PROCEEDINGS, 48th Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, February 6-8, 2023
SGP-TR-224

Novel Coiled Tubing Operations in a Hostile Thermo-Chemical Environment

Santiago Rocha[1], D.D. Faulder[1], Louis Capuano III[2], Louis Capuano Jr.[2], Patrick Walsh[1]

[1] Cyrq Energy, [2] Capuano Engineering Company

15 W South Temple, Salt Lake City, UT 84101[1], 2777 Yulupa Ave. No. 604, Santa Rosa, CA 95405[2]

santiago.rocha@cyrqenergy.com[1], dave.faulder@cyrqenergy.com[1], leciii@capuanoengineering.com[2], lcapuano@capuanoengineering.com[2], patrick.walsh@cyrqenergy.com[1]

Keywords: Salton Sea, scale removal, wellbore modeling, coiled tubing, open hole cleanout, hot mud motor, metal mud motor, root cause analysis, workover efficiency, high enthalpy reservoir, Hudson Ranch.

ABSTRACT

The production wells at Hudson Ranch 1 produce a 600°F hypersaline brine from the Salton Sea geothermal reservoir. The produced brine is 25-30 wt% dissolved solids and is highly corrosive with a strong scaling potential. Wellbore scaling has been observed in the casing, at the flash depth, and where secondary fluids enter along the open hole. In the cased interval of the wells, cleaning out the accumulated wellbore scale and debris presents many different challenges due to variations in mechanical properties and configurations of the casing. In the open hole, production interval cleaning challenges are complicated by intervals of hole instability and long open hole intervals necessary to reach the bottom production zones.

Cleanouts using a coiled tubing (CT) unit are less than 20% of the cost of a cleanout using a drilling rig. Past operators have used CT with either a hydroblasting head or a downhole mud motor in either a static or flowing well, but always in the cased hole. Cyrq Energy, working with consultants, has performed groundbreaking cleanouts in the open hole of production and injection wells using all Metal Mud Motors (MMM), a technique here described as Hot Mud Motor (HMM) method, as the tool is run while the well is flowing with hot production brine. This paper discusses historical well cleanouts, root cause failure analysis, and risk assessment performed to achieve more than ten CT cleanouts, some with over three thousand ft. of open hole through a fracture-dominated formation. The risk assessment includes the appropriate selection of CT size, workover technique, Bottom Hole Assembly (BHA), bit sizes, and operational parameters. These successful operations prove the effectiveness of CT and HMM at the Hudson Ranch project with careful planning, significant cost reduction compared to rig cleanouts, a reduction of mechanical risk, and increased operational safety.

1. INTRODUCTION

The Salton Sea field can produce brine at high temperatures (±600°F) and flowing wellhead pressures (>350 psig). However, the three-stage flash process removes steam from the brine, precipitating silicates (Gill and Jacobs, 2011) at the flash depth and upstream this point, before entering the Featherstone power plant which uses a Crystallizer Reactor Clarifier (CRC) process. The precipitation of iron silicates and calcium sulfates when pressure and temperature decrease (McLin and Kovac, 2006), creates a scale buildup on the production casing. This reduces the cross-section flow area for the brine, increasing wellbore frictional effects in the two-phase section of the well, impairing the flow rate, and lowering the producing wellhead pressure. This in turn reduces the separator pressures, and hence, the operating pressure of the plant, resulting in the reduced generation and operating efficiency. Therefore, the wellbores at the Hudson Ranch wellfield need to be cleaned frequently to maintain optimal production and power plant efficiency.

The first cleanout was in 2016, four years after the plant started operations,39 well cleanouts were conducted from 2016 through 2021. These cleanouts used coiled tubing and a variety of tools and methods to remove scale from the wellbores, primarily in the cased section above the flash depth. However, during this time there were three dropped mud motors each requiring a drilling rig to retrieve at a cost over an order of magnitude more than a coiled tubing cleanout. Unfortunately, just prior to Cyrq Energy assuming operations, there was a safety event that transcended economics. Thus, while a tool failure and fishing expedition could quickly overwhelm the economics of using coiled tubing for scale cleanout, safety is paramount in all operations, including wellfield. When Cyrq Energy assumed operations at Hudson Ranch, a root cause analysis was conducted of past coiled tubing operations and failures to develop revised tools, procedures, and protocols to increase safety and minimize operational risk.

2. HUDSON RANCH WELL OPERATIONS

Workover operations are common in the Salton Sea, with most of them performed in the cased section or in the open hole while the well is not flowing. Coil tubing has typically been used only for casing cleanouts with the well shut in, while open-hole cleanouts are typically performed using a full-sized drilling rig with a 20–30-foot substructure to accommodate the large wellhead assembly, requiring several days for mobilization and demobilization, and the well shut-in. The project goals were to develop safer, more effective means to clean the cased and open-hole sections of the wells without shutting in the wells. The reduced well cleanout expenses associated with full-sized rigs can be minimized by using coiled tubing, reducing generation losses, and avoiding thermal cycling of the casing. Attention to the Bottom Hole Assembly (BHA) design and tools are crucial to a safe and successful cleanout.

