of drilling personnel, and to train them to use the technology efficiently in a working environment (Cayeux, et al. 2012). HIL testing is a well-proved test methodology that is used in several other industries. The most important feature of HIL testing is the possibility to test in a virtual test bed in which there is no risk to personnel, vessel, or equipment (Pedersen and Smogeli 2013).

Portable Hardware drilling and well control simulators

This type of simulator is mainly made up of a laptop instructor station, a touch screen, and four consoles that are physical and accurate representations of drilling controls, a remote choke console, a BOP console, a driller's console, and a manifold console (Drilling systems 2022) (ESIMTECH 2022). To show the real oil drilling site experience and to train the trainees with relevant knowledge and skills, manufacturers have used these gadgets to establish a comprehensive 3D drilling and well control simulation, which completely reproduces the scene and working atmosphere of oil drilling work and improves trainees' perceptual knowledge of drilling work site. This system simulates various working conditions, parameters, and relations between the parameters in the petroleum engineering process by mathematical models, such as pressure, torque, drilling rate, discharge rate (ESIMTECH, 2020), etc. However, these types are classified as Partial-task (low-fidelity) simulators (PTS) as they are only able to recreate some aspects of the operational scenarios or components of some operating system and enable the trainees to go through limited training. For instance, the portable well-control simulator is a PTS because it simulates only the mechanisms and operations necessary to replicate the generation of the cues associated with, and the controlling of the kick. The system has three parts: (1) instructor control, (2) problem simulation, and (3) problem outputs and controls (K. K. Millheim 1986). Other drilling functions and mechanisms deemed unnecessary to the instruction of how to detect and control a kick are not used in the simulator process-e.g., most well-control PTSs do not have the physics to swab a kick or surge during tripping. This is a result of the lack of a hoisting model simulation capability and swab and surge modes (K. K. Millheim 1986). Another hardware-based simulator is the ‘On the Rig’ (OTR) which is a real-time portable simulator bringing drilling and equipment operations, well control, and crane training to the rig (Drilling systems 2022). The interactive unit is changing how training is delivered for the drilling industry with its instructor's mode and the ability to deliver continuous training, development, and assessment (Drilling systems 2022). Esimtech’s ESIM-FCC11 Drilling Simulation Training System is another hardware-based that simulates the real equipment on a real production site, including all the hardware systems, panel layout, operation methods, and parameter displays. Through a display screen, the 3D animation is presented by the working conditions, and the sound effect that simulates the real rig floor makes up an immersive training environment (ESIMTECH 2022). The non-sequence drilling operation mode, different from the stereotype training mode enables students to operate arbitrarily based on snapshots. This drilling simulator realizes the high emulation from good condition to system operation, improves the flexibility of students' operation, and enables students to make great progress on training efficiency and training effect (ESIMTECH 2022).

Full mission-size hardware-based drilling and well control simulators

This is another hardware-based simulator that gives an accurate representation of a conventional rig floor and 3D graphics, thereby creating a highly realistic and immersive simulation environment bringing the rig to the trainees (Drilling systems 2022). Both simple and highly complex tasks for land and offshore operations can be recreated to verify skills and competency in real-world situations. For instance, drillsim500 comes with a full downhole model which provides a dynamic 3D graphic visualization of the action taking place down a vertical or deviated well through a wide range of drilling operations (Drilling systems 2022). The Drillsim500 downhole model allows operators to develop and run drilling and well control exercises while providing a graphical 3D representation of what is happening downhole. This allows trainees to see and clearly understand the consequences of their actions or equally their actions throughout various drilling operations (Drilling systems 2022). They are therefore referred to as PS because they simulate entire systems with a reasonable resemblance of the instruments, controls, and other hardware used to operate the system. The PS differs from the High -fidelity simulators (HFS) in the fidelity and level of the visual, audio, and sensual cueing (K. K. Millheim 1986). It is designed more for teaching basic procedures in drilling and well control operations. However, they are relatively expensive to acquire and maintain. Figures 4.1.1, 4.2.1, 4.2.2, and 4.3.1 show some of the hardware-based simulators.

Figure 4.2.1 (OTR) Simulator (Drilling systems 2022)

Figure 4.2.2 The DrillSIM50 Portable Well Control Simulator (OU Simulation Lab)

Figure 4.3.1 The manual brake advance drilling and well control simulator (Drilling systems 2022)

Figure 4.3.2 The full-size cyber drilling and well control simulator (Drilling systems 2022)

4.5.2 Software-Based.

These are the type of simulators where the software is pre-loaded onto a computer that delivers a wide range of real-time drilling and well control simulations (endeavortech 2022). The software displays interactive on-screen versions of the control panels present in simulator hardware to ensure a realistic experience that provides the end user with proven reliability and confidence. It is believed that software and its accessibility are critical to the future of drilling simulators, especially those used in well control training. The aim is therefore to develop a simulation model that will achieve accuracy so close to reality that the simulation and the real world effectively overlap- Brad Reiser (Forrester 2021). e-Drilling is another software simulation device that provides the technology elements to realize real-time modeling, supervision, optimization, diagnostics, visualization, and control of the drilling process from a remote drilling expert center (Rolv Rommetveit, et al. 2007). Software simulation tool for no-aqueous drilling fluid is used to determine other complexities that occur during a well control incident such as multiple influxes from one or several formations, dynamic well control (suitable for managed pressure drilling), automated choke control, sudden pump startup/shutdown, non-Newtonian drilling fluids, arbitrary wellbore path, lost circulation, etc. (Z. Ma and R. May 2018). Software framework is malleable – it can be delivered online or on a physical simulator, whether on a rig or in a training center. It also allows flexibility in the presentation of different types of well geometries, fluids, and gases, as well as how these components interact with each other. Everything is modeled in 3D, including gravity and component movement – with solids settling and gases floating up – so the simulator can visualize fluid paths and migration exactly as they would occur in the field (endeavortech 2022). While it would be impossible to predict all use cases, the nature of the software infrastructure means it can be adapted to a virtually limitless number of scenarios-Brad Reiser (Forrester 2021). However, the physical element that provides that “touch feeling” is normally missing which is crucial to the trainee. The well simulator offers different benefits as selected wells are configured inside the well simulator which is then latched to mud log data streams. Dynamic mode calibration is performed by adjusting dedicated coefficients to reach an overlap between simulated and measured drilling parameters. It is therefore used for planning, real-time support, and post-job analysis for drilling operations, being integrated into all engineering processes (D. Santoro and K. Lahou 2023).

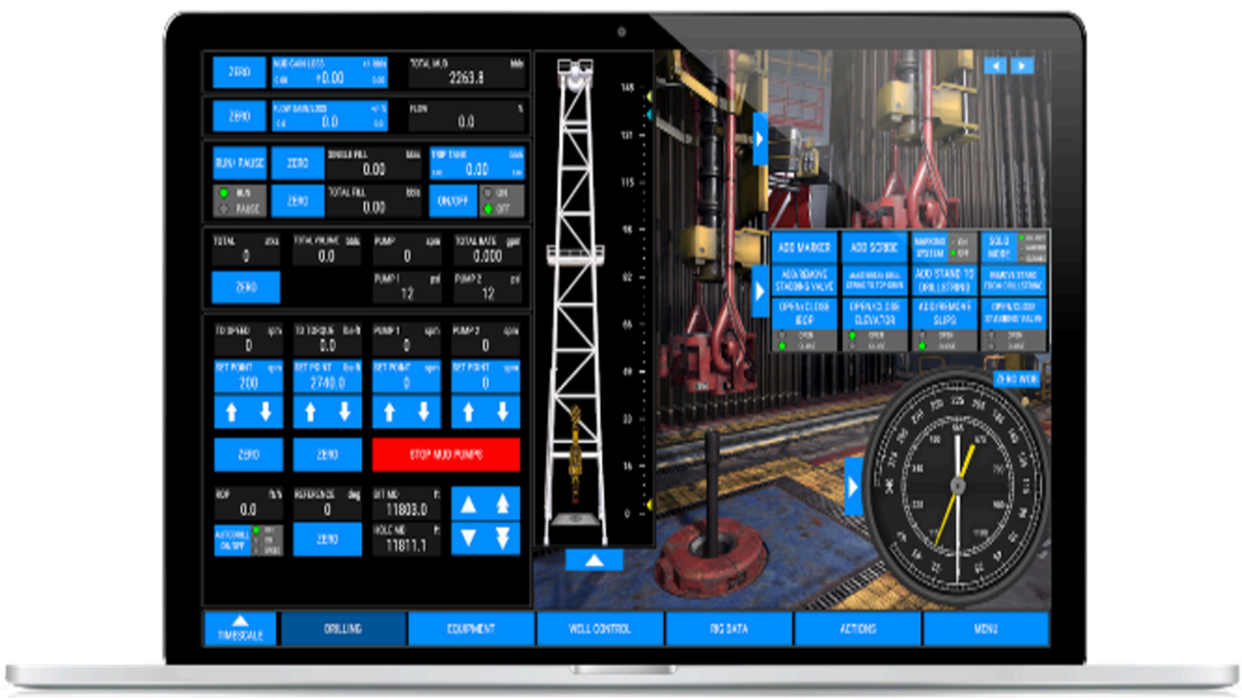


Figure 4.3.3 Software drilling and well control simulator (endeavortech 2022)

4.5.3 Cloud-Based

In contrast to the simulator categories mentioned above, the cloud-based simulator is one of the latest developments in drilling and well control simulation that requires no hardware or software installation (Drilling systems 2022). The advances in simulation technology and equipment have enabled remote simulation delivery with a reduced need for physical presence and increased virtual training activities (Forrester 2021). Cloud-based simulation enables the instructors and trainees to run the simulation online using a web browser with their own devices (e.g., PCs, laptops, tablets, or mobile devices), which offers the opportunity for the drilling and well control training institutions to continue educating and training our workforce regardless of where they are in the world- ensuring competency and compliance even in the face of restrictions posed by the covid-19 pandemic (Kim 2021). However, it is strongly believed that there are limitations such as the "touch feel", latency, bandwidth (across time zones and remote locations), and the fidelity experienced which is dependent on the device used (Kim 2021). Besides, for now, such features are only available for desktop, laptop, or tablet interfaces. In addition, the communication experienced by extension is not comparable to actual face-to-face interaction usually done in the training schools. Drilling and Well Control Web Simulator Meets IADC requirements for use in WellSharp Well Control courses as a replacement to traditional well control simulators by only using laptops and PCs (Drilling systems 2022).

Figure 4.4.1 Cloud Drilling and Well Control Simulator (Drilling systems 2022)

4.5.4 Features and Capabilities

Expanding on the features and capabilities of the above categories of simulators discussed is imperative to providing the framework for analyzing their strengths, weaknesses, and opportunities for novel applications.

In the case of a Hardware-based portable simulator, apart from the physical consoles such as drilling controls, remote choke console, BOP console, manifold console, a touchscreen PC, and a laptop which makes for the needed hands-on training, it is also equipped with a 3D schematic view of the rig floor and downhole graphic views. Additionally, it comes with a graphical on-screen representation of additional controls and instrumentation. Moreover, it can support a multi-station training environment when used with other suites (Drilling systems 2022). The hardware portable can set various drilling parameters, such as drilling tool structure, formation parameters, equipment parameters, etc., making training more flexible and targeted. Also, the software system adopts an unordered architecture, which can realistically simulate various operations of the drilling rig with synchronized on-site sound effects, making the system closer to reality. The hardware-based portable simulators are relatively easy to set up and less expensive but have low fidelity and low flexibility.

The Hardware full-size mission simulator as stated above also has an accurate representation of a conventional rig floor beside the physical hardware such as a Large thin bezel quad screen display, traditional drilling controls with analog gauges, hands-on controls, and a manual brake, realistic 3D graphic visualizations which create a highly realistic and immersive simulation environment bringing the rig to the trainee (Drilling systems 2022). Both simple and highly complex tasks for land and offshore operations can be recreated to verify skills and competency in the real world. In this sense, the Hardware-based full-size mission simulator provides a high level of fidelity and is indispensable for training regarding interpersonal skills (Drilling systems 2022). They also could be used in conjunction with newer technologies such as virtual reality due to their flexibility and fidelity. However, they are relatively expensive to set up and maintain. Moreover, they are complex in planning and executing exercise scenarios, as well as the need for skilled instructors for their optimal use. As much as the Hardware-based simulators afford the trainees the needed hands-on training, they are limited by their inability to support remote learning which has become the focus of discussions in terms of future design and development amidst the pandemic and post-pandemic era. They are not capable of hosting more trainees at the same time.

Software-based simulators on the other hand have pre-loaded software on a computer that delivers a wide range of real-time drilling and well control simulations. The software displays interactive on-screen versions of the control panels present in simulator hardware to ensure a realistic experience that provides the end user with proven reliability and confidence (endeavortech 2022). They also have an adaptive framework that makes them easy to be delivered online or physically on the rig or at a training site. Additionally, its features enable the presentation of different types of well-bore geometries, fluids, and gases as well as how these components affect each other. Notably, the software framework makes for an almost unlimited number of scenarios. However, they are limited by a lack of tactile element which provides the needed hands-on feeling to the trainee and by the functionality of the device on which it is deployed.

The cloud-based simulator uses a web browser and devices such as PCs, laptops, tablets, or mobile devices to offer the opportunity for the instructor and the trainees to simulate 3D virtual online drilling and well control scenarios without physical presence. No hardware or software installation is required and can display interactive, on-screen versions of control panels present in simulator hardware. It can be accessed from all industry-standard browsers with a device connected to the internet which makes it truly virtual (Drilling systems 2022). Therefore, the Cloud-based simulators have the potential to make training in drilling and well control possible everywhere with relatively fewer requirements of resources. However, they have some limitations such as a Lack of face-to-face contact interaction between the instructor and the trainees, latency, and bandwidth across different time zones and remote areas (Kim 2021).

4.5.5 Table of Comparison of Simulators

Analysis

To extensively analyze the three categories of drilling and well control simulators and determine how the changes in physical training activities caused by the pandemic and technological advancement will affect the evolution in the long term, strengths, weaknesses, and opportunities of novel applications, a full table that compares their strengths, weaknesses, and opportunities for upgrade is given below. Additionally, Table 2 shows how simulators could be selected based on their strengths and weaknesses to achieve efficiency.

