Drilling a Better Pair: New Technologies in SAGD Directional Drilling

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Summary

The precise placement of well pairs is one of the most-crucial factors in the successful execution of a steam-assisted-gravity-drainage (SAGD) drilling program. A SAGD drilling program includes placing the producer well relative to the reservoir boundaries and twinning the producer with the injector well accurately. Delivering on these high expectations in unconsolidated formations (e.g., the McMurray oil sands in Canada) requires a strong focus on technological innovation.

A common practice in drilling SAGD wells in northeast Alberta is to drill lateral SAGD pairs with conventional, steerable mud motors and logging-while-drilling (LWD) resistivity measurements. Although this combination has delivered success, certain limitations exist in terms of wellbore quality and placement. At a demonstration project by a major oil company, several industry firsts were implemented successfully, including a combination of the newest and most-cutting-edge directional, measurement, and LWD technology.

The keystone of these industry firsts was the application of a soft-formation-modified, point-the-bit rotary-steerable system (RSS) used on 20 horizontal wells. Combined with an ultradeep azimuthal resistivity sensor, the RSS provided precise geosteering along the bottombed boundary in the producer wells, resulting in improved reservoir capture and characterization. More on-bottom time enabled more-efficient drilling and reduced well costs significantly. Highly smooth liner runs reflected the lack of tortuosity in the wellbore, made possible by the rotary bottomhole assembly (BHA). Improved directional control made uniform well separation possible between lateral pairs, thereby reducing the risk of hot spots and short circuiting during SAGD operations. The use of an even-walled power section above the RSS increased the bit rev/min for improved BHA responsiveness while minimizing casing and pipe wear. Overall, the results and lessons learned from the demonstration of these new techniques provide a clear indication of the progressive future of directional drilling in SAGD.

Background

Reservoir Profile and Well Design. Key reservoir properties for the project were as follows:

- Formation: McMurray
- True vertical depth (TVD): 430 m
- Net-pay thickness: 10–40 m
- Reservoir pressure: 2500 kPa
- Reservoir temperature: 14°C
- Bitumen density: 1017 kg/m^3 (7.6°API)
- Bitumen viscosity: 2,950,000 cp

The dense, viscous bitumen is essentially immobile at virgin reservoir temperature. For this reason, a thermal production technique is required to mobilize the oil and bring it to surface for processing. The principal method employed by the oil company is SAGD, along with a small solvent-coinjection pilot. These production methods are discussed in depth in other technical papers (Butler 1998; Orr 2009). Both methods use a pair of horizontal wells, one well being drilled in parallel at a specified distance above the other. The upper (injector) well is used to inject hot fluids into the formation, while the lower (producer) well recovers the gravity-drained liquids, which consist of bitumen along with injected fluids and condensate.

Wells at the Leismer demonstration project (LDP) were planned for approximately 1400-m total depth (TD), with a vertical depth of approximately 430 m. The shallow reservoir TVD and required surface-casing depth (≈185 m) left a relatively tight space for the transition from vertical to horizontal. The well design planned for build rates of up to 8°/30 m over a 200- to 230-m-TVD interval to accomplish this. Injector wells were equipped with 11.75-in. (298-mm) intermediate casing and 8.625-in. (219-mm) slotted liner in the horizontal to accommodate dual injection strings and instrumentation. Producers generally had smaller 9.625-in. (244.5-mm) intermediate casing with a 7-in. (177.8-mm) slotted liner. Horizontal sections were typically 700–800 m and drilled entirely within the producing interval.

Project Scope and Challenges. SAGD is a relatively new drilling and production method, introduced commercially only in the 1990s. Until recently, the precision drilling of SAGD well pairs has been dependent on technology developed for other well designs that do not necessarily require the same level of accuracy. While this technology is rapidly improving, there are perceived limitations about the overall well quality that can be delivered, including the helical, tortuous nature of a wellbore; accurate TVD placement; and a relatively large window required for lateral steering. However, the desire to break those constraints and increase the value of each well pair has led to new ideas and the adoption of newly available technologies that had not previously been employed on an oil-sands project.

With this in mind, the drilling group tasked with this project set ambitious goals, particularly in the build and lateral sections. These goals included

- Maintaining producer-well standoff at 3 m from reservoir base (water) below. The LDP area is underlain by an extensive zone of bottomwater up to 20 m thick. A consistent standoff is crucial to efficient SAGD operation.
- Smooth, low (less than 3°/30 m) dogleg severity (DLS) in lateral trajectories to ease liner runs and ensure consistent, uniform well spacing and geometry.
- No overcorrections (tortuosity). It was viewed that making aggressive course corrections typically resulted in a sinusoidal well path, and, therefore, the directional driller was requested to make small, slight corrections to remain close to the well plan.
- Extremely tight injector/producer steering windows. Instead of a defined vertical and lateral window (in metres, or fraction of a metre), the company requested that the directional drillers maintain the well on the planned trajectory with no tolerance for deviation.
- Maintain 5-m offset between injector/producer in lateral section, and close to 4-m offset for last 100 m. This closure was to happen over 50 m of lateral and be a smooth drop. The closure was designed to assist with even steam distribution.
- Drill 75-m tangent in build section with less than 3°/30 m dogleg rates. This tangent is the landing area for production pumps and is necessary to avoid premature pump failure caused by wellbore tortuosity.

The previously described objectives created challenges not only for drilling engineers, but also for directional drillers and other services involved in the project. In addition to the challenges placed

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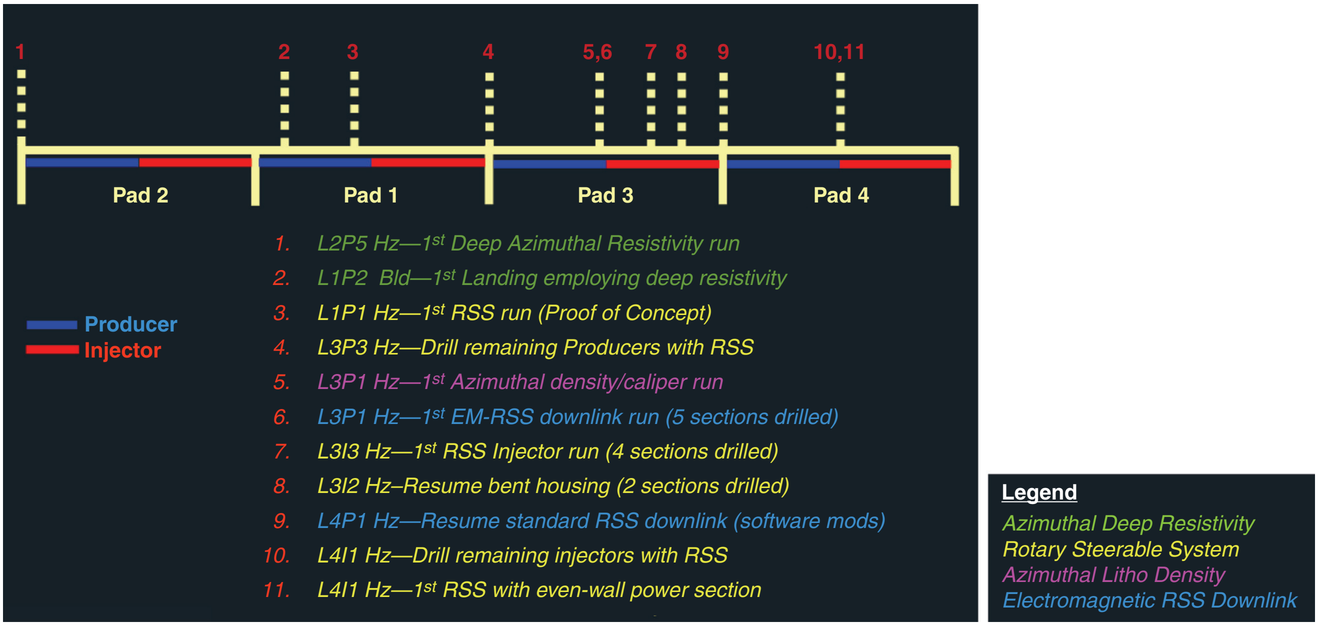

Fig. 1—Progressive project improvements.

on the drilling group by the asset planners, certain operational challenges are also apparent in oil-sands drilling.

• Rotary-speed limitations. Rig rotary speeds were limited to ensure safe and efficient operations at surface. The rev/min limits were chosen to allow surface equipment (i.e., mud system) and personnel to keep up and work safely, and to minimize pipe and casing wear.

• Improve overall rate of penetration (ROP), while maintaining strict control drilling measures. In addition to rev/min limitations, instantaneous ROP was also limited by the drilling group to ensure safe and efficient operations. These restrictions make improving the overall drilling rate a challenge because improvements must come from increases in efficiency and decreases in nonproductive time (NPT).

• Use of electromagnetic (EM) telemetry vs. mud-pulse telemetry. EM telemetry is fast and efficient; however, it also has certain limitations, one of which is communication near a casing shoe.