2.1 Well cleanout history prior to 2022

The Featherstone powerplant at Hudson Ranch started operations in 2012 with three production wells, A, B, and C. Initially the three wells had excessive production for the 60 MW_{gross} powerplant. This excess production capacity decreased for the first four years until the first well cleanout was conducted in 2016. A variety of methods using coiled tubing were tried; hydroblasting, cold mud motors, and all metal mud motors. Due to the mechanical properties of the production casing string, it is desirable to minimize thermal stress cycling. Cold mud motor (CMM) operations require the well to be shut-in and cooled down, while hydroblasting and all metal motor (MMM) or hot mud motor (HMM) allows the well to flow at a reduced rate to remove the dislodged scale and debris to the surface.

During 2016-2021, a total of seventeen in well A, thirteen cleanouts in well B, and nine cleanouts in well C for a total of 39 cleanouts were conducted, all in the cased hole only. The cleanout effectiveness diminished with time while the interval between cleanouts decreased, as different methods and tools were tried to optimally clean the wells. During this time coiled tubing or bottom hole assembly failure resulted in separate three fishing operations that required the mobilization of a drilling rig. **Figure 1** shows the failure in the BHA for two different cleanout operations. Note these are two separate failures have almost identical shear patterns, indicating a systemic design failure. Fishing operations at Hudson Ranch require a full-sized drilling rig due to the large wellhead assemblies, the continual pumping of cool water, and resulting risk of casing thermal cycling, lost generation, and expense. **Table 1** is a summary of equipment and tools used at Hudson Ranch during this time.

Figure 1. On the left: Two separate failures of the Acme Stub thread resulting in fishing operations. On the right: Corrosion on an 8-5/8 in. carbon steel hydroblasting head after approximately six months at 6800 ft from well A.

The extreme corrosivity of the Salton Sea brine at Hudson Ranch is illustrated in **Figure 1** on the right**.** This is an 8-5/8 in. hydroblast head that had been left in well A at 6800 ft for approximately six months, during this fishing operations, several pieces of carbon steel coiled tubing were recovered after ~90 days downhole. Wall thickness measurements of the recovered coiled tubing and time in the well suggest a downhole carbon steel corrosion of ±0.00005 in./day. The downhole conditions for carbon steel are extreme, 600°F, 28wt% brine with a pH~5.1. Thus, among other mechanical considerations, the extreme corrosivity requires additional planning.

The main problem was the decreasing effectiveness of the past cleanouts. Hydroblast tools using coiled tubing were initially used to restore production in the past, but their effectiveness reduced with each cleanout cycle. While underreamers have been used with positive performance when successful, there has been a two-third failure rate. Different alternatives were evaluated from an economic and technical standpoint. **Table 1** shows the different equipment and tools evaluated for this problem, along with a brief description of their capabilities, pricing, and limitations.

Wellbore scale is typically found in the cased hole, mostly above the flash depth which can range from 2000 ft to over 3000 ft depth, depending on the well productivity. Wells A and B typically have harder scale in the upper thousand feet or so where wellbore modeling (GSDS, 2019) indicates annular flow, with liquid flowing on the casing wall and two-phase flow in the center. Scale is also encountered in wells with shallower fluid entries in the open hole. All three production wells encountered high productivity intervals at depth. The increasing geofluid salinity with depth (Oldenburg, Pruess, and Lippmann, 1994) mixing with these shallower fluid increases the scaling potential at and above these shallower fluid entries.

While risk is lower with a full-size drilling rig, the cost is an order of magnitude higher than a CT, and to use a rig cleanout every few months would quickly become cost prohibitive. Thus, alternatives were needed.

Table 1: Summary of equipment and tools used in workover operations at the Hudson Ranch wellfield. Note: costs are approximate and there could be extra costs for personnel, and equipment such as bits, connectors, pumps, etc.

Equipment				
	Pros	Limitations	Risk	Rental Cost (Approx.)
Full-Size Rig	Ability to pull and push more weight. Withstands higher torque with 5 in. drill pipe. Capable of using a variety of tools such as Mud Motors, Hydroblast tools, Jet Nozzles, Underreamers, etc.	Well needs to be killed, leading to thermal cycling, while it requires several weeks to mob, operate, and demob.	Low	$1,200,000-$1,500,000
Coiled Tubing	Can be used while the well is flowing or static. Can use a variety of tools such as Mud Motors, Hydroblast tools, Jet Nozzles, Underreamers, etc. Can pull some weight	Cannot rotate, limited torque tolerance, do not place coiled tubing in compression. Fewer tools available	Medium	$120,000-$200,000
Wireline	Can be used while the well is flowing. Lower cost.	Very limited variety of tools. No ability to push and low pulling capability	High	$40,000-$80,000
Tools				
	Pros	Limitations	Risk	Rental Cost (Approx.)
Hydroblasting tool	Pressure cleaning removing almost to casing ID	Nozzles need to be close to casing ID. Not effective on hard scale	Medium-Low	$5,000-$10,000
Cold Mud Motor	Allows rotation of BHA, effective on hard scale	Well needs to be killed. Limited to minimum casing ID. Potential for adverse thermal cycling of the casing requires continuous circulation to lift scale out of well	Medium-Low	$10,000-$20,000
All Metal Mud Motor	Can be used while the well is flowing. Allows rotation of BHA, effective on hard scale	Limited to minimum casing ID	Medium	$13,000-$26,000
Underreamer	Allows to expand below casing limitations. Effective on hard scale	Can transmit higher torque into the coil	High	$11,000-$22,000

After Cyrq assumed operations, an engineering study was conducted by Blade Engineering to review past operations, procedures, and BHA design, and provide recommendations. Once this study was completed, the recommendations were implemented in early 2022 and the well cleanouts were resumed.