Manufacturer	Category	Strengths	Limitations	Opportunities for upgrade
NOV-Cyber-Bsaed Simulator	Hardware-based	1. Realistic physical interface, immersive training experience,and physical feedback for trainees 2. Offers hands-on expeience	1. Initial setup cost is high 2. Limited scalability 3.Cannot be accessed remotely	1. Hybrid type is the future. 2. Minimized initial setup costs with innovative designs
DrillSIM50 (Drilling Systems)	Hardware-based	1. Provides a physical representation of the actua drilling equipment 2. Feel-touch effect enhances hands-on training. 3. Promotes interpersonal skills.	1. Cannot support remote learning. 2. Limited to a couple of trainees at a time. 3. Requires skilled instructor, especially for full mission.. 4. Scenario setup could be complex.	1. Support multiple training stations. 2. Simplify setup process.
Drillbench (Kongsberg Digital)	Software-based	1. High customization capabilities. 2. Cost-effective compared to hardware.	1. Lacks physical interface for trainees. 2. Limited tactile feedback.	1. Add joystick attachment for tactile feedback. 2. Provide instant feedback.
e-DrillSim (Drilling Systems)	Software-based	1. Advanced physics-based simulations 2. Real-time data integration	1. Steeper learning curve for beginners. 2. Requires powerful computer hardware.	1. Include collapsible joystick and choke for hands-on training.
EndeavorTech	Software-based	1. Deployable online or physically on the rig. 2. Can deliver a wide range of real-time drilling and well control simulations. 3. Can provide more scenarios.	1. Susceptible to corruption. 2. Lacks tactile elements for hands-on training.	
Maersk Training Cloud (Maersk Drilling)	Cloud-based	1. Accessibility from anywhere with the internet. 2. Cost-effective scalability.	1. Over-reliance on internet connectivity. 2. Limited realism compared to hardware.	1. Add joystick attachment for tactile feedback.
Sim4crew (eDrill)	Cloud-based	1. Enable collaborative training with remote participants. 2. Real-time monitoring and analytics.	1. Data security concerns 2. Limited customization options...	
i-drill (Drilling Systems)	Cloud-based	1. It supports remote learning. 2. No hardware or software installation. is required. 3. It can be access from all industry-standard browsers.	1. No hands-on training support. 2. Lacks face-to-face contact interaction. 3. Limited by latency and bandwidth across time zones and remote areas.	1. It must include a collapsible joysticks and choke for hands-on training

Table 4.1 A full table of comparison of the three categories of Drilling and well control simulators

	Drilling well Control Simulator type	Manufacturer	Advantages	Disadvantages	Purpose			
					Hands-on Experience	Real-time data analysis	Remote-Training	Large-trainee size
1	Hardware	1. Nov-Cyber-Based (National Oilwell Varco) 2. DrillSim (drilling systems)	1. Provides a realistic physical interface 2. Provides feel-touch that enhances hands-on experience	1. It does not support remote learning 2. It takes limited of trainees	√	X	X	X
2	Software	1. Drillbench (Kongsberg Digital) 2. e-DrillSim (drilling systems) 3. Endeavor drilling & software (EndeavorTech)	1. Enables real-time data integration 2. Could be deployed online 3. Customizable capabilities and cost-effective in application	1. Lacks hands-on training experience 2. Requires powerful computer for deployment 3. It has the tendency to be corrupted	X	√	X	√
3	Cloud	1. Maersk Training Cloud (Maersk drilling) 2. Sim4crew (Drilling Systems) 3. i-drill (Drilling Systems)	1. Support remote learning 2. Cost effective in scalability 3. No hardware or software installation is required	1. Lacks hands-on training experience 2.It is limited by latency and internet bandwidth 3. Limited customization option	X	X	√	√

Table 4.2 Selection of drilling and well control Simulators by Purpose

From the tables above, it is obvious that each simulator type has unique strengths and limitations. Hardware-based systems excel in fidelity but lack remote capabilities, while software and cloud-based systems offer flexibility but may compromise tactile realism. Therefore, the selection of drilling and well control simulators can be done based on a specific purpose as shown in Table 4.2 A hybrid simulator that combines these strengths could address current gaps and ensure comprehensive training for future operations.

Chapter 5

Post-Drilling Simulation of Utah Forge well 16A-78-32

The purpose of this simulation is to analyze post-drilling data from the Utah FORGE Well 16A-78-32 to mitigate vibrations such as stick-slip and axial vibrations that impacted drilling performance. Using DrillScan technology, the simulation aimed to optimize key operational parameters, including weight on bit (WOB) and rotary speed (RPM), to reduce vibrations and enhance the rate of penetration (ROP). These optimal parameters were further tested in a DrillSIM50 simulator to compare performance with real field data, ensuring that future drilling operations are both safer and more efficient.

5.1 Simulations

The ultimate goal of the Utah FORGE project is to demonstrate to the public, stakeholders, and the energy industry that EGS technologies have the potential to significantly contribute to the future power generation capacity (Moore 2020). This section presents the post-drilling data simulation and analysis of some challenging sections of the Utah Forge Wells 16A-78-32, the first deviated well of the Utah Forge project to optimize future drilling operations.

The Utah Forge Wells 16A-78-32 was drilled for experimental purposes in Utah and the drilling report was issued amidst lessons learned from wrong equipment selection and drilling processes. Though being the most successful deviated well drilled at Utah Forge, the drilling summary report suggests drilling dysfunctions such as axial and torsional vibrations that impacted the ROP and equipment, thereby drilling performance. The post-drilling data is simulated using DillScan Technologies to obtain maximum operating parameters that mitigate vibrations and enhance the performance of future drilling activities. These parameters are replicated on drillSIM50 to assess the performance against field data.

Methodology

To understand the impact of drilling vibrations and processes on drilling performance, a detailed post-drilling data vibration analysis combined with dynamic modeling was performed on Utah Forge well 16A-78-32. (M.F. Al Dushaishi et. 2015) showed how post-well vibration analysis was used as a tool to determine the effect of operational parameters on the rate of penetration. DrillScan is a trusted engineering tool used for evaluating drill bit management, drilling dynamics, hydraulics, torque and drag, and well integrity. In this simulation, the data was modeled in the drilling dynamics of the DrillScan software, taking into account the BHA, WOB, RPM, TOB, Fluid viscosity, wellbore trajectory, Bit aggressivity, and drilling mud weight. The Model was run using varying WOBs and RPMs for each section of interest to obtain optimal operating parameters that mitigate the vibrations. The modeled well was drilled on drillsim50 with similar lithologies using similar BHAs to that of the Utah Forge well after the optimal operating parameters were determined by DrillScan software. The data obtained in the troubled sections drilled on drillsim50 at specific depths were evaluated and compared to the field data to determine inefficiencies.

Materials and Equipment Required

- Drilling simulator software (OU Lab DrillSIM50)
- H&P DrillScan Software (OU Simulation Lab)
- Computer with required hardware specifications
- Utah Forge drilling data
- User manual for DrillSIM50
- Data analysis tools (Excel)

5.2.1 Post-drilling Vibrations Simulation using DrillScan Technology

In the previous section, different modes of vibrations were introduced. However, this section investigates the cause of the problem at hand, which is stick-slip, and axial vibrations observed while drilling the intermediate section of Utah Forge well 16A-78-32, to determine optimum operating parameters that mitigate stick-slip and axial vibrations. Therefore, the next section runs a post-drilling simulation to determine the optimal operating parameters for the given BHAs that will eliminate drilling vibration encountered in the field.

Simulation Configuration

The process started with the extraction of field data such as drilling parameters (RPM, WOB, torque), wellbore trajectory, and BHA configurations used during drilling from the drilling summary report (see Table 5.1.1 and Figures 5.1.1.1a, 5.1.1.1b, 5.1.1.1c). The simulation software used for this analysis is H&P's DrillScan Technology, which is capable of modeling both BHAs and drilling activities. The collected field data were organized into a structured format compatible with DrillScan, and the inputs include BHA, well geometry, formation properties, and drilling parameters to replicate the well conditions accurately. Before the simulation of the vibrations, the well profile was divided into three (3) Sections: surface, Intermediate, and Production (see 5.1.11d, 5.1.1.1e, and 5.1.1.1f) The assumptions made during the development of the model are listed below.

- There is only one BHA configuration for a section; surface, Intermediate, or production (vertical, curved, and tangent)
- The drill pipe size for each section is 5''
- Right bit selection and favorable bit/BHA -rock interactions
- Maximum WOB of 60klb limited by drill string buckling and the bit
- Constant TOB for all sections
- Average Fluid Viscosity for each section

The parameters in Table 5.2.1 are converted to units compatible with the DrillScan software (see Table 5.1.1). The well trajectory, casing profile, and BHAs are configured to match the field conditions to ensure accuracy in the simulation results.

WOB(tf)	WOB(Klb)	TOB(kgf.m)	TOB/WOB(Kgm.f/tf)	RPM90	RPM110	RPM120	RPM140	RPM160	RPM170	RPM180
2.27	5	255	51	90	110	120	140	160	170	180
4.54	10	510	51	90	110	120	140	160	170	180
9.07	20	463	51	90	110	120	140	160	170	180
13.61	30	694	51	90	110	120	140	160	170	180
18.14	40	925	51	90	110	120	140	160	170	180
22.68	50	2550	51	90	110	120	140	160	170	180
27.21	60	1388	51	90	110	120	140	160	170	180

Table 5.1.1 Converted parameters for DrillScan Software model

			Surface	Depth=500m		
171/2" Hole section	WOB(Klb)	RPM	TOB(ft-lb)	TOB/WOB (ft-lb/lb)	Fluid Velocity	MW
	10	80	1670	167	30	1.04
	20	80	3340	167	54	1.07
	40	90	6680	167	55	1.07
	50	124	8350	167	60	1.08
	60	120	10000	167	60	1.08
		Average Fluid velocity-51				
			Intermediate	Depth=1550m		
121/4" Hole section	48	124	8016	167	55	1.07
	48	124	8016	167	54	1.08
	48	124	8016	167	54	1.08
	50	56	8350	167	40	1.07
	52	89	8684	167	43	1.06
	47	89	7849	167	48	1.06
		Average Fluid Velocity-49				
			Production	Depth=2200-3300m		
8 3/4" Hole section	30	90	5010	167	55	1.08
	30	93	5010	167	42	1.12
	35	125	5845	167	41	1.08
	50	135	8350	167	41	1.09
	45	158	7515	167	40	1.08
	50	156	8350	167	40	1.08
		Average Fluid Velocity -43				

Table 5.2.1 Data extracted from the Drilling Report for modeling

5.2.2 Running Simulations

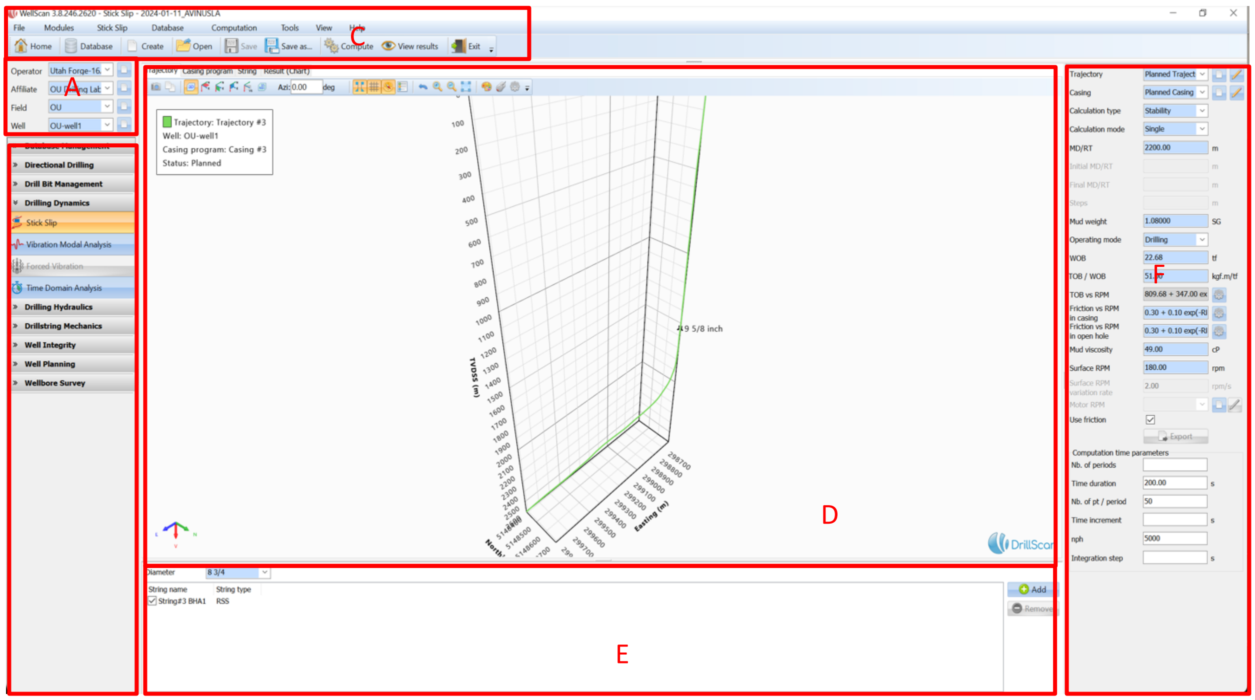


Figure 5.1.0 DrillScan interface for stick-slip analysis

Figure 5.1.0 illustrates a snapshot of the WellScan software used in the stick-slip analysis. Section (A) shows the module for selecting the well, while Section (B) displays the chosen model for performing the calculations. Section (C) is used to configure the bottom hole assembly for the downhole setup. Section (D) provides the main display, where the trajectory and casing are verified, and results are shown. Section (E) allows for string selection, and Section 6 includes the parameters used in the stick-slip computation.

5.3.1 Simulation Design

First, a baseline simulation using random drilling parameters, as reported from the field in Table 5.2.2, sets the basis for comparison. The field data were configured to be compatible with the DrillScan software, and gradually, the parameters such as RPM, WOB, and viscosity of the mud were adjusted to see their effect on the vibration levels at the various sections of interest for this research. These simulations were repeated multiple times by varying the parameters to observe their impact on the vibration severity. The purpose of the repeated simulations with varying WOBs and RPMs is to obtain repeatability. The results showed a correlation between WOB/RPM and the stick-slip severity index in Table 5.2.2. Having established that the research set a general simulation process.

WOB(tf)	RPM(revs./m)	TOB(kgf.m)	TOB/WOB(Kgm.f/tf)	FV(cp)	MSG	SSI
4.54	90/120	232	51	30	1.04	0.03/0.00
9.07	90/120	462	51	54	1.07	0.53/0.1
18.14	90/120	925	51	55	1.07	1.08/0.05
22.68	90/120	1157	51	60	1.08	1.12/0.15
27.21	90/120	1383	51	60	1.08	1.14/0.66

Table 5.2.2 Random Field Parameters for Baseline Simulation

The general simulation process is as follows.

1- For WOB of 5klb(2.27tf), the RPM is varied from 90 to 180 rpm, and the stick-slip severity index is recorded.

2- The step 1 was repeated for 10klb(4.54tf), 20klb(9.07tf), 30klb(13.61tf), 40klb(18.14tf), 50klb(22.68tf), and 60klb (27.21tf).

