A Reservoir of Definitions

In oilfield terms, and according to the Schlumberger Oilfield Glossary, a reservoir is a subsurface body of rock having sufficient porosity and permeability to store and transmit fluids. To draw an analogy, as geologists are wont to do, the Oilfield Glossary itself is a reservoir—a vast, rich reservoir of exploration and production terminology that is readily accessible on line at www.glossary.oilfield.slb.com.

Several unique features set the Oilfield Glossary apart from standard reference works. More detailed than dictionary entries, but more concise than an encyclopedia article, the definitions span key exploration, development and production disciplines from A to Z. You find that “abnormal pressure” refers to reservoir pore-fluid pressure that differs from normal saltwater gradient pressure. Several thousand terms later, you encounter “zip collars,” defined as drill collars that have been machined with a reduced diameter at the box end. In between, the Oilfield Glossary provides a wealth of other definitions.

Other aids are included in the glossary, such as Web links to information about Schlumberger technology and relevant Web sites. Rather than promoting Schlumberger products and services, these links are kept separate to eliminate any potential for injecting corporate bias into the technical definitions. Numerous definitions contain references to significant technical publications to help you find additional information on a topic. High-quality, full-color photographs and illustrations clarify many of the definitions.

At first glance, the glossary is a relatively simple tool. You might surmise correctly that maturing the glossary has not been as arduous as finding and producing oil and gas, but the reservoir analogy is relevant. The Oilfield Glossary definition of reservoir adds that a reservoir is a critical component of a complete petroleum system—the geologic pieces and processes necessary to generate and store hydrocarbons. Like its subsurface counterparts, the Schlumberger Oilfield Glossary has these features. In 1995, Jim Kent, then an editor of the Oilfield Review, recognized the rich source material contained in the Oilfield Review and saw how time and energy could mature it into a glossary that would encompass the whole of oilfield technology. Development of definitions for the Oilfield Glossary began in 1997. An interactive database “reservoir” was created in 1998 and Web explorers began exploiting it, even as the volume continued to fill.

In contrast to the complex and time-consuming processes of generation and migration that bring about hydrocarbons in reservoirs, the effort to build the glossary began more simply, with specialists writing definitions of terms within specific disciplines. Next, Schlumberger experts reviewed these definitions to eliminate the ambiguity found in many other existing glossaries and to make the definitions suitable for nonspecialists. The migration of definitions to the database occurred on a human time scale rather than a geologic one: A little more than six years and more than 4500 definitions later, this virtual reservoir is a reality. Since its launch in 1998, several million “hits” demonstrate that a diverse and enthusiastic worldwide audience has accessed many pages of the glossary.

Just as you must drill into a hydrocarbon reservoir to exploit its contents, you must drill into the Oilfield Glossary to obtain its rewards. Drilling for definitions is much simpler because the glossary pipes its contents to your computer in less time than it would take to retrieve a dictionary and look up a definition. Unlike an oil or gas reservoir, this reservoir of definitions will never be depleted, but instead will be augmented whenever new material becomes available. Thanks to the hard work of an internationally distributed team of writers, reviewers, editors, graphic designers and information technologists, this online database offers unfettered access 24 hours a day.

As you recover definitions from this resource, we will continue to charge this reservoir from the constant flow of new information and exciting technological advances in the oil field.

Gretchen M. Gillis
Senior Editor, Oilfield Review, and Oilfield Glossary Coordinator
Schlumberger Oilfield Services
Sugar Land, Texas, USA

Gretchen Gillis is a senior editor of the Schlumberger Oilfield Review and coordinator of the Oilfield Glossary project. Before joining Schlumberger in 1997, she worked as a geologist for Maxus Exploration Company and Oryx Energy Company in Dallas, Texas, USA. Chairman of the American Association of Petroleum Geologists (AAPG) Publications Committee since 2002, Gretchen holds a BA degree in geology from Bryn Mawr College, Pennsylvania, USA, and an MA degree in geological sciences from The University of Texas at Austin.
Unlocking the Value of Real Options

Real-options analysis captures the effects of uncertainty and change inherent in many projects. Unlike discounted cash flow analysis, it recognizes active project management that takes advantage of project enhancements related to improved technology or market changes. This article describes a way to determine the real-options value of projects.

A Safety Net for Controlling Lost Circulation

In extreme cases, lost circulation during cementing operations jeopardizes wellbores. Commonly accepted solutions, such as reducing slurry density, limiting friction pressure while pumping, or performing stage-cementing operations, do not always work. Recent cementing operations that incorporate advanced, chemically inert fibers demonstrate that mitigating lost-circulation problems need not compromise cementing operations or the quality of the slurry or set cement.

Positive Reactions in Carbonate Reservoir Stimulation

An innovative, nondamaging viscoelastic surfactant acid system overcomes many challenges in carbonate-reservoir stimulation. This solids-free fluid is self-diverting and compatible with common additives. It can be bullheaded or delivered through coiled tubing as a single fluid and remains effective at high temperatures. Case studies demonstrate successful treatments in both matrix- and acid-fracturing stimulation treatments.
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Mexico’s oil and gas industry is achieving great gains in efficiency and production by changing its way of doing business. The new model expands the scope of projects from single services in isolated wells to full field-development projects. This article describes successful integrated-services projects in two areas of Mexico—Burgos basin and Chicontepec paleochannel.

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Most wells with cemented casing rely on a static pressure differential to mitigate perforating damage. However, recent research indicates that the primary damage-removal mechanism is actually a rapid drop in transient pressure, or dynamic underbalance, immediately after gun detonation. This article discusses completion designs based on this innovative concept. Field results demonstrate substantial improvement in both production and injection performance.

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**Oilfield Review**

is published quarterly by Schlumberger to communicate technical advances in finding and producing hydrocarbons to oilfield professionals. **Oilfield Review** is distributed by Schlumberger to its employees and clients. **Oilfield Review** is printed in the USA.

Contributors listed with only geographic location are employees of Schlumberger or its affiliates.

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Oilfield Review subscriptions are available from:

Oilfield Review Services  
Barbour Square, High Street  
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(44) 1829-770959

Fax: (44) 1829-771354  
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Annual subscriptions, including postage, are 160.00 US dollars, subject to exchange rate fluctuations.

Oilfield Review is pleased to welcome Anelise Lara to its editorial advisory panel. Anelise became Reservoir Engineering Manager at Petrobras headquarters in Rio de Janeiro, Brazil, in 2003. She is responsible for implementation of new technologies, best practices assurance and knowledge management in the areas of reservoir management, reservoir simulation, well-test analysis, water management and enhanced-oil-recovery processes. Anelise joined Petrobras in 1986 as a well-test analysis specialist and had several management positions at CENPES, the Petrobras research center. She has a PhD degree in earth sciences from Université Pierre et Marie Curie in Paris, France. She serves on the board of directors of the Society of Petroleum Engineers and chairs the organizing committee of the 2005 Latin American and Caribbean Petroleum Engineering Conference.
Unlocking the Value of Real Options

Management often has flexibility in carrying out projects, capitalizing on new information and new market conditions to improve project economics. Real-options analysis provides a means to determine the value of flexibility in future activities.

In the early 1990s, Houston-based Anadarko Petroleum Corporation outbid competitors for the Tanzanite block in the Gulf of Mexico. It found oil and gas there in 1998 and was producing within three years. The Tanzanite discovery is significant not so much for an abundance of oil and gas, but that in bidding for it Anadarko broke with industry tradition. Rather than using only conventional discounted cash flow (DCF) to help it decide what the block was worth and how much to bid for the lease, the company opted for a new technique called real-options valuation (ROV). ROV gave Anadarko the confidence to outbid others because it suggested that there was more to Tanzanite than met the eye. Anadarko now routinely uses ROV when making investment decisions.

Options embedded in, or attached to, physical or real assets are real options. These are distinct from options relating to financial assets—securities and other financial claims. ROV is a process by which a real or tangible asset with real uncertainties can be valued in a coherent manner when flexibility—or potential for options—is present.

Most oil companies still use DCF to appraise potential investments. This method has served them well. Increasingly, however, companies are asking whether ROV might be used to complement DCF. ROV supporters argue that it gives a truer value than DCF only because the ROV model more closely reflects the variability and uncertainty in the world. ROV often can highlight extra value in projects, value that is possibly hidden or even invisible when DCF is used alone. Some companies that use ROV are reluctant to divulge parameter details of their models because of fears that revealing those details gives away a competitive advantage.

ROV is not on the verge of displacing DCF. In fact, real-options valuation employs DCF as one of its tools. In practice, ROV combines and integrates the best of scenario planning, portfolio management, decision analysis and option pricing.

This article reviews DCF and describes how ROV overcomes some, but not all, of its shortcomings. After explaining the parallels and differences between financial options and real options, it examines two of the many methods of valuing options, the Black-Scholes formula and binomial lattices. ROV is illustrated by a case study of a liquefied natural gas (LNG) transport option. A series of linked, synthetic examples describes several simple forms of binomial lattices.

Discounting Cash Flows
Discounted cash flow analysis is relatively simple. It predicts a stream of cash flows, in and out, over the expected life of a project, then discounts them at a rate—typically the weighted average cost of capital (WACC)—that reflects both the time value of money and the riskiness of those cash flows. The time value of money indicates that money held in the future is worth less than money held now, because money we
have in hand can be invested and earn interest, whereas future money cannot.2

The crucial item in any DCF calculation is net present value (NPV), the present value of cash inflows minus the present value of cash outflows, or investments (right). A positive NPV indicates that the investment creates value. A negative NPV indicates that the project as planned destroys value.

A DCF analysis provides clear, consistent decision criteria for all projects (see “Working Out Net Present Value,” page 6). However, it also has limitations:3

- DCF is static. It assumes that a project plan is frozen and unalterable and that management is passive and follows the original plan irrespective of changing circumstances. However, management tends to modify plans as circumstances change and uncertainties are resolved. Management interventions tend to add value to that calculated by DCF analysis.

<table>
<thead>
<tr>
<th>Time</th>
<th>n</th>
<th>Cash flow</th>
<th>Discount factor</th>
<th>Present value of cash flow</th>
</tr>
</thead>
<tbody>
<tr>
<td>Present</td>
<td>0</td>
<td>–5000</td>
<td>1.0000</td>
<td>–5000</td>
</tr>
<tr>
<td>One year</td>
<td>1</td>
<td>+4500</td>
<td>0.9091</td>
<td>+4091</td>
</tr>
<tr>
<td>Two years</td>
<td>2</td>
<td>+3000</td>
<td>0.8264</td>
<td>+2479</td>
</tr>
<tr>
<td>Undiscounted cash flow</td>
<td></td>
<td>+2500</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net present value</td>
<td></td>
<td></td>
<td></td>
<td>+1570</td>
</tr>
</tbody>
</table>

Discount factor = 1/(1+Discount rate)².

Net present value (NPV) calculation. A discount factor—based on a 10% discount rate—applied to future cash flows indicates the greater value of cash in hand compared with future cash. In this case, the difference between the NPV and undiscounted cash flow is almost a thousand, regardless of the currency used.

For help in preparation of this article, thanks to Steve Brochu, BP, Houston, Texas.
ECLIPSE is a mark of Schlumberger.
A series of examples using a fictitious field and simple synthetic models is presented in this article to illustrate some key valuation concepts. This section sets up the case and determines the net present value (NPV).

The fictitious Charon field in the Sargasso Sea is an anticline, divided into two blocks by a fault. The reservoir interval consists of shallow marine sediments up to 200-ft [61-m] thick, capped by a sealing shale. The operator, Oberon Oil, has devised a development plan to obtain first oil in three years. The plan calls for drilling six wells tied back to a dedicated production platform that can handle 50 million scf/D [1.4 million m³/d] of produced gas from the live oil. Expected development costs will be $177.5 million spread over three years (above right).

Company experts assign values to key reservoir properties, such as porosity and permeability, based on probability distributions (below right). The oil/water contact is not known precisely, which impacts the estimate of oil in place. Several geological realizations are constructed and used for simulation models. Hydrocarbon resources are computed for low, median and high estimates—considered representative of the oil in place occurring at the 5%, 50% and 95% values of the probability distribution (next page, top).

Decision-making is based on these three representative scenarios. ECLIPSE oil production predictions are made for each realization (next page, bottom). Oil production decline with time for this fictitious case can reasonably be modeled as a hyperbolic function, making the results easier to use for prediction. A standard discounted cash flow (DCF) model computes project NPV. The oil price is assumed to be $25/bbl at the start of the project and to increase 1% per year, with a tax rate of 33% for net positive revenue and no tax paid for negative net revenue. In this scenario, the median-case NPV for Charon field is $236.3 million.

---

### A Synthetic-Reservoir Example

**Working Out Net Present Value**

<table>
<thead>
<tr>
<th>Period</th>
<th>Time, years</th>
<th>Total development cost, million $</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0.6</td>
<td>50.0</td>
</tr>
<tr>
<td>2</td>
<td>1.2</td>
<td>75.0</td>
</tr>
<tr>
<td>3</td>
<td>1.8</td>
<td>107.5</td>
</tr>
<tr>
<td>4</td>
<td>2.4</td>
<td>150.0</td>
</tr>
<tr>
<td>5</td>
<td>3.0</td>
<td>177.5</td>
</tr>
</tbody>
</table>

\(^\text{^\text{Investment schedule for the synthetic Charon field. The three-year construction schedule is broken into five equal-length time periods. These five time steps are used in later examples.}}\)
• DCF assumes future cash flows are predictable and deterministic. In practice, it is often difficult to estimate cash flows, and DCF can often overvalue or undervalue certain types of projects.
• Most DCF analyses use a WACC discount factor. But instead of a WACC, companies often use a company-wide hurdle rate that may be unrepresentative of the actual risks inherent in a specific project.

The first two limitations relate to circumstances changing after a project begins. A new DCF analysis can be performed to reflect the new circumstances, but it may be too late to influence basic project decisions, since the project is already under way. The third limitation above results from companies adopting a company-wide hurdle rate for consistency rather than carefully recalculating a WACC for each project.

A sensitivity analysis can enhance information provided by DCF analysis. The consequences of possible changes to key variables—for example, interest rates, cash flows and timing—are evaluated to determine the results of a number of “what if” scenarios. However, the choice of which variables to alter and how much to alter them is subjective. Sensitivity analysis makes assumptions about future contingencies, rather than incorporating those contingencies as they occur.

**Embracing Uncertainty and Adding Value**

Unlike DCF, ROV assumes that the world is characterized by change, uncertainty and competitive interactions among companies. It also assumes that management has the flexibility to adapt and revise future decisions in response to changing circumstances. Uncertainty becomes another problem component to be managed. The future is regarded as one that is full of alternatives and options, both of which may add value.

The word option implies added value. When we speak of keeping our options open, having more than one option, or not foreclosing on our options, the underlying implication is that just holding the option usually has value, whether or not we exercise it. The same is true of real options.

---

Real-options analysis draws heavily on the theory of financial options. Financial options are derivatives; they derive their value from other underlying assets, such as shares of a company stock. A financial option is the right, but not the obligation, to buy or sell a share on (or sometimes before) a particular date at a particular price. The price at which a share can be bought or sold, if the option holder chooses to exercise the right, is known as the exercise, or strike, price. The two main kinds of options are a call option—to buy the share at the exercise price—and a put option—to sell the share at the exercise price (below right).

If the share price exceeds the exercise price, a call option is said to be in the money. If it exceeds it by a large amount, it is termed deep in the money. If the share price fails to reach the exercise price, the option is said to be out of the money. An investor would not exercise an out-of-the-money option since doing so would cost more than the market price for the share. This is where the caveat that the option holder has the right but not the obligation to buy the share at the exercise price is important. The investor allows the option to lapse if exercising it would not be beneficial.

Financial options can be further subdivided into many types. Two of the most common are European and American options. A European option can be exercised only on the expiration date specified in the option contract. An American option may be exercised at any time up to and including the expiration date.

Options have two important features. First, they give an option holder the possibility of a large upside gain while protecting from downside risk. Second, they are more valuable when uncertainty and risks are higher.

Financial and Real Options

Real-options valuation applies the thinking behind financial options to evaluate physical, or real, assets. By analogy with a financial option, a real option is the right, but not the obligation, to take an action affecting a real physical asset at a predetermined cost for a predetermined period of time—the life of the option. While real and financial options have many similarities, the analogy is not exact.

