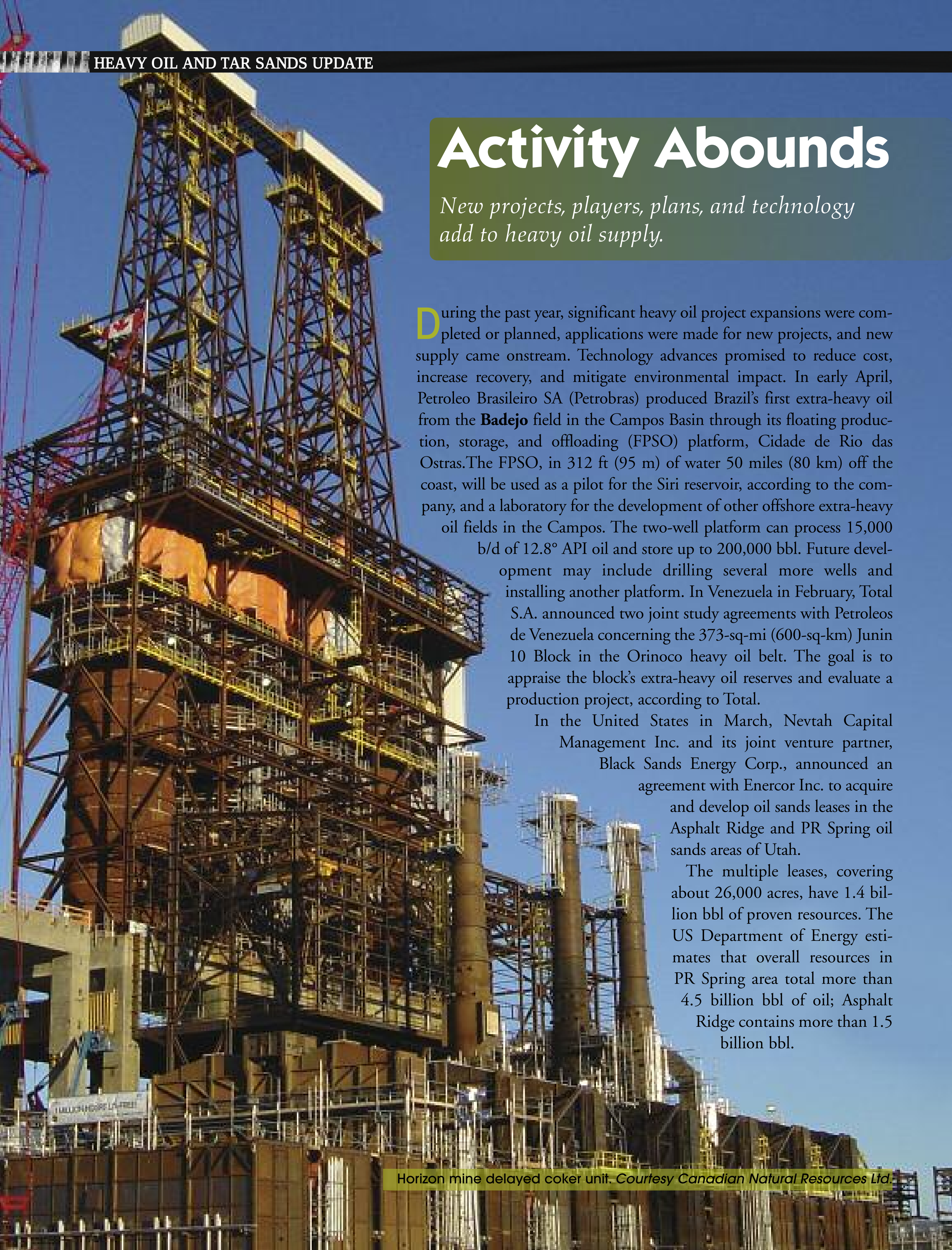
Activity Abounds

New projects, players, plans, and technology add to heavy oil supply.



