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Summary

This paper describes application of an integrated approach that combines drilling and completion techniques in a new use of reaming tools currently used for reaming-while-drilling (RWD) operations, in a way that minimizes the need for SOP of using a dedicated reamer run. The RWD application provides the enhanced wellbore geometry needed to design and engineer solutions using maximum size (OD) conventional casing, liners, expandable casing and multiple swellable packers. This type of assembly for drilling /completion design, currently utilized in multiple Williston Basin wells, ND, is shown to consistently result in shorter drilling time and successful first casing/liner runs. Currently this type of cross functional approach has been used on over 400 wells/ 4,000,000 ft. of lateral.

Introduction

Today, the industry is moving toward solutions that take a long-term view of the life of the well, requiring a more blended / integrated approach to the way wells are planned, drilled, completed, and produced. The ultimate goal of today's wells include a safe – cost effective well that comes on line quickly and can maximize production for years to come as well as being a repeatable process that is effective 100% of the time.

However some industry reports estimate that 10-20% of production liners being run today do not reach the specific landing depth targeted. This of course adversely affects long term production and increases the short term costs of well. The equipment is often damaged, placing extra demands on rig personal, and increasing both time and costs.

To enhance production and improve recovery processes, an effective approach has been implemented to integrate production engineering with drilling strategies to design a well program that optimizes hole sizes, casing sizes, well positions, etc., to maximize long-term hydrocarbon production.

Use of such a multi-faceted approach begins with combining the requirements of both the drilling and production groups, with the ultimate objective being to increase and maximize production from a safe, cost-effective drilled well. Additionally this strategy integrates specific objectives / technology for improving the success of landing the liner on depth and helping drill a cost effective – smooth – gauge hole.

Having a smooth, well-conditioned, non spiraled- gauge hole enables the largest, most-effective and highest number of packers to be run which is required to maintain the highest possible differential sealing action of the packers. Further, when the hole is drilled using reaming while drilling techniques described, excellent hole quality can be achieved without the need for dedicated clean out runs, while an enhanced packer design also aids in getting the liner down. Torque and drag analysis in combination with additional operational strategies increases the likelihood of achieving success. Additionally another objective is to have the liner / packers reach bottom with the least amount of damage possible - a smooth in gauge and established set of operating parameters helps facilate this type of operation.

Background

Historically, best drilling practices in the Bakken wells have required a dedicated reamer run at TD to ensure successful swellable packer installation in a single run as well as many other areas in the world. Already introduced successfully in over 400 wells, the new generation reaming tools & strategies are currently being used in reaming-while-drilling scenarios to eliminate the need for a dedicated reamer run in each well; this saves potential two to three rig days (full round trip from 20,000 – plus the actual reaming time – we have seen where customers actually took well over 5 days to complete the dedicated reaming operation). Attached is a well design sample from ND.

These tools can be built as steel or non-magnetic (non-mag) tools; hence, they can be run anywhere in the BHA plus be used to drill out. They reduce spiraling in the well bore, thereby reducing the risk of sticking the liner assembly before reaching TD. Below we have attached a sample BHA.

Operators are achieving over 98% success with packers going to TD when using this technology in the fully integrated approach. In addition, current BHA modeling techniques and field use document that use of the tools presents no significant steering control issues or any loss in penetration rate while still enabling subsequent installation of multiple packers. This can be critical in the North Dakota wells, where the application can require running as many as 35 swell packers or more to bottom.

Through combined efforts of proven North Dakota operations groups, rigs and service companies, the new reaming tool for reaming-while-drilling operations has helped to eliminate the dedicated reamer run at TD while delivering good wellbore condition that enables multiple swell packers to be run in a single, fast trip.

With this type of enhanced wellbore geometry, producing a maximum size and gauged hole is also a mandatory precondition for successful first run in long string casing, drilling/completion liners, and expandable casing applications. Tight annular clearances of post-job swellable packers and expandable casing requires more hole geometry data during pre-planning to ensure proper operations. Proven techniques using proper circulating methods, solids control in the mud system, directional control and minimal DLS across horizontal sections, are all imperative to a successful first run when casing, liners (expandable or conventional) and swellable packers are being utilized.

By working together with the operations groups, the teams have developed several innovative reaming-while-drilling scenarios to meet the operators' application-specific needs, and to date have documented over 4,000,000 feet of hole reamed and over 98 % successful installations of swellable packers on more than 400 wells with a number of Bakken operators.