ROV allows managers to evaluate real options to add value to their firms, by giving managers a tool to recognize and act upon opportunities to amplify gain or to mitigate loss. While many managers are not accustomed to evaluating real options, they are familiar with the concept of project intangibles. ROV gives managers a tool to move some of those intangibles into a realm where they can be dealt with in a tangible and coherent fashion.

Petroleum developments and mining operations were among the first examples used by ROV pioneers to demonstrate the parallels between real and financial options (see "How Oil Companies Use Real-Options Valuation," next page). The exploration, development and production stages of an oilfield project can be seen as a series of linked options.

At the exploration stage, the company has the option to spend money on exploration and, in return, receive prospective oil and gas resources. This is like a stock option, which gives the holder the right, but not the obligation, to pay the exercise price and receive the stock.

Money spent on seismic surveys and exploration drilling is analogous to the exercise price; the resources are analogous to the stock. An expiration option expires the day the lease terminates.

Once the company has exercised its option to explore, it is in a position to decide whether to exercise a second option, the option to develop the field. This gives the company the right, but not the obligation, to develop the resources at any time up to the relinquishment date of the lease for an amount of money given by the cost of development. If the company exercises the development option, it obtains hydrocarbon resources that are ready to be produced.

The final option is the option to produce. The company now has the right, but not the obligation, to spend money on extracting the oil and gas from the ground and sending it to market. It will do so only if a number of uncertainties are resolved, most notably that the oil price is likely to reach a level that makes production profitable.

This series of options is called a sequential or compound option because each option depends on the earlier exercise of another one.

11. This simple series of linked options ignores any contractual obligations to drill or develop that may accompany a lease.
Companies as diverse as BP, ChevronTexaco, Statoil, Anadarko and El Paso have shown an interest in real-options valuation (ROV). They usually regard it as complementary to techniques like discounted cash flow (DCF) and decision-tree analysis rather than as a stand-alone method of valuation.

In the mid-1990s, the executive management of Texaco (now ChevronTexaco) was split over what to do with a significant leasehold in a developing country. The lease included several existing oil discoveries and many other substantial undeveloped discoveries. It was at an early stage of exploitation. Part of the management team wanted to sell the asset, using the proceeds for more capital-efficient projects, while others on the team felt it could lead to other lucrative follow-up opportunities and the development of valuable relationships in the region.

The company management used ROV to decide which action would be better for the company. Results from the ROV substantiated parts of both viewpoints. Even after key options values had been included, the ROV indicated the asset was far less valuable than suggested by DCF. However, there was sufficient value to convince Texaco to retain the asset until some of the uncertainties were resolved, but to be prepared to sell if the price was right. Moreover, ROV enabled a major restructuring of the base plan. Texaco believed that ROV helped its executives reach a better strategic understanding of its holding.

A recent analysis of a transaction that took place in the early 1990s involving Amoco (now BP) and independent oil and gas company Apache Corporation showed how real-options analysis can disclose value that is not apparent when using DCF analysis alone. In 1991, after a strategic review, Amoco decided to dispose of some marginal oil and gas properties in the United States. It formed a new, separate company, MW Petroleum Corporation, to hold its interests in 9500 wells spread across more than 300 fields. Apache indicated interest in obtaining the properties, but Iraq’s invasion of Kuwait in the spring of that year had pushed oil prices to historic heights while increasing price uncertainty.

Amoco and Apache agreed on most of the provisions for the MW Petroleum transaction, but disagreed on oil-price projections. The gap was about 10 percent. The two companies found common ground by agreeing to share the risk of future oil-price movements. Amoco gave Apache a guarantee that if oil prices fell below an agreed price-support level in the first two years after the sale, Amoco would make compensating payments to Apache. For its part, Apache would pay Amoco if oil or gas prices exceeded a designated price-sharing level. The MW Petroleum portfolio included 121 million barrels of oil equivalent (BOE) [19.2 million m³] of proven oil and gas reserves, plus 143 million BOE [22.7 million m³] of probable and possible reserves.

This transaction was reexamined by independent analysts in 2002. They compared a deterministic DCF valuation of MW Petroleum assets with a real-options valuation. The DCF value of $350.7 million was $80 million less than the ROV result of $440.4 million, indicating additional value in the assets not included in the DCF analysis. In comparison, the purchase price agreed on by Amoco and Apache was $515 million plus 2 million shares of stock. Both methods gave values short of the actual price, but the ROV valuation was much closer than the DCF one.

In a third example, Anadarko, a Houston-based independent, is an enthusiast for ROV. A recent ROV analysis by the company examined the impact of deferring a project until new technologies became available. Anadarko had a deepwater development opportunity that the company approached in two stages. At the end of the first, exploration stage, uncertainties about the amount of oil and gas in place had been resolved. In the development phase, the operator could decide to develop the field using conventional means or wait and develop the field using new subsea completion technology that at that time was still at the research and development stage.

Conventional analysis neglecting the value of flexibility showed that development of the field using current technology would yield a value of $4 million. Including the flexibility associated with being able to wait until new technology was available—using a deferral option and waiting until the new technology was ready—increased the value to $50 million.

5. In its 2001 annual report, Anadarko says that it “seeks to maximize enterprise value by maintaining a strong balance sheet and applying option theory to assist investment decision-making.”
The extraction option is contingent on exercising the development option, which is contingent on exercising the exploration option. At each stage, a company obtains information to determine whether the project should be taken to the next stage.

Comparing Financial- and Real-Option Parameters
The variables used to value a financial option can be compared with their analogs in real options. An option to develop oil reserves, for example, is similar to a financial call option (below).

The NPV of the developed hydrocarbon reserves—what they would be worth at today’s prices—is similar to the price of the underlying stock, S, in a financial option. The NPV of the expenditure needed to develop the reserves is like a financial option’s exercise price, X. The time left on an exploration and production (E&P) lease is equivalent to the time to expiration of a financial option, T. The risk-free rate of return, r_risk-free — the rate of return on a guaranteed asset, such as a government bond—is identical for both financial and real options. The volatility of cash flows from an E&P project, including hydrocarbon price uncertainty, is analogous to the volatility of stock prices, σ. Finally, profits foregone because production has been delayed are like the lost dividends in the financial option, δ. As long as management holds an unexercised option to invest in a project, it foregoes the money that would have flowed from it had the project been producing revenue.

The analogies between real and financial options are not exact. Trying to force real options into a conventional financial-options framework may result in misleading outcomes. One key difference in the two options types is that the exercise price of a financial option is normally fixed. For a real option, this price is associated with development costs, and may be volatile, fluctuating with market conditions, service company prices and rig availability. In the E&P industry, volatility is usually a consolidated value comprising the uncertainty involved in many things, including oil prices and production rates. Determining volatility in real options can be difficult.

Another key difference between financial and real options lies in uncertainties surrounding an option’s underlying asset. With a financial option the uncertainty is external. The option is an arrangement between two outsiders—the option writer and the option purchaser—neither of whom can influence the rate of return on the company’s shares. In contrast, a company that owns a real option can affect the underlying asset—for example, by developing new technologies for the asset—and the actions of competitors—for example, by developing an adjacent property first, as described later in this article—which in turn can affect the nature of the uncertainty that the company faces.

Black-Scholes Option Valuation
Real options often are valued using financial-option pricing techniques. However, real-option valuation can be extremely complex, so any financial-option technique can provide only a rough valuation. Two approaches are discussed in this article: the Black-Scholes formula (a closed-form solution) and binomial lattices.

Early attempts to use DCF to value options foundered on the exercise of options. As long as management holds an unexercised option to invest in a project, it foregoes the money that would have flowed from it had the project been producing revenue.

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Financial and Real Options Compared

<table>
<thead>
<tr>
<th>Financial call option</th>
<th>Variable</th>
<th>Real option to develop hydrocarbon reserves</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stock price</td>
<td>S</td>
<td>Net present value of developed hydrocarbon reserves</td>
</tr>
<tr>
<td>Exercise price</td>
<td>X</td>
<td>Present value of expenditure to develop reserves</td>
</tr>
<tr>
<td>Time to expiration</td>
<td>T</td>
<td>For example, time remaining on lease, time to first oil or gas</td>
</tr>
<tr>
<td>Risk-free interest rate</td>
<td>r_risk-free</td>
<td>Risk-free interest rate</td>
</tr>
<tr>
<td>Volatility of stock price</td>
<td>σ</td>
<td>Volatility of cash flows from hydrocarbon reserves</td>
</tr>
<tr>
<td>Dividends foregone</td>
<td>δ</td>
<td>Revenue or profits foregone</td>
</tr>
</tbody>
</table>

Comparison of financial and real options. The variables of a financial call option can be related to similar variables for a real option to develop oil reserves.
Binomial-Lattice Option Valuation

Binomial lattices allow analysts to value both European and American-type options. This section describes how to construct a lattice for a simple European call option.

A lattice is a way to show how an asset’s value changes over time, given that the asset has a particular volatility. A binomial lattice has only two possible movements in each time step—up or down. It looks like a fan laid on its side. ROV uses two lattices, the lattice of the underlying asset and the valuation lattice.

Lattice of the underlying asset—The underlying asset pricing lattice, also known simply as the lattice of the underlying, is read from left to right and indicates how possible future asset values could evolve. The value of the left-most node is the NPV of the underlying asset, as calculated from the DCF model. In each time interval, the value of the asset increases by a multiplicative factor \( u \) (greater than 1), or decreases by a multiplicative factor \( d \) (between 0 and 1), represented as a step up or a step down the lattice (above). The factors \( u \) and \( d \), which determine the upward and downward movements at each node, are functions of the volatility of the underlying asset and the length of time between the periods under consideration. The right-hand nodes of the lattice represent the distribution of possible future asset values.

The most difficult issue in constructing the lattice of the underlying asset is estimating volatility. This value must reflect the uncertainties, both economic and technical, in the value of the underlying asset, and the way in which these uncertainties evolve over time. Methods for estimating volatility are nontrivial, and a discussion of these methods is beyond the scope of this article.

\[ u = \exp(\sigma \sqrt{\Delta T}) \]
\[ d = \frac{1}{u} \]

\[ C = S * e^{-rT} * \{N(d_1) - X * e^{-rT} * N(d_2)\} \]
where \( d_1 = (\ln(S/X) + \delta + \sigma^2/2) \sqrt{T}/(\sigma \sqrt{T}) \)
\[ d_2 = d_1 - \sigma \sqrt{T} \]
and where \( N(d) \) = cumulative normal distribution function.

13. The case of company executives who are given share options as an incentive to improve company value is an exception.
16. The Black-Scholes formula estimates the value of a call option, \( C \):
\[ C = S * e^{-rT} * \{N(d_1) - X * e^{-rT} * N(d_2)\} \]
where \( d_1 = (\ln(S/X) + \delta + \sigma^2/2) \sqrt{T}/(\sigma \sqrt{T}) \)
\[ d_2 = d_1 - \sigma \sqrt{T} \]
and where \( N(d) \) = cumulative normal distribution function, \( \ln \) is the natural logarithm and other terms are defined in the text.
18. In a European option, uncertainty is assumed to be fully resolved at expiration. However, valuation of American-type options can be more complex and caution is required. An American option can be exercised at any time prior to expiration, but that does not mean that all uncertainty has been resolved at the time the decision is made. New information about project uncertainties is likely to be streaming in all the time, so the decision is based on incomplete information. Unless all pertinent uncertainty has been resolved, it might be prudent to wait until the last moment to decide on the option.
19. Some ROV specialists argue that it is better to keep technical and market uncertainties separate, especially when managerial decision-making is tied to the resolution of technical uncertainty.
In summary, the lattice of the underlying illustrates the possible paths that an underlying asset value—like a stock’s price, and similarly designated as $S$—will take in time, given that it has a certain volatility.

Valuation lattice—The valuation lattice has exactly the same number of nodes and branches as the lattice of the underlying asset (above). Analysts work backward from the values in the terminal nodes at the right side to the left side of the lattice. The value placed in each terminal node is the maximum of zero and the difference between stock and exercise price, unless that difference is negative, in which case the node contains zero. The value in the node labelled C comes from the two adjacent Column 5 nodes, A and B, and uses the risk-neutral probability, $p$, as shown in the formula (bottom left). Remaining nodes and columns are constructed similarly, from right to left. The single node on the left contains the value of the option.

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Oberon, operator of the fictitious Charon field, has reservations about the eventual economic viability of the field. To protect itself from a negative result, the company has entered into negotiations with Thalassa Energy, which is eager to add Sargasso Sea assets to its portfolio. Thalassa offers Oberon, for an up-front premium of $45 million, a guarantee to take over the Charon field and reimburse Oberon all development costs incurred up to the exercise date, if Oberon chooses to exercise the option. The salvage value at any time is assumed to be the amount invested at that point. Oberon performs a real-options valuation (ROV) to determine whether the flexibility to recoup development expenses is worth the price asked by Thalassa.

The ROV involves four steps: identifying the underlying asset, determining its volatility, constructing the lattices and interpreting option value.

Oberon identifies the underlying asset as Charon’s project NPV. This NPV exhibits a log-normal probability distribution, so the volatility of the underlying asset is based on the logarithm of the future cash flows. Monte Carlo simulation on the DCF model indicates that the implied annual volatility is 66.41%, including both private and public uncertainties.

The engineers construct a lattice of the underlying asset with 0.6-year time steps using a five-step binomial lattice (next page). The asset value, $S$, or Oberon’s NPV for the project without any flexibility from salvage potential, is $236.3 million (see “Working Out Net Present Value,” page 6). The risk-free rate for the three-year period under consideration is 5% per year. The valuation and decision lattices are identical in form to that of the lattice of the underlying asset.

\[
C = [pA+(1-p)B] \cdot \exp(-rf \Delta T)
\]

\[
p = \frac{\exp(rf \Delta T)-d}{u-d}
\]

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These lattices allow Oberon to interpret option value. The added flexibility provided by the Thalassa contract increases Charon’s NPV to $285.5 million. This is the value of a rational, frictionless, free market, given the same information, assign to the project. It is $49.3 million more than the NPV without flexibility—simply because of the presence of the salvage option.

An offer to provide this flexibility for $45 million should be accepted by Oberon management since it appears that Thalassa underpriced the option by $4.3 million, the difference between the option value and the premium price. This apparent underpricing indicates that Thalassa has a different perception of risk and uncertainty than Oberon.

Real option for salvage. The lattice of the underlying asset begins with the project net present value in the left node and projects potential future values to the right (top right). The up and down multiplying parameters, \( u \) and \( d \), are calculated from the inputs of volatility, \( \sigma \), and the time step size, \( \Delta T \) (top left). The salvage value is based on investment to date (middle left). The valuation and decision lattice has the same form as the lattice of the underlying, but it is constructed from right to left (middle right). The last column of the valuation lattice is constructed by comparing the equivalent node in the lattice of the underlying with the salvage value at the final time step (bottom right). If the salvage value is greater, that amount is entered and the salvage decision is noted. Otherwise, the value from the node in the lattice of the underlying is used for the valuation-lattice node, and the decision is to retain ownership. The value in the node in the next column to the left comes from back-regression from two adjacent nodes, as indicated by the arrows. That value involves the risk-neutral probability, \( p \), the risk-free interest rate, \( r_f \), and the time step size, \( \Delta T \) (bottom left).

<table>
<thead>
<tr>
<th>Period</th>
<th>Years</th>
<th>Value, million $</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0.6</td>
<td>50.0</td>
</tr>
<tr>
<td>2</td>
<td>1.2</td>
<td>75.0</td>
</tr>
<tr>
<td>3</td>
<td>1.8</td>
<td>107.5</td>
</tr>
<tr>
<td>4</td>
<td>2.4</td>
<td>150.0</td>
</tr>
<tr>
<td>5</td>
<td>3.0</td>
<td>177.5</td>
</tr>
</tbody>
</table>

\[
\sigma = 66.41\% \\
\Delta T = 0.6 \\
u = \exp(\sigma \sqrt{\Delta T}) = \exp(0.6641 \cdot \sqrt{0.6}) = 1.67265 \\
d = \frac{1}{u} = \frac{1}{1.67265} = 0.59785 \\
p = \frac{\exp(r_f \cdot \Delta T - d)}{u - d} = \exp(0.05 \cdot 0.6) \cdot 0.59785 = 0.40250
\]

\[
\text{Valuation and decision lattice} \\
\text{Lattice of the underlying asset}
\]
Types of Real Options

Analysts generally classify real options by the type of flexibility they give the holder. The options may occur naturally, or may be built into a project. Management can defer investment, expand or contract a project, abandon for salvage or switch to another plan. Compound options also can be created.

