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Development and Field Results of a Unique Drilling Fluid Designed for Heavy Oil Sands Drilling

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Abstract

Drilling Heavy Oil Sands are traditionally fraught with many technical challenges. Stability of the wellbore, accretion of the tar on drill string and solids control equipment, torque-drag considerations, extreme temperature conditions, as well as the handling of oily solids are just some of the challenges that need to be met.

This paper describes the development and testing of a new drilling fluid designed to meet these challenges. The water-based fluid is based upon two guiding principles, the ability to incorporate the bitumen into the mud itself, and the capability of the system to later break the bitumen from the mud system. Incorporation of the bitumen into the mud is via a direct emulsification and results in zero accretion, virtually oil-free sand from the solids control equipment, fast drilling rates and good hole stability. The post drilling breaker allows for the oil/bitumen/tar to be skimmed from the surface of the drilling fluid allowing for conventional disposal of the liquid fraction.

Data from a six well horizontal heavy oil program in Northeastern Alberta shows the robustness and effectiveness of the system. The new oil in water direct emulsion system drilled 1100 meter average horizontal wells 35% faster, when compared to conventional inhibition salt technology based drilling fluids. Highlights include sand from centrifuging operation containing < 0.5% oil, elimination of accretion and common foaming problems, fluid reuse from well-to-well, as well as simple land disposal of liquid mud wastes. Total well costs, drilling fluids costs and disposal costs were significantly less than those wells drilled with conventionally inhibited drilling fluid systems.

Introduction

As conventional oil reserves are gradually being depleted, the oil industry focuses more and more on other types of

hydrocarbon reserves such as coal bed methane, gas hydrates and tar sands.

The rise of the oil price has allowed new production technologies to be successfully developed and economically applied to heavy oil and bitumen bearing sands in Northeastern Alberta, Canada. These tar sands contain more reserves than Saudi Arabia, however only 10% of those can be conventionally surface mined. To extract higher amounts of oil, techniques such as SAGD (steam assisted gravitational drainage), horizontal wells and SR (soak radials) horizontal wells are practiced.¹

There are a number of challenges that operators face when drilling into the poorly consolidated McMurray tar sands.² This 1-5 Darcy formation is composed of loose, well-sorted white sand and a bitumen matrix (up to 23% v/v). While drilling these types of wells, the friction generated through the drilling process creates higher downhole temperatures which partially melts the bitumen. Three results are noted:

- a. If mud temperature is not controlled, borehole stability becomes an issue as the tar sand formation bitumen matrix melts away. Such problems are typically alleviated by using mud coolers that maintain drilling fluid temperatures below the formation collapse temperature.
- b. Even with lower fluid temperatures, the number one challenge is tar sand accretion. Ribbons of tar sands adhere to the surface and subsurface equipment, thereby greatly reducing the performance of this equipment. Elevated torque and drag encountered while drilling and RIH with casing/liner, MWD and mud motors coated in sticky tar, shaker screens blinding, centrifuge's performance reduced due to tar plugging, drilling rig and mud tanks coated in tar sands are only a few problems generated by tar sands accretion.
- c. Accretion also leads to large volumes of drilling fluid being used. This in turn creates an environmental issue as seen in excessive disposal and clean-up costs.

Drilling fluids have been designed to reduce or alleviate tar sand accretion. These water based drilling fluids were polymeric based with additives such as potassium salts (KCl or K₂SO₄) or D'Limonene (orange oil extract) to inhibit tar

accretion. However, by using these types of fluids only part of the problem was addressed. While the tar sand accretion was reduced, the environmental issues were not reduced. Neither the liquid nor the solid wastes created by drilling with salts or D'Limone were environmentally friendly, and as such they were trucked away to special disposal sites at great costs. In addition, these drilling fluids are both typically very foamy in nature and difficult to control at surface, as well as post well from the disposal aspect. Recent work has focused on strongly emulsifying the tar sands itself into the water-based carrier by a combination of oil-wetting surfactants and water-wetting agents.³

In order to alleviate and eliminate these problems, an innovative approach to tar sands drilling fluids was developed. Approximately 280 lab tests and two field trials later, a new and fresh-water based drilling fluid has been developed. This paper describes the properties of system to remove tar from the sand, the simple ability to strip the tar from the mud system and the ease of disposal of the mud itself. Details of the field success of the Direct Emulsion drilling fluid system are also given.

