

DRILLING ENGINEERING CHALLENGES IN COMMERCIAL SAGD WELL DESIGN IN ALBERTA

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INTRODUCTION

The Alberta Oil Sands deposits, located in the areas of Athabasca, Cold Lake and Peace River, are widely recognized for their tremendous resources (Figure 1). The Alberta Energy and Utilities Board (AEUB) has estimated that the potential ultimate volume of crude bitumen in place in Alberta to be some 400 billion cubic metres (2.5 trillion barrels). Of these, the ultimate potential amount of crude bitumen recoverable from Cretaceous sediments by in situ recovery methods is estimated to be 33 billion cubic metres (200 billion barrels).

About 80% of the bitumen in Alberta are contained in the Athabasca Oil Sands Deposits, where the in situ viscosity is over 1 million centipoise. The oil industry and Alberta government have been searching for in situ techniques to recover the bitumen economically. Significant amount of research and development and piloting effort have been spent on in-situ combustion, cyclic steam stimulation and steamflooding with limited success. Finally, with the advance in horizontal well drilling, the Steam Assisted Gravity Drainage (SAGD) process was pioneered at the Underground Test Facilities (UTF) near Fort McMurray and has become the technology of choice for many new in-situ projects in Alberta. Some 39 SAGD well pairs have been drilled in Alberta to date. In the last two years, there are four announced new commercial in-situ development in the Athabasca Oil Sands, whereby SAGD is the selected recovery process. These projects are AEC Foster Creek, JACOS Hangingstone, Pan Canadian

Christina Lake and Petro Canada Mackay River. These commercial scale projects will utilize parallel pairs of horizontal wells which are key to the SAGD process. The lower horizontal well is the producer and the upper horizontal well, which is placed several metres directly above the producer, is the steam injector (Figure 2). As steam is injected into the reservoir along the upper horizontal well, the steam rises in the reservoir and heats up the bitumen. When the steam cools, the force of gravity enables the heated bitumen and condensate (water) to flow to the lower production well.

The amount of steam injected and fluid produced depend on reservoir qualities such as permeability, porosity, water saturation; on operating constraints such as operating pressure and steam trap control temperature; and on the length of the well. Some of the factors that determine the length of a well include geology and the pressure drop between the heel and the toe in the horizontal section. The pressure drop in an injector is a function of steam volume, pressure and pipe size. Using a larger casing will reduce this pressure drop. The selection of the size of the liner and the intermediate casing is also influenced by the size of tubing and other instrumentation strings inside the casings. All the injection/production process, monitoring and manipulation demands have to be defined and addressed prior to considering the more typical drilling engineering issues. Thus, the optimization in the drilling design of SAGD wells requires dramatically more multi-disciplined team synergy than do vertical wells.

The SAGD wells can be considered as extended reach

drilling (ERD) applications, where total length will be 3 to 8 times the true vertical depth (TVD). The well pairs must have uniquely precise 3-D trajectory control, since the accuracy of well separation is a critical parameter in the SAGD process. Typically the reservoir will be a very shallow depth (150 to 600 m TVD). Sloughing and hole stability are concerns in drilling in the unconsolidated oil sands while tight streaks, shale plugs in the reservoir and the erratic overlain glacial till deposits may cause deflection from the well path. All these aspects present significant design and operational challenges to the well construction team.

In the field pilots conducted to date, these challenges have been overcome with numerous technical and operational innovations. Magnetic vectoring for trajectory control, fibre optics for downhole instrumentation, expansion joints for tubular thermal distortion are examples. As the industry progresses from process validation (i.e., pilot) to commercial scale development, much more emphasis must be placed on the capital and operating costs of these wells. The well construction costs represent a significant portion of total project capital expenditures. The economic success of any SAGD development will depend on how cost effectively the multi-disciplined team can address and overcome the design and operational challenges of optimized well pairs.

This paper will focus on two specific drilling engineering issues: the requirement for fluid chilling and the choice of vertical vs. slant intermediate hole section geometry.