3- Steps 1 and 2 are repeated for the surface, intermediate, and production sections, as seen in Tables 5.3.1, 5.3.2, and 5.3.3.

The Utah Forge 16A-78-32 wellbore trajectory and casing profile for the surface, intermediate, or production section shown in figures 5.1.1.1a, 5.1.1.1b, 5.1.1.1c, 5.2.1.1d, 5.2.1.1e, and 5.2.1.1f respectively, are selected for each section's run to replicate the field.

5.3.2 Surface Section

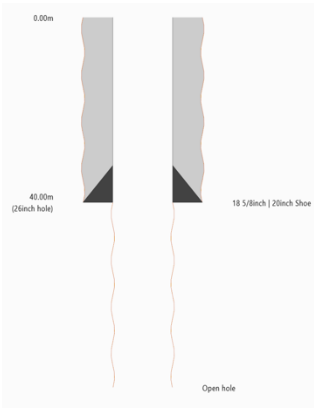
The first set of simulations for the surface section used field mud weight (8.9ppg) and an average fluid viscosity of 51cp at a depth of 1629ft (500m). A constant bit aggressivity (TOB/WOB) of 51 (kgm.f/tf) was maintained for all weight variations. The purpose was to determine the effect of WOB and RPM on if all the factors remain constant.

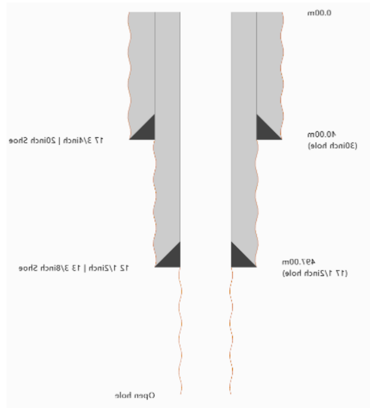
5.3.3 Intermediate Section

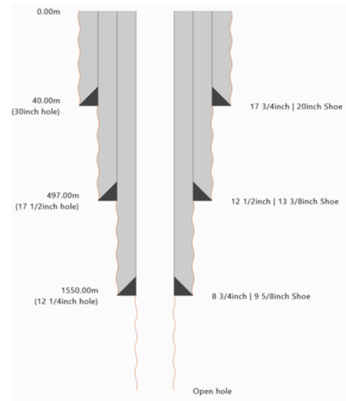
The next simulation was conducted for the intermediate section, using an average fluid viscosity of 49cp and mud weight of 9ppg, reflecting field values. These simulations aimed to assess the level of vibration observed in the drilling summary report.

5.4.1 Curved Section

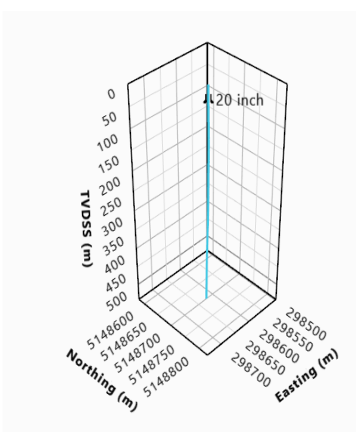
The last simulation set was done for the curved section of the 8 3/4'' section of the well. The simulation runs for each of the sections are depicted in Tables 5.3.1, 5.3.2, and 5.3.3 respectively.

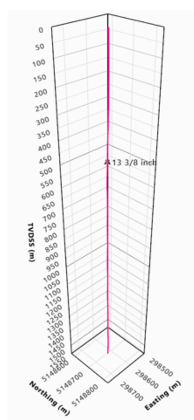


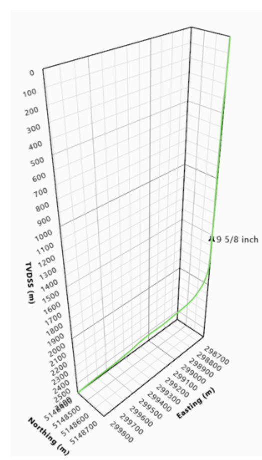




Figures: 5.1.1.1a SC Profile 5.1.1.1b IC Profile. 5.1.1.1d PC Profile







Figures: 5.2.1.1d Surface Trajectory 5.2.1.1e Intermediate Trajectory 5.2.1.1f Production Trajectory

5.4.2 Simulation Results

This section presents the results from the stick-slip simulation tests, which were conducted following a simulation procedure detailed in Section 5.2.1. Over 250 simulations were performed using varying WOBs and RPMs for surface, intermediate, and curved sections of the Utah Forge well 16A-78-32. The purpose was to determine the Stick-slip severity index for the various sections to obtain an optimal operating zone that has less or no torsional vibrations to optimize efficiency. In the results, two distinct types of stick-slip behavior were observed:

A mild stick-slip occurs with a severity index of less than 1, while a Severe stick-slip results when the severity index is greater than 1. The section outlines the following results

- Effect of RPM and WOB on mild vs severe stick-slip vibrations for 17 ½''surface hole section
- Effect of RPM and WOB on mild vs severe stick-slip vibrations for 12 ¼'' Intermediate hole section
- Effect of RPM and WOB on mild vs severe stick-slip vibrations for 8 ¾'' Production hole section

The results for the Stick-Slip Severity Index in each section were captured in two folds, first in the following tables:

Table 5.3.1 Stick-Slip Severity Results for 17 ½'' Hole Section

Table 5.3.2 Stick-Slip Severity Results for 12 ½'' Hole Section

Table 5.3.3 Stick-Slip Severity Results for 8 ¾'' Hole Section

WOB	WOB(Klb)	RPM90	SSI 90rpm	RPM110	SSI 110rpm	RPM120	SSI rpm120	RPM140	SSIrpm140	RPM160	SSI rpm160	RPM170	SSI rpm170	RPM180	SSI7rpm180
2.27	5	90	0.01	110	0	120	0	140	0	160	0	170	0	180	0
4.54	10	90	0.03	110	0	120	0	140	0	160	0	170	0	180	0
9.07	20	90	0.53	110	0.02	120	0.01	140	0	160	0	170	0	180	0
13.61	30	90	1.05	110	0.07	120	0.02	140	0	160	0	170	0	180	0
18.14	40	90	1.1	110	0.33	120	0.05	140	0.01	160	0	170	0	180	0
22.68	50	90	1.12	110	1.13	120	0.14	140	0.01	160	0	170	0	180	0
27.21	60	90	1.13	110	1.08	120	0.52	140	0.02	160	0	170	0	180	0

Table 5.3.1 Summary of Stick-slip Severity Results for 17 ½’’ Hole Section

WOB(Kgf.m)	WOB(Klb)	RPM90	SSI 90rpm	RPM110	SSI 110rpm	RPM120	SSI rpm120	RPM140	SSIrpm140	RPM160	SSI rpm160	RPM170	SSI rpm170	RPM180	SSI7rpm180
2.27	5	90	1.07	110	0.42	120	0.09	140	0.01	160	0.01	170	0	180	0
4.54	10	90	1.09	110	0.57	120	0.12	140	0.02	160	0.01	170	0.01	180	0
9.07	20	90	1.18	110	1.09	120	0.28	140	0.03	160	0.01	170	0.01	180	0
13.61	30	90	1.2	110	1.12	120	1.15	140	0.05	160	0.01	170	0.01	180	0.01
18.14	40	90	1.17	110	1.22	120	1.16	140	0.09	160	0.02	170	0.01	180	0.01
22.68	50	90	1.22	110	1.37	120	1.29	140	0.17	160	0.02	170	0.01	180	0.01
27.21	60	90	1.58	110	1.22	120	1.22	140	0.37	160	0.03	170	0.01	180	0.01

Table 5.3.2 Summary of Stick-slip Severity Results for 12 ½’’ Hole Section

WOB(Kgf.m)	WOB(Klb)	RPM90	SSI 90rpm	RPM110	SSI 110rpm	RPM120	SSI rpm120	RPM140	SSIrpm140	RPM160	SSI rpm160	RPM170	SSI rpm170	RPM180	SSI7rpm180
2.27	5	90	1..31	110	1.22	120	1.2	140	0.15	160	0.02	170	0.01	180	0.01
4.54	10	90	1.34	110	1.31	120	1.21	140	0.23	160	0.03	170	0.01	180	0.01
9.07	20	90	1.21	110	1.25	120	1.37	140	1.25	160	0.04	170	0.02	180	0.01
13.61	30	90	1.5	110	1.63	120	1.25	140	1.26	160	0.06	170	0.02	180	0.01
18.14	40	90	1.82	110	1.5	120	1.57	140	1.3	160	0.1	170	0.03	180	0.02
22.68	50	90	1.6	110	1.58	120	1.52	140	1.49	160	0.17	170	0.05	180	0.02
27.21	60	90	1.85	110	1.73	120	1.74	140	1.73	160	0.39	170	0.08	180	0.03

Table 5.3.3 Summary of Stick-slip Severity Results for 8 ¾’’ Hole Section

Second, the graphical representations of the Stick-slip severity Indexes, as provided in Figures 5.4.1a, 5.2.2.1b, and 5.2.2.1c, correspond to each section.

Figure 5.4.1a shows a graphical representation of the Stick-slip Severity Index results of 17 ½’’ hole section for the simulated WOBs/RPMs, which creates two zones separated by the red line: a zone of severe Stick-slip and a zone of Mild to no Stick-slip.

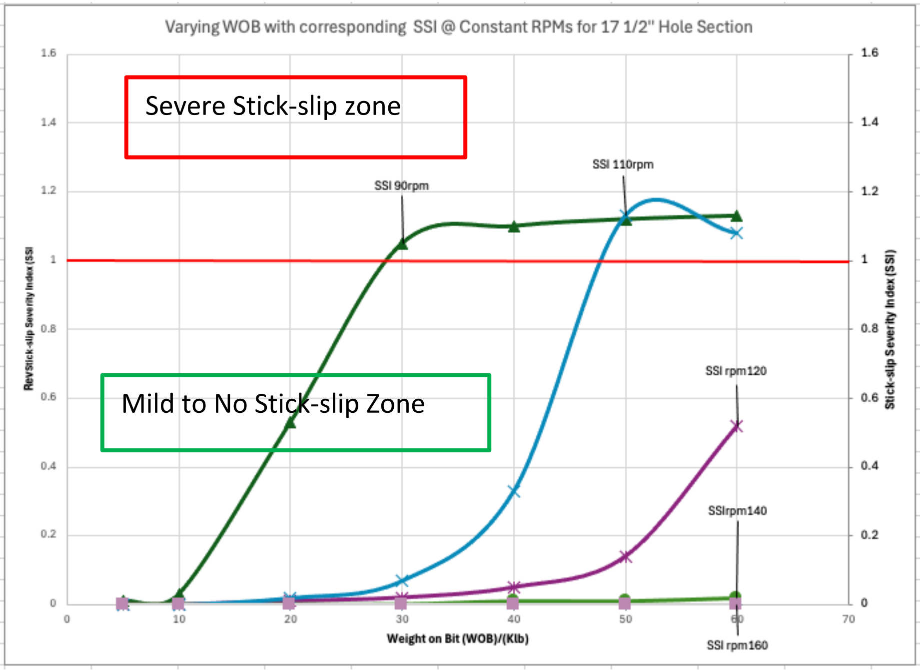


Figure 5.2.2.1a Graphical Representation of the Result of Stick-slip Severity Index for 17 ½’’Hole Section

The graph presented in Figure 5.2.2.1b illustrates the results of the Stick-slip Severity Index for the 12 ½’’ hole section, based on simulations involving various Weight on Bit (WOB) and Rotary Per Minute (RPM) combinations. The graph delineates two zones: one with severe stick-slip and another with mild to no stick-slip, which are separated by the red line. This distinction shows the critical operating parameters that determine the severity of stick-slip vibrations. The drilling efficiency is, therefore optimized by staying within the mild stick-slip zone.

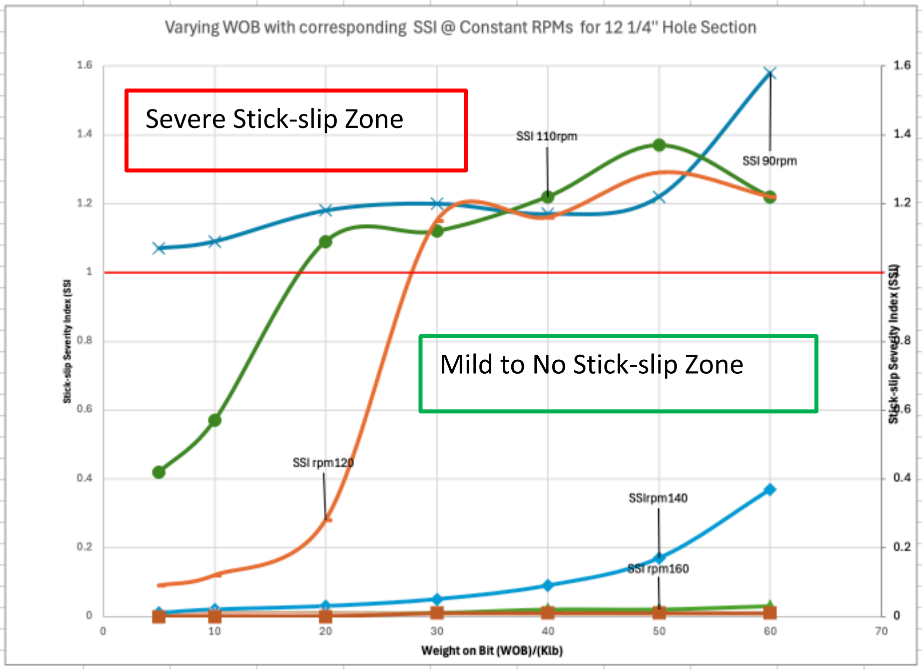


Figure 5.2.2.1b Graphical Representation of the Result of Stick-slip Severity Index for 12 ¼’’ Hole Section

Figure 5.2.2.1c also provides a visual summary of the Stick-slip Severity Index for the 8 3/4’’ hole section, based on simulations conducted with varying Weight on Bit (WOB) and RPM values. The graph divides the results into two distinct regions: one indicating severe stick-slip and the other representing mild or no stick-slip, separated by a red boundary. This distinction helps identify the optimal operating parameters that reduce vibration severity, allowing for improved drilling performance by operating within the mild stick-slip zone.

