Can oil and gas recover old ground?

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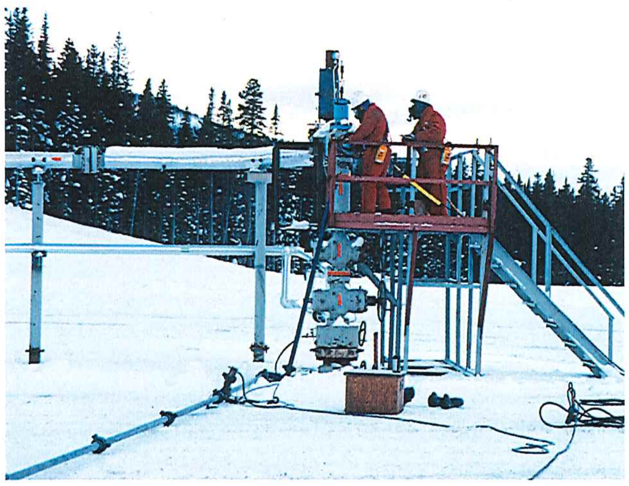
Laurier L. Schramm, Vice President, Energy Technologies at the Alberta Research Council, offers a Canadian perspective on technology development in reservoir recovery for conventional and unconventional petroleum reservoirs.

For maturing conventional oil and gas fields the challenges are improving recovery techniques, coning control, and near-well conformance processes, whereas for heavy oil and in-situ oil sands reservoirs the challenges are to access the resource, use gravity to advantage and increase recovery factors.

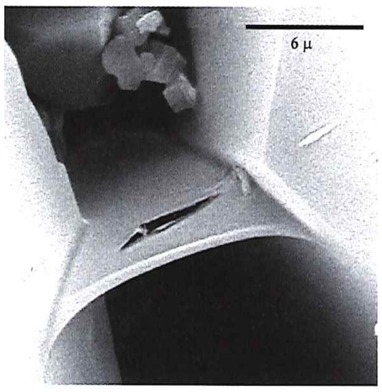
Recent years have seen western Canada's conventional oil and gas reserves in steady decline. In conventional fields less than half of the original oil in place (OOIP) is being recovered with current technology, and gas coning and high water cuts have led to increased operating costs and impairment of production. Yet Canada can maintain, or increase, its reserves by developing its massive in-situ oil sands resource. Representing almost two trillion barrels of bitumen in place, this resource is found but is difficult to develop economically; only about 43 billion barrels booked as mineable or in-situ recoverable reserves. Where there are active in-situ developments, less than 20 per cent of the OOIP is recoverable with current technology.

Conventional gas reservoirs

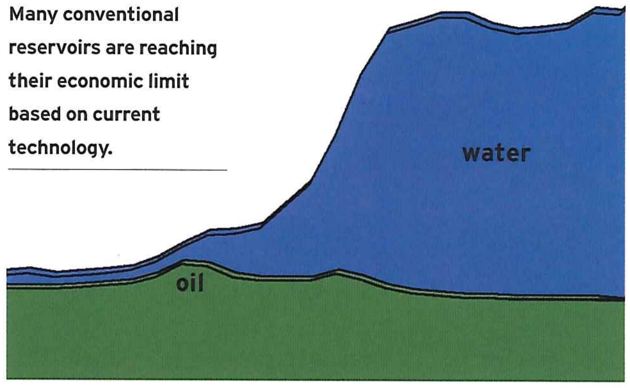
Natural gas exploitation in Canada continues to grow but suffers from near well-bore productivity problems ranging from formation damage due to phase trapping of aqueous drilling, fracturing and completion fluids, to excessive water production. A significant amount of research has been aimed at improving gas-well production suffering from water coning and channelling. »



Gas-gel treatment being applied through a gas well suffering from water channelling.



Scanning electron microscope image of a pore blocking-type foam lamella spanning sandstone grains.



Many conventional reservoirs are reaching their economic limit based on current technology.