Williston Basin Geology

The Bakken shale play is an oil reservoir, a dolomite layered between two shale's, with depths ranging from around 8,000 to 10,000 ft, from which oil, gas and natural gas liquids are produced. Each succeeding member of the Bakken formation – lower shale, middle sandstone and upper shale member – is geographically larger than the one below. (Figure 1) Both the upper and lower shales, which are the petroleum source rocks, present fairly consistent lithology, while the middle sandstone member varies in thickness, lithology and petrophysical properties.

Currently, Bakken oil wells have been completed either with uncemented liners or swellable packers, and the use of isolation tools has been extensive. The Bakken is not as naturally fractured as other shale plays and, therefore, requires more traditional fracture geometries in stimulation treatments. Recently, the Bakken has seen an increase in activity, with the trend being toward longer laterals – up to 15,000 feet for single laterals in some cases. In addition, some operators are drilling below the lower Bakken shale and fracturing upwards.

Subject Well Designs

The Williston Basin presents more than 30 formations from surface to the targeted zones, with challenges that include potential aquifers, sticking salt and bentonite beds, sloughing shales and known H 2S hazards. In a typical well design, the 8

¾-inch hole section is drilled vertically through 20 or more formations to a kick off point in the target formation at around 9,000 to 10,000 ft true vertical depth (TVD).

From there, 8 ¾-inch hole continues and builds angle to horizontal in the Bakken target formation at around 11,000 ft TVD. Once landed and horizontal, a 6-inch lateral hole is drilled and extends laterally for up to 10000 feet.

To insure successful swellable packer installation in a single run, best drilling practices in the Bakken wells have required a dedicated reamer run at TD. Oil and water based mud is used during swell packer installations, and as many as 20 or more zones are isolated, with some additional zones plugged and perforated.

In addition, the project allowed introduction of a 5 7/8-inch OD PDC reamer for use in the 6-inch lateral section, using both non-magnetic and steel body tools. The objective was to enable successful installation of multiple swellable packers – up to 40 – while providing significant time savings of up to 3 days rig time per well.

The geology of ND is used to provide a detailed example as there are a wide range of similar geologic conditions and drilling – completion issues globally.

Driller-Reamer Tool Design

The PDC reaming tool is a drilling enhancement reamer equipped with PDC cutters on a beveled profile to maintain gauge of wellbore in cases of severe swelling and/or borehole instability. The tool also improves borehole shape, straightness and quality by removing ledges and micro-doglegs, and features a hydraulic profile that optimizes mud flow and resists balling.

In addition to drilling, the PDC reamer enables reaming through its integral chamfered blade design. Providing 360- degree cutter coverage, the spiraled blades incorporate tungsten carbide insert (TCI) to provide additional reaming or stabilization according to drilling and formation conditions.

TCI distribution is optimized for specific conditions to provide continuous reaming in longitudinal and radial directions, while PDC distribution is in accordance with an axi-symmetric design technique that allows for balanced drilling and reduced vibrations. The stud cutters are oriented for optimum cutting action, and are deeply inserted in the blade to eliminate the shear plane and prevent failure.

As a result of having both PDC and TCI cutters, the PDC reamer executes a unique cutting mode of both scraping and shearing that smoothes the wellbore and is effective in delivering a high quality hole through changing formations.

The PDC reamer is ideally installed as the uppermost gauge device in the BHA to prevent sticking by back reaming/drilling the way for the rest of the BHA while pulling out of hole (POOH). While the PDC reamer typically replaces the topmost stabilizer, it can be placed on top of the downhole motor in cases where unconsolidated formations or hole cleaning problems are expected.

In the subject wells, the PDC reamer was 5 7/8-inch OD, with a four-bladed, bi-directional design which enables the tool to act as backup hole opener when bit gets under-gauge. Specifications are given in Table 1.

Table 1. PDC Reamer Tool Specifications

Cutting Elements	PDC Cutters
Reaming Elements	Tungsten Carbide
Coverage	360 Deg.
Blade Width	1-1/2”
Equivalent Drill Collar Size	5.33” Diameter
Total Flow Area	4.76 Sq. Inches
Tool Total Length (L)	63”
Tool Gauge Diameter (OD)	5.875”
Fishing Neck Length min. (FN)	18.57”
Bottom Neck Length min. (BN)	21.57”
Neck Diameter (D)	4.875”
Tool Bore Diameter (d)	2.5”
Wall Contact Length (B)	11.65”

There is a wide range of versatility with these types of tools as we can easily change cutter structures to handle:

More abrasive formations
Longer runs
Higher azimuth applications
Low torque requirements
Hole sizes drom 4 1/8” to 26”

A key discussion point is to have the directional drilling groups – geologic - rig operations and completions groups discussing the requirements with the drilling engineering team.