During the past year, significant heavy oil project expansions were completed or planned, applications were made for new projects, and new supply came onstream. Technology advances promised to reduce cost, increase recovery, and mitigate environmental impact. In early April, Petroleo Brasileiro SA (Petrobras) produced Brazil's first extra-heavy oil from the **Badejo** field in the Campos Basin through its floating production, storage, and offloading (FPSO) platform, Cidade de Rio das Ostras.The FPSO, in 312 ft (95 m) of water 50 miles (80 km) off the coast, will be used as a pilot for the Siri reservoir, according to the company, and a laboratory for the development of other offshore extra-heavy oil fields in the Campos. The two-well platform can process 15,000 b/d of 12.8° API oil and store up to 200,000 bbl. Future development may include drilling several more wells and installing another platform. In Venezuela in February, Total S.A. announced two joint study agreements with Petroleos de Venezuela concerning the 373-sq-mi (600-sq-km) Junin 10 Block in the Orinoco heavy oil belt. The goal is to appraise the block's extra-heavy oil reserves and evaluate a production project, according to Total.

In the United States in March, Nevtah Capital Management Inc. and its joint venture partner, Black Sands Energy Corp., announced an agreement with Enercor Inc. to acquire and develop oil sands leases in the Asphalt Ridge and PR Spring oil sands areas of Utah.

The multiple leases, covering about 26,000 acres, have 1.4 billion bbl of proven resources. The US Department of Energy estimates that overall resources in PR Spring area total more than 4.5 billion bbl of oil; Asphalt Ridge contains more than 1.5 billion bbl.

Horizon mine delayed coker unit. *Courtesy Canadian Natural Resources Ltd.*

Both of these deposits, to be mined with conventional surface mining techniques, lend themselves to the partners' patented oil extraction technology. The resources tend to be close to surface, are fragmented by multiple beds, and are highlighted by several rich zones. In tests, the process has been capable of more than 90% oil recovery; solvent recovery with the closed loop system is 99.5%.

In Canada, the December 2007 Alberta Oil Sands Industry Update cited these regulatory filings during the last half of 2007:

- Suncor Energy Inc., in July, for approval for the Voyageur South Project, a 120,000 b/d mine to come onstream by 2012;
- Shell Canada Ltd., in December, for approvals regarding the Jackpine mine expansion to 100,000 b/d by 2015 and the Pierre River mine project to 200,000 b/d by 2018, with construction beginning in 2009-2010;
- EnCana Corp., in October, for the first 35,000 b/d phase of the Borealis steam-assisted gravity drainage (SAGD) project, which has a total design capacity of 100,000 b/d;
- Canadian Natural Resources Ltd., in September, a combined application and Environmental Impact Statement for the Kirby 45,000-b/d SAGD project;
- North American Oil Sands Corp., a subsidiary of StatoilHydro ASA, in August, to develop the Kai Kos Dehseh *in situ* project to produce 220,000 b/d by the end of the next decade from leases that hold about 2.2 billion bbl of recoverable reserves – first 10,000 b/d phase will be onstream by early 2010;
- North American Oil Sands, in November, to build a 250,000 b/d upgrader in Strathcona County;
- Shell Canada, in July for a four-stage expansion of the Scotford upgrader in Strathcona County to 400,000 b/d by 2022;
- Total E&P Canada, for approval to build a 200,000 b/d upgrader in Strathcona County to come onstream by 2014; and
- Northwest Upgrading Inc., in August, received approval for its upgrader in Sturgeon County. After three phases, it will eventually process 150,000 b/d. Construction will begin this year, and the first 50,000 b/d of capacity will be ready in 2010 or 2011.

NEW PARTNERSHIPS

Husky Energy Inc.'s agreement with BP plc, effective Jan. 1, 2008, created two 50/50 partnerships: a Canadian oil sands enterprise operated by Husky and a US refining LLC operated by BP. Husky contributed its Sunrise asset to the venture and BP contributed its Toledo, Ohio, refinery.

Sunrise, 37 miles (60 km) northeast of Fort McMurray, has probable reserves of 1 billion bbl, and possible reserves of 2.2 billion bbl. The first of three phases, expected to be sanctioned by Husky this year, will produce 60,000 b/d in 2012; production will build to 200,000 b/d by 2015 to 2020.

The refining LLC plans to expand bitumen-processing capacity at Toledo to 120,000 b/d and total refinery throughput to 170,000 b/d by 2015, investing about $2.5 billion. Current throughput is about 135,000 b/d, including 60,000 b/d of heavy sour crude.

In October, Marathon Oil Corp. completed its acquisition of Western Oil Sands Inc.

The acquisition will link oil sands production with heavy oil upgrade projects at Marathon's refineries. The deal provides access to about 2 billion bbl of mineable bitumen and an additional 600 million net bbl of potential *in situ* resource, according to Marathon.