Progressive Project Improvements. There were numerous modifications and improvements made to the directional program throughout the project, in which a collaborative working environment allowed the operator and service-company personnel to work closely together for continuous, progressive advancements, as shown in **Fig. 1.**

Technology improvements first began with the azimuthal deep-resistivity LWD tool combined with geosteering in real time. The RSS was then added, which required more attention to optimize the tool's performance. The next progressive step was to add an even-walled power section to improve bit rev/min and enhance RSS performance. Finally, an EM-RSS downlink was employed for the first time approximately half-way through Pad 3. The fully integrated, real-time, two-way EM telemetry downlink was successful between the measurement (M)/LWD, rotary-steerable, and surface systems; however, a need for enhancement was identified to optimize the downlink-timing routines over the "old" downlink-pressure-pulse system. A software upgrade has been designed and was implemented soon after the LDP concluded.

Geology and Azimuthal Measurement

The azimuthal deepreading-resistivity sensor was used, as shown in **Fig. 2.** This sensor features multiple spacing, and multiple frequencies and is based on the tilted-antenna concept (Bittar et al. 2007). By using multiple spacings and operating frequencies, the azimuthal deep resistivity capitalizes on the high frequency and short spacing to map the near-wellbore properties. The longer spacing and lower frequencies are used to measure the formation properties of the uninvaded zone. The sensor retains the advantages of high-frequency data (e.g., greater accuracy in high resistivities

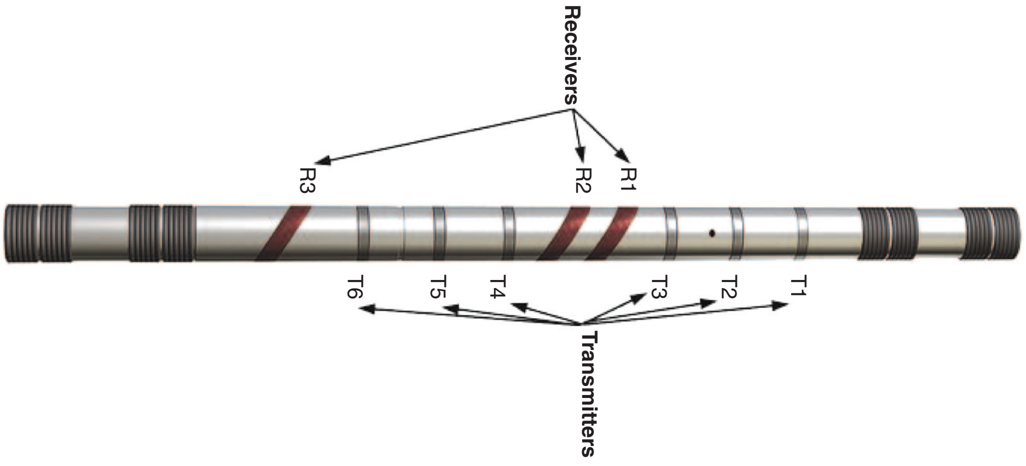

Fig. 2—The azimuthal deep-resistivity sensor.

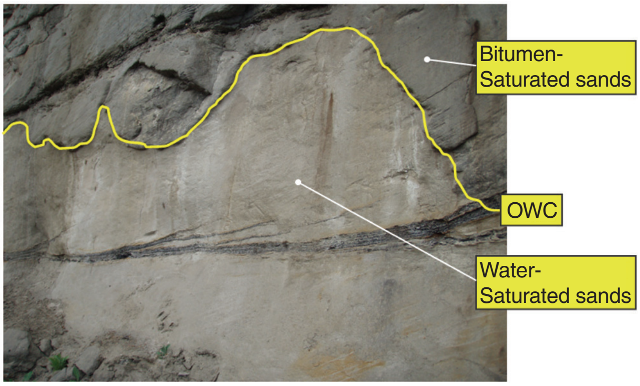

Fig. 3—OWC from outcrop, Christina River, northeast Alberta.

and better vertical resolution), while gaining the advantages of the lower-frequency measurements, including significantly greater depths of investigation – thus, sensing the bed boundaries around the borehole up to 18 ft deep.

As the tool rotates, phase-shift and-attenuation data are acquired in 32 azimuthally oriented bins, referenced to either the high side of the borehole or magnetic north using magnetometers.

The azimuthal deep-resistivity sensors also deliver a series of measurements called geosteering signals or geosignals, indicative of nearby boundaries (Seifert et al. 2009). By design, a geosignal features high sensitivity to interfaces between intervals of different resistivity. Through inversion, the geosignal can determine the distance to boundary with great accuracy, with fine depth resolution. The magnitude of the geosignal is safely above the electronic-noise floor of the sensor for a boundary located more than 18 ft away from the wellbore. However, in the reverse case of trying to detect a high-resistivity caprock (e.g., anhydrite from a low-resistivity formation), the reach and the sensitivity of the geosignal are reduced significantly from their nominal values.

The reservoir sands of the LDP are part of a fluvial-dominated estuarine complex within the Middle to Lower Cretaceous McMurray formation. Base pay is predominantly defined in the LDP development by an oil/water contact (OWC) and associated bottomwater in the basal McMurray sands. The OWC can be troublesome to map and predict because it is rarely flat for any appreciable lateral extent. It is not uncommon to observe 1- to 3-m-TVD variations in the OWC at outcrop scale **(Fig. 3).** The planned well placements of the producer laterals intended a 3- to 4-m standoff from appreciably thick bottomwater zones.

Bottomwater can first act as a heat sink (thief zone) during warm-up circulation of the producer lateral. Insufficient standoff of the producer well to the bottomwater can lead to significant conductive heat loss during circulation, impacting the desired warm-up of the reservoir between the injector and producer wells. Without sufficient standoff, the producer well could also encounter bottomwater coning during the production cycle, which presents a significant risk to the SAGD process that has been observed in other SAGD developments and is an important factor in the overall economic viability of a project.

The azimuthal deep resistivity, in combination with real-time geosteering, was run primarily to map the base of pay, by way of resistivity contrast, in real time and collect compensated shallow- and medium-depth-resistivity data to later aid reservoir characterization. The base-of-pay mapping was also used to make well-trajectory adjustments to maintain the prescribed standoff from the OWC when present. When employed in selected build sections, it was used to confirm standoff from the reservoir base near the intermediate-casing-point (ICP) landing points and for producer horizontal sections to maintain the desired 3- to 4-m standoff from water contact below. A total of 19 100 m in 27 hole sections was drilled over 1,496 operating hours in various (222 mm, 270 mm, and 311 mm) hole sizes, with no downhole failures.

Fig. 4 shows an example of mapping a resistivity contrast, which may be interpreted as base pay (OWC), with the combined distance-to-bed boundary and azimuthal-resistivity measurements. It provides a good appreciation for what is now possible with recent technological advancements. The middle two tracks (gamma is green, average res is red) show little response. Normally, this is all that is observed with "omnidirectional" or bulk-measurement resistivity tools. Looking at the top two tracks, the azimuthal capability is up/down resistivity curves and geosignal. There is significantly more character in the curves, which, in turn, is extremely useful for interpretation. The vertical black lines in all tracks are "geological adjustments" made by the geosteering professionals to honour the

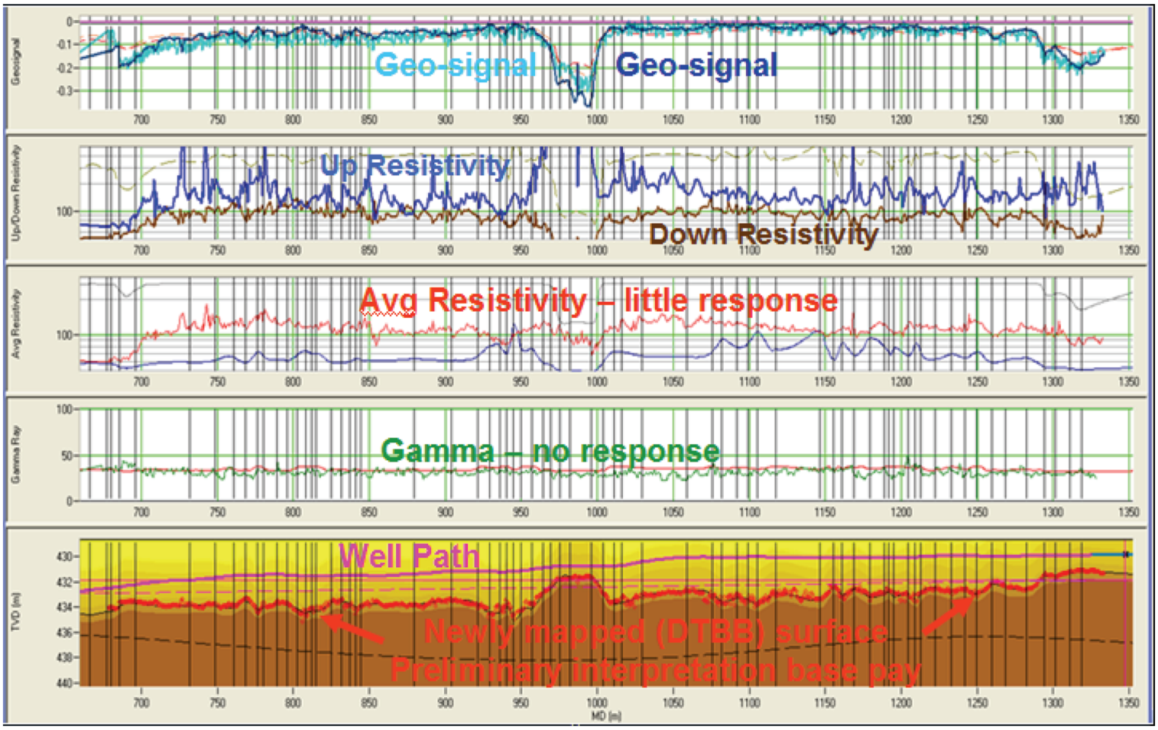

Fig. 4—L3P6 cross section: final distance to bed boundary mapped surface interpretation.