Typical Packer Design

The swell packers being installed in Williston Basin wells comprise a standard oilfield grade tubular with layered rubber bonded along its length. With the packer installed downhole, the rubber swells through absorption of hydrocarbons or fresh water, resulting in an annular seal. Swelling is time-dependent, and is homogeneous along the length of the element, although in the subject wells the packers have a minimum swell time of five days, with 14 days maximum swell time.

Self-healing swell packers use oil- or water-swelling elastomers to provide long-term zonal isolation in temperatures from 35° to over 400°F, and can support differential pressures up to 10,000psi, in oil or water environments with varying salinity concentrations.

The focus with use of the PDC reamers is to drill a smooth well bore that is as close to 6-inch gauge as possible. Some eccentric or bi-center tools can drill an over-gauge hole (for example, 6 1/8-inch or 6 ¼-inch in a 6-inch hole); this actually reduces the efficiencies and sealing effectiveness of the swellable packers.

Reaming-While-Drilling Performance

In the subject wells, the PDC reamer was run to ream while drilling the production hole section to enable subsequent installation of multiple swell packers. Multiple RWD BHA designs were run, incorporating both non-magnetic and steel body PDC reamer tools, to test steer capability and torque performance for comparison with previous lateral BHAs, both slick and stabilized.

Sample Well #1: Picked up two non-mag PDC reaming tools after MWD failure at 19,495 ft depth left another 800 feet to TD. The BHA was made up with one PDC reamer positioned above the 5 ¼-inch 6/7 motor with 1.5° bend, followed by UBHO and 2 x NMDC, and a second PDC reamer. The 6-inch PDC bit was green from previous run with an average ROP of 18 ft/hr.

Table 2. Bottomhole Assembly Well #1

Type	OD (in)	ID (in)	Length (ft)
PDC Bit	6		1
Motor 5.25 OD 6/7 8 stage 1.5 fixed	5		28.9
WEPS PDC reamer NM	5.875	2	3.02
NMDC	4.5	2.3	30.39
NMDC	4.25	2.3	30.57
WEPS PDC Reamer NM	5.875	2	5.09
XO	4	2.1	2.49
31 stds DP	4	3	2939
agitator	4.94		11.22
Shock sub	4.94	2	11.1

This BHA reamed the lateral section back to bottom at 19,495 ft, at 200-250 ft/hr, operating at a flow rate of 205 GPM with 65 RPM surface rotary and 165 RPM at motor for 230 RPM. Reaming was finished after 32 hours reaming and with 9000 feet of open hole, on bottom drilling at 19,495 ft depth.

On- bottom drilling resumed at 19,895 ft depth, with an average ROP of 25 ft/hr in rotary mode and 12 ft/hr sliding. The first slide to nudge angle back up went well, but there was difficulty with the second slide in getting the required high side tool face.

The rig was limited to 4250psi differential and the Directional Driller would like to have had at least 4800psi operating parameters. After a planned, 10-20 stand short trip, and reaming the last 800 feet to TD at 20,278 ft, the BHA was POOH and 21 swell packers were successfully run. Table 3 summarizes the run parameters.

Table 3. Run Parameters Well #1

Depth In	19,495	**Torque**	8-12k		OBM
Depth Out	20,278	**RPM**	230	**MW (ppg)**	12.3
Feet	783	**Flow (gpm)**	205	**PV/YP**	26.9
Hours	30	**SSP (psi)**	4000	**Visc.**	71
ROP (ft/hr)	26.1	**WOB**	7-10k	**Solids %**	na

Sample Well #2: In this well, where the previous slick BHA achieved an ROP of 70 ft/hr rotating and 17 ft/hr sliding, the objective was to ream the lateral hole from 10,500 to 15,552 ft, then ream-while-drilling from 15,552 ft to TD at 19,576 ft depth. The BHA comprised a 6-inch PDC bit, 4 ¾-inch 7/8 fixed housing motor with 1.5° bend; the 5 7/8-inch non-mag PDC reamer, a UBHO and NMDC, followed by a second non-mag PDC reamer.

