Preventing the Next Oil Crunch

BILL ROSS *Tony Stone Images*

Enough oil remains in the earth to fill the reservoir behind Hoover Dam four times over—and that's just counting the fraction of buried crude that is relatively easy to recover and refine. Little wonder, then, that as the world's economies have hit the accelerator in the past decade, the production of oil that powers them has also soared, reaching a record of 65 million barrels a day last year. The ample supply has kept oil cheap and has helped to lay inflation low.

But could this be the peak before the fall? The authors of the first article in this special report conclude that before the next decade is over the flood of conventional oil will crest, and production will enter a permanent decline.

These analysts marshal an impressive body of statistics to support their projections. If they are right, the world will need to move quickly to avoid the price hikes, recessions and political struggles that oil shortages—or threats of them—have historically provoked. But as explained here, there are alternatives. The industry can eke more out of aging oil fields and can sink new wells beneath deeper ocean waters. And the technology already exists to convert natural gas and oil sands, both still plentiful, into liquid fuels that are as cheap as those refined from oil. The means for an orderly transition away from crude oil appear to be nearly ready; all that is needed is the will, the time and the money. —*The Editors*

The End of Cheap Oil

Global production of conventional oil will begin to decline sooner than most people think, probably within 10 years

by Colin J. Campbell and Jean H. Laherrère

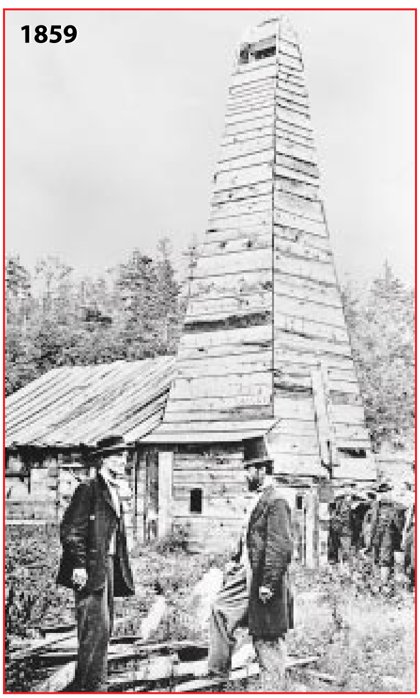
In 1973 and 1979 a pair of sudden price increases rudely awakened the industrial world to its dependence on cheap crude oil. Prices first tripled in response to an Arab embargo and then nearly doubled again when Iran dethroned its Shah, sending the major economies sputtering into recession. Many analysts warned that these crises proved that the world would soon run out of oil. Yet they were wrong.

Their dire predictions were emotional and political reactions; even at the time, oil experts knew that they had no scientific basis. Just a few years earlier oil explorers had discovered enormous new oil provinces on the north slope of Alaska and below the North Sea off the coast of Europe. By 1973 the world had consumed, according to many experts' best estimates, only about one eighth of its endowment of readily accessible crude oil (so-called conventional oil). The five Middle Eastern members of the Organization of Petroleum Exporting Countries (OPEC) were able to hike prices not because oil was growing scarce but because they had managed to corner 36 percent of the market. Later, when demand sagged, and the flow of fresh Alaskan and North Sea oil weakened OPEC's economic stranglehold, prices collapsed.

The next oil crunch will not be so temporary. Our analysis of the discovery and production of oil fields around the world suggests that within the next decade, the supply of conventional oil will be unable to keep up with demand. This conclusion contradicts the picture one gets from oil industry reports, which boasted of 1,020 billion barrels of oil (Gbo) in "proved" reserves at the start of 1998. Dividing that figure by the current production rate of about 23.6 Gbo a year might suggest that crude oil could remain plentiful and cheap for 43 more years—probably longer, because official charts show reserves growing.

Unfortunately, this appraisal makes three critical errors. First, it relies on distorted estimates of reserves. A second mistake is to pretend that production will remain constant. Third and most important, conventional wisdom erroneously assumes that the last bucket of oil can be pumped from the ground just as quickly as the barrels of oil gushing from wells today. In fact, the rate at which any well—or any country—can produce oil always rises to a maximum and then, when about half the oil is gone, begins falling gradually back to zero.

From an economic perspective, when the world runs completely out of oil is thus not directly relevant: what matters is when production begins to taper off. Beyond that point, prices will rise unless demand declines commensurately.



CORBIS-BETTMANN

HISTORY OF OIL PRODUCTION, from the first commercial American well in Titusville, Pa. (*left*), to derricks bristling above the Los Angeles basin (*below*), began with steady growth in the U.S. (*red line*). But domestic production began to decline after 1970, and restrictions in the flow of Middle Eastern oil in 1973 and 1979 led to inflation and shortages (*near* and *center right*). More recently, the Persian Gulf War, with its burning oil fields (*far right*), reminded the industrial world of its dependence on Middle Eastern oil production (*gray line*).

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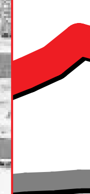


Using several different techniques to estimate the current reserves of conventional oil and the amount still left to be discovered, we conclude that the decline will begin before 2010.

Digging for the True Numbers

We have spent most of our careers exploring for oil, studying reserve figures and estimating the amount of oil left to discover, first while employed at major oil companies and later as independent consultants. Over the years, we have come to appreciate that the relevant statistics are far more complicated than they first appear.

Consider, for example, three vital numbers needed to project future oil production. The first is the tally of how much oil has been extracted to date, a figure known as cumulative production. The second is an estimate of reserves, the amount that companies can pump out of known oil fields before having to abandon them. Finally, one must have an educated guess at the quantity of conventional oil that remains to be discovered and exploited. Together they add up to ultimate recovery, the total number of barrels that will have been extracted when production ceases many decades from now.

The obvious way to gather these numbers is to look them up in any of several publications. That approach works well enough for cumulative production statistics because companies meter the oil as it flows from their wells. The record of production is not perfect (for example, the two billion barrels of Kuwaiti oil wastefully burned by Iraq in 1991 is usually not included in official statistics), but errors are relatively easy to spot and rectify. Most experts agree that the industry had removed just over 800 Gbo from the earth at the end of 1997.

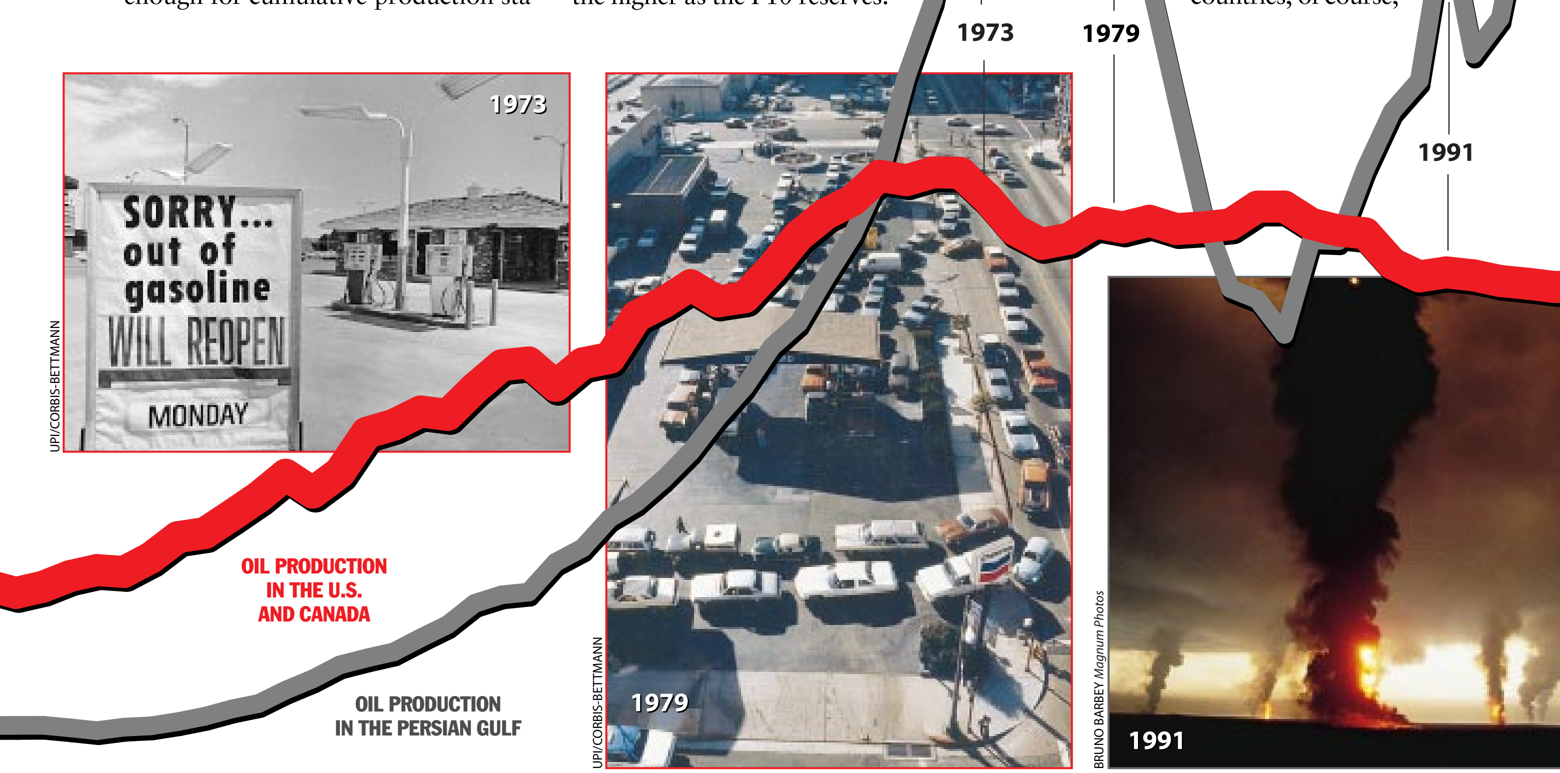
Getting good estimates of reserves is much harder, however. Almost all the publicly available statistics are taken from surveys conducted by the *Oil and Gas Journal* and *World Oil*. Each year these two trade journals query oil firms and governments around the world. They then publish whatever production and reserve numbers they receive but are not able to verify them.

The results, which are often accepted uncritically, contain systematic errors. For one, many of the reported figures are unrealistic. Estimating reserves is an inexact science to begin with, so petroleum engineers assign a probability to their assessments. For example, if, as geologists estimate, there is a 90 percent chance that the Oseberg field in Norway contains 700 million barrels of recoverable oil but only a 10 percent chance that it will yield 2,500 million more barrels, then the lower figure should be cited as the so-called P90 estimate (P90 for "probability 90 percent") and the higher as the P10 reserves.

In practice, companies and countries are often deliberately vague about the likelihood of the reserves they report, preferring instead to publicize whichever figure, within a P10 to P90 range, best suits them. Exaggerated estimates can, for instance, raise the price of an oil company's stock.

The members of OPEC have faced an even greater temptation to inflate their reports because the higher their reserves, the more oil they are allowed to export. National companies, which have exclusive oil rights in the main OPEC countries, need not (and do not) release detailed statistics on each field that could be used to verify the country's total reserves. There is thus good reason to suspect that when, during the late 1980s, six of the 11 OPEC nations increased their reserve figures by colossal amounts, ranging from 42 to 197 percent, they did so only to boost their export quotas.

Previous OPEC estimates, inherited from private companies before governments took them over, had probably been conservative, P90 numbers. So some upward revision was warranted. But no major new discoveries or technological breakthroughs justified the addition of a staggering 287 Gbo. That increase is more than all the oil ever discovered in the U.S.—plus 40 percent. Non-OPEC countries, of course,



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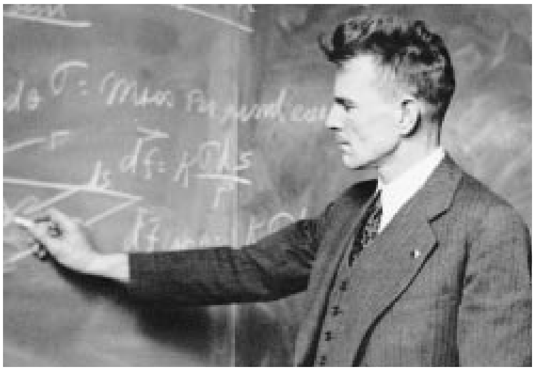
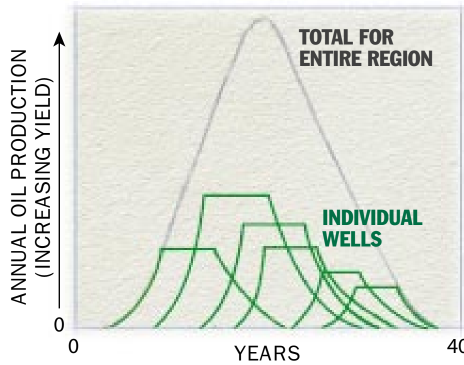
BRUNO BARBEY *Magnum Photos*

JENNIFER C. CHRISTIANSEN; SOURCE: JEAN H. LAHERRÈRE



COURTESY OF THE SOCIETY OF EXPLORATION GEOPHYSICISTS

FLOW OF OIL starts to fall from any large region when about half the crude is gone. Adding the output of fields of various sizes and ages (*green curves at right*) usually yields a bell-shaped production curve for the region as a whole. M. King Hubbert (*left*), a geologist with Shell Oil, exploited this fact in 1956 to predict correctly that oil from the lower 48 American states would peak around 1969.