Option to defer investment—An opportunity to invest at some point in the future may be more valuable than an opportunity to invest immediately. A deferral option gives an investor the chance to wait until conditions become more favorable, or to abandon a project if conditions deteriorate. An E&P lease, for example, may enable an oil company to wait until present uncertainties about oil and gas prices and about development technology have been resolved. The company would invest in exploration and development only if oil price increased enough to ensure that developed acreage on the lease would be profitable. If prices declined, the company would allow the lease to lapse or would sell the remainder of the lease to another company. The exercise price of the option is the money required to develop the acreage.

Option to expand or contract a project—Once a project has been developed, management may have the option to accelerate the production rate or change the scale of production. In an oil or gas field, there might be the option to increase production by investing in an enhanced oil recovery plan or by drilling satellite wells. The original investment opportunity is defined as the initial project plus a call option on a future opportunity.

Option to abandon for salvage—if oil and gas prices go into what seems likely to be a prolonged decline, management may decide to abandon the project and sell any accumulated capital equipment in the open market. Alternatively, it may sell the project, or its share in the project, to another company whose strategic plans make the project more attractive (see “Salvage an Investment,” page 12). Selling for salvage value would be similar to exercising an American put option. If the value of the project falls below its liquidation value, the company can exercise its put option.

Option to switch to another plan—A switching option can provide a hedge against the likelihood that another technology or project will be more economic sometime in the future (see “Switch Option,” page 16).

Sequential or compound options—Real options may lead to additional investment opportunities when exercised. The process of exploration, development and production described earlier in this article was a sequential option.

This list of options is not exhaustive. Many other types of options are available. El Paso Corporation, the largest pipeline company in North America and a leading provider of natural gas services, used a location spread option—relying on a difference in a price between different locations—to evaluate a new line of business. Various other spread options are possible, for example based on different prices at different times or at different stages of commodity processing.

Real Options for LNG Transport

El Paso owns a liquefied natural gas (LNG) terminal at Elba Island, Georgia, USA, one of only four land-based terminals in the USA. The company investigated purchasing transport vessels and expanding into the LNG transport business. Each tanker, outfitted specifically for use in LNG transport with a regasification capability for downloading at offshore buoys called energy-bridge buoys, costs several hundred million US dollars.

The essence of the problem facing the evaluation team was how to value shipping and diversion flexibility. The company had a variety of potential LNG sources and destinations, and the evaluation was intended to determine how many tanker ships El Paso should purchase.

El Paso felt DCF was deficient for this analysis. The LNG market and its related shipping were relatively new ventures for El Paso, and the company had no history for forecasting the revenues and costs required by DCF. Even if those forecasts had been available, the DCF technique does not have the flexibility necessary to reflect the additional value of a price difference between delivery locations that occurs only for a brief time period. The team tried to model the simple case of a fixed source and destination using DCF, but the model could not correctly value inbuilt options allowing El Paso not to sell if the LNG delivery price did not cover variable expenses.

The base case for this ROV involves transporting LNG from a terminal in Trinidad, West Indies, to the company’s Elba Island facility. The LNG producer in Trinidad would pay for infrastructure costs to enable this base-case trade and would in turn receive the netback gas price, which is the gas price at Elba Island less the cost of shipping and regasification and less the margin paid to El Paso. For example, for the analysis presented here this margin was assumed to be $0.20/MMBtu [$0.19/million J]. The NPV of this business over 20 years was $176.7 million.

The first option evaluated included diversion flexibility—adding a second destination terminal offshore New York, New York, USA. El Paso evaluated both intrinsic and extrinsic values for this option. The intrinsic value of this spread option represents the difference in price—the basis spread—between the Georgia and New York markets (next page). The extrinsic value includes the effects of time and reflects the probability that the basis spread will change over the 20-year period of the analysis.

In this spread option, El Paso would buy the LNG on the basis of the Elba Island price and sell it at the New York price, when that choice adds value. Otherwise, El Paso would sell at Elba and receive no incremental value. With an average basis spread of $0.62/MMBtu [$0.59/million J], the total intrinsic value of this spread option is $558.7 million. In this model, El Paso would assume the costs for converting the terminals and purchasing an additional ship to effect this option. The net value of the option after those expenses is $68.5 million. Including the variability over time gives an additional extrinsic value of $101.7 million.

The company then added in the value of having multiple choices of source and destination, termed a rainbow option. The value of a rainbow option increases with increased price volatility at the individual locations, and it also increases when the cross-correlations between prices are low. With two additional destination options, offshore New York and Cove Point, Maryland, USA, there is an additional value of $14.8 million, even though the price correlations between these pairs of locations are high. The rainbow option value increases when there is more flexibility in source and destination locations. In certain scenarios with additional sources in the

22. A project with many embedded options can be difficult to evaluate using the simple forms of the Black-Scholes and lattice models presented in this article.
Middle East and Africa and additional destinations in Europe and North America, El Paso found the rainbow option added more than $100 million to the value of each ship.

The evaluation team provided a caveat to the company. Spread options tend to overestimate available flexibility, because contractual obligations would have to be maintained. In addition, the effects of price shifts caused by any reduction in supply were not included in the analysis.

Although real-options analysis indicated a positive value to a business model based on LNG imports to the USA and to diversion flexibility as a value-maximizing technique for shipping, El Paso made a strategic business decision not to enter this market.

Alternatives and Options
In the English language the word option may be used in two technically different senses. In ROV the term option (or real option) is used to denote a decision that may be deferred to some time in the future, and that is accompanied by some uncertainty that can be resolved. On the other hand, in common parlance, an option can simply be an operational alternative, which is a decision that is to be made today and for which there is no future recourse.

For example, a company may decide to drill a well in a certain location. If the well is dry, then the company has lost the cost of drilling. The well location was an operational alternative, a decision that had to be made there and then. However, if there were another party guaranteeing some minimum return on the well, the company drilling the well would have a real option, because it could decide in the future whether to call on that guarantee, thereby minimizing any downside risk and maximizing any upside potential.

A project containing an option is always worth more than one with just a corresponding alternative. This is because deferral allows an owner to eliminate unfavorable outcomes while retaining favorable ones. This is often referred to as optionality. A project having only a set of alternatives has no such cushion. The decision, which must be made today, is effectively irreversible. The estimated NPV must average over all outcomes, both favorable and unfavorable.

Both options and alternatives can be computed using standard lattice-type methodologies (see “True Option and an Alternative Valued under Uncertainty,” page 18). Alternatives may often be evaluated using simpler methods that automatically average out the possibilities. For example, a forward contract, which obligates the holder of the contract to buy or sell an asset for a predetermined price at a predetermined time in the future, may be valued simply, without the volatility assumption that is required in the Black-Scholes or lattice valuation of a European option.

Within the class of options there are many distinctions. One is the distinction between financial and real options that has been discussed. Another is that between options that are purely internal—residing solely within the company itself—and ones in which an outside party provides flexibility for some agreed up-front payment. Many real options possess just an internal character, while financial derivatives normally exist in the presence of a contracted external party. Fortunately, all these option types can be computed using the same techniques, most notably standard lattice-type methodologies.

Real-World Complications
A real-options methodology attempts to model behaviors of real properties. However, the many possibilities created by human ingenuity limit any such modeling. Actual situations typically have many embedded options, making any analysis complicated. The few examples discussed in this section illustrate a few types of complications that may have to be dealt with in using real options.

The holder of a financial option is guaranteed that the option may be held until the expiration date and, apart from general market movement, its value cannot be undermined by the actions of other individuals. In most real options, there is no such guarantee.

Two oil companies might hold identical leases on adjoining blocks. In effect, they would both have identical options to spend money on exploration and receive undeveloped resources in return.

(continued on page 18)
At this time, the design criteria for the fictitious Charon field project have been established and a three-year development phase is about to begin. A critical technical issue is the gas-throughput capacity of a surface separator. Economic analysis suggests a maximum separator capacity of 50 million scf/D [1.4 million m³/d]. A facilities contractor, Proteus Fabrication Inc., has been commissioned to design, fabricate and install it.

Although a 50 million scf/D throughput design—termed Case 50—is deemed adequate, an upside production potential of an extra 10 million scf/D [286,000 m³/d] is possible. A 60 million scf/D [1.7 million m³/d] separator—Case 60—would be more expensive, and Charon might not have enough production potential to utilize it fully. The company would like to delay the design-capacity decision for as long as possible.

Proteus can implement this design change within the first year of construction, but cannot make changes after the first year. The implementation cost to switch from a smaller to a larger design, set at $17.72 million, is equivalent to an option exercise price, $X$.

In addition to this exercise price, Proteus insists on an additional up-front nonrefundable payment. This up-front payment accommodates changing the initial design to allow for later expansion and covers a possible overrun on the agreed exercise price. Oberon initiates a simple switching-option study to determine what the initial payment to Proteus should be.

Case 50 and Case 60 are independent cases with different cash-flow NPVs and volatilities. ECLIPSE modeling establishes the static NPV, excluding switching costs, and associated volatility of the two cases (top right). Values for Case 60 are obtained in manner similar to Case 50, the base case used in the previous examples.

A switching option can be analyzed by constructing two lattices, one for each of the two underlying assets (next page). The simplest case assumes these two lattices are completely correlated—each step up or down in one underlying lattice corresponds with the same step in the other. In this way, nodes in the two cases can be directly compared to construct a valuation lattice for the upgrade.

The valuation lattice is obtained by subtracting the upgrade cost, $17.72 million, from the last column of the Case 60 lattice, comparing this to the last column of the Case 50 lattice, and selecting the larger value at each node. This reflects Oberon’s right to choose the better of the two cases in any eventuality. The option value is then computed by backward induction using the Case 50 risk-neutral probabilities, $p$. 
Changing the cost to upgrade affects the value of the upgrade option (previous page, bottom). In this case, the five-step lattice is too coarse, resulting in an unrealistic kink in the result. A finer 200-step lattice resolves the kink and indicates that it would be appropriate for Oberon to pay Proteus a $1.653 million premium for the option to switch in the first year at the stated upgrade price. In an actual case, final decisions would be based on finer lattices than the five-step lattices used in these illustrations.

With this arrangement Oberon gains the ability to demand a design change resulting in accelerated cash and throughput from reservoir production, if conditions warrant. Proteus gets an up-front premium of $1.653 million and a locked-in payment of $17.72 million if Oberon chooses to upgrade the facility. Proteus has a cash incentive to explore more cost-effective and efficient design solutions for the upgrade.

The lattices for synthetic Charon surface separator cases. Case 50 and Case 60 have different lattices of the underlying asset, but the lattice structure is the same, allowing a node-by-node comparison between them (top). Nodes in Case 60 are greyed out, except for the final column, to indicate that no decision is made until the end of one year. The last column of the valuation lattice is constructed by comparing the value of Case 50 to equivalent node value of Case 60 minus the implementation cost of $17.72 million (bottom). This also provides the decision to keep Case 50 or switch to Case 60. The other nodes of the valuation lattice are constructed by back-regression, using the risk-neutral probabilities from Case 50, the base case. The value of the project with the switch option is $237.57 million.
Actions of one company can affect the business results of the other. Most governments now insist on unitization, an arrangement that requires parties on both sides to jointly develop reserves located on more than one lease or auctioned tract. Each party pays a share of the costs and receives a proportionate amount of the revenues. In a sense, when governments do this, they are ensuring the purity of the real options involved.

It is possible to conceive of circumstances—such as constructing a pipeline to an area where only one is needed—in which if Company A took up the option to invest, it would preempt Company B from doing so, rendering B’s option worthless, or certainly worth less. The real-options approach attaches a positive value to delay, but in instances such as this one, delay can undermine value.  

Finally, the parameters used in real-options calculations can be difficult to determine. There is no simple road map to computing volatility and there is still debate over the correct approach to finding this value. Obtaining an estimate often entails performing a Monte Carlo simulation on the existing DCF model and examining the standard deviation of the natural logarithm of the cash-flow returns. The cost of deferment requires knowledge of the profits foregone during the period prior to exercising an option, but the value of the missed cash flows may be poorly known.

Financial-option pricing relies on an assumption that the underlying asset can be traded, meaning there is a large liquid market for the asset. This is often not true for real options. Factors affecting the prices of financial options are also easier to determine—that is, more transparent—than those for real options.

The simplified discussion in this article is intended only to introduce the concept of real options. It uses simple examples that correlate with financial options. Use for an actual case is typically more complicated, with an expanding array of possible options available, as demonstrated in the El Paso LNG case. Ultimately, real options are not financial options. The techniques of financial options provide a basis for.

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evaluating real options, but an expert in ROV should be consulted to assure the techniques are properly applied.

These complications should not dissuade a company from using real options. Valuation experts can determine when ROV should be used, and when other methods, such as decision trees incorporating Monte Carlo simulation, are more appropriate. Working with managers and experts in other disciplines, valuation experts can help place a value on the options inherent in many projects.

The Real-Options Mindset
Actually recognizing options that are embedded in a project takes practice. Managers often learn to discern options simply by brainstorming with one another about the project.

In many ways, having a real-options mindset is as important as using the mathematics. Real-options thinking emphasizes and values management flexibility. It recognizes that in a world characterized by change, uncertainty and competitive interactions, management can be active. It can alter and modify plans as new information becomes available or as new possibilities arise. It can be reactive to changing circumstances or proactive—intervening to take advantage of possibilities that may improve the value of the project. If management understands that flexibility is valuable, it will look for that flexibility in its projects and capitalize on it to increase shareholder value. —MB, MAA

Comparison of an option and an alternative. The lattice method can be used to value an alternative. Both use the same lattice of the underlying (top). For an option, the right-hand column is the maximum value of zero and the difference between the underlying value and the $750,000 implementation cost (middle). The values for an alternative can be negative, because the function is simply the difference between the value and the implementation cost (bottom). This leads to an $8,198 difference in value between the option, valued at $574,776, and the alternative, valued at $566,578.
A Safety Net for Controlling Lost Circulation

Extreme circulation losses during cementing operations jeopardize wellbores. To limit the potential impact of lost circulation, engineers typically reduce slurry density, limit friction pressure while pumping, or perform stage cementing operations, but these approaches do not always work. Cementing operations using advanced, chemically inert fibers mitigate lost-circulation problems without compromising operational efficiency or the quality of the slurry or set cement.

How do you catch a thief? When the “thief” is a fractured formation, a cavern or a highly permeable formation that is stealing the fluid circulating in a wellbore, its capture requires advanced technology. This type of theft, known as lost circulation, is a common problem in oil fields. Lost circulation costs the industry hundreds of millions of dollars each year in lost or delayed production and in spending to deal with drilling problems, repair faulty primary cement jobs and replace wells irreparably damaged by lost circulation.

Lost circulation is the reduced or total absence of fluid flow up the formation-casing or casing-tubing annulus when fluid is pumped down drillpipe or casing. Loss of fluid circulation is a familiar hazard when drilling and cementing in highly permeable reservoirs, in depleted zones, and in weak or naturally fractured, vugular or cavernous formations. Circulation may be impaired even when fluid densities are within the customary safety margin—less dense than the formation fracture density. Stopping circulation losses before they get out of control is crucial for safe and economically rewarding operations.

Although engineers define lost circulation in many ways, it may generally be classified as seepage when losses are less than 10 bbl/hr [1.5 m³/hr] (below). Partial lost returns involve losses greater than 10 bbl/hr, but some fluid returns to surface. During total lost circulation, no fluid comes out of the annulus. In this most
severe case, the borehole may not retain a fluid column even if the circulating pumps are turned off.

