

Heavy-Oil Reservoirs

Oil producers involved in heavy-oil recovery face special production challenges. However, innovative drilling, completion, stimulation and monitoring techniques help make heavy-oil reservoirs profitable assets.

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1. The formula relating specific gravity (S.G.) to API gravity is $API\ gravity = (141.5/S.G.) - 131.5$. Thus, water, with a specific gravity of 1, has an API gravity of 10. (From Conaway C: *The Petroleum Industry: A Nontechnical Guide*. Tulsa, Oklahoma, USA: Pennwell Publishing Co.,

1999.) Oils that are denser than water are called ultra-heavy or extraheavy.

2. Nehring R, Hess R and Kamionski M: *The Heavy Oil Resources of the United States*. R-2946-DOE (February 1983).

3. Paraffinic hydrocarbons have high wax content, high pour point and are nonreactive. In contrast, naphthenic hydrocarbons have low wax content, low pour point and are nonreactive. Aromatic hydrocarbons are reactive and have higher solvency than paraffinic or naphthenic hydrocarbons. (From Tissot BP and Welte DH: *Petroleum Formation and Occurrence*. Berlin, Germany: Springer-Verlag, 1978.)

4. Ehlig-Economides CA, Fernandez BG and Gongora CA: "Global Experiences and Practice for Cold Production of Moderate and Heavy Oil," paper SPE 58773, presented at the SPE International Symposium on Formation Damage Control, Lafayette, Louisiana, USA, February 23–24, 2000.

Heavy oil is often overlooked as a resource because of the difficulties and costs involved in its production. But the more than 6 trillion barrels [1 trillion m³] of oil in place attributed to the heaviest hydrocarbons—triple the amount of combined world reserves of conventional oil and gas—deserve a closer look.

While other factors such as porosity, permeability and pressure determine how a reservoir will behave, it is the oil density and viscosity that dictate the production approach an oil company will take. Dense and viscous oils, called heavy oils, present special, but not insurmountable, production challenges.

Natural crude oils exhibit a continuum of densities and viscosities. Viscosity at reservoir temperature is usually the more important measure to an oil producer because it determines how easily oil will flow. Density is more important to the oil refiner because it is a better indication of the yield from distillation. Unfortunately, no clear correlation exists between the two. A medium-density, or light, crude with high paraffin content in a shallow cool reservoir can have a higher viscosity than a heavy, paraffin-free crude oil in a deep hot reservoir. Viscosity can vary greatly with temperature. Density varies little with temperature, and has become the more commonly used oilfield standard for categorizing crude oils.

Density is usually defined in terms of degrees American Petroleum Institute (API) gravity, which is related to specific gravity—the denser the oil, the lower the API gravity.¹ Liquid hydrocarbon API gravities range from 4° for tar-rich bitumen to 70° for condensates. Heavy oil occupies a range along this continuum between ultraheavy oil and light oil (right). The US Department of Energy (DOE) defines heavy oil as between API gravities 10.0° and 22.3°.² However, nature recognizes no such boundaries. In some reservoirs, oil with gravity as low as 7° or 8° is considered heavy rather than ultraheavy because it can be produced by heavy-oil production methods. In this article, we discuss reservoirs with oils of API gravities between about 7° and 20° that are produced by techniques that are atypical for medium or light oils. The most viscous tar, pitch and bitumen deposits at even lower API gravities usually require mining-style methods for economic exploitation.

When originally generated by petroleum source rock, crude oil is not heavy. Geochemists generally agree that nearly all crude oils start out with API gravity between 30° and 40°. Oil becomes heavy only after substantial degradation during migration and after entrapment.

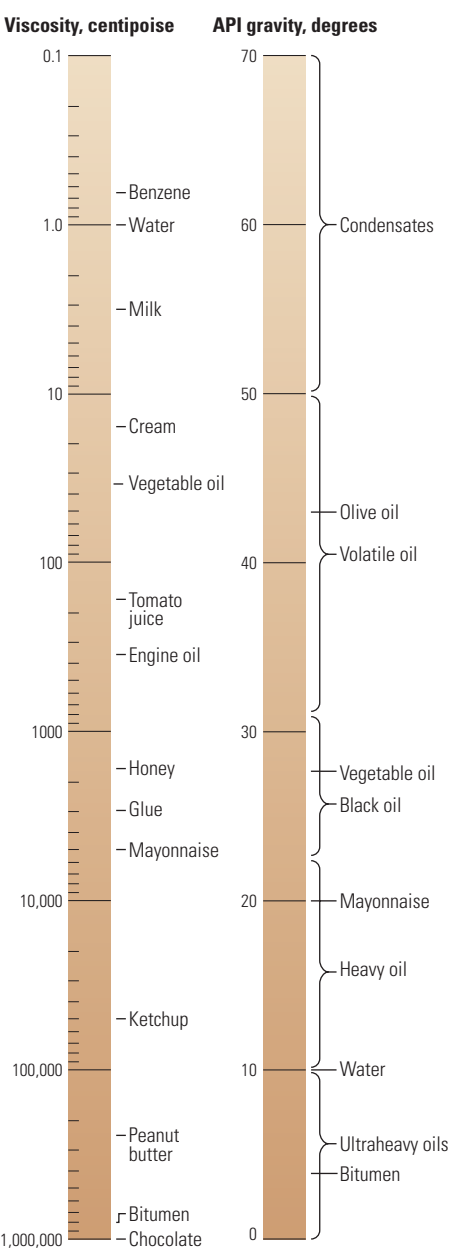
Degradation occurs through a variety of biological, chemical and physical processes. Bacteria borne by surface water metabolize paraffinic, naphthenic and aromatic hydrocarbons into heavier molecules.³ Formation waters also remove hydrocarbons by solution, washing away lower molecular-weight hydrocarbons, which are more soluble in water. Crude oil also degrades by devolatilization when a poor-quality seal allows lighter molecules to separate and escape.

Heavy oil typically is produced from geologically young formations—Pleistocene, Pliocene and Miocene. These reservoirs tend to be shallow and have less effective seals, exposing them to conditions conducive to forming heavy oil. The shallow nature of most heavy-oil accumulations means that many were discovered as soon as people settled nearby. Gathering oil from seeps and digging by hand were the earliest forms of recovery, followed by tunneling and mining.

By the early 1900s, these methods gave way to the progression of techniques employed today to produce heavy-oil reservoirs. Most operators try to produce as much oil as possible under primary recovery, called cold production—at reservoir temperature. Typical recovery factors for cold production range from 1 to 10%. Depending on oil properties, cold production with artificial lift—including injection of a light oil, or diluent, to decrease viscosity—may be successful. Many reservoirs produce most efficiently with horizontal wells. In some cases, encouraging sand production along with oil is the preferred production scheme. Choosing the optimal cold-production strategy requires an understanding of fluid and reservoir properties and production physics.⁴

Once cold production has reached its economic limit, the next step is usually thermally enhanced recovery. Here again, several methods are available. In a technique called cyclic steam injection, producing wells can be stimulated by steam injection then returned to production. Cyclic steam injection can raise recovery factors to 20 to 40%. In steamflooding, steam pumped into dedicated injection wells heats viscous oil that is then produced at production wells. Injection and production wells may be vertical or horizontal. Well placement and injection schedules depend on fluid and reservoir properties. Recovery factors can reach 80% in some steamflooding operations.

For oil producers involved in heavy-oil recovery, the enterprise requires a long-term investment. The high viscosity of heavy oil adds to transport difficulties and requires special, and therefore more costly, refining techniques to produce marketable products. Technology value is assessed



▲ Gravities and viscosities of hydrocarbons and other liquids. Liquid hydrocarbon API gravities range from 4° for tar-rich bitumen to 70° for condensates. Heavy oil can have viscosity similar to that of honey.

by its ability to reduce total cost. Since most heavy-oil fields are shallow, drilling costs have not been the dominant factor, but the growing use of complex horizontal and multilateral wells is introducing some cost at this stage of development. The primary cost typically is that of the energy needed to generate and inject the steam required to mobilize viscous oils. In many cases, these operating costs are projected to continue for 80 years or more.

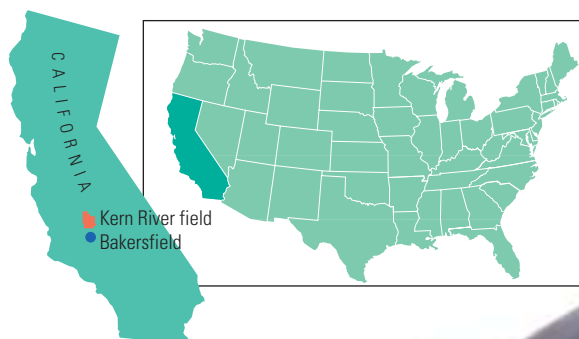
Every region has oil of different physical properties and is at a different stage of process maturity, so every region uses different development and production techniques. This article describes how operating companies in selected areas—the USA, Indonesia, Venezuela and Canada—are getting the most from their heavy-oil assets.

California, USA—Producing for More Than a Century

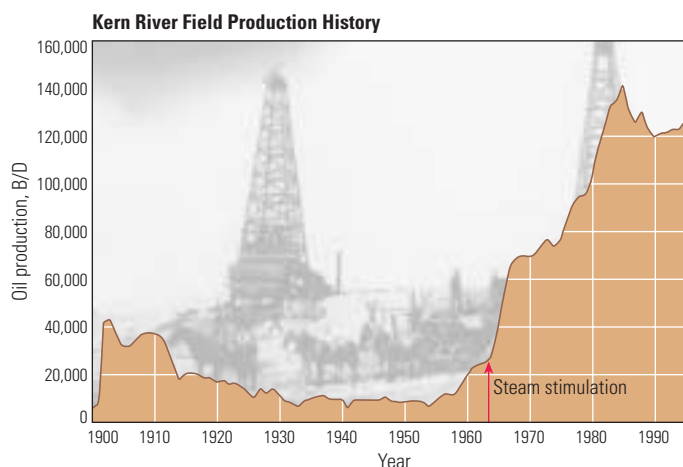
In the late 1800s, settlers and prospectors discovered oil in California by drilling near surface seeps of heavy oil and tar. Three of California's six supergiant fields are heavy-oil fields: Midway-Sunset, Kern River and South Belridge have already produced more than 1 billion barrels [160 million m³] of oil each.

The Kern River field, located near Bakersfield, California, was discovered in 1899 when the hand-dug discovery well encountered oil at 43 ft [13 m]. The field is about 6 miles long and 4 miles wide [10 km by 6.4 km], and produces heavy oil from the Miocene- to Pleistocene-aged Kern River formation (right). Sands in the Kern River formation had an average initial oil saturation of 50%. Average porosity is 31% and permeability ranges from 1 to 10 darcies. The field contained an estimated 4 billion barrels [640 million m³] of original oil in place (OOIP). However, the oil density of 10° to 15° API and viscosity of 500 to 10,000 cp [0.5 to 10 Pa-s], combined with low initial reservoir temperature and pressure, resulted in low primary recovery.

Production from Kern River field peaked at just over 40,000 B/D [6356 m³/d] in the early 1900s (right). Poor reservoir performance and low demand for heavy crude caused production to decline to low levels until the advancement of heavy-oil refining techniques in the early 1950s. The arrival of bottomhole heaters in the mid-1950s turned flat production into increasing production. Experimentation with steam injection in the early 1960s proved the potential of thermal-recovery methods. Kern River crude responds remarkably well to heat: viscosity of 12,000 cp [12 Pa-s] at reservoir temperature of 90°F [32°C] is reduced by a factor of 600, to 20 cp [0.02 Pa-s] at steamflood temperature of 260°F [128°C].⁵ By 1973, 75% of Kern River production was from steam-displacement projects.

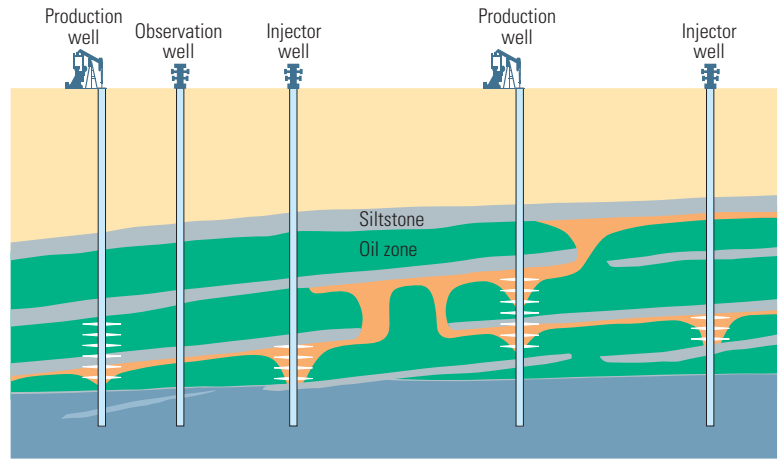
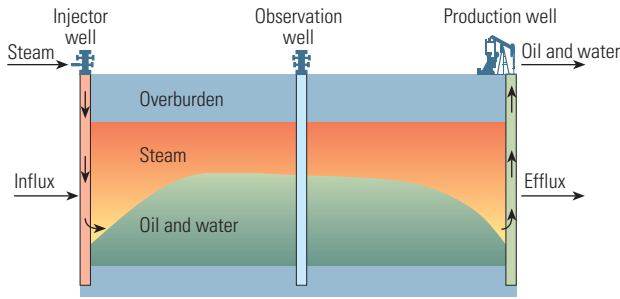


▲ Kern River field, operated by ChevronTexaco near Bakersfield, California, USA. The outcrop, seen from the west, shows light-colored sands and dark-colored siltstones of the Kern River formation dipping 3 to 5 degrees to the southwest. The sands are oil-producing and the siltstones are permeability barriers to the movement of oil and steam.



▲ History of oil production from the Kern River field. Low primary recovery using cold-production techniques ended in the 1960s, when steam-injection methods rejuvenated the field—a program that continues today.

5. Brelih DA and Kodl EJ: "Detailed Mapping of Fluvial Sand Bodies Improves Perforating Strategy at Kern River Field," paper SPE 20080, presented at the 60th SPE California Regional Meeting, Ventura, California, USA, April 4–6, 1990.

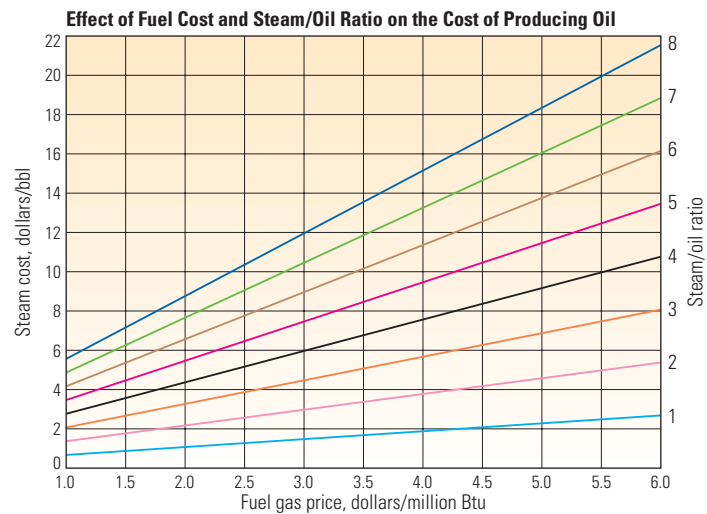


^ Ideal and more realistic scenarios for movement of injected steam. Ideally (*left*), steam rises from perforations in the injection well until it reaches a barrier, then spreads out laterally toward producing wells until it breaks through. Then the steam volume extends downward as oil is produced by gravity drainage. More commonly (*right*), reservoir and borehole complexities allow steam to travel along unknown paths. These complexities include discontinuous siltstone barriers, allowing sand-to-sand contacts, which act as conduits to upper sands; inadequate cement jobs and incomplete zonal isolation; water influx, which requires high steam volumes to heat; and contact with air-filled sands, resulting in high heat losses.