JENNIFER C. CHRISTIANSEN; LAURIE GRACE

are not above fudging their numbers either: 59 nations stated in 1997 that their reserves were unchanged from 1996. Because reserves naturally drop as old fields are drained and jump when new fields are discovered, perfectly stable numbers year after year are implausible.

Unproved Reserves

Another source of systematic error in the commonly accepted statistics is that the definition of reserves varies widely from region to region. In the U.S., the Securities and Exchange Commission allows companies to call reserves "proved" only if the oil lies near a producing well and there is "reasonable certainty" that it can be recovered profitably at current oil prices, using existing technology. So a proved reserve estimate in the U.S. is roughly equal to a P90 estimate.

Regulators in most other countries do not enforce particular oil-reserve definitions. For many years, the former Soviet countries have routinely released wildly optimistic figures—essentially P10 reserves. Yet analysts have often misinterpreted these as estimates of "proved" reserves. *World Oil* reckoned reserves in the former Soviet Union amounted to 190 Gbo in 1996, whereas the *Oil and Gas Journal* put the number at 57 Gbo. This large discrepancy shows just how elastic these numbers can be.

Using only P90 estimates is not the answer, because adding what is 90 percent likely for each field, as is done in the U.S., does not in fact yield what is 90 percent likely for a country or the entire planet. On the contrary, summing many P90 reserve estimates always understates the amount of proved oil in a region. The only correct way to total up reserve numbers is to add the mean, or average, estimates of oil in each field. In practice, the median estimate, often called "proved and probable," or P50 reserves, is more widely used and is good enough. The P50 value is the number of barrels of oil that are as likely as not to come out of a well during its lifetime, assuming prices remain within a limited range. Errors in P50 estimates tend to cancel one another out.

We were able to work around many of the problems plaguing estimates of conventional reserves by using a large body of statistics maintained by Petroconsultants in Geneva. This information, assembled over 40 years from myriad sources, covers some 18,000 oil fields worldwide. It, too, contains some dubious reports, but we did our best to correct these sporadic errors.

According to our calculations, the world had at the end of 1996 approximately 850 Gbo of conventional oil in P50 reserves—substantially less than the 1,019 Gbo reported in the *Oil and Gas Journal* and the 1,160 Gbo estimated by *World Oil*. The difference is actually greater than it appears because our value represents the amount most likely to come out of known oil fields, whereas the larger number is supposedly a cautious estimate of proved reserves.

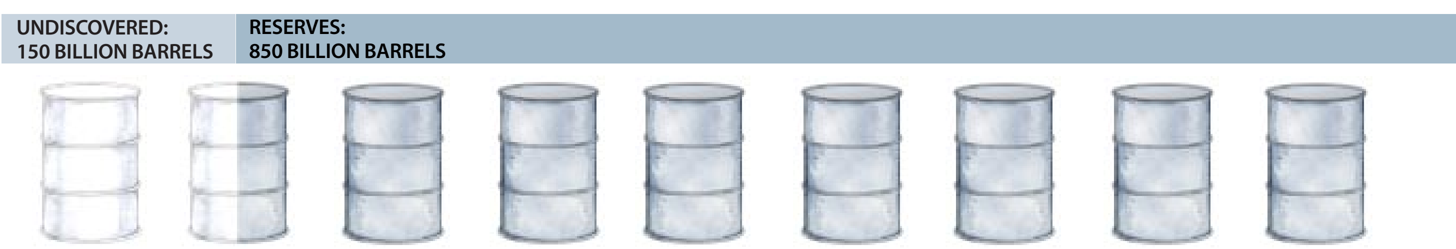
For the purposes of calculating when oil production will crest, even more critical than the size of the world's reserves is the size of ultimate recovery—all the cheap oil there is to be had. In order to estimate that, we need to know whether, and how fast, reserves are moving up or down. It is here that the official statistics become dangerously misleading.

Diminishing Returns

According to most accounts, world oil reserves have marched steadily upward over the past 20 years. Extending that apparent trend into the future, one could easily conclude, as the U.S. Energy Information Administration has, that oil production will continue to rise unhindered for decades to come, increasing almost two thirds by 2020.

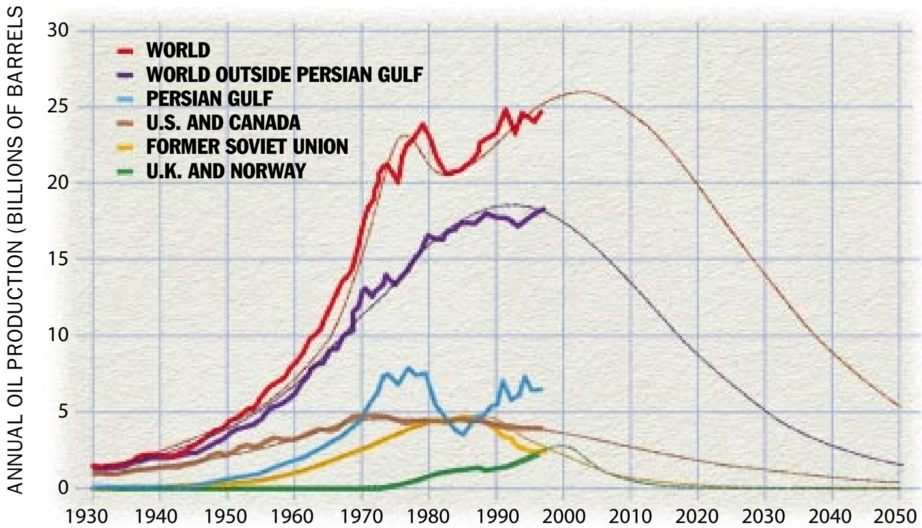
Such growth is an illusion. About 80 percent of the oil produced today flows from fields that were found before 1973, and the great majority of them are declining. In the 1990s oil companies have discovered an average of seven Gbo a year; last year they drained more than three times as much. Yet official figures indicated that proved reserves did not fall by 16 Gbo, as one would expect—rather they *expanded* by 11 Gbo. One reason is that several dozen governments

EARTH'S CONVENTIONAL CRUDE OIL is almost half gone. Reserves (defined here as the amount as likely as not to come out of known fields) and future discoveries together will provide little more than what has already been burned.



LAURIE GRACE

GLOBAL PRODUCTION OF OIL, both conventional and unconventional (*red*), recovered after falling in 1973 and 1979. But a more permanent decline is less than 10 years away, according to the authors' model, based in part on multiple Hubbert curves (*lighter lines*). U.S. and Canadian oil (*brown*) topped out in 1972; production in the former Soviet Union (*yellow*) has fallen 45 percent since 1987. A crest in the oil produced outside the Persian Gulf region (*purple*) now appears imminent.



LAURIE GRACE; SOURCE: JEAN H. LAHERRÈRE

opted not to report declines in their reserves, perhaps to enhance their political cachet and their ability to obtain loans. A more important cause of the expansion lies in revisions: oil companies replaced earlier estimates of the reserves left in many fields with higher numbers. For most purposes, such amendments are harmless, but they seriously distort forecasts extrapolated from published reports.

To judge accurately how much oil explorers will uncover in the future, one has to backdate every revision to the year in which the field was first discovered—not to the year in which a company or country corrected an earlier estimate. Doing so reveals that global discovery peaked in the early 1960s and has been falling steadily ever since. By extending the trend to zero, we can make a good guess at how much oil the industry will ultimately find.

We have used other methods to estimate the ultimate recovery of conventional oil for each country [*see box on next two pages*], and we calculate that the oil industry will be able to recover only about another 1,000 billion barrels of conventional oil. This number, though great, is little more than the 800 billion barrels that have already been extracted.

It is important to realize that spending more money on oil exploration will not change this situation. After the price of crude hit all-time highs in the early 1980s, explorers developed new technology for finding and recovering oil, and they scoured the world for new fields. They found few: the discovery rate continued its decline uninterrupted. There is only so much crude oil in the world, and the industry has found about 90 percent of it.

Predicting the Inevitable

Predicting when oil production will stop rising is relatively straightforward once one has a good estimate of how much oil there is left to produce. We simply apply a refinement of a technique first published in 1956 by M. King Hubbert. Hubbert observed that in any large region, unrestrained extraction of a finite resource rises along a bell-shaped curve that peaks when about half the resource is gone. To demonstrate his theory, Hubbert fitted a bell curve to production statistics and projected that crude oil production in the lower 48 U.S. states would rise for 13 more years, then crest in 1969, give or take a year. He was right: production peaked in 1970 and has continued to follow Hubbert curves with only minor deviations. The flow of oil from several other regions, such as the former Soviet Union and the collection of all oil producers outside the Middle East, also follows Hubbert curves quite faithfully.

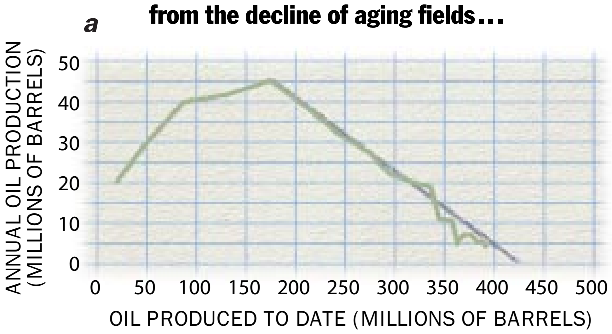
The global picture is more complicated, because the Middle East members of OPEC deliberately reined back their oil exports in the 1970s, while other nations continued producing at full capacity. Our analysis reveals that a number of the largest producers, including Norway and the U.K., will reach their peaks around the turn of the millennium unless they sharply curtail production. By 2002 or so the world will rely on Middle East nations, particularly five near the Persian Gulf (Iran, Iraq, Kuwait, Saudi Arabia and the United Arab Emirates), to fill in the gap between dwindling supply and growing demand. But once approximately 900 Gbo have been consumed, production must soon begin to fall. Barring a global recession, it seems most likely that world production of conventional oil will peak during the first decade of the 21st century.

Perhaps surprisingly, that prediction does not shift much even if our estimates are a few hundred billion barrels high or low. Craig Bond Hatfield of the University of Toledo, for example, has conducted his own analysis based on a 1991 estimate by the U.S. Geological Survey of 1,550 Gbo remaining—55 percent higher than our figure. Yet he similarly concludes that the world will hit maximum oil production within the next 15 years. John D. Edwards of the University of Colorado published last August one of the most optimistic recent estimates of oil remaining: 2,036 Gbo. (Edwards concedes that the industry has only a 5 percent chance of at-

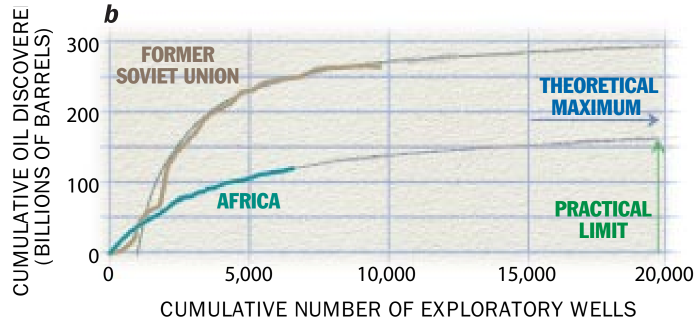
How Much Oil Is Left to Find?

We combined several techniques to conclude that about 1,000 billion barrels of conventional oil remain to be produced. First, we extrapolated published production figures for older oil fields that have begun to decline. The Thistle field off the coast of Britain, for example, will yield about 420 million barrels (*a*). Second, we plotted the amount of oil discovered so far in some regions against the cumulative number of exploratory wells drilled there. Because larger fields tend to be found first—they are simply too large to miss—the curve rises rapidly and then flattens, eventually reaching a theo-

We can predict the amount of remaining oil from the decline of aging fields…



…from the diminishing returns on exploration in larger regions…



taining that very high goal.) Even so, his calculations suggest that conventional oil will top out in 2020.

Smoothing the Peak

Factors other than major economic changes could speed or delay the point at which oil production begins to decline. Three in particular have often led economists and academic geologists to dismiss concerns about future oil production with naive optimism.