» A field pilot test of nitrogen injection into an aquifer underlying a gas pool has demonstrated reduced water production. Injecting polymer into tight gas reservoirs has proven to be a viable technique for reducing water production in true coning situations, whereas for situations where well inflow is primarily via fractures, placement of a cross-linked polymer (gel) is the desired treatment. Recently, a successful field trial was carried out in a deep fractured carbonate gas reservoir; with treatment pay-out in four months. Several gas-producing companies are scheduled to conduct field pilots with this technology in Canada at an activity level that will permit us to assess what works, what does not work, and why.

Another area of gas research is production from unconventional sources, such as using CO_2 to accelerate methane production from reservoirs containing gas hydrates in which gas molecules are encaged within ice lattices. The amount of methane stored in hydrate reservoirs around the world has been estimated at about 1016m^3, including Canada's Mackenize Delta. CO_2 injection offers a number of potential technical advantages plus the disposal of a greenhouse gas.

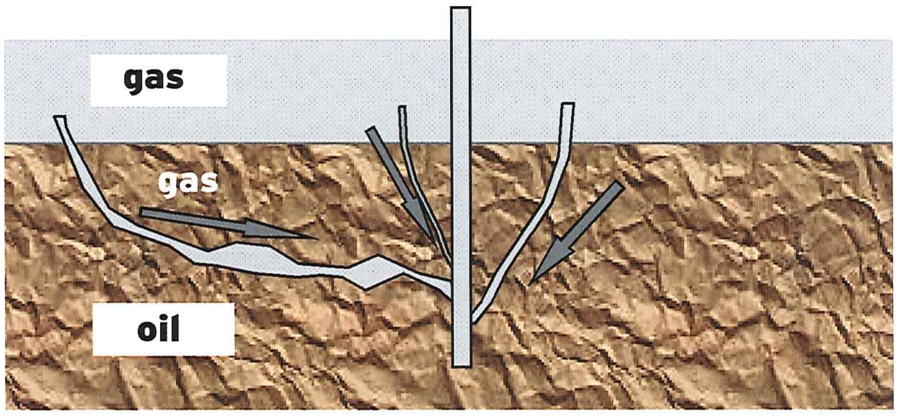
Another unconventional source will be CO_2-enhanced coal-bed methane production, a resource that comprises at least 200 trillion cubic feet in Alberta, Canada alone. Current research is aimed at developing recovery methods that will unlock this presently untapped resource and add to our reserves. Key issues are to be able to enhance coal-bed methane recovery factors and production rates. This approach provides another opportunity for a beneficial use of CO_2 that includes disposal while putting coal back in the energy picture without emissions. We have a field pilot test underway at Fenn-Big Valley, Alberta, that includes a surface power-generation plant.

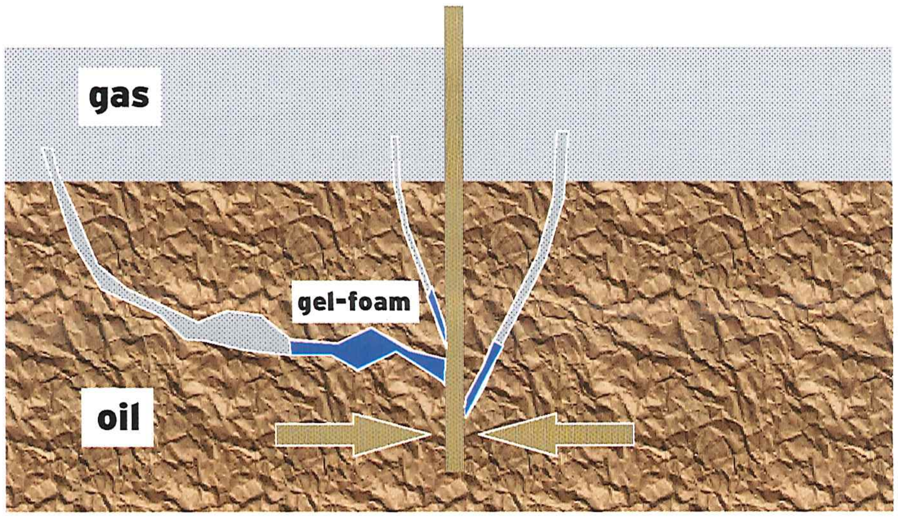
In conventional fields less than half the original oil in place is being recovered by current technology; gas coning and high water cuts have meant increased costs and lost production.