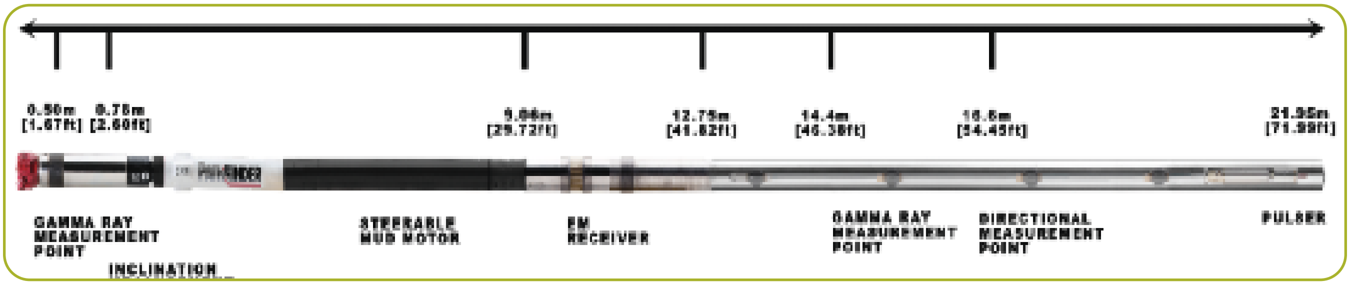
Total S.A., on April 28, agreed to acquire Synenco Energy Inc. for about $480 million. Synenco's main asset is a 60% stake in the Northern Lights oil sands project 62 miles (100 km) northeast of Fort McMurray that contains 108 billion bbl of bitumen. Sinopec subsidiary SinoCanada Petroleum Corp. has the remaining 40%. An application to develop the mining project is being reviewed, according to Total.

OIL SANDS PROJECTS UPDATED

Suncor will add new cokers in 2008, and a third complete upgrader in 2012, said Rick George, president and chief executive officer at the World Heavy Oil Congress, March 10, 2008, in Edmonton. In January, Suncor approved investment of $20.6 billion (C$20.6 billion) to expand its Fort McMurray oil sands operation by 200,000 b/d to 550,000 b/d by 2012. For the first two months of 2008, oil sands production averaged 247,000 b/d.

Phase 1 of CNRL's Horizon project is expected to produce first oil in the third quarter of this year. Capacity is 110,000 b/d of 34° API synthetic crude oil. Four planned stages will take capacity to 232,000 b/d to 250,000 b/d by 2013 and future expansions could increase capacity to 500,000 b/d, according to CNRL. Horizon reserves are estimated at 6 billion bbl of mineable bitumen.

CNRL's Kirby SAGD project in the regional municipality of Wood Buffalo will include four well pads near the processing facility and a 45,000 b/d standalone bitumen-processing facility without an upgrader.



MWD/LWD Passive Ranging BHA. *Courtesy of Pathfinder Energy Services*

At ConocoPhillips Co.'s Surmont project, 37 miles (60 km) southeast of Fort McMurray, steam injection began in June 2007 and first oil was produced in October. At midyear, the company was producing about 10,000 b/d of bitumen. Phase 1 has a capacity of 25,000 b/d and is expected to reach a production plateau in 2012. When fully operational, injection will be into 36 well pairs.

ConocoPhillips now has regulatory approval for its 75,000 b/d Phase 2 expansion. Construction start is planned for 2009, with completion scheduled for 2013, when steam injection will begin. In early 2008, engineering work required for sanction of the expansion was under way. Average production of 100,000 b/d from both phases is expected in 2015.

"We are committed to creating local benefits from the project," said Matt Fox, senior vice president, Oil Sands, ConocoPhillips Canada, "As one example, Phase 1 of the Surmont project resulted in over $70 million in local contract spend."

In conjunction with Total S.A., ConocoPhillips is also contemplating future phases for Surmont. Total has begun the process to build an upgrader in the Edmonton area to process 150,000 b/d of bitumen "before 2015," according to the company.

ConocoPhillips has undeveloped heavy oil resources in the Saleski, Thornbury, and Clyden areas where it drilled over 100 delineation wells last winter. These projects will be an important part of the portfolio in the 2015 to 2025 range.

In aggregate, the company holds about 1 million net acres, with access to an estimated 15 billion bbl of net resource. "Over the next few decades our goal is to produce a million b/d from our oil sands interests," Fox said.

