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Improved Drilling Performance and Economics Using Hybrid Coiled Tubing Unit on the Chittim Ranch, West Texas

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Abstract

A significant performance and cost improvement was achieved with the application of hybrid Coiled Tubing (CT) drilling equipment and techniques on the Chittim Ranch in Maverick county Texas. During this drilling program, 233 wells were grass-root drilled using the hybrid CT unit. Coiled tubing drilling equipment and techniques reduced the average time to complete a well by 60% when compared to conventional rotary rig drilling. This increase in drilling performance coupled with a turnkey contract resulted in a 14% (33% adjusted for inflation) cost reduction per well when compared to the most recent conventional drilling data from this area.

This paper will review the process used in choosing a CT solution, the hurdles overcome, the problems encountered, and the lessons learned in managing and operating this CT Drilling (CTD) campaign. The paper will also provide an overview of CT coring performed in one of the wells during the CTD campaign.

The drilling performance increase was realized using a top-set rig to set surface casing and a hybrid “Big Wheel” CT rig to drill the production hole. Finalized project data demonstrated that field performance using CTD met and in some areas exceeded project goals.

Introduction

The Chittim lease or Sacatosa field is located in Maverick County, Texas near the Zavala and Dimmit County lines and lies 19 miles east of Eagle Pass, Texas (**Fig.1**). Production in the field has been mainly limited to the San Miguel-1 reservoir which was discovered in December, 1956. Since 1956, there have been approximately 1,573 wells drilled; 896 producers, 653 injectors and 24 service wells. The lease is presently developed on 10-acre spacing utilizing 20 acre 5-spot waterflood patterns (**Fig.2**). Waterflooding under this method began in 1966 and was subsequently followed by major field wide waterflood expansions in 1970, 1975 and 1983. Current San Miguel-1 production occurs on 13,000 of the 30,000 acres held. 716 production, 383 injection and 20 service wells are currently in operation.



Figure 1: Location of Chittim Ranch Field, West Texas.

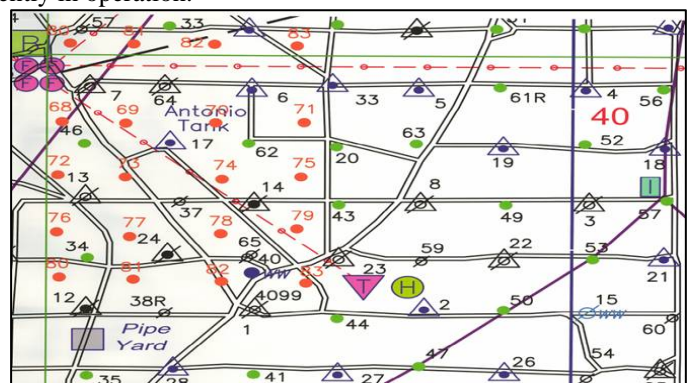


Figure 2: Roads and wells in a 1/4 section of the Chittim Ranch Field.

The Sacatosa field is located on the crest of the Chittim anticline, a prominent structural element in the Northern Maverick basin. This Northeast verging fold plunges to the Southeast at 1 to 2 degrees. The depth of the San Miguel-1 throughout the productive limit of the lease ranges from 1,135 feet to 1,768 feet. The San Miguel formation is sandstone encased by Marine shelf and coastal-plain mudrocks. The original permeability of these rocks was drastically reduced by diagenetic alteration, so the use of hydraulic fracturing is always required.

During a replacement drilling program in 2006, a modern open hole logging suite identified multiple compartments to the San Miguel-1 reservoir. Subsequent logging and tests confirmed the existence of independent flow units within the reservoir. These flow units are identified from youngest to oldest as zones A, B, C, and D. Each “Flow Unit” is sealed by calcite-cemented sandstone having essentially zero permeability that ranges in thickness from one to five feet (**Fig.3**).