Direct Emulsion Development

The research and development of the Direct Emulsion System was structured in seven steps. The process was intended to cover all of the steps in the development of a typical tar sands drilling fluid. Following were the steps undertaken:

Step 1 – Search for a tar cleaning product. The primary step in the methodology was to find a material/method of removing the tar from the sand itself. Fifty-eight potential tar cleaning products were selected and tested, with the majority of them being hydrocarbon based. One hydrocarbon product, designated hereafter as oil-sands cleaner (OSC), stood out as the best performer. When used in concentrations of 2% v/v in fresh water the OSC cleaned 75% w/w of the tar from the core sample. At 5% and 10% v/v concentrations, 96% and 98% w/w of the tar sand core were cleaned, respectively.

OSC is a hydrocarbon liquid with extremely low toxicity level that biodegrades in less than a month. The positive environmental aspects of OSC, along with the technical capabilities as described above, make this liquid a versatile and effective remover of oil from oil-sands.

Step 2 – Search for a polymeric combination compatible with Oilsands Cleaner (OSC). The second step focused on determining if a fresh-water based, direct-emulsion (oil in water) system can be formed with OSC.

Typical emulsions are formed in the presence of high shear and an emulsifier to keep it stable. Under the microscope it was discovered that when emulsifiers were present, the dispersed phase droplets of OSC were very small, coated by the emulsifier and therefore ineffective in cleaning the tar. The emulsifiers in the fresh water medium water created an environmental issue as the water failed the regulatory bioassay test, Microtox. It was very important to find an emulsifier-less

polymeric combination that created and supported a semi-stable direct emulsion.

Six polymeric combinations were evaluated with both natural and synthetic polymers until one was found that produced very good results with regards to tar cleaning ability, mud rheology control, filtration control, emulsion forming and emulsion stability. The table below shows the ability of the system to clean tar from the sands with two different viscosifiers. Both systems work very effectively once 5% OSC is achieved in the fluid.

System A (with Viscosifer A @ 1.5 kg/m3)		
System B (with Viscosifer B @ 2 kg/m3)		
% w/w tar sand cleaned	System A	System B
Blank	19.1%	17.6%
Blank+2.5% OSC v/v	74.6%	73.3%
Blank+5% OSC v/v	96.0%	93.9%
Blank+10% OSC v/v	97.6%	95.5%

Table 1 – Efficiency of OSC to clean tar from sands in two viscosifier modified systems.

As seen in Table 2, using a 5% OSC concentration and various rheological viscosifiers, Viscosifier A was deemed the best additive to enhance the removal of oil from the tar sand.

System with 1.5 kg/m3 viscosifiers & 5% OSC %v/v	% w/w
Viscosifier A	96.0
Viscosifier B	70.5
Viscosifier C	87.8
Viscosifier D	85.1
Viscosifier E	86.7

Table 2 – Effect of various viscosifiers on ability of OSC to clean tar from sands.

The following table shows the ability of the polymeric drilling fluid to retain good viscosity in the presence of the oilsands cleaner.

System with 5% v/v OSC	PV (mPa.s)	YP (Pa)	GS 10" (Pa)	GS 10' (Pa)
0.75 kg/m3 Visc A	16	13	2	2
1.5 kg/m3 Visc A	18	17	4	4.5

Table 3 – Stability of rheological properties in a Direct Emulsion mud containing 5% v/v OSC.

Step 3 – Direct Emulsion System - Resistance to contaminants. In order to determine the newly-formed drilling fluid's behavior, multiple fluid samples were exposed to four common drilling contaminants:

- gypsum (CaSO₄*8H₂O simulating anhydrite contamination)
- lime (Ca(OH)₂ simulating cement contamination)
- salt (NaCl simulating evaporates contamination)
- low gravity solids (tar sand core simulating an overload of the system with excess solids and heavy oil).

The Direct Emulsion System proved to be very resilient with regards to tar cleaning ability, mud rheology control, filtration control and emulsion stability. Table 4 shows the effect of contaminants on the basic direct emulsion system. As expected with a polymer based fluid which contains no bentonite, the effects of lime, elevated pH and salt are minimal

on the basic rheological properties. Gypsum addition resulted in a decrease of plastic viscosity and yield point. Increasing the solids content gave an expected increase in plastic viscosity, while the yield point and gel strengths remained stable.

System w Visc. A & 5% Tar Sand	600	300	200	100	60	30	6	3	PV (mPa.s)	YP (Pa)	GS 10" (Pa)	GS 10' (Pa)	API-FL (mL)
Blank	64	47	39	28	23	16	8	6	17	15.0	3.0	3.5	10.0
+ 5 kg/m ³ Gypsum	48	35	29	20	16	12	5	4	13	11.0	2.5	2.5	9.5
+ 1 kg/m ³ Lime	64	47	39	28	23	16	8	6	17	15.0	3.0	3.5	10.0
+ Caustic for pH=12.0	62	46	38	28	22	15	7	5	16	15.0	3.0	3.0	10.0
+ 20 kg/m ³ Salt	49	35	29	21	16	11	5	4	14	10.5	2.0	2.5	8.0
+ 6 % Tar Sand (LGS)	72	52	42	31	24	18	9	6	20	16.0	3.0	3.5	6.0

Table 4 – Effect of typical drilling contaminants on fluid properties of Direct Emulsion system.