First, some argue, huge deposits of oil may lie undetected in far-off corners of the globe. In fact, that is very unlikely. Exploration has pushed the frontiers back so far that only extremely deep water and polar regions remain to be fully tested, and even their prospects are now reasonably well understood. Theoretical advances in geochemistry and geophysics have made it possible to map productive and prospective fields with impressive accuracy. As a result, large tracts can be condemned as barren. Much of the deepwater realm, for example, has been shown to be absolutely nonprospective for geologic reasons.

What about the much touted Caspian Sea deposits? Our models project that oil production from that region will grow until around 2010. We agree with analysts at the USGS World Oil Assessment program and elsewhere who rank the total resources there as roughly equivalent to those of the North Sea—that is, perhaps 50 Gbo but certainly not several hundreds of billions as sometimes reported in the media.

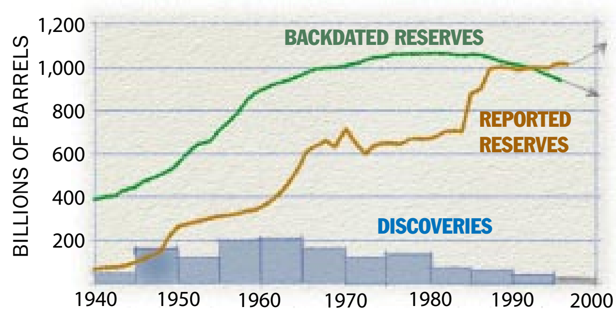
A second common rejoinder is that new technologies have steadily increased the fraction of oil that can be recovered from fields in a basin—the so-called recovery factor. In the 1960s oil companies assumed as a rule of thumb that only 30 percent of the oil in a field was typically recoverable; now they bank on an average of 40 or 50 percent. That progress will continue and will extend global reserves for many years to come, the argument runs.

Of course, advanced technologies will buy a bit more time before production starts to fall [see "Oil Production in the 21st Century," by Roger N. Anderson, on page 86]. But most of the apparent improvement in recovery factors is an artifact of reporting. As oil fields grow old, their owners often deploy newer technology to slow their decline. The falloff also allows engineers to gauge the size of the field more accurately and to correct previous underestimation—in particular P90 estimates that by definition were 90 percent likely to be exceeded.

Another reason not to pin too much hope on better recovery is that oil companies routinely count on technological progress when they compute their reserve estimates. In truth, advanced technologies can offer little help in draining the largest basins of oil, those onshore in the Middle East where the oil needs no assistance to gush from the ground.

Last, economists like to point out that the world contains enormous caches of unconventional oil that can substitute for crude oil as soon as the price rises high enough to make them profitable. There is no question that the resources are ample: the Orinoco oil belt in Venezuela has been assessed to contain a staggering 1.2 trillion barrels of the sludge known as heavy oil. Tar sands and shale deposits in Canada and the former Soviet Union may contain the equivalent of more than 300 billion barrels of oil [see "Mining for Oil," by Richard L. George, on page 84]. Theoretically, these unconventional oil reserves could quench the world's thirst for liquid fuels as conventional oil passes its prime. But the industry will be hard-pressed for the time and money needed to ramp up production of unconventional oil quickly enough.

Such substitutes for crude oil might also exact a high environmental price.

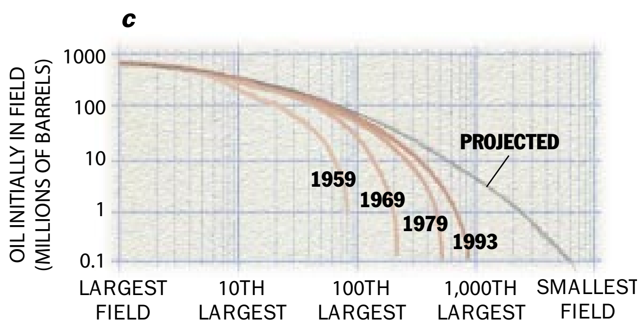


LAURIE GRACE; SOURCE: PETROCONSULTANTS, *OIL AND GAS JOURNAL* AND U.S. GEOLOGICAL SURVEY

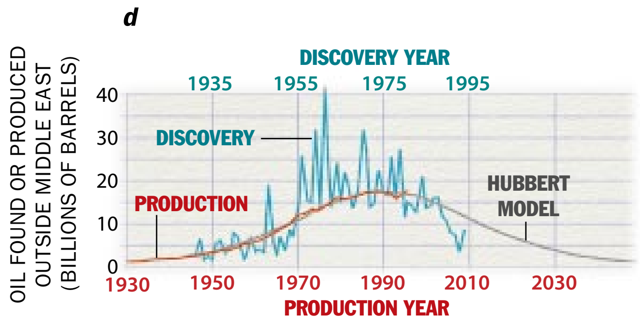
GROWTH IN OIL RESERVES since 1980 is an illusion caused by belated corrections to oil-field estimates. Backdating the revisions to the year in which the fields were discovered reveals that reserves have been falling because of a steady decline in newfound oil (*blue*).

retical maximum: for Africa, 192 Gbo. But the time and cost of exploration impose a more practical limit of perhaps 165 Gbo (*b*). Third, we analyzed the distribution of oil-field sizes in the Gulf of Mexico and other provinces. Ranked according to size and then graphed on a logarithmic scale, the fields tend to fall along a parabola that grows predictably over time (*c*). (Interestingly, galaxies, urban populations and other natural agglomerations also seem to fall along such parabolas.) Finally, we checked our estimates by matching our projections for oil production in large areas, such as the world outside the Persian Gulf region, to the rise and fall of oil discovery in those places decades earlier (*d*). —*C.J.C. and J.H.L.*

...by extrapolating the size of new fields into the future...



...and by matching production to earlier discovery trends.



LAURIE GRACE; SOURCE: JEAN H. LAHERRÈRE

Tar sands typically emerge from strip mines. Extracting oil from these sands and shales creates air pollution. The Orinoco sludge contains heavy metals and sulfur that must be removed. So governments may restrict these industries from growing as fast as they could. In view of these potential obstacles, our skeptical estimate is that only 700 Gbo will be produced from unconventional reserves over the next 60 years.

On the Down Side

Meanwhile global demand for oil is currently rising at more than 2 percent a year. Since 1985, energy use is up about 30 percent in Latin America, 40 percent in Africa and 50 percent in Asia. The Energy Information Administration forecasts that worldwide demand for oil will increase 60 percent (to about 40 Gbo a year) by 2020.

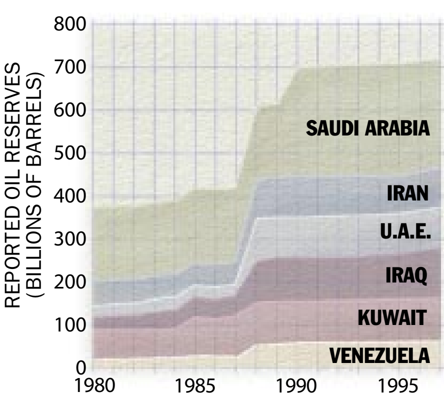
The switch from growth to decline in oil production will thus almost certainly create economic and political tension. Unless alternatives to crude oil quickly prove themselves, the market share of the OPEC states in the Middle East will rise rapidly. Within two years, these nations' share of the global oil business will pass 30 percent, nearing the level reached during the oil-price shocks of the 1970s. By 2010 their share will quite probably hit 50 percent.

The world could thus see radical increases in oil prices. That alone might be sufficient to curb demand, flattening production for perhaps 10 years. (Demand fell more than 10 percent after the 1979 shock and took 17 years to recover.) But by 2010 or so, many Middle Eastern nations will themselves be past the midpoint. World production will then have to fall.

With sufficient preparation, however, the transition to the post-oil economy need not be traumatic. If advanced methods of producing liquid fuels from natural gas can be made profitable and scaled up quickly, gas could become the next source of transportation fuel [see "Liquid Fuels from Natural Gas," by Safaa A. Fouda, on page 92]. Safer nuclear power, cheaper renewable energy, and oil conservation programs could all help postpone the inevitable decline of conventional oil.

Countries should begin planning and investing now. In November a panel of energy experts appointed by President Bill Clinton strongly urged the administration to increase funding for energy research by $1 billion over the next five years. That is a small step in the right direction, one that must be followed by giant leaps from the private sector.

The world is not running out of oil—at least not yet. What our society does face, and soon, is the end of the abundant and cheap oil on which all industrial nations depend. SA



LAURIE GRACE; SOURCE: *OIL AND GAS JOURNAL*

SUSPICIOUS JUMP in reserves reported by six OPEC members added 300 billion barrels of oil to official reserve tallies yet followed no major discovery of new fields.

The Authors

COLIN J. CAMPBELL and JEAN H. LAHERRÈRE have each worked in the oil industry for more than 40 years. After completing his Ph.D. in geology at the University of Oxford, Campbell worked for Texaco as an exploration geologist and then at Amoco as chief geologist for Ecuador. His decade-long study of global oil-production trends has led to two books and numerous papers. Laherrère's early work on seismic refraction surveys contributed to the discovery of Africa's largest oil field. At Total, a French oil company, he supervised exploration techniques worldwide. Both Campbell and Laherrère are currently associated with Petroconsultants in Geneva.

Further Reading

UPDATED HUBBERT CURVES ANALYZE WORLD OIL SUPPLY. L. F. Ivanhoe in *World Oil,* Vol. 217, No. 11, pages 91–94; November 1996.

THE COMING OIL CRISIS. Colin J. Campbell. Multi-Science Publishing and Petroconsultants, Brentwood, England, 1997.

OIL BACK ON THE GLOBAL AGENDA. Craig Bond Hatfield in *Nature,* Vol. 387, page 121; May 8, 1997.

Mining for Oil

COURTESY OF SYNCRUDE

More oil is trapped in Canadian sands than Saudi Arabia holds in its reserves. The technology now exists to exploit this vast resource profitably

by Richard L. George

The term "oil" has, to date, been synonymous with conventional crude oil, a liquid mixture of hydrocarbons that percolates through porous strata and flows readily up drilled boreholes. But much of the world's remaining endowment of oil takes a less convenient form: a black, tarlike substance called bitumen, which sticks stubbornly in the pore spaces between the grains of certain sands and shales (solidified muds). Because bitumen normally will not flow through such formations, the straightforward way to recover it is to scoop it out of open-pit mines.

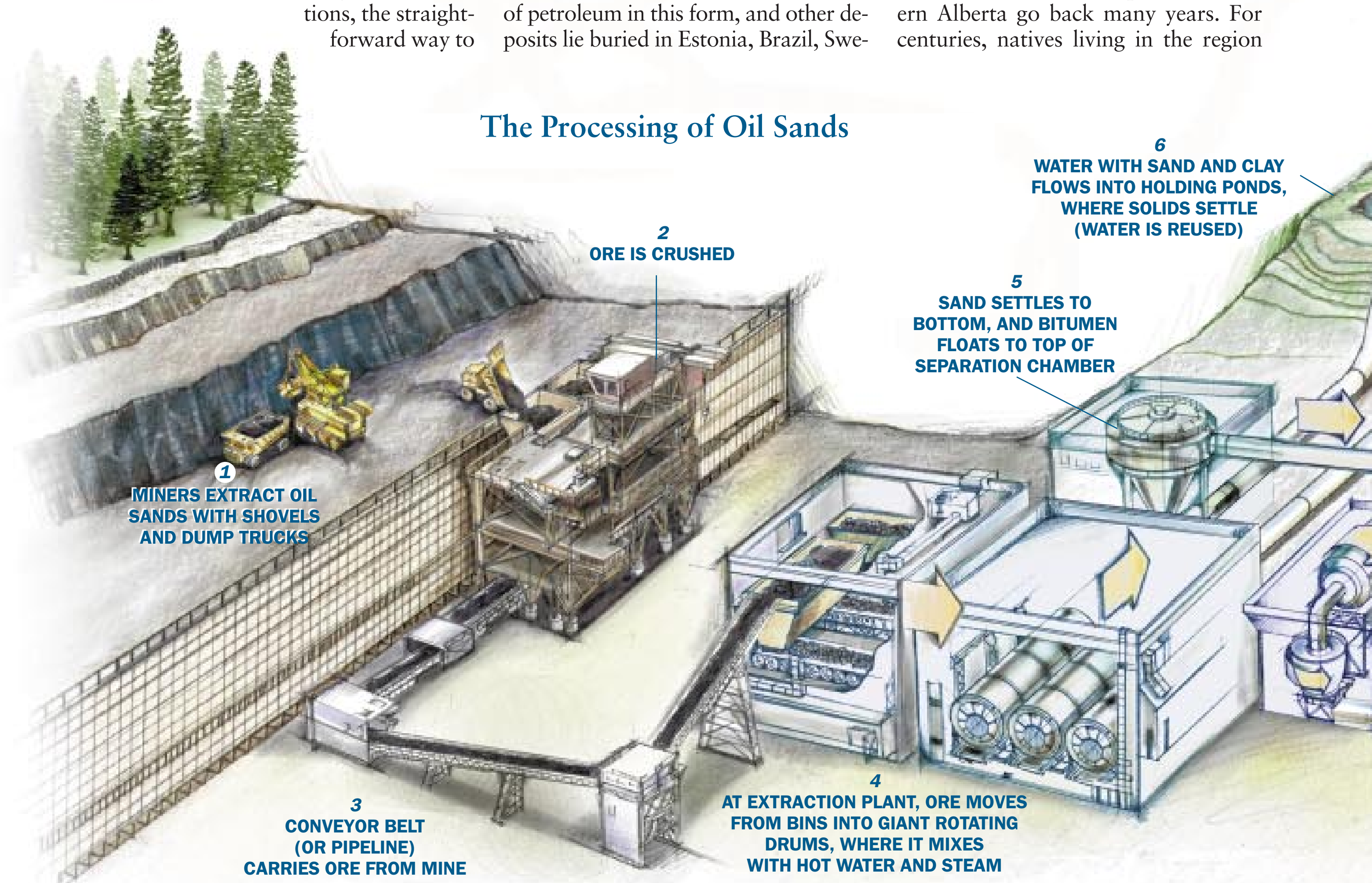
Digging for oil is certainly more troublesome than simply drilling and pumping, but the enormity of this resource makes it hard to ignore. Current processing methods could recover about 300 billion barrels from oil sands in the Canadian province of Alberta alone—more than the reserves of conventional oil in Saudi Arabia. Oil shale appears to offer a less prodigious supply, but Australia contains at least 28 billion barrels of petroleum in this form, and other deposits lie buried in Estonia, Brazil, Sweden, the U.S. and China. All told, oil sands and shales around the world could, in principle, hold several trillion barrels of oil.