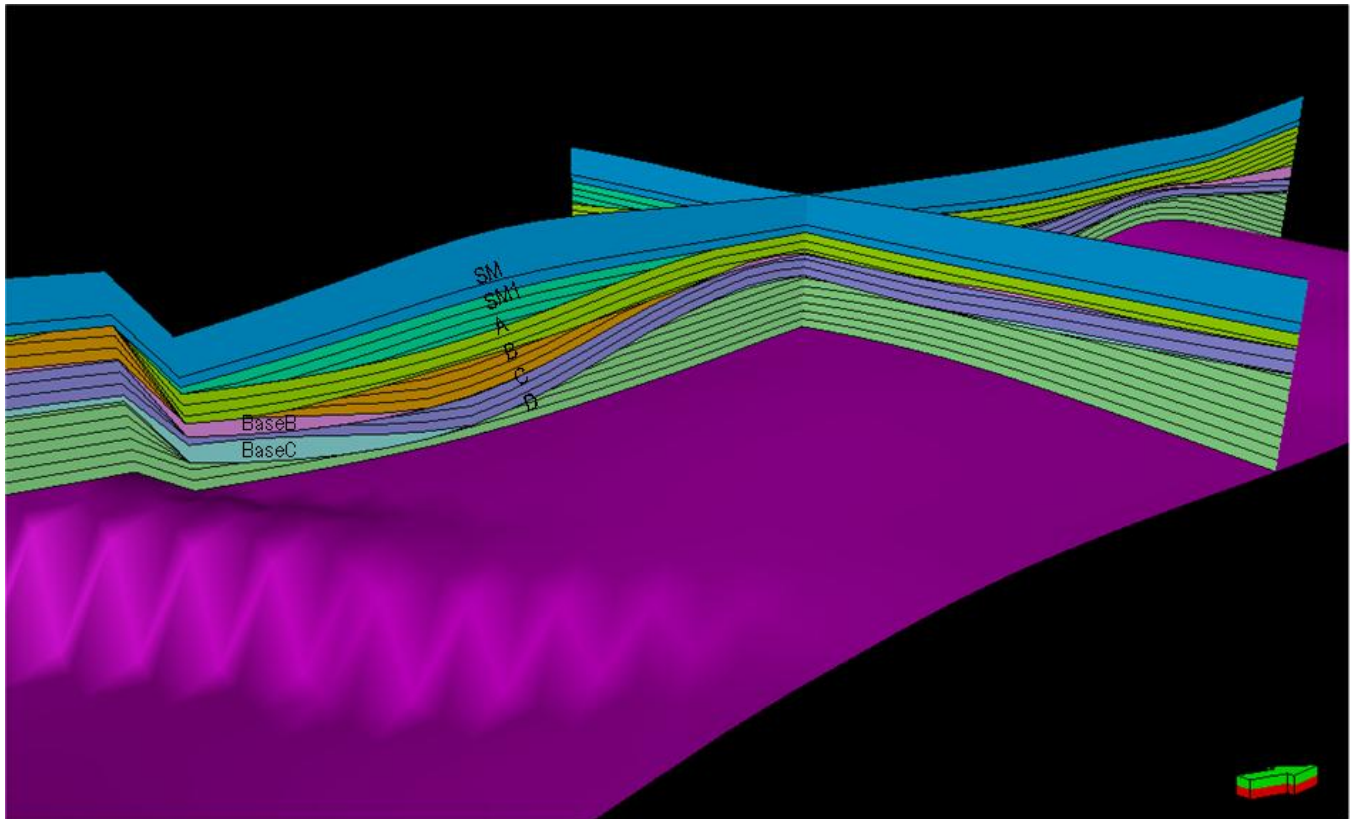


Figure 3: Complex compartmentalized flow units identified and modeled late in Chittim field history. This improved understanding of the old reservoir was a driver in redevelopment and additional infill drilling.

Recompletions in 2007 were performed on wells with low production (less than 2 BBLs/day). These wells were re-perforated in individual flow units and frac'd. Increases in production were greater than ten fold. Based on these results, a 5-acre down spacing program was designed for 2008 and is the basis for this paper. The fracturing program and infrastructure connection work that followed the new drilling, casing, and cementing activity, are not covered in this paper.

Chittim Redevelopment Drilling Project Goals

Recent studies and field models suggest there are more recoverable reserves than previously projected. The 2006 discovery of multiple flow units within the reservoir along with the ability to fracture the flow units individually lead to the 2008 5-acre down spacing drilling project. The project was designed for drilling 300 wells per year for 5 years. The goals for this project were defined as reduce the cost per well, drilling time, vendor count and HSE exposure.

Reduce Finding Development Costs; Accommodate a High Volume Program

To sustain a long term drilling program in low production rate wells, it was essential to decrease the cost per well. Historically, wells conventionally drilled required greater than 3 days total time per well. To be able to drill 300 wells per year would require at least 3 conventional rigs. This was unacceptable from an economics and operations standpoint. At the time there was not enough manpower to handle this amount of activity. There were also concerns raised regarding rig availability. To address the goals of reducing cost and drill time, a step change in operations had to occur. The plan looking forward was to develop a system that would allow for one rig to drill one well per day.

Minimizing HSE Risk

Another driver for the application of a one rig system was the concern for safety. If multiple rigs were used, this would actually increase the risk for the project. This was not acceptable and further leveraged the idea for a one rig system. To aid in decreasing the HSE exposure for the project, a contract was sought to include multiple services provided by the same contractor. The idea was to decrease the number of third party personnel at the wellsite.

Step Out Evaluation: Core

During the 2008 drilling program the asset team required a core to be cut in the Northwest portion of the field. This is an area of the lease that has not been previously down spaced. The project team needed a core to test the formation for waterflood and horizontal drilling opportunities. Based on the results of the team's research, CT coring was considered to be a viable option. The process used to cut a core with CT was found to be very similar to cutting cores traditionally with the exception of the core barrel being rotated by a mud motor.