Conventional oil reservoirs

Some of the largest conventional oil reservoirs in western Canada have been extensively waterflooded since the late 1950s and are now reaching their economic limits, leaving more than half of the OOIP behind due to poor sweep efficiency and poor displacement efficiency. Improved oil recovery techniques are needed to extend the lives of reservoirs: the volume of unrecoverable oil in existing reservoirs is about 5 x 109m^3 (30 billion barrels) in Canada. Chemical flooding, whether micellar-polymer or alkali/surfactant polymer, provides a means of reducing waterflood residual oil saturation while improving sweep efficiency. Modern micellar-polymer flooding involves reducing the interfacial tension between reservoir brine and oil to such ultralow values that micro-emulsification occurs (< 10-3mN/m) and has been proven to be tremendously effective in reducing residual oil saturation.

The injected micellar fluids are complex formulations containing surfactants, cosurfactants, cosolvents, and polymers, injected as a finite chemical slug and displaced through the reservoir using a salinity gradient at the trailing edge of the chemical slug to permit





Above: Illustration of excessive gas production due to gas channelling compared to oil production following a gas-blocking gel-foam treatment (below).

miscible displacement by a polymer drive fluid and minimise surfactant adsorption on the reservoir rock. Recent pilot tests with proper reservoir characterization, well patterns, and properly designed chemicals, have been successful, recovering two-thirds of the residual oil. Concerns over the chemical costs are being met by using inexpensive alkali such as sodium carbonate to produce most of the needed surfactant from the crude oil itself, while minimising detrimental rock-fluid interactions.

Together with a very small amount of cosurfactant and a polymer, an efficient and economic alkali/surfactant/polymer (A/S/P) process can be developed for specific reservoirs. Several successful field trials have been conducted, reporting recoveries of 40 to 50 per cent of waterflood residual oil at costs as low as $3 per incremental barrel of oil. Research also has shown that the A/S/P process can be effective at much lower acid numbers (lighter oils) than would be expected from conventional wisdom. This, coupled with the increased use of horizontal wells, should open up new opportunities for effective use of this process.

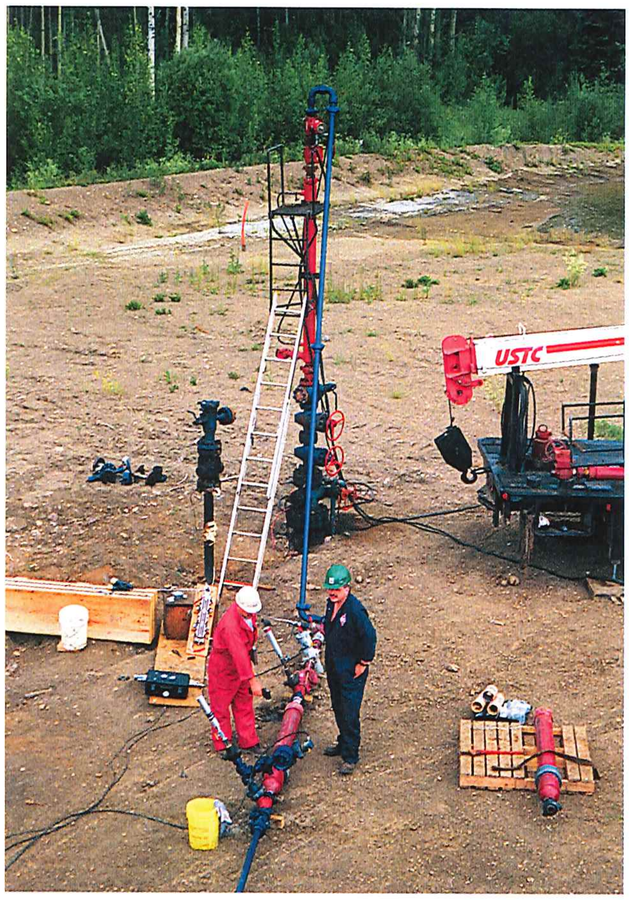
Hydrocarbon, steam, or CO_2 flooding refers to oil-recovery processes in which solvent or steam are injected into a petroleum reservoir. In immiscible flooding increased oil recovery is obtained by achieving a low interfacial tension between solvent and the oil (raising the capillary number). In the case of steam flooding oil viscosity reduction also contributes to increased oil recovery. In miscible flooding the aim is to increase oil recovery by one of three ways: oil displacement by the solvent through the generation of miscibility; oil swelling (increasing the oil saturation and therefore the oil relative permeability); and reducing the oil viscosity.