If the borehole does not remain full of fluid, then the vertical height of the fluid column drops and the pressure exerted on exposed formations decreases. As a result, another zone can flow into the wellbore while the primary loss zone is taking fluid. In the extreme, a catastrophic loss of well control can occur. Even in the less severe situations of seepage and partial losses, fluid loss to a formation represents a financial cost that the operator must address. The impact of lost circulation is directly related to the cost of the drilling rig, the drilling fluid and the loss rate over time. In addition, high daily rig costs in deepwater and other frontier operating arenas mean that any time spent mitigating lost circulation is extremely expensive.¹

During cementing operations, lost circulation commonly leads to insufficient cement fill in the annulus, either because of leakoff during the pumping stage or cement fallback after the pumps are shut down. When this happens, the final cement level is below the planned placement level. Lost circulation during cementing may lead to drilling difficulties in subsequent sections of the borehole or to inadequate zonal isolation. Other deleterious effects, such as fluid leakage or corrosion caused by poor cement placement around the casing, might not be evident for years, by which time these problems might be impossible to repair. In some situations, remedial cementing operations, known as cement squeezes, may be sufficient to repair the damage, but these procedures can be expensive and time-consuming, and the success rate is generally low. In extreme situations, total lost circulation can result in a blowout—complete loss of well control—or a borehole collapse.

In this article, we discuss lost circulation in the context of well cementing. Examples from

the Middle East, Southeast Asia, North Sea and North America demonstrate the effectiveness of advanced technology in addressing lost-circulation problems during well cementing.

**Common Approaches to Lost Circulation During Cementing**

Engineers choose from several techniques and materials to alleviate lost circulation during cementing operations (below left). If circulation losses occur, a key task is to locate the loss zone. Downhole flowmeter, or spinner, surveys, temperature logs, or radioactive tracer injection and monitoring commonly reveal loss zones. The location of a loss zone also may be apparent if losses occur immediately after penetration by the drill bit. Once the loss zone is identified, treatment or actions to avoid additional losses can begin.

In some situations, merely reducing slurry density is enough to avoid significant losses. The slurry density may be reduced by foaming the slurry or adding extenders—low-density particles or materials that allow the addition of extra water. Pumping different cement systems as the lead slurry and the tail slurry can prevent some lost-circulation problems.

Limiting friction pressures during slurry placement mitigates some lost-circulation problems because reducing friction pressure also reduces the pressure exerted by the slurry on the formation. Adjusting rheological properties of the slurry by using dispersants, changing concentrations of fluid-loss additives and anti-settling agents, using an optimized particle-size distribution slurry, or reducing the pumping rate may lessen circulation losses during cementing operations.

Some operators elect to perform stage cementing operations, in which individual portions of a zone are cemented separately using special tools that isolate each stage. Stage operations reduce cement-column heights, lowering the dynamic and hydrostatic pressures. However, multistage operations require more rig time than a single-stage operation. Multistage operations also pose the risk of fluid contamination from one stage to the next, and the stage tool is a weak point in the casing string.

Another option for minimizing losses during cementing is to use a shear-sensitive, thixotropic cement slurry, which gels as soon as shearing ceases; these cements develop high gel strength as soon as they are lost to a formation, plugging the zone.

^Workflow for countering lost circulation during cementing operations.

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3. Primary cementing operations may involve as many as four slurries, but jobs with two slurries, known as the lead slurry and the tail slurry, are more common. “Lead” refers to the first slurry pumped during primary cementing operations. “Tail” refers to the last slurry pumped during primary cementing operations. Typically, the tail slurry covers the pay zone and is denser than the lead slurry.


5. For more on stage cementing operations: Boisnault et al, reference 4.


Engineers may also adjust tubular designs or casing-setting depths on the basis of computer modeling. Modeling helps operators apply a combination of approaches to limit losses during cementing. However, recent innovations in cementing materials are helping operators combat lost circulation.

**Uncommon Cementing Technology for Lost Circulation**

For decades, cementing specialists have incorporated grains, fibers, flakes or other lost-circulation materials (LCMs) in cement slurries. Although LCMs may alleviate lost-circulation problems, many LCMs are difficult to disperse in slurries and to mix and pump using ordinary cementing equipment. The low specific gravity of some LCMs causes them to float on the slurry surface. The inability of some of these materials to disperse in the slurry or to become properly water-wet has caused plugging problems in both mixing and downhole equipment.

A new, advanced fiber can be mixed with cement slurries to form a high-performance bridging network across zones of lost circulation. The fibers of CemNET advanced fiber cement, engineered to optimal sizes generally less than 12 mm [0.5 in.] long and 20 microns in diameter, are chemically inert and compatible with most cementing systems and additives at temperatures up to 450°F [232°C]. These fibers can be added at the wellsite, and may be combined with the portions of the slurry that will be placed across potential loss zones.

The main advantage of the CemNET fibers is their ability to easily disperse in the cement slurry. Unlike conventional fibers, CemNET fibers are coated with a special surfactant that keeps individual fibers together when dry, but also helps the fibers disperse and mix without difficulty when added to the slurry (previous page, right). When added at an optimal concentration, CemNET fibers form a bridging network, but do not alter crucial slurry or cement properties, such as thickening time, rheological properties, fluid loss, free-water content, tensile strength, shear strength and compressive strength (above).

By incorporating advanced fibers, operators may avoid problems such as low cement tops, the need for squeeze-cementing operations, and more serious cement losses and borehole failures. When the bridging action of fibers in the cement slurry seals loss zones, less slurry is lost during pumping operations. Laboratory experiments have verified the effectiveness of fiber-laden slurries in plugging loss zones.

Net-like fibers to bridge loss zones. Fluid loss in fractured formations, shown schematically in red, is an undesirable occurrence during cementing operations (top). By adding fibers to cement slurry, a fibrous net forms, the cement slurry builds a filter cake and slurry circulates up the annulus to provide zonal isolation and prevent additional fluid losses (bottom).
Alleviating Lost Circulation in the Middle East

Carbonate rocks of the Middle East are known not only for prolific oil and gas reserves, but also for lost-circulation problems. Abu Dhabi Company for Onshore Oil Operations (ADCO) confronts these problems regularly when drilling the Umm El Radhuma and Simsima formations. In the past, the company attempted to control lost circulation by performing stage cementing operations and top jobs, by using lightweight cements and by setting plugs during primary cementing operations. None of these approaches is satisfactory because any casing not surrounded by cement is exposed to corrosive brines. However, the operator continues to perform top jobs when the most severe losses occur to protect the casing as much as possible from corrosion.

Recently, ADCO cemented two wells using slurries containing CemNET fibers. During the drilling of one well, the rate of lost circulation reached 150 bbl/hr [23.8 m³/hr], even though a relatively light, 9.1-lbm/gal [1091-kg/m³] drilling fluid was being pumped. A heavier cement slurry—10.7 lbm/gal [1283 kg/m³]—was planned, so the operator was concerned about additional losses. A combination of fiber-laden slurry and high-performance lightweight slurry was pumped, followed by a 16.7-lbm/gal [2002-kg/m³] tail slurry. After recovering full returns of 134 bbl [21.3 m³] of drilling fluid at surface, and experiencing no difficulties in mixing or pumping the slurries, ADCO deemed this operation successful.

The second well suffered losses at an even greater rate—500 bbl/hr [79.5 m³/hr]—while drilling with 8.65-lbm/gal [1036-kg/m³] mud. The company decided to set casing 500 ft [152 m] higher than originally planned to address the losses. An ultralightweight slurry weighing 8.0 lbm/gal [969 kg/m³] at surface was blended with CemNET fibers. This slurry was followed by a 15.7-lbm/gal [1882-kg/m³] tail slurry. Although returns were not expected, partial returns were observed at surface. To protect the casing from corrosive brine, a top job was pumped. However, the volume of slurry pumped for the top job was reduced by approximately 40%, or 100 bbl [15.9 m³], because more CemNET slurry had been placed in the annulus during the primary cementing operation. In light of these results, ADCO plans to use CemNET slurries routinely.

Applying Advanced Cementing Technology in Asia

The giant Duri field in Sumatra, Indonesia, has been steamflooded for enhanced recovery of heavy-oil reserves since 1985. The operator, P.T. Caltex Pacific Indonesia (CPI), produces more than 205,000 B/D [32,575 m³/d] of oil from 6800 wells. The 200- to 900-ft [61- to 274-m] deep sandstone reservoirs have gravel-pack completions. Lost circulation in these unconsolidated and faulted reservoirs often necessitates remedial cementing operations. The recent introduction of CemNET technology is reducing cementing costs by limiting the need for remedial cementing. Previously, many different cementing techniques were attempted in the...
Duri field, such as cement plugs incorporating various LCMs and foamed, thixotropic or other types of primary cement. Even though these techniques increased the primary cementing success rate to 60%, the failure rate remained unacceptably high.

To improve the cementing success rate, CPI pumped CemNET slugs—15.0-lbm/gal [1797-kg/m³] cement slurry with 2.5 lbm/bbl [7.1 kg/m³] of fibers—in cases of total lost circulation. In certain circumstances, a 5-bbl [0.8-m³] cement plug cured losses, although seepage continued in the most severe instances. CPI next decided to use CemNET technology in the primary cement slurry to cure lost circulation, adding 2.5 lbm/bbl of fibers while pumping a 15.8-lbm/gal [1893-kg/m³] cement slurry. In one situation, a Duri well suffered total lost circulation while drilling, which was reduced to seepage losses after placement of a CemNET plug. Nevertheless, this well was cemented successfully using CemNET slurry.

Of the 98 most recent CemNET plugs in Duri field, 63 completely cured lost circulation, and in 18 others, losses were reduced. In 30 primary cementing operations using CemNET fibers, 28 had complete cement coverage. Overall, the cementing success rate improved from 60% to 85%. Using CemNET technology, CPI saves 32 hours of rig time per well because the initial cementing operation is usually successful and remedial operations are required much less frequently.

CPI is finding additional uses for CemNET technology in other fields it operates. For example, CemNET slurries are pumped through coiled tubing to shut off perforations that produce water.

Curing Losses in the UK North Sea

Shell Expro experienced severe circulation losses in the Brent field, UK North Sea, in reservoirs penetrated by extended-reach and nearly horizontal wells. This field, which began producing oil in 1976, contains substantial solution-gas reserves in bypassed and residual oil zones. The company began depressurization operations to recover gas as it evolved from the oil by fracturing the rock. The results of the leakoff test dictate the diameter of the production string might be narrower than planned and production economics not as favorable, or it might not be possible to drill to the target formation.

Avoiding Wet Shoes in the Norwegian North Sea

In one of the fields in the Tampen area of the Norwegian North Sea, Statoil sets 18%-in. casing in unconsolidated sand formations. Historically, Tampen-area wells have been prone to poor leakoff test (LOT) results at this casing shoe because of a phenomenon known as a “wet shoe.” A wet shoe occurs when the cement does not set around the shoe or when the cement is lost to thief zones. More generally, any time a driller does not tag, or contact, hard cement around a shoe, it is known as a wet shoe.

When a wet shoe occurred, Statoil usually performed squeeze-cementing operations to obtain adequate LOT results, but this remedial cementing work was costly. Taken to an extreme condition, an inadequate LOT might require a contingency casing string, meaning that the diameter of the production string might be narrower than planned and production economics not as favorable, or it might not be possible to drill to the target formation.

9. For details of the experiments: Low et al, reference 8.
11. Top-job operations involve pumping cement down the annulus from surface, rather than down the drillpipe and up the annulus, to fill the space between the formation and the casing.
16. For more on the use of CemNET technology in Indonesia: El-Hassan et al, reference 12.
17. A leakoff test is performed to determine the strength or fracture pressure of the open formation, and is usually conducted immediately after drilling below a new casing shoe. During the test, the well is shut in and fluid is pumped into the wellbore to gradually increase the pressure on the formation. At some pressure, fluid will enter the formation, or leak off, either moving through permeable paths in the rock or by creating a space by fracturing the rock. The results of the leakoff test dictate the maximum pressure or mud weight that may be applied to the well during drilling operations. To maintain a small safety factor to permit safe well-control operations, the maximum operating pressure is usually slightly below the leakoff test result.
Working with Schlumberger, Statoil developed new cementing practices to solve the wet-shoe problem. These included reducing the lead-slurry density and the length of the shoe track cemented using a tail slurry. Although these techniques reduced the number of wet shoes, the problem was not eliminated. Therefore, Statoil began pumping tail slurries containing CemNET fibers. To date, two wells have been cemented using CemNET tail slurries; both operations were successful and required no remedial work (right). Consistent with other CemNET cementing operations, the fibers were mixed and pumped with ease.

Avoiding Lost-Circulation Problems in North America

Onshore operations in North America encompass an enormous variety of challenges in reservoirs of many geological ages and lithologies. Nevertheless, many drilling operations throughout the continent have something in common—lost circulation. Recently, several operators have successfully counteracted lost circulation using CemNET technology.

In West Virginia, USA, Cabot Oil & Gas Corporation required excellent zonal isolation in a low-pressure producing reservoir that would be fracture stimulated. Like most wells in the area, this well was drilled using air as the drilling fluid, which often leads to lost circulation during cementing. Because of the low fracture gradient of some of the formations, the cement had to be lightweight, but the planned stimulation treatment meant that the cement also would have to be durable.

In previous cementing operations, 12 of 41 production-casing strings required remedial cementing. After studying these results, Cabot employed a variety of advanced cementing systems, each with progressively better results. Initially, Cabot used RFC regulated fill-up cement, which is a thixotropic and expansive mixture of Portland cement and plaster—a seemingly ideal formulation to avoid losses and provide good cement bonding in lost-circulation zones. Even though the RFC slurry is designed to quickly become immobile after placement, cement losses continued. Next, CemNET fibers were added to RFC cement slurry. This system yielded better results in obtaining the desired cement heights.

Later, Cabot decided to reduce the slurry density using KOLITE cementive additive for low-density slurries. The lightweight KOLITE granular solids have a specific particle-size distribution designed to combat lost circulation. Although this additive led to some improvement, cement heights remained suboptimal, so CemNET fibers were added to the KOLITE slurries. This system has produced the best and most reproducible results to date in terms of achieving the cement height necessary to cover multiple zones of interest.

To better satisfy the requirements for lightweight yet durable slurries, Cabot next used a LiteCRETE slurry system with CemNET fibers to achieve zonal isolation. In a well that is 3500 ft [1067 m] deep, 2095 ft [639 m] of cement was placed in the annulus instead of being lost to the formation. Although this result continues the trend towards steady cementing improvement, Cabot continues to evaluate the use of the LiteCRETE and CemNET blend for future wells. To date, Cabot has used CemNET slurries in 51 cementing jobs.

Cementing improvements were not limited to slurry selection; Cabot and Schlumberger engineers also developed guidelines for using lighter slurries, reducing water content and minimizing slurry viscosity and fluid loss.

Hundreds of miles from West Virginia, the Permian-age Brown Dolomite formation of the Texas panhandle, USA, presents significant lost-circulation problems. Total lost circulation while drilling is not uncommon. This naturally fractured reservoir is prone to damage from excessive drilling-mud and cement losses. Thousands of barrels of cement have been pumped into this formation in attempts to offset circulation losses.

In a well in Roberts County, Texas, Brighton Energy LLC encountered total lost circulation in the Brown Dolomite formation. Two attempts to stop losses using ordinary cement plugs failed. After one week of lost rig time, Brighton decided to discontinue pumping massive volumes of cement as lost-circulation treatments, and instead contacted Schlumberger for assistance. A CemNET plug was placed in the Brown Dolomite loss zone. The severity of the losses caused the plug to break down when drilling resumed. A second CemNET plug was pumped, which successfully sealed the loss zone.

Brighton was able to continue drilling operations with full circulation. Brighton saved approximately US $26,000 per day on rig time, mud losses and other materials, and plans to use CemNET technology when cementing troublesome Brown Dolomite wells.

Nearly 2000 miles [3200 km] north of the Texas panhandle, coals and other shallow formations in southern Alberta, Canada, are prone to lost circulation. However, predicting which wells...
will have lost-circulation problems is difficult; these problems strike no particular formations or areas consistently. In some formations, particularly the coals, this inconsistency stems from the erratic distribution of the rock.

To protect groundwater resources, the shallow gas wells in this region must have cement returns to surface. Like other operators in the area, PanCanadian Energy, now Encana Corporation, typically pumped significant volumes of excess slurry to place sufficient cement to protect groundwater resources, but the cost to dispose of excess cement was high because the wells were drilled with minimal surface disturbance and there was no disposal facility on location. Given the marginal economics of these shallow gas wells, the operator investigated other approaches, such as changing drilling fluids, but met with limited success. Most other approaches tended to increase drilling time without solving the lost-circulation problem. In fact, the lost circulation typically occurred after drilling—during cementing operations.