Yet it is difficult to predict how much of that potential can be profitably recovered, because the processing needed to turn oil sands or shales into useful petroleum products is quite challenging. My company, Suncor Energy, is one of only two in the world that have successfully exploited oil sands by mining them.

The roots of our enterprise in northern Alberta go back many years. For centuries, natives living in the region

ILLUSTRATION BY DANIELS & DANIELS; SOURCE: SUNCOR

The Processing of Oil Sands



OIL SANDS, coated with tarlike bitumen, have the appearance of coffee grounds.

used the sticky bitumen that oozes out of the banks of the Athabasca River to patch leaks in their canoes. And as early as 1893 the Canadian government sponsored investigations of the Athabasca "tar sands" as a potential source of petroleum. Then, in 1920, Karl A. Clark of the Alberta Research Council found a practical way to separate the bitumen from the sand. After shoveling some of the asphalt into the family washing machine and adding hot water and caustic soda, he discovered that the bitumen floated to the surface as a frothy foam, ready to be skimmed off.

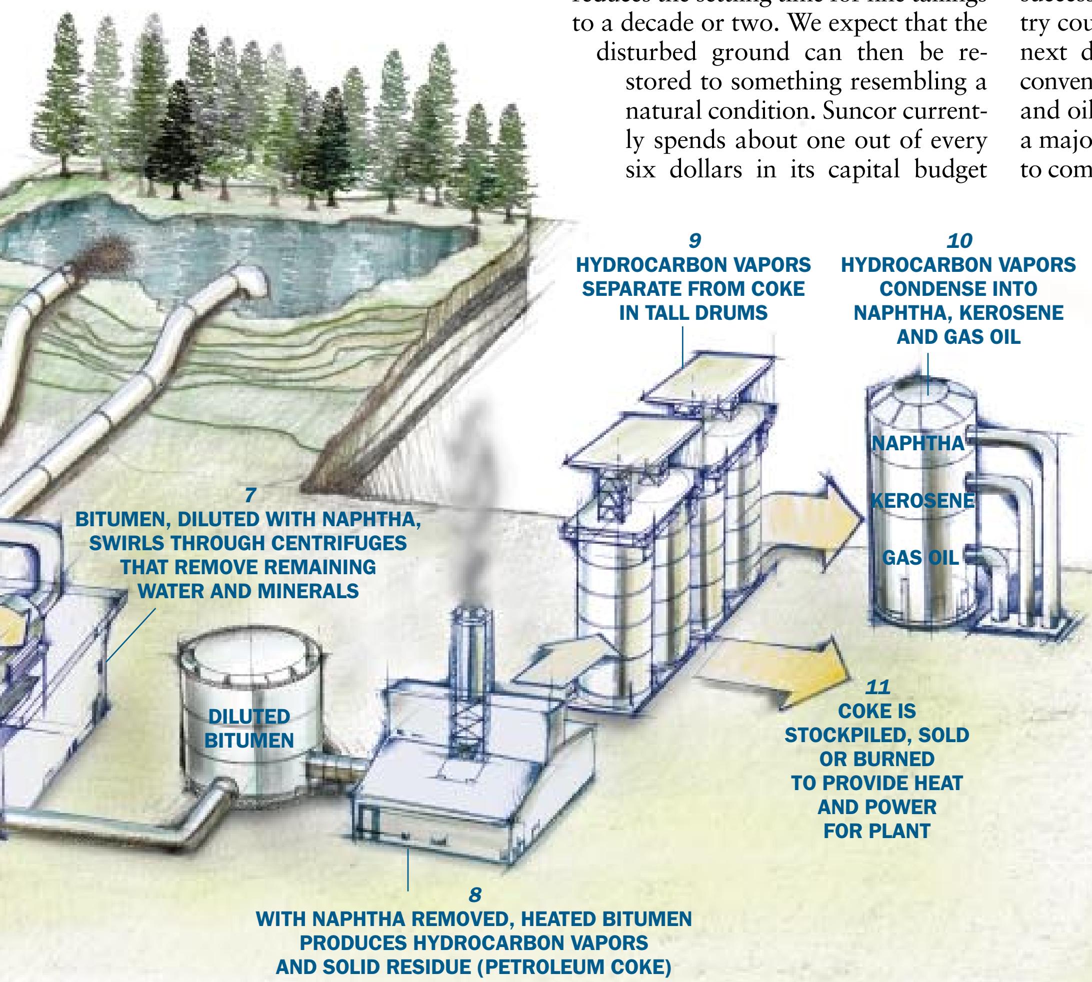
Clark's method was clearly workable. Yet the idea languished for decades until the precursor of Suncor Energy, the Great Canadian Oil Sands Ltd., began large-scale mining of oil sands in 1967. Rising petroleum prices during the 1970s helped to keep the expensive operation afloat. But failures of the excavating equipment dogged the miners until 1992, when Suncor modernized the facility in a concerted effort to reduce the cost of extracting this oil.

For the past five years, my colleagues at Suncor have been producing oil that is quite profitable at current market prices. Our production has expanded by 38 percent over that period, and we now sell 28 million barrels of unconventional oil a year. This growth will most likely accelerate in the future, limited in part by the need to ensure that the local environment is harmed as little as possible.

The handling of residues, called tailings, is of particular concern. The coarser grains settle quickly from a slurry of water and sand, and we put these materials back into the ground. But the water still contains many fine particles, so we have to hold it in large ponds to avoid contaminating nearby rivers and streams. Left alone, the fine tailings would not sink to the bottom for centuries. But researchers in industry and government discovered that adding gypsum (a by-product of the sulfur that is removed from the oil) to the ponds reduces the settling time for fine tailings to a decade or two. We expect that the disturbed ground can then be restored to something resembling a natural condition. Suncor currently spends about one out of every six dollars in its capital budget on reducing environmental disturbance.

One alternative technology for extracting bitumen sidesteps such problems and could, in principle, allow industry to tap huge deposits that are too deep to mine. It turns out that the oil in these sands can be made to flow by injecting steam into the ground. Once it is heated, the oil thins and pools underneath the site of injection. Ordinary oilfield equipment can then bring it to the surface. This process, called steam-assisted gravity drainage, is now being tested by oil companies such as the Alberta Energy Company. Suncor, too, may exploit this approach in the future.

Engineers at Suncor are also examining a system to bake the oil out of crushed rock in a giant, drum-shaped kiln. Although this method (invented by William Taciuk, collaborating with the Alberta Department of Energy) is not particularly appropriate for oil sands, it appears to work well for processing oil shales. If a demonstration plant that Suncor is building with its Australian partners—Southern Pacific Petroleum and Central Pacific Minerals—proves successful, a whole new oil shale industry could develop in Australia over the next decade. So as production from conventional oil fields dwindles, oil shale and oil sand reserves may well become a major source of energy in the century to come. SA



The Author

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Further Reading

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Oil Production in the 21st Century

Recent innovations in underground imaging, steerable drilling and deepwater oil production could recover more of what lies below

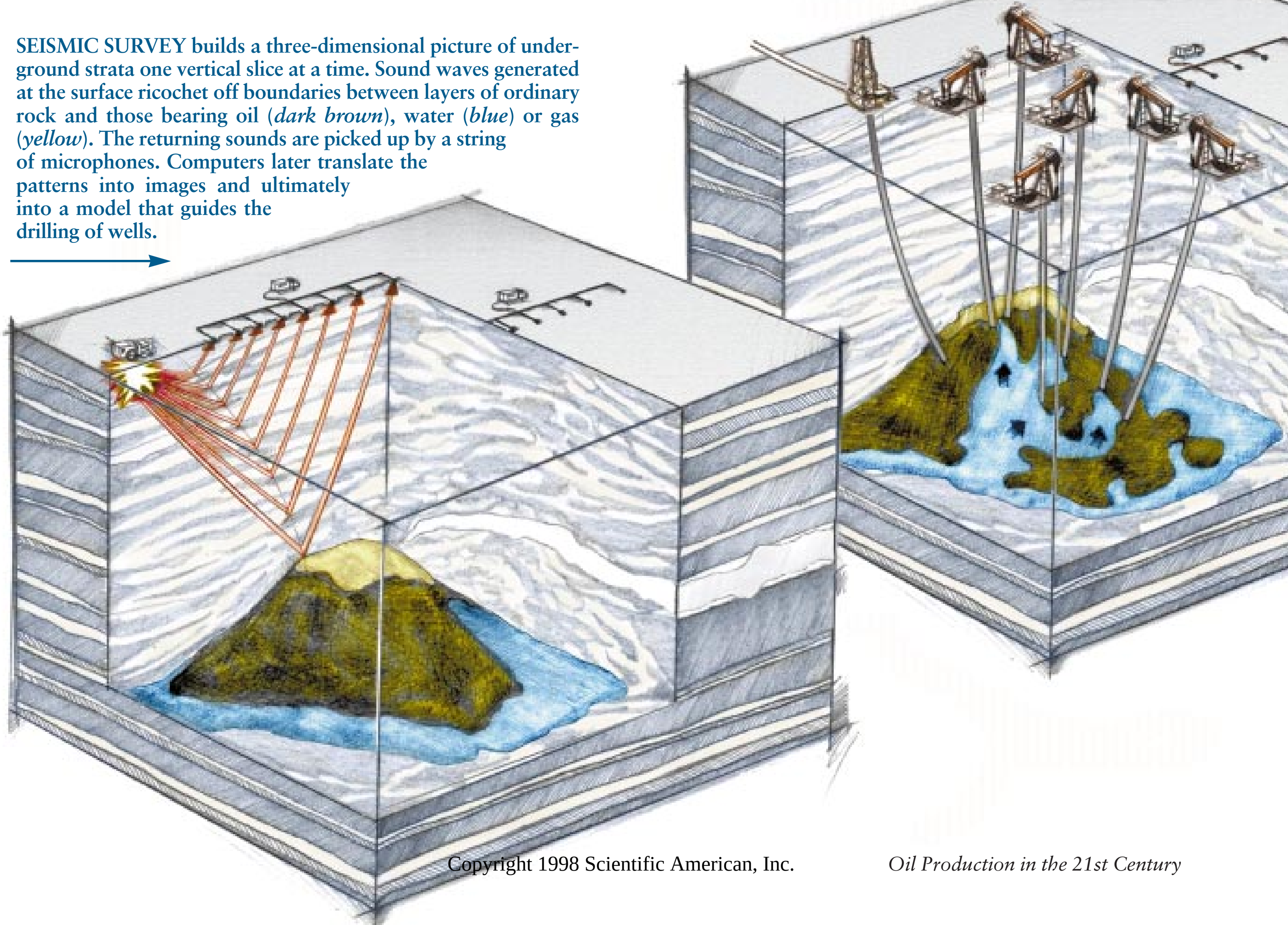
by Roger N. Anderson

On the face of it, the outlook for conventional oil—the cheap, easily recovered crude that has furnished more than 95 percent of all oil to date—seems grim. In 2010, according to forecasts, the world's oil-thirsty economies will demand about 10 billion more barrels than the industry will be able to produce. A supply shortfall that large, equal to almost half of all the oil extracted in 1997, could lead to price shocks, economic recession and even wars.