MUD COOLING

An extensive series of informal interviews with SAGD pilot operators revealed a spectrum of opinion in respect to the value added of mud chilling during drilling operations. The argument promoting mud cooling is relatively straightforward. The in-situ temperature of the typical SAGD reservoir is low. The "Cold Lake" type deposits will have reservoir temperature around 12-16 °C. The deposits of the more tar-like bitumen in the Fort McMurray region to the north tend to occur at a shallower depth and will have in-situ temperatures in the 7-10 °C range. While drilling, the fluid gains temperature due to the pumping action. The relatively hot drilling fluid will warm the near wellbore radius. The bitumen being heated along the well will thin, and this would lead to a reduction in the cohesive nature of the tar sand material. This may lead to a higher risk of hole instability, wellbore collapse and a host of other potential aggravations to the drilling operations. One can argue that mud chilling is an appropriate preventative maintenance step to reduce these potential hole trouble risks.

However, a significant proportion of experienced SAGD pilot operators claim mud cooling is expensive and relatively inefficient, and simply question the "value added" of this undertaking. In the publicly available documentation of SAGD field pilot operations there exist very little detailed data on either the effectiveness of mud cooling, or any definitive field observations of improved hole conditions being the direct result of mud chilling. During extensive interviews with SAGD pilot operators, it became clear that the issue is driven by personal opinion and common sense, as opposed to any detailed field data, which either strongly supports or challenges the benefit argument.

The authors conducted a review of the field data available from a pilot drilled in the Cold Lake area in the winter season. During extended bitumen drilling intervals (horizontal hole exposure time averaged 7.3 days per well), the drilling fluid temperature increased to a maximum of approximately 35 °C. Mud chilling was attempted by adding dry ice to the mud tanks. The field data was too sparse to define the chilling efficiency of this method, although it was expensive. The limited hole condition monitoring of torque and drag values (T&D) conducted on these wells precluded any ability to validate a value added, or risk avoided by mud chilling. The fact that all well pairs (for the most part) were successfully completed is not definitive proof of a mud chilling benefit. This "rather indefinite" scenario is common.

Heat Generation and Dissemination

There are many unknowns in regard to how much heat is gained by the drilling fluid via handling and pumping. There exists a complex set of unknowns in terms of where and how fast the heat is disseminated throughout the hole and surface system, as well as how deep and how fast the heat is transferred from circulating fluid to the wellbore wall along the horizontal section in the reservoir.

In an attempt to quantify the heat generation and dissemination in a generic SAGD well design, the following assumptions were made:

1. A 1-km horizontal section is drilled with water. The total hole volume (total measured length is 1,500 metres) is 110m³, the surface tank volume is 250 m³, total system volume is 360 m³
2. A 1,200 HP pumping system is employed and operates 18 hours in a 24-hour period at 95% mechanical efficiency. The in-situ temperature is 10 °C, the ambient and mix water temperature is average of 10 °C and constant.
3. A heat generation of 2,545 BTUs/hour per

horsepower of pump is assumed for the heat generated by pumping. In one day of drilling operations (18 hours pump activity), this would predict the total system volume would experience a heat gain of approximately 18 °C, thus, the system temperature would be 28 °C after the first day with zero heat loss.

The monitored heat gain values in the reviewed pilots were far less than this figure. Perhaps 5-7 °C gain per day is more in line with reported field observation. This would suggest that the majority of the heat is lost by the drilling fluid as it is circulated. How much of this heat is taken up by the bitumen wellbore wall is difficult to quantify.

The effectiveness of introducing dry ice, liquid nitrogen, or other agents to the system is not well documented in the public domain. One operator employed liquid nitrogen to “boil” the active drilling fluid in a Fort McMurray area pilot during the winter season. This appeared to help, since the mud temperature was controlled at low levels. The two pilot pairs were constructed without any major hole stability problems. However, the incremental well cost was quoted in the \$70,000 to \$100,000 range. For a 50-well commercial project, this would relate to a 3 to 5 million-dollar trouble avoidance expenditure. In a commercial scale development, perhaps a more capital intensive (consumable free) commercial chilling unit would be more cost effective.

Recently an operator employed a 30 tonne commercial chilling unit in a SAGD pilot. The first well pairs were drilled in the winter season without major hole trouble observed related to mud temperature. The second phase pilot drilling was to be conducted in the summer. The operator employed a commercial chiller for the summer drilling operations to restrict the drilling fluid temperature to that experienced during winter drilling. This 30-tonne chilling unit is similar in scale to the refrigeration system required in a typical community ice rink.