2.2 Unit and BHA selection criteria

The coiled tubing is a continuous spool and can be mobilized and rigged up faster than a conventional drilling rig, allowing for swifter operations, and less lost generation. When evaluating cleanout economics, the generation loss plus the equipment expenses, a full-size rig could be ten times more expensive than the cost of using a coiled tubing unit for single or several days of operations. Furthermore, the CT can use similar tools as a full-size rig, though it still has limitations as the coiled tubing work string cannot be rotated and tensile strengths are much less than that of drill pipe used by a conventional drilling rig.

The CT unit seemed to be the best option, nevertheless, venturing into the open hole entails risks as the well diameter may not be constant, the inclination can go beyond 7° increasing drag, and the tubing axial strength operating guidelines can be approached as more coiled tubing is used for deeper cleanouts. Safety and risk are critical in any operation and to minimize these issues, Cyrq had an engineering study (Blade, 2021) conducted to provide technology, engineering support, and to develop standards, procedures, and protocols for both cased and open-hole cleanouts.

Past tools used for the BHA were evaluated, considering the geometry of the production wells and historical results from previous workover operations. Several were discarded for the following reasons:

1. *Underreamers*: high risk due to the torque transmitted to the coil when it stalls and the high failure of retracting the underreamer arms using this tool, with approximately two-thirds failure rate. It is also important to highlight that according to Blade (2021) "the previous experience using such underreamer tools in 2019 and 2020 seems to be unique in the industry".
2. The *hydroblast tool* initially had positive results on initial cleanouts, however, its effectiveness diminished dramatically as the scale build-up became harder in the production wells.

3. *Cold mud motors* or standard drilling motors were also used in the past and provided positive results, nevertheless, this tool has temperature limitations and requires continuous circulation of cool water during operations risking thermocycling the Inconel casing.

Root cause analysis determined that portions of the BHA were mechanically under-designed for the torsional and axial forces experienced by the work string. The rotational torque experienced by the work string was considered and specific tools and operating procedures were developed to minimize torque due to a mud motor stall-out. The procedures use a metal mud motor to rotate various size bits, using thicker wall tubing, and do not require the well to be killed, reducing casing thermocycling. One ancillary benefit is returning the cleaned well to the plant once the tools are out of the hole, as the coiled tubing equipment is being demobilized.

A study was conducted in 2021 to review historical well cleanouts and the appropriate thickness for coiled tubing. Three sizes were evaluated: 2-3/4 in., 2-5/8 in., and 2-7/8 in. The engineering study recommended the best option is a metal HMM using an HS-90, 2-5/8 in., 3.85 lb/ft coil. The study recommended using the 2-5/8 in. coil as it has greater fatigue resistance up to injection pressures of 4,000 psi with the thicker wall, providing additional strength for shear and axial stresses. The 2-7/8 in. was discarded due to the limited availability of equipment to run this size of coil on the West Coast.

Blade (2021) also recommended a BHA for the desired purposes. Starting from top to bottom, the norm is to use a CT dimple connector, a double flapper check valve, a hydraulic disconnect, and a circulation sub. These tools are common in the oil and gas industry and need to be rated for higher temperatures. On two previous operations, the stabilizers failed (**Figure 1**), causing the loss of the BHA and required fishing. The root cause for this failure was bending fatigue on an Acme thread non-rotating stabilizers used. Blade's recommendation was to use conventional rotating stabilizers instead to ensure stabilization yet provide enough annular area to minimize vibration while the well is flowing. Finally, as the coiled tubing work sting cannot be rotated, all-metal hot mud motors (MMM) or hot mud motors (HMM) were recommended as positive displacement motors can withstand high temperatures (Hunting, 2023) and can work above 600°F. These motors have also been used in previous operations with coiled tubing and were not the cause of the previous failures.

2.3 Pre-job, job procedure, and operational parameters

Pre-job planning and preparation are key to a safe and successful well cleanout specific program and well evaluation is prepared before, during, and after a well cleanout. Standard procedures were developed for cleanout operations. Modifications and changes can be made specific to each well's mechanical configuration and well behavior.

The hostile environment requires proper storage of the units, coil, tools, and equipment. It was recommended to visually inspect the complete string of coil before and after each cleanout to spot possible damage. A complete record of the coil's maintenance, fatigue, and wall thickness measured is maintained. Coil tubing fatigue software is used to monitor the coil usage, time in the well, and other parameters to predict likely coil life and specific intervals to watch. This is used to predict possible plastic deformation that the coil suffers with repeated bending over the spool and the gooseneck. Coil life is reduced by changing tensile and yield strength with use, diameter growth, wall thinning, corrosion, loss of wall thickness, collapse resistance, and elongation. Coiled tubing is a consumable, not a capital expense.