No foam was generated through mixing the fluid or by any of the contaminants. Previously used fluids based upon salts were typically very foamy in the presence of any amount of tar sand.

Step 4 – Breaking the emulsion under static conditions (low energy environment). The impetus in this step was to simplify and improve upon the environmental disposal issue. Previous inhibitive muds were impossible to directly apply to the land because of both the saltiness and oil contamination. Wastes were be trucked to a special disposal site and disposed of at considerable cost. However, if drilling fluid was broken into its basic components of oil, water and solids, these components could be disposed of safely and cheaply and without affecting the environment. The challenge was to find such breaker that was environmentally friendly in itself.

Static conditions refer to the storage of the fluid waste in open sump/tanks, the breaker mixed in and time allowed for emulsion separation. The following then takes place:

- oil is skimmed off the top and processed/sold
- water recovered and re-used or pumped off
- solids are mixed-buried-&-covered on location

Fourteen emulsion breakers were tested with various results. The best performance was produced by an environmentally friendly breaker, designated as Oil Sands Breaker (OSB). The oilsands breaker works by modifying fluid’s rheology to the point where oil and solids are released from the external water phase. Under static conditions gravitational segregation takes place over a number of days, allowing oil migration to surface solids migration to bottom and leaving clear water in between. Figures 1 and 2 below show the effect of OSB on the rheology of the direct emulsion system, in which 5% w/w tar sands has been incorporated. As the yield point falls over time, the separation into the distinct phases begins. The process is slowed by colder temperatures, especially in the later stages when water clarification occurs. Figure 3 shows the direct emulsion fluid breaking into its components over time.

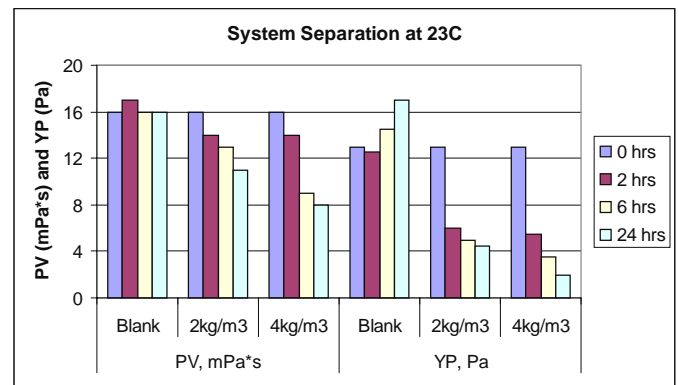


Figure 1 – Effect on Plastic Viscosity and Yield Point on room temperature Direct Emulsion fluid containing increasing amounts of oil-sands breaker.

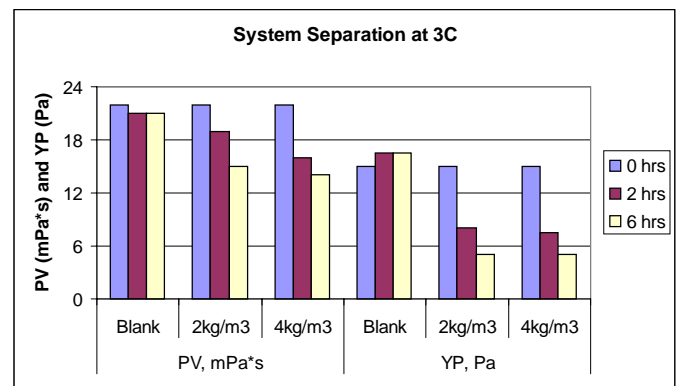


Figure 2 – Similar to Figure 1 above but with a test temperature of 3 °C.