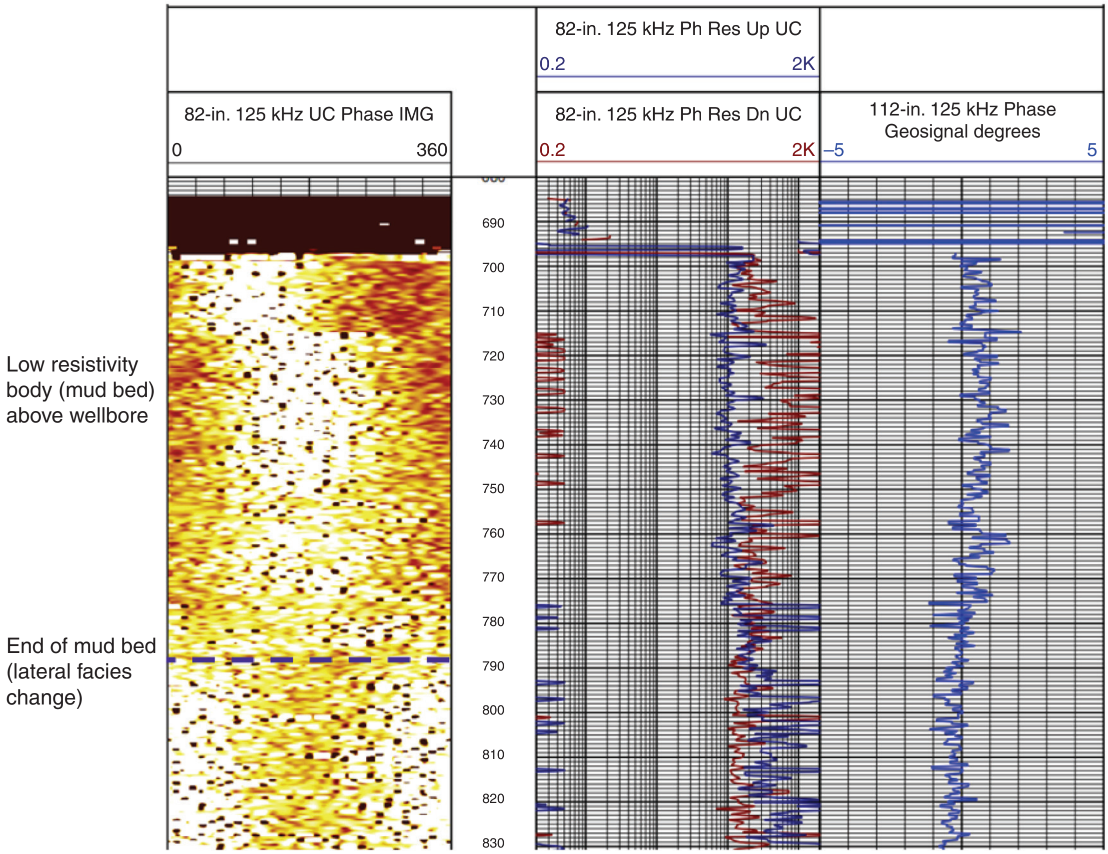

Fig. 5—L1P6 azimuthal-resistivity image.

LWD data measured in real time. The net result out of all of this is that the well-path trajectory has been modified from the original well plan (dotted pink) to the actual well path drilled (solid pink). Without the minor course corrections, the original well plan would have made contact with the nonflat, contrasting-resistivity surface, interpreted as the reservoir base. The well-path adjustments are subtle, but because there is capability to see farther away adjacent to the well path (≈3 m in this case), the subtle course corrections can be made in a smooth manner.

The azimuthal deep-resistivity tool was also used to map reservoir heterogeneities (muds) over 1 m from the wellbore and outside the typical near-wellbore depth of investigation of other resistivity tools. An example of this can be illustrated in the L1P6 producer well **(Fig. 5).** Near the landing point of that build section, a 1.5-m- to 2-m-thick mud bed was encountered and drilled through. The ICP point ended up being ≈0.5 m below the overlying mud. The subsequent drilling of the producer lateral, using the azimuthal deep resistivity, provided the azimuthal-resistivity data and depth of investigation to determine the lateral extent of the heterogeneity.

As observed on the log section (Fig. 5), the 82-in.-phase-resistivity image and up/down resistivity bins display a relatively abrupt change, from the high side being more conductive (low resistivity) up to 790-m measured depth (MD), to the low side being slightly more conductive past 790-m MD. The deeper-reading 112-in., 125-kHz-phase geosignal displays the same characteristic at 790-m MD, which was interpreted as the overlying mud terminating at 790-m MD as a result of a lateral facies change. Past 790-m MD, it is interpreted that the reservoir above the wellbore has a slightly higher resistivity than that of the 3 to 4 m underneath.

Subsequently, the interpretation of the lateral extent of the heterogeneity between the injector and producer wells was used to alter the completion strategy for the well pair.

Curves plotted for analysis were as follows:

• 82-in., 125-kHz long span (uncompensated) phase resistivity image with ROI at 100 Ω-m true resistivity (Rt) of approximately 2.5 m.

• 82-in., up/down 125 kHz phase resistivity with ROI at 100 Ω-m Rt of approximately 2.5 m.

• 112-in., 125-kHz phase geosignal ROI at 100 Ω-m approximately 3 m.

Rotary-Steerable Drilling

Potential Challenges With RSS. SAGD has typically been applied in bitumen-filled clastic formations (e.g., the McMurray). This low-strength reservoir rock is most often drilled by limiting ROP to 50 to 60 m/h to ensure good hole cleaning. It is well known in the industry that drilling unconsolidated oil sands has its own unique set of challenges largely related to borehole quality, including bitumen accretion, borehole instability, borehole washout, and borehole cleaning. In addition, maintaining a smooth, relatively flat well trajectory is important for a number of production-related reasons, including uniform steam distribution, good well hydraulics, and ease of twinning injector wells.

Before the first RSS run, a number of performance-related concerns needed to be addressed. First, would the rear of the extended-gauge bit or bit/sleeve combination maintain the required contact points? The RSS BHA relies on stabilizer borehole contact and bit-fulcrum point. Second, would there be adequate directional (build/turn steerability) control maintained in this unconsolidated formation? Third, would the RSS tool respond and would the magnetic-ranging data be of adequate quality given the environment and operating parameters? The minimum recommended operational rotary speed (60 rev/min) was actually the maximum rev/min allowable by the operator.

There were other concerns, including increased pipe and casing wear with higher revolutions of the drillstring. Inexperience in drilling the McMurray formation and SAGD pairs with RSS technology was a consideration. Economics was also a consideration, given that RSS has a higher operating and lost-in-hole cost.

As a result of the success of running liners in laterals drilled with RSS assemblies, the next logical step was to improve drilling efficiencies further (e.g., eliminating wiper trips and backreaming).

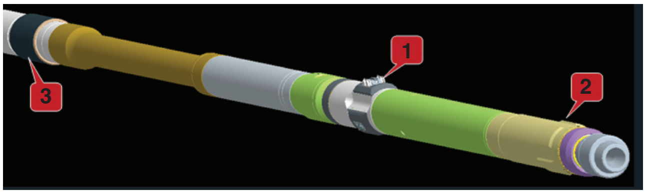

Fig. 6—Soft-formation package.

However, because this was near the completion of the project and there were few spare liner joints available, and considering the risk of the liner not reaching bottom because of hole issues, the operating company chose to consider those options in future operations.

RSS and Track Record at LDP. The RSS contributed a large degree to the overall drilling success of this project. A total of 20 horizontal hole sections were drilled with this system, including 12 producer horizontals and eight injector horizontals. In all, a total of 13 000 m of hole was drilled, in both 222-mm and 270-mm hole sizes, with 744 operating hours and only one battery-related downhole tool failure.

Point-the-Bit RSS. The RSS uses point-the-bit geometry matched with extended-gauge bits to provide directional control with low sensitivity to formation strength and produce optimum hole quality (Alvord et al. 2004). This system uses long gauge-stabilized bits with a passive gauge profile that produces a straight, smooth hole with minimum tortuosity. Hole enlargement is a risk in extremely soft formations that can lead to reduced directional performance and poor hole quality. Pointing the bit removes the need for aggressive sidecutting features that can lead to hole enlargement, formation of ledges, and hole spiralling. The RSS points the bit by deflecting a driveshaft between two bearings. The lower-bearing acts as a fulcrum, allowing the end of the driveshaft and bit to point in the desired direction. The amount of driveshaft bend is variable; therefore, the DLS output can be controlled as needed. Because the tool does not push the bit sideways to deviate, this RSS can use extended-gauge stabilized bits.