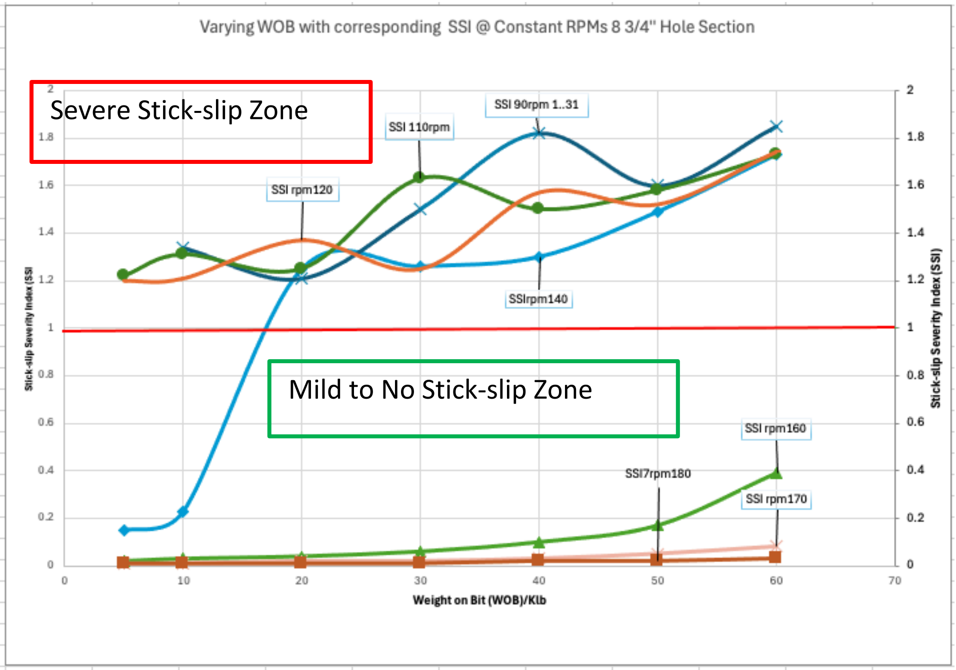


Figure 5.2.2.1c Graphical Representation of the Result of Stick-slip Severity Index for 8 ¾'' Hole Section

5.4.3 Effect of RPM and WOB on mild vs severe stick-slip vibrations for 17 ½'' Surface Hole Section

This section presents the results of simulations conducted to evaluate how variations in weight on bit (WOB) and surface RPM affect both mild and severe stick-slip vibrations. The findings are summarized in Table 5.3.1, which details the stick-slip severity indexes corresponding to different combinations of WOB and RPM. Additionally, Figure 5.2.2.1a visually illustrates the optimal operating zone for the 17 ½'' hole section, showing the RPM and WOB ranges that minimize stick-slip severity. The results indicate a clear relationship between WOB/RPM and stick-slip severity. Lower WOB and high RPM values tend to reduce the severity of stick-slip vibrations, whereas increasing WOB and lowering RPM beyond the optimal range results in more intense vibrations. These insights provide valuable guidance for selecting operating parameters that minimize vibration and enhance drilling efficiency.

5.4.4 Effect of RPM and WOB on mild vs severe stick-slip vibrations for 12 ¼'' Intermediate Hole Section

This part presents the results of simulations exploring the effect of varying weight on bit (WOB) and surface RPM on both mild and severe stick-slip vibrations for the 12 ¼'' hole section. The findings are summarized in Table 5.3.2, which provides the stick-slip severity index for different WOB and RPM values. The results are further visualized in Figure 5.2.2.1b, showing the optimal operating range that minimizes stick-slip vibrations in this section of the well. The results highlight two key zones: The Mild to No Stick-Slip Zone, where lower WOB and RPM combinations effectively mitigate stick-slip vibrations.

The Severe Stick-Slip Zone is where higher WOB and RPM values lead to increased stick-slip severity. Figure 5.2.2.1b identifies the optimal operating parameters that reduce vibrations and enhance drilling efficiency. Operating within this zone can help minimize equipment wear and improve overall performance.

5.5.1 Effect of RPM and WOB on mild vs severe stick-slip vibrations for 8 ¾'' Intermediate Hole Section

The simulation result here presents the effect of varying weight on bit (WOB) and surface RPM on stick-slip vibrations in the 8 ¾'' hole section. The outcomes, detailed in Table 5.3.3, provide the stick-slip severity index across different WOB and RPM combinations. The findings are visually represented in Figure 5.2.2.1c, which outlines the optimal operating parameters for reducing stick-slip vibrations.

The results differentiate between two zones: The Mild to No Stick-Slip Zone, where optimal combinations of lower WOB and high RPMs successfully minimize vibration severity. The Severe Stick-Slip Zone, where regardless of the test WOB if RPM is less than 140 leads to heightened stick-slip severity. Figure 5.2.2.1c highlights the optimal operating range for the 8 ¾'' hole section, showing the WOB and RPM values that significantly mitigate vibrations. Operating within these parameters not only enhances drilling efficiency but also reduces equipment wear and the potential for vibration-related damage.

Application of the optimized parameters (RPMs and WOBs)

The analysis of the simulation results shows that the optimal parameters (RPMs and WOBs) significantly minimize or eliminate vibrations for a given BHA design and well trajectory for the section under consideration. These optimal parameters were then applied in a simulation using DrillSim50 to compare the results against field data in terms of ROP to validate their effectiveness for future drilling operations.

5.5.2 Post-drilling Simulation on DrillSIM50

This section presents the drilling simulation of the Utah of Well 16A-78-32U using the optimal parameters obtained from the DrillScan simulations. This simulation aims to compare the DrillSim50 results with field data from an actual drilled well in terms of ROP. To replicate the actual on the simulator as closely as possible, the formation, drill string, BHA, and the well trajectory were applied as much as possible.

The 17 ½’’ hole section of the well was drilled from 40m to a target depth of 500m using the BHA configuration detailed in Table 5.4.2. The optimal parameters obtained from the DrillScan simulations were applied to this section. The drilling started with 5klb WOB and RPM of 90. This was varied to 180 rpm, and the average RPM was recorded. This was repeated for 10klb, and 20klb average RPMs were recorded. However, for 30klb and 40klb, the simulation started with an RPM of 110rpm to 180rpm as the optimal operating zone. To avoid vibrations, 50klb and 60klb WOBs were simulated using RPMs from 120 rpm. This was to see if the elimination of vibration would impact the ROP.

Next, the 12 ¼’’ hole section was drilled from 500m to 1550m using the BHA in Table 5.4.3. Due to limitations with the simulator, only one type of PDC bit applied in the field was used in the model since it is assumed to have negligible effects. The optimal operating parameters for this section start with an RPM of 110rpm and increase to 180rpm for 5klb and 10klb. For 20klb the RPM starts at 120rpm to 180rpm. To remain within the optimal operating zone, the WOBs of 30klb, 40klb, 50klb, and 60klb were simulated using RPM of 140rpm to 180rpm.

The final section, the 8 ¾’’ hole section, consisted of vertical, curved, and tangent sections that were simulated using the BHA configuration in Table 5.4.4. In this section, the optimal operating zone starts at 140 rpm for WOB of 5klb and 10klb, but for 20klb, 30klb, 40klb, 50klb, and 60klb, the optimal operating RPMs begin at 160rpm to 180rpm.

5.5.3 Procedure

The default snap was loaded and saved with the name (Utah Forge well 16A-78-32). The snapshot is adjusted and edited to reflect the environment of the Utah Forge well (Onshore). The post-drilling data for the formation and selected BHAs were organized to be compatible with the simulator (DrillSIM50).

Utah Forge Well 16A-78-32's Drilling BHA Data

BHA Detail								
#	Description	Mfg.	Serial #	O.D.	I.D.	Length	Sum	Top Conn
1	TKC76 Bit	NOV	A275580	17 1/2		2	2	7 5/8 REG
2	14" Vertical Scout RSS	Scout	SDI-1400-VS08-002	14		21.11	23.11	7 5/8 REG
3	7 5/8 Reg Pin X 6 5/8 Reg Pin X-Over	Scout	SDI-950-XO-010	9 1/2	2 3/4	2.15	25.26	7 5/8 REG
4	9 5/8" Scout 7/8 5.9 stg Straight Fixed 17 3/8" Stab	Scout	TDI-OSA-962-01-	9 5/8		41.08	66.34	6 5/8 REG
5	8" Shock Sub	NOV	160-80692	8 3/8	2 3/4	13.52	79.86	6 5/8 REG
6	17 3/8" Steel Stabalizer	Stabildrill	SD24282	8 3/8	2 7/8	7.96	87.82	6 5/8 REG
7	8" NMDC	Stabildrill	SD55421	8 1/4	3 1/4	29.52	117.34	6 5/8 REG
8	8" Hang off Sub	Scout	SDI-825-OSTM-008	8 1/4	3 1/4	5.09	122.43	6 5/8 REG
9	4 Stands of 8" DC					378	500.43	6 5/8 REG
10	6 5/8 Reg Pin X 4 1/2IF Box X-Over	Rig	111111	8	2 3/4	2.8	503.23	4 1/2 IF
11	3 Stands of HWDP						503.23	4 1/2 IF

Table 5.4.2 BHA 01: 17 ½'' Hole from 40m to 500m (Duane Winkler, Leroy Swearingen 2021)

BHA Detail								
#	Description	Mfg.	Serial #	O.D.	I.D.	Length	Sum	Top Conn
1	Z713S Smith 2x18's 4x20' 1x16	Smith	JP4755	12 1/4		2	2	6 5/8 REG
2	9 5/8" Vertical Scout RSS	Scout	SDI-962-VS08-027	9 5/8		20.65	22.65	6 5/8 REG
3	6 5/8 Reg Pin X 6 5/8 Reg Pin X-Over	Scout	SDI-800-XO-046	8	2 3/4	2.16	24.81	6 5/8 REG
4	HT 9 5/8" Scout 7/8 5.9 stg Straight Fixed 12 1/8" Stab	Scout	OSA-962-01-031C	9 5/8		41.18	65.99	6 5/8 REG
5	8" Shock Sub	NOV	160-80692	8 3/8	2 3/4	13.52	79.51	6 5/8 REG
6	12 1/8" Steel Stabalizer	Stabildrill	SD25600	8 3/8	2 3/4	5.8	85.31	6 5/8 REG
7	8" NMDC	Stabildrill	SD55421	8 1/4	3 1/4	29.52	114.83	6 5/8 REG
8	8" Hang off Sub	Scout	SDI-825-OSTM-008	8 1/4	3 1/4	5.09	119.92	6 5/8 REG
9	4 Stands of 8" DC					366.49	486.41	6 5/8 REG
10	6 5/8 Reg Pin X 4 1/2IF Box X-Over	Rig	Rig	8	2 3/4	2.8	489.21	4 1/2 IF
11	3 Stands of HWDP					276.35	765.56	4 1/2 IF

Table 5.4.3 BHA 06 12 ¼'' Intermediate Hole Section from 500 to 1550m (Duane Winkler, Leroy Swearingen 2021)

BHA Detail								
#	Description	Mfg.	Serial #	O.D.	I.D.	Length	Sum	Top Conn
1	XS 616 Smith Bits	Smith	JV2705	8 3/4		0.85	0.85	4 1/2 REG
2	712 Vertical Scout RSS	Scout	712-VS08-011	7 1/8		19.6	20.45	4 1/2 IF
3	6 1/2 Scout 7/8 3.0 Straight Fixed 8 15/16 Stab Pin	Scout	650-05-433	6 1/2		28.48	48.93	4 1/2 IF
4	6 1/2" Shock Sub NOV	NOV	147-0009	6 3/4	2 1/4	10.81	59.74	4 1/2 IF
5	6 3/4 Stabil Drill NM Stabilizer	Stabil	SD 610501	6 3/4		6.87	66.61	4 1/2 IF
6	6 1/2" Scout UBHO	Scout	650-UBHO-083	6 1/2	2 3/4	3.11	69.72	4 1/2 IF
7	6 3/4 NMDC	Stabil Drill	SD 55831	6 3/4		30.35	100.07	4 1/2 IF
8	7 Stands of DC's		Rig	6 1/2	3	644.15	744.22	4 1/2 IF
9	3 Stands of HWDP					276.35	1020.57	4 1/2 IF

Table 5.4.4 BHA 09 8 ¾'' Hole Section from 1550m to 1836m (Duane Winkler, Leroy Swearingen 2021)

BHA Detail								
#	Description	Mfg.	Serial #	O.D.	I.D.	Length	Sum	Top Conn
1	Reed Hycalog TKC63 PDC bit	Reed Hycalog	A255857	8 3/4		1	1	4 1/2 REG
2	6 1/2" Scout 7/8 5.7, Fixed 1.50, 8 1/4" Stab. valve	Scout	650-05-376	6 1/2	1 1/4	33.56	34.56	4 1/2 IF
3	6 1/2 Scout String Sub with PUK sensor	Scout	650-CSS-005	6 1/2	3 1/4	2.34	36.9	4 1/2 IF
4	6 3/4 NM Pony Collar	Stabildrill	SD 55005	6 3/4	3 1/4	9.22	46.12	4 1/2 IF
5	6 1/2" NM UBHO	Scout	650-UBHO-083	6 1/2	2 3/4	3.11	49.23	4 1/2 IF
6	6 3/4" NMDC with MWD	Stabil Drill	SD 55831	6 3/4	3 1/4	30.35	79.58	4 1/2 IF
7	6 3/4" NMDC (2 joints)	Stabildrill	SD56089 SD49788	6 3/4	3 1/4	60.66	140.24	4 1/2 IF
8	6 1/2" DC's (2 stands)		RIG	6 1/2	3	183.22	323.46	4 1/2 IF
9	5" HWDP (15 stands)		RIG	5	3 1/4	1384.33	1707.79	4 1/2 IF
10	5" Drill Pipe to surface		RIG	5	4 1/4		1707.79	I.F.

Table 5.5.1 BHA 18: 8 ¾'' Curved Hole Section from 1836 to 2264m (Duane Winkler, Leroy Swearingen 2021)

BHA Detail								
#	Description	Mfg.	Serial #	O.D.	I.D.	Length	Sum	Top Conn
1	Reed Hycalog TKC63 PDC, 3x13-3x14s	Reed Hycalog	A255857	8 3/4		0.85	0.85	4 1/2 REG
2	6 1/2" Motor 7/8 5.7, Fixed 1.25, 8 1/4" Stab. valve	Scout	650-05-438	6 1/2	1 1/4	34.24	35.09	4 1/2 IF
3	6 1/2 Scout String Sub with PUK sensor	Scout	650-CSS-005	6 1/2	3 1/4	2.34	37.43	4 1/2 IF
4	6 5/8 x 8 1/2" Roller Reamer	Redback	GU 3783	8 1/2	2 1/4	6.63	44.06	4 1/2 IF
5	6 3/4 NM Pony Collar	Stabildrill	SD 55005	6 3/4	3 1/4	9.22	53.28	4 1/2 IF
6	6 1/2" NM UBHO	Scout	650-UBHO-076	6 1/2	2 3/4	3.08	56.36	4 1/2 IF
7	6 3/4" NMDC with MWD	Stabil Drill	SD 55831	6 3/4	3 1/4	30.35	86.71	4 1/2 IF
8	6 3/4" NMDC (2 joints)	Stabildrill	SD56089 SD49788	6 3/4	3 1/4	60.66	147.37	4 1/2 IF
9	5" HWDP (15 stands)		RIG	5	3	1384.33	1531.7	4 1/2 IF
10	5" Drill Pipe to surface		RIG	5	3 1/4		1531.7	4 1/2 IF

Table 5.5.2 BHA 30: 8 ¾'' Tangent Hole Section from 1836 to 2264m (Duane Winkler, Leroy Swearingen 2021)

5.5.4 Configuration of Simulation Parameters:

The post-drilling data for Utah Forge 16A-78-32, especially drilling parameters such as rate of penetration (ROP), weight on bit (WOB), rotary speed, mud weight, and formation characteristics in Table 5.5.3 were selected for the analysis. The data is organized in a structured format compatible with the simulator (DrillSIM50) as shown in Table 5.5.3 and inputted. The snapshot was configured to reflect the data and prepare to drill on the simulator. The readings were taken and tubulated in the table for analysis and evaluation.