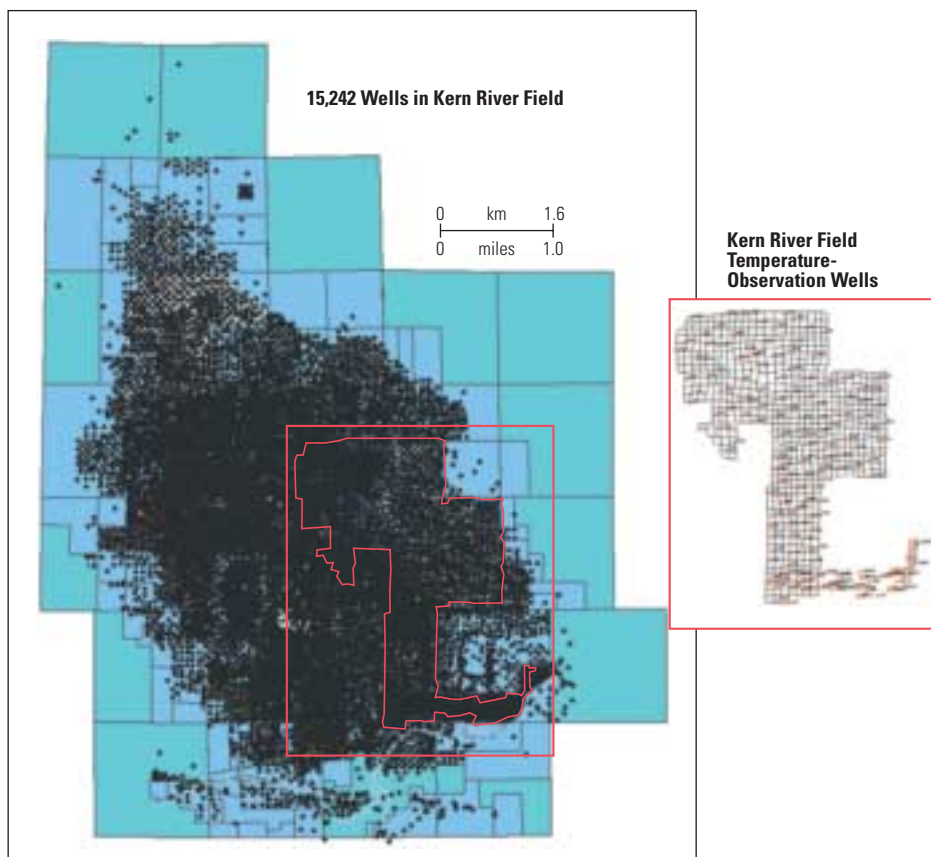
Projected growth in production requires heat management, or using steam in the most efficient manner. The steam/oil ratio (SOR) is an important factor in assessing recovery efficiency. The SOR is defined as the number of barrels of steam—in terms of cold-water-equivalent (CWE)—required to produce one barrel of oil. The SOR and the cost associated with steam generation directly impact profitability (*right*). When the price of gas, the fuel required for steam generation, is too high, and the price of heavy oil is low, steam-injection operations have been curtailed.

For ChevronTexaco, the Kern River field operator, reservoir surveillance is a critical element in heat management. Accurate and timely descriptions of the reservoir heat distribution are needed to calculate the appropriate amount of steam injected.

Typical steam injection is in a 5-spot pattern covering 2.5 acres [10,120 m²] with a producer at each corner and an injector in the center. Variations to this configuration include the 9-spot and combination patterns. Injected steam rises from the perforations in the injection well until it encounters an impermeable lithologic barrier. Steam then extends laterally until breakthrough occurs at a producing well. As oil is produced by gravity drainage, the steam chest, or steam-saturated volume, grows downward (*top*). In reality, geologic heterogeneities and borehole complexities allow steam to travel along unplanned paths.

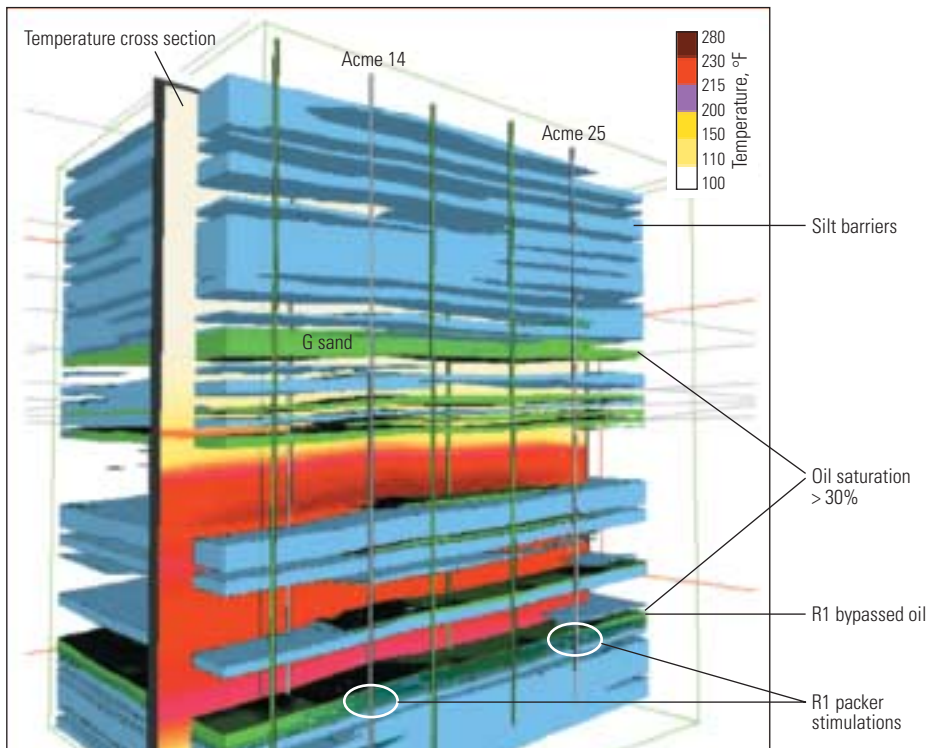


^ How the cost of fuel and the steam/oil ratio (SOR) affect the cost of heavy-oil production. The SOR is defined as the number of cold-water-equivalent (CWE) barrels of steam required to produce one barrel of oil. Its value is determined by the reservoir and the efficiency of the steam-application process. The intersection of the fuel price (gas, in the case of California) and the SOR (colored lines) determines the cost of steam per barrel of oil produced. Operators can use this chart to determine the maximum fuel price for which production remains profitable.



▲ Injection and production wells (black dots) in the Kern River field. The inset on the right shows the density of observation wells (red dots) in the southeast part of the Kern River field.

3D Visualization, Looking East to West



▲ A three-dimensional view of sands, siltstones and temperature in part of a Kern River project. Sands with oil saturations greater than 30% are shown in green. Siltstones, resistivity below 10 ohm-m, are shown in light blue. This view indicates that the lower R1 zone still has good oil saturation and has relatively low temperature, making the interval a potential candidate for a packer-isolated cyclic steam-stimulation job.

Kern River field has more than 15,000 injection and production wells, and a network of 540 observation wells (left). There is roughly one observation well for every five injection patterns. Recently, openhole resistivity, EPT Electromagnetic Propagation Tool and density-neutron logs have been acquired in every well drilled. Cased-hole logs run on a set schedule in observation wells monitor steam progress. These include temperature logs to show reservoir temperature variation with depth and RST Reservoir Saturation Tool logs to determine oil saturation using carbon/oxygen (C/O) ratios.⁶ These logs are used to create three-dimensional (3D) models of temperature, oil saturation and steam distribution. These models, when combined with a lithology model produced from openhole resistivity logs, are used to create cross sections and visualization models that facilitate accurate heat-injection rates. Temperature surveys are run every three months because temperature can change quickly in active steam-injection projects, and it is important to react quickly: changing injection rates at the right time can result in significant cost savings.

At Kern River, ChevronTexaco geologists input observation-well data into 3D visualization tools for model manipulation, volumetric calculation and heat management (below left). In this example, resistivity data have been used to model the distribution of silt and sand layers across a small Kern River project. Integrated with the geologic model is one vertical plane through the 3D temperature-distribution model. The display reveals that the lower R1 and the G sand in the Acme 14 well contain good oil saturations at relatively low temperature. This combination makes for an attractive target for a packer-isolated cyclic steam-injection job. Before the job, the Acme 14 well was producing 20 BOPD [3 m³/d], which is higher than the 14-BOPD [2.2-m³/d] average for the field. Following a job in this interval, the Acme 14 well responded with an additional 40 BOPD [6.4 m³/d], a 300% increase, placing it in the top 10% of all producers in the field.

These visualization tools allow asset team members to determine steam distribution, adjust steam rates, and optimize perforations accordingly in existing projects, as well as plan future projects.

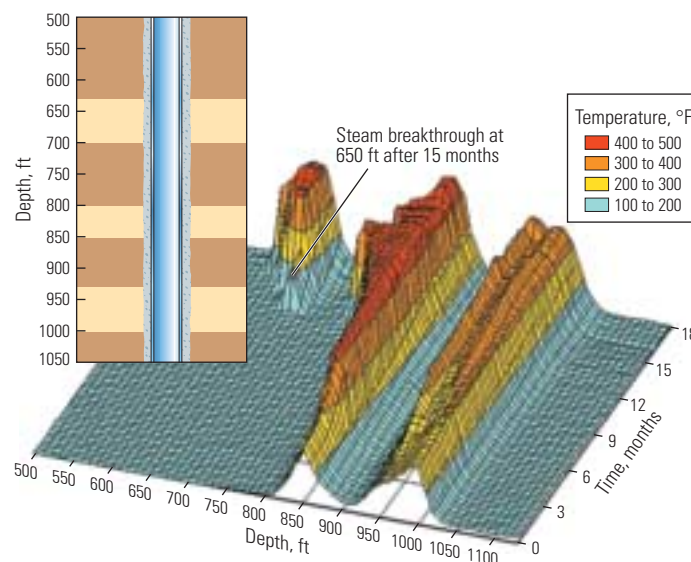
Some California operators are evaluating other ways to monitor steam movement. Since 1996, several heavy-oil fields have been instrumented with SENSE fiber-optic distributed temperature sensors (DTS). The optical fiber serves as both a sensor and transmission system, providing temperature readings at 1-m [3.3-ft] intervals. The system has been used in numerous

rod-pumping wells at temperatures up to 249°C [480°F]. When deployed in producing wells, the DTS system can be installed in a ¼-in. stainless-steel tube attached to the outside of casing or production tubing. In one example, the fiber-optic system detected indications of a steam leak behind casing, moving toward the surface. The well was worked over to repair the leak before a surface breakout of high-temperature steam occurred.

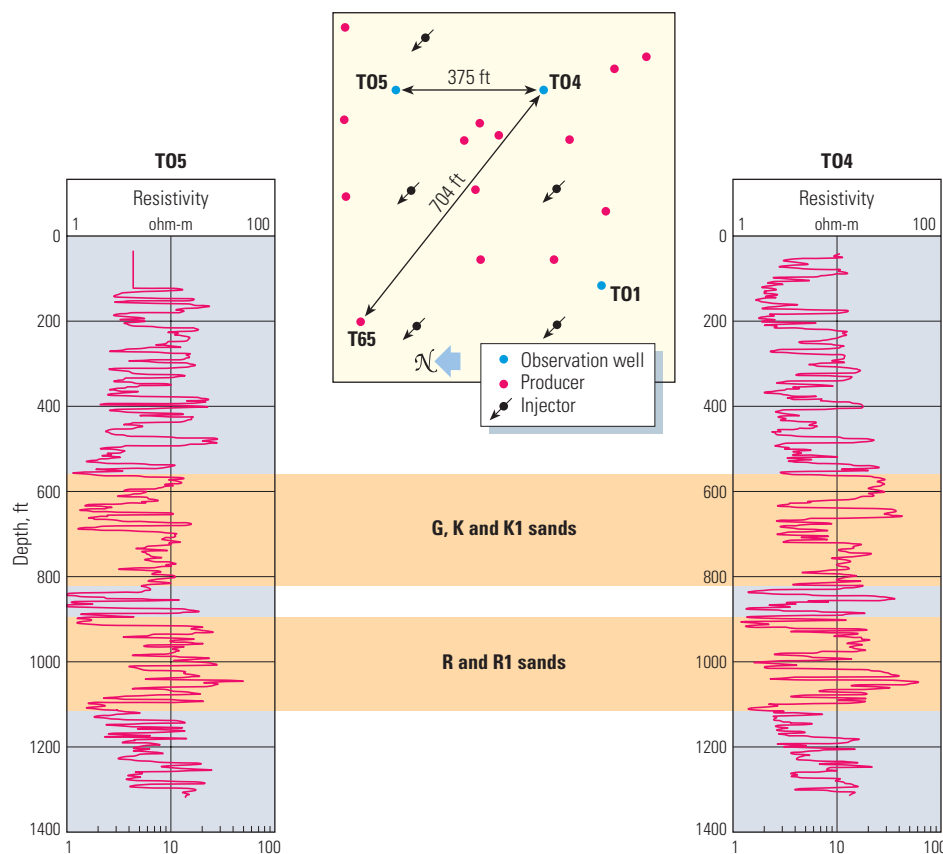
In another example, steam injection into three sands was monitored from an observation well. By the time monitoring began, steam had reached two of the sands at the observation-well location (right). After 15 months, the DTS system detected steam breakthrough in the top sand. SENSE fiber-optic systems have been installed for steam monitoring in more than 150 wells, including projects in Indonesia, Venezuela, Canada and Oman, in vertical producing and observation wells and in horizontal wells.

ChevronTexaco and other California heavy-oil producers are testing crosswell electromagnetic (EM) surveys as another means to map residual oil saturation and determine factors that control steam and oil flow. The crosswell EM method is designed to map the interwell conductivity distribution. A crosswell EM field system consists of a transmitter tool deployed in one well and a receiver tool deployed in a second well located up to 1 km [0.6 mile] from the source well. The tools are connected with surface wire telemetry and deployed with standard wireline equipment. By positioning both the transmitter and receiver tools above, below and within the zone of interest, data can be collected for tomographic inversion resulting in a model of conductivity between the wells.