Design features for the extended gauge were determined for this application using bit- and BHA-modelling software that calculates dynamic forces and loading on the bit and bit gauge. The extended-gauge length, number of blades, degree of spiral, and gauge size were designed to minimize side forces on the formation while producing maximum directional control. Point-the-bit systems use a fulcrum point on the bit gauge to produce bit tilt. The number of blades and degree of spiral distribute side forces over a wider area to reduce point load on the formation. Minimizing and distributing side forces on the extended gauge reduce hole enlargement in soft formations.

The system allows inclusion of the stabilized, rotating magnet sub directly above the bit for use with the rotary magnet-ranging system. The magnet sub was designed as an integral part of the bit's extended-gauge geometry, with gauge features optimized for this application.

Point-the-bit technology helped achieve several of the goals of the project, including a high degree of directional control in soft formations, minimal tortuosity, and good hole quality.

Soft-Formation Package. Before the first run at LDP, there was concern that a typical RSS would not be capable of delivering consistent build rates in extremely soft formations. Drilling in these formations can result in hole enlargement, which can affect several aspects of RSS performance. Modifications were made to the RSS system to optimize performance and mitigate risks associated with hole enlargement. The soft-formation package consists of several tool modifications that have been developed from extensive experience drilling soft formations in Alaska, Brazil, and other areas. The soft-formation package consists primarily of the following elements.

Extended-Reach Rollers. RSS bit tool-face control is achieved by housing the tool-face-control mechanism in the reference housing that is decoupled from the drillstring in the rotational sense. Reference-housing rotation is maintained at a slow rate to enable tool-face control. The reference housing has a reference stabilizer that provides resistance to rotation using a set of spring-loaded rollers that contact the borehole wall. Under extreme hole-enlargement conditions, the conventional roller system may not contact the borehole wall sufficiently to provide resistance to rotation, resulting in poor tool-face control. An extended-reach roller mechanism was designed (Point 1 in **Fig. 6**) to provide additional radial reach, yet still collapse back into the housing when required by gauge hole. The system provides reference-housing control with up to 1.8 in. of borehole washout. The reference stabilizer has bypass channels along the body to increase the flow area around the reference stabilizer and reduce the washout effect.

Lower-Housing Stabilization. Hole enlargement at the bit can impact directional performance significantly by reducing the bit-fulcrum force. If the formation compressive strength is less than the force at the fulcrum point, the hole will enlarge until the force drops to a level it can support. This enlargement will negatively impact DLS capability. Lower-reference-housing stabilization (Point 2 in Fig. 6) helps maintain DLS capability by reducing side force at the bit and supporting the bit face in borehole-enlargement conditions. The fulcrum moves back to the lower-housing stabilizer, which is nonrotating, thereby reducing the degree of hole enlargement. Even with the stabilized lower housing, right-side walk and less-than-effective build rates were encountered, especially with the larger (270-mm) hole sections.

Upper Stabilization Optimization. The RSS soft-formation package also includes upper stabilizer gauge and location optimization (Point 3 in Fig. 6). This in-line stabilizer is a wired stabilizer allowing electrical communication above and below. The upper-stabilizer position and gauge affect DLS performance and reference-housing control. Side force on the reference stabilizer is one of the parameters that controls how effective the reference stabilizer is at providing resistance to rotation in soft formation and borehole enlargement. BHA-modelling software is used to optimize the reference-stabilizer position and side force to provide maximum tool-face control and DLS capability.

Bit Restrictor. A pressure restrictor in the bit is included in the soft-formation package. The restrictor provides some backpressure on the system to enable downlink communications while opening the bit-jet nozzles to maximum size to reduce hydraulic force and optimize the jet velocity on the formation. Minimizing hydraulic force on the formation reduces borehole enlargement by reducing jetting the formation ahead of the bit. Note that pressure drop, either through the bit nozzles or through the bit restrictor, is unnecessary when employing the EM-RSS downlink operation, which was trialed on Pad L3.

Walled Performance Motor Above RSS. The rev/min limit of 60 was imposed on the drilling rig for this project, which affected several aspects of the drilling operation. The RSS-tool-face-correction rate, when tool-face adjustments are made, is a function of tool and string rev/min. The low rev/min reduces the speed at which tool-face corrections can be made and, thus, affects the directional response of the BHA. The low rev/min also affected the rotary magnet-ranging-system-data quality because this measurement acquisition is statistical in nature. Because of the abrasiveness of the sand formations being drilled, a significant amount of wear can occur to the drillpipe during rotation.

To address these issues, an even-walled performance motor was used with the RSS system. This performance motor is a wired mud motor with an even-walled power section designed for use with the RSS system. It is modular in that it can be placed anywhere in the LWD-RSS BHA while passing power and high-speed communications through the tool. Rotation and torque are applied directly to the RSS and bit without requiring drillstring rotation from the surface.

The even-walled power section used for this application was 6/7 lobe, 4.5 stage with .099 rev/L output. By pumping a flow rate of 2,100 rev/min, 200 rev/min was generated from the performance motor and, combined with 30 rev/min from the surface, resulted in a bit speed of 230 rev/min. The higher bit speed improved BHA directional response significantly and made toolface adjustments nearly instantaneous. The quality of the data from the rotary magnet-ranging system improved, and wear on the drillpipe was reduced by reducing string rev/min.

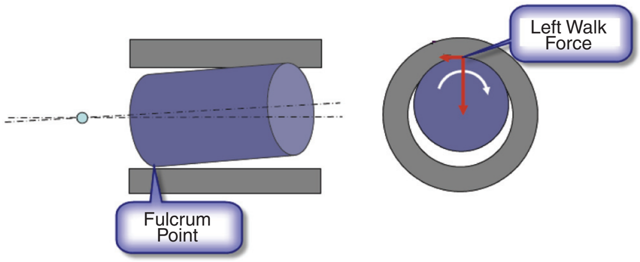

Fig. 7—Walk of long gauge/sleeve pad in building angle.

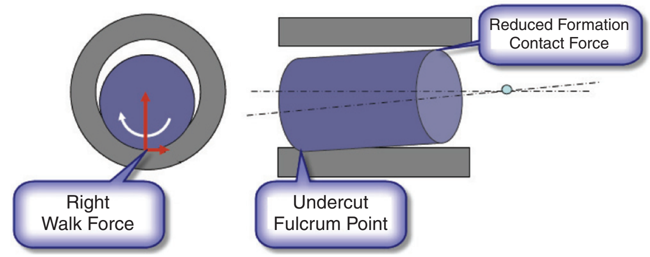

Fig. 8—Right-hand walk of long gauge/sleeve pad in building angle.

RSS Bit Behaviour

As with other components used in SAGD drilling operations, bit technologies have evolved. The evolution to "matched drilling system" designs allows operators to achieve their goal of producing the best possible wellbore quality by means of maintaining effective directional control. Extended-gauge bits or combination bits provide this directional control and performance when combined with a properly configured RSS.

When using a long-gauge or sleeved polycrystalline-diamond-compact (PDC) bit with a point-the-bit system, the ability to generate required doglegs varies significantly with the rock strength encountered and the RSS configuration (Chen et al. 2008). **Fig. 7** illustrates the action of such a design in a hard-rock application. Note that the fulcrum point is located at the top of the gauge sleeve. Under normal drilling conditions, a left-side walk force is created. This configuration will produce maximum DLS because the rock is not compromised at the fulcrum point.

When rock strength is reduced significantly, as in the LDP, several changes to drilling characteristics occur. For example, the formation becomes undercut at the fulcrum point because of the lack of support of the extended gauge or sleeve. This causes reduced contact with the cutting structure, adversely affecting directional performance. The resulting walk force switches to a right-side force because the undercut section of the sleeve has the largest formation contact area **(Fig. 8).**

The final system modification was to custom design a bit for this specific application. By using directional modelling software within the bit design program, a solution was created for the 222-mm lateral sections. This design incorporated a wide-blade modified extended gauge sleeve to provide support on the low side of the hole to prevent undercutting. It also uses an aggressive lateral cutting structure to take full advantage of any side forces delivered by the BHA, which enabled the bit to provide maximum performance in the unconsolidated sands. Before using the new design, approximately 25% of the total distance steered was to correct for azimuth deviation, in particular to combat right-side walk. This average dropped to 8.4% with the introduction of the new bit. The average distance drilled with maximum RSS deflection went from 16.8 to 6.1%, reducing wear and tear on the complete system.

Wellbore Quality

Mason and Chen (2005) suggest the following definition for an ideal well:

- No unexpected deviations from the planned wellbore
- Minimum tortuosity
- No wellbore spiralling
- No residual-cuttings bed
- No ledges
- No wellbore breakout/hole in gauge/no hole ovality
- Minimum hole size drilled for required casing
- Hole fit for purpose to run casing with ease

This paper also mentions the importance of cost effectiveness, safety, meeting reservoir objectives, and that the success of a well is not dependent only on the directional-drilling achievements. It is widely understood that a smoother, straighter, and more in-gauge wellbore is easier to drill and complete, and typically has less probability of problems or failures. This idea has helped drive the development of new drilling, measurement, and logging technologies (e.g, azimuthal deep-resistivity and RSS systems). These systems are designed to deliver the highest-quality wellbore possible. Benefits of a high-quality borehole include more-efficient drilling rates, reduced NPT, minimized tortuosity and spiralling, reduced torque and drag, and less wear on tools. However, characterizing the overall quality of a wellbore can be a difficult and subjective task. Several indicators give clues to hole condition, including directional surveys, pressure/volume/temperature data, torque and drag during drilling, casing runs, and, where possible, borehole logs.