Fortunately, four major technological advances are ready to fill much of the gap by accelerating the discovery of new oil reservoirs and by dramatically increasing the fraction of oil within existing fields that can be removed economically, a ratio known as the recovery factor. These technologies could lift global oil production rates more than 20 percent by 2010 if they are deployed as planned on the largest oil fields within three to five years. Such rapid adoption may seem ambitious for an industry that traditionally has taken 10 to 20 years to put new inventions to use. But in this case, change will be spurred by formidable economic forces.

For example, in the past two years, the French oil company Elf has discovered giant deposits off the coast of West Africa. In the same period, the company's stock doubled, as industry analysts forecasted that Elf's production would increase by 8 percent in 2001. If the other major oil producers follow suit, they should be able by 2010 to provide an extra five billion barrels of oil each year, closing perhaps half the gap between global supply and demand.

This article will cover the four advances in turn, beginning with a new way to track subterranean oil.



SEISMIC SURVEY builds a three-dimensional picture of underground strata one vertical slice at a time. Sound waves generated at the surface ricochet off boundaries between layers of ordinary rock and those bearing oil (*dark brown*), water (*blue*) or gas (*yellow*). The returning sounds are picked up by a string of microphones. Computers later translate the patterns into images and ultimately into a model that guides the drilling of wells.

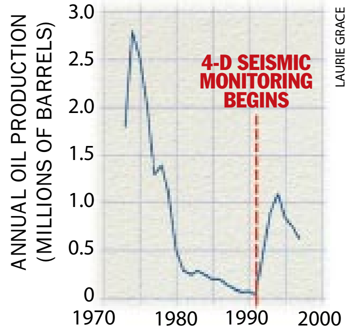
DANIELS & DANIELS

Tracking Oil in Four Dimensions

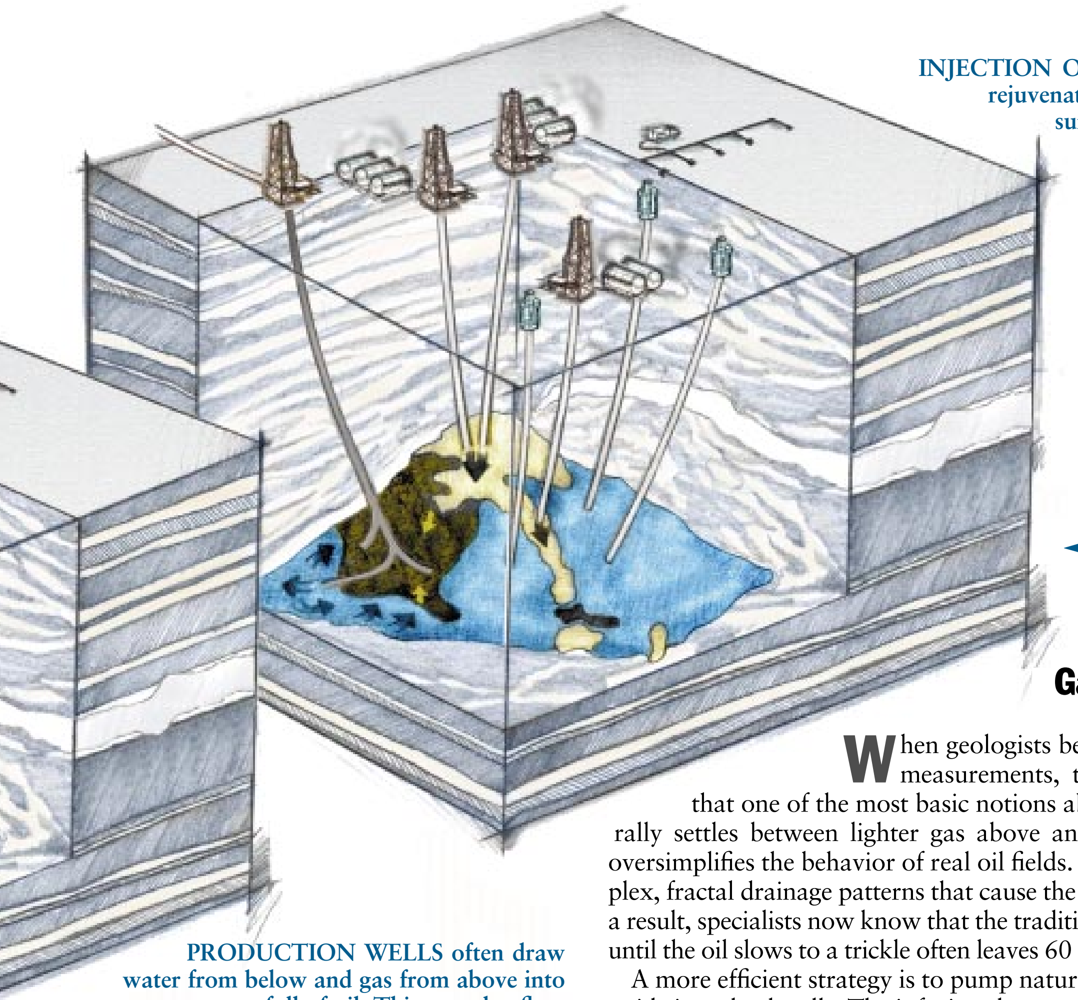
Finding oil became much more efficient after 1927, when geologists first successfully translated acoustic reflections into detailed cross sections of the earth's crust. Seismologists later learned how to piece together several such snapshots to create three-dimensional models of the oil locked inside layers of porous rock. Although this technique, known as 3-D seismic analysis, took more than a decade to become standard practice, it is now credited with increasing oil discovery and recovery rates by 20 percent.

In recent years, scientists in my laboratory at Columbia University and elsewhere have developed even more powerful techniques capable of tracking the movement of oil, gas and water as drilled wells drain the subterranean strata—a "4-D" scheme that includes the added dimension of time. This information can then be used to do a "what if" analysis on the oil field, designing ways to extract as much of the oil as quickly and cheaply as possible.

Compared with its predecessor, the 4-D approach seems to be catching on quickly: the number of oil fields benefiting from it has doubled in each of the past four years and now stands at about 60. Such monitoring can boost recovery factors by 10 to 15 percentage points. Unfortunately, the technique will work in only about half the world's major fields, those where relatively soft rock is suffused with oil and natural gas.



FLOW OF OIL from a reservoir in the largest field off the Louisiana shore resurged in 1992, shortly after operators began using 4-D seismic monitoring to locate hidden caches of oil.



INJECTION OF LIQUID CARBON DIOXIDE can rejuvenate dying oil fields. Pumped at high pressure from tanks into wells that have ceased producing oil, the carbon dioxide flows through the reservoir and, if all goes well, pushes the remaining oil down toward active wells. Steam and natural gas are sometimes also used for this purpose. Alternatively, water can be injected below a pocket of bypassed crude in order to shepherd the oil into a well. In the future, "smart" wells currently under development will be able to retrieve oil simultaneously from some branches of the well while using other branches to pump water out of the oil stream and back into the formation from which it came.

PRODUCTION WELLS often draw water from below and gas from above into pore spaces once full of oil. This complex flow strands pockets of crude far from wells; traditional drilling techniques thus miss up to two thirds of the oil in a reservoir. But repeated seismic surveys can now be assembled into a 4-D model that not only tracks where oil, gas and water in the field are located but also predicts where they will go next. Advanced seismic monitoring works well on about half the world's oil fields, but it fails on oil buried in very hard rock or beneath beds of salt (*thick white layer*).

Gassing Things Up

When geologists began studying the new time-lapse measurements, they were surprised to discover that one of the most basic notions about oil movement—that it naturally settles between lighter gas above and heavier groundwater below—oversimplifies the behavior of real oil fields. In fact, most wells produce complex, fractal drainage patterns that cause the oil to mix with gas and water. As a result, specialists now know that the traditional technique of pumping a well until the oil slows to a trickle often leaves 60 percent or more of the oil behind.

A more efficient strategy is to pump natural gas, steam or liquid carbon dioxide into dead wells. The infusion then spreads downward through pores in the rock and, if one has planned carefully, pushes oil that otherwise would have been abandoned toward a neighboring well. Alternatively, water is often pumped below the oil to increase its pressure, helping it flow up to the surface.

Injections of steam and carbon dioxide have been shown to increase recovery factors by 10 to 15 percentage points. Unfortunately, they also raise the cost of oil production by 50 to 100 percent—and that added expense falls on top of a 10 to 25 percent surcharge for 4-D seismic monitoring. So unless carbon dioxide becomes much cheaper (perhaps because global-warming treaties restrict its release) these techniques will probably continue to serve only as a last resort.

Steering to Missed Oil

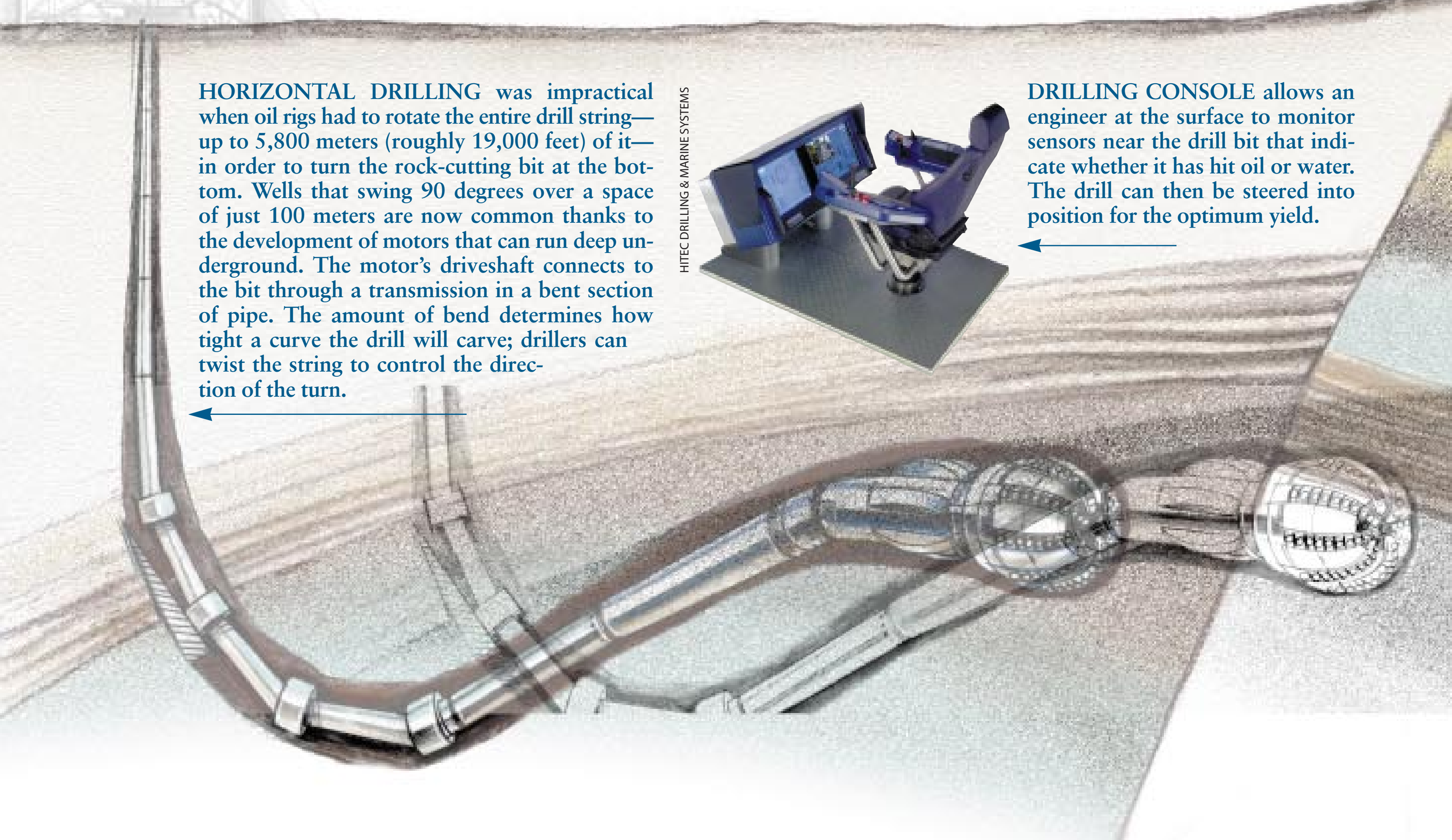
A third major technological advance, known as directional drilling, can tap bypassed deposits of oil at less expense than injection. Petroleum engineers can use a variety of new equipment to swing a well from vertical to entirely horizontal within a reservoir several kilometers underground.