"The first full year of our integrated oil business with ConocoPhillips has been very successful," said Alan Boras, EnCana spokesman. The joint venture operates the Foster Creek and Christina Lake developments.

Two expansion phases now under construction will double Foster Creek capacity to 120,000 b/d. Christina Lake production averages about 5,000 b/d, but an expansion under way will increase capacity to 23,000 b/d by the end of the year.

"The next stage will be a 40,000 b/d step-up," Boras said. "And over the next few years we are targeting total production in the neighborhood of 400,000 b/d by around 2015."

For 2008, EnCana expects to invest about $1.17 billion in heavy oil operations, about half upstream and half downstream.

Devon Energy Corp. completed 35,000 b/d Phase 1 of its Jackfish SAGD oil sands project, 9 miles (15 km) southeast of Conklin, Alberta, and began steaming in the third quarter of 2007. Full production should be reached this year, according to Devon. Total recoverable reserves are more than 300 million bbl. Construction of the 35,000 b/d **Jackfish 2** adjacent to the initial Jackfish is scheduled to begin this year with production beginning in 2010.

Corporate sanction for Imperial's proposed Kearl oil sands mining, pipeline, and upgrading project in Alberta could come in fourth quarter 2008 or early 2009, according to Gordon Wong, Imperial spokesman. Plans include an initial 100,000 b/d phase as early as 2010 and two additional phases in 2012 and 2018. Total recoverable bitumen is estimated at 4.6 billion bbl.

After a joint review panel representing both federal and provincial governments issued a recommendation to the government, environmental organizations challenged the panel's report in Canada's federal court in early 2007.

For the most part, the federal court upheld the joint review panel's conclusions. But it asked the panel to provide its rationale for one of its conclusions. Because of that ruling, Canada's Department of Fisheries withdrew a permit it had issued and Imperial then challenged the decision in federal court. A hearing was scheduled for May, but work continued at the Kearl site that was not dependent on that particular permit.

First bitumen production and the start-up of an upgrader are scheduled for this year at Long Lake, a joint venture SAGD project of Nexen and OPTI Canada. Full production of premium synthetic crude oil is expected within 12 to 18 months of upgrader start-up. The company has said it plans to sanction Phase 2 in late 2008, expanding in 60,000 b/d phases to a total capacity of 240,000 b/d over the next decade.

In late February, Connacher Oil & Gas Ltd. reported bitumen production at its Great Divide Pod One project had exceeded 5,000 b/d; design capacity is 10,000 b/d. In early 2008, 12 of 15 well pairs had been converted to SAGD production.

Early this year, the company's Algar application was proceeding through the regulatory process. If approved, construction and drilling will begin this summer and the $326 million project could start up in late 2009. Target production rate is 10,000 b/d of bitumen from an expected 15 to 20 SAGD pairs.

Petro-Canada has begun site work for the 190,000 b/d Fort Hills Oil Sands Mining and Upgrading Project, according to the Alberta Oil Sands Industry Update, and has filed application for its Sturgeon upgrader. First production would be in 2011; full capacity of 340,000 b/d would be reached by 2013.

MEG Energy Corp. plans to submit a regulatory application late this year for a 50,000 b/d project on its 19 sections of oil sand leases in the Surmont area. Steaming the reservoir could begin early in 2013. MEG has a 100% working interest in the leases that contain recoverable resources estimated at 554 million bbl.

Korean National Oil Corp. (KNOC)'s BlackGold oil sands project is its first venture in Canada. Acquired from Newmont Mining Corp. in late 2006, BlackGold is 87 miles (140 km) southeast of Fort McMurray and has reserves of more than 200 million bbl. KNOC has drilled 18 core holes and acquired 9 sq mile (23 sq km) of 3-D seismic data, according to company information, and is now developing a reservoir model and preparing an environmental impact assessment and development plan. This year, the company will submit a proposal for government approval to produce 10,000 b/d by 2010 in Phase 1.

Chevron Corp. will use *in situ* thermal recovery at its Ells River project, 26 miles (42 km) southwest of the Athabasca oil sands project. In 2007, it completed a 66-well appraisal drilling program and plans a similar number of wells and a small 2-D and 3-D seismic program this year.

Oilsands Quest Inc., at its Axe Lake discovery, planned to begin a reservoir field test program in the first half of 2008 that will help design a pilot *in situ* production program currently scheduled for start-up in 2009.