PanCanadian also sought to minimize remedial cementing operations in shallow gas wells. Previously, the operator tried granular and lamellar LCMs to combat lost circulation, but these proved ineffective. Over the course of a 77-well project, PanCanadian and Schlumberger optimized pumping procedures and CemNET concentrations. Cement returns improved, which allowed the company to reduce slurry volumes after cementing the first 10 wells. As the project continued, less of the slurry included CemNET fibers, yet the operator continued to pump less excess cement, reduced disposal costs and eliminated remedial cementing operations. After analyzing results from the 77-well project, PanCanadian was able to reduce fiber-laden slurry volumes an additional 25%, which decreased cement returns to approximately 2 m³ (12.6 bbl).

The numerous changes in cementing procedures and materials eventually led to cost reductions of Canadian $250 per well, which becomes significant for projects involving hundreds of wells.

Winning by Not Losing

In the oil field as elsewhere in the world, thieves will always exist. While lost circulation during well cementing might never be prevented, dealing with this type of thief is certainly not a lost cause. Ideally, lost-circulation problems should be addressed before primary cementing operations occur. When lost-circulation problems are anticipated during primary cementing operations, careful cement-slurry and job design are essential: there is only one opportunity to execute the job successfully.

New technology, including CemNET technology, will combat the most serious side effects in a broad range of temperature conditions and slurry densities. Already a proven remedy for lost circulation, more than 1300 CemNET jobs have been pumped in coal beds, depleted reservoirs, faulted and fractured reservoirs, carbonate rocks, sandstones and shales throughout the world (above). New applications for these exceptional fibrous cement slurries will surely continue to proliferate. —GMG
Positive Reactions in Carbonate Reservoir Stimulation

Carbonate reservoir stimulation has improved significantly with the application of innovative viscoelastic surfactant chemistry to acidizing. This simple, novel, nondamaging acid system has been used in both matrix and acid-fracturing stimulation treatments, and has led to substantial injection and production increases—in some cases adding millions of dollars of production per month—in many oil and gas fields worldwide.

Carbonate reservoirs contain about 60% of the world’s oil reserves and hold huge gas reserves. Yet experts believe that over 60% of the oil trapped in carbonate rocks is not recovered because of factors relating to reservoir heterogeneity, produced fluid type, drive mechanisms and reservoir management. The quantity of trapped oil becomes even greater in carbonate reservoirs producing heavy oil—API gravities below 22°—where untapped reserves exceed 70%. A considerable percentage of these resources currently are not accessible because of economic and technological barriers.

Limestone and dolomite reservoirs present tremendous completion, stimulation and production challenges because they commonly contain thick completion intervals with extreme permeability ranges. Often, they are vertically and laterally heterogeneous, with natural permeability barriers, natural fractures and a vast array of porosity types, from intercrystalline to massive vugular and cavernous porosity. In these reservoirs, engineers and geologists know that the rock that is penetrated by the drill bit and evaluated through coring and logging may not fully represent the reservoir at a larger scale.

Completion and stimulation engineers must consider these complexities during the design stage and when selecting appropriate technologies to optimize production and hydrocarbon recovery. Carbonate reservoirs are stimulated using acid—predominantly hydrochloric acid [HCl]—to create conductive pathways from the reservoir to the wellbore, and to bypass the wellbore region that has been damaged during drilling and cementing. Acid-fracturing

For help in preparation of this article, thanks to Saad Al-Driweesh, Mohamed Al-Muhareb, Richard Marcinew and Mohamed Safwat, Al-Khobar, Saudi Arabia; Salah Al Harthy, Muscat, Oman; Leo Burdylo, Pia-Angela Francini and Zhijun Xiao, Sugar Land, Texas, USA; Keng Seng Chan, Kuala Lumpur, Malaysia; Trevor Hughes and Tim Jones, Cambridge, England; Bipin Jain, Bombay, India; and Bruce Rieger, Calgary, Alberta.

3. Skin is the dimensionless factor calculated to determine the production efficiency of a well by comparing actual conditions with theoretical or ideal conditions. A positive skin value indicates that some damage or influences are impairing well productivity. A negative skin value indicates enhanced productivity, typically resulting from stimulation.
techniques are also used in areas where the natural permeability of carbonate reservoirs is insufficient to promote effective matrix acid stimulations. The goal in carbonate reservoir stimulation is to effectively treat all latent productive zones, reducing formation skin and improving productivity or injectivity.

Matrix stimulation is even more complex when there are multiple intervals having significantly different permeabilities. High-permeability zones preferentially take the acid and leave zones with lower permeability untreated. These untreated intervals mean less production and lost reserves. This nonuniform stimulation can also lead to high drawdown, causing early and undesirable gas and water production. For these reasons, acid-diverting techniques, both mechanical and chemical, have been developed and recommended to ensure uniform stimulation of carbonate reservoirs.

However, many placement and performance problems complicate the acidizing process. This article examines the development and use of a new self-diverting acid system based on non-damaging viscoelastic surfactant (VES) technology. Also included is a general discussion of matrix acidizing, acid fracturing and a description of challenges encountered when stimulating carbonate reservoirs. Case studies from around the world demonstrate the overwhelming success of this new technology.

**Acidizing Is Not Basic**

Acid stimulation in carbonate rocks involves a reaction of hydrochloric acid with the minerals calcite and dolomite $[\text{CaCO}_3 \text{ and CaMg(CO}_3\text{)}_2$, respectively], producing calcium chloride $[\text{CaCl}_2]$, carbon dioxide $[\text{CO}_2]$ and water $[\text{H}_2\text{O}]$ in the case of calcite, and a mixture of magnesium chloride $[\text{MgCl}_2]$ and calcium chloride in the case of dolomite. As live acid is introduced, more $\text{CaCO}_3$ dissolves, creating small conductive channels, called wormholes, which eventually form a complex, high-permeability network.
Chemical retardation techniques typically include emulsification and formation of gels. Depending on the acid concentration and the pumping environment, an acid-diesel blend, SXE SuperX emulsion for example, can be highly effective because it slows reaction times by a factor of 15 to 40 compared with conventional HCl acid systems. The dissolving power—a function of acid strength—of the HCl-base SXE system, coupled with slower carbonate reaction time—retardation—creates deeper wormholes and makes the emulsion less corrosive to steel casing and tubing. The corrosion threat to steel tubulars, especially at higher temperatures, can be reduced further by adding inhibitors to acid systems. Retardation of the reaction and corrosion minimization can also be achieved by using organic acids, but because of their cost and lower dissolving capability, their use is limited.

Many treatment-design factors must be considered to optimize reaction rate and cleanup, including acid strength, temperature, pressure, leakoff rate and the rock composition. Controlling the acid-reaction rate in the target formation is critical to the success of acid-stimulation treatments in carbonate reservoirs. The acid system must bypass the damaged zone to open up reservoir communication to the wellbore but must also minimize damage to tubulars and clean up sufficiently after the acid has spent. Additives play a key role by limiting fluid loss, minimizing the generation of emulsions and precipitates, regulating viscosity, decreasing corrosiveness and improving cleanup.

Even a well-designed matrix-acid fluid system does not guarantee a successful stimulation. The stimulation fluid must be properly placed in the selected intervals. Acid systems are generally pumped downhole through the casing or tubing—a technique called bullheading—or delivered through coiled tubing. In bullheading operations, undesirable preferential placement of acid into high-permeability zones leaves intervals with lower permeability untreated. In some cases, high-permeability water-producing zones take a disproportionate amount of acid, increasing undesirable water production and associated water-disposal costs.

Mechanical-diversion techniques, such as use of ball sealers or coiled tubing with straddle packers, are widely used, but may not always be feasible or recommended (above right). Mechanical methods are not very effective in the stimulation of long horizontal and extended-reach wells. Conventional chemical-diversion methods include nitrogen foam, bridging agents like benzoic acid flakes and crosslinked polymer gels. These methods temporarily plug high-permeability carbonate zones to effectively divert the treatment fluids to zones of lower permeability. Chemical-diversion methods vary in effectiveness. Sometimes temporary plugs become permanent, and the reservoir that was meant to be stimulated becomes damaged, diminishing well productivity.

A common chemical-diversion technique uses polymer-base gels. These acid systems use reversible pH triggered crosslinker additives to alter the viscosity of the fluid at critical times during an acid treatment. For example, SDA Self-Diverting Acid is a polymer system mixed with HCl. It initially has a low viscosity to allow easy pumping, but once this fluid enters a carbonate formation and when the acid spends, the polymer crosslinks when the pH reaches 2, increasing its viscosity. The increase in gel viscosity restricts further flow of new acid through
the wormholes, thereby diverting fresh acid to zones with lower permeabilities, and eventually to other zones. As the acid continues to dissolve the rock, pH increases. Once the pH rises to about 3.5, the gelled acid breaks, reducing the viscosity and enabling fluids to flow back and clean up.

Polymer-base acid systems have several drawbacks. Independent studies by Stim-Lab, FRAC TECH Services, L.L.C., Saudi Aramco and other companies have shown that conventional polymer-base acid systems obstruct wormholes and could damage the formation. Cleanup of fractured wells was also systematically studied using flowback analysis and showed cleanup at less than 45%. Because of a narrow pH window, this crosslinking and breaking phenomenon can be difficult to control, especially in treatments with several stages of different fluids. Moreover, the stability of polymer systems degrades as the bottomhole temperature increases. This instability hinders proper diversion or, at worst, permanently damages the formation to the point of preventing flow. Complicating matters even more, in sour environments where hydrogen sulfide [H2S] is present, formation damage and scaling problems can occur when metal crosslinker additives react to precipitate sulfides.

A Unique Fluid Emerges

The potential damaging effects of polymer-base stimulation fluids prompted researchers at the Schlumberger Product Center at Tulsa, Oklahoma, USA, to explore the use of viscoelastic surfactants (VES) in hydraulic-fracturing fluids, leading to the introduction of ClearFRAC polymer-free fracturing fluids in 1997. Subsequent R&D led to the development of VES molecules tolerant to higher temperatures. In 2001, the ClearFRAC HT fluid was introduced to extend the practical operating temperature to 275°F [135°C].

More recently, Schlumberger applied VES chemistry to produce a polymer-free acid called the VDA Viscoelastic Diverting Acid system. The viscoelastic-surfactant molecule used in the VDA system is made up of a hydrophilic head composed of positive quaternary ammonium groups, and a negative carboxylate group with a long hydrophobic tail that is a hydrocarbon chain. While being pumped down the tubing or casing, the VDA fluid system—a blend of HCl, viscoelastic surfactant and common additives required for acid treatment—maintains a low viscosity. The amount of acid in the mixture determines the system’s initial viscosity (above right).

As the acid is consumed through the reaction with calcite or dolomite, the surfactant gels. Two factors trigger the gelation process. When the acid spends, the increased pH allows the surfactant molecules to come together and form long structures called micelles, in which the hydrophilic heads point outward and the hydrophobic tails point inward. Dissolution of CaCO₃ in HCl results in the formation of CaCl₂ brine, which further stabilizes the worm-like micelles. The micelles continue to grow longer and become entangled above a critical concentration of the surfactant, forming a mesh structure and producing a highly viscous, elastic gel (top). The increased viscosity of the gel further reduces flow into existing wormholes and fissures within the treated zones, thereby providing effective in-situ acid diversion to unstimulated, low-permeability and damaged zones. The viscosity of the spent VDA fluid is related to several factors, including temperature, and to the initial percentages of both acid and surfactant (above).

After a treatment, the surfactant gel breaks down on contact with produced oil, condensate and mutual solvent preflush flowback, or when diluted with produced formation brine during flowback. During breakdown, the elongated micellar structures are reduced to spherical structures, and the fluid system attains a low viscosity because the spherical micelles do not entangle. A preflush or postflush solution of mutual solvent enhances the breakdown of the gelled surfactant and promotes quick cleanup.

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The new acid system can be used to stimulate wells that have a bottomhole static temperature up to 300°F [149°C].

Prior to its first use, the effectiveness of the VDA system in treating carbonate rocks was documented in simultaneous multicore flow tests. Schlumberger and Stim-Lab compared several acid systems for their diversion and retained-permeability characteristics, including straight hydrochloric acid as a baseline, a polymer-base acid, a foamed acid and the VDA fluid system. The tests showed that the straight acid penetrated only the most permeable core, while the VDA system increased permeability in all cores because it successfully diverted acid to the lower-permeability cores. Computed tomographic (CT) cross-sectional imaging employed at each inch along the length of the cores demonstrated the changes in pore structure due to acidizing (above).

10. A micelle is a colloidal droplet in which the internal phase of the droplet has an opposite affinity for water than is present in the external phase. The bounding layer has both hydrophobic and hydrophilic ends.

Compared with the viscosity of polymer-base acid, the VDA fluid viscosity remained high as the acid was consumed, while the polymer gels broke down when the pH reached 3.5 to 4.0. Examination of the injection core faces showed that the cores injected with the VDA fluid remained clean and showed no trace of residue. In contrast, cores treated with the polymer-base acid system clearly had damaging residue on the injection face and also inside the wormholes.

From an operational standpoint, the new VDA fluid can be pumped as a one-stage fluid or combined with other stimulation fluids in stages, depending on the application. By comparison, polymer-base fluids require several stages of acid and diverter to achieve the desired stimulation and diversion. This can be a significant disadvantage since the more polymer that is pumped into the formation, the greater the formation damage. Moreover, laboratory tests have shown better cleanup of spent VDA fluid as evidenced by lower flow-initiation pressures when subsequently injecting mutual solvent into test cores. The excellent performance of this VDA system is particularly beneficial in low-pressure oil reservoirs.

The importance of laboratory testing of stimulation fluids cannot be overstated. In Schlumberger, this work is done in local laboratories around the world, supported by three Client Support Laboratories (CSLs) located in Houston, Texas, USA; Aberdeen, Scotland; and Kuala Lumpur, Malaysia.

Diversion in Kuwait
The new VDA system was first used in the northern Kuwait Sabriya field, which is operated by the Kuwait Oil Company (KOC) (below). The six lithological units within the multilayered Mauddud carbonate reservoir range in permeability from 3 to 600 mD. Perforated intervals range between 100 and 200 ft [30 and 60 m] in total length. Reservoir pressure averages 2500 psi [17.2 MPa] and typical well temperatures reach 170 to 180°F [77 to 82°C]. During matrix stimulation, high-permeability zones tend to take acid and become further stimulated, leaving damaged and low-permeability zones untreated. This increases the drawdown within a limited distance from the wellbore and could cause production problems. For this reason, uniform stimulation of the entire zone with chemical-diversion fluids is critical for production optimization.

In the past, acidizing long, heterogeneous carbonate intervals within the Mauddud formation required either foam or chemical diverters, most commonly crosslinked polymer systems. Acid concentrations of 15% were used for tubular pickling and formation breakdown, whereas acid concentrations of only 3 to 5% were used with polymer-base diverter stages. The polymer diverter fluids were crosslinked either at surface or in situ, and usually one stage was pumped for each of four to five sets of perforations. For each Mauddud interval, acid-treatment volumes varied according to the formation characteristics. Zones with lower permeability and porosity were treated with up to 200 gal/ft [2.5 m³/m] of perforations, while zones with higher permeability and porosity were treated with 75 gal/ft [0.9 m³/m]. Openhole completions were commonly stimulated with 10 to 20 gal/ft [0.1 to 0.2 m³/m]. After treatment, the wells were displaced with diesel and, if required, the fluids were lifted with nitrogen pumped down coiled tubing.

Early in the field test of the VDA system, reservoir experts from KOC and Schlumberger identified several potential wells that would benefit from the new VDA technology. These included newly drilled wells, underperforming older wells, horizontal wells with openhole completion intervals, wells with shallow and depleted reservoirs, and high-pressure, high-temperature (HPHT) wells.