Traditionally, drillers rotated the long steel pipe, or "string," that connects the rig at the surface to the bit at the bottom of the well. That method fails when the pipe must turn a corner—the bend would break the rotating string. So steerable drill strings do not rotate; instead a mud-driven motor inserted near the bit turns only the diamond-tipped teeth that do the digging. An elbow of pipe placed between the mud motor and the bit controls the direction of drilling.

Threading a hole through kilometers of rock into a typical oil zone 30 meters (about 100 feet) thick is precise work. Schlumberger, Halliburton and other international companies have developed sophisticated sensors that significantly improve the accuracy of drilling. These devices, which operate at depths of up to 6,000 meters and at temperatures as high as 200 degrees Celsius (400 degrees Fahrenheit), attach to the drill pipe just above or below the mud motor. Some measure the electrical resistance of the surrounding rock. Others send out neutrons and gamma rays; then they count the number that are scattered back by the rock and pore fluids. These measurements and the current position of the bit (calculated by an inertial guidance system) are sent back to the surface through pulses in the flow of the very mud used to turn the motor and lubricate the well bore. Engineers can adjust the path of the drill accordingly, thus snaking their way to the most oil-rich part of the formation.

Once the hole is completed, drillers typically erect production equipment on top of the wellhead. But several companies are now developing sensors that can detect the mix of oil, gas and water near its point of entry deep within the well. "Smart" wells with such equipment will be able to separate water out of the well stream so that it never goes to the surface. Instead a pump, controlled by a computer in the drill pipe, will inject the wastewater below the oil level.

DANIELS & DANIELS (*background illustration*)

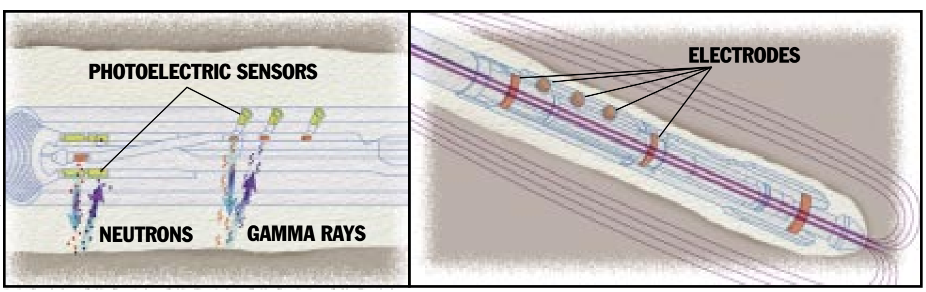


HORIZONTAL DRILLING was impractical when oil rigs had to rotate the entire drill string—up to 5,800 meters (roughly 19,000 feet) of it—in order to turn the rock-cutting bit at the bottom. Wells that swing 90 degrees over a space of just 100 meters are now common thanks to the development of motors that can run deep underground. The motor's driveshaft connects to the bit through a transmission in a bent section of pipe. The amount of bend determines how tight a curve the drill will carve; drillers can twist the string to control the direction of the turn.

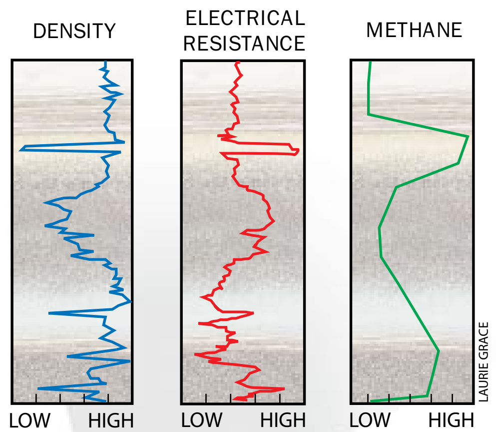
HITEC DRILLING & MARINE SYSTEMS

DRILLING CONSOLE allows an engineer at the surface to monitor sensors near the drill bit that indicate whether it has hit oil or water. The drill can then be steered into position for the optimum yield.

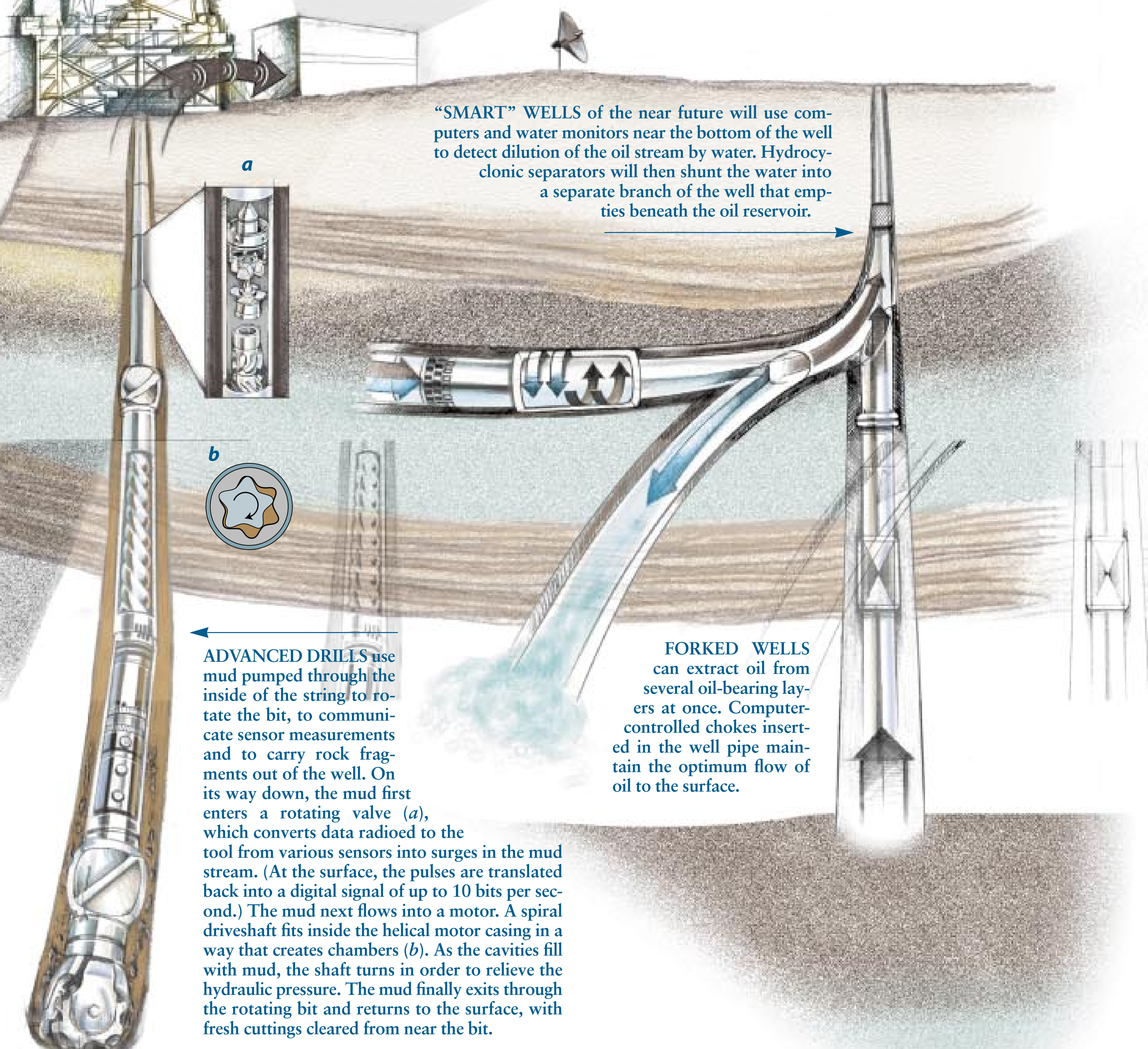
LAURIE GRACE; SOURCE: SCHLUMBERGER



SENSORS near the bit can detect oil, water and gas. One device measures the porosity of the surrounding rock by emitting neutrons, which scatter off hydrogen atoms. Another takes a density reading by shooting out gamma rays that interact with adjacent electrons. Oil and water also affect electrical resistance, measured from a current passed through the bit, the rock and nearby electrodes.



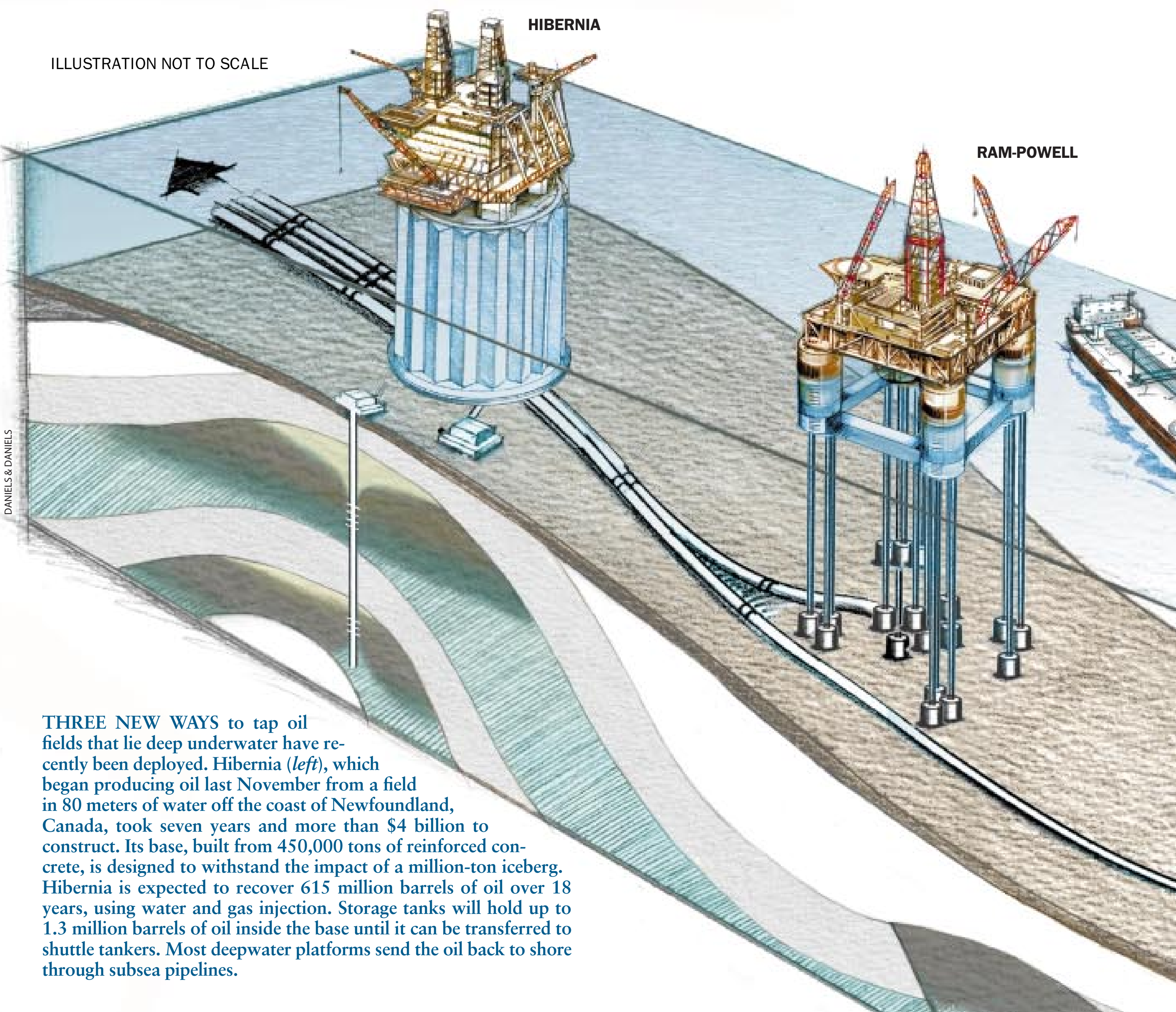
GEOLOGIC MEASUREMENTS collected by sensors near the bottom of the drill pipe can be analyzed at the wellhead or transmitted via satellite to engineers anywhere in the world. Several characteristics of the rocks surrounding the drill bit can reveal the presence of oil or gas (*left*). Petroleum tends to accumulate in relatively light, porous rocks, for example, so some geosteering systems calculate the bulk density of nearby strata. Others measure the electrical resistance of the earth around the drill; layers soaked with briny water have a much lower resistance than those rich in oil. Gas chromatographs at the surface analyze the returning flow of lubricating mud for natural gas captured during its journey.



"SMART" WELLS of the near future will use computers and water monitors near the bottom of the well to detect dilution of the oil stream by water. Hydrocyclonic separators will then shunt the water into a separate branch of the well that empties beneath the oil reservoir.

