Quiet above ground, the extreme subsurface environment of thermal operations spurs evolution in artificial-lift technology for thermal developments

by Darrell Stonehouse
When British writer Rudyard Kipling visited the southeastern Alberta city of Medicine Hat in 1907, he famously commented that “this part of the country seems to have all hell for a basement,” referring to the area’s prodigious natural gas resources lighting the streets and heating the homes and factories of the prairie city.
can also be pump-killers, as can high volumes of gas and produced water. This extreme in situ environment has led to an evolution of artificial-lift systems over the last decade as producers and pump suppliers experimented with a variety of technologies aimed at securing efficient and cost-effective production.

In the early days of SA gD development, “poor-boy” gas lift or traditional rod-and-tubing plunger pumps were the artificial-lift systems of choice for operators. The visible part of the rod-and-tubing system is the familiar pumpjack, common across Western Canada. A poor-boy gas lift system pumps gas downhole through a pipe into the production stream where it mixes with the bitumen, lowering its viscosity and allowing it to flow to the surface.

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While maybe not comparable to the eternal fire of the metaphorical hell Kipling referred to during his Medicine Hat visit, these temperatures are definitely hell on the downhole pumps used to artificially lift bitumen in thermal oilsands developments. And the heat is only part of the challenge facing pump manufacturers and operators working to create reliable production from the in situ resource base.

Wild temperature swings from the surface, which can be as low as -40 degrees Celsius during winter, also stress pumps. Corrosive liquids and gases eat away at seals and coatings, seriously limiting pump life. Abrasive sands wear down pump components. Inconsistent or intermittent flow rates can also be pump-killers, as can high volumes of gas and produced water.

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The issues with the early artificial-lift systems caused operators to look at other...
existing pumping mechanisms, including electrical submersible pumps (ESPs) and progressing cavity pumps (PCPs). Early tests using both pumping methods proved less than stellar, with reliability issues and short run-life common. But since then, pump suppliers have re-engineered both systems. Competition between technologies has now narrowed, with new-generation ESPs becoming the method of choice for lifting heated bitumen to the surface. But more recently, the PCPs are giving ESPs a run for their money.

ESP systems have been in use since the 1940s in oilfields around the world. An ESP is made up of a series of centrifugal pumps to move fluids upwards to the surface, an electric motor to drive the system, a protector to keep fluids out of the motor, and a cable connecting the pump to the surface.

Standard ESPs offered a number of potential advantages to early oilsands developers experimenting with the pumping system. The instruments could handle the large volumes of liquids generated by SAGD wells, which can produce hundreds of barrels of heavy oil and thousands of barrels of water per day. They could meet lift parameters, providing up to 10,000 feet of lift, and could function in wells with long horizontal sections. But probably most importantly, ESPs worked in low-pressure environments. This could allow operators to lower reservoir pressures after the initial buildup of the steam chamber in SAGD operations, leading to lower steam-to-oil ratios (SORs). The lower ratio can provide large economic benefits.

But the existing ESP systems came with some drawbacks as well. The standard downhole electric motors tended to overheat and shut down in high-temperature thermal operations. Temperature swings stressed seals and bearings. Corrosion and abrasion from fluids and sand also damaged the pumps, shortening their useful lifespan.

Schlumberger began working with in situ oilsands developers in the early 1990s in an effort to develop a high-temperature ESP that would function in this extreme downhole environment. In 1996, the first REDA Hotline ESPs rated for 180 degrees Celsius well conditions were installed in SAGD operations. Many systems were subsequently installed with run times of up to four years (1,460 days) achieved. The limitations of the early systems were due to the maximum working temperature of the ESP, in particular the motor insulation materials. Since then, the company and its competitors have been continually improving high-temperature ESPs.