Rig Selection Process

Eight operational and contracting strategies were considered over a six month period for the Chittim program. These included:

- company operated day work
- managed services day work
- bundled services day work
- footage program
- coiled tubing day work
- coiled tubing turnkey

Past drilling programs involved hiring a local day work contractor with the operator directing all aspects of the procedure. Two contractors were considered for day work with a high likelihood of some marginal performance improvements. This cost strategy would not meet the aggressive cost criteria of the current large scale development. Managed service contract strategies included a combination of rig operations with some completion and pumping services but these services were not in the contractor's core expertise. The footage rig contract strategy showed a lot of promise as far as fast drilling, but did not reduce the level of safety exposure and cost due to the number of additional service companies required. One of the CT rigs was available on a day work basis but the incentive for high performance drilling was not there. The turnkey contract strategy for the CT rig exceeded all criteria when compared to the other contract strategies. The one contractor was able to pre-set surface casing, drill the well, run and cement casing, all with a minimal number of personnel. The rig mobilization terms were also considered in the cost analysis.

In addition to the contract terms analysis, a performance drilling prediction was also performed. The turnkey CT contractor was the only one with a tried-and-proven track record of drilling these types of wells in less than 24 hours. The other CT rig and the footage contractor could likely drill one well in 48 hours but all others were in the 3 day range. Both coiled tubing operations required pre-setting of surface casing so that guaranteed a performance advantage. Only three of the contractors were capable of running casing and just two were capable of providing their own cementing services. It was apparent that the turnkey contract with a drilling contractor who could supply the most supplemental services would have the highest likelihood of drilling safe, fast, and cost effectively.

Turnkey CT Option Discussion

The coiled tubing turnkey options met or exceeded the majority of the aforementioned goal specifications. One of the turnkey contractors proposed providing several support services. These included water hauling, casing running, and cementing. This type of turnkey operation significantly reduced safety risk exposure by reducing the number and variety of service personnel on location.

If the coil tubing turnkey operation performed as expected, then one rig should be able to drill 300 wells per year. The alternative was a minimum of 3 conventional rig operations expected to meet the same program goals. If the coil tubing operation performed as expected, then production volumes would be accelerated by 3-6 months.

Coil tubing drilling is a proven technology in other areas such as Canada and Alaska. The turnkey contract provided the contractor with motivation for continual performance improvement. For the operator, capitalizing on the contractor's experience was preferable to a gradual and expensive learning curve on a day work contract basis.

One commercial risk was that if the initial drilling campaign was completed as expected in the 2008 program and the rig was released, was that the rig may not have been available for the following year. This justified a case for continuous operations without a delay for the next year's budget cycle.

CT Rig Comparison

Two pre-award rig visits were made to evaluate coil tubing rigs offered by Rig 1 and Rig 2. Both coil tubing rigs appeared to be capable of meeting operator's rig requirements for pumps, pits, BOPs, etc. They were similar in rig capacities and ratings. Both rigs are capable of drilling 3000' wells with their 2-7/8" coil tubing. Neither Rig 1 nor Rig 2 had a recordable accident in the previous 2 years.

One difference noted by the inspection team was the experienced and engaged personnel for Rig 1. This not only included the rig hands, but the dedication of contractor's management.

Items	Rig 1	Rig 2
Coiled tubing capacity	3500' 2-7/8"	4300' 2-7/8"
Pump Capacities	350 gpm	400 gpm
Blocks/Elevators	Yes	Yes
Mud capacity	200 bbl	315 bbl
Trip tank	None	20 bbl
Pipe racks	Yes	Yes
Shaker	Yes	Yes
Degasser	No	Yes
BOP 7-1/16 3000 psi	Annular + more if requested	Annular + Dual Ram
Choke manifold	2" 3000 psi	2X3X2 3000 psi
Generator	212 KW	1225 KW
Drill collars	6- 4 3/4"	8- 4 3/4"
Survey equipment	Memory	MWD telemetry
Pason system	Yes	Yes
Pre-set surface	Rig contractor	3 rd party
Rig crews	US	Canada
Casing crew	Not Needed	3 rd party
Cement service	Yes	3 rd party
Water truck	Included	No
Backhoe	included	3 rd Party
Forklift	Included	No
Trucks for rig moves	Included	3 rd Party
Max Load height	15" 6"	16'
Rig move loads	5	7
Trailer mounted skids	Yes	All but 1 load is skid mounted
Field moves, est. time	3 hrs	3 hrs
TRIR rig	0.00	0.00
Eye wash	Station	Bottle
Shower	No	No
Fire extinguishers	Current inspection	Current inspection
Job Safety Analysis	Yes	Yes
Behavior Based Safety	In development	Yes
Lock out/Tag out program	Yes	Yes
Permit system	Yes	Yes

Table 1: Comparison of two Hybrid CT rig proposals to perform Chittim infill drilling program.