A new private company, Peace River Oil Inc., plans to submit a regulatory application for its Bluesky upgrader near McLennan in the second half of 2008, according to the Alberta Department of Energy. First stage would be completed by 2011 and have a capacity of 25,000 b/d of bitumen; expansion in four stages would reach 100,000 b/d.

THE IMPORTANCE OF SOR

Thermal methods – especially those using steam – will be increasingly important in increasing heavy oil recovery factors. Currently, the primary fuel for steam generation is natural gas.

"Because natural gas is a significant cost component in thermal operations, one of our technology development goals is to find new ways to optimize the use of steam," said Jacob Thomas, director of Strategic Technology, Halliburton.

The steam-oil ratio (SOR) is used to define economic limits for thermal operations. The lower the ratio, the more efficient will be the use of steam for oil recovery during thermal operations. At current gas prices of $8 to $10/Mcf, the incremental cost associated with steam for thermal recovery ranges from $20 to $30/bbl of oil produced.

In addition to increasing steam-generation efficiency, managing steam distribution as it enters the reservoir is critical to optimizing the use of steam. When injecting steam into the upper well of a SAGD pair, for example, reservoir heterogeneity makes it difficult to distribute steam uniformly along the horizontal section of the well.

"If there is a permeability streak in the reservoir between the injector and the producer, for example, steam can break through into the producer," said Thomas. "Steam bypasses the oil and enters the producing well. To prevent this, the steam injection rate is reduced, and this leads to a drop in production rate and recovery."

To be effective, tools for steam diversion need to be combined with the ability to monitor temperature. WellDynamics' distributed temperature sensing technology uses high temperature fiber optics to monitor steam distribution in real time. The horizontal section can be compartmentalized, if needed, using valves to divert steam to unswept sections of the reservoir.

"It is this combination of technologies that helps optimize steam oil ratio," said Thomas.

Downhole steam generation could also reduce steam requirements compared to surface steam generation where there are potentially significant losses between the boiler and the reservoir. Downhole generation technologies also reduce the environmental footprint because the operation is in the well bore on a much smaller scale.

Surface steam generation is not feasible in all environments. Offshore, for example, the steam in the tubulars is affected by the cold water column and loses quality before it reaches the reservoir. In permafrost applications, heat transfer through the casing could have detrimental effects on the surrounding permafrost.

Downhole steam generation technology can also be used in green field environments where there is no existing steam infrastructure; to develop smaller accumulations that cannot justify a large surface facility; and where surface generation facilities are disallowed by regulation.

Mobile oil sands test unit recently completed endurance tests.
Courtesy Nevtah Capital Management Corp.

One advantage is that CO_2 produced by downhole steam generation using combustion goes into the reservoir rather than into the atmosphere. And the presence of CO_2 can enhance productivity for some reservoir conditions.

Heavy oil technology has advanced dramatically, but there are still areas ripe for innovation. Thomas cites these opportunities for further heavy oil technology development:

- Partial upgrading in the field to remove asphaltenes and reduce or eliminate the need for expensive diluent, a transportation solution proposed by Halliburton;
- Processes to develop oil sands in shallow zones below where mining is possible and above where *in situ* steam is currently applied;
- A better understanding of the effect of differential temperatures on the cement sheath, tubing, packers, and downhole equipment during heat cycles in cyclic steam stimulation;
- Innovative ways to use drill more wells from a pad, thereby reducing the surface footprint; and
- Improvements in thermal simulation that would speed run time by an order of magnitude.

TAKING TECH TO THE FIELD

Imperial will eventually convert all of its **Cold Lake** cyclic steam stimulation wells to use the company's patented Liquid Addition to Steam for Enhanced Recovery (Laser) technology, said company spokesman Pius Rolheiser. Imperial, with about 465,000 acres of oil sands leases, is 100% owner and operator of the Cold Lake project, one of the largest thermal heavy oil recovery operations in the world.

The Laser process was pilot tested on one well pad at Cold Lake in 2002; the first production cycle was completed two years later. The process replaces 5% to 10% of the total volume of steam with diluent, the light hydrocarbon blended with Cold Lake bitumen for shipment.

"We're excited about the technology," Rolheiser said, "because the pilot pad recovered about 50% more bitumen than a comparable cyclic steam stimulation well." Based on pilot results, Imperial applied two years ago to the Alberta Energy and Utilities Board to use Laser at all the pads at Cold Lake.