A good-quality wellbore is desirable not only for drilling and completion operations but also for producing and depleting the reservoir effectively. Particularly in SAGD pairs, where uniform separation and proximity in the formation is critical, there is significant value in drilling the best wells possible. Data from LDP described in the following subsections suggest that the RSS, along with the other technologies implemented, helped to deliver a higher-quality wellbore that meets numerous criteria of an "ideal well" **(Fig. 9).**

Cumulative Doglegs. Doglegs are an indicator of tortuosity in a wellbore. The degree, frequency, and positioning of doglegs can affect drilling operations, casing runs, and future completions. By drilling with a conventional mud motor and bent housing, tortuosity and irregularity in the well path is inevitable. Furthermore, because of survey frequency with directional tools (typically one survey per joint of drillpipe), this drilling system leaves hidden microdoglegs in the wellbore that are not observed on a final directional survey. These doglegs, if not properly addressed and understood, can dramatically increase torque and drag, fatigue, and casing-running issues. As explained in previous subsections, a point-the-bit RSS eliminates the BHA bend, creating a smoother, straighter well profile, and reduces tortuosity. This result is evident in our analysis of DLS for the LDP. **Figs. 10 and 11** show cumulative dogleg curves for a sampling of producer and injector wells, respectively.

Cumulative doglegs are a method of representing the aggregation of twists and turns in the wellbore. Therefore, the higher the slope of each curve, the more tortuous, in general, the wellbore. The comparison shows that the rotary-steerable runs were predominantly less tortuous in terms of dogleg accumulation. The RSS wells were also far more consistent, indicating the repeatability of its performance in the unconsolidated sands. Further evidence of an improvement is the fact that on the final 11 rotary-steerable wells, the maximum allowed dogleg was increased to 5°/30 m from 3°/30 m because of confidence in the reduction in microdoglegs between survey stations. Even with the increase in allowed rates, the cumulative curves for those wells remained below those of the average conventional well. These dogleg curves cannot tell the entire story of hole condition; however, they give a clue that with further refinement, the RSS could dramatically improve hole quality in soft, unconsolidated sand environments and allow longer extended-reach wells with consistent trajectories.

Pull Downs. The use of compression or rotation to force slotted liners to TD in long SAGD laterals is a fairly common practice. The extra force is required to overcome friction and drag and to move liners through obstructions in the well path. Typically, the action of rotating while using pull-down force is limited because the slotted liners are vulnerable to damage under combined torsional and compressional loading scenarios. Most operators establish strict

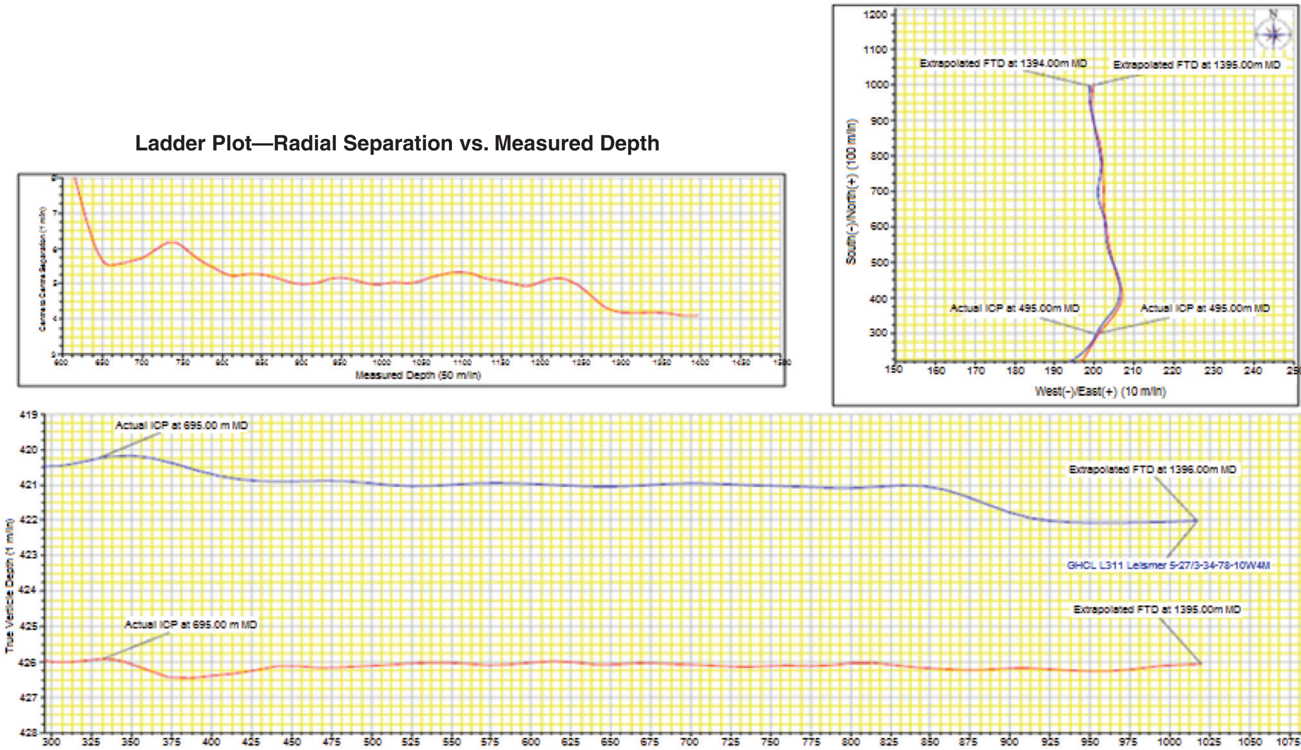

Fig. 9—Ladder plot for producer well drilled with RSS at LDP, showing smooth, straight trajectory.

guidelines for running slotted liners to avoid slot deformation; however, these limits may be pushed or exceeded in problem situations, especially considering the hidden microdoglegs that typically exist in a conventionally drilled wellbore. Thus, it is important to minimize the need for supplementary force by ensuring the best possible hole condition before running liners.

At LDP, rotating during liner runs was prohibited, leaving pull downs as the only means for overcoming drag and restrictions. **Table 1** summarizes the average pull down data during liner runs for all lateral sections at LDP.

A significant reduction in force used to run liners was experienced in holes drilled with the RSS. This was particularly noticeable in the 222-mm producer hole, where greater than 50% fewer wells required pull downs. The smaller producer holes allowed for a tighter tool standoff, which likely contributed to the smoother, more in-gauge hole. In addition, most producer wells did not require magnetic ranging, which tends to have the effect of increasing the sinusoidal, tortuous nature of a wellbore. The 270-mm injectors, which were magnetically ranged, also had liners go to bottom with greater ease in the rotary-steerable wells, with greater than 20% fewer liners requiring pull downs. This result was also despite the added challenges and learning curve of drilling a larger-gauge hole, and twinning the well by magnetically ranging to the producer. For both hole sizes, when force was required on RSS wells, it was significantly less and was predominantly needed only to break static friction (8000 daN vs. up to 18 000 daN), and not for the entire length of the joint. These results suggest a reduction in tortuosity, better hole cleaning, and less overall obstruction in wells drilled with the RSS, allowing the liner to slide to the bottom with greater ease and less restriction.

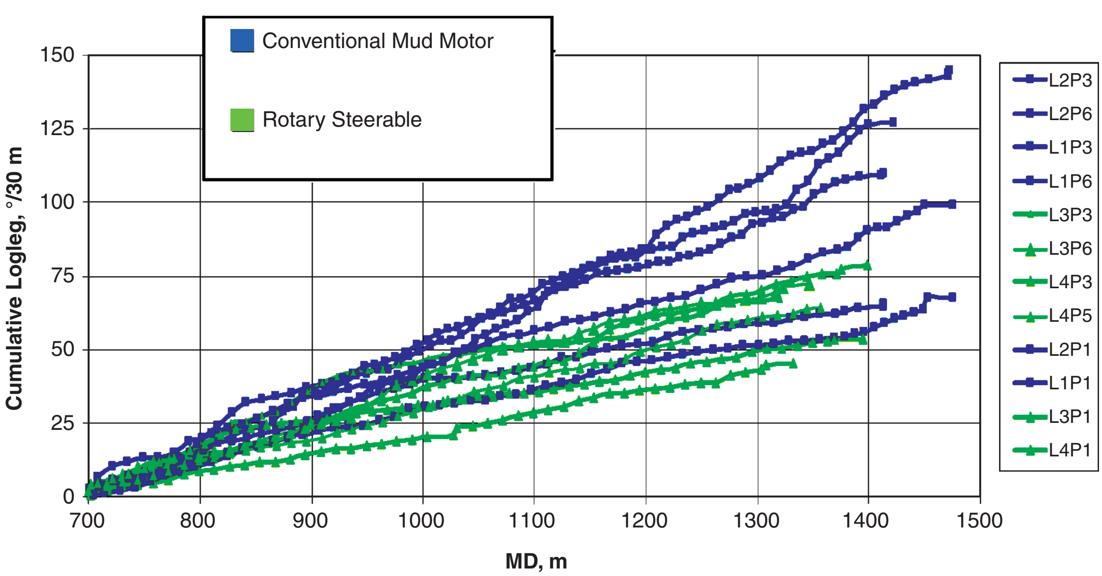

Fig. 10—Producer cumulative doglegs.