Once the pre-job recommendations are followed, a job procedure is prepared with minimum and maximum operating parameters, and identification of past intervals of concern (flash depth, casing condition, shallow fluid entries, past tight spots, etc.). Procedures were developed for stall-outs to minimize torque being transmitted up the work string during a HMM.

After rigging up, pressure testing, pull testing the dimple connector to 30K lbf, zeroing out the depth to kelly bushing (KB) and the weight indicator, it is recommended to open the valve to allow fluid to flow through the warmup line and to the Atmospheric Flow Tank (AFT) - which is a metal tank that allows the produced steam to be vented out while bypassing the plant process the remaining fluid and solids are then sent to the brine pond. Previous experiences have shown that not flowing the well can cause scale and debris to accumulate at the wellhead, creating a blockage, preventing the BHA and coiled tubing from entering the wellhead assembly, and potentially pushing debris downhole plugging and killing the well.

Once past the wellhead, the maximum speed should not exceed 50 ft./min at any time, 15 ft./min within 100 ft. of a known restriction, and 5 ft./min within a known restriction. This reduces the likelihood of putting excessive weight (compression) on the working string if hard scale or other issues are encountered, decreasing the buckling potential. Pull tests are performed every 500-1000 ft. for at least 25 ft. to check that the string weight does not exceed operational limits (excessive drag). These tests should not be done at exact 500 ft. increments to avoid fatigue on the same spots on the coil. Near entering the open hole, a pull test is performed for comparison when pulling out of the hole. If the motor stalls, the flow rate should be reduced to 50% of the original flow rate prior to picking up the string to slowly release the accumulated torque, then pick up slowly until normal weight is observed. Then bring back the flow rate to the prior conditions prior to the stall-out and continue slowly into the hole. When TD is reached, it is recommended to run out of the hole at a maximum speed of 30 ft./min, reducing the speed by 50% while approaching known restrictions in the well. It is imperative to record all the stall locations, or restrictions detected during the operations for future cleanout planning to minimize risk and compression of the coil tubing and BHA.

3. PROCEDURE IMPLEMENTATION

Production well A at Hudson Ranch experienced a productivity decrease of nearly 50%. Two tools have been dropped and fishing operations were conducted and yet, productivity was not restored. While most of the fish had been retrieved from the well any remaining carbon steel material would be corroded away due to the extreme thermo-corrosivity of the brine. This well encountered a high-angle feature at depth with approximately ten feet of little to no weight on bit (WOB) during drilling. The hanging wall has poor formation integrity and instability as past fishing operations encountered bridges and two to five feet of fill while fishing across this feature.

As well A is the largest production well, it was crucial to recover the well productivity to maximize power generation. The main problems in the past were hard scale in the shallow portion of the casing and rubble/debris at the main production zone at depth. As this was a new procedure, tools, and BHA, it was important to proceed in measured steps to fine-tune procedures, train crews, implement improved safety protocols, gain experience, refine tool and bit selection, and evaluate risks.

3.1 Hot Mud Motor Field Operations

Once risks were evaluated and mitigated, and the planning was carefully reviewed, well specific procedures were prepared before cleanouts were restarted. The next section presents examples from more than ten cased and open hole cleanouts in the production wells and one injection cleanout where the CT operation that previously was performed by a drilling rig.

3.1.1 Cased hole cleanouts

Thus, the first set of well cleanouts were only in the cased hole sections; it was only after four cased hole cleanouts that it was decided to attempt an open hole cleanout. As safety and risk mitigation were primary operational considerations, it was decided to not attempt a HMM to total depth, but instead approach the problem in small bites, increasing with experience and confidence in procedures, tools, equipment, and crews. This approach yielded almost immediate benefits, as the first few entries into the cased hole, equipment incidents occurred, requiring a pause in operations until resolved. Most of these issues occurred due to the hostile nature of the brine produced while the crew and the equipment were getting familiar with the environment and procedures. Once the personnel was familiar with the equipment and procedures, the open hole cleanouts started with initial targets of 500 to 1000 ft. into the open hole.

3.1.2 Initial 500 to 1,000 ft. of open hole cleanouts

The initial cleanouts performed were planned to go only to 500 to 1000 ft. of open hole in wells B and C (the smaller wells) to gain experience and refine the cleanouts procedures in a lower flow rate environment. The initial cleanouts were performed at rates as low as 5 ft/min. while progressing in the open hole, as tight spots in the open hole from secondary fluid entries sections were anticipated from wellbore simulator studies. Thus, confidence and experience were gained, risk was reduced, and the management and personnel running the equipment felt confident venturing into the open hole.