ElectroMagnetic Instruments, Inc. has conducted crosswell EM surveys in several active oil fields. One survey in the Kern River field recorded EM induction data between three pairs of wells, including fiberglass-cased observation wells, T04 and T05, and a steel-cased production well, T65. Wireline induction-resistivity logs distinguish higher resistivity sands (8 to 50 ohm-m) from lower resistivity silts (2 to 8 ohm-m), and identify the main reservoir intervals under steam injection (right). Because of the low salinity of the



▲ Fiber-optic temperature monitoring in steamflood observation well. Steam was injected into three sands (*inset*), and by the beginning of this monitoring period had reached the lower two sands at the location of the observation well. The distributed temperature sensor (DTS) system detected steam breakthrough in the top sand after 15 months.



▲ Resistivity logs in wells selected for a Kern River crosswell electromagnetic (EM) survey. Wireline resistivity logs distinguish higher resistivity sands (8 to 50 ohm-m) from lower resistivity silts (2 to 8 ohm-m), and identify the main reservoir intervals under steam injection: G, K and K1; and R and R1. The crosswell survey recorded EM induction data between three pairs of wells (*inset*), including fiberglass-cased observation wells, T04 and T05, and a steel-cased production well, T65.

6. Albertin I, Darling H, Mahdavi M, Plasek R, Cedeño I, Hemingway J, Richter P, Markley M, Olesen J-R, Roscoe B and Zeng W: "The Many Facets of Pulsed Neutron Cased-Hole Logging," *Oilfield Review* 8, no. 2 (Summer 1996): 28-41.

Harness P, Shotts N, Hemingway J, Rose D and van der Sluis R: "Accurate Oil Saturation Determination and Monitoring in a Heavy Oil Reservoir," paper SPE 46245, presented at the SPE Western Regional Meeting, Bakersfield, California, USA, May 10-13, 1998.

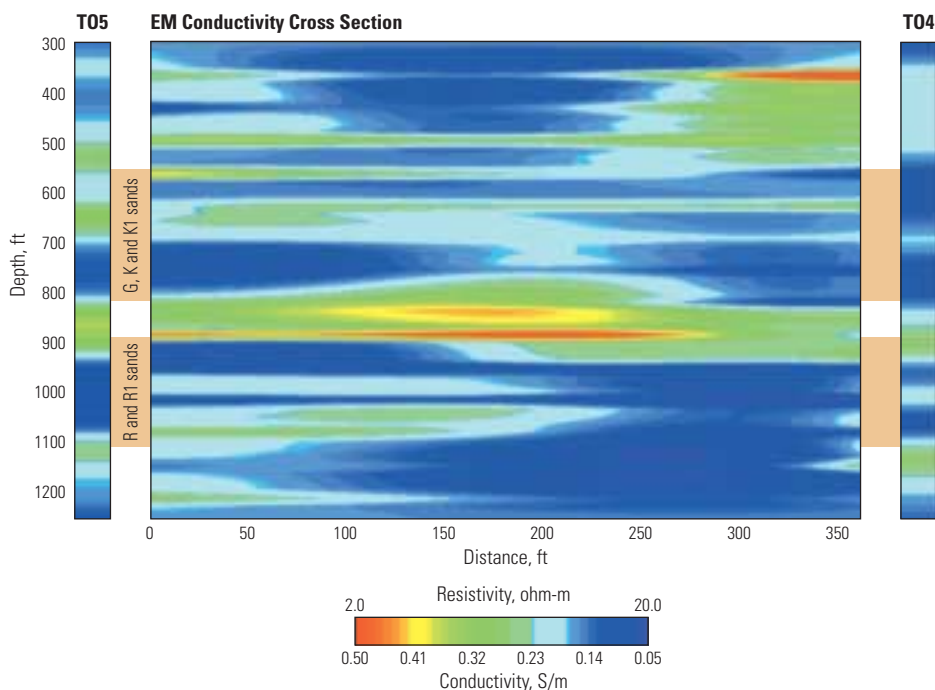
connate water, oil and water phases are not distinguishable from each other in resistivity logs alone. However, steam-saturated intervals can be distinguished from oil- or cold water-saturated intervals primarily because the high temperature reduces formation resistivity by up to 40%. For example, the induction logs across the G, K and K1 sands show correlation between T05 and T04, but the resistivities of the sands are 30 to 40% lower in T05. Well T04 was drilled into an unexpected “cold spot;” temperatures were 100F° [56C°] lower in T04 than in T05. Injected steam had, for some reason, bypassed the productive intervals in T04, leaving high oil saturation. Kern River geologists have identified a number of such areas, and discovering the cause of the isolation is a priority for them in their quest to maximize production.

Inversion of the crosswell EM data takes an initial model of interwell conductivity (reciprocal of electrical resistivity), usually derived from resistivity logs in the two wells, then adjusts the model until the observed and calculated data fit within a given tolerance. The final model indicates some stratigraphic and possible structural variation in the interwell region (above right). The high-conductivity siltstone layer separating the two producing units thickens substantially but discontinuously about halfway between the observation wells. The discontinuous thickening may correspond to a small fault that is causing steam to bypass the productive intervals in Well T04.

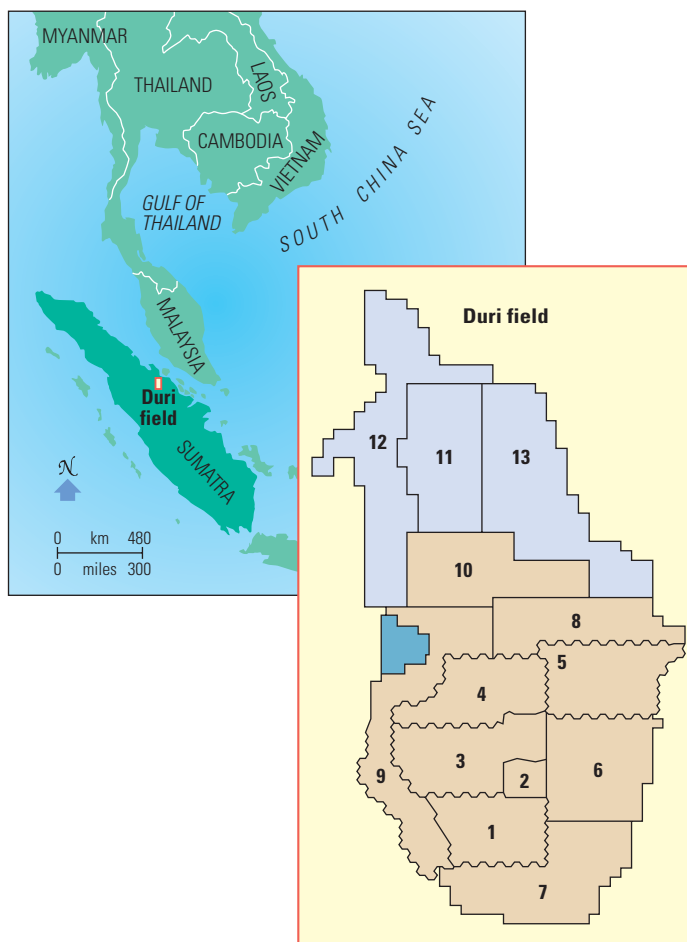
Tomographic inversion and imaging are new techniques and active areas of research.⁷ The inversions are nonunique, meaning a number of resistivity models can satisfy the observed data. Results improve when additional data, such as crosswell seismic surveys, are used to constrain the inversion. Later in 2002, ElectroMagnetic Instruments is planning to conduct at least five new crosswell EM surveys in this area of Kern River field to test the idea that sweep efficiency might be influenced by faulting.

Indonesia—The Biggest Steamflood

Heavy oil in Indonesia is practically synonymous with Duri, a large shallow field that is the biggest steamflood operation in the world in terms of oil production and steam injected (right). Duri field, discovered in 1941, was not put on production until completion of a pipeline in 1954. Primary production, mostly from solution-gas and compaction drives, peaked at 65,000 BOPD [10,300 m³/d] in the mid-1960s and was projected to result in an ultimate recovery of only 7% of OOIP.⁹ Cyclic steam stimulation proved helpful in individual wells, and led to the start of



^ Inversion results of the EM survey between observation wells, T04 and T05. Blue indicates low conductivity (high resistivity) and yellow points to higher conductivity (lower resistivity). The siltstone layer (yellow-green) separating the producing units thickens substantially about halfway between the observation wells, which may explain the diminished steam flow toward T04.



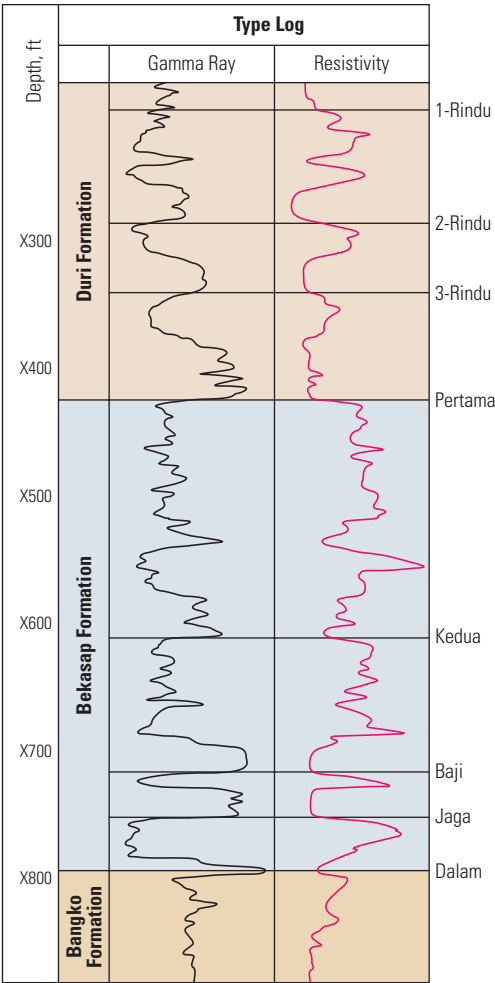
^ Duri field in central Sumatra operated by PT. Caltex Pacific Indonesia (CPI). The field is divided into 13 areas, of which ten (brown) are at some stage of steamflooding. Seismic surveys have been run in several portions of the field, in some cases repeatedly, for time-lapse reservoir surveillance.

a pilot steamflood project in 1975. After the pilot successfully recovered 30% OOIP, the first major project was begun in 1985. Duri field now produces nearly 230,000 BOPD [36,500 m³/d] from the injection of 950,000 BCWE/D of steam, with ultimate recovery factors expected to approach 70% in some areas. There are currently 4000 producers, 1600 injectors and 300 observation wells. Duri is operated by PT. Caltex Pacific Indonesia (CPI) under a production-sharing contract with the Government of Indonesia.

The Duri reservoir formations consist of three main groups—Rindu, Pertama-Kedua and Baji-Jaga-Dalam (right). Since the last group is oil-bearing only in a few structural highs in the south and steamflooding started only recently in the Rindu, most of the production comes from the Pertama and the Kedua. Steamflooding has been applied throughout the field, with 10 of 13 areas currently at some stage of steam injection. The total volume of steam injected has remained constant since the mid-1990s, so new areas are opened up only when an existing area has been sufficiently flooded—usually after about 10 years. The majority of injection patterns are an inverted 9-spot over 15.5 acres [250 m by 250 m]. In areas with less net pay, a 5-spot pattern is used on 15.5 acres, while earlier designs used an inverted 7-spot on 11.625 acres [217 m by 217 m].

Production occurs mainly as a result of pressure generated by the steam before breakthrough into production wells. After a few months of injection, oil production rates increase rapidly to about five times presteam rates, with horizontal pressure gradients of up to 1 psi/ft [22.6 kPa/m] between injectors and producers. The injector wells are completed so that the amount of steam injected into a layer is proportional to the estimated net oil in place. Even so, steam fronts are usually well defined, with breakthrough occurring first in the interval with highest permeability, as expected.

General steam breakthrough occurs in a particular layer of a pattern after approximately one pore volume (PVI) of steam has been injected. After this, steam injection into that layer continues at a lower rate until reaching about 1.4 PVI. Steam then is diverted to other areas. After breakthrough, average horizontal pressure gradients decrease to below 0.2 psi/ft [4.5 kPa/m], so that production depends on gravity drainage and heating of adjacent layers. Duri's heavy oil is relatively light (17° to 21°API) and has a relatively low viscosity (300 cp at 100°F) [0.3 Pa-s at 38°C]. The maximum viscosity reduction caused by



Average Reservoir Properties	
Average depth	500 ft
Presteam reservoir pressure	100 psi
Presteam reservoir temperature	100°F
Average net-pay thickness	120 ft
Average porosity	0.34 vol/vol
Average initial oil saturation	0.53 vol/vol
Average permeability	1500 mD
Rock compressibility	57 x 10 ⁻⁶ psi ⁻¹
Average oil gravity	20° API
Solution gas/oil ratio	15 scf/STB
Oil viscosity at 100°F	330 cp
Oil viscosity at 300°F	8.2 cp

^ Type log for reservoirs in the Duri field, and average properties for the Pertama and Kedua units.

steam is 40-fold, far less than in California. Gravity drainage is limited due to relatively thin sands, heterogeneity within the sands, low structural relief and large pattern spacing.

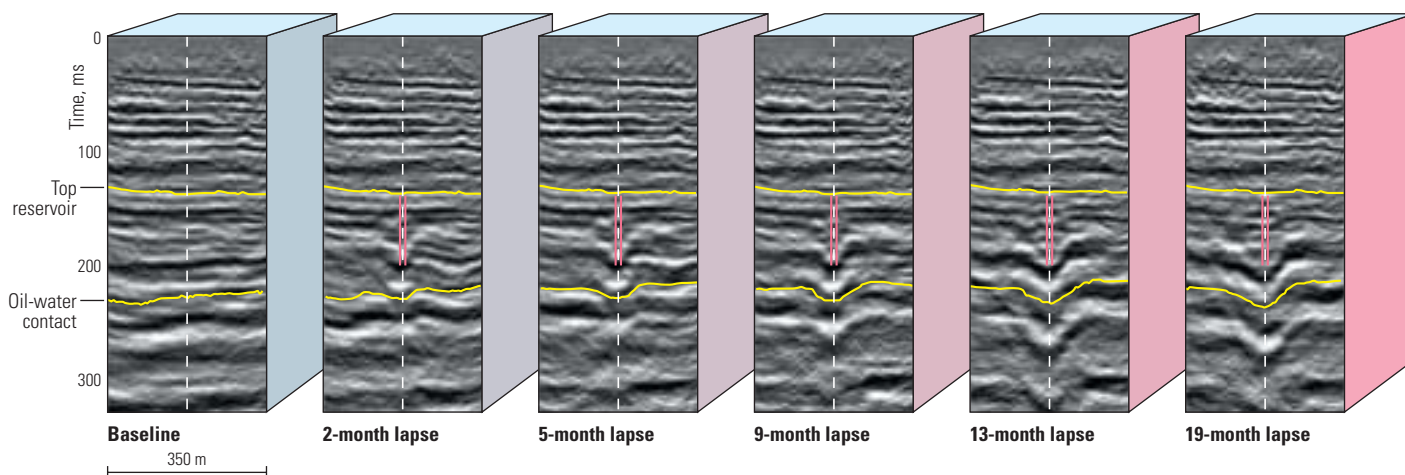
CPI realized early that good recovery depended on understanding the vertical and areal conformance of the flood. At the same time, economic success depended on efficient heat management. In addition to careful planning, implementation and reservoir management, it is important to monitor the steam progress as closely as possible.