Depending on temperature, pressure, and oil and solvent composition, the injected solvent may be completely (first-contact) miscible or may become miscible due to continuous mass transfer of components between oil and solvent during flow through the reservoir (multiple-contact miscible). Such solvent injection usually is chased by the injection of a less expensive drive fluid, such as natural or flue gas, or water. Most of the world's enhanced oil-recovery production comes from injection of solvent vapour into a petroleum reservoir and this remains an active research area.

Regardless of the type of gas injected, large density and viscosity contrasts exist between the displacing and displaced fluids resulting in poor sweep efficiency because of gravity over-ride and viscous fingering. Much research therefore has been devoted to the development of effective foam-injection processes.

Heavy oil reservoirs

Primary production of heavy oil is driven predominantly by the exsolution of gas from the oil and is maintained by the growth of foamy oil within the pay zone. In cold production an operator intentionally produces sand from the reservoir to develop more aggressively heavy oil pools and increase oil production rates. Foamy oil flow, or the formation and flow of a dispersion of gas »



Surface-generated foam field test showing well-head and foam generators.

» bubbles in oil, is one of the important contributing factors in the success of cold heavy oil production. Research is aimed at identifying the driving force behind foamy oil flow and at producing ways to enhance significantly recovery factors and reserves.

Meanwhile, we are working on improved rule-of-thumb operating guidelines and now have field-scale numerical models for cold production. Cold production produces only eight to 15 per cent of the OOIP, resulting in a significant and growing need for a post-cold production follow-up process. The best potential appears to be in thermal processes for pay zones thicker than 10m and in cyclic solvent processes for pools less than 10m thick, using CO_2 and CO_2/hydrocarbon gas mixtures.

For heavy oil and in situ oil sands, the steam-assisted gravity drainage (SAGD) process, combined with horizontal well technology, offers a cost-effective alternative to other thermal processes with vertical wells such as cyclic steam, or steam-flood. A number of SAGD pilots and commercial applications are underway or planned for the Athabasca deposit. Current research is aimed at enhancing SAGD oil-production rates and process economics, and also at alternates such as the hybrid process based on the continuous co-injection of steam and solvent. Preliminary results show gas injection following a SAGD operation could be a feasible wind-down process. Unfortunately, thermal processes are energy intensive and have high CO_2 emissions.

In VAPEX, a gaseous solvent is injected rather than steam, creating a solvent chamber that grows as solvent-diluted oil drains down its sides. Laboratory and numerical simulation results have been encouraging and several VAPEX field tests are being planned.

Solvent-based processes are likely to have good recovery factors, perhaps as high as SAGD under some circumstances, and for a given amount of oil produced they will consume much less energy, with correspondingly lower CO_2 emissions than would a comparable steam-based process. Other advantages of solvent processes include lower water handling and surface facilities costs, applicability in water-sensitive reservoirs, and possibly the production of an upgraded and higher-value product.

Hybrid thermal solvent processes, gravity driven and utilising some combination of heat and solvent, also should be able to provide SAGD-like performance with significantly reduced energy inputs and greenhouse gas emissions. Examples include SAGD with solvent additives (expanding solvent SAGD), heated solvent VAPEX, and combined waterflood/solvent flood processes.