CTD rig 1 was chosen by the evaluation team based on the matrix in **Table 1** and the pre-award rig visits. This CTD rig used a "Big Wheel" injector as shown in **Figure 4**. Unlike some "Big Wheel" units with the wheel mounted in the mast, the CT injector wheel could be raised or lowered in a matter of minutes to allow access for the draw works to handle conventional Bottom Hole Assembly (BHA) equipment, jointed drill pipe, tubing, and casing as shown in **Figure 5**.

Similar equipment was known to have been used for similar CTD applications in Argentina¹, California, and Canada, which increased the team's acceptance of this CT equipment for this shallow drilling project.



Figure 4: “Big Wheel” CTD rig on location in Chittim Ranch.



Figure 5: Injector Wheel laid down for BHA & jointed pipe handling.

“Factory Drilling” Challenges

The 2008 drilling program was based upon 16 wells per quarter section to establish a 5-acre pattern. The 16 wells would be staked and roads would then be constructed. Due to the 14’ width of the rig’s trailers, new roads were constructed in each quarter section. Each section was developed with two right-of-ways and two new roads entering each section from existing lease roads. As a cost savings measure the new roads were built in the same corridor as the right of ways. Turn outs from the roads were cleared to each stake, and the pads were constructed.

Pad construction was very basic. A 220’ x 175’ section of land was cleared and then the pad was rolled. Since the rig could be leveled hydraulically, little time and effort was needed to construct a level drill site. Once all 16 pads were constructed, line and dirt crews would install the electrical infrastructure and bury flow lines to the edge of the pad. After electrical and dirt work was completed, the surface top-set rig would move in set, and cement surface casing.

Once the top-set rig had completed that ¼ section, the CTD rig would move in and drill the production hole and set production casing. The production casing was then cemented and the wellbore displaced with produced water. Rig crews would install a 5K frac valve on the wellhead once the CTD unit was rigged down. Each well was cased hole and cement bond logged two days after it was drilled. Three to five days later the well was perforated. Once the CTD rig moved out of the quarter section, frac crews would move in and hydraulically stimulate one well per day.

During the planning phase for this fast paced operation, some key concerns were identified and planned for. One such issue was the large amount of casing that needed to be handled. To solve this issue, the procurement group contracted an offsite pipe yard to receive, tally, inspect and distribute casing directly from the mill. This yard was less than 20 miles from the ranch. Logistics were arranged for surface casing to be delivered once all pads were constructed. Once all surface pipe was set, production casing was ordered and staged on all locations before the CTD rig entered the section.

Efficiently managing inventory and logistics for casing hardware was the next challenge. To maintain proper inventory of this equipment, the float equipment and centralizers were packaged and shrink-wrapped on individual pallets, and delivered to location. These pallets were ordered out before the quarter section was complete and stored in shipping containers inside Chittim’s pipe yard. Once pad construction was complete, service crews would deliver the pallets to each wellsite. This proved to be very effective in managing inventory and invoices for each individual well.

One of the more costly issues was the lack of freshwater supply on the lease for cementing. To address this, water was trucked from 20 miles away and stored in a frac tank in the lease’s pipe yard and resupplied on a continuous basis.

The next obstacle was the drilling fluid. There is a salt water bearing zone above the reservoir called the Olmos. Olmos water is used in the field as injection water and was readily available on the lease. This proved to be a very cost efficient source for drill water.

Since the field has been water flooded for the last 33 years, another challenge was the potential for water flows due to above normal pressure gradient. To address the potential for water flow, the plan was to use heavy weight mud to kill the well. Unfortunately, the rig selected for this program did not have adequate mud mixing capabilities. As an example, it could take up to 18 hours to raise mud weight up from 9 ppg to 15 ppg. The solution for this problem was to have an outside vendor store and maintain a 15 ppg mud in the pipe yard. Once it was determined that kill weight fluid was required, the rig's fluid transportation truck would haul the mud to location.

Cementing the wells was another challenge given the quantity and speed of the wells drilled. Each day two strings of pipe would need to be cemented. To solve this issue, the rig contractor built and operated a cement plant within the Chittim pipe yard. Application specific cement equipment was built to handle two strings a day. The cement pump truck was built with a large hopper on the rear as the suction. Two large front end loading cement mixers, one for each string, were used to mix and transport the blended cement from the plant to location. The mixer would pull behind the pump truck and deliver the blended cement into the hopper on the back of the pump truck as shown in **Figure 7**.

Drilling Performance Overview and Challenges: A Continuous Improvement Process

The drilling program in Chittim used two rigs, a top-set rig and a hybrid CTD rig. The first, the top-set rig was a water well drilling rig used to drill the surface section of the well (**Fig.6**). The rig would move in and drill 260' of 9-5/8" open hole using a roller cone mill tooth bit. The drilling fluid used for this surface section was Olmos water. After drilling the surface hole, 250' of 7" J-55 20# casing was run using the water well rig.