Observation wells in Duri have been monitored from the beginning using the same techniques as in California. In injection wells, radioactive-tracer surveys, using krypton gas as the tracer, record the steam-injection profile. Steam breakthrough in production wells is detected from wellhead temperature, pressure and flow rate as well as from temperature and spinner surveys. These techniques have recently been augmented by high-temperature spinner

flowmeters in injection wells, fiber-optic temperature surveys and oil fingerprinting.

However, none of these techniques give a picture beyond the wellbore, and, even in combination, may be insufficient to give an accurate view of overall steamflood conformance. Time-lapse seismic monitoring is one technique that can reveal areal and interwell steam distributions. It has been used extensively in Duri.

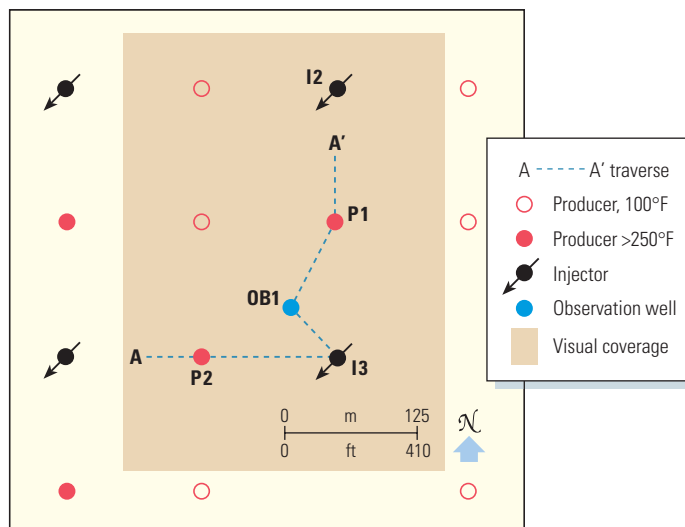
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- Wilt M, Lee KH, Becker A, Spies B and Wang B: "Crosshole EM in Steel-Cased Boreholes," *Expanded Abstracts*, 66th SEG Annual International Meeting, Denver, Colorado, USA (November 10-15, 1996): 230–233.
- Gael BT, Gross SJ and McNaboe GJ: "Development Planning and Reservoir Management in the Duri Steam Flood," paper SPE 29668, presented at the SPE Western Regional Meeting, Bakersfield, California, USA, March 8–10, 1995.



▲ Seismic data from the Duri baseline survey recorded before steam injection started, and five monitor surveys recorded later. The seismic section passes through the injector-well location (white dashed line) and steam-injection interval (pink). As steamflooding proceeds, decreased velocities in treated areas cause an apparent sag in reflectors. At the same time, the altered acoustic impedance increases the reflection strength. The steamflood advance is preceded by a zone of increased pressure. This increases velocities and causes an apparent small rise in reflectors.

Time-lapse seismic monitoring—Time-lapse seismic monitoring in Duri started with a pilot project in 1994.⁹ A 3D baseline survey was recorded over an injection pattern one month before steam injection started, and repeated five times over the next 20 months. Laboratory data and acoustic rock physics predict that the temperature increase and vapor phase associated with steam will lower seismic velocity, causing reflections within and below the steam zone to be pushed down, or delayed in time. On the other hand, the increased pressure caused by the steam injection pushes free gas generated during primary production back into solution, raising the velocity and pulling up the reflectors. The superposition of these effects was observed (above). The pressure front moves faster than the temperature front, causing reflectors near the injection well to be first pulled up moderately before being pushed down strongly as the formation heats up.

The changes in velocity also cause reflection amplitudes to change. Once steam is present, the seismic response is similar to the classic gas bright spot—a high-amplitude negative reflection (trough) at the top of the zone followed by a high-amplitude positive reflection (peak). These bright spots can help identify steam



▲ An injector pattern showing location of injection (I), production (P) and observation (OB) wells, and the traverse A to A'. Steam breakthrough is considered likely when the temperature rises above 250°F, as in P1 and P2.

9. Jenkins SD, Waite MW and Bee MF: "Time-Lapse Monitoring of the Duri Steamflood: A Pilot and Study Case," *The Leading Edge* 16, no. 9 (September 1997): 1267–1273.

10. Waite MW, Sigit R, Rusdibiyu AV, Susanto T, Primadi H and Satriana D: "Application of Seismic Monitoring to Manage an Early-Stage Steamflood," paper SPE 37564, *SPE Reservoir Engineering* 12, no. 4 (November 1997): 277–283.

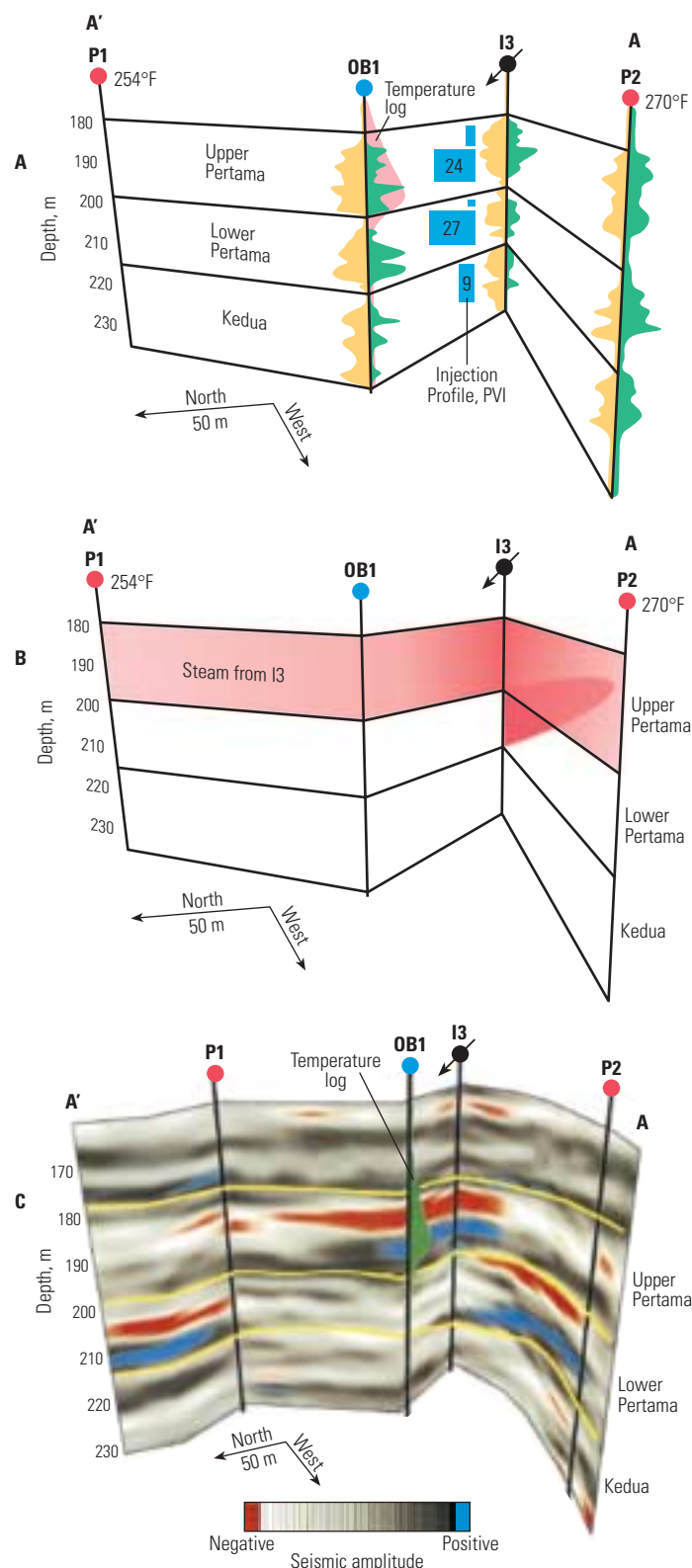
zones, but need to be carefully correlated with well data before being interpreted as formations taking steam.

Following the success of the pilot, 3D surveys have been recorded in different areas of the project and at different times. One particular case illustrates why monitoring using wellbore information is often insufficient to understand and manage steamflood conformance.¹⁰ In this pattern, wellhead temperatures above 250°F [121°C] in the two producing wells, P1 and P2, indicate undesirable steam breakthrough after only seven months of injection (previous page, bottom). The injection profile in nearby injection Well I3 showed that the Upper and Lower Pertamina were receiving most of the steam. A temperature log in observation Well OB1 showed a steam-related peak in the Upper Pertamina, but no steam in the other zones. The faster moving steam front in the Upper Pertamina at OB1 was consistent with petrophysical analysis, which assigned it the highest average permeability of the three zones (right).

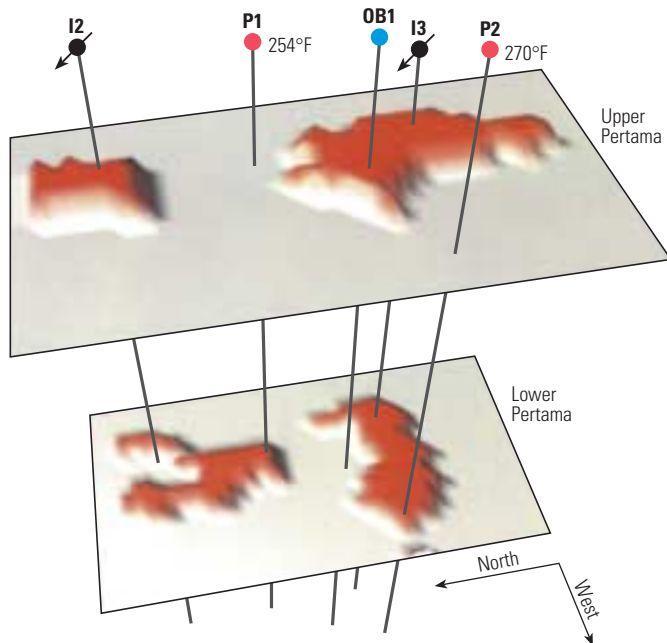
From these logs, a plausible interpretation is that the steam produced in Wells P1 and P2 comes through the Upper Pertamina. A remedial strategy would be to shut off this zone in the two producers, forcing steam to expand into other areas of the pattern. However, this interpretation is not unique. It assumes that Well I3 is the source of the steam, rather than Wells I2 or I4, and that the steam being injected into the Lower Pertamina is moving south and east into other patterns.

A 3D seismic survey was recorded at the same time as the well logs. The data were wavelet-processed to zero-phase by match filtering to a vertical seismic profile (VSP) acquired at the same time in the observation well. An expanded image through the reservoir indicates several steam paths (red trough over blue peak), but not in the expected directions. Two paths can be seen emanating from Well I3—one in the Upper Pertamina toward the observation well, thus explaining the temperature log, and the other in the Lower Pertamina toward Well P2. Well P1 does not appear to receive any steam from Well I3, receiving it instead in the Lower Pertamina from Well I2 to the north. Based on this information, it is the Lower Pertamina that should be shut off in Wells P1 and P2—a different conclusion than was arrived at with the well data alone.

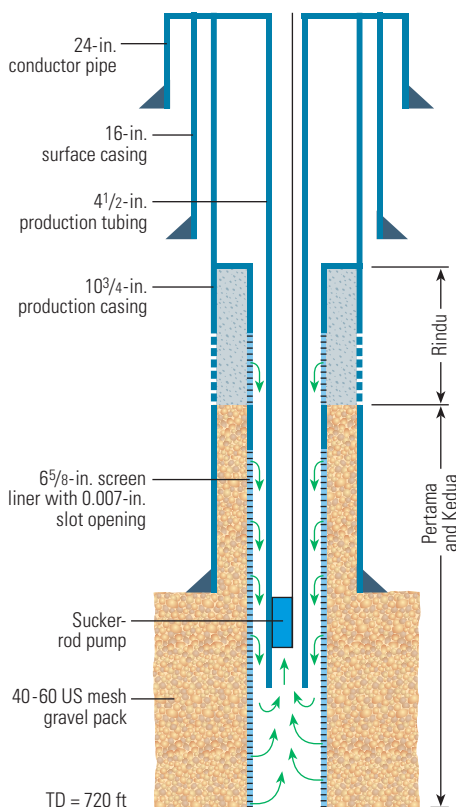
This interpretation has been further refined to produce a steamflood conformance picture for



▲ A) Cross section A to A' from the map on the previous page showing well-log data: resistivity (green), gamma ray (yellow) and temperature log (pink) in OB1 and steam-injection profile from Well I3 in percentage of pore volume injected (PVI) for each formation. B) The simplest consistent interpretation of log data suggesting that steam from the Upper Pertamina is the source of heat in both P1 and P2. C) The seismic section along the same traverse showing three distinct red over blue, high-amplitude steam indicators, hence three separate steam pathways between the wells. These results are still consistent with the well data but show that the source of steam in P1 and P2 is the Lower, not the Upper, Pertamina.



▲ A visualization of steamflood conformance for Upper and Lower Pertamina showing highly nonuniform development of the flood front from the injectors. The visualization is based on a binary classification (steam or no steam) derived from multiple seismic attributes extracted within each layer and from wellbore information. Steam is shown in red.



▲ A typical completion through the Rindu and the Pertamina-Kedu. In this case, the Pertamina-Kedu has an openhole gravel pack, while the Rindu has a cased-hole frac pack.

each layer (above). This shows the presence or absence of steam based on a discriminator function derived from seismic attributes and well information.¹¹ With this information, the appropriate actions can be taken to improve vertical and areal conformance. In addition to isolating breakthrough intervals in producers, conformance is improved by modifying injection-well profiles, stimulating producers with cyclic steam, and choking back producers so that steam is pushed into unswept areas. Interpretation of 3D and time-lapse seismic data has removed much of the uncertainty in understanding steam distribution, and has more recently been applied to locate bypassed oil.¹²

Production performance—Steamfloods are particularly sensitive to certain production problems. Since steamflooding nearly always takes place in shallow unconsolidated sands, sand production is a major concern. Steam is reactive and introduces large changes in temperature and pressure, conditions that are favorable for corrosion and scaling. For these problems, Duri is no exception and, because of its size, the effects are large. In a typical Duri week, there are 10 new wells drilled, 100 wells worked over or serviced, 300 truckloads of sand removed and 35,000 gallons [132 m³] of acid consumed.

With so many wells, any cost-effective improvement in production technique can have a large impact on profitability.