Newly drilled wells in the Sabriya field required acidizing because drilling damage and low reservoir pressure limit their ability to flow naturally. Many new wells employ dual completions, with the Mauddud intervals completed on the short string. These completions discourage the use of coiled tubing for acidizing because there is a risk of getting stuck. Without the coiled tubing option, bullheading the treatments from surface is required. Proper chemical diversion has been deemed critical for the uniform stimulation of the Mauddud carbonates.
The entire completion interval is treated with concentrations up to 28% HCl have been used. Treatments typically contain 15% acid, although preflush containing a mutual solvent. The VDA are used for both tubing pickling and as an HCl treatments from surface, 15 wt% acid concentrations treated exceptional chemical diversion during 

[Image 48x498 to 306x687]

PLT Production Logging Tool surveys before and after VDA stimulation. Before the VDA matrix treatment, Well 5 was not producing from all perforations, and maintained a flowing wellhead pressure (FWHP) of only 195 psi [1.3 MPa] (left). After the VDA stimulation, all perforations contributed to production, the well produced 1760 BOPD [280 m³/d] with no gas, and the FWHP was now 750 [5.2 MPa] (right). The well was producing gas prior to stimulation because of excessive pressure drop. After the VDA treatment, the well no longer produced gas because effective stimulation reduced the pressure drop in the well. In the PLT displays: Track 1 contains the gamma ray curve for correlation; Track 2 shows the location of perforations; Track 3 displays the volume of produced fluids and the spinner response; and Track 4 shows the PLT measurements, which include fluid density, temperature and downhole pressure.

On new wells requiring bullheaded treatments from surface, 15 wt% acid concentrations are used for both tubing pickling and as an HCl preflush containing a mutual solvent. The VDA treatments typically contain 15% acid, although concentrations up to 28% HCl have been used. The entire completion interval is treated with 50 gal/ft [0.6 m³/m]. After the VDA treatment, a 15% HCl overflush containing a mutual solvent is bullheaded and then overdisplaced with diesel. In early wells, a one-to-one ratio of HCl to the VDA treatment volumes was pumped. However, subsequent wells have shown better performance with higher percentages of VDA fluid.

In Well 5, a new completion, the Mauddud reservoir was completed on the short string, so a bullheaded VDA treatment was planned to treat five different sets of perforations over a 133-ft [41-m] interval. Severe permeability contrasts between zones and the strong possibility of formation damage due to an earlier loss of 800 bbl [127 m³] of polymer-base drilling fluid necessitated exceptional chemical diversion during stimulation. To monitor the impact of stimulation, the operator decided to run pre stimulation and post stimulation PLT Production Logging Tool surveys (above). Before the VDA stimulation, the PLT log showed that not all the perforations were contributing to production. The well was also producing below the bubblepoint of 1800 psi [12.4 MPa] because of high drawdown pressure, causing gas to come out of solution. The flowing wellhead pressure (FWHP) was only 195 psi [1.3 MPa].

After a successful VDA treatment, oil production increased from 510 to 1760 BOPD [81 to 280 m³/d] at an increased FWHP of 750 psi [5.2 MPa], and the PLT log showed all perforations were contributing to production. The


15. The picking procedure uses an inhibited acid to remove scale, rust and similar deposits from the internal surfaces of equipment such as treating lines, pumping equipment or the tubing string through which an acid or chemical treatment is to be pumped. The picking process removes materials that may react with the main treatment fluid to create undesirable secondary reactions or precipitates damaging to the near-wellbore reservoir. Nasr-El-Din HA, Al-Mutairi SH and Al-Dirweesh SM: “Lessons Learned from Acid Pickle Treatments of Deep/Sour Gas Wells,” paper SPE 72716, presented at the SPE International Symposium and Exhibition on Formation Damage Control, Lafayette, Louisiana, USA, February 20–21, 2002.
comparison of well tests, before and after the treatment, further demonstrated the success of the VDA system (right). The prestimulation well test analysis showed high drawdown pressure and a skin factor of +170, while the post-stimulation well test showed a significantly reduced pressure drop and a greatly improved skin factor of –3. Higher downhole pressures minimized drawdown and eliminated the undesired gas production.

Successful treatments in the initial wells prompted KOC to stimulate Wells 11, 12 and 13 on the flanks of the Sabriya field structure. These wells, which produce heavier oil—17 to 20°API gravity—had not produced for 6 to 10 months. Coiled tubing was used when acidizing these three older wells that would not produce even after initial, and sometimes multiple, conventional acid treatments and nitrogen-lift techniques. These wells contain single-string completions, so coiled tubing operations pose less of a risk. A disadvantage of pumping conventional acids and diverters through coiled tubing was the inherent reduction in pumping rate caused by high friction losses because of the smaller tubing diameters and high fluid viscosities. However, as it is pumped down coiled tubing, the VDA system has drag-reducing characteristics that significantly reduce the friction, allowing higher pumping rates. After the VDA treatments, all three wells began flowing naturally, adding a cumulative production gain of 3280 BOPD [521 m³/d].

Shallow and depleted reservoir zones in the Eocene carbonate rocks have been stimulated with VDA fluid alone, with 5% mutual solvent added in the postflush, with excellent results. With reservoir pressure down to 400 psi [2.8 MPa], these wells are produced through sucker-rod pumps. Well 7 was identified as a stimulation candidate well because it had an upper zone with extremely high permeability and multiple lower zones of lower permeability that had not been stimulated in the past because of a lack of acid diversion. A 50-gal/ft treatment of 15% VDA fluid was successfully bullheaded through a dual packer (next page). When the VDA system is pumped as a single fluid, it enters the high-permeability zones, stimulates them and then diverts the treatment to lower permeability zones. This behavior can be observed repeatedly on the treatment plot as more zones are stimulated. Production from Well 7 increased dramatically, from 300 BOPD [48 m³/d] with a water cut of 11% before the VDA treatment to 1300 BOPD [207 m³/d] with a water cut of 15% two months after VDA stimulation.

Another beneficial application of VDA technology for KOC is in HPHT wells where bottomhole temperatures reach 295°F [146°C] and reservoir pressure is 10,000 psi [69 MPa]. Two HPHT wells, Well 14 and Well 17, have been stimulated with the VDA system. Here, the reservoir is extremely tight, so KOC and Schlumberger have found it beneficial to spot HCl using coiled tubing. Next, a staged treatment consisting of a 28% breakdown acid, a 20% VDA fluid and then 28% HCl is bullheaded from surface. One stage of each has yielded exceptional results; Well 14 production increased from 2760 to 9029 BOPD [439 to 1445 m³/d], and Well 17 production increased from 3140 to 5242 BOPD [499 to 833 m³/d] with a substantial increase in FWHP—from 2914 to 3930 psi [20.1 to 27.1 MPa].

The VDA system also proved successful in a Kuwait Oil Company horizontal well. Well 13 contained a 2000-ft [610-m] horizontal open-hole-completion interval in the Mauddud
reservoir and was flowing 1037 BOPD [165 m³/d] naturally at a FWHP of 320 psi [2.2 MPa]. NODAL production system analysis before stimulation indicated a +10 skin factor, suggesting that the well had been damaged during drilling. KOC and Schlumberger decided that several acidizing stages might be needed to effectively treat the long openhole interval. The acidizing team pumped a combination of 10 gal/ft VDA fluid, and 10 gal/ft of 15% regular, emulsified acid, or HCl containing additives to combat high mud and silt percentages. Ultimately, only two stages were required to reach the desired productivity. A production test conducted after the VDA stimulation showed a substantial production increase to 3800 BOPD [604 m³/d] at a FWHP of 275 psi [1.9 MPa].

KOC has treated more than 75 wells with this innovative fluid. The VDA system’s unique rheological behavior allows for higher pumping rates for operations using coiled tubing, while offering the superior diversion capability required for bullheading operations in more complex completion scenarios. It uses less equipment for mixing and fewer chemicals at the website, and requires no crosslinkers that can lead to damaging precipitates in the reservoir. Quality assurance and quality control on location were also easier and reproducible when using the new fluid. The economic impact of viscoelastic surfactant technology is immense; on the first 10 VDA wells alone, KOC realized an additional $4.4 million per month in oil revenues above that expected using conventional technology.

A Summary of Saudi Successes

Saudi Aramco started moving from polymer-base stimulation fluids to VES alternatives in 2001 with the introduction of OilSEEKER acid diverter technology. A significant shift towards the non-damaging VDA system has similarly occurred in carbonate reservoir stimulation. Saudi Aramco has successfully used VES fluids in numerous stimulation applications, including matrix acidizing and diversion in production wells and water-injection wells, and acid fracturing in HPHT gas wells and water-injection wells.¹⁷

Conventional matrix stimulation of carbonate reservoirs in Saudi Arabia used crosslinked gelled and emulsified acid systems. Unfortunately, iron-control agents do not prevent the precipitation of iron sulfides in sour environments—those containing H₂S.¹⁸ Interested in ways to improve diversion, lessen damage and increase production, Saudi Aramco decided to test the VDA system on matrix-stimulation wells under challenging conditions.

Some candidate wells for VDA matrix stimulation were long horizontal wells with openhole horizontal sections ranging from 1500 to 6000 ft [460 to 1830 m] and temperatures approaching 250°F [120°C]. In many cases, there were serious concerns about a water zone immediately below the targeted horizontal section, making proper diversion extremely important for reducing or eliminating water production. On the extended-reach wells, coiled tubing was used to deliver the treatment to the reservoir, which consisted of VDA surfactant in 20 to 28% HCl and a corrosion inhibitor. In the event that the coiled tubing does not make it to total depth, the VDA treatment can be bullheaded from the coiled tubing from that point. The lower pumping rates would still be sufficient to achieve stimulation and diversion of the entire horizontal section. Most of the wells used VDA fluid energized with 30% nitrogen. Treatment rates down coiled tubing remained between 1.0 and 1.5 bbl/min [0.15 to 0.24 m³/min]. The use of nitrogen accelerated cleanup and minimized acid leakoff, provided better coverage and reduced acid-volume requirements.

Saudi Aramco and Schlumberger engineers found poststimulation production rates of the first five VDA wells to be much greater than the

**Acid Fracturing in Saudi Arabia**

In some Saudi Arabian water-injection wells, conventional matrix-acid treatments do not generate the required injection rates, so these wells need to be acid-fractured. An initial pad is pumped at pressures exceeding the fracture pressure of the formation; a hydraulic fracture is initiated and propagated by continued injection. In conventional hydraulic fracturing, proppant is used to hold the fracture open and to create a conductive pathway for flowback and production. However, in carbonate rocks, acid is used to create nonuniform etched patterns on the fracture surfaces. This gives the fracture sufficient conductivity after closure. In acid fracturing, the effective hydraulic-fracture length is that portion of the fracture that has been sufficiently etched.

To combat fluid leakoff, conventional acid-fracturing treatments use multiple stages of polymer and acid. The objective of these systems is to limit leakoff by increasing fluid viscosity. The increased viscosity and emulsified acids reduce the rate at which the acid reacts with the carbonate formation, helping to reduce leakoff and improve fracture geometry. This technique has been successful. However, polymers form filter cake that, if left in the fracture, can hinder production, especially in tight formations. Additionally, crosslinkers function within a narrow pH range and their behavior can be difficult to predict at high temperatures. They can also cause precipitates that damage the formation.

The reactivity of the acid to the rock, which helps create a permeable fracture, also promotes undesired fluid loss during pumping. This leakoff negatively impacts fracture growth and hinders the creation of wormholes along the length of the fracture. There are several ways to limit fluid loss during acid fracturing, including pumping intermittent viscous pads that deposit filter cake to reduce acid leakoff and using two-phase fluids, such as foams, emulsions and crosslinked gels. These techniques can be effective but can damage the permeability of both the formation and the fracture. The acid can also destabilize commonly used fluids that are high in pH and can hydrolyze the pad making it less effective. For this reason, several large-volume pads are pumped. When using foam, foam-stability problems can negatively impact acid-fracturing operations, especially in the presence of hydrocarbons at high temperatures.

In Saudi Arabia, the combination of ClearFRAC fluid, emulsified acid, VDA fluid and a mutual solvent has proved to be an effective treatment. This combination eliminates the average production from 11 offset wells that were stimulated without the VDA system (top). Water cut in the wells treated with the VDA fluid is much lower than in wells treated with other systems, primarily because the high viscosity in water zones is not broken, whereas gel formed in the hydrocarbon zones is broken and allows the acid to migrate further into the matrix. Therefore, these hydrocarbon-bearing zones are more effectively stimulated and produce higher volumes of oil or gas.

Recently, Saudi Aramco stimulated seven water-injection wells using foamed VES fluid as the diverter system, a combination of 20% HCl regular acid and 20% HCl diesel-emulsified acid, and a mutual solvent overflush. These injection wells are crucial for maintaining reservoir pressure. The injection zone is 200 ft [60 m] thick and contains widely varying permeability streaks. When stimulating this section without proper diversion, all of the acid goes into the most permeable zone and does not treat the damaged zone and zones with lower permeability. Treatments have been bullheaded from surface or delivered through coiled tubing, and have improved injectivity when compared with wells treated with a combination of emulsified acid and gelled polymer-base acid systems (above). Polymer-base systems also require crosslinker and breakers. Furthermore, the VES diversion fluid has eliminated the need to flow back for cleanup because it does not use any polymers.
Acid creates conductive wormholes.

near-wellbore region is sufficiently stimulated.

to gas. This can be avoided by ensuring that the banks can form because of a pressure drop in the required. Once production starts, condensate higher concentrations of inhibitor additives are environment is that the acid is more corrosive, so possibility. Another problem in this high-temperature extension and conductivity, as well as productivity. The hydraulic fracture, thereby reducing fracture extension and conductivity, as well as productivity. Another problem in this high-temperature environment is that the acid is more corrosive, so higher concentrations of inhibitor additives are required. Once production starts, condensate banks can form because of a pressure drop in the near-wellbore region, lowering the permeability to gas. This can be avoided by ensuring that the near-wellbore region is sufficiently stimulated.

The fracture closes but retains conductivity because of the etching and wormhole creation.


Nasr-El-Din et al, reference 7.

Samuel and Sengul, reference 5.


In 2003, Saudi Aramco acid-fractured eight Khuff gas wells using a combination of crosslinked gel and new viscoelastic surfactant technology (above). The pad stage used a high-temperature borate gel to initiate and extend the hydraulic fracture, with emulsified acid to etch the fracture. In the final stages, VDA fluid containing 5 to 6% surfactant, was pumped to limit fluid loss and minimize the total amount of polymer pumped into the fracture and formation.

21. Pad refers to the fluid used to initiate hydraulic fracturing that does not contain proppant.

sufficiently etch the fracture along its length. The viscous borate gel also cooled the formation, controlled leakoff and stabilized the bottomhole pressure. Acid pumped after the high pH borate gel destabilizes the filter cake and increases leakoff. To minimize this, acid was followed by gelled fluid that helped finger the next acid stage. Importantly, VDA fluid, containing 28% HCl and 5% to 6% surfactant, was pumped in the final stages when the leakoff became excessive. If a leakoff-control acid is not used, at high leakoff rates, the fracture will close and will not take any more fluid.

Since the operation was performed down tubing, significant steps to pickle the tubing were taken by pumping HCl across the tubing and connecting lines. This removes pipe dope, corroded iron, corrosion-inhibitor additives and scale from the tubing and connecting lines to ensure that only the intended fluids are pumped into the formation during acid fracturing.

Prior to designing and pumping the job, the emulsified acid and the VDA fluids were tested in Schlumberger and Saudi Aramco laboratories to determine their respective viscosity profiles under demanding temperature conditions. Laboratory testing determined that both the VDA fluid and emulsified acid could be used in the Khuff wells. Additionally, a systematic study on the influence of various additives on the rheology of live and spent VDA system has recently been published.

In the eight Khuff candidate wells, the permeabilities in the completion intervals varied from 0.001 to 2.8 mD and the porosities ranged from 0.1 to 15%; typical perforated intervals were approximately 70 ft [21 m]; reservoir pressures were around 7500 psi [52 MPa]; and fracture gradients ranged from 0.976 to 1.06 psi/ft [22 to 24 kPa/m]. Before the acid-fracturing jobs, each well was flow-tested to determine a prefracture production rate and FWHP. This information was used later to assess the effectiveness of the stimulation treatments. All wells responded positively to the acid-fracturing treatments, surpassing Saudi Aramco expectations. In addition, all of the stimulated wells cleaned up quickly, saving time and reducing the volume of flared gas before the wells could be put on line.

Normally, because of the high fluid loss when acid fracturing with conventional systems, the pumping rate needs to increase substantially to keep the fracture open. However, with the VDA fluid, the leakoff rate is reduced because the in-situ viscosification dramatically lowers pump rates and hence horsepower.
Another technique to further enhance the requirements. The success of these treatments in deep, sour HPHT environments demonstrates the extended operating range of this new fluid.