ADVANCED DRILLS use mud pumped through the inside of the string to rotate the bit, to communicate sensor measurements and to carry rock fragments out of the well. On its way down, the mud first enters a rotating valve (*a*), which converts data radioed to the tool from various sensors into surges in the mud stream. (At the surface, the pulses are translated back into a digital signal of up to 10 bits per second.) The mud next flows into a motor. A spiral driveshaft fits inside the helical motor casing in a way that creates chambers (*b*). As the cavities fill with mud, the shaft turns in order to relieve the hydraulic pressure. The mud finally exits through the rotating bit and returns to the surface, with fresh cuttings cleared from near the bit.

FORKED WELLS can extract oil from several oil-bearing layers at once. Computer-controlled chokes inserted in the well pipe maintain the optimum flow of oil to the surface.



THREE NEW WAYS to tap oil fields that lie deep underwater have recently been deployed. Hibernia (*left*), which began producing oil last November from a field in 80 meters of water off the coast of Newfoundland, Canada, took seven years and more than $4 billion to construct. Its base, built from 450,000 tons of reinforced concrete, is designed to withstand the impact of a million-ton iceberg. Hibernia is expected to recover 615 million barrels of oil over 18 years, using water and gas injection. Storage tanks will hold up to 1.3 million barrels of oil inside the base until it can be transferred to shuttle tankers. Most deepwater platforms send the oil back to shore through subsea pipelines.

Wading in Deeper

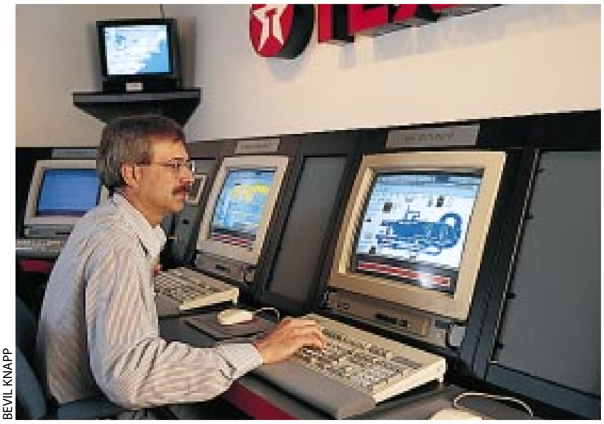
Perhaps the oil industry's last great frontier is in deep water, in fields that lie 1,000 meters or more below the surface of the sea. Petroleum at such depths used to be beyond reach, but no longer. Remotely controlled robot submarines can now install on the seafloor the complex equipment needed to guard against blowouts, to regulate the flow of oil at the prevailing high pressures and to prevent natural gas from freezing and plugging pipelines. Subsea complexes will link clusters of horizontal wells. The collected oil will then be funneled both to tankers directly above and to existing platforms in shallower waters through long underwater pipelines. In just the next three years, such seafloor facilities are scheduled for construction in the Gulf of Mexico and off the shores of Norway, Brazil and West Africa.

More than deep water alone hinders the exploitation of offshore oil and gas fields. Large horizontal sheets of salt and basalt (an igneous rock) sometimes lie just underneath the seafloor in the deep waters of the continental margins. In conventional seismic surveys they scatter nearly all the sound energy so that oil fields below are hidden from view. But recently declassified U.S. Navy technology for measuring tiny variations in the force and direction of gravity, combined with ever expanding supercomputer capabilities, now allows geophysicists to see under these blankets of salt or basalt.

Extracting oil from beneath the deep ocean is still enormously expensive, but innovation and necessity have led to a new wave of exploration in that realm. Already the 10 largest oil companies working in deep water have discovered new fields that will add 5 percent to their combined oil reserves, an increase not yet reflected in global reserve estimates.

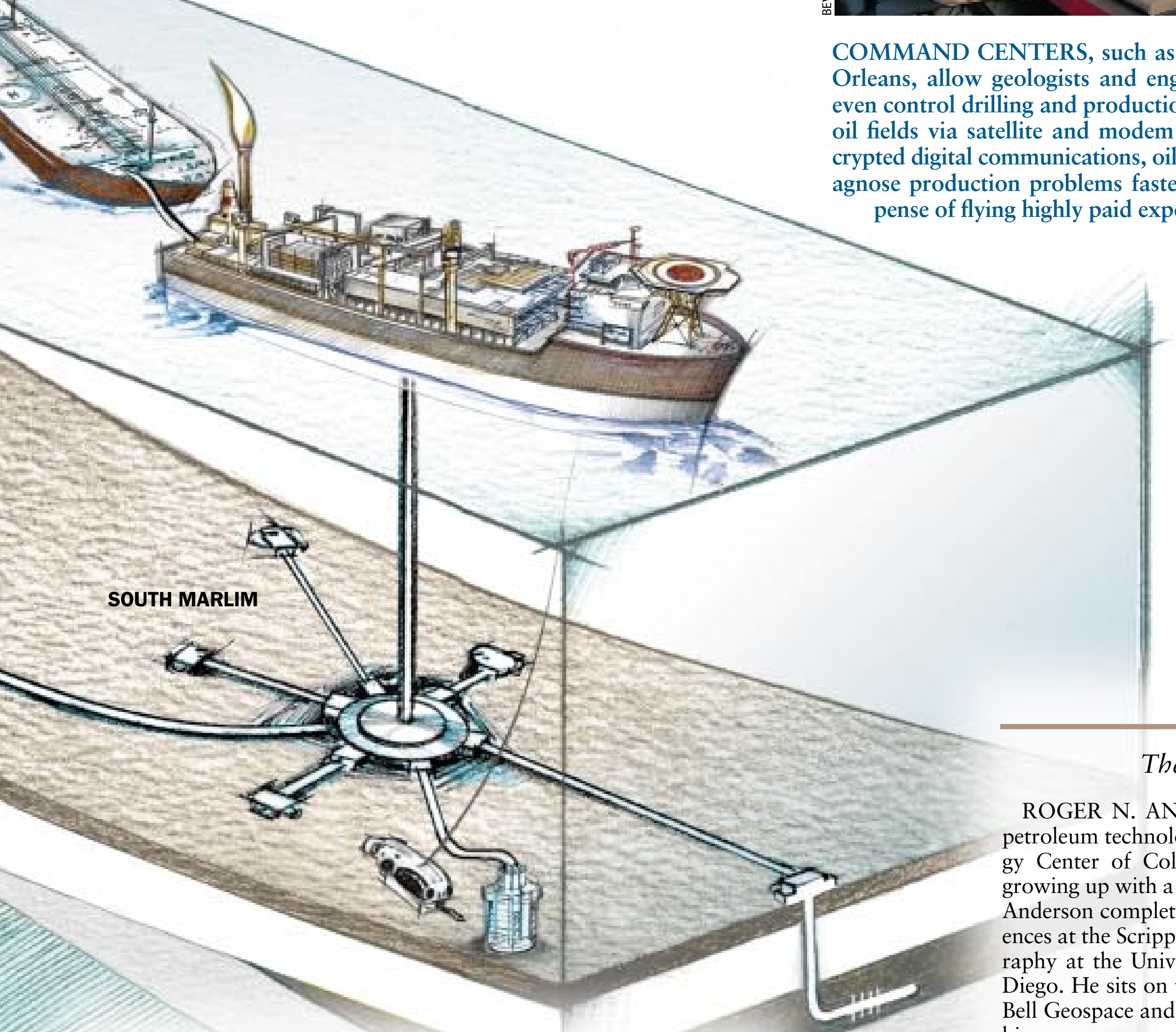
The technology for oil exploration and production will continue to march forward in the 21st century. Although it is unlikely that these techniques will entirely eliminate the impending shortfall in the supply of crude oil, they will buy critical time for making an orderly transition to a world fueled by other energy sources.

RAM-POWELL platform (*center*), built by Shell Oil, Amoco and Exxon, began production in the Gulf of Mexico last September. The 46-story platform is anchored to 270-ton piles driven into the seafloor 980 meters below. Twelve tendons, each 71 centimeters in diameter, provide a strong enough mooring to withstand 22-meter waves and hurricane winds up to 225 kilometers per hour. The $1-billion facility can sink wells up to six kilometers into the seabed in order to tap the 125 million barrels of recoverable oil estimated to lie in the field. A 30-centimeter pipeline will transport the oil to platforms in shallower water 40 kilometers away. Ram-Powell is the third such tension leg platform completed by Shell in three years. Next year, Shell's plans call for an even larger platform, named Ursa, to start pumping 2.5 times as much oil as Ram-Powell from below 1,226 meters of water.



BEVIL KNAPP

COMMAND CENTERS, such as the one above in New Orleans, allow geologists and engineers to monitor and even control drilling and production equipment in remote oil fields via satellite and modem connections. With encrypted digital communications, oil companies can now diagnose production problems faster and can save the expense of flying highly paid experts around the world.



DEEPEST OIL WELL in active production (*above*) currently lies more than 1,709 meters beneath the waves of the South Atlantic Ocean, in the Marlim field off the coast of Campos, Brazil. The southern part of this field alone is thought to contain 10.6 billion barrels of oil. Such resources were out of reach until recently. Now remotely operated submarines are being used to construct production facilities on the sea bottom itself. The oil can then be piped to a shallower platform if one is nearby. Or, as in the case of the record-holding South Marlim 3B well, a ship can store the oil until shuttle tankers arrive. The challenge is to hold the ship steady above the well. Moorings can provide stability at depths up to about 1,500 meters. Beyond that limit, ships may have to use automatic thrusters linked to the Global Positioning System and beacons on the seafloor to actively maintain their position. These techniques may allow the industry to exploit oil fields under more than 3,000 meters of water in the near future.

The Author

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Liquid Fuels from Natural Gas

Natural gas is cleaner and more plentiful than oil. New ways to convert it to liquid form may soon make it just as cheap and convenient to use in vehicles

by Safaa A. Fouda

Recently countless California motorists have begun contributing to a remarkable transition. Few of these drivers realize that they are doing something special when they tank up their diesel vehicles at the filling station. But, in fact, they are helping to wean America from crude oil by buying a fuel made in part from natural gas.

Diesel fuel produced in this unconventional way is on sale in California because the gas from which it is derived is largely free of sulfur, nitrogen and heavy metals—substances that leave the tailpipe as noxious pollutants. Blends of ordinary diesel fuel and diesel synthesized from natural gas (currently produced commercially by Shell in Indonesia) meet the toughest emissions standards imposed by the California Air Resources Board.

But natural gas is not only the cleanest of fossil fuels, it is also one of the most plentiful. Industry analysts estimate that the world holds enough readily recoverable natural gas to produce 500 billion barrels of synthetic crude—more than twice the amount of oil ever found in the U.S. Perhaps double that quantity of gas can be found in coal seams and in formations that release gas only slowly. Thus, liquid fuels derived from natural gas could keep overall production on the rise for about a decade after conventional supplies of crude oil begin to dwindle.

Although global stocks of natural gas are enormous, many of the deposits lie far from the people in need of energy. Yet sending gas over long distances often turns out to be prohibitively expensive. Natural gas costs four times as much as crude oil to transport through pipelines because it has a much lower energy density. The so-called stranded gas can be cooled and compressed into a liquid for shipping by tanker. Unfortunately, the conversion facilities required are large and complex, and because liquefied natural gas is hard to handle, the demand for it is rather limited.

But what if there were a cheap way to convert natural gas to a form that remains liquid at room temperature and pressure? Doing so would allow the energy to be piped to markets inexpensively. If the liquid happened to be a fuel that worked in existing vehicles, it could substitute for oil-based gasoline and diesel. And oil producers would stand to profit in many instances by selling liquid fuels or other valuable chemicals made using the gas coming from their wells.

Right now the gas released from oil wells in many parts of the world holds so little value that it is either burned on site or reinjected into the ground. In Alaska alone, oil companies pump about 200 million cubic meters (roughly seven billion cubic feet) of natural gas back into the ground daily—in large part to avoid burdening the atmosphere with additional carbon dioxide, a worrisome greenhouse gas.

But recent technical advances have prompted several oil companies to consider building plants to convert this natural gas into liquid form, which could then be delivered economically through the Alaska pipeline. On the Arabian Peninsula, the nation of Qatar is negotiating with three petrochemical companies to build gas conversion plants that would exploit a huge offshore field—a single reservoir that contains about a tenth of the world's proved gas reserves. And Norway's largest oil company, Statoil, is looking at building relatively small modules mounted on floating platforms to transform gas in remote North Sea fields into liquids. Although these efforts will use somewhat different technologies, they all must address the same fundamental problem in chemistry: making larger hydrocarbon molecules from smaller ones.