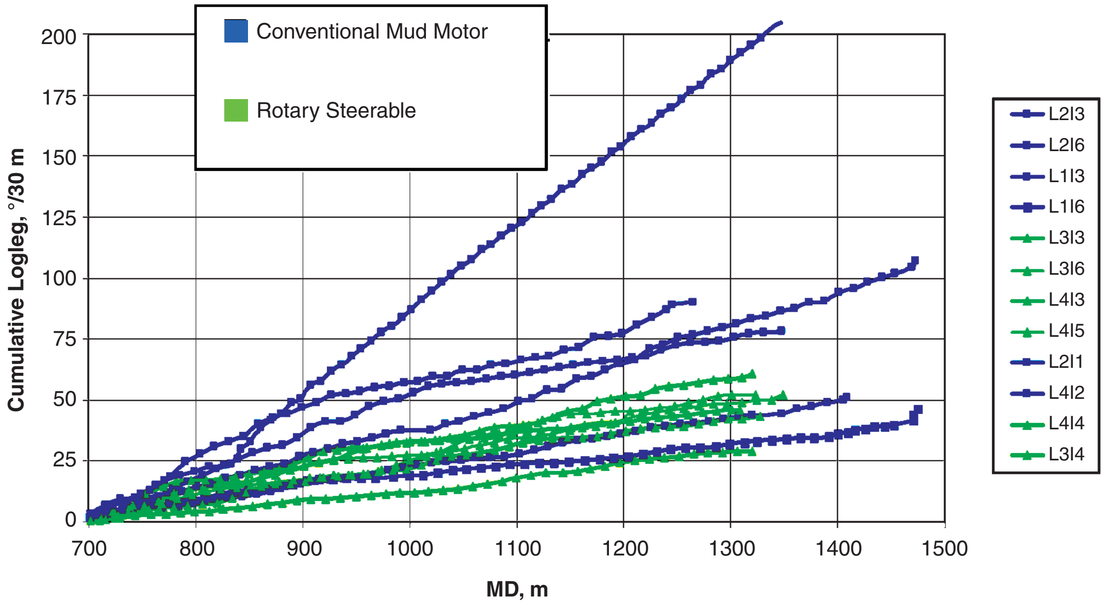

Fig. 11—Injector cumulative doglegs.

TABLE 1—SUMMARY OF PULL DOWNS USED IN SLOTTED-LINER RUNS AT LDP

	Conventional Motor		Rotary Steerable	
	222-mm Hole 177.8-mm Liner	270-mm Hole 219.1-mm Liner	222-mm Hole 177.8-mm Liner	270-mm Hole 219.1-mm Liner
Min. Force Used (daN)	0	4,000	0	0
Max. Force Used (daN)	18,000	16,000	8,000	8,000
Requiring Pulldowns	75%	100%	35%	78%

Torque Trends. Torque trends during drilling operations are shown in **Fig. 12.** The lowest surface torque was recorded with the power section and RSS combination. The trend shows relatively higher peak surface torques with RSS alone and with the conventional mud motor. The difference is attributed to several factors, including torque being delivered by the power section downhole, increased rotary rev/min with RSS, and improved hole quality with the RSS system. The power section used with the conventional motor and

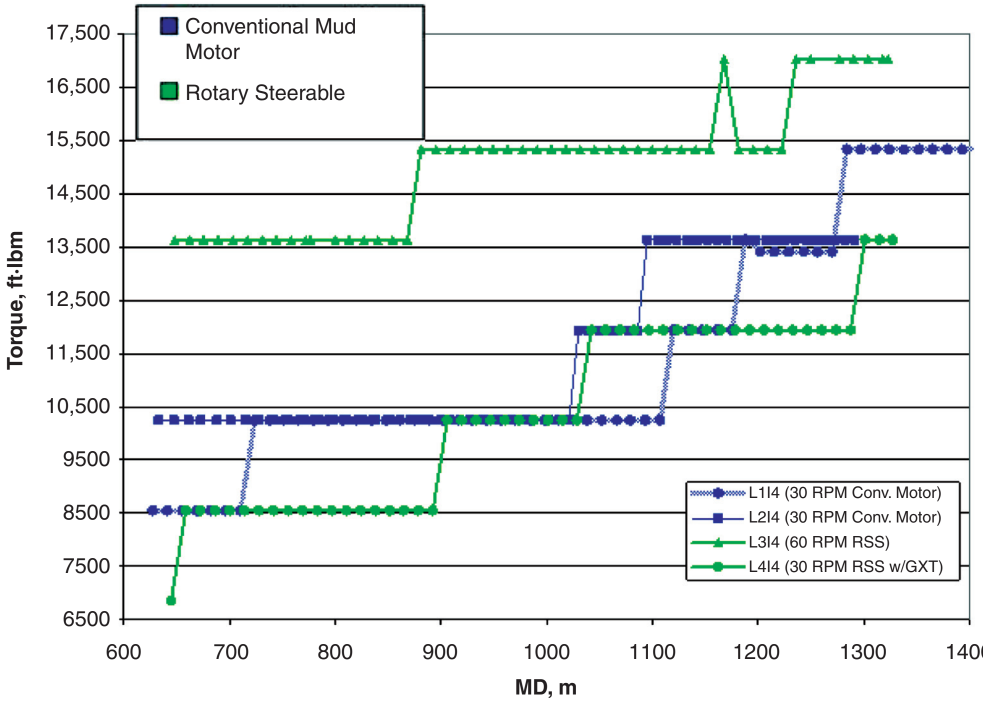

Fig. 12—Rotary-torque trends.

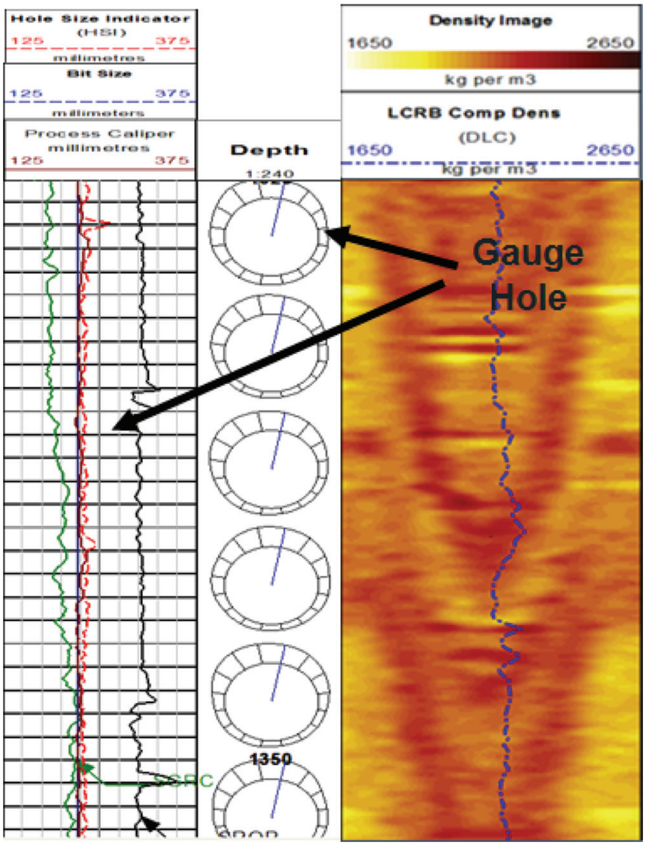

Fig. 13—Azimuthal litho density (ALD): Hz borehole density imaging and caliper on L3P1 Hz (drilling).