Table 4. Bottomhole Assembly Well #2

Type	OD (in)	ID (in)	Length (ft)
PDC Bit	6		1
Motor 7/8 3.8S 1.5 fixed	4.75		23.66
NM WEPS PDC reamer	5.875	2	5.09
UBHO	4.75	2.75	3.05
NMDC	4.75	2.63	31.24
NM WEPS PDC reamer	5.875	2	5.1
NMDC	4.75	2.63	31.18
X-over	5	2.56	3.97
31 Stds DP	4	3	2920
Agitator	5	1.75	11.22
Shock sub	5	1.91	11.11
79 Stds DP	4	3	7440.49
17 Stds HWDP	4	2.563	1566.09
4 DP	4	3	7523
BHA Total Length (ft) = 19576.2			

This assembly was run in at 5000 ft to ream to bottom, holding inclination from 89.4° -88.3° over 4024 feet. The BHA was used to ream-while-drilling from 15,552 ft to TD at 19,576 ft, with 5.14% sliding in 24.5 hours, and 94.86% rotating with 49.58 rotary hours. Average rotating ROP was 77 ft/hr over 3817 feet; and 9 ft/hr in sliding mode over oriented footage of 207 ft.

There were no issues with the ability to steer, and average rotary ROP increased from 70 ft/hr to 79 ft/hr. Utilization of the PDC reamer eliminated the need for a dedicated reamer run at TD, and 21 swell packers were successfully installed with no problems. Table 5 summarizes run parameters, while Figure 6 shows one of two non-mag PDC reamer tools after reaming 5000 feet.

Table 5. Run Parameters Well #2

Depth In	15,552	**Torque**	7-13K		OBM
Depth Out	19,576	**RPM**	230	**MW (ppg)**	10.7
Feet	4,024	**Flow (gpm)**	210-228	**PV/YP**	20.9
Hours	74	**SSP (psi)**	3900	**Visc.**	52
ROP (ft/hr)	54.4	**WOB**	20-65	**Solids %**	17

Sample Well #3: Two steel PDC reaming tools with 30ft spacing were used in the lateral BHA when drilling out of the 7-inch shoe, then proceeded to ream-while-drill the lateral. The entire lateral of 9500 feet was successfully reamed-while-drilling to well TD at 19820 ft. There were no issues with torque, steering control or ROP, and 30 swellable packers were successfully installed after TD, eliminating a dedicated reamer run.

Table 6. Run Parameters Well #3

Depth In	10,320	**Torque**	7-13K		Brine
Depth Out	19,820	**RPM**	230	**MW (ppg)**	9.8
Feet	9,500	**Flow (gpm)**	230-240	**PV/YP**	1
Hours	108	**SSP (psi)**	2900	**Visc.**	52
ROP (ft/hr)	88.0	**WOB**	15-30	**Solids %**	na

Observations and Results

Over the course of these Williston Basin wells, the RWD BHA, using both non-mag and steel body PDC reamer tools, eliminated a dedicated reamer run and allowed for 100 percent successful swell packer installations. It was determined that the optimal RWD BHA for the application was 30-foot spacing between PDC reamers positioned on top of the lower BHA using steel body tools; and 30-foot spacing between PDC reamers in the lower BHA using non- mag tools.

We found that running two PDC reamers with 60-foot spacing caused the BHA to have dropping tendencies while in the rotary. Stacking two PDC reamers together with no spacing created too stiff an assembly and was difficult to steer / orient during slides.

Use of the PDC reamer tool had no adverse effect on steering or orientation, and compared to previous slick and stabilized lateral BHAs, resulted in low / manageable torque increase from 7 to 13, with 20 percent increase in rotary ROP, which produced a smooth well bore and greater on-bottom WOB. The RWD BHA assembly was able to drill out 7-inch casing shoe.

It should be noted that on several wells, the vibration was monitored and showed no increase levels to adversely affect the MWD system and cause premature failures. Actually, the MWD service companies prefer a stabilized lower BHA to protect and improve mean-time-between failures (MTBF).

Conclusions

Experience has shown there are definite reasons and factors for liners not going to TD, and in fact, even though the drilling and completions community has developed effective solutions for today's well, the wells and liners themselves continue to grow more complex. Hence, this will likely continue to be an ongoing problem.

As a result, there are strategies – including tools / equipment and design strategies -- for increasing the chances of the liner going to TD successfully. The effort must start in the planning phase, by having completions – reservoir – geology – on site geologists & operations group all assist in planning an effective well that hits the target in a cost effective – safe manner.