Wellbore modeling calibrated with recent pressure/temperature logs, suggested that well B's flash depth was about 300 ft. below the casing shoe; this interval had encountered scale during the initial open hole runs. While the circulating pressure (shown in **Figure 2**) of the motor increased while working through this scale ring at 3267 ft., the HMM was able to successfully remove the obstruction and increase production by 45%. The same spot has been encountered in the well multiple times, validating the wellbore model, diminishing the risk by knowing the approximate depth to anticipate a scale ring and lowering speeds when approaching, and making other operational adjustments.

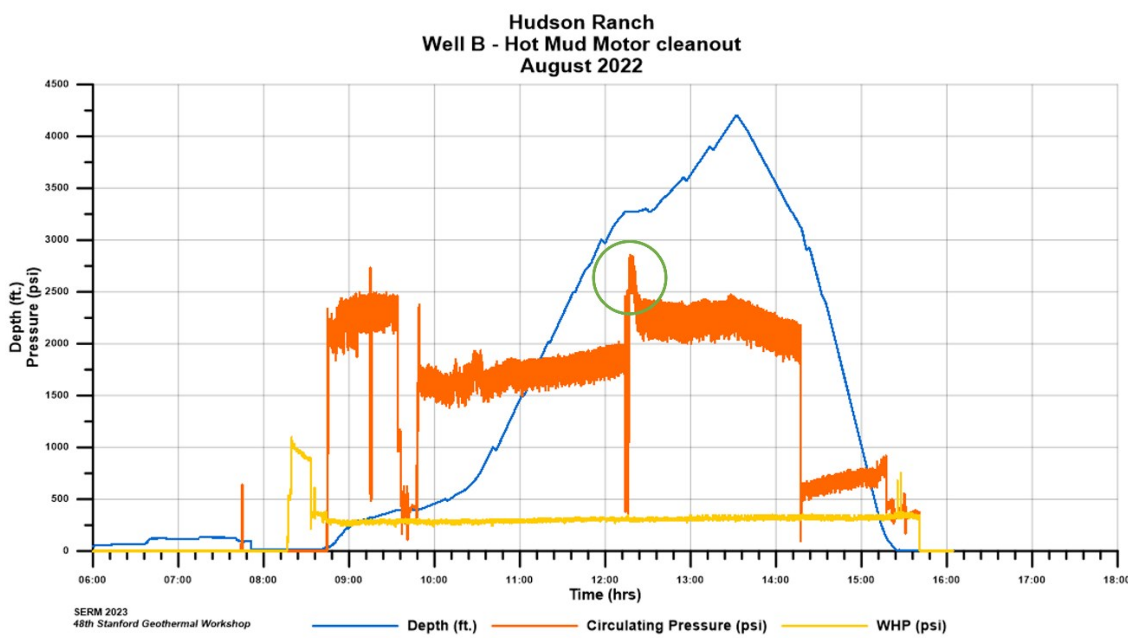

Figure 2: Open hole cleanout in well B where obstruction was found at 3,267 ft., the flash depth.

3.1.3 1,000 ft.+ of open hole cleanouts

After initial cleanouts reaching 500 to 1,000 ft. into the open hole, the recommended procedures proved effective in mitigating the risks. Well A was the strongest producer and is nearly 6,900 ft. deep. Therefore, the decision was made to remove the obstruction at depth. This required reaching over 3,000 ft. into the open hole, with increased risks; added string weight, more time coil spends in a hostile thermo-chemical environment, no ability to rotate the coiled tubing work string, and increasing the potential torque transferred to the coil if encountering an unanticipated obstruction. Three workover operations (four complete runs) were performed to reach the target depth and achieve cleanout objectives.

The first run targeted a depth of 6,805 ft. using a 9-5/8 in. bit, having a 1-5/16 in. drift in the 12-1/4 in. open hole. The target depth was successfully reached and cleaned, and an obstruction (mostly debris and fill) was identified from 6,775 ft. to the target depth. A second pass was planned to remove scale from the formation to depth; however, the unit was not able to reach the same depth as operational constraints to minimize buckling had been reached for the CT injector head. The decision was made to pull out of the hole to check equipment, consider the downhole conditions encountered, and evaluate operational options. Scale may have been dislodged from the throat of the feed zone, allowing for increased flow, and preventing the bit from returning to the same depth as before. While pulling out off the bottom, the CT unit experienced overpulls of nearly 30,000 lbf until it was almost at the casing shoe. This indicated debris was packed off around the BHA as the weight normalized as the well mechanical configuration changed near the casing shoe. After four hours of tripping out of the hole, the BHA was on the surface. The well flow increased by 23% and the flowing WHP increased by 22%, which was equivalent to nearly 4 MW of generation recovery.

The second workover in well A consisted of three runs. The first run was to the casing shoe at 3,800 ft. using an 11-5/8 in. bit, followed by a second run to 6,810 ft. using a 9-5/8 in. bit, which was intended to initially clean the obstruction at depth and leave a smaller drift for a third run to the same depth using a 10-3/4 in. bit. The first run in the casing experienced no problems. The second run was like the one performed in the previous workover, reaching an additional five ft. depth. The same obstruction was encountered from 6,775 ft. to 6,810 ft. Although the coil was able to reach the target depth, an overpull of around 40,000 lbf, 10,000 lbf greater than in previous operations. As before, the weight normalized as the casing shoe was reached when pulling out of the well. The third run used a 10-3/4 in. bit to reduce the risk observed in the previous run with the high weights with the smaller bit diameter. The same obstruction was encountered from 6,775 ft. to the target depth. Multiple passes were performed through this zone with drag but without incident. While pulling out of the hole, an overpull was observed of 30,000 lbf, the same weight felt in the previous run performed to 6,805 ft. The tools reached the surface with no major issues, and the well flow increased 25% and 11% increase in WHP, which was equivalent to nearly 4 MW recovery in generation.