A series of tubes were installed in a conventional mud tank to act as a heat exchanger. A coolant was circulated to lower the drilling fluid temperature in the tank. This arrangement can be used to either pre-chill the mix water or to actively chill the drilling fluid. Other than the purchase cost or rental of the chiller itself, the only daily expense was fuel to operate the chiller compressors and transfer pumps. The operator reported that this system was relatively inexpensive and trouble free to employ during the drilling operations. The quoted capability of the chiller was 480,000 BTUs per hour. At 90% efficiency, this chiller would remove approximately

10.4 million BTUs from the drilling fluid in a 24-hour period. For our example well scenario, the 360 m³ water system could be chilled approximately 7 °C in 24 hours, or about equal to the field observation of the heat retained in the drilling fluid from the pumping activity.

A review of the field data from this pilot suggests that in general, this degree of cooling was achieved. The well pairs were successfully completed, the fluid temperature was lowered to winter condition levels, and thus the operator is inclined to assign a benefit to the mud cooling efforts.

The critical unknown is the effectiveness of heat transfer from the fluid to the wellbore wall, and the threshold bitumen temperature where thinning causes hole trouble. Recently one operator conducted lab tests on site-specific cores to identify this threshold temperature gain at which thinning of the bitumen would generate hole instability. The tests did identify a target “trouble” temperature, although it must be stressed that it is extremely difficult to mimic all downhole physical and chemical dynamics. There are many inter-related factors other than mud temperature at play. Annular velocities and flow regime, solids distribution, reservoir character, fluid chemistry and rheology, pipe movement, hole exposure time, etc., all may have significant impact on hole integrity. The operator did suggest that for a commercial scale SAGD development, conventional chiller mud-cooling expense will probably average \$10,000 per well. They concluded that this may represent a reasonable “trouble avoidance” expense.

To Cool or Not to Cool?

Most drilling engineers will quickly accept the fact that hot drilling fluid could help aspirate poor hole conditions in a SAGD well setting. It also appears that chillers can be employed to counteract some of the heat gain generated by the drilling activity. Does this mean that mud cooling is a must for commercial SAGD operations?

Figure 3 presents the temperature/viscosity relationship of some sample bitumen. As seen, there is a variance of character. The bitumen in the more northern Athabasca and Fort McMurray regions have higher in-situ viscosity than do the Cold Lake type deposits. This more viscous bitumen tends to be at a shallower depth, and their in-situ temperatures are therefore lower than the deeper, less viscous varieties.

If a SAGD well was drilled in an Athabasca Bitumen (in-situ viscosity of 4,000,000 centipoise @ 10°C); and if the drilling fluid was allowed to heat to 30°C; and if the hot mud was 100% effective in heating the wellbore wall to a

similar temperature of 30 °C, the altered material would still be significantly (i.e., 10 times) thicker than the Cold Lake material in its unheated native state. Given the observation that relatively hot fluid was employed at a Cold Lake area pilot, and the holes had very extensive exposure times without any major hole collapse problem, leads one to conclude that mud chilling will be less critical in a colder, thicker, bitumen application. The thicker and cooler the target bitumen, the less it will be susceptible to hole trouble related to heat transfer from the drilling fluid.

SLANT OR VERTICAL INTERMEDIATE SECTION DESIGN

The optimal 3-dimensional profile of the well will be defined by numerous issues. A pilot program may involve a few well pairs having relatively simple 2-D curve shapes from a small surface pad. On a commercial scale, SAGD development strongly promotes utilization of multi-well pads. The primary benefits of this surface geometry being minimized land disturbance, optimized drilling operations, heat conservation and surface facilities consolidation. Assuming the reservoir areal distribution allows for symmetrical exploitation with parallel well pairs, the vast majority of well pairs will require a 3-D intermediate hole section design.

Figure 4 provides one possible plan view example for a twin, 8-10 pair pad geometry. As seen, most of the wells must have 3-D shape in their intermediate hole section to generate symmetrical, parallel steam chambers. This example design employs 200-metre inter-well pair spacing with horizontal productive intervals of 1-km length. The total area exploited by this layout would be approximately 4.75 km² (1.75 miles²). This geometry puts the gathering system in the ground and exploits almost 2 sections of resource from one central plant facility.