Figure 6: Water well rig used to drill and set 250' surface casing. Figure 7: Cementing equipment for surface casing.

The CTD rig's cementing crew would then come in and cement the well to surface with a 15.6 ppg Class A neat cement (**Fig.7**). Total time from rig up to rig down for the surface section required 7-8 hours.

After the surface section of the well was complete, the CTD rig moved in and drilled the production section of the well. The production section consisted of 1,500-1,800' of 6-1/4" OH. The CTD would drill this section with a 6-1/4" Polycrystalline Diamond Compact (PDC) bit, a 5"OD 1.01 rev/gallon positive displacement motor and 5 to 6 each 4-3/4" drill collars. The wells were drilled with 2-4 Klbs weight on bit with the neutral point maintained below the coiled tubing connector. The flow rate used to drill was 325 gpm. Coupling this flow rate with the high performance motor resulted in bit rotation of 328 rpm. The drilling fluid used in the program was one of the most successful fluids used in the history of Chittim. It consisted of using the Olmos water as the base fluid and adding 1 ppb of polyanionic cellulose polymers, 3% KCl, and three cans of partially hydrolyzed polyacrylamide/polyacrylate (PHPA) copolymer per well.

When TD was reached, 2 bottoms up circulations were completed and the CT and Bottom Hole Assembly (BHA) were pumped out of the hole. The rig would lay the CT injector wheel down and rig up to run the casing. The rig crews would run the production casing. The casing for this program was 4.5" J-55 10.5#. Once the casing was run and the mandrel set in the well head, rig crews would rig up the cementing head and begin circulating. During circulation, the cement crews would begin mixing the cement at the plant located in the pipe storage area. A volume of 200 cubic feet of Class A cement with 3% bentonite and 0.75 gps of fluid loss additive were mixed up and transported to the well site. The wells were cemented back to surface. After the casing was cemented in place, inclination surveys were run on slick line with a memory tool.

Surveying after the casing was run resulted in some risk taking. The production group limited the target deviation of the wellbores to 5° from vertical, to minimize pump rod and tubing wear. The rig contractor believed this would not be a problem for coiled tubing drilling considering the low weight on bit required to drill softer formations. To justify this risk, a cost versus risk analysis was performed. This analysis compared the risk of drilling an out of compliance well versus the cost to monitor deviation while drilling. It was concluded that the most cost effective method was to drill the well then survey after. Of the 232 program wells, only one well required redrilling due to deviation.

During directional surveys, rig crews would begin rigging down and ready to move to the next well at first light. A typical as-drilled schematic of a Chittim well is shown in **Figure 8**.

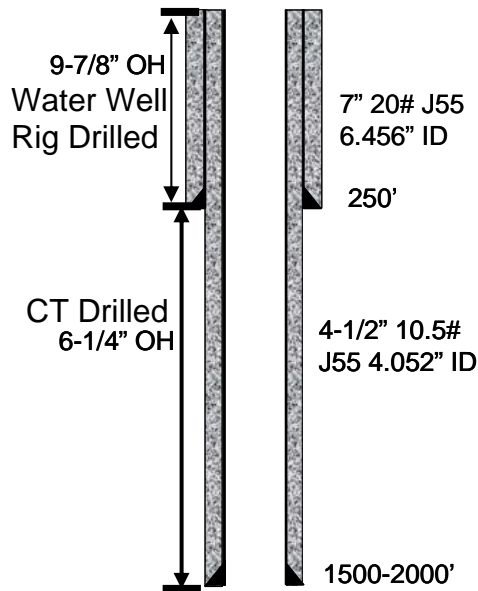


Figure 8: Typical Chittim Ranch schematic.



Figure 9: Olmos water in pit used as base fluid for drilling mud.

Mud and Hole Condition Discussion

The first 16 wells were drilled with just Olmos water (**Fig.9**) and a variety of problems presented itself. The mud weight was started at 8.6 ppg and would rise to almost 10 ppg due to inclusion of drill solids. The rig would dump and dilute to bring the weight back down to 9 ppg. This had to be done several times throughout, which ultimately required a larger cuttings pit. The casing had to be washed down through tight spots occurring at about 1,000' and also the last ten joints. The first cement job pumped had 50% excess and only 2-3 bbls of cement circulated back at surface. Cement jobs on the next group of wells were pumped using 75% excess cement volume, and a few wells did not have desired volume of clean cement returns at surface. The excess cement volume was then increased to 100%, yet still, this volume was not sufficient for some wells. The reasoning for increasing the excess cement and not adjusting the drilling fluid was the cement would have been cheaper than building a mud system with the limited rig equipment. There were also concerns raised about reducing ROP with a more substantial mud system.