Rock Type	Parameters	Value	Unit	Source
Alluvium	Depth	3176	ft	Drilling Summary
	RS	13	Kpsi	(Gahssemi et al. 2024)
	RSSF	2		DrillSIM50
	RAS	1		DrillSIM50
	FMG	0.46	psi/ft	Drilling Summary
	Porosity	10	%	(Gahssemi et al. 2024)
	Permiability	0.004	mD	(Gahssemi et al. 2024)
Rhyolite	Depth	20	ft	Drilling Summary
	RS	13	Kpsi	(Gahssemi et al. 2024)
	RSSF	3		DrillSIM50
	RAS	2	Kpsi	DrillSIM50
	FMG	0.48	psi/ft	Drilling Summary
	Porosity	10	%	(Gahssemi et al. 2024)
	Permiability	0.0004	mD	(Gahssemi et al. 2024)
Granite	Depth	4340	ft	Drilling Summary
	RS	18.3	kpsi	(Gahssemi et al. 2024)
	RSSF	7		DrillSIM50
	RAS	3		DrillSIM50
	FMG	0.52psi/ft	psi/ft	Drilling Summary
	Porosity	10	%	(Gahssemi et al. 2024)
	Permiability	0.0004	mD	(Gahssemi et al. 2024)

Table 5.5.3 Formation Characteristic properties for the model

5.5.5 Drilling Processes

Drilling Surface Section

The drilling of the surface section started with the 20'' conductor casing already in place at 130ft(40m) using BHA 01 in Table 5.4.2. The WOBs and RPMs were varied within the optimal parameters to see how the ROP is impacted. An average on-bottom ROP of 71.67ft/hr was maintained for 232ft. When the WOB was increased to 50klb and 60klb, the average ROP moved to 97.6 ft/hr and 129.4ft/hr, respectively.

		17 1/2" Hole Section				
Depth (ft)	WOB (klb)	Average ROP (ft/hr)	RPM(revs/m)	MW (ppg)	SPM	Formation Rock Type
130-1550	5	1.86	90-180	8.6	85	Alluvium
	10	15.14	90-180	8.6	85	Alluvium
	20	17.43	90-180	8.6	85	Alluvium
	30	42.17	110-180	8.6	85	Alluvium
	40	71.67	110-180	8.6	85	Alluvium
	50	97.6	120-180	8.6	85	Alluvium
	60	129.4	120-180	8.6	85	Alluvium

Table 5.5.4 DrillSIM50 Result for 17 ½'' Hole Section Using the Optimal Parameters

Drilling Intermediate Section

The BHA 06 in Table 5.4.3 was used to drill the intermediate section after the 13 3/8'' Surface Casing had been secured in place at 1629ft(500m). First, the WOB and RPM were restricted to 45klb and 140, respectively, to observe how it would impact the ROP. After maintaining an average ROP of 157 ft/hr of on-bottom time, the weight on bit was reduced to 40klb and maintained throughout the section. This was to determine the impact of these parameters on ROP. The ROP had steadily declined from an average ROP of 123.88 ft/hr to 78 ft/hr on top of rhyolite and further declined when it touched the top of the granite, as seen in Table 4.5.5. At a depth between 4520-4544ft, a survey was taken at a constant SPM of 85 with Varying WOBs and RPMs. Another survey was taken for varying SPMs with the same RPM of 140rpm and tabulated in Table 4.6.1 and 4.6.2, respectively.

		12 1/4" Hole Section				
Depth (ft)	WOB (klb)	Average RROP (ft/hr)	RPM(revs/m)	MW (ppg)	SPM	Formation Rock Type
1550-1790	45	157	140	8.9	85	Alluvium
1790-2422	40	123.88	140	8.9	85	Alluvium
2422-2512	40	117.5	140	9	85	Alluvium
2512-2781	40	123.33	140	9	85	Alluvium
2781-4502	40	78	140	9	85	Rhyolite
4502-4520	40	27	140	9	85	Top of Granite
4520-5113	40	21	140	9	85	Granite

Table 5.5.5 DrillSIM50 Result for 12 ¼’’ Hole Section Using the Optimal Parameters

Drilling the 8 ¾’’ Production hole section

This section is divided into three parts: the vertical, curved, and tangent sections. Due to the limitations of the DrillSIM50, slide drilling could not be performed. As a result, the curved section was drilled without sliding drilling with an average ROP of 40ft/hr while the tangent section was not drilled to assess the impact of optimal operating parameters on ROP. However, BHA 09, as listed in Table 5.4.4, was used to drill the vertical section up to the kick-off point at 6000 feet.

A constant weight on bit (WOB) of 40 klb and a rotary speed of 140 RPM was applied, maintaining an average rate of penetration (ROP) of 29 ft/hr for the first 100 feet. This performance remained consistent throughout most of the section, with a bit wear rate of 50% for every 100 feet drilled. Despite being the same granite formation, the ROP gradually decreased to 24 ft/hr as drilling approached 6000 feet. The deviation kicked off at 5,900 ft measured with depth the build rate of 5 degrees per 100 ft and ended at 7,268 ft measured depth. During this period, the WOB And RPM were varied within the optimal operating zone with an average of 40ft/hr, as shown in Table 5.6.0.

Similar surveys to the one conducted in the intermediate section were carried out to verify if the results would align with the previous findings. The results from the surveys are presented in Tables 5.6.4, 5.6.5, 5.6.6, and 5.7.1

The curved section maintained the 40klb and 140 RPM with an average rate of penetration of 40ft/hr as shown in Table 5.6.6.

5.6.1 Results

Here, the findings from the simulations conducted on the DrillSIM50 simulator for the Utah Forge well 16A-78-32 are presented. Following the procedure outlined in Section 5.3.1.1, the simulations were performed over a depth range of 500-6000 feet and involved varying WOB and RPM settings across the surface, intermediate, and curved sections of the well. The primary goal was to evaluate the rate of penetration (ROP) for each section and analyze how these parameters influence overall drilling efficiency. The outcomes are detailed in Tables 5.5.4, 5.5.5, and 5.5.6.

Table 5.5.4 summarizes the results for the 17 ½'' hole section, displaying the optimal WOB and RPM settings that maximized ROP.

Table 5.5.5 presents the data for the 12 ¼'' hole section, showcasing the most efficient parameters for enhancing ROP.

Table 5.5.6 outlines the results for the 8 ¾'' hole section, emphasizing the combination of WOB and RPM that yielded the best performance.

5.6.2 Survey Results

To further investigate the relationship between RPM, SPM, and ROP in the intermediate hole section, two surveys were conducted, focusing on how. Different combinations of optimal WOB and RPM impacted ROP. The survey results, provided in Tables 5.6.2 and 5.6.3, clearly show a positive correlation between increased RPM, SPM, and improved ROP performance. Table 5.6.2 shows the results for varying RPMs and WOBs at a constant SPM of 85, identifying optimal combinations. Table 5.6.3 displays the effect of varying SPMs at a constant RPM of 140, further illustrating the benefits of optimizing both parameters. A follow-up survey was conducted at the 8 ¾'' hole section (5613-6000ft) to validate the consistency of these results with the initial survey conducted in the intermediate section. The findings, shown in Tables 5.6.4 and 5.6.5, confirm the trends observed in the first survey. Table 5.6.4 summarizes the results for varying RPMs and WOBs at a constant SPM of 85. Table 5.6.5 shows the effect of varying SPMs while keeping RPM constant, further reinforcing the importance of these parameters in improving ROP. Table 5.6.6 shows the Summary of Drilling Phase Performance in Terms of ROP (ft/hr) Utah Forge Well 16A-78-32. The results for the surface, intermediate, and vertical sections are detailed in Tables 5.5.4, 5.5.5, and 5.5.6.

		17 1/2" Hole Section				
Depth (ft)	WOB (klb)	Average ROP (ft/hr)	RPM(revs/m)	MW (ppg)	SPM	Formation Rock Type
130-1550	5	1.86	90-180	8.6	85	Alluvium
	10	15.14	90-180	8.6	85	Alluvium
	20	17.43	90-180	8.6	85	Alluvium
	30	42.17	110-180	8.6	85	Alluvium
	40	71.67	110-180	8.6	85	Alluvium
	50	97.6	120-180	8.6	85	Alluvium
	60	129.4	120-180	8.6	85	Alluvium

		12 1/4" Hole Section				
Depth (ft)	WOB (klb)	Average RROP (ft/hr)	RPM(revs/m)	MW (ppg)	SPM	Formation Rock Type
1550-1790	45	157	140	8.9	85	Alluvium
1790-2422	40	123.88	140	8.9	85	Alluvium
2422-2512	40	117.5	140	9	85	Alluvium
2512-2781	40	123.33	140	9	85	Alluvium
2781-4502	40	78	140	9	85	Rhyolite
4502-4520	40	27	140	9	85	Top of Granite
4520-5113	40	21	140	9	85	Granite

Table 5.5.4 DrillSIM50 Result for 17 ½'' Hole Section Using the Optimal Parameters

		8 3/4" Verttical hole Section				
Depth (ft)	WOB (klb)	Average RROP (ft/hr)	RPM(revs/m)	MW (ppg)	SPM	Formation Rock Type
5113-5214	40	28	140	9.3	85	Granite
5214-5312	40	29	140	9.3	85	Granite
5312-5415	40	28	140	9.3	85	Granite
5415-5514	40	29	140	9.3	85	Granite
5514-5613	40	29	140	9.3	85	Granite
5613-5812	40	27	140	9.3	85	Granite
5812-6000	40	24	140	9.3	85	Granite

Table 5.5.5 DrillSIM50 Result for 12 ¼'' Hole Section Using the Optimal Parameters

	8 3/4" Curved hole Section					
Depth (ft)	WOB (klb)	Average ROP (ft/hr)	RPM(revs/min)	MW (ppg)	SPM	Formation Rock Type
6000-6113	40	40	140	9.3	85	Granite
6113-6215	40	41	140	9.3	85	Granite
6215-6361	40	39	140	9.3	85	Granite

Table 5.5.6 DrillSIM50 Result for 8 ¾'' Hole Section Using the Optimal Parameters

Table 5.6.0 DrillSIM50 Result for 8 ¾''Curved Hole Section Using the Optimal Parameters

Survey @ the depth 4342-43644ft

	RPMs				
WOBs	140	160	170	180	
40	27	29	30	31	ROPs
50	41	43	44	47	ROPs
60	56	60	62	64	ROPs

Table 5.6.1 17 1/2'' Hole Section Survey at a constant SPM of 85 for varying optimal RPMs and WOBs

	SPMs					
WOBs	85	90	100	110	120	
40	27	28	32	35	37	ROPs
50	40	43	50	53	57	ROPs
60	57	61	70	72	78	ROPs

Table 5.6.2 17 ½'' Hole Section Survey at a constant RPM of 140 for varying SPMs and WOBs

Survey @ 5670-6000ft

	RPMs				
WOBs	140	160	170	180	
40	27	29	30	31	ROPs
50	41	43	44	47	ROPs
60	56	60	62	64	ROPs

Table 5.6.3 12 ¼'' Hole Section Survey at a constant SPM of 85 for varying optimal RPMs and WOBs

	SPMs					
WOBs	85	90	100	110	120	
40	27	28	32	35	37	ROPs
50	40	43	50	53	57	ROPs
60	57	61	70	72	78	ROPs

Table 5.6.4 12 ¼’’ Hole Section Survey at a constant SPM of 85 for varying SPMs

Survey @ the curved section 6000-6060ft

	RPMs				
WOBs	140	160	170	180	
40	33	35	37	39	ROPs
50	47	51	53	6	ROPs
60	60	68	70	74	ROPs

Table 5.6.5 8 ¾’’Hole Section Survey at a constant SPM of 85 for varying RPMs and WOBs

	SPMs					
WOBs	85	90	100	110	120	
40	33	34	37	42	43	ROPs
50	47	53	59	63	65	ROPs
60	60	68	72	78	83	ROPs

Table 5.6.6 8 ¾’’Hole Section Survey at a constant RPM of 140 for varying SPMs and WOBs

Drilling Phase	Utah Forge Average ROP (ft/hr)
Surface Hole	134
Intermediate Hole	49
Vertical portion of Production Hole	12.7
Curved Section of the Production Hole	32.7

Table 5.7.1 Summary of Drilling Phase Performance in Terms of ROP (ft/hr) Utah Forge Well 16A-78-32

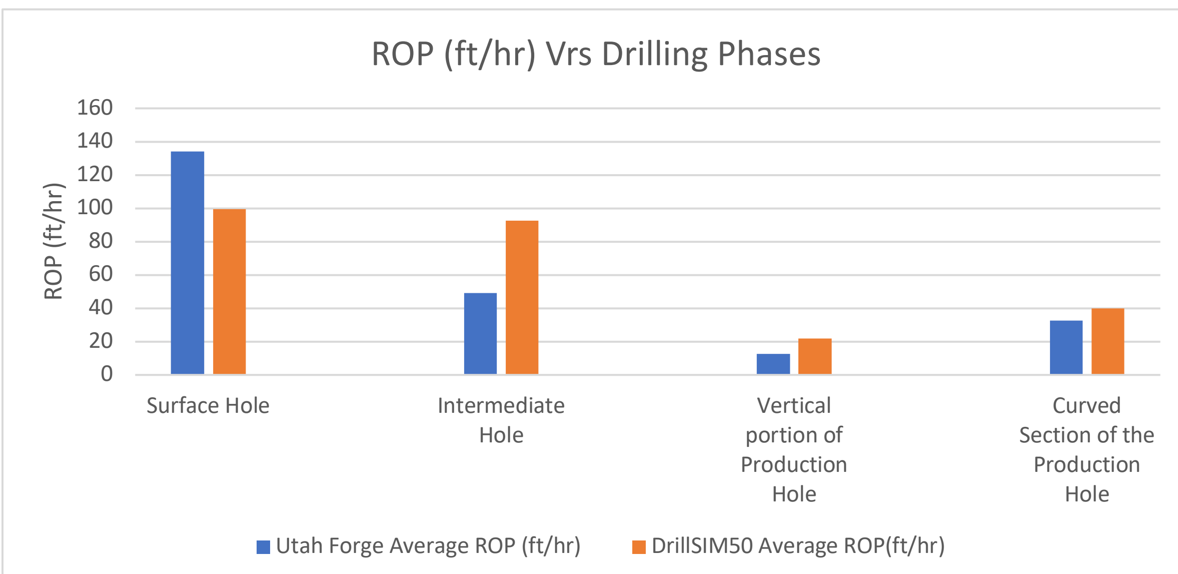


Figure 7.0 Comparison Between Field ROPs and Simulated ROPs

Chapter 6

6.0 Impact of Conventional Well Control on Geothermal Drilling and Construction

This chapter is not meant to present geothermal energy viability and sustainability but to show one aspect that ensures its safety and success. Geothermal energy represents a vital component of the global push towards sustainable and renewable energy sources. However, the extraction of geothermal energy poses significant technical challenges, particularly in well control during drilling and construction, due to a lack of related technology and equipment (Deong et al. 2014). Drilling is a fundamental operation in both geothermal and petroleum industries, but it is associated with significant hazards such as kicks and blowouts, which can endanger both equipment and personnel. Although well control methods are well-established in the oil and gas industry, they are not as thoroughly adapted for geothermal drilling, despite both fields sharing similar processes. The differences in subsurface conditions, formation fluids, and pressure origins often make oil and gas well control techniques unsuitable for geothermal environments. Understanding their impact on geothermal drilling is essential for improving operational safety and efficiency.