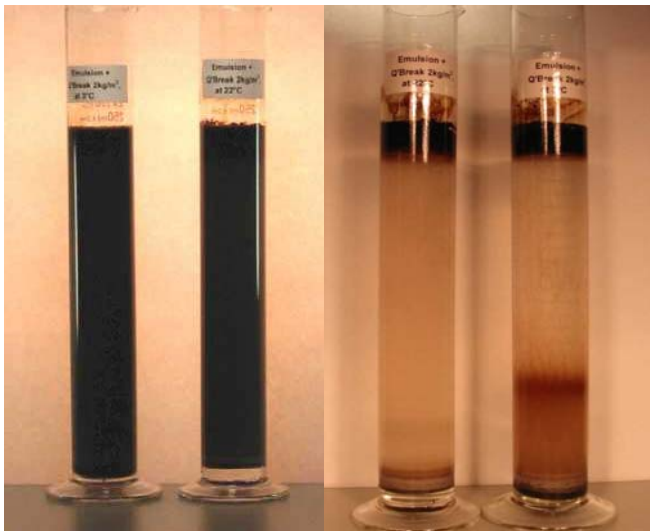


Figure 3 – Left Picture is beginning of a static OSB test at 3 °C (left side) and 23 °C (right side). Right-hand picture show the separation of the oil, water and solids phases after 7 days time, at 23 °C (left side) and 3 °C (right side).

The clear water and solids/sand generated by OSB contains <0.5% oil within 2-3 days of static conditioning. Both waste streams passed the regulatory bioassay test Microtox, which allows for the simple disposal of the liquids on-site.

Step 5 – Breaking the emulsion in dynamic condition (high energy environment). Batch drilling of hole sections in the tar sands is commonly practiced. This results in the generation of large volumes of fluid and a need to quickly break the emulsion into its basic components. The most common field procedure for separating drilling fluids is de-watering them using high speed centrifuges with anionic or cationic polyacrylamide polymers for flocculation.

This process has been applied to samples of the Direct Emulsion system with very good results, thereby indicating that fluid de-watering is possible. The best phase separation was obtained by centrifuging the system with a cationic polymer commonly used in de-watering operations. Figure 4 provides an example of the separation of the phases under dynamic centrifuging conditions.

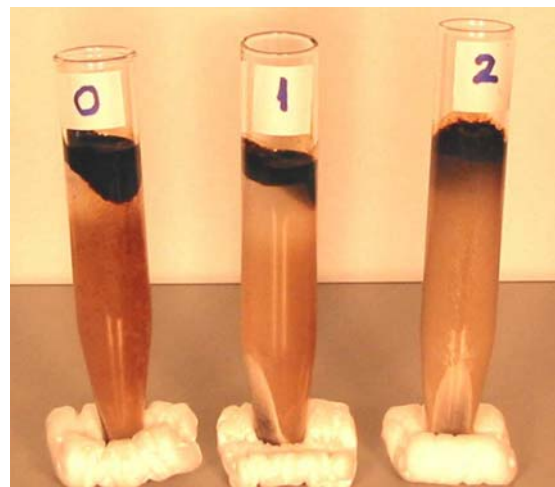


Figure 4 – Centrifuging of Direct Emulsion mud using a cationic PHPA polymer. The three phases of oil, water and solids are readily seen.

Step 6 – Steel accretion performance. This step concentrated on determining the non-accretive ability of the novel Direct Emulsion System. Samples of the mud contaminated with tar sand core were rolled in high-carbon steel cells for 72 hrs. Excellent non-accretive ability was noticed on inspection, and as seen in Figure 5. The left hand cell shows tar accretion from a sample that contains no OSC, while the right hand cell shows the Direct Emulsion containing OSC. No accretion is evident in that cell.



Figure 5 – Accretion forming properties of Fluid without Oil Sands Cleaner (left side) and fluid containing 5% Oil-Sands Cleaner (right side)

Step 7 – Health, Safety & Environment. This step provided an overall look at the components of the Direct Emulsion System, from the HS&E point of view. The fluid was fresh water based containing polymers and a breaker that are environmentally friendly natural products. The cleaner is a highly biodegradable hydrocarbon-based product with extremely low toxicity.

No special handling procedures or equipment were required. No special rubber seals on the rig were required. The fluid had the ability of being separated into its components and disposed of cheaply and effectively without environmental impact.

Japan Canada Oil Sands Hangingstone 2004 Steam Assisted Gravity Drainage (SAGD) Project

General Information. The Hangingstone field is situated approximately 30 km south of Ft. McMurray in northeastern Alberta (Figure 6). The entire area contains heavy oil of varying viscosities and is located at various depths up to 600 meters deep. The shallow McMurray oil bearing sands are generally mined, while those at greater depth are often produced through Steam Assisted Gravity Drainage (SAGD). The Hangingstone field encounters the McMurray formation between 275 and 300 mTVD.

The results described below are for three pairs of injector/producers drilled in the 2004 year in the Hangingstone field.