Initially, there were also problems encountered in getting openhole logging tools to total depth (TD) in these initial "water only" drilled wells. Chittim has a history of problems when attempting to get openhole logs to TD. In past drilling programs, many wiper trips would have to be made and some logging attempts would still fail to reach TD.

Adding the aforementioned chemicals to the fluid resulted in solving the hole problems. The mud weight would start at 8.7 ppg and at TD the weight was 9.1 to 9.2 ppg, without any dumping or diluting. The hole was in gauge with no over or under gauge sections throughout. This new drilling fluid allowed dropping the excess cement to 25% with adequate returns. All logging attempts proved successful with no tight spots reported. Another advantage to using this fluid system was that the polymer in the mud acted as a friction reducer. The pump pressure was reduced from 2,000 psi to 1,500 psi at the desired rate of 325 gpm (7.75 bpm). This was advantageous for CT life; since as the pressure inside the coil decreases, the number of cycles the coil can endure increases. The expected coiled tubing life was increased based on CT life prediction software estimates.

Well Control Stack Discussion

During the drilling of these wells, problems occurred that resulted in some changes to our well control equipment. Originally there was a "Category 1" system set up that consisted of a 7-1/16" annular with a mud cross below it to be able to divert the water flows that were encountered. This worked effectively until it was discovered the annular was not capable of full

closure and seal on an open hole. This discovery led to a BOP stack redesign by the addition of a blind ram below the mud cross. This allowed for full closure of the wellbore during well control operations or while out of the hole. This also allowed us to exploit one of the advantages of coiled tubing. If the well had taken a kick while the rig was out of the hole, the blind rams could be closed to secure the well. The coiled tubing could then be rigged up to snub in the hole either with or without using a lubricate and bleed procedure to minimize pressures.

Coring Overview

The well to be cored in the NW corner of the field (**Fig.10**) was drilled in the same manner the development wells were drilled. The surface rig moved in first and preset 250' of 7" J-55 casing. Then the coil tubing rig moved in and drilled a 6-1/4" hole to a depth of 1,112'. The drilling assembly was then pulled out of the hole and the coring BHA was picked up. The BHA consisted of a 31'- 5-3/4" OD x 3-1/2" ID core barrel, 0.46 rev/gallon motor, hydraulic disconnect, 6 each 4-3/4" drill collars and another hydraulic disconnect below the CT connector and check valves. The coring BHA was run in the hole and 31' of core was cut.

Significant BHA motor work was noticed while running the core through the open hole section above the targeted core location, even though the diameter of the core bit was the same as the drill bit; something not experienced in drilling BHA tripping events. It was believed to be due to the difference in gauge lengths between the two bits, with the core bit gauge length of 4" being significantly longer than the 2" length on the drilling bit. The drill bit apparently produced micro-tortuosity though the openhole sections requiring the coring bit to clean up the walls.

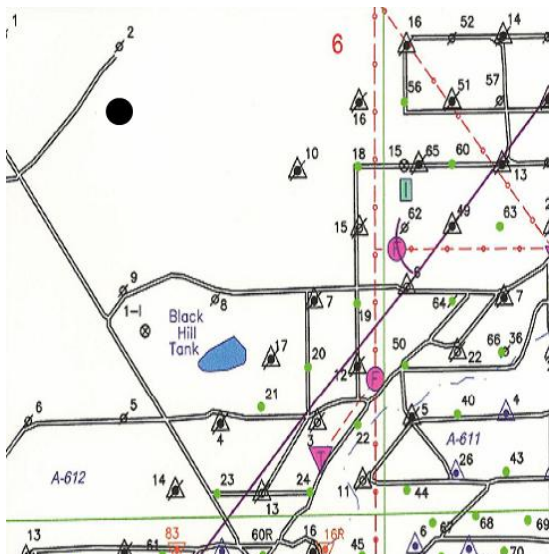


Figure 10: Location of cored well (black dot).

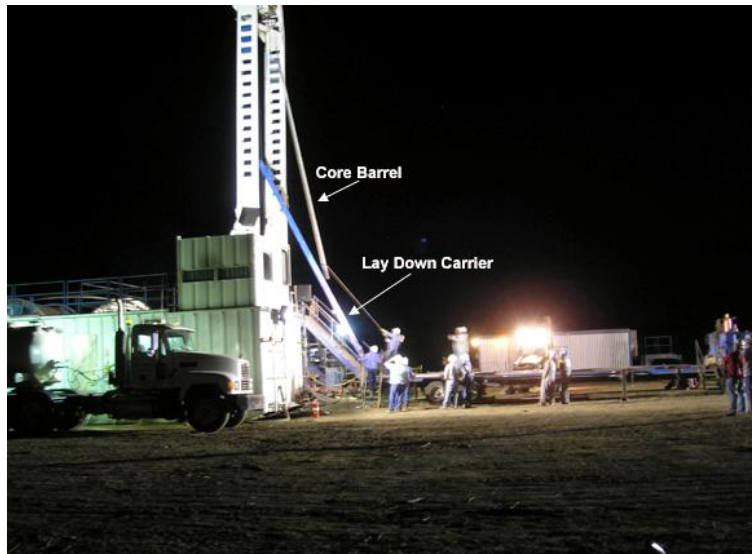


Figure 11: Core barrel lay down challenge to prevent damage to core.