The purpose of this experiment is to simulate conventional well control methods—specifically the Driller's Method and the Wait-and-Weight Method—using the DrillSIM50 simulator to test the effectiveness, limitations, and potential for adaptation.

6.1.0 Well Control

Generally, well control involves the prevention or management of uncontrolled fluid flow into the wellbore, which can result in a blowout if appropriate action is not taken. A Blowout" is a kick leading to an uncontrolled flow of formation fluids into the wellbore; this may be either a surface Blowout or an Underground Blowout. This can be very dangerous to the crew, the environment, and the company's reputation, affect the project's economics, and, at worst, can result in loss of life (Ma et ai. 2016). Well Control can be divided into three types, namely, Primary, Secondary, and Tertiary (Emergency).

Primary well Control is achieved by always maintaining the hydrostatic pressure due to the fluid column within the wellbore.

Secondary Well Control occurs when the formation pressure, or pore pressure, surpasses the bottom hole hydrostatic pressure (BHP) due to various reasons, such as drilling into a zone with higher pore pressure, swabbing during trips, or encountering gas-cut mud, etc. When primary well control is lost, it may result in an influx of formation fluids, known as a kick. In such cases, blowout preventer (BOP) equipment must be utilized to manage the kick. This is done through one or more "kill" methods, which will be explored in the next section.

Tertiary Well Control occurs when a blowout is underway or when other uncommon well control challenges require the use of specialized methods (such as disconnection, drilling of relief well, etc.) expertise, or equipment.

6.1.1 Well-control challenges in Geothermal wells

Despite the similarities in the overall process, the subsurface conditions and hazards encountered in geothermal and petroleum drilling differ significantly. (Rolv Rommetveit, et al. 2007) stated that the frequency of well control incidents is higher than one per HPHT well, and an increasing number of these take place during completion. Geothermal has a similar condition, especially in terms of temperature and pressure, so this could be a possible outcome. In some geothermal fields, shallow pore pressures can be higher than what is found in a typical hydrostatic column, a condition known as overpressure. This is often observed in areas like Tiwi in the Philippines and parts of the Salton Sea in California, typically due to elevated shallow temperatures (Blankenship 2010). However, most geothermal fields are under pressured, meaning the pore pressure is lower than the fluid pressure in a wellbore. In these cases, fluid influx into the wellbore occurs when there is a decrease in wellbore pressure. Two main scenarios can lead to a loss of well control. The first happens when hot fluids from deeper depths are brought to the surface, causing them to turn into steam, which reduces hydrostatic pressure and can trigger further steam flashing, known as a boil-down effect. The second occurs when lost circulation causes the fluid level and pressure in the wellbore to drop significantly, allowing the same steam flashing process to happen (Blankenship 2010). In addition, gas caps or gas zones may develop at or above the reservoir in some geothermal reservoirs. These zones often remain undetected because oil and gas logging techniques, which would normally identify such zones, are not commonly used in geothermal drilling (Blankenship 2010). However, the volume of influx determines the risk level of the kick, and therefore, conventional well control relies on early kick detection and shut-in to ensure blowout prevention (Vajargah et al. 2015). A new technology (see figure), called automated well control, has been developed to fully automate the process of detecting influxes and initiating shut-in procedures during drilling operations (B. W. Atchison 2021). This system enables continuous monitoring of the well in real-time and automatically manages the flow of any detected influx. Once the influx is detected, the automated system controls the rig by executing a series of actions, including stopping the top drive, spacing out the drill string, halting the pumps, and activating the blowout preventer (BOP) to secure the well. However, the Kill process remained largely manual and dependent on the well control situation.

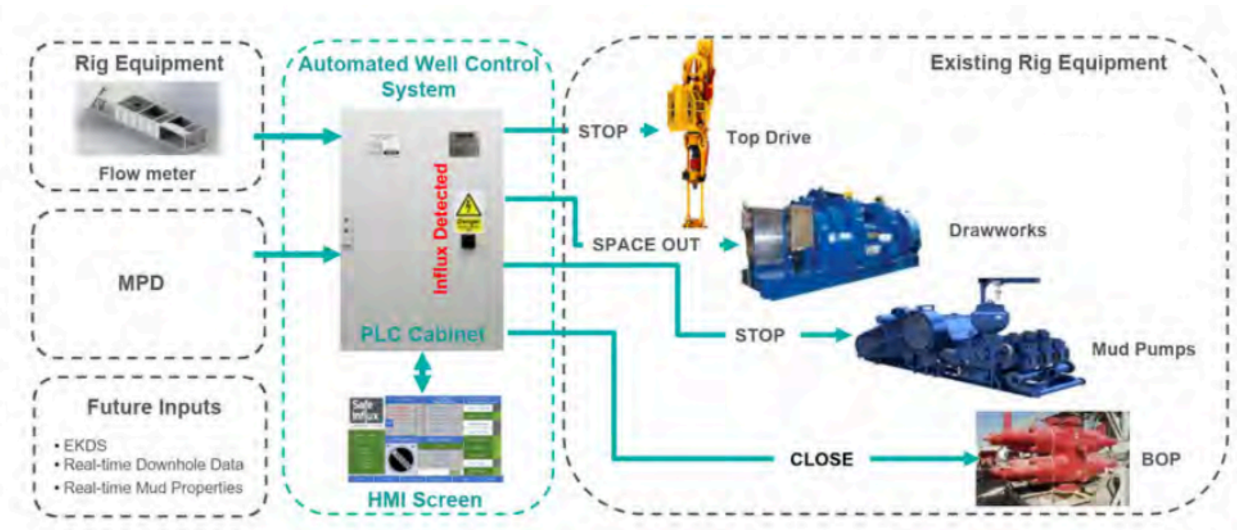


Figure 6:1—Automated well control topology (B. W. Atchison 2021)

Causes of Kicks

Many factors induce a kick in a wellbore, but we will limit our steady to the few below.

- Failing to ensure hole fill when tripping out: this is when drill pipe and drill collars are pulled out of the hole without filling the hole with an equivalent amount of mud.
- Swabbing while tipping out: This is when the drill string is pulled too fast to create a lower bottom hole pressure.
- Insufficient mud weight: this results from the penetration of an unexpected abnormally high-pressure zone or deliberate underbalanced drilling
- Abnormal formation pressure: Formation pressure greater than the expected formation pressure

- Lost circulation: this occurs when part or the whole mud is lost to the natural formation or induced fracture.
- Shallow gas: These gas pockets are encountered when drilling the surface hole. It is one of the most dangerous situations that can be encountered while drilling
- Excessive drilling rate in gas-bearing sands: This is when the mud becomes gas-cut and breaks out from cuttings as it is being circulated.
- Human Error: This is due to a lack of attention on the part of personnel.

6.1.2 Kick Indicators

Several indicators and warning signs can alert a Driller to the presence of a kick or an imminent one. While not all signs will be visible in every situation, some are always present to provide a warning. Kicks are generally categorized into two groups:

1. Positive signs that a kick is already happening

2. Warning signs indicating approaching underbalanced or loss of balance

The latter group are only warning signs that may or may not indicate a kick.

6.1.3 Positive Kick Indicators

Flow Rate Increase

One of the first definitive signs of a kick during drilling is an increase in the return flow of drilling fluid. When a kick occurs, the surface pressure required to control it will largely depend on the size of the influx entering the wellbore. If a small kick is detected early and the well is shut in quickly, it will involve lower pressure, making the situation easier to handle. One of the Driller's key responsibilities is to shut in the well efficiently and with minimal gain.

Increase in Pit Volume

When formation fluids enter the well, they displace the drilling mud, which results in an increase in surface volume within what is usually a closed circulation system. Detecting changes in pit volume, especially during a slow influx, can be difficult, especially on floating rigs.

Kick Warning Signs

Pump Pressure Decrease/Pump Stroke Increase: The presence of an influx in the annulus reduces the pump pressure or increases the pump stroke.

A Change in Penetration Rate: It may signal an increase in permeability and a loss of pressure overbalance. Both these effects result in faster drilling.

Incorrect Hole Fill Volume: the incorrect amount of mud returns from the hole as the drill string is run into the hole, which is a possible indicator of a kick.

Well-flowing between stands while running: If the well has not stopped flowing by the time the next stand is ready for running in, something is probably wrong.

KILL METHODS

The objective of all Kill methods is to remove the influx from the wellbore and circulate a satisfactory weight of the kill mud into the well without allowing a further influx into the well. To accomplish this, the kill mud must be fully circulated within the well with minimum damage to the well. The circulated mud must provide a hydrostatic pressure that maintains constant bottom-hole pressure at least equal to or slightly greater than the formation pressure.

Pressure Balance within the Wellbore

Once the well is deemed to be underbalanced and the well is shut, if there is no formation or casing shoe breakdown, the pressures in the well will be balanced.

Formation Pressure (FP) = Hydrostatic mud Pressure in Drill Pipe + Shut-in Drill Pipe Pressure (SICP) or Hydrostatic Pressure due to the height of the (mud + influx) + Shut-in Casing Pressure (SICP).

There are four basic Well Control kill methods: (1) The Driller's Method, (2) The Wait and Weight method, (3) The Volumetric Method, and (4) the Concurrent Method. Regardless of the Method employed, the aim is to maintain the Bottom Hole Pressure constant and at least equal to the formation pressure. However, for this research, the most applied method in the field will be considered, that is, the Driller's and Wait and Weight Methods. This section simulates conventional well control techniques (Driller's and Wait and Weight Methods) in geothermal drilling operations using DrillSIM50 to determine the effectiveness, limitations, and potential for adaptation.

Experimental Setup:

Here, the DrillSIM50 formation characteristics are modeled in geothermal formation with an average temperature gradient of 0.038°F/ft (M. Nathenson 1988) , as shown in Table 6.1.

Parameters for the well model

Rock Type	Parameters	Value	Unit	Source
Alluvium	Depth	3176	ft	
	RS	1.2	Kpsi	
	RSSF	1		DrillSIM50
	RAS	1	Kpsi	
	RASF	1		DrillSIM50
	FMG	0.49	psi/ft	Driling Summary
	Tep. Grdadiet	5/100	°F/ft	
	Depth	20	ft	
Rhyolite	RS	2	Kpsi	
	RSSF	1.5		DrillSIM50
	RAS	1	Kpsi	
	RASF	1		DrillSIM50
	FMG	0.49	psi/ft	Driling Summary
	Depth	4340	ft	
Granite	RS	25+	kpsi	
	RSSF	7		DrillSIM50
	RAS	5	Kpsi	
	RASF	4.5		DrillSIM50
	FMG	0.62psi/ft	psi/ft	Driling Summary
	Tep. Grdadiet	38/100	°F/ft	M. Nathenso 1988

Table 6.1 Parameters used for the well model

Before simulating the well control technique, the well was drilled to a depth of 5640 (MD/TVD), where the influx kick-in

Well Specifications:

Wellbore Diameter: 8 ¾ inches

Depth (TVD): 56405ft (MD/TVD)

Casing Shoe Depth: 9 ⅝ inches casing set at 5,113 feet (TVD/MD)

Internal Volumes:

Drill Pipe: 5 inches in diameter, with a capacity of 0.0178 barrels per foot

Heavyweight Drill Pipe: 5 inches, 270 feet in length, with a capacity of 0.0087 barrels per foot

Drill Collars: 6 5/8 inches, 360 feet in length, with a capacity of 0.0049 barrels per foot

Pump and Mud Circulation Data:

Pump Efficiency: 98%, with a displacement of 0.1 barrels per stroke

	(PL)Dynamic Pressure Loss(PSI)	
Slow Ciculation Rate Data	Pump 1	Pump 2
25 SPM	471	470
30 SPM	650	624

Table 6:1-2 Slow circulating Rates for the pumps (1) & (2) before Drilling the model well

Simulation Setup:

All the well specifications, mud circulation data, and drill string details were input into the DrillSIM50 simulator. Before initiating drilling, all gauges were calibrated, with return flow deviations set to ±5 bbls and pit deviations to ±10 bbls. Slow circulation rates were recorded for both Pump 1 and Pump 2 at 25 SPM and 30 SPM, as indicated in Table 6:1-2. When the well reached a depth of 5640 feet (MD/TVD), an influx (kick) was detected, evidenced by an increased flow rate and pit gain. Upon identification of the kick, the rotation was halted, and the blowout preventer (BOP) was immediately closed. Key data, including the Shut-In Drill Pipe Pressure

(SIDPP), Shut-In Casing Pressure (SICP), and pit gain, were captured (see Table 6:1-3).

Driller's Method

The Driller's Method was first chosen and applied due to the well's characteristics and the fact that the drill string volume exceeded the hole volume (as shown in Figure 1-1). Once the well was stabilized (Table 6:1-4), the Initial Circulating Pressure (ICP) was calculated, and the first circulation began. The existing mud was used, and the pump was gradually sped up, maintaining constant casing pressure (SICP) until the kill speed of 30 SPM was reached using Pump 2.