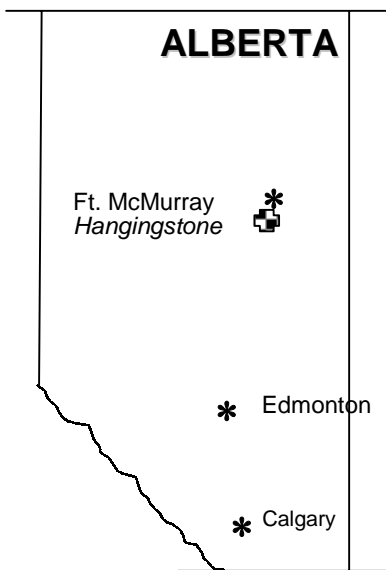


Figure 6 – Hangingstone Field situated 350 km N.E. of Edmonton, Alberta.

Twinned upper and lower horizontal well pairs are the keys to SAGD production, with the upper well being the steam injector. The lower producer well collects the hot, lower viscosity oil. The well pairs are often drilled from a central pad area, thereby allowing for typically three to four well pairs from a single pad.

A typical well design is shown in Figure 7. The surface holes are batch drilled and a 340 mm casing set at approximately 80-90 meters depth. The 311 mm intermediate section is drilled with water to ~ 300 mMD and to a hole angle of 60-65 degrees from vertical. At this point the system is switched to drilling fluid and drilled to horizontal casing point at 500-600 mMD. The injectors are landed at the top of the McMurray heavy oil sand while the producer is fully within the McMurray formation. A 500-700 meter displacement, 222 mm horizontal leg is then drilled. 178 mm screened liners are then run to TD and tied back. No cement is run in the horizontal sections.

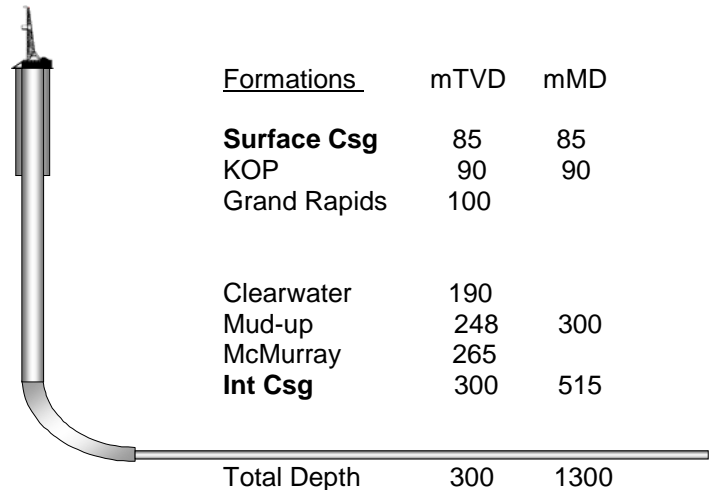


Figure 7 – Typical formation and casing depths of the SAGD horizontal wells in Hangingstone Field.

The SAGD wells typically encounter the following problems during the drilling phase:

- mud rings and sticky gumbo from below the casing shoe to approximately 300 m in the Grand Rapids and Clearwater formations
- running horizontal liner to TD is often difficult due to the shallow vertical depth and long horizontal reach
- instability of semi-consolidated oil sands is common if fluid type is not inhibitive or if wellbore temperature rises above 26°C
- accretion of the oil onto drilling tubulars, solids control equipment and tanks leads to equipment failures and downtime
- disposal of oil contaminated solids and oil contaminated drilling fluids is costly
- dump and dilute mud system in order to maintain drilling fluid properties. Oil content within drilling fluid can affect rheology and filtration control, high solids contents also required dumping of whole mud
- mud foaming with salt water based fluids

Drilling Fluid System Selection. Historically, drilling fluid selection for the McMurray formation has been based upon preventing the tar from dispersing into the water based fluids. The plan was to bring the tar sands to surface, remove the oily sands from the circulating fluid and continue to drill ahead with this same “oil-free” fluid. Commonly, the fluids of choice have been salt based polymer muds of either potassium chloride (KCl) or potassium sulfate (K₂SO₄). Unless the drilling fluids were kept at temperatures of less than approximately 25 °C with chilling units, the problems described above invariably occurred. Accretion, mud foaming, and dump/dilute cycles of whole mud were common with these systems.

The new Direct Emulsion fluid, as described earlier in the development phase of this paper, deals with the tar in a completely different manner. Oil from the tar sands was expected to loosely emulsify itself within the drilling fluid with the aid of OSC, thus leaving the sands themselves clean and with low/no residual oil content. Those solids would then be easily disposed of at the wellsite. The drilling fluid itself would be separated into the oil, water and solid phases using the OSB additive with the waste streams being easily handled on-site (for the solids and water phases) and the oil transported to a near-by processing facility.

Well Performance. The drilling cost performance and time to rig release for the six well 2004 project is given in Table 5. The wells are presented in chronological order.