After well A's productivity decreased again, a similar procedure was used. It was proposed to do a single 10-3/4 in. bit run to 6,795 ft, a 10 ft. reduction to minimize overpull experienced in the previous operations. No obstructions were encountered to 6,700 ft. where cleaning was started in increments of 20 ft. and weight checks were performed. This iteration was repeated to the target depth of 6,795 ft., where there were minimal changes in the circulating pressure, weight, and injector speeds. The bit was pulled out of the hole to 6,300 ft. with weight checks performed, with only 8,000 lbf of overpull, compared to the 40,000 lbf and 30,000 lbf experienced in the previous two CT workover operations. After the weight check, the hole was cleaned again to 6,795 ft. the target depth and the tools were pulled out of the hole. The same 8,000 lbf of overpull was experienced until the casing shoe depth, where weights returned to operation string weight. The 10 ft. of targeted depth made a difference of nearly 32,000 lbf of weight as shown in **Figure 3** and **Figure 4**. After returning well A back to the plant, the production increased 45% and the WHP increased 20% compared to prior to the cleanout. As experience was gained and the procedure was refined, the cost of the third cleanout was one-third less than the second cleanout. This job confirmed the design requirements to clean out well A, minimizing risk and reducing costs. The drag experienced when pulling out for the three cleanouts tends to validate poor formation integrity and instability of the fault hanging wall at the major production zone. Targeting 10 ft. shallower cleanout depth reduced the overpull, as possibly less debris was catching in the BHA above the bit while cleaning this deep feature, the production was restored to about the same after each cleanout, reducing risk.

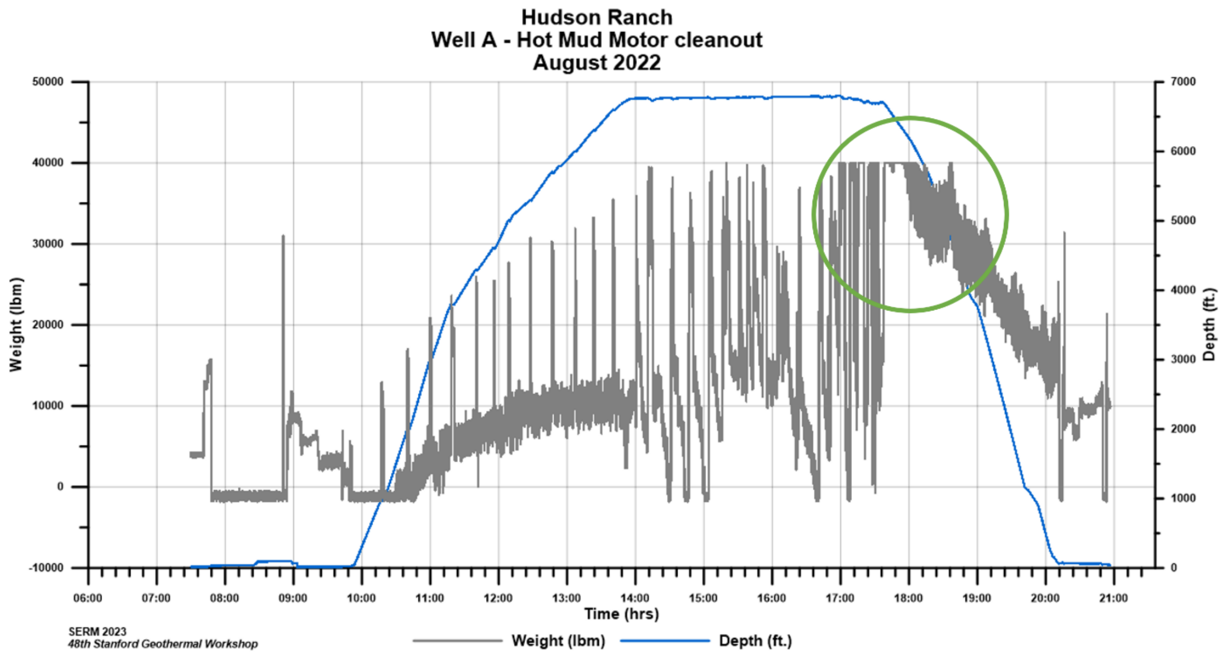

Figure 3. Second workover on well A to 6805 ft. TD *The maximum weight that the digital gauge is 40,000 lbf, the manual gauge has a maximum of 80,000 lbf of weight.