One issue is whether or not to employ a slant design in the upper hole section vs. a more conventional vertical surface hole arrangement. The slant design would reduce the dogleg severity (DLS) in the curve. The DLS is a critical design issue since it constrains ability to drill the wells and install completion tubulars. It also will significantly impact well intervention capabilities, and affects the stress on the thermal casing around the curve. Figure 5 illustrates the performance envelope variation for thermal grade casing as a function of DLS. As seen, the more gentle the bend, the greater the performance capability of the tube. Connector performance is also dramatically affected by the bend rate. In general terms, the greater the bend rate, the more the stress on the connector, thus, the higher the risk of failure. Limiting the DLS is attractive, and thus employing a slant intermediate hole design appears advantageous.

Torque and Drag

A comparison of predicted surface torque and drag values was conducted on the far corner well, illustrated in Figure 4, with progressively shallower settings. For this analysis, the ability to run 1 km of 178 mm slotted liner was investigated in the well where the only change was the shape of the intermediate hole section (slant or curve) and the target TVD. Figure 6 shows the 3-D image of two wells (slant and vertical) having identical starting points and horizontal landing points. For this example it is assumed that all wells must start at a 300 degree Azimuth direction and that directional drilling cannot be initiated above a TVD of 60 metres and Azimuth turns cannot be initiated above a depth of 120 metres TVD. A maximum allowable build rate of 9.5 degree per 30 metres is assumed (both vertical and Azimuth bend rate). All wells have identical heel landing point (275 metres north, 241 metres west of surface location).

The minimum TVD required for a conventional build rate of 8.5° in the vertical plane is approximately 200 metres, assuming the curve is initiated at surface. Since many SAGD settings have glacial till coverage where directional drilling (build rate capability) can be both unpredictable and troublesome, it is assumed a 60-metre TVD vertical conductor barrel is required in the conventional (non-slant) case. The shallowest possible target reservoir depth for the conventional design would therefore be approximately 260 metres.

It must be stressed that there are near infinite number of possible 3-D curves and slant trajectories which would achieve the same landing point. The final choice of 3-D shape must be balanced within spatial constraints, drilling and completion component bend rate capability, instrumentation and downhole component access, optimized drilling parameters, time, cost, etc. This example has not been optimized in this manner, and is offered simply to investigate the torque and drag (T&D) implications of the two basic intermediate hole section shapes.

All well trajectories survey files are roughened at 300 metre frequency with 0.5 degree of torture in the intermediate cased hole and 1 degree in the horizontal section. The curves are thermally cased with 344 mm intermediate casing. One km of 311 mm horizontal section is drilled and then slotted liner is run. The 178 mm (7") slotted liner weighs 25 kg per metre and is run with the necessary length of a running string of 127 mm (5") heavy weight drill pipe topped with 80 metres of 203 mm (8") drill collar for weight inversion. The amount of drag generated (or push required) to install the liner at

the end of the well is predicted utilizing friction factors of 0.28 and 0.22 (open/cased hole respectively). Similar comparison were made for 3 different target TVD (352, 302, and 252 metres). The following figures provide the results of this analysis.

Figures 7 and 8 compare the predicted maximum pushdown and dogleg severity required installing liner to the end of the horizontal section. Figure 9 illustrates the maximum surface torque required to rotate the liner @ 20 RPM during installation. These T&D values are unrealistically high since none of the trajectories or parameters have been optimized. All are kept as similar as possible to illustrate the comparison. The torque dynamics are particularly interesting. The ability to rotate the liner during installation is critical, but must be balanced by torque capability of all downhole tubular components. Special care must be taken with any sand control devices, as they could be distorted or destroyed by pipe manipulation during installation.

This generic comparison illustrates that the surface slant design offers reduction in DLS and section length and a resultant reduction in push and torque requirements. The shallower the depth, the larger the benefit. Assuming the maximum allowable DLS for all potential well components is 8.5 degree, then vertical surface hole would not be practical in any development setting shallower than approximately 250 metres. At deeper target TVD applications, the slant design offers progressively less benefit. For example, the hole conditions of a 352 metre TVD setting have significantly more impact than does the slant design. If the open hole friction factor is improved to 0.25 from 0.28, the drag (push required) for the vertical well case is reduced by 13% compared to the 6% reduction achieved by the slant design at this depth.