In 2003, the next generation of REDA Hotline ESP pumps was introduced with a well temperature up to 218 degrees Celsius. Downhole electric motors are now protected from extreme temperatures by special insulation rated up to 288 degrees Celsius (550 F). Seals, bearings, and other mechanical parts have been re-engineered as well to allow for thermal expansion and to provide wear resistance from sand and corrosive fluids. New-generation coatings provide added protection. Systems to handle gas and vapours have also been added to enable effective gas and steam management and to improve pump performance and production rates.

Today there are over 200 REDA Hotline ESPs in operation in Canadian SAGD wells with continually increasing run times.

Producers recognize the results these improved pumps can bring. Cenovus Energy re-

The high-temperature electric submersible pump

Manufacturers say that ESP components have been redesigned with harder stage and bearing materials to improve radial stability, special coatings to help withstand corrosion/abrasion, and improved insulation materials to endure extreme temperatures, improving reliability.

High temperatures The pumps are specifically designed to tolerate extreme bottomhole temperatures. For example, ESP motors use special high-temperature insulation rated up to 288 degrees Celsius.

Temperature swings New-generation ESP systems incorporate special features like oversized oil reservoirs, parallel-bladder systems in the seal, and specialized high-temperature insulation designed to tolerate wide swings in temperature.

Wide flow ranges Pumps include a specially designed bearing system that allows for thermal growth and wear resistance from abrasive production, allowing operations across a wide range of flow rates and through unstable or intermittent flow.

Corrosion and abrasion Special coatings help protect the new-generation ESP systems against corrosion and abrasion. Specialized mechanical seal designs enhance stability and reduce the need to use elastomers.

Gas exclusion Gas exclusors have self-orientating intake ports designed to direct fluid flow to the bottom side of the horizontal wellbore, thus closing off possible entrance of gas into the system.
ports that ESPs have played a key role in improving the economics at its SAGD operations at Foster Creek and Christina Lake.

“One of the most significant technological improvements to our SAGD process has been the introduction of ESPs, rather than using natural gas, to bring the oil to the surface. We worked with various vendors to design and develop the pumps for SAGD operations, which were introduced at Foster Creek in 2003,” says Cenovus. “One of the benefits of using ESPs is a reduction in our steam-to-oil ratio. A low SOR results in lower water usage, more efficient use of steam, a reduction of emissions per barrel of oil recovered, and an overall reduction in operating costs. At our Christina Lake project the reduction in SOR has shown a 15 per cent decrease in the amount of water we use to produce one barrel of oil and a 12 per cent decrease in steam-generation costs.”

While ESPs now dominate the SAGD market, PCP suppliers have also been working on adapting their systems for thermal developments. A PCP consists of a stator and a rotor. The stator is a helix resembling a DNA molecule. The rotor, which resembles half a DNA strand, is rotated within the stator using either a surface motor or a bottomhole motor. Turning the rotor within the stator creates cavities within the pump that sequentially pass produced fluids upwards towards the surface.

Like ESPs, PCP systems offer a number of characteristics desirable for thermal production. They can handle large volumes of fluids, are resistant to abrasives and solids, and can operate at the depth of most in situ oilsands developments. They are also very cost efficient. The standard PCP’s one big downside, however, is that the stator component constructed from elastomers isn’t durable enough for SAGD operations.

“Elastomer stators make standard progressing cavity pumps unsuitable for use at extremely hot temperatures,” says Nicolas Parise, director of the oil and gas unit for French pump manufacturer PCM.

In 2008, after 10 years of experimentation in partnership with producers in Alberta, PCM, and its Canadian sister company Kudu Industries, introduced an all-metal PCP system called the Vulcain designed for thermal heavy oil operations. The system can pump at temperatures of 350 degrees Celsius. It has been field tested at Total’s SAGD leases in the Athabasca oilsands and at Imperial Oil’s Cold Lake CSS operations. In 2009, the company announced one of its Vulcain pumps had been operating non-stop for 20 months in the SAGD trial. It is has now been released for commercial use.