Following approval for the first 10 well pads, initial solvent injection began on those pads late last year. Cold Lake has about 200 well pads, each containing 20 to 30 wells.

An added benefit of the LaserR technology is that the diluent that is injected would have to be injected anyway for bitumen shipment. Incremental investment is modest because the wells, steam plant, and other facilities are already in place.

"It's too early to talk about specific results, but the pilot tests were very encouraging," said Rolheiser.

Petrobank Energy and Resources Ltd. and its subsidiary, Whitesands Insitu Inc., are proposing to develop the May River oil sands project using the THAI™ (toe-to-heel air injection) *in situ* combustion process. The process combines a vertical air injection well with a horizontal production well. Initial phase will produce 10,000 to 15,000 b/d of partially upgraded bitumen, according to the company. Additional phases will take capacity to 100,000 b/d.

Value Creation Inc. (VCI) submitted an application near the end of last year for the 10,000 b/d Terre de Grace pilot project northwest of Fort McMurray. "Our hope is that we will have approval by the end of this year," said Mark Beacom, vice president, Resource Development. Target date for first production is 2011.

The operation would use VCI's proprietary upgrading technology to form an "integrated SAGD" operation comprising a central processing facility fed by up to 16 well pairs. "This technology should make a significant difference in overall operating and capital costs," Beacom said.

VCI's accelerated decontamination (ADC™) process provides rapid and selective separation of asphaltenes from heavy residue fractions in bitumen streams, using relatively simple hardware facilities under moderate pressures and temperatures. VCI's ultra-selective pyrolysis (USP™) unit cracks the heavy residue in the decontaminated crude oil into lighter products that are collected through a conventional product recovery system.

Deloro Resources Ltd. will conduct a full pilot test using Electro-Petroleum Inc.'s (EPI) Electrically Enhanced Oil Recovery technology on Deloro's Wilkie heavy oil field in Saskatchewan. EPI's patented technology uses direct current for both *in situ* heating and electrochemical reactions to upgrade and recover oil. The current passes between cathodes in producing intervals and anodes either at the surface and/or at depth in other wells. Six vertical wells and one horizontal well drilled into the structure defined a heavy oil pay zone in the field with gross sand thickness of 30 to 50 ft (9 to 15 m). The leases contain an estimated 63 million bbl.

NEW RESERVOIR TOOLS

Schlumberger's research and development direction is guided by the industry's needs for technologies that will enable conventional workflows and procedures to be used in the development of heavy oil reservoirs.

It is critically important to adequately characterize heavy oil reservoirs and measure the viscosity of the fluids contained in them, said Schlumberger Heavy Oil Theme Director Kambiz Safinya.

Schlumberger can now determine oil viscosity by logging the well with a nuclear magnetic resonance logging tool, eliminating the need to collect an oil sample for lab testing. Collecting the sample is not easy because the oil does not flow; ensuring that the sample accurately represents the original fluid in the reservoir is also difficult.

The ability to measure oil viscosity helps in choosing the best recovery method. Schlumberger is currently field-testing a system that will significantly improve recoverable reserves estimates by clearly identifying producible heavy oil in the reservoir rock.

Advances have also been made in measuring reservoir performance. During the past year, Schlumberger has tested an advanced flow meter in Canada that measures flow rates of bitumen, gas, and water from SAGD well pairs. It would take the place of the large separators needed for traditional well testing.

"The flow meter will allow a much more accurate assessment of reservoir performance," Safinya said. "That has a big impact on the ability to plan for future extraction."

Schlumberger also has completed four years of continuous operation of one of its high temperature electric submersible pump artificial lift systems without failure. SAGD well temperatures can run to 424°F (218°C). In Canada, 90% of the planned future expansions of *in situ* projects will make use of SAGD, Safinya said.

Schlumberger also has released its new fiber optic-based temperature-monitoring systems that are inserted in an SAGD well to measure temperatures along the entire well trajectory. At high temperatures, optic fiber can experience "hydrogen darkening" that can ruin the fiber. Schlumberger's fiber has been tested to 572°F (300°C) and tested for more than a year in a 100% hydrogen atmosphere without failure.

Maintaining the proper sub-cool temperature – the temperature difference between the injection well and the producing well in a SAGD pair – allows the operator to manage the steam chamber, which ultimately determines well performance, Safinya said.