Several techniques have been used in Duri to improve well productivity while controlling sand production. Since the start of the steamflood, wells have been completed using conventional sand-exclusion screens and openhole gravel packs, or in some cases cased-hole gravel packs (below left). In the mid-1990s, CPI introduced cased-hole frac packs, creating short, wide hydraulic fractures in pay sands using the tip-screenout technique. Sanding was controlled by screened liners and sometimes also by packing curable resin-coated sands into the fractures.¹³ Although improvements were observed, the longer term cost-effectiveness was not clear.¹⁴

Recently, fracturing techniques have been improved by using coiled tubing to ensure that all perforations are properly packed, and by placing materials such as PropNET proppant-pack additives in the fractures to control sanding.¹⁵ In some wells, these techniques eliminate the need for a screen or a gravel pack, reducing the amount of completion hardware needed and allowing individual zones to be worked over or controlled in the future. While initial results are encouraging, openhole gravel packing is still the standard completion method for new wells.

Several techniques also have been used to remove the scale that forms across screened liners and inside production tubulars (next page, top). Replacing the screens is expensive in terms of workover time and lost production. Acidization is cumbersome and expensive, and shows only moderate success. Starting in 2001, the deployment of jetting tools on coiled tubing has proved successful.¹⁶

Jetting processes, such as the Jet BLASTER scale-removal service, deliver a high-velocity hydraulic jet onto the screen while rotating and being pulled up by coiled tubing. The fluids used are carefully designed to remove the layers of calcite and organic material found on screens and wellbore tubulars. Surface testing showed that successive application of three fluids would give the best results without damaging the screened liner. A solution of 2% KCl removes most of the scale on the inner wall through jetting action; KCl is inert so its use in place of acid reduces the problem of waste disposal. A combination of xylene and asphaltene solvent removes the layers of organic scale, while 15% HCl dissolves the layers of calcite. These fluids are applied in nine stages, using sufficient time and volumes to ensure that they penetrate the gravel-pack matrix. This procedure was developed for wells

Basepipe Before Treatment



Wire Wrap Before Treatment



Jet BLASTER Spray



Basepipe After Jet BLASTER Treatment



Wire Wrap After Jet BLASTER Treatment

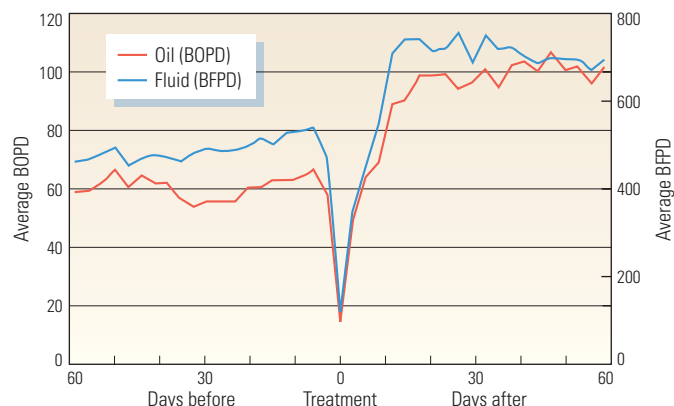


^ Scale removal using the Jet BLASTER tool. Thick scale (A) appears on both parts of the screen liner—on the wire wraps, and also fills the ports in the basepipe (*inset*). Strong jet action forces fluid from the nozzle of the Jet BLASTER tool (B) at a 4-bbl/min [0.6-m³/min] pump rate. Yard tests show the results of jetting with the selected fluids (C). Scale has been removed from not only the ports in the basepipe but also the wire wraps.

that had been recompleted to add production from the Rindu to that of the Pertama and Kedua. The latter two are hot from steam injection; when the cold, calcium-rich Rindu water enters the borehole, there is a high likelihood of calcite scale deposition.

By early 2002, 111 wells had been treated with the coiled tubing jetting technique. These wells had been selected because, based on produced-water analysis and wellhead temperatures, they were considered likely to develop scale, and had shown a steady production decline. Sand production and pump efficiency were not problems. The economic analysis of 39 wells showed an average oil production gain of 38 bbl [6 m³] per well for at least 60 days and a payout time of 46 days (*right*).¹⁷

Jet blasting has clearly paid for itself and resulted in additional oil. However, the gains are often lost after several months when scale reprecipitates. Since conventional scale inhibitors have been only moderately successful, four recent wells have been treated with a special phosphonate-based inhibitor, placed as a final stage after the jet-blasting treatment.¹⁸ Early results are encouraging.



^ Average production rates from 39 wells before and after the designed treatment. By 46 days after treatment, the gain in oil has paid for the cost of treatment.

11. The discriminator function is derived from a combination of various attributes such as root mean square, mean, minimum and maximum amplitude, and several Hilbert-based attributes.
12. Sigit R, Satriana D, Peifer JP and Linawati A: "Seismically Guided Bypassed Oil Identification in a Mature Steamflood Area, Duri Field, Sumatra, Indonesia," paper SPE 57261, presented at the SPE Asia Pacific Improved Oil Recovery Conference, Kuala Lumpur, Malaysia, October 25–26, 1999.
13. Putra PH, Nasution RD, Thurston FK, Moran JH and Malone BP: "TSO Frac-Pack: Pilot Evaluation to Full-Scale Operations in a Shallow Unconsolidated Heavy Oil Reservoir," paper SPE 37533, presented at the SPE International Thermal Operations & Heavy Oil Symposium, Bakersfield, California, USA, February 10–12, 1997.
14. Butcher JR: "New Area Development Strategy for Duri Field: Evaluation of Gravel Pack/Frac Pack," paper SPE 68633, presented at the SPE Asia Pacific Oil and Gas Conference and Exhibition, Jakarta, Indonesia, April 17–19, 2001.
15. Degenhardt KF, Stevenson J, Gale B, Gonzalez D, Hall S, Marsh J and Zemlak W: "Isolate and Stimulate Individual Pay Zones," *Oilfield Review* 13, no. 3 (Autumn 2001): 60–77.
16. Ali SA, Irfan M, Rinaldi D, Malik BZ, Tong KK and Ferdiansyah E: "Case Study: Using CT-Deployed Scale Removal to Enhance Production in Duri Steam Flood, Indonesia," paper SPE 74850, presented at the SPE/ICoTA Coiled Tubing Conference and Exhibition, Houston, Texas, USA, April 9–10, 2002.
17. Payout time is the average treatment cost (\$30,000), divided by the oil gain (BOPD) and the oil price (taken as \$17).
18. Ferdiansyah E: "Single Trip Scale Removal and Inhibition—A Unique Approach," Schlumberger General Field Engineer paper, presented in Dubai, UAE, September 9, 2002.

Venezuela—The World's Largest Heavy-Oil Accumulation

The first important Venezuelan heavy-oil field, Mene Grande, was discovered in 1914. Shallow sands at 550 ft [168 m] produced oil of API gravity down to 10.5° at rates of 264 B/D/well [42 m³/d/well]. Steam injection was tested in Mene Grande in 1956, but steam from the shallow formation erupted at the surface. The test was stopped, and when injection wells were opened to further release pressure, they produced oil. This led to the fortuitous discovery of the benefits of cyclic steam injection, sometimes called “huff and puff” or “steam-soak.”

Venezuela has many heavy-oil reservoirs, none more significant than the largest accumulation of heavy and ultraheavy oil in the world—the 55,000-km² [21,240-sq mile] Faja del Orinoco (right). A 1935 discovery well produced 7° API crude at 40 B/D [6 m³/d], but the Faja was not studied in detail until 1968. These studies led to a major five-year campaign by Petróleos de Venezuela S.A. (PDVSA) in which various hot- and cold-production techniques were assessed. Reservoir properties were found to be typical of shallow, unconsolidated heavy-oil sands (next page, top). Original calculations estimated that no more than 5% of the 7 to 10° API oil initially in place could be recovered without heating. By the late 1980s, the cost of heating made the commercial viability of developing the Faja unfavorable.

Several factors combined to improve the situation. Faja crude has a lower viscosity at any given API gravity than most heavy oils (right). Thus in spite of extremely low API gravity, it was possible to pump oil without the cost of heating and achieve rates of a few hundred barrels per day.¹⁹ Higher rates were needed for economic development, but higher rates caused significant sand production and required more powerful downhole pumps. Horizontal wells solved the first problem, allowing higher flow rates with less pressure drawdown, thereby minimizing sand problems. Cold production from horizontal wells also could yield a recovery factor similar to that of cyclic steaming in vertical wells, at much lower cost. By the mid-1990s, horizontal-well techniques had become cost-effective, while progressive-cavity and electrical submersible pumps had evolved to handle heavy crudes and large volumes. The technology was in place for commercial development of Faja heavy oil.

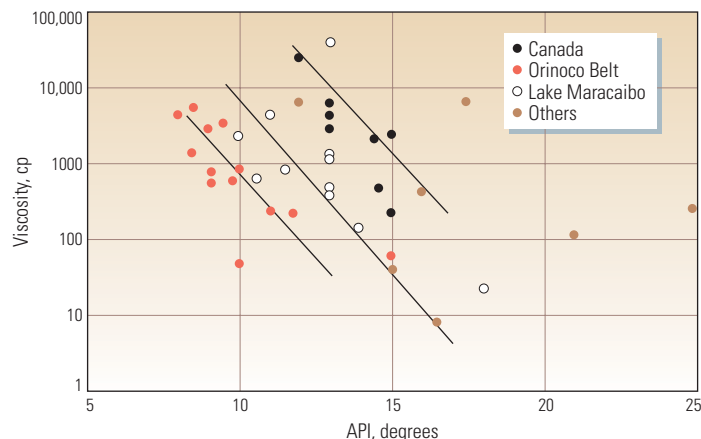
Today, the region is estimated to contain 1.36 trillion barrels [216 billion m³] of oil in place. The Orinoco Heavy Oil Strategic Association,

formed to develop Orinoco reserves, consists of four joint-venture companies.²⁰ Operadora Cerro Negro, consisting of ExxonMobil, Veba Oil & Gas and PDVSA, is active in the Cerro Negro area; Petrozuata (ConocoPhillips and PDVSA) and Sincor (TotalFinaElf, Statoil and PDVSA)

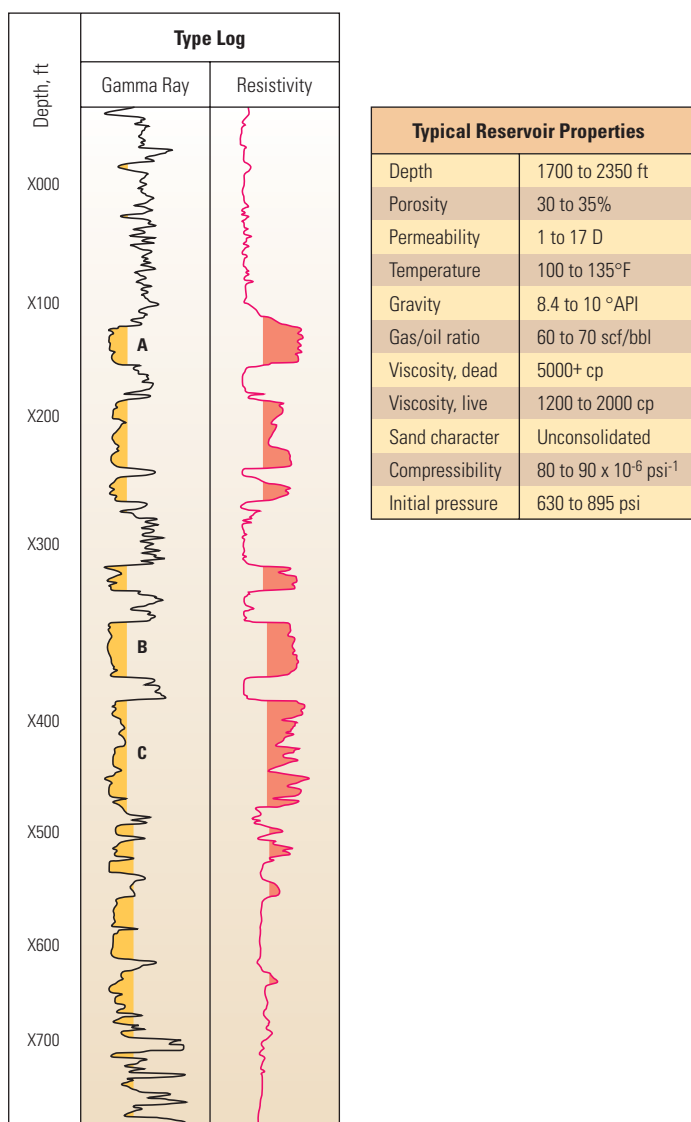
are developing concessions in the Zuata area; and Ameriven (ConocoPhillips, ChevronTexaco and PDVSA) in Hamaca. The goal is to reach a heavy-oil production rate of 600,000 B/D [95,300 m³/d] by 2005 and to maintain this rate for 35 years.



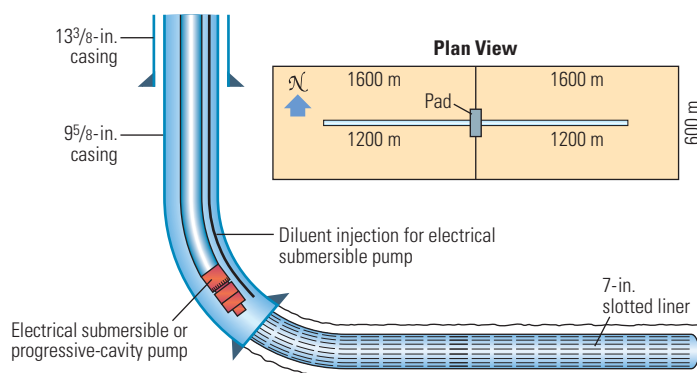
▲ Location of the Orinoco extra-heavy oil belt—the Faja Petrolífera de Orinoco in Spanish—commonly called the Faja. The area is divided into four areas, operated by four joint-venture operating companies.



▲ Relationship between viscosity and API gravity for different heavy-oil areas. (Adapted from Ehlig-Economides et al, reference 4.)



▲ Typical reservoir properties and type log for the Faja, in this case from the Zuata area. The type log is constructed from three wells, so the depth intervals are not even. The thick, high-resistivity sands (A and B) are most likely from a fluvial environment, while the more irregular sands (C) have had more marine influence.