Well	Over/(Under) \$ AFE Cost	Actual time (days)	AFE time (days)	Time Over/(Under)
HZMP	243,244	12.64	7.67	4.97
HZMI	(103,089)	8.50	7.67	0.83
HZNP	(282,276)	6.04	7.67	(1.63)
HZNI	(98,768)	5.52	7.67	(2.15)
HZLP	(244,019)	5.92	7.67	(1.75)
HZLI	(511,583)	5.75	7.67	(1.92)
Totals	(\$966,491)	44.37	46.02	(1.65)

Table 5 – Costs and time information for six horizontal wells drilled in the 2004 Hangingstone SAGD project.

The total days savings was slightly better than AFE. The performance on a per-well basis started out poorly but showed significant improvement by the end of the third well and steady performance to the end of the drilling process. The primary time overrun was on the first well and is attributed mainly to thawing of rig equipment in the cold conditions (-45 °C) and issues with the wellhead operations.

The total AFE cost for the 6 wells were \$7.78 million dollars. Realized savings of \$996,419 dollars was equivalent to a 13% cost reduction over the 6 wells. As described below in the drilling fluid performance, the Direct Emulsion system was in-part responsible for a portion of the savings.

Productive and Non-Productive Time. Figure 8 shows the productive and non-productive times for each of the six wells, from spud to rig release. The average of those 2004 wells is compared to the last set of wells in 2002 and 2003. While the scopes of the projects are somewhat different from year to year (in terms of horizontal displacements), the figure clearly shows an improvement in non-productive time in the 2004 set of wells. In addition, the 2004 suite of 6 wells showed improvement throughout the drilling operations, in both drilling time and non-productive operations.

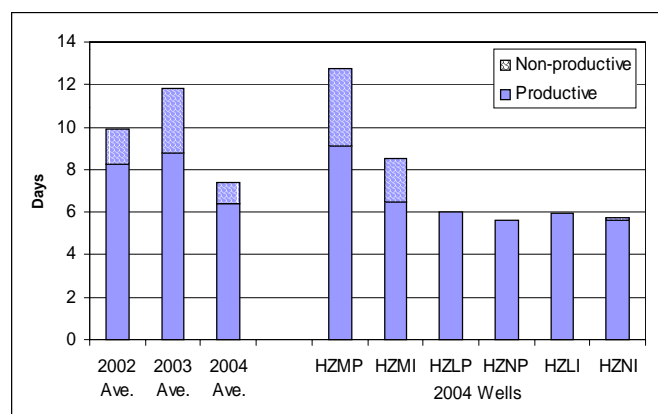


Figure 8 – Productive and non-productive time breakdown for SAGD wells drilled in 2002 through 2004.

The primary drivers to improved drilling times are either ROP enhancements, fewer drilling problems or less time taken to condition hole and run casing. Analysis of the data showed minor average ROP improvements in the 2004 set of wells compared to the 2003 wells. Table 6 provides the ROP values for the intermediate and main production horizontal sections of the wells.

WELL	INTERMEDIATE HOLE ROP (m/hr)	PRODUCTION HOLE ROP (m/hr)
2002 Average	13.98	22.36
2003 Average	16.99	22.85
2004 Average	16.87	23.35
HZMP	14.67	17.06
HZMI	8.38	27.33
HZLP	22.00	27.60
HZNP	23.82	19.89
HZLI	25.00	21.19
HZNI	25.25	30.16

Table 6 – Rate-of-penetration data for intermediate and horizontal hole sections for Hangingstone SAGD wells drilled in 2002 through 2004.

Significant time savings were seen in the running casing/liner operations, in both the intermediate and horizontal well sections. Table 7 provides those results. The improved efficiency is directly related to improved hole conditions and the resulting less hole conditioning required and a distinct ease in running the casing to bottom.

WELL	INTERM. HOLE RUNNING TIME (hrs)	PRODUCTION HOLE RUNNING TIME (hrs)
2002 Average	45.29	46.79
2003 Average	31.56	45.00
2004 Average	19.79	29.58
HZMP	29.00	41.25
HZMI	20.00	32.25
HZLP	16.50	30.25
HZNP	16.25	25.50
HZLI	16.50	26.25
HZNI	20.50	21.50

Table 7 – Time values for running casing and liners in intermediate and production holes, respectively, for 2002-2004 Hangingstone SAGD wells.

Drilling Fluids Performance – Intermediate Section.

Water drilling was successfully used to drill to the top of the oil-sand McMurray formation. The advantages of this practice is to promote faster drilling, segregation of non-oil containing solids and minimization of mud rings. Once at the top of the McMurray, the drilling fluid was switched over to the Direct Emulsion system to drill the remainder of the intermediate hole. This same fluid was processed of excessive solids and then used to drill the horizontal injector and producer legs.