The goal of all of these is to increase substantially the recovery factor of primary or waterflood processes by using solvents. Current research involves a combination of small-scale mechanistic experiments, larger-scaled experiments incorporating most mechanisms of a field process, and numerical simulation to interpret the laboratory experiments and to predict field performance.

Another unconventional source perhaps, but CO_2-enhanced coal-bed methane comprises at least 200 trillion cubic feet of Canada's mounting reserves in Alberta.

Reservoir access, conformance control and water shut-off

The past two decades have seen a momentous switch from vertical wells to horizontal wells in a variety of improved oil-recovery schemes that benefit from increased reservoir access.

In Canada, the first horizontal well was drilled in

1978; by 2000 more than 11,000 horizontal wells had been drilled, about half in conventional and medium-light reservoirs, and the rest in heavy oil and bitumen reservoirs. Having improved reservoir access, water shut-off and conformance control remain as some of the greatest challenges in the petroleum industry; in extra heavy oil reservoirs, water coning will render horizontal wells no more efficient than vertical wells.

In Alberta, produced water from petroleum production amounted to more than three billion bbls in 1997, averaging more than 6bbls of water for every bbl of oil produced.

Foams can be injected into a reservoir to reduce the effects of poor mobility ratio between injected and reservoir fluids, or remedy other causes of poor areal sweep efficiency, poor vertical sweep efficiency, seal off non-oil-saturated or thief zones, or partially overcome effects due to reservoir heterogeneities.

In gas-flooding processes injecting the gas as a foam lowers the gas mobility disproportionately in the swept and/or higher permeability intervals and diverts the displacing gas into other parts of the formation that previously were unswept or underswept, improving both vertical and horizontal sweep efficiency.

In producing wells, the near-wellbore placement of a foam-blocking agent can prevent gas coning, a major production problem, as has been successfully demonstrated in the North Sea and North America.

Oil-tolerant foams can be formulated for injection with air/nitrogen, natural gas, carbon dioxide, or steam, and are being used in the design of foam applications for fields in Canada, the North Sea, and Cuba. Polymer enhanced (thickened) foams that have increased viscosity and stability, also are being used more often, as are polymer-thickened foams that also incorporate time-delayed cross-linking agents (gelling-foams). The latter can be used to improve the efficiency of oil displacement by blocking swept zones and by diverting fluids into underswept zones in reservoirs containing large permeability variations and/or fractures.

These gelled foams function like conventional gels, but with only a small fraction of the pore space being occupied by gelled liquid. Gelling-foams also have been developed for the prevention of gas coning, in which case the gelation has to be sufficiently delayed for the foam to be propagated into the reservoir. When properly placed, gelation progresses to completion, effectively gelling the foam in situ.

In oil producers, the relatively low density of a gelling-foam allows it to be placed near the top of the oil-bearing zone into the gas cap so that gas channelling is blocked without significantly reducing oil production. Similarly, injection wells dominated by a thief layer near the top of the pay zone can be treated. Such gelling-foams have been field-tested successfully and additional field tests are planned in Canada and internationally.

Prediction tools for improved oil recovery

After conducting approximately one thousand experimental field pilots and about two hundred semi-commercial projects worldwide, we have reached the stage at which improved screening of reservoirs for IOR applications provides valuable assistance to reservoir and production engineers seeking to increase production. Integrated analytical software, such as PRIze™, provides quick engineering evaluations of the IOR potential of oil reservoirs based on up-to-date published experience, analytical models from technical literature and constant interactions with users.

This approach involves the technical screening of prospects for IOR by checking the reservoir data against critical parameters using a go/no go approach. A waterflood option utilises a variety of prediction methods in order to take into account such specific characteristics as heterogeneity and water tonguing.

The software further performs calculations of incremental recovery, injection/production profiles, and produces gas-oil ratio (GOR) or water cuts for selected processes. Current research and development is aimed at extending the applicability of such tools to emerging recovery processes, including SAGD and VAPEX, and to less favourable reservoirs, including those with smaller pay zone thickness and lower permeability.

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