Kick Depth(ft)	Time/s	SIDPP(PSI)	SICP (PSI)	Kick Volume(bbl)
5640	11:31	578	672	8
	11:33	586	675	
	11:35	588	678	
	11:37	591	685	
	11:39	594	691	
	11:41	597	695	
	11:43	597	695	

Table 6:1-4 Stabilizing pressure

Circulation of Influx

Following the selection of the Driller's Method, the influx was circulated using the current mud. Throughout this process, bottom-hole pressure was kept equal to or greater than the formation pressure. Constant monitoring of pit volume and casing pressure changes was essential to maintain well integrity. After the first circulation, the well was shut to verify if any additional influx had occurred. As both SIDPP (597 psi) and SICP (599 psi) remained nearly equal, this confirmed no further influx was present.

Circulation of Kill Mud:

The kill mud circulation process began with an Initial Circulating Pressure (ICP) of 1221 psi (as shown in Figure 6:1-4). The drill pipe pressure progressively dropped, following the step-down chart as the drill pipe filled with kill mud. The pressure continued to decrease from ICP to Final Circulating Pressure (FCP), and once the kill mud exited the bit, FCP was maintained at 751 psi by adjusting the choke until the kill mud reached the surface. After circulating the kill mud through the well, the pump was shut off, and the well was stabilized.

Wait and Weight (W&W) Method

The W&W Method was also applied to circulate and kill the well in only one circulation. In this method, the influx is circulated out while the kill mud is simultaneously pumped into the wellbore. The pump is started slowly until the initial circulating pressure of 1221psi and the drill pipe pressure step-down chart schedule in Figure 6:1-2 is followed to maintain constant BHP as the kill mud is pumped from the surface to the bit. Once the kill mud is at the bit, the drill pipe pressure is held constant until the kill mud returns to the surface.

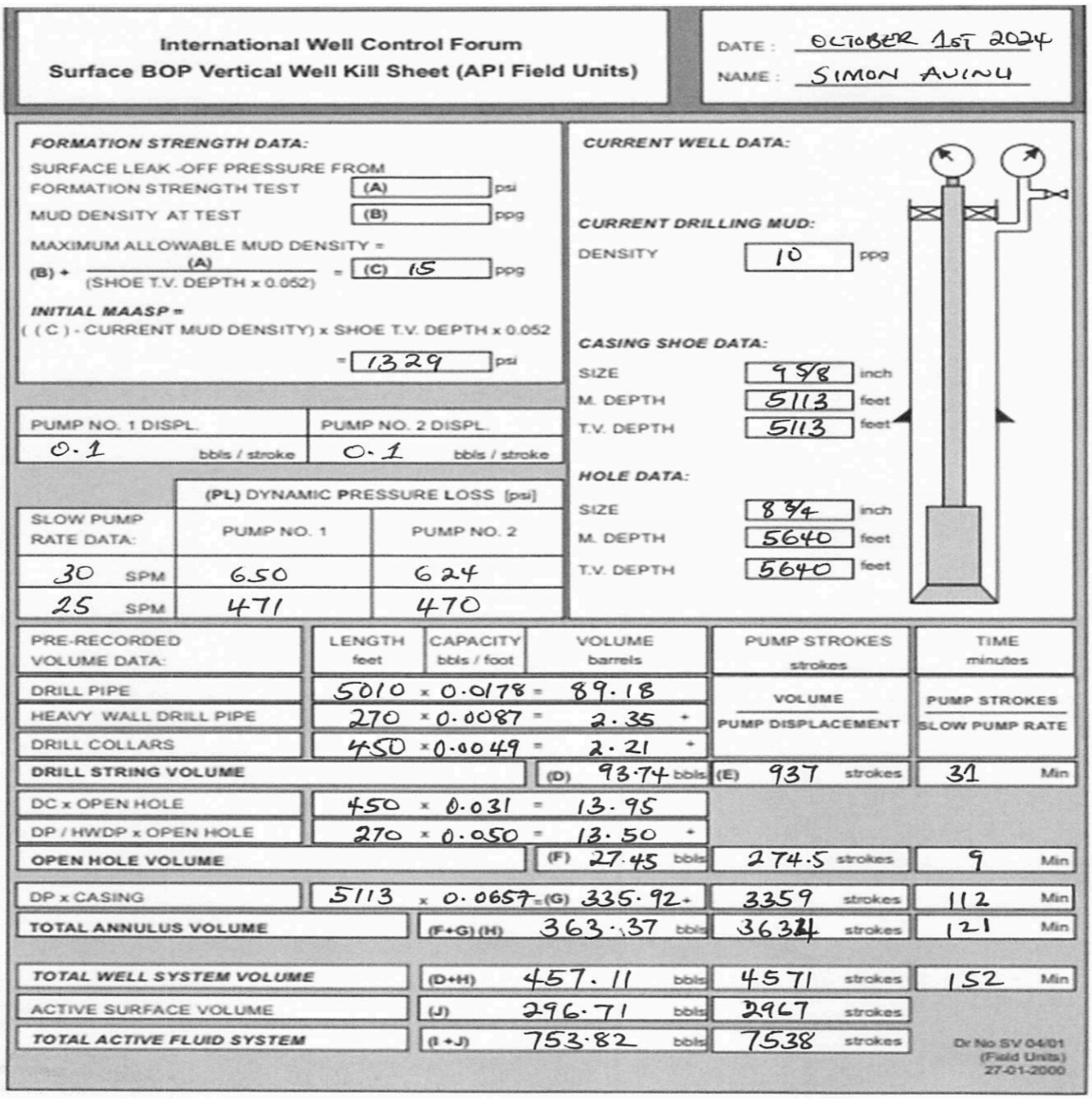
Results

This simulation successfully demonstrated one of the key causes of well control loss in geothermal drilling: gas influx. However, due to limitations in the DrillSIM50 simulator, it was unable to replicate the movement of hot fluids from deeper formations to the surface, which typically causes fluids to flash into steam. The results showed that conventional well control techniques, specifically the Driller's and Wait and Weight Methods, are effective as long as the influx remains gas, and the temperature remains below 100°C. The simulation produced kick data (Table 6:1-3) and stabilized well data after shutting on the kick at a depth of 5640 feet (MD/TVD) (Table 6:1-4). Figure 1-1 presents the kill sheet calculations used for determining volumes, strokes, and circulating pressures required for the Maximum Allowable Surface Pressure (MASP). Figure 6:1-2 illustrates the drill pipe pressure step-down chart, which shows how kill mud circulation was achieved.

Kick Parameters:

Parameters	Value	Units
Shut-In Drill Pipe Pressure (SIDPP)	597	Pounds per Square Inch (PSI)
Shu-In Casing Pressure (SICP)	695	Pounds per Square Inch (PSI)
Pit Gain	8	Barrels (bbls)
Mud Weight	10	Pounds per Gallons (ppg)
Surface Leak-off Test (FIT EMW)	15	Pounds per Gallons (ppg)

Table 6:1-3 Kick Parameters for the model well



International Well Control Forum
Surface BOP Vertical Well Kill Sheet (API Field Units)

DATE : OCTOBER 1ST 2024
NAME : SIMON AUINU

FORMATION STRENGTH DATA:

SURFACE LEAK -OFF PRESSURE FROM FORMATION STRENGTH TEST (A) psi

MUD DENSITY AT TEST (B) ppg

MAXIMUM ALLOWABLE MUD DENSITY = (B) + (A) / (SHOE T.V. DEPTH x 0.052) = (C) 15 ppg

INITIAL MAASP =
((C) - CURRENT MUD DENSITY) x SHOE T.V. DEPTH x 0.052 = 1329 psi

PUMP NO. 1 DISPL.	PUMP NO. 2 DISPL.
0.1 bbls / stroke	0.1 bbls / stroke

SLOW PUMP RATE DATA:	(PL) DYNAMIC PRESSURE LOSS [psi] PUMP NO. 1	PUMP NO. 2
30 SPM	650	624
25 SPM	471	470

CURRENT WELL DATA:

CURRENT DRILLING MUD:
DENSITY 10 ppg

CASING SHOE DATA:
SIZE 9 5/8 inch
M. DEPTH 5113 feet
T.V. DEPTH 5113 feet

HOLE DATA:
SIZE 8 3/4 inch
M. DEPTH 5640 feet
T.V. DEPTH 5640 feet

PRE-RECORDED VOLUME DATA:	LENGTH feet	CAPACITY bbls / foot	VOLUME barrels	PUMP STROKES strokes	TIME minutes
				VOLUME / PUMP DISPLACEMENT	PUMP STROKES / SLOW PUMP RATE
DRILL PIPE	5010 x	0.0178 =	89.18		
HEAVY WALL DRILL PIPE	270 x	0.0087 =	2.35 +		
DRILL COLLARS	450 x	0.0049 =	2.21 +		
DRILL STRING VOLUME			(D) 93.74 bbls	(E) 937 strokes	31 Min
DC x OPEN HOLE	450 x	0.031 =	13.95		
DP / HWDP x OPEN HOLE	270 x	0.050 =	13.50 +		
OPEN HOLE VOLUME			(F) 27.45 bbls	274.5 strokes	9 Min
DP x CASING	5113 x	0.0657 =	(G) 335.92 +	3359 strokes	112 Min
TOTAL ANNULUS VOLUME			(F+G) (H) 363.37 bbls	3634 strokes	121 Min
TOTAL WELL SYSTEM VOLUME			(D+H) 457.11 bbls	4571 strokes	152 Min
ACTIVE SURFACE VOLUME			(J) 296.71 bbls	2967 strokes	
TOTAL ACTIVE FLUID SYSTEM			(I +J) 753.82 bbls	7538 strokes	

Dr No SV 04/01
(Field Units)
27-01-2000

Figure 6:1-1Vertical Kill Sheet for the Stimulated well

International Well Control Forum

Surface BOP Kill Sheet - Vertical Well (API Field Units)

DATE : OCTOBER 1ST 2024

NAME : SIMON AVINU

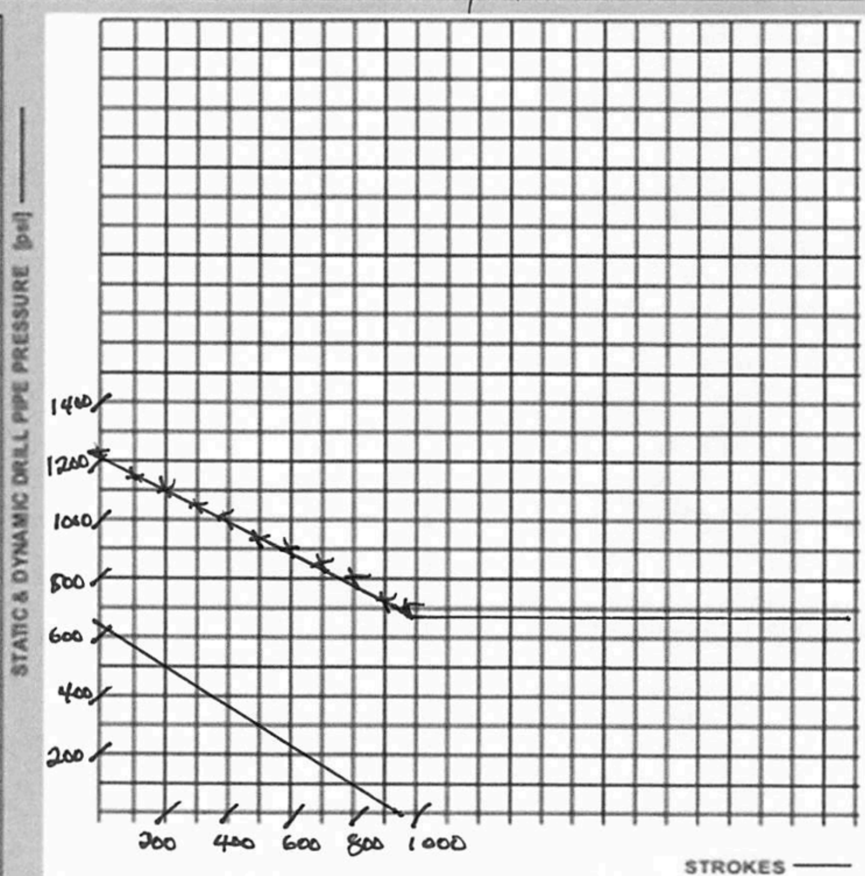
KICK DATA : SIDPP 597 psi SICP 662 psi PIT GAIN 8 barrels

KILL MUD DENSITY KMD	CURRENT MUD DENSITY + $\frac{\text{SIDPP}}{(\text{TVD} \times 0.052)}$ $10 + \frac{597}{5640 \times 0.052} =$ 12.04 ppg
INITIAL CIRCULATING PRESSURE ICP	DYNAMIC PRESSURE LOSS + SIDPP 624 + 597 = 1221 1221 psi
FINAL CIRCULATING PRESSURE FCP	$\frac{\text{KILL MUD DENSITY}}{\text{CURRENT MUD DENSITY}}$ x DYNAMIC PRESSURE LOSS $\frac{12.04}{10} \times 624 =$ 751 psi

(K) = ICP - FCP = 1221 - 751 = 470 psi

$\frac{(K) \times 100}{(E)} = \frac{470 \times 100}{937} =$ 50 psi / 100 strokes

STROKES	PRESSURE (psi)
0	1221
100	1171
200	1121
300	1071
400	1021
500	971
600	921
700	871
800	821
900	771
940	751



Dr No SV 04/02 (Field Units) 27-01-2000

Figure 6:1-2 Drill pipe Step-down Chart for the Stimulated well

Chapter 7

Discussions and Conclusions

This study successfully conducted a comprehensive post-drilling simulation of Utah FORGE Well 16A-78-32 using advanced tools such as DrillScan Technology and DrillSIM50. The primary focus was to examine the relationship between key drilling parameters—Weight on Bit (WOB) and Revolutions per Minute (RPM)—and the severity of vibrations, particularly stick-slip vibrations. Stick-slip is a common issue that leads to inefficiencies, equipment wear, and a reduced rate of penetration (ROP). In addition, conventional well control methods adapted to geothermal drilling were also simulated. To achieve accurate results, field data such as drilling parameters (RPM, WOB, torque), wellbore trajectory, and bottom-hole assembly (BHA) configurations were extracted from the drilling summary report (refer to Table 5.1.1 and Figures 5.1.1.1a, 5.1.1.1b, 5.1.1.1c). The collected data were then structured to be compatible with DrillScan and DrillSIM50 for accurate simulation of the well conditions.

This section discusses the Results from various simulation methods, providing insights into torsional vibrations. The DrillScan analysis examined how process parameters (RPM and WOB), and well configurations impact the severity of Stick-slip. The results, presented in Tables 5.3.1 through 5.3.3 and Figures 5.2.2.1a-c, outline the Stick-Slip Index (SSI) and optimal operating zones for the surface, intermediate, and production Hole sections.