Acid Fracturing in Mexico

PEMEX has employed acid fracturing in the Veracruz basin, Mexico, since 1995 and attributes the last decade’s increased gas production in the basin to these techniques. The Veracruz basin covers an area of 18,000 km² [6950 sq miles] and is located approximately 40 km [25 miles] southwest of Veracruz City (previous page, bottom). Here, attempts to divert treatments using ball sealers and to control leakoff using gelled oil-base pads were frequently unsuccessful. The introduction of self-diverting acid containing polymers improved diversion in 1997, but concerns regarding the damaging effects of polymers led to the use of VES technology in 1999.

Now, the combination of the ClearFRAC fluid and the new VDA system provides PEMEX with another technique to further enhance the production gains already realized from the acid-fracturing technique in this basin. Fracturing treatments use three fluids and the steps are repeated until the designed fracture parameters are achieved.

First, a viscous nonacid ClearFRAC pad initiates the hydraulic fracture and creates fracture length and width. Second, an alcohol-acid stage, containing 20% methanol or isopropanol and 80% acid at 15 wt% HCl concentration, etches a portion of the fracture and creates wormholes, which eventually lead to the loss of fluid. Third, a VDA fluid stage is pumped to fill the wormholes. The VDA fluid extends these established wormholes far more efficiently because the previously stimulated zones take less fluid, and wormholes far more efficiently because the VDA fluid.

The buildup-test results were then used in a NODAL analysis and produced an inflow performance relationship (IPR) that matched the initial production results, verifying the reservoir permeability, reservoir pressure and skin factor, and NODAL analysis to forecast the production after acid fracturing. Two wells in the Matapionche field were identified as promising candidates for the proposed acid-fracturing treatment using ClearFRAC fluid, alcohol-acid and VDA fluid.

The first well, the Matapionche Well 2181, was drilled in November 2002 and was subsequently perforated across three carbonate intervals between 9235 and 9416 ft [2815 and 2870 m] and then matrix stimulated. Porosity in the intervals ranged from 7 to 11% and the reservoir temperature averaged 180°F [82°C]. After the stimulation, the well produced 1.1 MMcf/D [31,504 m³/d] at a pressure of 420 psi [2.9 MPa] on a ½-in. choke. The well was not producing prior to the matrix stimulation. Buildup-test analysis determined an average permeability of 0.069 mD, a reservoir pressure of 3300 psi [22.8 MPa] and a skin factor of +1, indicating that the formation was slightly damaged (top left).

The buildup-test results were then used in a NODAL analysis and produced an inflow performance relationship (IPR) that matched the initial production results, verifying the reservoir parameters. Another IPR was constructed that incorporated the proposed acid-fracturing treatment, in the form of a lower skin factor. This analysis predicted that gas production would increase to 3.9 MMcf/D [85,920 m³/d] if a skin of −5 were achieved through stimulation (above left).

NODAL analysis on Matapionche Well 2181. Using the prestimulation production figure, inflow performance relationship (IPR) curves (red) and the representative tubing intake curve (green), NODAL analysis confirmed the buildup-test results. It also predicted that the Matapionche Well 2181 was capable of producing 3 MMcf/D [85,920 m³/d] of gas if the estimated poststimulation skin factor of −5 was achieved (blue curve).

Another IPR was constructed that matched the initial production results, verifying the reservoir parameters. Another IPR was constructed that incorporated the proposed acid-fracturing treatment, in the form of a lower skin factor. This analysis predicted that gas production would increase to 3.9 MMcf/D [85,920 m³/d] if a skin of −5 were achieved through stimulation (above left).
Once the Matapionche Well 2181 was selected as a potential candidate, laboratory tests were performed to ensure the proper viscosity response of the VDA fluid at both room temperature and the expected bottomhole temperature of 180°F. Break tests evaluated the effectiveness and the amount of the mutual solvent proposed in the design. In this test, gelled VDA fluids at pH values of 5 and 6—highly viscous after the acid spends—were mixed with the mutual solvent. A significant decrease in viscosity resulted, indicating a quick and effective cleanup would occur in the reservoir.

The final treatment was designed using local expertise and input from the Schlumberger InTouchSupport.com online support and knowledge management system. Hydraulic-fracture behavior was simulated in FracCADE fracturing design and evaluation software to optimize the design and obtain fracture parameters. The FracCADE simulation predicted that the optimal job in this case would yield an etched fracture half-length of 61.0 ft [18.6 m], an average etched fracture width of 0.33 in. [8.4 mm] and an average fracture conductivity around 133,500 mD-ft.

The treatment—16,000 gal [60 m³] of ClearFRAC fluid, 16,000 gal of alcohol-acid and 12,500 gal [47 m³] of VDA fluid—was bullheaded through 3 1⁄2-in. casing at a rate of 20 bbl/min [3.2 m³/min] (above). Throughout the job, nitrogen was pumped at a constant rate to enhance well cleanup. The acid stages were radioactively tagged and a postfracture gamma ray survey was run to evaluate the effectiveness of the stimulation.

Gas production after the acid-fracturing treatment exceeded PEMEX expectations; the Matapionche Well 2181 produced 5.2 MMcf/D [148,928 m³/d] at a FWHP of 1420 psi [9.8 MPa] on a ½-in. choke just after well flowback. After one week, the well stabilized to 3.3 MMcf/D [94,512 m³/d] at 700-psi [4.8-MPa] FWHP, matching the 300% increase seen in the NODAL forecast.

The postfracture gamma ray log showed that all three zones had been properly stimulated with acid (next page). Well cleanup has exceeded expectations; it is estimated that 70% of the treatment volume will be recovered. Another well in the Matapionche field, Well 1002, experienced similar results using the same methodology and the new acid-fracturing treatment.

In the Mecayucan field, PEMEX chose two adjacent candidate wells to acid fracture. On the Mecayucan Well 415, the company employed the same analysis, design and execution techniques used in the Matapionche field. This well contained five intervals of around 7% porosity, making this bullheaded stimulation down 3 1⁄2-in. casing a challenging task. After successful bullheading of the fracturing treatment, which
included the VDA fluid for diversion, the well produced 2.5 MMcf/D [71,600 m³/d] of gas, matching the NODAL prediction. After the well stabilized, the well produced 2.0 MMcf/D [57,280 m³/d] of gas, a 100% increase in gas production from that recorded after the initial matrix treatment.

Nearby Well 411, a second candidate well for acid fracturing, contained four intervals to be stimulated, ranging in porosity from 3 to 7%. VDA fluid was not used in this well. After acid fracturing, this well significantly underperformed against the NODAL prediction, and the postfracture gamma ray log indicated that one zone was unstimulated and another zone was understimulated, clearly showing that proper diversion was not achieved.

The VDA system has proved highly effective for diversion in the Veracruz basin, even when treatments are bullheaded from surface to multiple zones of varying reservoir quality.

New Life for Egyptian Oil Fields
In the oil fields of eastern Egypt, much of the production comes from heterogeneous dolomitic reservoirs. Commonly, these formations are layered, naturally fractured and mineralogically complex, containing dolomite, calcite, glauconite and various clays. Reservoir permeabilities are variable and formation damage caused by drilling and stimulation fluids can be severe. In addition, reservoir temperatures are low—less than 130°F [54°C]—and produced oil is heavy.

Historically, these characteristics have complicated conventional stimulation efforts and limited their effectiveness because conventional acids are less reactive to low-temperature dolomite. The use of polymer diversion systems, which use breakers and metal crosslinkers, has led to reservoir damage and lower production volumes. Moreover, iron from tubing can induce polymers to crosslink prematurely, increasing friction pressure and thus requiring more horsepower during pumping. Consequently, operators in Egypt are investigating new stimulation methods for both new and old wells, and even wells that have been temporarily abandoned.

The Schlumberger CSL in Kuala Lumpur played a key role in the development of a customized treatment to address the specific
stimulation challenges in this region. First, the complicated reservoir mineralogy was defined through extensive petrographic studies (below). Next, multiple laboratory tests were performed to optimize the treatment fluid.

Given the low reservoir temperature, the high risk of formation damage and precipitate development, and the reservoir heterogeneity, an intensified VDA fluid was recommended to provide the most effective diversion and stimulation. Moreover, the high quantity of formation silt and clay suggested that the MSR Mud and Silt Remover system should be incorporated into the treatment schedule. The MSR system has been used successfully to disperse drilling-fluid damage and help in the suspension of formation silts so that they can be removed from the wellbore. The combined VDA-MSR treatment was thoroughly tested on formation samples and with different additives at simulated reservoir temperatures to ensure the optimum chemical dissolution rate and to minimize formation damage. Heavy-oil samples from the reservoir were also tested for potential emulsion problems.

The treatment design called for alternating stages of the MSR and intensified VDA fluids, with each fluid being batch-mixed before pumping. Operational challenges were overcome through the innovative use of available technologies. For example, a dual-injection technique was used to treat heavy-oil-producing intervals on dual completion. Other wells producing heavy oil were completed openhole and required a different method to administer the treatment. In these cases, the VDA-MSR treatments were delivered to the reservoir through 1½-in. coiled tubing. The VDA fluid is especially suited for pumping down small tubing since it maintains a low viscosity during pumping and does not viscosify until it reacts with the formation. As a result, the lower friction pressure made this technique feasible.

The VDA-MSR treatments have been performed on more than 100 wells with excellent results. Effective diversion was clearly demonstrated during pumping (next page). The new technique has been responsible for an increase in production ranging from 400 to 800%. The wells clean up faster and production-decline rates are notably slower than with conventional treatments. The operator experienced quick payback of the stimulation costs, ranging from one day to just over a month. Most of the treatments paid out in less than one week. The overwhelming success of this program is having a sizable impact on drilling and development plans in Egypt’s eastern desert, and has made VDA technology an important element in the stimulation of new, old, and even abandoned wells.

The Right Chemistry
VDA treatment successes have been reported around the world. In September 2003, Transmeridian Exploration, Incorporated, Houston, Texas, USA, attributed significantly higher rates from their South Alibek 1 well in the Caspian Sea, offshore Kazakhstan, to improved stimulation and cleanup using the VDA system. This helped bolster the South Alibek field’s estimated reserve potential of more than 300 million barrels [47.6 million m³]. In Bahrain, the VDA system was used to matrix stimulate dry gas reservoirs in two wells, leading to 82% and 65% increases in gas production rates over the initial rates. During 2003, impressive results have also been documented in Canada, Indonesia, United Arab Emirates, Pakistan, Venezuela, Russia, West Africa, Tunisia and the USA, including the highly depleted, low-pressure dry gas reservoirs in the Permian Basin, Austin Chalk and the Gulf of Mexico.

These successes have been the result of extensive research, uncompromising support from stimulation experts around the globe, Schlumberger CSLs and through the InTouch-Support.com system. Research on carbonate reservoirs continues at Schlumberger-Doll Research in Ridgefield, Connecticut, USA, and at Schlumberger Dhahran Carbonate Research in Al-Khobar, Saudi Arabia, because thorough
knowledge of the reservoir is the first step in effective stimulation. The knowledge gained from these research activities is exploited every day at the Schlumberger CSLs and other laboratories around the world. A vast field-support network is crucial for proper fluid selection, treatment design and quality control, and directly benefits the operating companies that use this technology. Real-time monitoring of stimulation jobs using InterACT real-time monitoring and data delivery from remote locations brings more expertise to the wellsite, facilitating rapid evaluation of both the stimulation treatment and the results.

Recent VDA treatments for Rosetta Exploration, Incorporated, in Canada demonstrate the important role of the CSL when well conditions are harsh and the stakes are high. A high-temperature 4600-m [15,000-ft] deep well in Canada had failed to produce to expectations after a 30,000-liter [7925-gal] energized-acid treatment. The well was producing at 2 MMcf/D [57,270 m³/d] at 2 MPa [290 psi] FWHP and then subsequently scaled off. Coiled tubing was required to clear the pyritic scale and to deliver a new treatment to the reservoir. Unfortunately, the well was known to contain 22% H₂S and 8% carbon dioxide [CO₂], making it a difficult environment for coiled tubing operations. At this depth, high temperatures and the combination of corrosive gases and acid meant the treatment would require careful selection of inhibitor additives to ensure a safe and successful treatment.

The CSL in Houston, Texas, working with the coiled tubing team in Red Deer, Alberta, Canada, determined the optimal combination and concentration of compatible additives. A 21,000-liter [5550-gal] VDA treatment, carefully designed by experts, provided sufficient diversion at the required low injection rates and successfully stimulated this problematic well. After the VDA treatment, the well produced 6.5 MMcf/D [186,160 m³/d] at 7 MPa [1015 psi] FWHP and has now stabilized at a production rate 50% above the previous rate.

The quest for better stimulation fluids continues. At Schlumberger Cambridge Research (SCR), new molecules are designed and tested to continue the momentum begun by previous breakthroughs. Scientists at SCR and the Sugar Land Product Center continue their drive to expand the capabilities of existing fluid systems and to develop new fluid systems that overcome current challenges.

The enormous success of the VDA system is due to the combination of innovative chemistry, far-reaching technical support, uncompromising quality control during the design and operation stages, and the willingness of operators to apply new technology. This development in carbonate stimulation is making a clear and positive impact on production and injection rates, from the smallest wormholes to the largest fields.

—MGG

The way of doing business in Mexico’s oil and gas industry is changing. The results are high gains in efficiency and production as project scopes evolve from single-service contracts for logging, cementing or stimulation to full-scale field-development projects. This article highlights projects in two regions of Mexico—Burgos basin and Chicontepec paleochannel.

When national oil companies and resource holders need to increase activity in a field, they usually have three alternatives: They can invest in personnel and expertise; they can partner with another oil and gas company; or they can team up with an integrated-services provider.

Each option has advantages and disadvantages. Hiring expertise, while appropriate for some companies and some projects, may not suit every situation. Partnering with other companies can be successful in many cases, but is not allowed in some countries. Working with an integrated-services provider may allow operating company staff to concentrate efforts on more complex problems, but often requires learning a new way to operate.

Burgos basin in northern Mexico, covering 3706 sq miles [9595 km2]. Gas fields in the Burgos basin could contain up to 18 Tcf [515 billion m3]. They currently produce around 1 Bcf/D [29 million m3/d] of nonassociated gas. The Chicontepec paleochannel lies near Poza Rica.
Several oilfield services companies offer integrated services. At Schlumberger, the business segment charged with organizing and managing integrated-services projects is known as Integrated Project Management (IPM). The IPM organization offers a variety of project-management solutions, including development of new fields, rehabilitation of mature fields, well construction, production management and integration of well and production services.

In this article, we describe how Schlumberger IPM is working with Petróleos Mexicanos, or PEMEX, the national oil company of Mexico, to enhance production from fields in the Burgos basin and in the Chicontepec paleo-channel. Over the lifetime of these projects, the scope and commercial models have evolved to meet new challenges and to satisfy the project objectives of both operator and service provider.

Burgos Basin

Gas was discovered in the Burgos basin in 1945. Of the four basins in Mexico that produce non-associated gas, Burgos, covering 3766 sq miles [9695 km²], produces the most (previous page). Recent geological studies conducted by PEMEX indicate the Burgos fields could contain up to 1 Tcf [35.5 billion m³]. Today, the basin produces around 1 Bcf/D [29 million m³/d], and PEMEX Exploración y Producción is moving aggressively to double that production level.

The Burgos basin contains sediment thicknesses up to 30,000 ft [9000 m] of Upper Mesozoic- and Tertiary-age strata, and are geologically equivalent to the Queen City, Vicksburg, Wilcox and Lobo sandstones that are productive just to the north, in the Gulf Coast basin of southern Texas, USA.

Reservoirs in these low-permeability siliciclastic sediments are small and compartmentalized by faulting. Each compartment must be considered separately, with different petrophysical and depth-dependent properties. In this complex geology, formations with lost circulation and high pressure present drilling challenges. Most wells are drilled to depths of 9500 to 9800 ft [2900 to 3000 m], completed, and then hydraulically fractured. Initial well productivity is high, but declines quickly.

Project Evolution

In January 1994, faced with decline in production of nonassociated sweet gas from the Burgos basin, PEMEX established a small team of professionals to estimate the remaining production potential and recoverable gas reserves in the Burgos basin. The group outlined the necessary steps the company would have to take to continue working profitably from its center in Reynosa, Mexico.