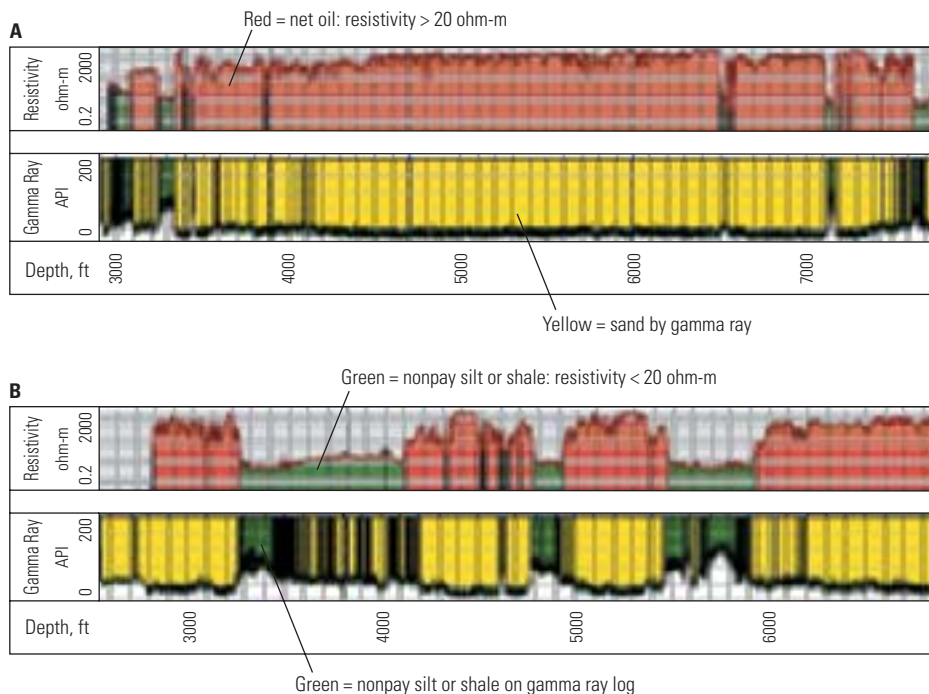
▲ A completed horizontal well with a single lateral. The plan view shows the initial development scheme: two wells drilled east-west out to 1200 m [3940 ft] from the pad drain two rectangles, each 1600 m by 600 m [5249 by 1968 ft]. These wells drain one sand; other wells from the pad are placed vertically above or below to drain other sands. Inside the wellbore, a diluent line is added to the completion only if an electrical submersible pump is installed.

Basic development plan—Petrozuata was the first of the four projects to go into operation, beginning their activities in 1997. Predevelopment studies concluded that the Petrozuata acreage was better suited for primary development using cold horizontal wells than cyclic steam in vertical or horizontal wells. The original reservoir model, built from limited well-log data and no seismic data, was composed of a succession of large fluvial deposits that coalesced to form continuous, well-connected sand bodies. These sand bodies were estimated to be at least 15 m [50 ft] thick and to reside in channel belts several kilometers wide, trending southwest to northeast.

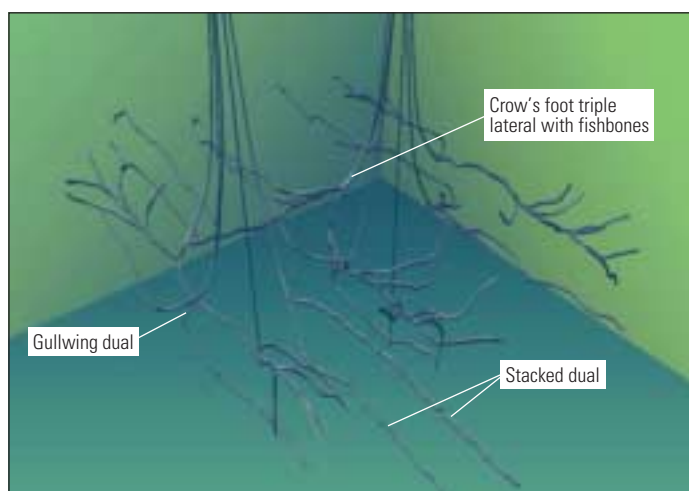
Petrozuata divided their 74,000-acre [300-km²] concession into drainage rectangles of 1600 m by 600 m [5249 ft by 1968 ft] and planned to drill two horizontal wells into a single sand body from a pad located on the borders of two drainage rectangles. Each well had a 1200- to 1500-m [3940- to 4921-ft] horizontal section drilled east-west to cut across several channels, and completed with a slotted liner (below left). Since the sand bodies could be locally isolated, it was important to develop more than one sand body within each rectangle. Each pad therefore holds between 4 and 12 wells. The first well is a vertical stratigraphic well, drilled solely for information. It is logged and sometimes cored, and then abandoned. After the stratigraphic well is correlated with other wells and 3D seismic data, the best sands are selected for placement of the horizontal wells—best initially meaning the thickest in and around the pad within the constraints of the reservoir-development plan. As will be seen, the design of the horizontal wells evolved considerably during the project.

Each well is outfitted with an electrical submersible pump or a progressive-cavity pump to lift the crude to surface. A diluent—naphtha, or 47° API light oil—is injected at some point to reduce viscosity and improve dehydration. Additional diluent is added at the pad gathering centers before multiphase pumps send the 16° API blend to a central processing plant and then on to the upgrading facility on the northern Venezuelan coast. The upgrader synthesizes the medium oil and other products for export, at the same time extracting the naphtha for return to the field.

19. In a high-quality sand, the permeability may be 20 D and the live-oil viscosity 2000 cp, leading to a mobility of 10 mD/cp, comparable to that of many light-oil reservoirs. Trebolle RL, Chalot JP and Colmenares R: "The Orinoco Heavy-Oil Belt Pilot Projects and Development Strategy," paper SPE 25798, presented at the SPE International Thermal Operations Symposium, Bakersfield, California, USA, February 8–10, 1993.
20. Layrisse I: "Heavy-Oil Production in Venezuela: Historical Recap and Scenarios for the Next Century," paper SPE 53464, presented at the SPE International Symposium on Oilfield Chemistry, Houston, Texas, USA, February 16–19, 1999.



▲ Logs recorded while drilling two horizontal wells. Well A encounters continuous high-quality sand throughout the 1525-m [5000-ft] section; Well B encounters short intervals of generally lower resistivity sand interspersed with silt. These short sands are most likely just a few meters thick vertically. Thin, low-quality sands occur mainly in deposits from a marine-influenced environment.



▲ Actual well paths of ten multilateral wells, of which four have fishbones, drilled from two pads in the Zuata area of the Faja. The ability to drill these complex wells has resulted in more effective tapping of sand bodies and higher production.

Multilaterals—The economic success of the project depends on drilling high-productivity horizontal wells at minimum cost. Petrozuata had hoped to achieve average production of between 1200 and 1500 B/D [190 to 238 m³/d] per well. Unfortunately, results from the first 95 single-lateral wells averaged 800 B/D [127 m³/d]. Clearly, something was not going according to plan.

The first clue lay in the well logs recorded while drilling the horizontal wells.²¹ Some wells had long, continuous intervals of high-quality sand, while others encountered much shorter intervals of sand separated by long intervals of unproductive silt (top). Short sand intervals meant that the well was penetrating thin reservoirs connected to small oil volumes.

Resistivities in these sands were often low, indicating poor reservoir quality. These factors explained the poor well performance and showed that the geology was more complicated than originally expected.

In late 1998 Petrozuata launched an extensive data-acquisition program to better characterize the reservoir. Additional core and log data were acquired in new stratigraphic wells drilled at the pad locations and between pads.²² The studies showed that the reservoir contained not only fluvial but also distributary and tidal estuarine deposits.²³ The latter two have much more variable net-to-gross pay ratio, lower vertical-to-horizontal permeability ratio, k_v/k_h , and lower connectivity. As a result, the average bed thickness was found to be 9 m [30 ft], not 15 m, with the majority of the producible oil in beds 6 to 12 m [20 to 39 ft] thick. The data supplied by the 149 stratigraphic wells also provided the well control to assess the distribution of sand bodies.

To drain thinner and more discontinuous sands it was clear that additional laterals and more complex well designs would be needed. Given the cost of a complete new well, multilaterals offered an attractive solution (see "New Aspects of Multilateral Well Construction," page 52). However, more laterals would not be effective without developing the ability to place them accurately. Three key factors have helped maximize sand count and optimize placement: first, an accurate depth conversion of the 3D seismic data using logs from the stratigraphic wells; second, identification and correlation of major geologic markers throughout the field; and third, knowledge of the expected net pay and its areal distribution from an updated depositional facies model. Then, during drilling, the logging-while-drilling (LWD) resistivity and gamma ray logs are integrated with the 3D seismic volume and reservoir-characterization studies to compare the encountered formation with the geologic prediction. If necessary, the well path is modified, or even sidetracked to optimize the amount of sand drilled.

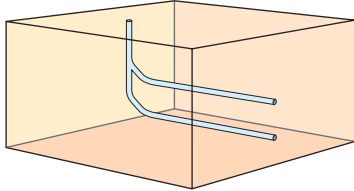
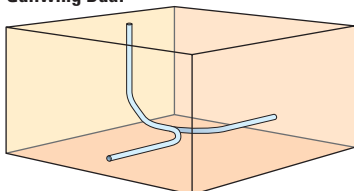
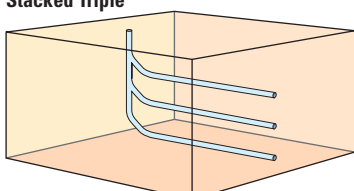
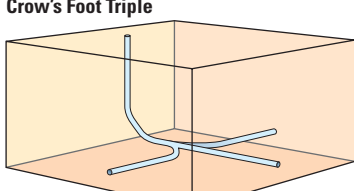
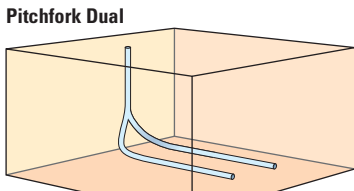
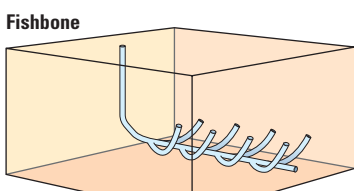
With improved lateral placement, different types of multilaterals can be used for different purposes and different geological environments (next page). All but the ribs of a fishbone are completed with a liner using Level 3 junctions.²⁴ The pump is placed above the upper lateral providing it is no more than 45 m [148 ft] above the lowermost lateral. Fishbones are particularly suitable for the thin, layered sand bodies deposited in a near-marine environment. The Petrozuata fishbone ribs are usually cut upward

in an arc for about 300 m [984 ft] away from the spine, rising vertically for 7 to 15 m [23 to 50 ft], to penetrate different lenses within the sand body and to facilitate gravity drainage of oil back to the main trunk. Longer ribs have been used to tap thin isolated sands up to 122 m [400 ft] above the lateral. The average multilateral well with fishbones includes a network of 6100 m [20,000 ft] of hole, with the single-well record reaching 19,200 m [63,000 ft]. Realistic development combines different types of multilaterals from one pad ([previous page, bottom](#)).

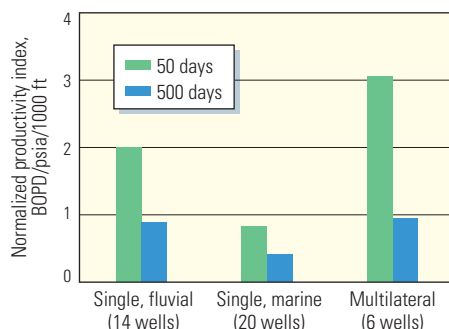
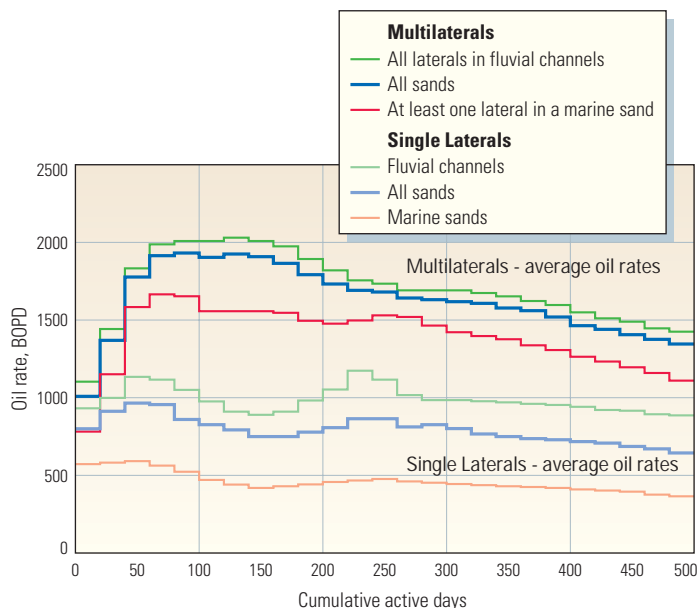
Fishbones have also been used to explore the reservoir in the vicinity of a lateral. Since the deepest laterals are drilled first, vertical exploratory fishbones can evaluate the overlying section and optimize or cancel the drilling of the subsequent shallower laterals. Exploratory fishbones provide information on sand presence and thickness at a cost that is much less than that of the traditional stratigraphic well drilled vertically from the surface. Overall, the successful adoption of fishbone multilaterals by Petrozuata and Schlumberger represents a major step forward in field-development technique.

Multilaterals clearly increase the length of sand open to production per well for only a moderate increase in cost.²⁵ For Petrozuata, average production rates from multilaterals have

21. Stalder JL, York GD, Kopper RJ, Curtis CM, Cole TL and Copley JH: "Multilateral-Horizontal Wells Increase Rate and Lower Cost Per Barrel in the Zuata Field, Faja, Venezuela," paper SPE 69700, presented at the SPE International Thermal Operations and Heavy Oil Symposium, Porlamar, Margarita Island, Venezuela, March 12–14, 2001.
22. By mid-2001 the data set included: 149 stratigraphic wells, 298 laterals, 291 km² of 3D seismic data, 18 check-shot surveys, 3 VSPs, 137 synthetic seismograms, 8 wells with whole core (4 outside area), 6 image logs (3 in cored wells), 2229 sidewall cores from 51 wells, biostratigraphy on 335 samples from 17 wells, geochemistry on 243 samples from 23 wells, and 12 oil and 6 gas samples.
23. Kopper R, Kupecz J, Curtis C, Cole T, Dorn-López D, Copley J, Muñoz A and Calcedo V: "Reservoir Characterization of the Orinoco Heavy Oil Belt: Miocene Oficina Formation, Zuata Field, Eastern Venezuela Basin," paper SPE 69697, presented at the SPE International Thermal Operations and Heavy Oil Symposium, Porlamar, Margarita Island, Venezuela, March 12–14, 2001.
24. A Level 3 junction has a cased and cemented main wellbore with the lateral cased, but not cemented. Bosworth S, El-Sayed HS, Ismail G, Ohmer H, Stracke M, West C and Retnanto A: "Key Issues in Multilateral Technology," *Oilfield Review* 10, no. 4 (Winter 1998): 14–28.
25. Theoretically, it might be possible to increase the length of a single lateral. In practice, this does not tap as many thin sands and was not an option because of sand-production problems and the difficulty of running liners to distances of more than about 1850 m [6070 ft]. Also, the friction drop during production would cause a diminishing return from the increased length.

Well type	Cost relative to single lateral	Features
Stacked Dual 	1.58	Accesses as much sand as two single laterals, but at less total cost.
Gullwing Dual 	1.67	Allows drilling in adjacent drainage rectangle, thereby eliminating the need for a pad. Will save 50 to 70 pads (\$43 million).
Stacked Triple 		Can also be in three dimensions, one example being the crow's foot triple below.
Crow's Foot Triple 	2.54	Central foot taps oil directly underneath an adjacent pad that is otherwise not drained.
Pitchfork Dual 		Less common, although used when other options are not a good fit to local geology.
Fishbone 	1.18 (8 ribs)	The path of oil to the well is shorter through a rib than through the rock, both in homogeneous sands and even more in heterogeneous sands with barriers and baffles. Ribs can be added to any lateral.