The first core was pulled out and laid down and the assembly was run back in and an additional 31' of core was taken. The limited mast height of the CTD rig made laying down the core in the core barrel carrier a challenge that was overcome by creative rigging (**Fig. 11**). The carrier was used to minimize bending forces while laying the core barrels down. After two cores were taken, the drilling BHA was run back in the well and drilled to 1,333'. Again the coring BHA was picked up and 93' more core was taken on three subsequent runs. All 5 cores were reported to be in excellent condition by the core analysis company. The mud system used for this well was similar to the normal drilling fluid except for the addition of 1% starch for additional waterloss control and a tritium tracer to determine drilling fluid invasion. The coring analysis company reported the drilling fluid did not invade the cores significantly enough to alter oil and water saturation values.

Summary of Program Results

Following the success of the first 81 well program for 2008, an additional 100 wells were added followed by an additional 54 wells to bring the total to 233 wells (including 1 re-drill due to deviation). Of the 233 wells, 176 were producers and 54 were injectors. More wells were on the schedule to be drilled, but funding was cut from this project due to budget restrictions caused by the reduction of oil prices. Upon completion of the program data was compiled and compared to the project goals.

The first 81 well program consisted of 64 producers and 17 injectors. The average time to drill these wells full cycle was 40 hours, with the surface rig averaging 9 hours and the CT rig averaging 31 hours per well. For use in this drilling program, full cycle is defined as the time required by the surface rig to complete the surface section added to the rig up to rig release

time of the CT rig per well. During the drilling of the producers, key learning's i.e., drilling fluid optimization and heavy weight mud management, were applied to the injectors. This resulted in the CT rig drilling the 17 injectors in 17 days, which met our project goal of drilling a well a day.

The success of this initial 81 well program prompted a contract extension of 100 wells to complete, bringing the total target in 2008 to 181 wells. This next 100 well program consisted of all producers. Due to increased efficiencies in Rig up/Rig down time for the CT rig and overall performance increases for the surface rig, average full cycle time for this program was reduced to 35 hours per well. The surface rig would complete a well in 8 hours while the CT rig would finish in 27 hours.

Once budgets were finalized for 2009, the contract was extended to include another 52 wells. This well package consisted of 15 producers and 37 injectors. The goal of drilling one well per day with the CT rig was achieved while drilling these wells. The full cycle time for drilling these wells averaged 32 hours. The surface rig completed the surface section of the well in 8 hours while the CT rig required 24 hours to complete the wells.

Coiled tubing drilling equipment and techniques reduced the average time to complete a well by 60% when compared to conventional rotary rig drilling. The most recent conventional drilling data was taken from a 32 replacement well program completed in 2006. These 32 wells averaged 79 hours from rig up to rig release. The average ROP while drilling the production section was 92 feet per hour. In comparison, drilling with coiled tubing resulted in an average full cycle time of 32 hours and an average ROP of 210 feet per hour in the production section. A comparison of the original conventional drilling efficiency versus the 3 groups of CT drilled wells is shown in **Figure 12**.