If the sub-cool temperature is too high, condensation will not occur and liquid cannot flow into the producer. If too low, the steam chamber is not effective.

A difference of zero means steam is breaking into the producing well, which will destroy pumps and produce little oil. Depending on the reservoir and the operation, the subcool temperature might range from 5°F to -4°F (-15°C to -20°C).

"Optimizing that number is a key to managing the SAGD process," Safinya said. "And proper management can better regulate steam to reduce waste and equipment problems."

DRILLING, COMPLETION CHALLENGES

Medium heavy oil, ranging from 10° to 22° API, can pose transportation challenges, but it can typically be produced using conventional technology. It is extra heavy oil and bitumen that pose the most severe well completion and production challenges, said Brent Emerson, product line director, Wellbore Construction, Baker Hughes Inc.

Challenges include: to optimize recovery, well bores must be precisely located; thermal stimulation involves extreme temperatures; sand production can reduce equipment life; and steam injection must be carefully managed.

"Today's drilling technologies have dramatically increased the viability of heavy oil reserves," said Emerson. Baker Hughes Inteq's AutoTrak™ rotary closed loop drilling system, for example, combines the advantages of a downhole guidance system, two-way communication and continuous drill string rotation to drill "designer profile" and extended reach wells.

Nevtah's patented process extracts over 90% of the oil, leaving clean sand. Courtesy Nevtah Capital Management Corp.

"For SAGD wells, MWD [measurement while drilling] and LWD [logging while drilling] capabilities are necessary for drilling two straight horizontal wells a few meters apart," Emerson said.

Optimizing heavy oil recovery also requires maximum reservoir exposure. "In some areas, we drill long extended reach wells to get that exposure; in other parts of the world, we drill multilateral wells with an impressive array of branches," he said.

Steam stimulation, involving temperatures in the 400°F to 680°F (204°C to 360°C) range, requires downhole tools that can withstand high temperatures as well as the forces resulting from those high temperatures. For the special conditions of cyclic steam injection, for example, Baker Oil Tools offers a packer that can be fitted with an internal integrated expansion joint to accommodate tubing movement.

Baker Hughes continues to develop high-temperature gauges for real-time downhole monitoring to help boost steam efficiency and oil recovery. High temperature safety valves will also be needed for offshore heavy oil wells.

Heavy oil production often includes significant sand volumes. Baker Oil Tools' new wire wrap sand screen design has almost 10 times more inflow area than slotted pipe of the same opening size. Improving the sand tolerance of its electric submersible pumps is a goal of Baker Hughes' Centrilift division.

Baker Hughes is also applying its Equalizer™ technology to provide a more efficient sweep of the formation by the injected steam, Emerson said. When used in an injector, the Equalizer can help provide a uniform steam injection profile from the toe to the heel of the horizontal section. In a producing well, the Equalizer inflow control device is typically run with a sand control screen surrounding it.

GUIDING SAGD WELLS

PathFinder® Energy Services has developed a new method for twinning horizontal well pairs in SAGD heavy oil recovery projects that incorporates at-bit measurements. Typically, pairs of SAGD wells are drilled from a single pad. For each pair, an initial "target" well – usually the producer – is drilled and cased. A second well, the injector, is then drilled parallel to the target well.

In this new technique, the producer casing is magnetized with a predetermined pattern prior to installation. Passive magnetic ranging is then implemented by using the casing magnetic interference to determine the distance and position of the injector relative to the nearest part of the producer. Combining at-bit gamma ray and inclination measurements with complex magnetic vector analysis allows the passive ranging technique to accurately place the well.

PathFinder's approach contrasts to an alternate technique that deploys an active electromagnetic source in the producer while drilling the injector.

This new technique eliminates the need for special downhole tools, does not require any additional surface equipment, and typically improves the economics of drilling SAGD wells, according to PathFinder.

One of the key elements in the technique is the company's PZIG™ (Payzone Inclination and Gamma Ray) tool that provides real-time at-bit measurements to help guide the well path. The instrumented sub has been used extensively in drilling and logging horizontal wellbores including SAGD wells. The tool is compatible with any positive displacement motor or rotary steerable tool and with all mud types. Wireless electromagnetic "short-hop" communication between upper and lower subs transmits data via PathFinder's MWD system. The tool communicates when pumps are on or off and is downhole programmable for multiple user selectable variables. •