These groups need to communicate and jointly develop a safe well bore that is in alignment with the completion objectives. All equipment, plus remedial options, needs to be reviewed so that bit sizes / tubular are all in alignment and available per the drilling schedule.

In terms of drilling fluids, what is required is an effective fluid for maintaining hole gauge, providing lubricity and removing cuttings by circulating bottoms up, so the well bore is as clean as possible; and of course, it must yield drilled fluid that is environmentally approved for the area. Additionally, procedures like circulating bottoms up / breaking circulation while tripping in all need to be addressed in the drilling program. As well as providing flexibility for the rig operations team to modify when required.
The objective is to drill a smooth wellbore, even when Geo-steering. If possible, the wellbore should be aligned to miss extreme faults and flexure points.

During and after drilling, it is necessary to review and analyze T & D, as well as use of T & D equipment / mud properties / rig properties / centralizers. In fact, all equipment being run in the well bore should be monitored and analyzed for increasing T & D, and solutions designed to reduce these factors if possible. For example the end rings on the swell packer were incorporated in order to reduce T&D.

Reaming the hole while drilling is a viable and effective strategy when conducted according to proven established running procedures, as described. The new PDC reamer tool design is shown to provide a cleaner, better-reamed out hole in these Williston Basin wells where the application has required running as many as 40 swellable packers to bottom.

As wells and completion designs become more complex due to the reservoirs being pursued in today's market, pre-job planning from the beginning has become essential in maximizing all phases of wellbore requirements. Equally important is aligning all service companies' equipment design or needs to the drilling program.

Operators and service company groups need to communicate and jointly develop a safe well bore that is in alignment with the completion objectives. All equipment plus remedial options need to be reviewed so that bit size / tubular are all in alignment.

In the subject wells, utilization of this fixed blade PDC reamer is shown to provide a cleaner, better-reamed out hole in these Williston Basin wells where the application has required running as many as 40 swellable packers to bottom. Its use resulted in no issues with steering control and an increase in average rotary ROP. The RWD application eliminated the need for a dedicated reamer run at TD and enabled successful installation of multiple swell packers with no problems. Contributing to the success, optimized BHA design, operating parameters and mud properties were determined, and now constitute best practice for typical Bakken wells.

Because operators are using various packer OD sizes in attempts to get the swell packers to TD, swell packer and production string design has been refined to further assist in successful installations. In this case, the economic impact of eliminating the dedicated reamer run at TD reduced rig time per well an average savings of three days.

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Traditional Bakken well design from several years ago