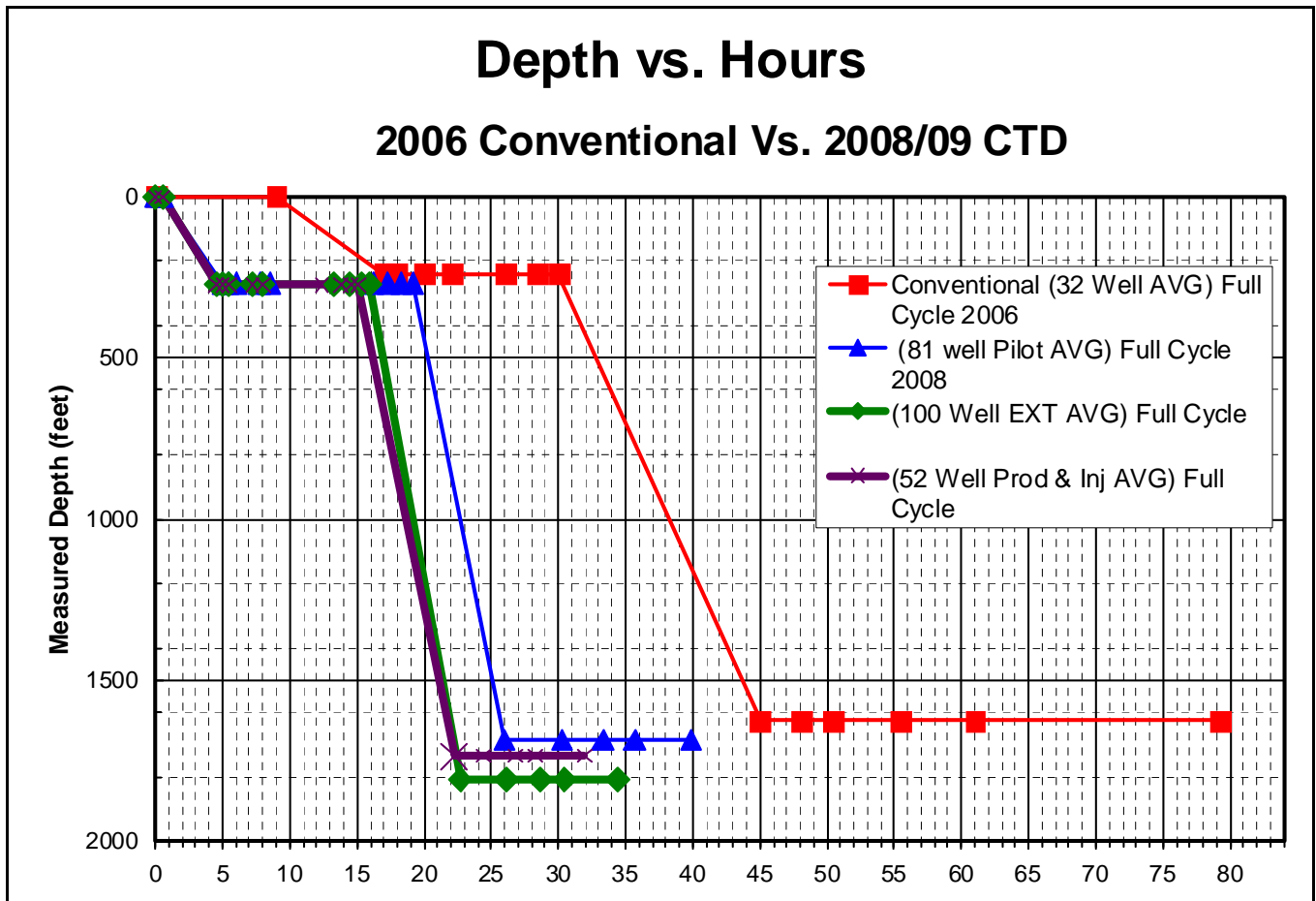


Figure 12: Depth vs. Hours chart comparing 2006 Conventional Drilling, and 3 campaigns using CT Hybrid unit in Chittim. Continual improvement can be seen in the CTD campaigns listed in chronological order in the key.

The increase in drilling performance coupled with a turnkey contract resulted in a 14% cost reduction per well when compared to the most recent conventional drilling data. When adjusted for inflation from 2006 to 2008, the cost savings per well increased to 33%. The target cost/BOE for Drilling and Completions for this program was met.

HSE exposure was minimized by the use of a single CT drilling rig and the reduction of supporting vendors by 65%. Seventeen different vendors were used to support the conventional drilling program in 2006. Only 6 vendors' services were

required for these coiled tubing program operations. The reduction in vendors was accomplished by the turnkey contract and services supplied from the rig crews; cementing services, casing running and rig and fluid transportation. Exposure and risk was mitigated by the reduction in the number of 3rd party vendors required at the rig site. All equipment used was stored in Chittim's pipe yard and transported to the wellsite by rig personnel or roustabout crews assigned to the drilling program.

Another reduction in HSE exposure was realized with the inherent safety of Coiled tubing drilling. 118 connections are required to drill a well conventionally in Chittim. To drill a well using coiled tubing, 14 connections are made. This reduces the time spent on the rig floor thus reducing the risk by approximately 88% in an activity known to be one of the highest risk for injury.

Conclusions

The hybrid coiled tubing drilling equipment and techniques were shown to be effective in delivering the majority of the desired goals of this in-fill drilling program including cost per barrel of oil equivalent. Program effectiveness led to the 2 additional groups of wells being drilled over the base case; from 81 wells to a total of 233 wells, including both production and injection wells.

The following are some of the highlights of the Chittim drilling program:

- Minimal site preparation for CTD rig improved economics.
- Innovative design and operation of the cementing solution, 2 cement jobs per day, significantly improved the operational efficiency of the program.
- Coiled tubing drilling reduced the time to drill a well by 60% when compared to conventional drilling.
- Project management and the use of a turnkey contract resulted in per well cost savings of 14%, or 33% if adjusted for inflation.
- Reducing the number of vendors and using a Coiled Tubing Drilling rig minimized HSE exposure.
- Coiled tubing demonstrated the ability to drill straight holes, without complex drilling equipment.
- The ability to core and retrieve high quality cores using coiled tubing with a motor was demonstrated.

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