Surface Hole Section

As shown in Table 5.3.1, in the surface hole section, applying a WOB of 5-20klb results in an SSI of less than 1, even with a low RPM of 90, as indicated by the green zones. However, when the WOB increases to 30klb at the same RPM, the SSI rises to a severe level (shown in pink). This implies that green zones in the table represent WOB/RPM combinations that minimize or eliminate vibrations. Therefore, with the rig's ability to adjust the top drive RPM and manage bit weight, a higher ROP can be achieved (see Table 5.5.4). Figure 5.2.2.1a graphically represents zones of severe and mild-to-no stick-slip.

Intermediate Hole Section

Table 5.3.2 provides results for the intermediate hole section, indicating severe SSI at 5-20klb WOB and 90 RPM (highlighted in pink). However, as RPM increases to 140 and beyond, SSI decreases, moving from mild to no stick-slip for all WOB values (shown in green). The green zones in the table mark optimal WOB/RPM combinations that reduce vibrations. Figure 5.2.2.1b illustrates these zones, and compared to the surface hole section, the optimal operating zone here is narrower.

Production Hole Section

In the production hole section, Table 5.3.3 shows that an SSI of severe intensity occurs for 5-60klb WOB at 90 RPM (in pink). However, when the RPM exceeds 160, SSI decreases to mild or no stick-slip for all WOB values (in green). The green areas in the table again mark combinations that ensure minimal vibrations. Figure 5.2.2.1c visualizes these zones, and like the intermediate section, the optimal operating zone is also narrow but effective.

Analysis and Findings

The analysis of these simulations highlights how optimal RPM and WOB values can significantly reduce or eliminate vibrations, given a specific BHA design and well trajectory. This is especially important in the intermediate and curved sections of the well.

DrillSIM50 Results

The results from DrillSIM50 simulations, as presented in Tables 5.5.4 to 5.5.6, demonstrate significant improvements in the average ROP across most sections, except for the surface hole section.

Surface Hole Section

The 17 ½'' surface hole, drilled primarily through alluvium formations, recorded an average ROP of 99.56 ft/hr for a WOB of 30-60klb (Table 5.5.4), which was lower than the field results. This was attributed to the simulator not being equipped with the type of PDC bit used in this section.

However, a survey indicated a positive correlation between increasing RPM, SPM, and improved ROP (see Table 5.6.5).

Intermediate Section:

For the 12 ¼'' intermediate section, the DrillSIM50 simulation revealed a significant increase in average ROP to 92.53 ft/hr (Table 5.6.5), compared to the field result of 49 ft/hr. This improvement suggests that operating within the optimal parameter zone reduces equipment wear and enhances overall drilling performance.

Production Section

The DrillSIM50 results for the production section (Tables 5.5.6, 5.6.0, and 5.6.5) showed an improvement in ROP to 29 ft/hr and 40 ft/hr represented in Table 7.0 for the vertical and curved sections, respectively.

Drilling Phase	Utah Forge Average ROP (ft/hr)	DrillSIM50 Average ROP(ft/hr)
Surface Hole	134	99.56
Intermediate Hole	49	92.53
Vertical portion of Production Hole	12.7	21.71
Curved Section of the Production Hole	32.7	40

Table 7.0 Comparison Between Field ROPs and Simulated ROPs

Optimization

Post-drilling simulations using DrillScan software determined the optimal operating parameters for the BHA configurations to eliminate the vibrations encountered in the field (Figure 7.1.) When these parameters were applied in DrillSIM50 simulations, there was a notable improvement in ROP across all sections, except for the 17 ½'' surface hole, as displayed by the accompanying graph in Figure 7.0. The blue bars in the graph represent the actual field ROP performance for Utah Forge Well 16A-78-32, while the orange bars indicate the ROP achieved during simulations on DrillSIM50 using the optimized parameters.

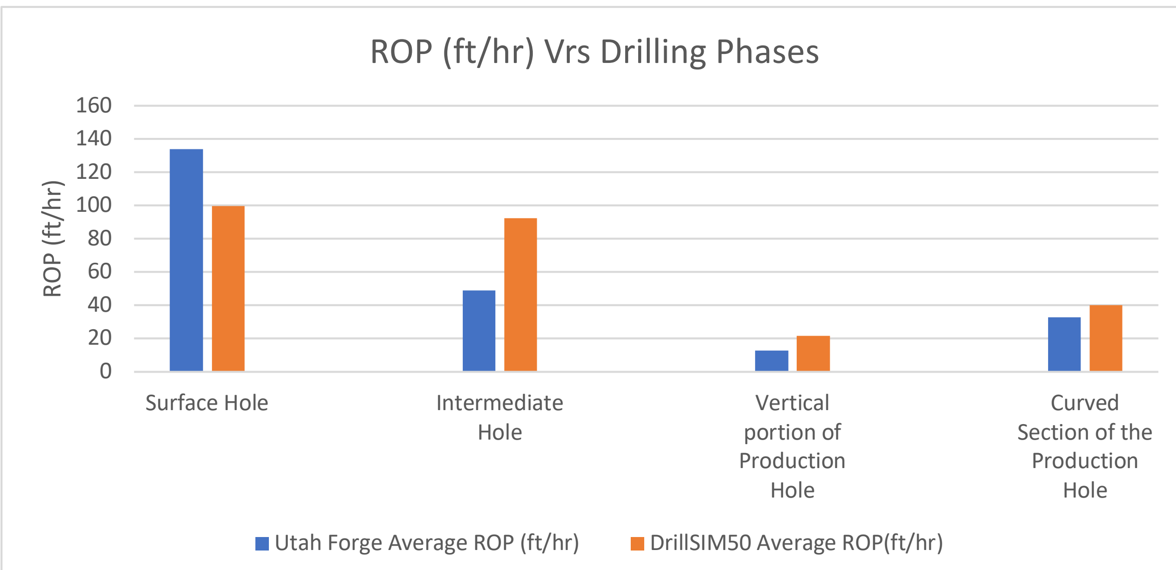


Figure 7.0: Comparison of Field ROPs vs. Simulated ROPs

Depth (ft)	WOB (Klb)	RPM (rev/min)	SPM (stks/min)	ROP (ft/hr)
4552-4964	40/50	90/84	88	34.5/59.3

Figure 7.1 shows where micro-chipping, bit spalling and degraded ROP as a result of vibrations

Conventional Well Control Method Adapted to Geothermal

The simulation of well control using conventional techniques, specifically the Driller's Method, produced important insights into geothermal well control under typical operational frameworks. The results demonstrated that while conventional well control techniques can be effectively applied in geothermal drilling, certain limitations arise, particularly when dealing with higher temperatures and fluid dynamics unique to geothermal formations.

Effectiveness of the Driller's and Wait and Weight Methods

The Driller's Method was successfully implemented to control a gas influx during the simulation limiting gas migration since the hole volume is smaller than the string volume shown in Figure 6:1-1. By maintaining bottom-hole pressure equal to or slightly above the formation pressure, the influx was circulated out of the wellbore using the existing mud system. This simulation result aligns with the expectations that the Driller's Method can be an effective technique for managing gas influxes, as long as the temperature remains within manageable limits (i.e., below 100°C). While the W&W Method was equally effective in killing the well, its advantages, particularly in reducing shoe pressure was limited in this simulation due to the smaller hole volume compared to string volume. However, the surface pressure recorded for the W&W method was lower than that of the driller's method lower surface pressure. These results confirm that conventional well control methods, such as the Driller's and W&W methods, can be effective for certain geothermal scenarios where the influx is gas rather than steam. Pressure stabilization was observed in the simulation where the Shut-In Drill Pipe Pressure (SIDPP) and Shut-In Casing Pressure (SICP) became equal after the first circulation, which shows that the influx had been successfully circulated out without taking a secondary kick. Again, after the second circulation in Driller's Method and the application of the W&W method, both showed zero on the SIDDP and SICP gauges, indicating that the well had been successfully brought under control.

Temperature Limitations

However, a major limitation identified in this simulation is the inability to model high-temperature scenarios where fluids from deeper formations flash to steam as they approach the surface. This phenomenon, which occurs frequently in geothermal drilling, presents a more complex challenge for conventional well control techniques like the Driller's and W&W Methods. The DrillSIM50 simulator cannot currently replicate the behavior of steam flashing, which means that the more severe risks associated with this process were not fully captured in this simulation. In real-world geothermal wells, especially those with temperatures exceeding 100°C, steam flashing can lead to rapid pressure loss, making well control more difficult (Blankenship 2010). The inability to simulate this situation represents a gap in the current simulation framework and highlights the need for adaptive modifications to conventional well control techniques when applied to geothermal drilling.

Circulation of Influx and Kill Mud

The simulation successfully demonstrated the circulation of both the influx and kill mud. The use of the current mud system allowed for the controlled circulation of the gas influx, and the drill pipe pressure step-down was observed as expected, following the predetermined chart. The process showed that by maintaining constant casing pressure and controlling pump speed, the influx could be circulated out of the well with minimal risk to Well Integrity. The kill mud was successfully circulated into the well, and the pressure was stabilized by adjusting the choke, keeping the final circulating pressure constant as the kill mud reached the surface. This indicated that the Driller's and W&W Methods, when applied under favorable conditions (such as manageable temperatures and a gas influx), are an efficient means of restoring well control.

Limitations in Handling High-Temperature Fluids:

Despite the success in controlling the gas influx, the simulation could not fully replicate conditions where high-temperature fluids flash to steam. This is a significant challenge in geothermal wells, where the rapid transition from liquid to vapor can cause well control to deteriorate quickly. In geothermal environments, fluid flashing can result in an uncontrolled loss of pressure, leading to further complications such as rapid expansion of steam and potential blowouts. Without simulating this scenario, the results of the simulation are somewhat limited in scope. Geothermal wells, particularly those in areas with extreme temperature gradients, would require more advanced techniques to handle such steam flashing events effectively. This underscores the need for additional research and the development of enhanced simulation tools capable of modeling these unique conditions.

Comparison with Field Data:

When comparing the simulation results to actual field data, it becomes clear that while conventional methods may work under certain geothermal conditions, they may fall short in extreme scenarios. Real-world geothermal drilling often encounters higher temperatures than those replicated in this simulation, which means field operations would require additional safety measures and adaptive techniques to mitigate risks effectively. The results also suggest that traditional well control methods must be adapted or supplemented with new techniques to meet the challenges of geothermal environments. In particular, handling steam-related influxes remains a critical area for further research and development.

Conclusions

This thesis demonstrates that the application of advanced simulation tools like DrillScan and DrillSIM50 is critical for optimizing geothermal drilling operations. The study provides detailed insights into how varying WOB and RPM parameters can significantly impact drilling vibrations and ROP. By identifying optimal operational zones, the research offers practical solutions for mitigating drilling vibrations, improving equipment longevity, and enhancing overall drilling efficiency. In addition, conventional well control methods adapted to geothermal drilling were also simulated.

The conclusions of the study include:

- The use of simulation tools in both post-drilling analysis and operational planning is vital for identifying and mitigating drilling challenges.

- The simulations demonstrated that optimal combinations of WOB and RPM can significantly reduce or eliminate stick-slip vibrations. This is crucial in maintaining drilling efficiency, minimizing equipment wear, and improving the overall rate of penetration (ROP), particularly in challenging wellbore sections.
- The DrillSIM50 simulations indicated that operating within the optimal parameter zone not only mitigated torsional vibrations but also led to increased ROP across most sections. The intermediate and production Hole sections showed the most significant improvements, with ROP increasing to 92.53 ft/hr and 40 ft/hr, respectively. In contrast, the surface hole section showed lower-than-expected ROP due to limitations in the simulation model, which did not account for the specific PDC bit used in the field.
- The study confirms that drilling vibrations, particularly torsional stick-slip vibrations, are a major cause of inefficiencies in geothermal drilling. By identifying the optimal WOB and RPM ranges, the study offers solutions for reducing these vibrations, thus extending equipment life and improving ROP.
- The post-drilling simulations identified optimal drilling parameters that could significantly enhance performance and reduce downtime when applied in real-world operations. The results suggest that using these optimized parameters can help reduce vibration-related issues, such as equipment wear and inefficient drilling, thus improving the overall operational efficiency.
- Conventional Well Control Needs Adaptation: While conventional well control techniques can be applied to geothermal drilling, they must be adapted to account for the unique conditions found in geothermal formations. Automated well control systems offer a promising path forward but require further development and testing.

- It also highlighted the unique features of the simulators and elaborated on their mode of training delivery, challenges, and opportunities for future development.

Research Limitations and Future Work include:

- The thesis considers further research into refining simulation tools and adapting well control systems for geothermal drilling. This is to address the limitations of current technologies, particularly in replicating high temperatures and geothermal fluid types, to improve future geothermal operations.
- Simulation Capability Expansion: Future iterations of the DrillSIM50 simulator or other well control simulators should include the ability to model steam flashing and its associated effects on well control. This would allow for a more comprehensive understanding of how to manage geothermal wells in high-temperature environments.

- The study modeling is limited by only one BHA configuration for all sections; a simulator that can simulate all kinds of BHA will enhance the result for the surface, Intermediate, or production (vertical, curved, and tangent)
- Future cloud-based simulators and software base simulators should include collapsible hardware pads and chokes that will enable trainees to touch and operate the choke and the joysticks on a homemade cyber chair as part of the equipment in drilling and well control training.

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NOMENCLATURE

BHA = Bottom Hole Assembly

BTC = Buttress Connection

cp = Centipoise

DOE = Department of Energy

EGS = Enhanced Geothermal Systems

FORGE = Frontier Observatory for Research in Geothermal Energy

fph = Feet Per Hour

ft = Feet

gpm = Gallons Per Minute

H&P = Helmerich and Payne

IC = Intermediate Casing

IRENA = International Renewable Energy Agency

klb = Kilo pounds

lbf = Pound foot

MD = Measured Depth

mD = MilliDarcy

m = Meters

MSE = Mechanical Specific Energy

MWD = Measurement While Drilling

MW = Measured Depth

NPT = Non-Performing Time

NREL = National Renewable Energy Laboratory

OU = University of Oklahoma

PC = Production Casing

ppg = Pounds Per Gallon

ppf = Pounds Per Foot

PDC = Polycrystalline Diamond Cutter

RASF = Rock Abrasion Scale Factor

RASF = Rock Abrasion Scale Factor

Rock Strength Scale Factor = RSSF

Rock Strength = RS

RPM = Revolution Per Minute

ROP = Rate of Penetration

ROV = Remote Operated Vehicle

RS = Rock Strength

RSSF = Rock Strength Scale Factor

SC = Surface Casing

SITLA = School and Institution Trust Land

SSI = Stick-slip Severity Index

TD = Total Depth

tf = Ton Force

TOB = Torque on Bit

TVD = True Vertical Depth

US = United States

WOB = Weight on Bit

Appendix

Unit Conversion Table

Unit	Conversion Factor	Resultant Unit
Kgf.m	7.23	ft-lb
lbs	2.202	tf
m^2	$1x10^{15}$	mD