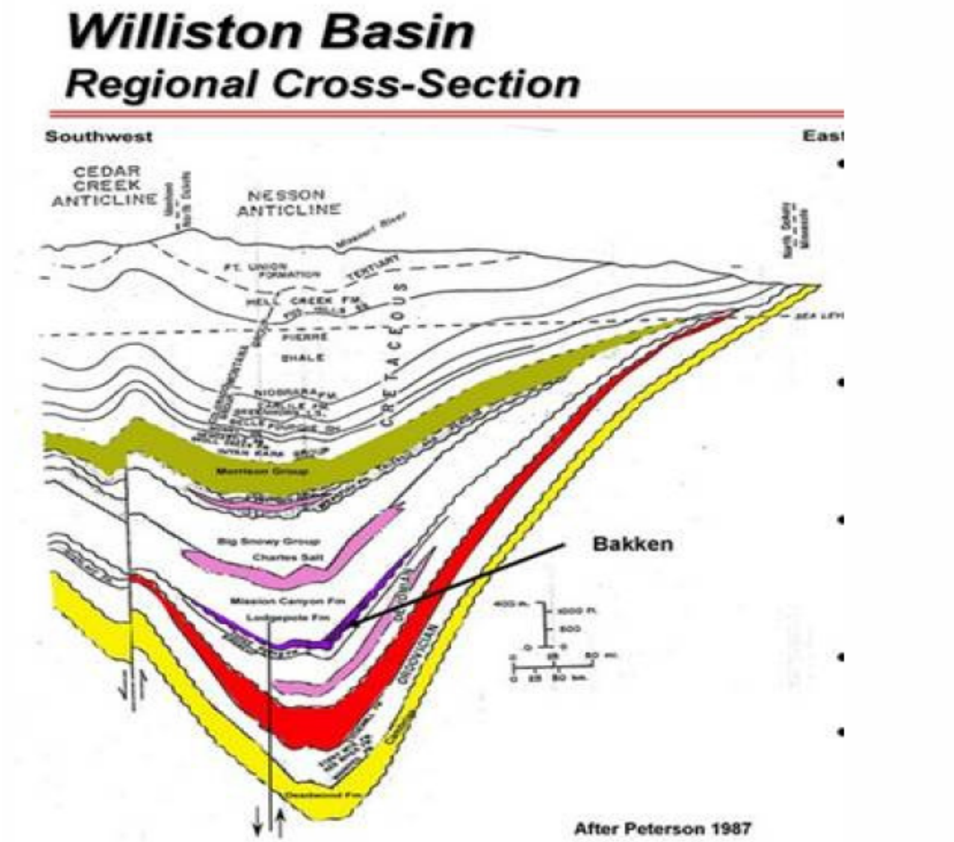
T&D Analysis

Illustration of a Conventional VR RSS Table

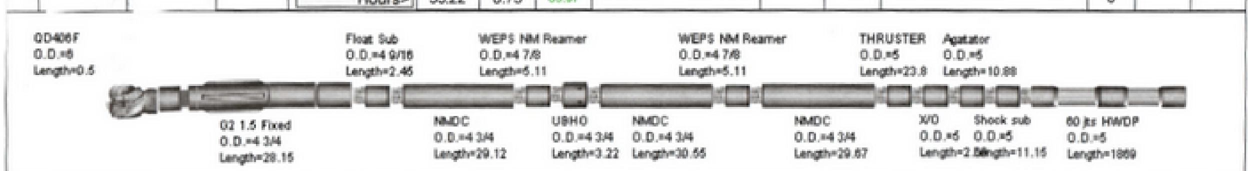
Illustrations relating to Hole Spiraling

Dakota RWD Motor Drilling

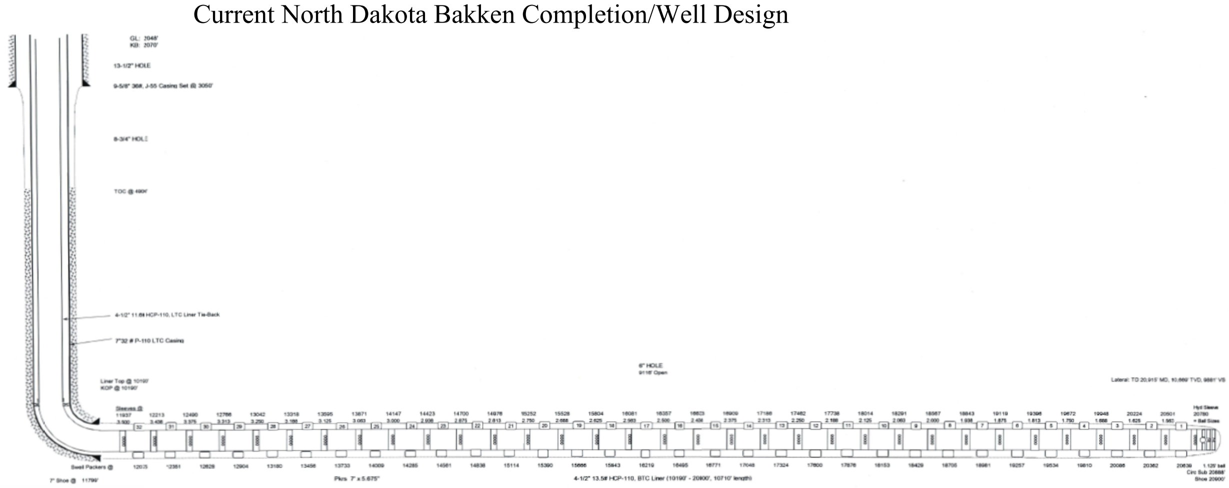
Typical North Conventional Assembly



#	TIME IN - OUT			DEPTHs		Footage			ROP			RPM	FLOW	Incl.		Azimuth		Weight Ranges		
	Time IN	Time Out	Hrs.	IN	OUT	Rotary	Slide	Total	AVG.	Rotary	Slide		Rate	IN	OUT	IN	OUT	SO	PU	RAB
			119.67	17825.0	20578.0	2647.0	106.0	2753.0	43.04	47.9	12.1	40-50	225-277	.0	.0	.0	.0	160-180	215-250	190-190
					Hours>	55.22	8.75	63.97												



Current North Dakota Bakken Completion/Well Design



Reamer Picture

Reamer Picture