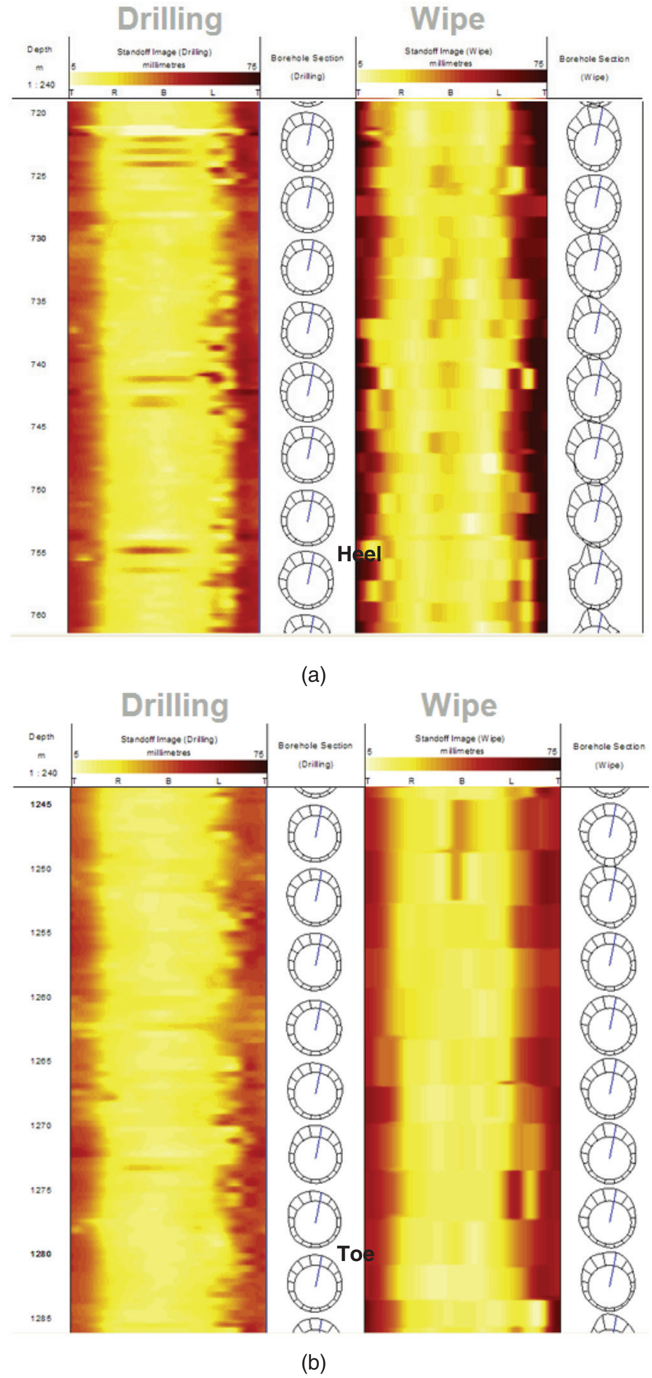

Fig. 14—ALD: Hz borehole density imaging and caliper on L3P1 Hz (drilling vs. wipe).

the powered RSS delivers 3,000 to 4,000 lbf-ft of torque directly to the bit, reducing the torque required at surface. With the RSS system, the entire torque requirement is delivered at the surface. Also, on wells drilled with conventional directional motors, rotary speeds were approximately 30 rev/min with a limit of 50 rev/min; however, the RSS required a recommended minimum of 60 rev/min to operate effectively. This added rotational speed would account for some increase in surface torque with the RSS system. A better comparison of torque trends is the conventional motor vs. the powered RSS, in which both systems have torque being delivered by a downhole power section. The powered RSS shows lower torque as a result of improved hole quality produced by the RSS.

It is important to note that the rotary torque levels experienced in the rotary-steerable runs were still well below the makeup torque of the drillpipe connection and the rig's top drive-torque limits; therefore, the impact of the increased torque with RSS was relatively minimal. The torque levels returned to a lower level with the use of the power section on top of the RSS, as shown in Fig. 12.

Borehole Caliper and Imaging. Both the operating company and the service provider were interested in proving that the borehole was in good shape geometrically when drilling with an RSS and extended-gauge bit. On the L3P1 well, it was decided to run a real-time LWD density imaging and borehole-caliper tool to acquire density and borehole-caliper data while drilling and, after TD, backream out of hole and relog 305 m of data (1000 m to 695-m MD), followed by a wiper trip. A 30-m drilling interval near TD is shown in **Fig. 13,** confirming that the 222-mm centric hole is in gauge when initially drilled. A borehole of this quality inevitably enables minimized tortuosity, improved log response, decreased friction factor leading to reduced NPT, and no ledging through stringered formations.

Fig. 14 shows the comparison between a drilled and wiped section near the ICP. The hole is in gauge while drilling, but the hole deteriorates because washout develops between the drilling pass and backreaming pass. The washout becomes more pronounced from toe to heel.

Drilling-Related Efficiencies. ***Time Efficiencies***. The LDP was drilled under controlled drilling parameters, which included rev/min and ROP restrictions. Decreasing drilling times in this environment required improvements in efficiencies (e.g., reducing sources of NPT while maintaining a consistent ROP and good hole cleaning). Sources of NPT include survey time, connections, flow checks, rewiping the hole, orienting steerable mud motors, and backreaming. **Fig. 15** shows the "overall" drilling rate from spud to TD for producer-lateral sections. This rate is the ratio of the total spud to TD lateral time over the length of section drilled, including all NPT. The results show that the average rotary-steerable run was drilled 7 m/h (39%) faster than conventional-mud-motor runs.

For the injector laterals, two step changes in performance were experienced. The initial attempt at RSS while magnetically ranging yielded a modest improvement of 2 m/h (10%) better than conventional. This result was because of rev/min limitations and their

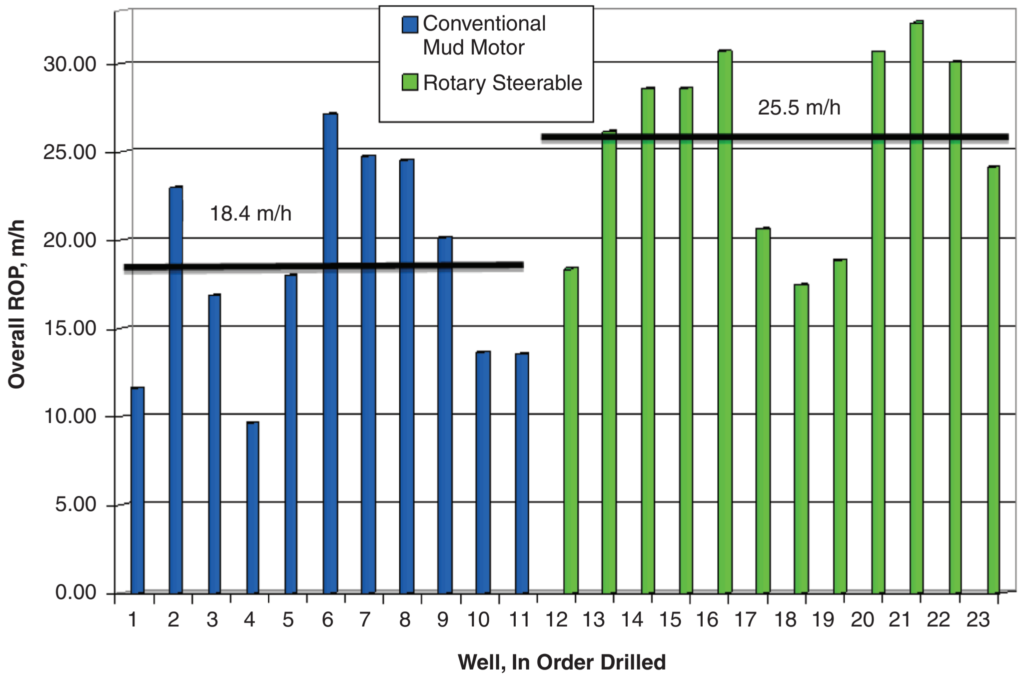

Fig. 15—Average overall ROP for LDP producer laterals.

effect on the RSS responsiveness, magnetic-ranging performance, and BHA configuration not being optimized during the pilot runs.

The introduction of a performance motor power section (even-walled performance motor) above the RSS on the final pad allowed an increase in rev/min at the bit to 230 from 60 rev/min. The corresponding enhancement in directional control, steerability, and ranging quality resulted in a total gain of greater than 12 m/h (53% ROP improvement) above the average conventionally drilled injector lateral. The chronological order of wells drilled, shown in **Fig. 16,** shows that strides in performance were still being made on the final two injector laterals drilled.

Operating Efficiencies: Integrated EM Telemetry and Downlink to RSS

This RSS had always been electronically connected to the M/LWD and controlled from operator-initiated downlinks from surface. By "closing the EM loop" and removing the mud-pulse-telemetry downlink from surface, all real-time tool communications between the M/LWD system, RSS, and surface are now fully integrated using EM communication. The operation became safer by removing the surface downlink skid unit from the equation. The induced pressure drops were no longer necessary, thus lowering stand-pipe pressures and removing some mechanical components from the system, inevitably leading to a simpler, more-efficient, and more-reliable overall system.