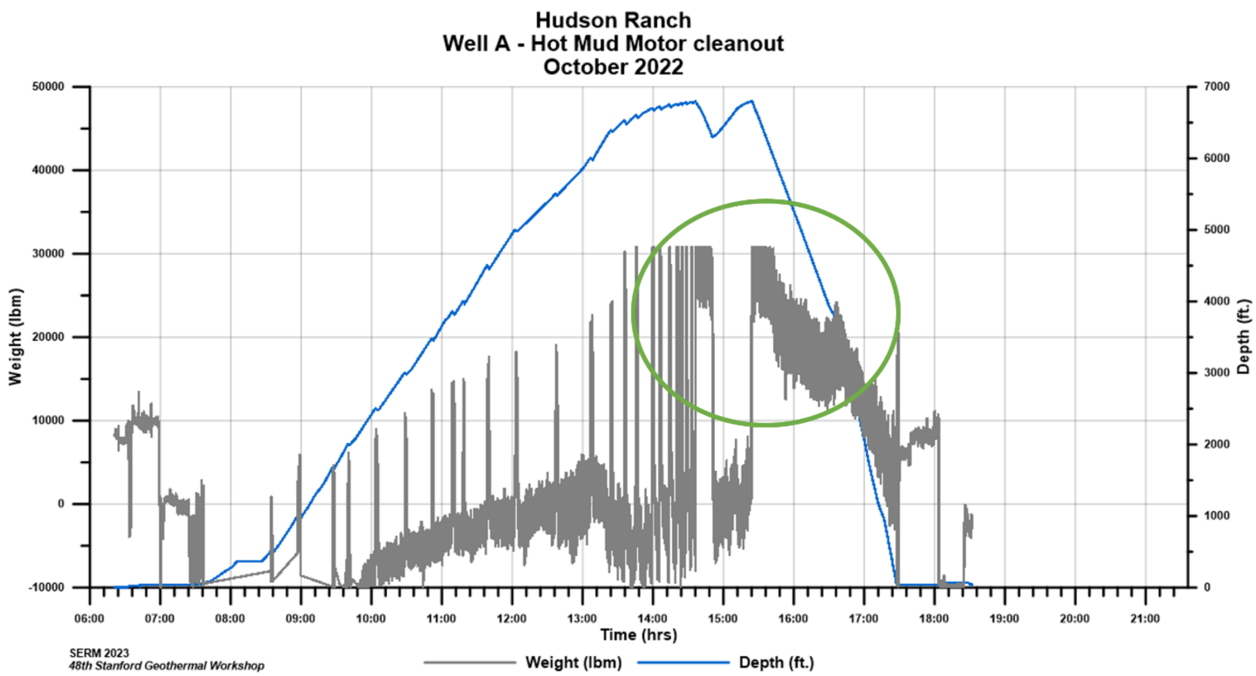

Figure 4. Third workover on well A to 6795 ft. TD. The maximum weight that the digital gauge can read its 40,000 lbf, the manual gauge can read to a maximum of 38,000 lbf of weight. Note: the reduction in weight or drag (green circle) compared to Figure 3.

3.1.4 Injection well workover – nitrogen cleanout

The procedures and experience described in the previous section to remove scale in production wells were used to clean injection well D which had a dramatic reduction in injectivity, resulting in the well no longer receiving any flow. Typically, a drilling rig would have been used for cleanout, as the problem was identified at the bottom, 4,092 ft. or 1,392 ft. of open hole. It was uncertain whether the decrease in injection was caused by damage to the wellbore or debris at the bottom of the well. A high-strength acid treatment was considered but discarded due to potential casing damage and the uncertainty of whether it would be effective. The plan was to proceed slowly as before to identify any obstructions in the well with the CT, building on the confidence gained from previous open hole cleanouts in the production wells. Well D had a smaller diameter than the production wells and the well was static during cleanout operations. Four runs were necessary to complete this work. During the first run, debris was identified near the bottom as the bit was unable to go beyond 3,795 ft, leaving 297 ft. remaining in the hole. As this was an injection well, the only way to remove the debris and scale from downhole was to lift it out, so nitrogen was used on the last three runs to purge the well. The first run with nitrogen was able to remove debris, but there was still weight felt with more debris remaining. The second run with nitrogen was able to remove the additional debris until the baker tanks used became full and the vacuum trucks were unable to keep up as the well started to clean up. Overnight, the well was placed on injection but did not show sufficient improvement in injectivity, so another cleanout was made. The final run with nitrogen reached 4,051 ft. (41 ft. of debris remaining) and the bit was able to pass this point with minimal resistance as nitrogen was pumped. The fluid on the surface had solids and the volume removed again exceeded the wellbore volume capacity, indicating fluid from the formation was also being lifted with nitrogen. After the CT unit was removed from the hole and returned to injection on a vacuum. After six months of injection, the well is still under vacuum. The successful operation restored an injection well while costing less than a quarter of a rig operation.