The Classic Formula

The main component of natural gas is methane, a simple molecule that has four hydrogen atoms neatly arrayed around one carbon atom. This symmetry makes methane particularly stable. Converting it to a liquid fuel requires first breaking its chemical bonds. High temperatures and pressures help to tear these bonds apart. So do cleverly designed catalysts, substances that can foster a chemical reaction without themselves being consumed.

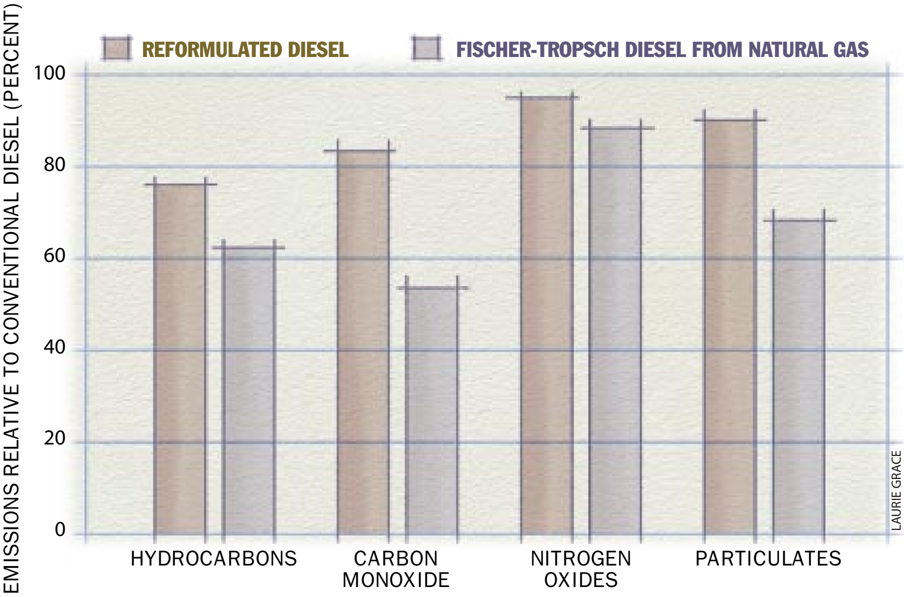
The conventional "indirect" approach for converting natural gas to liquid form relies on brute force. First, the chemical bonds in methane are broken using steam, heat and a nickel-based catalyst to produce a mixture of carbon monoxide and hydrogen known as syngas (or, more formally, synthesis gas). This process is called steam re-forming.

The second step in the production of liquid fuels (or other valuable petrochemicals) from syngas uses a method invented in 1923 by Franz Fischer and Hans Tropsch. During World War II, Germany harnessed this technique to produce liquid fuels using syngas made from coal and atmospheric oxygen, thus establishing a reliable internal source for gasoline and diesel.

This Fischer-Tropsch technology has allowed Sasol in South Africa to produce liquid fuels commercially for decades using syngas derived from coal. The company uses the same basic technique today: syngas blown over a catalyst made of cobalt, nickel or iron transforms into various liquid hydrocarbons. Conveniently, the Fischer-Tropsch reaction gives off heat, and often this heat is

LARRY MAYER *Liaison International*

FLARED GAS heats the air uselessly around an oil well in Wyoming. Such supplies of natural gas are wasted because they are much more expensive than oil to transport by pipeline.



HARMFUL VEHICLE EMISSIONS were lowered somewhat in 1993, when U.S. regulations required that diesel fuel be reformulated to reduce pollution. Fuel derived from natural gas using Fischer-Tropsch synthesis creates even fewer emissions than reformulated diesel.

used to drive the oxygen compressors needed to make syngas.

Just which liquids emerge from the reaction depends on temperature. For example, running a reaction vessel at 330 to 350 degrees Celsius (626 to 662 degrees Fahrenheit) will primarily produce gasoline and olefins (building blocks often used to make plastics). A cooler (180 to 250 degree C) operation will make predominantly diesel and waxes. In any case, a mixture results, so a third and final step is required to refine the products of the reaction into usable fuels.

Refining synthetic crudes derived from gas is in many respects easier than working with natural crude oil. Synthetic crude contains virtually no sulfur and has smaller amounts of cancer-causing compounds than are found in conventional oil. So the final products are premium-quality fuels that emit fewer harmful substances.

A Partial Solution

This brute-force method of converting gas to liquids is reliable, but it is expensive because it uses so much energy. Conventional steam re-forming compresses methane and water vapor to about 30 times normal atmospheric pressure and heats these reactants to about 900 degrees C. And one must add more heat still, to coax the energy-hungry reaction continuously along. This extra heat comes from injecting a small amount of oxygen into the mixture, which combusts some of the methane (and, as an added benefit, makes more syngas). Chemists call this latter maneuver partial oxidation.

In general, syngas is generated using various combinations of steam re-forming and partial oxidation. In most cases, the process requires large quantities of oxygen—and oxygen is costly. Existing methods of separating oxygen from air rely on refrigeration to cool and liquefy it, an energy-intensive and expensive manipulation. Hence, lowering the cost of oxygen is the key to making syngas cheaply.

Fortunately, recent developments promise to revolutionize the way oxygen is produced over the next few years. One strategy is simply to work with air instead of pure oxygen. Syntroleum Corporation in Tulsa has developed a way to make liquid fuels using blown air and methane for the re-forming step, followed by Fischer-Tropsch synthesis. At sites where natural gas is sufficiently cheap (for example, places where it is now being flared), the process should prove profitable even at current crude oil prices. Together with Texaco and the English company Brown & Root, Syntroleum plans to build a commercial plant that will use this technique within two years.

Several other private companies, universities and government research laboratories are pursuing a wholly different approach to the oxygen problem: they are developing ceramic membranes through which only oxygen can pass. These membranes can then serve as filters to purify oxygen from air. Though still difficult and expensive to construct, laboratory versions work quite well. They should be commercially available within a decade.

Such materials could reduce the cost of making syngas by about 25 percent and lower the cost of producing liquid fuels by 15 percent. These savings would accrue because the production of syngas could be done at temperatures about 200 degrees lower than those currently used and because there would be no need to liquefy air. With cheap and plentiful oxygen, partial oxidation alone could supply syngas. This first step would then release energy rather than consume it.

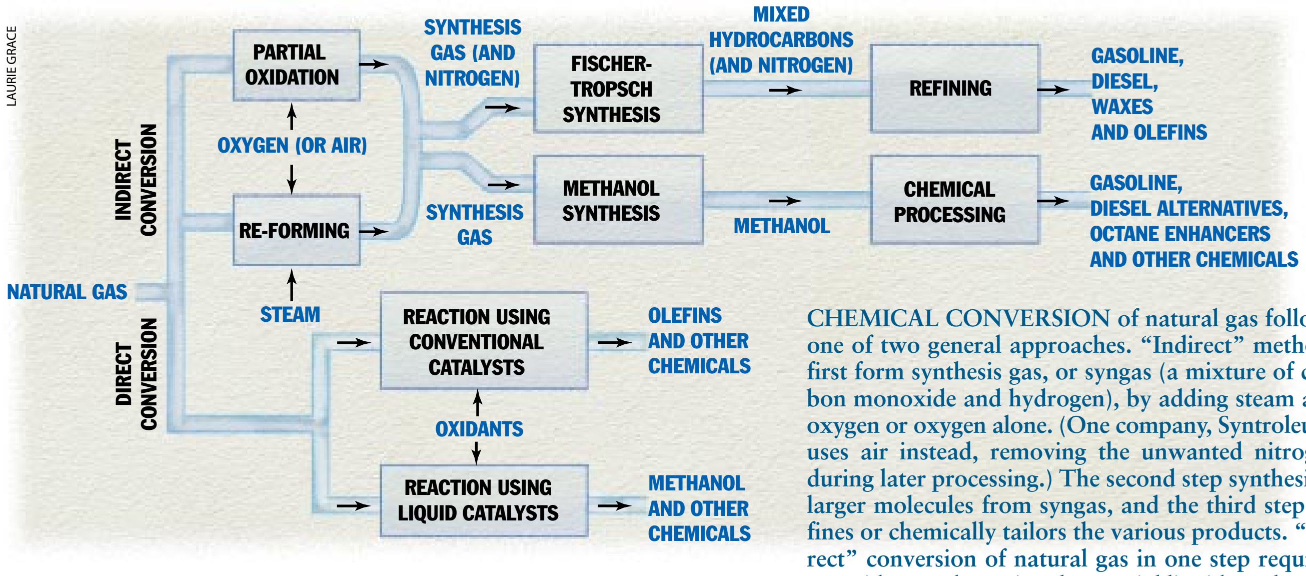
My Canadian colleagues and I, along with researchers at the University of Florida, are now attempting to create a different kind of ceramic membrane that would offer yet another advantage. The membranes we are trying to develop would remove hydrogen from the gas mixture, driving the partial oxidation of methane forward and providing a stream of pure hydrogen that could be used later in refining the final products or as an energy source itself.

We also expect to see significant improvements soon in the catalysts used to make syngas. In particular, researchers at the University of Oxford are studying metal carbides, and my colleagues at the Canadian Center for Mineral and Energy Technology are investigating large-pore zeolites. Both materials show great promise in reducing the soot generated during operation, a problem that not only plugs the reactor but also reduces the activity of the catalysts over time.

Cheaper than Oil?

Although the prospects for such brute-force methods of converting natural gas to liquid fuel improve every day, more ingenious techniques on the horizon would accomplish that transformation in a single step. This approach could potentially cut the cost of conversion in half, which would make liquid fuels produced from natural gas actually less expensive than similar products refined from crude oil.

Early efforts to achieve such "direct" conversion by using different catalysts and adding greater amounts of oxygen had produced mostly disappointment. The hydrocarbons that were formed proved more reactive than the methane supplied. In essence, they burned up



CHEMICAL CONVERSION of natural gas follows one of two general approaches. "Indirect" methods first form synthesis gas, or syngas (a mixture of carbon monoxide and hydrogen), by adding steam and oxygen or oxygen alone. (One company, Syntroleum, uses air instead, removing the unwanted nitrogen during later processing.) The second step synthesizes larger molecules from syngas, and the third step refines or chemically tailors the various products. "Direct" conversion of natural gas in one step requires an oxidant and may involve special liquid catalysts.

faster than they were produced. Unless the product is somehow removed from the reaction zone, yields are too low to be practical.

Fortunately, researchers have recently found ways to circumvent this problem. The trick is to run the reaction at comparatively mild temperatures using exotic catalysts or to stabilize the product chemically—or to do both. For example, chemists at Pennsylvania State University have converted methane to methanol directly using a so-called homogeneous catalyst, a liquid that is thoroughly mixed with the reactants and held at temperatures lower than 100 degrees C. And Catalytica, a company in Mountain View, Calif., has achieved yields for direct conversion that are as high as 70 percent using a similar scheme. Its liquid catalyst creates a relatively stable chemical intermediate, methyl ester, that is protected from oxidation. The final product (a methanol derivative) is easily generated with one subsequent step.

Methanol (also known as wood alcohol) is valuable because it can be readily converted to gasoline or to an octane-boosting additive. And in the near future methanol (either used directly or transformed first into hydrogen gas) could also serve to power fuel-cell vehicles on a wide scale. Thus, methanol can be regarded as a convenient currency for storing and transporting energy.

Moreover, the reactions used to synthesize methanol can be readily adjusted to churn out diesel alternatives such as dimethyl ether, which produces far fewer troublesome pollutants when it burns. So far dimethyl ether, like propane, has found little use as a transportation fuel because it is a gas at room temperature and pressure. But recently Air Products, a supplier of industrial gases in Allentown, Pa., announced the production of a dimethyl ether derivative that is liquid at ambient conditions. So this substitute for conventional diesel fuel would reduce emissions without major changes to vehicles and fueling stations.

Now You're Cooking with Gas

Scientists and engineers are pursuing many other possible ways to improve the conversion of natural gas into liquids. For instance, process developers are constantly improving the vessels for the Fischer-Tropsch reaction to provide better control of heat and mixing.

The most ambitious efforts now under way attempt to mimic the chemical reactions used by specialized bacteria that consume methane in the presence of oxygen to produce methanol. Low-temperature biological reactions of this kind are quite promising because they can produce specific chemicals using relatively little energy.

Whether or not this bold line of research ultimately succeeds, it is clear that even today natural gas can be converted into liquid fuels at prices that are only about 10 percent higher per barrel than crude oil. Modest improvements in technology, along with the improved economics that come from making specialty chemicals as well from gas, will broaden the exploitation of this abundant commodity in coming years. Such developments will also provide remarkably clean fuels—ones that can be easily blended with dirtier products refined from heavier crude oils to meet increasingly strict environmental standards. So the benefits to society will surely multiply as people come to realize that natural gas can do much more than just run the kitchen stove. SA

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Further Reading

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