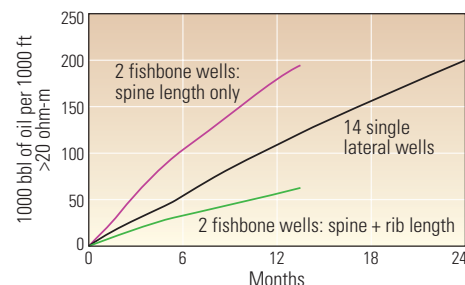
^ Different types of multilateral wells used to tap more oil, more economically in the Faja. For example, the two branches of a dual lateral should contribute twice as much as a single lateral for only 58% higher cost. The choice of multilateral type depends on the expected geology. In areas with thinner, more disconnected sand bodies, multilaterals permit access to more sand.



^ Comparing performance of single laterals and multilateral wells. Multilaterals clearly produce more than single laterals, particularly in the poorer marine sands (*top*). This is not surprising since the sand count is higher. When productivity is normalized by sand count, the advantage of multilaterals is not so clear. However, multilateral wells are produced with less average drawdown than single lateral wells. Once both sand count and drawdown are allowed for through the normalized productivity index (*bottom*), the multilaterals perform better after 50 days in all sands, and after 500 days in marine sands. In thick, fluvial sands, single laterals and multilaterals perform similarly after 500 days.

consistently been twice those of single laterals (*above left*).²⁶ In particular, the thinner, more marine sand bodies produce three times more with multilaterals. The advantage of multilaterals is best captured by examining the normalized productivity index (NPI)—production rate normalized by drawdown pressure and length of sand. The initial 50-day NPI of single laterals in fluvial sands is twice that in marine sands, but still only 66% of that in multilaterals penetrating all sands. For pseudo-steady-state flow at 500 days, the productivity of multilaterals is similar to that of single laterals in thick fluvial sands, but superior in marine sands.

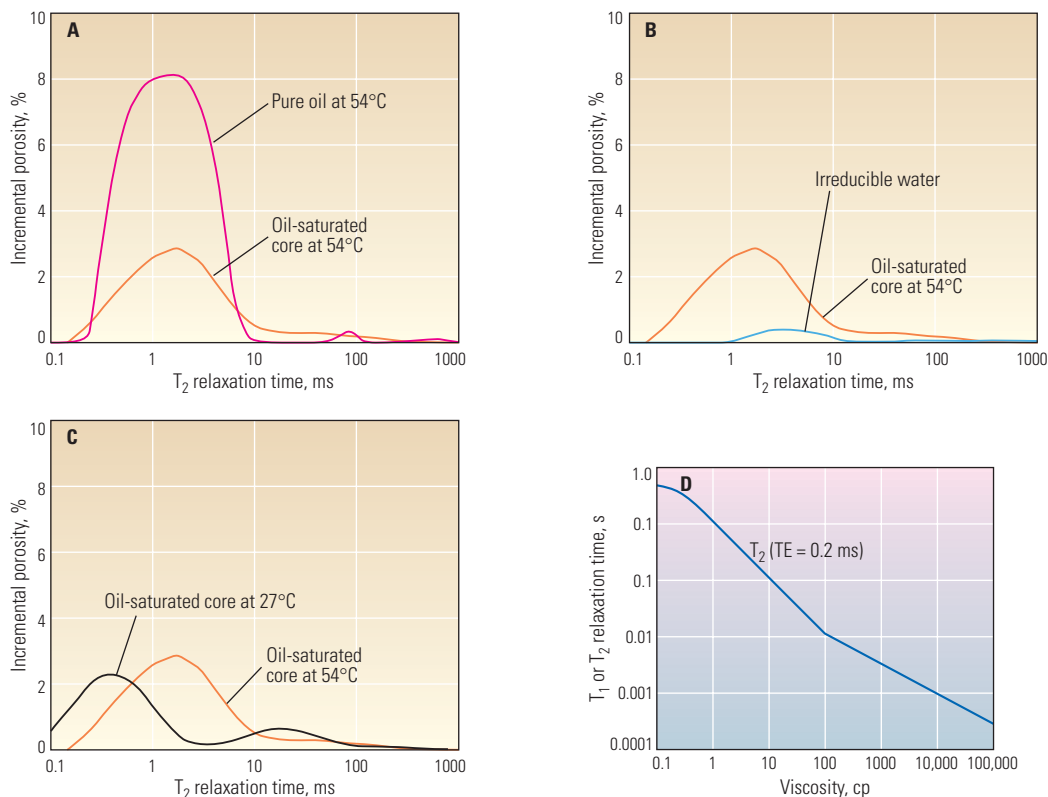
Normalizing cumulative recovery by effective length of the fishbone spine indicates that fishbones far surpass the single lateral well penetrating the same fluvial package (*above right*). The enhanced well performance justifies the 10 to 20% increase in well cost of adding fishbones. However, normalizing by total effective length—spine plus fishbones—indicates that fishbone performance falls below that of the average single lateral. This suggests that flow interference occurs between the spine and the fishbone segments near the spine, especially in a well-connected sand package. For this reason, fishbone drilling has focused on targeting less well-connected marine facies.



^ A comparison of the cumulative oil production per 1000 ft [304 m] of sand from 14 single laterals (black) and 2 fishbone wells drilled in the same sand. If, in calculating the sand count, only the spine length is taken into account, the fishbone performance (purple) is far better than that of the single laterals, showing that the ribs contribute significantly to production. If the total spine and rib length is used (green), the performance is lower, showing that ribs do not contribute as much as the spine. Since the curve for the single laterals lies between the two fishbone curves, it is possible to estimate that the contribution per 1000 ft of sand from a rib is about half that from a spine.

In this heavy-oil development, multilaterals have proved to be a cost-effective method of accelerating production and tapping reserves in thinner sands. In the future, these wells will permit greater depletion of the reservoir before the lowest economic production rate is reached.²⁷ Multilaterals and improved target placements helped Petrozuata reach their target of 120,000 B/D [19,070 m³/d] in late 2001.

Formation evaluation—Multilaterals improved Petrozuata's production rate by accessing longer sand intervals in each horizontal well. While thin sands may be less of a problem in other areas of the Faja, oil viscosity and sand quality are important factors everywhere. Oil viscosity, and



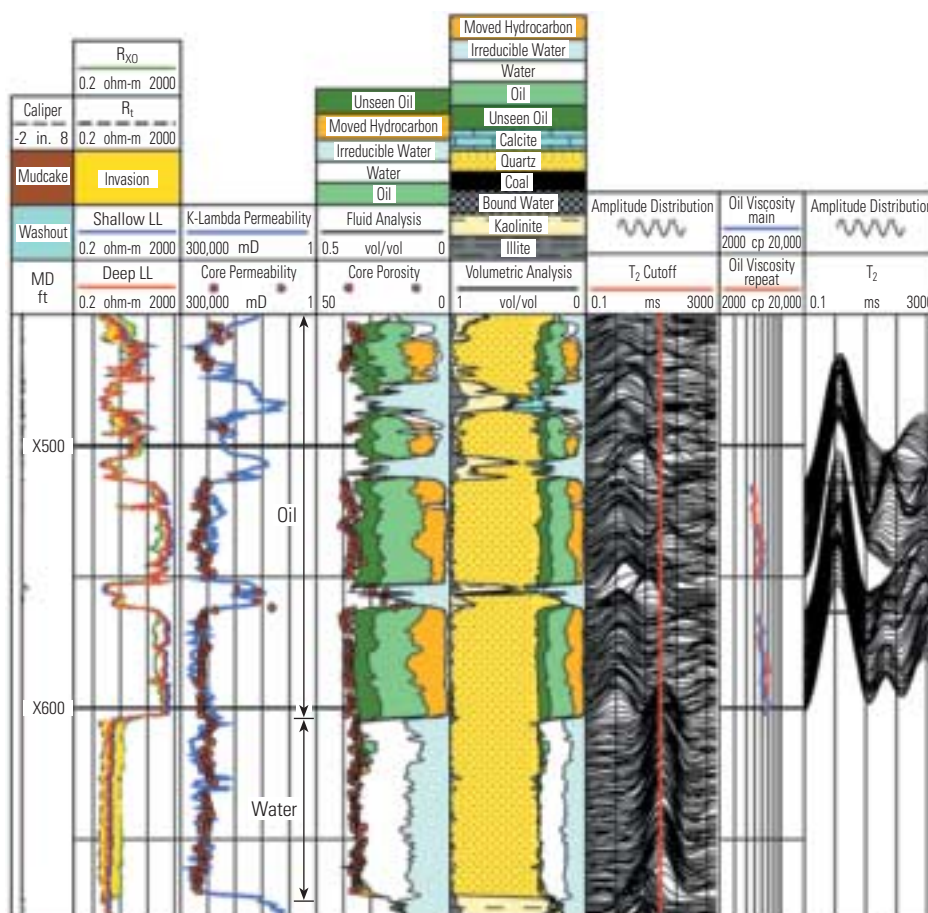
▲ Measurements on core plugs and oil samples, demonstrating that oil viscosity can be determined from the NMR response of reservoir rock. The T_2 distribution from the oil-saturated core (A) is much smaller than that from pure oil, reflecting the lower quantity of oil in the core. However, the peaks occur at the same time, showing that the oil in the core plug is not significantly affected by surface relaxation and reflects the bulk relaxation of oil. This implies that the NMR signal originates primarily from oil that is not in contact with the rock, as in a water-wet reservoir. (B) The core plug is cleaned, filled with water and centrifuged to remove all but the irreducible water. In good, producible sands such as here, the irreducible water volume is much less than the oil volume. (C) The shift in T_2 is explained almost entirely by the decrease in viscosity with temperature. Note that at 27°C [80°F], in particular, the distribution is still decaying at 0.1 ms, indicating some signal has relaxed too fast to be measured. (D) The commonly-used correlation is shown between viscosity and logarithmic mean T_2 of oils, with some adjustment above 100 cp to account for heavy-oil effects.

therefore mobility, can vary between sands both vertically and horizontally throughout the Faja.²⁶ Some sands, often those in close proximity to water, contain oil of significantly greater viscosity. The degree to which water has “washed” the oil can control oil gravity, viscosity and chemistry. In the Zuata area, there is a fairly predictable oil-water contact, but elsewhere in the Faja this is not so. Water sands can be found between oil sands; in a few sands, water can be found above heavy oil—not so surprising, since the water is lighter. In other poorer sands, it is not obvious whether the water is irreducible or free to move. There are also thin gas sands. Finally, sand quality varies, from permeabilities of less than 1 D to more than 10 D.

Operadora Cerro Negro, another operator in the Faja, found that successful development depended on identification of oil-bearing sands, determination of oil viscosity and prediction of water-production potential.²⁹ With these issues in mind, they cored and logged a series of stratigraphic wells with modern tools, including the CMR Combinable Magnetic Resonance tool. Nuclear magnetic resonance (NMR) is the most direct logging technique for estimating oil viscosity and irreducible-water saturation in situ, and has been successful in other parts of the Faja.³⁰ It is well-known that the NMR signal-decay time, T_2 , of light and medium oil is directly related to the oil’s viscosity. Laboratory results confirm that NMR measurements can be used to estimate

the viscosity of heavy oils found in the Faja (above). Although the exact transform needs to

26. Summers L, Guaregua W, Herrera J and Villaba L: “Heavy Oil Development in Venezuela—Well Performance and Monitoring,” presented at the Oil and Gas Journal Multilateral Well Conference, Galveston, Texas, USA, March 5–7, 2002. <http://www.global-energy-events.com/multilateral/proceedings.htm>
27. Suppose the lowest economic production rate of a well is 50 B/D [8 m³/d]. This rate may be reached when the production of each branch of a dual lateral is 25 B/D [4 m³/d]—clearly much later than for a single lateral.
28. Kopper et al, reference 23.
29. Guzman-Garcia AG, Linares LM and Decoster E: “Integrated Evaluation of the Cerro Negro Field for Optimized Heavy Oil Production,” *Transactions of the SPWLA 43rd Annual Logging Symposium*, Oiso, Japan, June 2–5, 2002, paper T.
30. Carmona R and Decoster E: “Assessing Production Potential of Heavy Oil Reservoirs from the Orinoco Belt with NMR Logs,” *Transactions of the SPWLA 42nd Annual Logging Symposium*, Houston, Texas, USA, June 17–20, 2001, paper ZZ.



▲ Logs and interpreted results from a Faja stratigraphic well. In Track 1, resistivity clearly identifies the water zone; in Track 2, core and log-derived permeability match well, particularly in the water zone; Tracks 3 and 4 show the fluid and total volumetric analysis alongside core porosity. Note the tar and heaviest oil fractions “unseen” by NMR due to very fast decay, and the moved hydrocarbon (calculated from the volume of filtrate seen on the T_2 distribution above 33 ms). The T_2 distributions in Track 5 are averaged over 2 ft [0.6 m], and those in Track 7 over 10 ft [3 m]. The oil signal is transformed into viscosity in Track 6. Results from both main and repeat passes agree well.

be refined, the relative prediction is considered reliable.

NMR logging tools record the T_2 distribution continuously in situ (above). The CMR tool can record T_2 down to 0.1 ms, the same range as laboratory instruments, so that laboratory-derived results can be applied to logs. In the oil sands, the wireline-derived T_2 distribution is similar to that of the oil-saturated core but includes

significant signal above 33 ms. After the oil signal is isolated, the logarithmic mean T_2 of the oil peak is calculated and converted to viscosity. The viscosity is moderately high for the area, and increases steadily down to the oil-water contact.

In the previous example, the water zone is clearly identified by the resistivity log. Elsewhere, the resistivity shows significant water but it is not clear whether this water is at

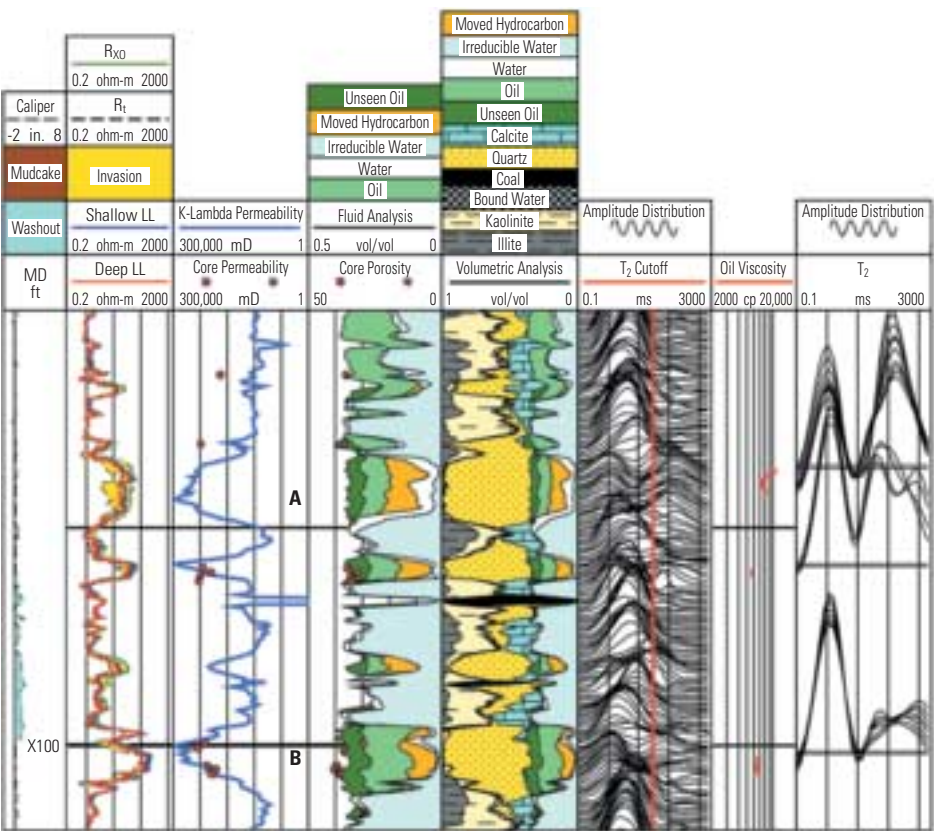
irreducible saturation (next page, top). In light-oil sandstone reservoirs, the volume of irreducible water is estimated from the NMR signal below about 33 ms, but extracting this information is difficult in heavy oil because the irreducible-water signal is mixed with the oil signal. By carefully selecting cutoffs, it is possible to make sufficiently accurate estimates to distinguish

sands at irreducible-water saturation from those with free water.