4. DISCUSSION

As when this paper was written, eleven successful consecutive HMM cleanouts have been performed at the Hudson Ranch wellfield. Using a simple binomial calculation would suggest an incident rate of less than 8%, a marked improvement compared to the operations prior to 2022. Eight of the eleven cleanouts have gone more than 1000 ft. into the open hole and the remaining three operations have gone 500 ft. No major incidents were recorded, and operational targets were met. Five of the runs were in well A, located 3000 ft. in the open hole with temperatures of 600°F. While the initial operations did show overpulls higher than normal, later cleanouts procedures were changed to reduce drag while pulling out of the hole. Cleanout costs have been reduced by a third from the first cleanouts as the operating experience was gained and progress through the learning curve. These cleanouts have successfully cleared obstructions and scale in the open hole with no major incidents, resulting in improved production by 45% and generation recovery of 4 MW. One of the cleanouts was performed on a plugged injection well where, in combination with nitrogen lifting, the injectivity was restored with the well receiving brine under vacuum, performing an operation that was initially planned with a workover or full-size rig. While an injection well cleanout does not directly lead to increased generation, it does reduce parasitic power consumption, improving plant economics. The new coil tubing procedures have resulted in significant savings of more than 80% compared to a full-size rig, while also saving nearly the same amount of money by avoiding lost generation while cleaning the well.

The value of careful planning, engineering design, written protocols, and standards before performing cannot be overestimated. Implementation of these standards has increased operational safety, reduced risk, restored generation, and improved operating economics in a hostile thermo-chemical environment. This process confirms the adage, *'no one plans to fail, they fail to plan'*.

5. CONCLUSIONS

The historical experience using CT at Hudson Ranch was reviewed by outside consultants who conducted a root cause analysis of past coiled tubing well cleanout operations. This engineering study recommended specific tools, BHA design, procedures, operating guidelines, and protocols. These recommendations were implemented in early 2022, with the first HMM cleanouts only venturing into the cased hole. The cautious approach to the problem in small bites, resulted in increasing experience and confidence in the procedures, tools, equipment, and crews training. Once sufficient confidence was gained, open hole operations were started first in wells B and C, the smaller wells to minimize not only well cleanout risk but also the risk of losing a large well and adversely impacting generation.

Eleven open hole cleanouts of more than 500 ft. have been conducted successfully with no incidents by properly choosing a 2-5/8" coil, with Hot Mud Motors or All Metal Motors with conventional rotating stabilizers with careful drill bit size selection and a redesigned BHA for improved torsional and fatigue resistance. An example from an injection was presented in which injectivity was restored CT with nitrogen to lift the debris/fill that was found at depth. The well changed from nearly zero injectivity to being under vacuum.

Incidents have been minimized due to careful attention to pre-job, job procedures, and operational parameters such as reduced speeds at known restrictions, weight checks at certain depths, and stall-out procedures. Each new workover learned more about the complex thermo-chemical brine produced in the Salton Sea with wellfield problems such as flash zones and hard scale in annular flow regimes that correlate with wellbore models, collapsing formations, well casing mechanical considerations, reoccurring cleanouts, and additional operating costs. The implementation of the engineering study recommendations has reduced cleanout costs, increased safety, restored generations, and reduced cleanout risk in a hostile thermo-chemical environment.

ACKNOWLEDGMENTS

Special thanks to Claude "Buddy" Burke, Roger Almond, Nolen Abernathy, and all the C&J and Hudson Ranch personnel involved in this operation that has restored wellfield production while always keeping a safe work and environment. The authors would also like to thank the management at Cyrq Energy for the opportunity to present this paper.

REFERENCES

Blade Energy Partners.: Job Procedure: Coiled Tubing Scale Removal Operations in Geothermal Production Wells. Internal report for Cyrq Energy dated 27 Oct 2021, (2021), 29 pages plus attachments.

Blade Energy Partners.: Hudson Ranch Power, Review of Scale Milling with CT. Internal report for Cyrq Energy dated 17 Sep 2021, (2021), 37 pages.

Fournier R. O.: Double-Diffusive Convection in Geothermal Systems: The Salton Sea, Californica, Geothermal System as a Likely Candidate, Geothermics, Vol. 19, no.6 (1990), 481-496.

Geothermal Science & Data Solutions: 2019, WellSim, Version 4.15.11.16, http:/wwe.dsds.co.nz.

Gill J. S., and Jacobs, G. T.: Development of New Silica Inhibitor - Laboratory and Field Study, Geothermal Resources Council Transactions, Vol. 35 (2011), 1243-1247.

Hunting Intl.: WellDrill™ & WellDrill™ XTR Downhole Motor. Web Page Accessed 15 Jan 2023. http://www.hunting-intl.com/media/2309489/WI.TT.MOT-PF-WellDrill_XTR_Downhole_Motor-03.pdf, (2023).

McLin, K. S., Kovac, K. M., Moore, J. N., Kaspereit, D., Berard, B., T. Xu, McLin, R. H., Hulen, J. B.: Modeling the Geochemical Effects of Injection at Salton Sea Geothermal Field, California: Comparison with Field Observations, Geothermal Resources Council Transactions, Vol. 30 (2006), 507-512.

Oldenburg, C. M., Pruess, K., and Lippmann, M.: 1994, Double-diffusive convection in liquid-dominated geothermal systems with high-salinity brines, Proc. 19th Workshop on Geothermal Reservoir Engineering, Stanford University, January 18–22, 1994, p. 209–216.