In previous years of 2002/2003, a salt based potassium chloride or potassium sulfate system was used to drill the build section after mudding up. Even with keeping the mud temperatures below 26 °C, accretion of tar onto the drilling equipment and blinding of the shaker screens was problematic. Shaker screens run on those projects were typically 84 to 100 mesh at the finest, and removed only the largest of cuttings. Reducing screen size caused blinding of the screens with tar. Drilling fluid density for this interval averaged 1095-1100 kg/m³ under normal drilling conditions.

The Direct Emulsion system performed much better than the salt based systems used previously. The bitumen from the tar sand appeared to separate out from the sand over the shale shakers, but without adhering to those same shakers. The tar typically ran over the end of the shakers in long ribbons and without sand entrapment. Running finer shaker screens enhanced the process of tar removal from the McMurray sand. Shaker screen sizes were commonly reduced to 210/175/175/145 and 210/210/180/145 over the sets of shakers. As a result of the finer mesh shakers, the drilling fluid density was maintained at 1070 kg/m³ for the build sections. Shaker screen life also increased up to 9 fold using the Direct Emulsion fluid. No borehole instability was noted.

Drilling Fluids Performance – Horizontal Section. The Direct Emulsion system was used to drill out the cement and casing shoe and then drilled to TD on each of the 6 horizontal legs. The fluid was stored and saved, or partially stripped after each horizontal leg.

Similar projects drilled in 2002 and 2003 employed the salt muds, as described above, for the horizontal wells.

The Direct Emulsion system typically had densities controlled between 1050 to 1070 kg/m³. The same shaker screen specifications that were run in the build section were continued throughout the horizontal drilling process. Accretion was not observed in the Direct Emulsions system as the tar flowed over the shaker screens.

The concentration of OSC in the drilling fluid was monitored and evaluated after the completion of each horizontal leg. In the first well, OSC was run initially at 5.5% v/v and was allowed to drop to 3.5% by the completion of the horizontal leg. As mentioned previously, that concentration was sufficient to prevent accretion and blinding of the shaker screens. However, conditioning the hole to run the liner did lead to tar accretion on the drillpipe and directional tools after they were pulled out of the hole. Bringing the OSC concentration back to 5% did improve hole conditions, however pull down forces on the liner were higher than anticipated. Tar accretion inside the intermediate casing was suspected.

The second well maintained active OSC concentrations of 7% v/v throughout the intermediate and main hole sections. No accretion was observed. Some minor accretion on the pipe and tools was noted while running the liner.

The subsequent wells had a circulating OSC percentage of 9% or greater. No accretion was observed while drilling or while running the production liners to bottom on any of those four final wells. Pull down forces on the liner were within expected operating windows.

Accretion was also eliminated on the surface equipment. Using potassium-based fluids, where accretion has been a problem, cleaning of the drilling fluid tanks averaged 17 hours per event. By comparison, cleaning of the surface tanks averaged 15 minutes with the Direct Emulsion system.

Foaming of most freshwater and saltwater based fluids used in heavy oil sands or tar sands drilling is common. This is believed to arise when the tar/oil is not incorporated into the fluid itself, but rather acts like an oily drilled solid. The Direct Emulsion fluid did not foam in any of the six wells. Incorporation of the tar into the fluid itself is believed to be the reason for the non-foaming. No defoamers or bacteriacides were used throughout the six wells.

Drilling Fluid Costs. Table 8 shows the costs for the drilling fluid for the 2002 through 2004 wells, specifically for the intermediate and production hole sections.

Year/Well	Mud Type	\$ Mud Cost Interm.	\$ Mud Cost Product.	\$ Mud Cost Total	mM D at TD
2002 Aver.	K ₂ SO ₄ Polymer			28,000	
2003 Aver.	KCl Polymer	4,394	38,534	42,928	1505
2004 Aver.	Direct Emulsion	14,653	7,878	22,531	1078
HZMP	Direct Emulsion	18,450	13,856	32,306	1027
HZMI	Direct Emulsion	21,317	11,855	33,172	1014
HZLP	Direct Emulsion	12,183	8,492	20,675	1140
HZNP	Direct Emulsion	7,605	8,146	15,751	1140
HZLI	Direct Emulsion	12,685	4,915	17,600	1006
HZNI	Direct Emulsion	4,189	11,671	15,680	1140

Table 8 – Drilling fluid costs for intermediate and production holes during 2002-2004 Hangingstone projects.