It must be stressed that there are numerous other concerns in this choice. Most experienced field personnel will accept that a vertical operation is typically more efficient than drilling or intervening a slant well. Drilling and service rig availability may be a concern where slant design is considered. Wellhead and well servicing components may have to be customized. Future well operations such as concentric string centralization and artificial lift options may be restricted by the slant design.

This discussion illustrates that there are many conflicting concerns involved in the trajectory design. This generic comparison was generated utilizing software programs (WELLPATH and DDRAG) from the DEA-44 Maurer Engineering Suite. Given the uniqueness of each potential SAGD setting, it is clear that detailed thought and trajectory customization is required in the planning of

these 3-D profiles. Other concerns may arise from glacial till, lost zones, gas caps, etc., as they are penetrated by the 3-D trajectories. These are very complex geometries which must be explored and optimized with these software technologies to define the optimum site-specific 3-D profiles. The torque and drag predictions are particularly important as they are the primary indicators of hole conditions to be calibrated and monitored during well construction operations. Without this detailed parameter modeling and monitoring, the well construction team will have difficulty in achieving their goals in an optimized manner.

SUMMARY AND CONCLUSIONS

Alberta has huge amount of bitumen resources. The industry is now on the verge of commercial exploitation of this resource base after having confirmed the viability of the SAGD process through field pilots. As these commercial scale developments are pursued, the well construction team will have to place more focus on cost effective solutions to numerous design and operational challenges. This paper provides a brief examination of two well design issues:

(A) Mud Cooling

Information to-date has not provided definitive proof on the requirement of mud cooling, however, some practical observations and conclusions can be offered:

1. The shallower and thicker the bitumen target, the less emphasis required on mud chilling.
2. Drilling in the winter season will significantly reduce or eliminate the need for mud chilling.
3. The larger the system volume, the less temperature elevation will occur and the faster it will disseminate.
4. Hole exposure time may be a dominant factor in the requirement for mud cooling. The faster the horizontal section can be drilled/lined, the less priority will be given to mud chilling.
5. In a commercial scale project, where mud cooling is deemed a necessary trouble avoidance expense, "built-for-purpose" holding tanks and commercial scale chillers are potentially more cost effective than introducing chilling agents such as dry ice or liquid nitrogen.
6. Spotting cold fluid may help installation of liners where hole conditions are observed to be deteriorating.

7. Given the variation of bitumen character and the uniqueness of each rig setup and drilling fluid system in respect to thermal-dynamic behavior, it will be difficult for one to pre-determine the value-added of mud cooling site-specifically. Detailed operational parameter monitoring would be required to confidently claim a risk avoidance benefit. There are many inter-related cause and effect scenarios which will lead to troublesome hole in a SAGD application. Proper monitoring of downhole conditions (particularly torque and drag values) and a detailed understanding of these cause and effect relationships in an ERD/unconsolidated big hole setting, are the primary tools employed to justify the team's decision either for, or against, mud chilling expenditures.

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(B) Slant vs. Vertical

1. In SAGD commercial development, multi-well pads will be the surface geometry of choice. This will demand complex 3-D trajectories in the curved sections of the wells.
2. Based on maximum acceptable DLS limits, vertical surface hole design will not be practical at depths above a threshold minimum. For 8.5° DLS, this minimum target TVD will be 200 to 250 metres and slant surface hole design will be required at shallower settings.
3. Slant surface hole design does provide advantages in respect to section length, DLS and related drilling parameters (e.g., torque and drag values). The degree of this benefit diminishes as the target TVD increases beyond the vertical design threshold minimum depth.
4. There are many inter-related issues involved in the choice of slant vs. vertical surface hole design. The well construction team must examine all long-term impacts of the 3-D trajectory design in addition to the immediate effect on drilling operations.
5. Hole condition modeling and monitoring (i.e., T&D, friction factors, etc.) are the fundamental tools the well construction team must employ to both optimize these complex 3-D trajectories and cost-effectively construct these challenging ERD well pairs.

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