Economic Efficiencies

The most desirable outcome of increasing drilling efficiency is decreasing the time-based costs of drilling a well, which can be significant. Although a technology or process may be more expensive to employ in an operation, the resulting efficiency savings could far outweigh the added cost. This is demonstrated in **Figs. 17 and 18,** showing average spud-to-TD time and average cost per metre for injector and producer laterals on each pad, respectively. This cost

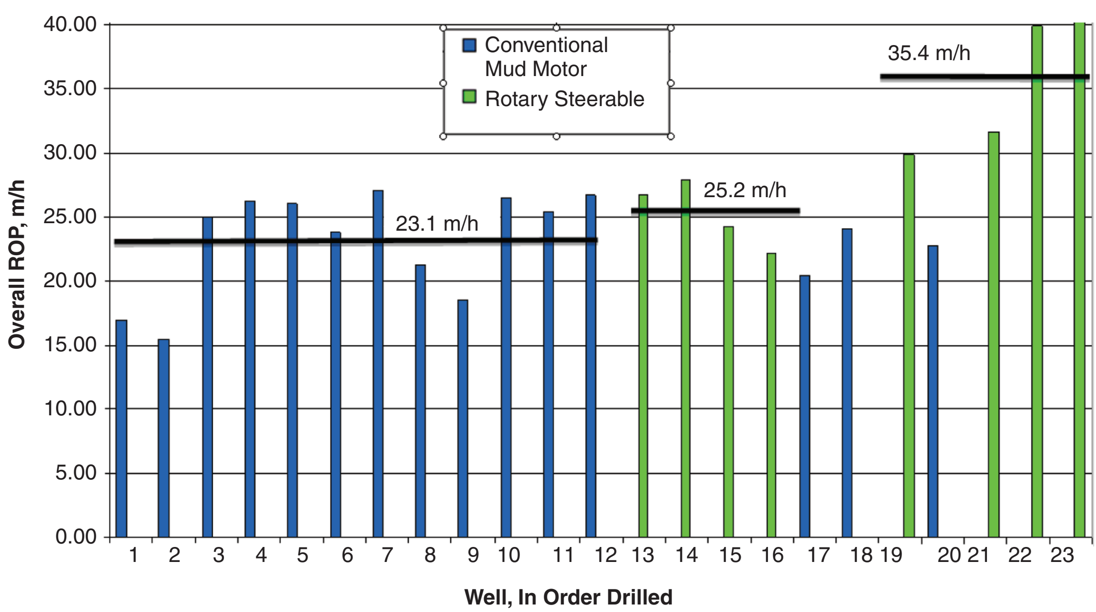

Fig. 16—Average overall ROP for LDP injector laterals.

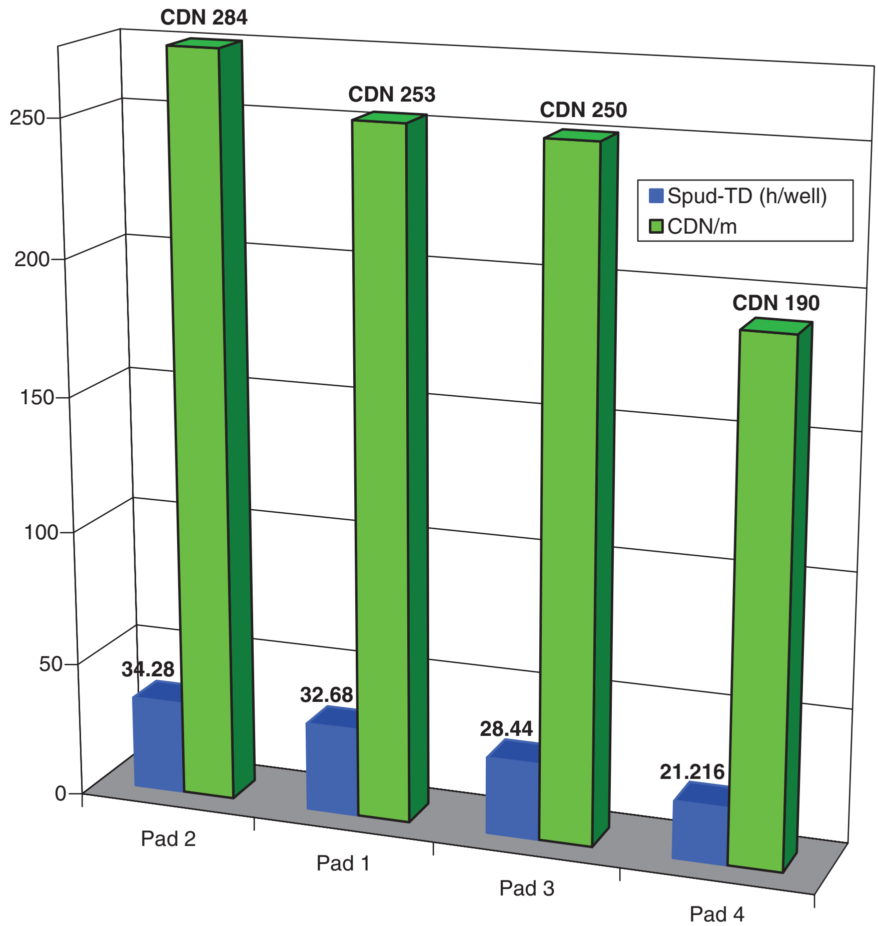

Fig. 17—Time and operating costs of injectors.

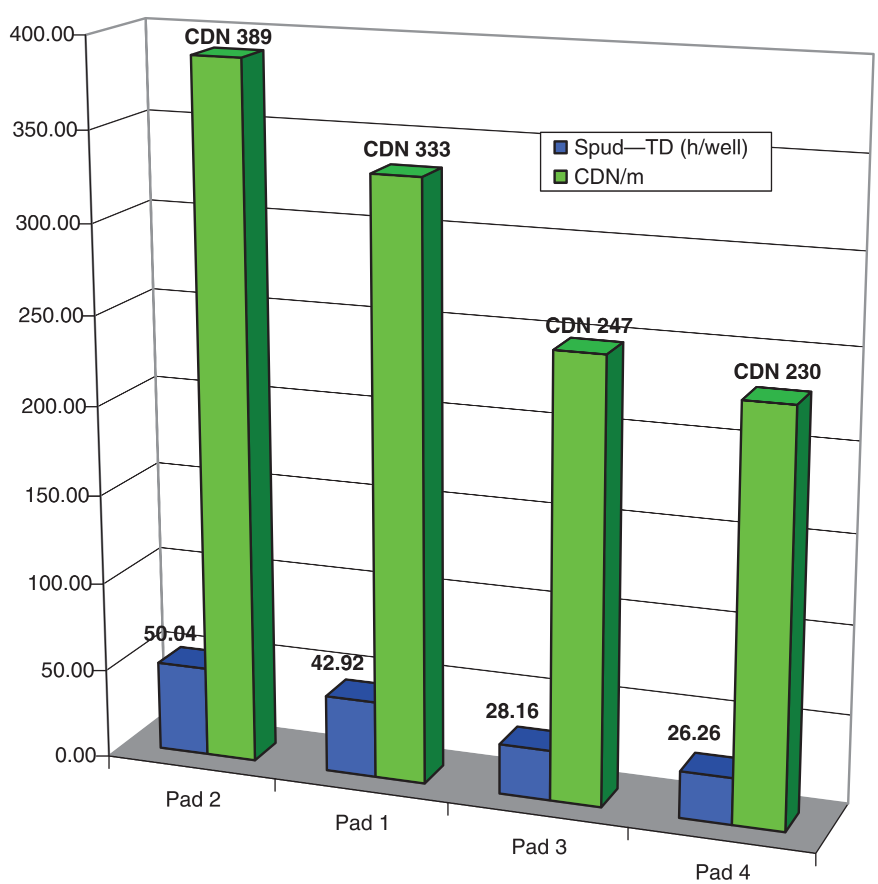

Fig. 18—Time and operating costs of producers.

is based on an average hourly operating rate, calculated over the course of the project. For injector laterals, the positive effect of the RSS was gradual, culminating in a total cost reduction of approximately 33%. On producers, the effect was felt immediately, resulting in an even greater reduction of nearly 40% in overall cost.

Quantifying the exact savings that are attributable to the implementation of rotary-steerable technology is difficult because of the progressive nature of the project. The approximate cost savings accomplished over the course of the project are a result of not only the RSS but also other operational learnings and improvements throughout the course of the project. From a technological standpoint, however, the RSS was without a doubt a cornerstone of the project and the most significant contributor to the results achieved.

Conclusions

An optimal wellbore has been described as one with the following characteristics:

- No unexpected deviations from the planned wellbore
- Minimum tortuosity
- No wellbore spiralling
- No residual-cuttings bed
- No ledges
- No wellbore breakout/hole in gauge/no hole ovality
- Minimum hole size drilled for required casing
- Hole fit for purpose to run casing with ease

In addition, cost effectiveness, safety, meeting reservoir objectives, overall performance, and other factors should also be considered in an impartial analysis of wellbore quality. With these criteria in mind, it is expected that the operating company was able to accomplish a level of optimization in their horizontal wellbores at LDP that exceeded the current industry standard for SAGD. The advancements made while drilling the LDP can be summarized as follows:

- Reduced overall well costs
- Superior borehole
- Improved directional control
- Enhanced well-pair placement.

These results are demonstrated by a reduction in accumulated doglegs, easier casing running, smoother well trajectories, an in-gauge hole, and more-efficient drilling operations, resulting in a better well at a lower overall cost. This was made possible through the use and refinement of a modified rotary-steerable drilling system combined with advanced geosteering and sound operational practice. Drilling, logging, and casing-running data suggest improved wellbore geometry, reduced tortuosity, more-precise well spacing, and improved well-pair placement relative to the reservoir base. Not only were the horizontal sections drilled with enhanced directional control and performance, but the results were carried over to well completions and should increase recovery and SAGD efficiency during the production phase of the project.

Using RSS in SAGD opens up the possibility for longer, extended-reach wells in which delivering weight to bit is a concern. Reducing or eliminating wiper trips and backreaming is another opportunity to streamline oil-sands-drilling operations further. Overall, the results of LDP show the potential of advanced drilling techniques and will encourage further technological development, enabling even higher-quality wells to be delivered, and facilitating more-effective and -efficient resource recovery.

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