For a similar reason—mixing of oil and irreducible-water signals—NMR permeability estimates are not precise in heavy-oil reservoirs. Instead, Operadora Cerro Negro successfully estimated permeability using the mineralogical form of the k-Lambda method.³¹ This technique depends on measuring the volumes of the major minerals present, in particular clays, since these contribute strongly to the surface area and hence permeability. Core analysis has identified kaolinite and illite as the most common Faja clays. These, plus quartz and calcite, are readily quantified through natural gamma ray spectroscopy and other nuclear logs. Results agree with core in water zones, and also with permeability inferred from pressure buildups during water sampling with wireline formation testers. Through a suitable program of data acquisition in stratigraphic wells, Operadora Cerro Negro engineers have been able to derive preliminary estimates of oil viscosity and reservoir permeability from logs, and to understand the producibility of their oil-bearing sands. These data are fundamental to the successful optimization of the Cerro Negro development.

Canada—Huge Shallow Deposits

At 400 billion cubic meters [2.5 trillion barrels], Canada has the largest portion of the world's ultraheavy oil and bitumen reserves.³² The most well-known deposit is the Athabasca oil sands, in Alberta, Canada (right). Explorers and hunters first reported encountering outcrops of the tar-filled sands in the late 1700s. The early 1900s saw the arrival of mining-style methods to exploit the asphalt-like oil for paving material. Today, several companies are developing projects to tap these sands, which hold 7.5° to 9.0° API bitumen with viscosity up to 1,000,000 cp at reservoir temperature (15°C) [59°F]. Surface mining of the sands is an important and growing industry in the area, where companies



▲ Logs and interpreted results from a well that has a sand with free water (A) above a sand without free water and hence at irreducible-water saturation (B). Irreducible-water volume is determined from the NMR signal below 33 ms, after taking into account the heavy-oil signal and the clay-bound water. Total water volume is determined from resistivity.

such as Syncrude Canada, Suncor Energy and Shell Canada extract crude from pit mines. The Athabasca oil sands currently deliver about one-third of Canada's total oil production, and are expected to deliver 50% by 2005.³³

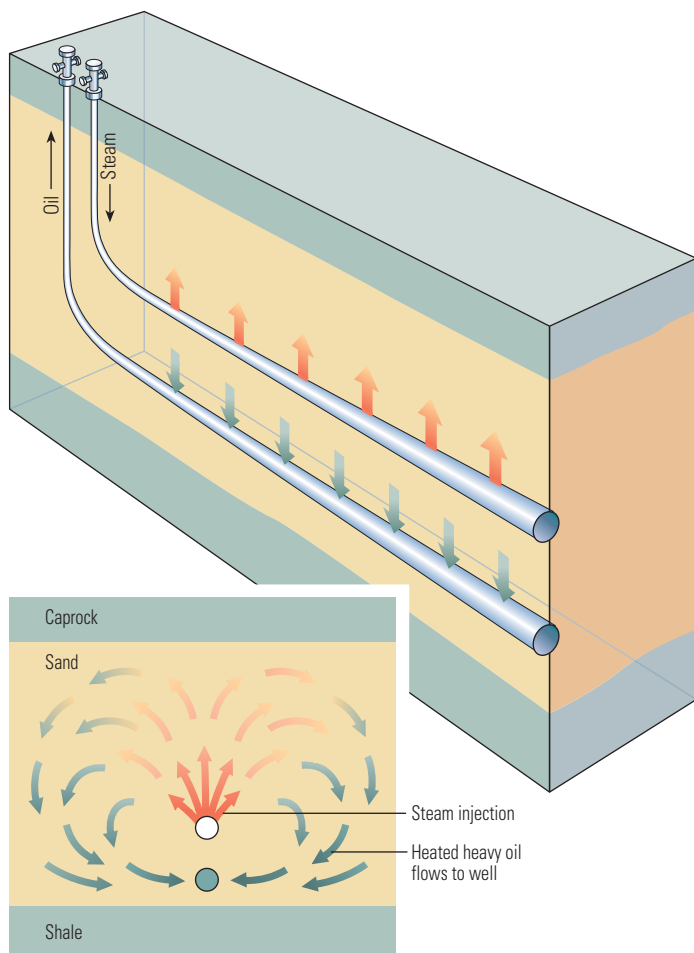
Several operators are turning to deeper reserves that can be reached only through wells. The high oil viscosity of Athabasca crudes renders cold production from wells unfeasible. However, once the oil is heated, it flows readily, so companies are investing in steamflooding facilities from the outset.

EnCana is in the first phase of their three-phase Christina Lake Thermal Project, which, over its 30-year life, will produce an estimated 600 million barrels [95 million m³] of oil from the sands of the McMurray formation.³⁴ Production will be through steam-assisted gravity drainage (SAGD), a technique developed in Canada and tested in several pilot studies. Pairs of stacked parallel horizontal wells form the basic elements



▲ The Athabasca oil sands of Alberta, Canada.

31. Herron MM, Johnson DL and Schwartz LM: "A Robust Permeability Estimator for Siliciclastics," paper SPE 49301, presented at the SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, USA, September 27–30, 1998.
 32. Canadian Petroleum Communications Foundation, http://www.pcf.ab.ca/quick_answers/default.asp
 33. Government of Alberta, <http://www.energy.gov.ab.ca/com/Sands/default.htm>
 34. Suggett J, Gittins S and Youn S: "Christina Lake Thermal Project," paper SPE/Petroleum Society of CIM 65520, presented at the SPE/Petroleum Society of CIM International Conference on Horizontal Well Technology, Calgary, Alberta, Canada, November 6–8, 2000.



▲ The concept of steam-assisted gravity drainage (SAGD). Horizontal wells drilled in stacked pairs form the basic unit of SAGD project (*top*). Steam injected into the upper well melts surrounding oil (*bottom*). Gravity causes the mobilized oil to flow downward to the lower well for production. SAGD well pairs can be drilled to track depositional features or in patterns for optimal recovery.

of the SAGD concept (*above*). Steam injected into the upper well heats a volume of surrounding oil, decreasing its viscosity enough to let it flow downward to the lower, producing, well.

Nearly 75 stratigraphic wells have been drilled, and 2D and 3D seismic surveys have been acquired. The McMurray sands are about 20 to 58 m [65 to 190 ft] thick, with 30 to 35% porosity and permeability from 3 to 10 D. The high quality and thickness of the pay make these reservoirs good candidates for SAGD. However, core analysis shows the presence of some mudstone layers within the pay. These layers probably will act as barriers to rising steam. The lateral extent and continuity of the impermeable mudstones, as yet unknown, will influence the rate at which steam rises.

As with any steam project, the goal is to produce as much oil as possible with minimum capital and production costs. The steam/oil ratio (SOR) is the most important variable affecting the economic return of the project. The key objective of Phase 1 is to reduce the uncertainty in the project's forecast SOR, currently expected to average 1.9. (For more on reducing uncertainty, see "Understanding Uncertainty," *page 2*.) EnCana plans to monitor production using 4D seismic, crosswell seismic and crosswell EM surveys.

EnCana expects to drill 250 to 360 SAGD well pairs, each with a horizontal section of 500 to 750 m [1640 to 2460 ft]. Injection and production wells are completed with slotted liners in the horizontal sections. The remainder of the well-bore has cemented casing. One of the challenges

in a thermal project is to maintain the integrity of the cement seal. This prevents communication of fluid between formations and to the surface. Initial cement operations may provide a good hydraulic seal, but changes in pressure and especially temperature associated with steam injection can induce stresses and destroy cement integrity. Changes in the downhole stress conditions that occur during the life of a SAGD well are extreme. High temperatures and cycling between steam injection and oil production can result in mechanical damage and ultimate failure.

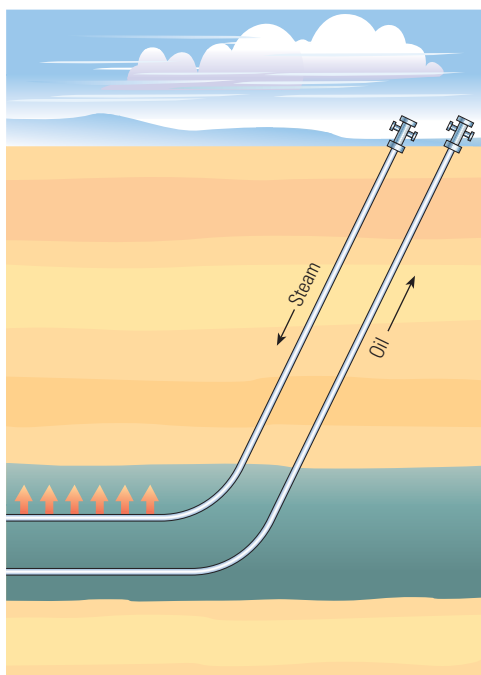
A new Schlumberger cement system with improved flexibility resists stress cracking. FlexSTONE advanced flexible cement technology maintains high compressive and tensile strengths compared with conventional cements.³⁵ Six wells in Phase 1 of the Christina Lake project have been cemented with FlexSTONE cement, designed to maintain impermeability and flexibility while accommodating thermal expansion of the casing and cement (see "Solutions for Long-Term Zonal Isolation," *page 16*).

Petro-Canada is following a similar approach to develop the oil sands in their MacKay River field. Seismic surveys, core and well logs in more than 200 delineation wells help identify the presence, thickness and areal extent of oil.³⁶ The oil-rich formations, which contain estimated reserves of 230 to 300 million bbl [36 to 47 million m³], are about 400 ft [122 m] deep, with thicknesses varying from about 50 to 250 ft. The 7 to 8° API crude will be produced with the SAGD method. Pairs of horizontal SAGD wells will be drilled 3280 ft [1000 m] long: one near the base of the reservoir, about 3.5 ft [1 m] off the bottom, and another 15 ft [4.5 m] above that. The wells plunge from the surface at a 45° angle so they can be horizontal at 400 ft (*next page*). Sand control is an issue in the 34% porosity, 5- to 10-darcy, unconsolidated sands. Wells are completed in the horizontal sections with uncemented slotted liners. Some wells have dual

35. Stiles D and Holliès D: "Implementation of Advanced Cementing Techniques to Improve Zonal Isolation in Steam Assisted Gravity Drainage Wells," paper SPE/Petroleum Society of CIM/CHOA 78950, prepared for presentation at SPE International Thermal Operations and Heavy Oil Symposium and International Horizontal Well Technology Conference, Calgary, Alberta, Canada, November 4–7, 2002.

36. Stott J: "Canada's Oil Sands Revival Special Report," *Oil & Gas Journal* 100, no. 23 (June 10, 2002): 24–29.

37. Urgeli D, Durandea M, Foucault H and Besnier J-F: "Investigation of Foamy-Oil Effect from Laboratory Experiments," paper SPE 54083, presented at the SPE International Thermal Operations and Heavy Oil Symposium, Bakersfield, California, USA, March 17–19, 1999.



^ Angled drill rig in the shallow Mackay River field, operated by Petro-Canada (*right*). Wells dive at a 45° angle so they can make the turn to horizontal by the target depth of 400 ft [122 m] (*left*).

tubing strings, to produce or inject from the toe and the heel of the well.

Petro-Canada anticipates their wells will be high-volume producers, at 2000 to 3000 bbl of fluid per day [318 to 477 m³/d]. Currently there are 25 well pairs in the Mackay River field. First steam is scheduled for the third quarter of 2002, with oil production to begin by the end of the year. To keep the plant operating at capacity over the project's 25-year life, up to 100 additional well pairs are planned. Reservoir-surveillance plans include downhole temperature monitoring with fiber optics, vertical observation wells and time-lapse seismic monitoring.

SAGD allows Canadian operators to develop their oil-sand resources more fully and with reduced environmental impact compared with surface-mining methods.

Producing More Heavy Oil

The vast amounts of heavy and ultraheavy oil dominate the world's hydrocarbon reserves, but the more easily produced resources of conventional oil and gas outpace their sluggish

counterparts in terms of current production levels. Many reserves of the heaviest hydrocarbons await new technologies that will transform them into economically feasible projects.

Understanding production mechanisms in unconsolidated sands is one area of active study. Some reservoirs produce unexpectedly high rates and volumes when sand production is encouraged. Although this mechanism is not completely understood, it is assumed to occur when gaps left by dislodged sand grains coalesce to form tunnels, called "wormholes." Wormholes propagate and form networks similar to fractures, thereby enhancing permeability and porosity. Promoting wormholes while ensuring formation stability is a challenge for heavy-oil producers. Dealing with produced sand is another concern.

Many researchers are investigating the behavior of "foamy" heavy oil. As reservoir pressure decreases, dissolved gas disperses as small bubbles trapped by the viscous oil. The resulting foamy oil—with the consistency of chocolate mousse—has low viscosity.³⁷ Reservoirs with foamy-oil behavior are reported to experience higher than expected recovery factors.

Improved enhanced-oil recovery methods may unlock the hydrocarbons trapped in many heavy-oil reservoirs. Hot-water flooding has been tested with limited success. Water does not transfer heat as effectively as steam does, and the large viscosity difference between water and heavy oil results in less than optimal sweep. Injection of water alternating with gas or steam (WAG or WAS) has also been tested in pilot projects. In-situ combustion, known as fireflooding, has been tested, but is not widely applied; air or other combustible gas is injected and the oil is ignited. The warmed oil is forced toward a producer, leaving the heaviest components behind in a charred zone.

Methods that can crack heavy oils in situ, that is, separate large molecules from small ones downhole rather than in surface facilities, are the dream of many heavy-oil specialists. The combination of these and existing technologies will make it easier to realize the value trapped in the trillions of barrels of our world's heavy oil.

—LS, JS