The Direct Emulsion fluids were less expensive than the KCl polymer fluids drilled in the previous year. Comparing \$ mud cost/m drilled, the averages for 2003 and 2004 respectively were \$28.52/m and \$20.90/m. The Direct Emulsion system was more expensive in the intermediate wellbores but considerably less in the horizontal wells. This is attributable to both fluid reuse for the Direct Emulsion fluid from well to well, and to the lack of drilling problems in the horizontal sections of these same wells. Note that the first two wells in the 2004 program were more expensive than the other four; primarily due to the new fluid being built during those two wells.

Disposal Impacts. Heavy tar and drilled solids, and heavy tar in drilling fluids leads to expensive disposal and clean-up costs. Current regulations within Alberta make it very difficult to dispose of any salt laden fluids except by downhole injection or by hauling to landfill. Given the remoteness of the Hangingstone field to either option, the Direct Emulsion fluid gives the ability to ease disposal by on-site mix/bury/cover operations.

Based on laboratory testing, it was thought that the following waste disposal methods may be possible:

- Disposal of stripped Direct Emulsion fluids in an earthen sump followed by pump off after minor treatments
- Disposal of whole Direct Emulsion mud, after treatment with OSB in an earthen sump, followed by pump off of the liquids after minor treatment and disposal of the solids by mix-bury-cover.
- Treatment of the solids on site followed by disposal of the solids by mix-bury-cover.

As this was the first field trial of the PolyTar system and all of the data was based on lab testing, all three disposal methods

were not fully implemented as a failure could result in significant cost over-runs. The first option of disposal and pump off of stripped Direct Emulsion fluid was undertaken on as much of the fluid as possible.

In normal drilling operations, the majority of the tar is not contained within the Direct Emulsion system, but is rather attached to the solids on the shaker screen overflow. Any solids which were retained within the drilling fluid and processed by the centrifuges on-site contained only a trace of oil.

Initial sampling of the sump containing the stripped Direct Emulsion fluid showed a failure for on-site disposal for both the liquid and solid phases. Oil content was too high to allow for pump-off methods. Following treatment with aluminum sulphate and a PHPA, the oil was skimmed off the surface of the sump. The liquid phase then passed disposal criteria at 100%, and 800 m³ was subsequently pumped off. The solid phase contained sludge from degradation of the sump wall lining, and did not pass disposal regulations. This material was therefore hauled to an approved disposal site.

A disposal pilot test was conducted on site. The project consisted of solids sampling and then washing of these solids with water for 3 minutes and allowing the solids to settle. After removal of the water and oil, the solids were retested for oil content. The results are as follows:

Group 1:

- Unwashed centrifuge underflow – Dry cuttings had a higher oil content than those that appear wet. Wet cut solids would at times meet 3:1 mix-bury-cover criteria without washing.
- Washed centrifuge underflow – All washed cuttings met 3:1 mix-bury-cover criteria.

Group 2:

- Unwashed solids from stripping of Direct Emulsion mud – Very high oil content. Approximately 10 times acceptable criteria.
- Washed solids from stripping of Direct Emulsion mud – All washed cuttings met 3:1 mix-bury-cover criteria.

Group 3:

- Unwashed solids from the scalping shaker – Extremely high oil content, particularly if finer mesh (100+) screens are run. When fine mesh screens were run, a significant amount of separation of the oil from the mud took place over the shakers resulting in streams of almost pure bitumen running off the shakers.
- Washed solids from the scalping shaker – not tested due to extremely high oil content.

An average of \$46,750/well was spent on reclamation and drilling waste disposal for the 2004 wells. By contrast, the 2003 wells drilled with KCl brine based fluids, which were primarily just hauled to a landfill site, cost an average of \$70,000 per well. A potential for greater savings is possible with the Direct Emulsion fluid if the OSB technology proves as viable in the field as it does a laboratory setting.

Conclusions and Recommendations

1. Laboratory development of a unique tar/oil dissolving fluid was accomplished. The key components to the process are the oil-sands cleaner while actively drilling and the oil-sands breaker to separate the Direct Emulsion into three separate phases.
2. The Direct Emulsion drilling fluid provides a viable method of drilling tar sands and heavy oil containing sands.
3. The fluid prevents accretion of the tar/oil onto drilling strings, casing, and any surface equipment. A minimum concentration of >5% v/v oil-sands cleaner is needed while actively drilling, and a minimum of 9% is needed while running the liners.
4. Foaming of Direct Emulsion systems was not seen in either laboratory or field conditions.
5. Pump off disposal of liquid portions of stripped Direct Emulsion fluid is viable and readily accomplished. Washing of the solids in a pilot-test was promising as a method of full scale removal of oil from the majority of oily drilled solids.

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