The task force members produced a vision that many considered overly ambitious. However, through innovative contracting strategies, teamwork and the selective use of technology, implementation of their vision resulted in a sixfold increase in the rate of production from the basin—from 183 MMcf/D [5 million m³/d] in December 1993 to 1030 MMcf/D [29.5 million m³/d] in January 2003. During the course of the revitalization project, more than 74 new fields were discovered, and more than 3 Tcf [86 billion m³] of new reserves were added. Development and exploratory drilling activity increased from 10 wells completed in 1994, to 343 wells completed in 2002. In all, 1313 wells were completed during that time.

This extended period of success began with small-scale contracts and simple improvements to the well-construction process that evolved to encompass larger projects with greater impact. To increase production from wells in the central area of the Burgos basin, PEMEX awarded Schlumberger IPM a first contract to acquire 650 sq miles [1680 km²] of 3D seismic data, perform two integrated reservoir studies, drill 31 wells and construct a gathering station and four gas-compression plants. This work was completed in 11 months starting in mid-1997.

PEMEX awarded the second Burgos contract to a Schlumberger IPM competitor to construct, complete and connect 18 wells in a 10-month period ending in early 1999. After a few months of deficiencies in performance, PEMEX voided the contract and opened a new bid. Schlumberger IPM was awarded the drilling of 18 additional wells. By the end of the second contract, IPM had improved drilling performance in this part of the basin from an average drilling time of 36 days in 1997 to a new average of 22 days per well in 1999 (above left). This downward trend in drilling times continued through all subsequent stages of the Burgos projects.

In the next phase, PEMEX awarded IPM a contract to prepare 40 wellsites, drill 54 wells, and complete and connect 50 wells. The project, which was to take 18 months beginning in March 1999, took only 16 months.

By the middle of 2000, a drop in crude-oil prices motivated PEMEX to reduce oil exploration and production activities and invest in gas projects. More rigs were mobilized to continue the aggressive drilling program in the Burgos basin. Schlumberger IPM won the new bid with another integrated-services solution, this time one that included supplying and managing rigs, supervising and providing all necessary services, and utilizing PEMEX personnel. Drilling times in this area decreased from 25 to 15 days per well. Schlumberger directed management, engineering and operational issues for the preparation of locations, drilling and completion of all wells.

1. Nonassociated gas is natural gas that accumulates alone, without oil.
2. Sweet gas refers to gas containing no hydrogen sulfide.
The original contract included 40 wells. Novel approaches compounded the success of the project; for example, using production tubing as drillpipe resulted in cost savings that allowed 14 additional wells to be drilled. Over the course of drilling the 54 wells, 90 drilling-rig days were saved.

The next integrated-services project included preparation, drilling, completion and connection of 60 wells, to be completed by June 2001. Because of the efficiency of the PEMEX-Schlumberger cooperation, the contract was extended to a total of 190 wells by February 2002.

In the most recent contract, the scope of the integrated-services project, which initially included 100 more wells, was amended to increase the number of new wells to 210.

Schlumberger responsibilities were expanded to include the following:
- construction of access ways and wellsites
- design of drilling programs
- management and execution of operations
  - wellsite supervision
  - drilling fluids
  - directional drilling
  - logging
- completion
  - perforating
  - well testing
  - fracturing
- installation of flowlines
- provision of drilling rigs
- all logistics
- waste management.

Since January 2003, Schlumberger has completed 72 wells in this contract, with a collective initial production rate of 189 MMcfd [5.4 million m³/d]. Average initial production per well exceeded 2.6 MMcfd [74,500 m³/d], which is 5% higher than the past initial rate average. While completing these wells, Schlumberger performed 93 fracturing operations, perforating and testing 122 intervals.

Advances in well construction and improved drilling efficiency are not the only factors responsible for this dramatic production increase in the Burgos basin. New methods that help identify gas zones and improve understanding of reservoir properties are increasing completion efficiency and boosting production.

### Production Enhancement

Production from the Burgos formations has been enhanced by more accurate methods of characterizing gas-bearing reservoirs and by using this information to optimize well completions. An integrated approach to identifying productive zones combines dynamic reservoir information, obtained from wireline formation testers, with high-resolution porosity and permeability data obtained from nuclear magnetic resonance tools. These formation properties also contribute to better stimulation modeling and hydraulic-fracture design.

This strategy, known as the PowerSTIM well optimization service, can reduce operating costs and increase efficiency by allowing completion of only the most productive gas layers in every well. The PowerSTIM method, introduced in North America in 2000, has a current activity level of 150 projects per month, and has been successful in Russia, the Middle East, Europe, Africa, China and Southeast Asia. Examples
from three wells in the Burgos basin show how this integrated approach distinguishes zones worth completing from poor candidates.

The first Burgos candidate in which this methodology was used was a development well that encountered multiple layers of gas-bearing sandstones. Lithologically, the reservoir units are shaly sandstones with fine to very fine grains of quartz and feldspar, igneous rock fragments, clays and micas. The low permeability of these sandstones—0.05 to 5 mD—makes it necessary to hydraulically fracture them if they are to produce at economic rates. Permeability is so low that conventional production testing can take more than four days at each zone of interest to acquire sufficient buildup pressure for permeability analysis. Typically, in such a well, five or six layers would be tested, with unproductive results. Completion takes an average of 35 days per well, including testing, stimulating and plugging the unproductive zones, which are often in the majority.

In this well, the comprehensive formation evaluation facilitated by a full suite of petrophysical logs, plus measurements from CMR Combinable Magnetic Resonance and MDT Modular Formation Dynamics Tester, helps identify the zones most suitable for completion (previous page). Analysis of gamma ray, resistivity, CMR and MDT measurements points to the Queen City formation QC-5 and QC-3 intervals as the best performers. Pressures and permeabilities derived from the MDT tool are highest in these zones. The match between high-resolution permeabilities inferred from the CMR results and those from the MDT measurements brings confidence in the ability of the CMR tool to produce reliable permeability values at all well depths.

A synthetic flow profile computed from the CMR measurements indicates how much each level will contribute to overall well production. While numerous gas-bearing sands were detected in this well, two sands would deliver 70% of the potential gas production: 30% from the QC-5 zone at the bottom of the well and 40% from the QC-3 zone.

By ranking the most productive intervals, engineers can select the best candidates for hydraulic fracturing, thus drastically improving completion efficiency. In this case, only intervals QC-5 and QC-3 were stimulated. This optimization process cut 65% off the completion time required in comparable wells, accelerating production by 20 days and saving 20 days of completion time.

In another development well, the integrated approach to completion design involving interpretation of CMR, MDT and other log data helped to rule out some shallow zones that were being considered for completion (above). Again, permeabilities from the CMR tool matched those calculated from the MDT data at the five levels tested. Interpretation of petrophysical logs showed two sand-rich intervals. However, in the few zones that had the potential for gas, the CMR tool also indicated high volumes of free water. The well was not completed over the logged section due to the computed high water cut, saving rig time and termination costs to PEMEX.

The final Burgos example comes from an exploration well. Conventional log interpretation and formation evaluation based on high resistivities and crossover of the neutron-porosity and density-porosity log curves had limited value

when trying to identify productive reservoir within thin-bedded gas-filled sandstone (below). Since the CMR tool responds primarily to pore space, it gives a more reliable indication of gas-filled volumes than do other measurements. In this example, the CMR tool identified thicker continuous zones of pay than indicated by the crossover technique. The thickest of these, at 10-ft [3-m] thickness, was tested with the MDT tool. Permeabilities calculated from the MDT measurements correlated closely with permeabilities derived from averaging the high-resolution CMR results, and averaged 10 mD throughout the zone. The good correlation between CMR and MDT permeability estimates in this zone gave engineers confidence that the 6-mD permeabilities measured by the CMR tool alone in a shallower zone were real and reliable.

At 6 and 10 mD, the two zones were permeable enough for the well to produce without being hydraulically fractured, according to production simulation results. Simulations from ProCADE well analysis software estimated production at 2653 MCF/D [75,982 m³/d]. The interval was perforated and produced 2571 MCF/D [73,633 m³/d] without stimulation.

PowerSTIM methodology, which integrates petrophysical and reservoir knowledge with completion design, execution and evaluation, was applied to more efficiently select sands with high productivity potential and to design more efficient fracturing programs. Before implementation of this methodology, the average Burgos well produced 1 MMCF/D [29,000 m³/d]; now the average is 4.5 MMCF/D [129,000 m³/d]. The PowerSTIM process reduced completion times by an average of 60% in the Burgos basin. Completion costs have dropped by a similar percentage.

Today, the Burgos contract between PEMEX and Schlumberger calls for the construction of wells at a given price and location. Schlumberger, however, has proposed that it can bring additional value to PEMEX by taking more responsibility in the selection of well locations, designing the completions and optimizing production.
Selecting optimal well locations will require reservoir characterization and integrated geological studies. Advanced seismic techniques such as amplitude variation with offset (AVO) analysis, inversion, sequence stratigraphy and attribute analysis will help interpreters choose well locations based on a geological model, maximizing productivity and minimizing the risk of drilling uneconomical holes. Technology to detect gas in low-resistivity pays will help tap more gas zones. Simulating field performance and including the effects of surface facilities will help optimize production. Adding high-, medium- and low-pressure lines in production systems will help optimize individual well performance and eliminate bottlenecks in surface facilities (above).

**Chicontepec Production Enhancement**

The Chicontepec region is another mature area with potential for production enhancement. Oil was discovered there in 1926, and first commercial production began in 1952. The current fields all lie within a geological feature called the Chicontepec paleochannel, located in northern Veracruz state, 250 km [153 miles] from Mexico City and 5 km [3 miles] from Poza Rica. The paleochannel is a 3815-km² [1473-sq mile] accumulation of Paleocene-age sediments. This thick, low-permeability deposit contains 139 billion barrels [22 billion m³] of original oil in place and 50 Tcf [1.4 trillion m³] of gas. About 12 billion barrels [2 billion m³] and 31 Tcf [888 billion m³] are recoverable, making it the largest PEMEX asset.

From 1952 to 2002, 951 production wells were completed. On average, the wells were modest producers, with initial production rates on the order of 70 to 300 BOPD [11 to 48 m³/d]. By 2002, total field production averaged 2500 BOPD [397 m³/d] and 12 MMcf/D [344,000 m³/d]. In its first 50 years, the field had produced just 111 million barrels of oil [18 million m³] and 195 Bcf [5.6 billion m³] of gas.

In 2002, PEMEX initiated an aggressive strategy to increase field production over the next four years. The production goal for 2006 is to reach 39,000 BOPD [6200 m³/d] and 50 MMcf/D [1.4 million m³/d], increasing oil production by a factor of more than 10, and boosting gas production more than fourfold. Central to the success of this project is the construction of wells whose productivity is significantly higher than the historical average.

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To make this vision a reality, Schlumberger IPM, in partnership with ICA Fluor and Drillers Technology de México, has signed a contract with PEMEX to develop the Coapechaca, Tajín and Agua Fría fields of the Chicontepec asset. Building on the Burgos contract performance, PEMEX has contracted Schlumberger to take greater responsibility in the Chicontepec project. The Schlumberger IPM role is to deliver the field-development plan, including reservoir-characterization studies, optimization of subsurface well locations, drilling and completing all wells, rig management, a pilot test for water injection, construction and upgrade of gas-compression stations, pipeline construction and all logistics.

The project began with bid preparation and submission at the end of 2002 and reached full mobilization by mid-2003, with the first well spudding in May. Project timing allows 1400 days for 200 wells. Key project goals for 2003 included updating the sector reservoir studies to better identify the most suitable locations to place higher productivity wells; drilling 59 wells and completing 46 wells before year-end; building 8 multiwell pads; constructing 50 km [30 miles] of pipeline; and constructing and upgrading 6 production- and compression-facility modules.

The environment surrounding the Chicontepec area is sensitive, and home to many protected plant species. Wellsites have been designed for minimal environmental impact. Fit-for-purpose drilling rigs have been built to optimize drilling times and rig moves on multiwell pads (above). Wells are drilled directionally, with 3 to 18 wells from each pad. State-of-the-art rigs with topdrives and telescoping masts keep pipe in the derrick when moving between wells on the same pad. Rigs are equipped with skidding mechanisms to reduce move time from three days to less than 12 hours. Perforating, fracturing, coiled tubing operations and testing are performed without a rig.

**Stimulation Strategies in the Chicontepec Paleochannel**

To help PEMEX further improve production from the Chicontepec area, Schlumberger stimulation specialists are evaluating the potential to increase production through the application of the PowerSTIM methodology that has proved so successful in Burgos projects. However, instead of applying the technique on individual wells, engineers and interpreters are developing a stimulation strategy to optimize the overall performance of the fields in the Chicontepec paleochannel. This large-scale study encompasses the area bounded on the west by the Sierra Madre Oriental and on the east by the Faja de Oro reef.

The first step in the study was to evaluate the current development plan and to validate well locations proposed by PEMEX Exploracion y Produccion (PEP) asset teams. This required complete reevaluation and integration of 3D seismic, geological, production, core and log data. Analysis of the stimulation history of each sandstone layer indicated that cost-effective production improvements could be realized by selectively stimulating higher quality zones.

Candidate selection and stimulation-treatment design using the PowerSTIM method helped achieve higher production per fracturing job and at lower cost compared with production levels and costs achieved on previous drilling campaigns.
Further Growth in Chicontepec Production and Beyond

The enhanced candidate-selection techniques and fracturing practices encompassed by the PowerSTIM approach have been shown to improve the cost-effectiveness of stimulation in the Chicontepec paleochannel. Further improvements will focus on optimizing the productivity of the highest potential zones. New logging and imaging services are already being introduced to increase understanding of the reservoir and to aid the stimulation process. As in the Burgos basin, the CMR-MDT combination is helping Chicontepec reservoir engineers improve the completion process for each well. The next steps will introduce new fracturing fluids and technologies to this high-potential asset, increasing the ability of stimulation treatments to enhance production from each well and to increase profitability for PEMEX.

Properly exploited, Chicontepec reserves constitute one step toward overcoming Mexico's current oil production decline. Efficient development of other fields and discovery of new accumulations are required to reverse the decline and replace reserves. So far, Mexico's reservoirs have mostly undergone only primary recovery, and are now experiencing varying degrees of depletion. Developing strategies for enhanced recovery will become important to maintaining production goals.

One area likely to see expanded activity is the Mexican sector of the Gulf of Mexico. As of 2001, more than 20,000 wells had been drilled targeting natural gas in the US sector of the Gulf of Mexico, while only 400 wells were drilled in the Mexico sector (left). This vision of the future predicts an increased number of integrated projects and dramatic growth in drilling activity and hydrocarbon production in the next five to ten years.

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^ Vision of Gulf of Mexico oil and gas exploration and production activity. Currently, the vast majority of oil and gas fields are in the US sector of the Gulf of Mexico (top). One vision of future production shows a similar level of activity spread across the Mexico sector within ten years (bottom). Red and yellow dots are gas wells. Green dots are oil wells. [Adapted from “México at a Glance: The MCA Story,” México Interchange (November 11-14, 2003): 21.]
The New Dynamics of Underbalanced Perforating

Controlling the transient pressure differential in a wellbore during perforating is a key to more effective cased-hole completions. This technique uses an innovative design process and specialized hardware to significantly improve well productivity and injectivity.

Every cased well must be perforated so fluids can flow from subsurface zones or be injected downhole. The controlled detonation of specially designed and manufactured shaped charges creates holes—perforations—in steel casing, cement and the surrounding formation. Optimizing production or injection requires careful design, prejob planning and field implementation to obtain clean, conductive perforations that extend beyond formation damage into unaltered reservoir rock.

Unfortunately, explosive perforating also pulverizes formation rock grains, causing a low-permeability crushed zone in the formation around perforation cavities and creating a potential for migration of fine particles. This process also leaves some residual detonation debris inside the perforation tunnels. Elastic rebound of the formation around newly created perforations generates additional shock damage and loose material (next page).

Minimizing flow impairment and conductivity restrictions caused by this induced perforating damage are crucial for obtaining effective perforations. For 25 years, standard completion procedures have relied on a relatively large static pressure differential, or underbalance, to eliminate or minimize perforating damage.

Underbalanced pressure is the most widely accepted technique for optimizing perforated completions. This method establishes a static wellbore pressure before perforating that is less than the adjacent formation pressure. Conventional wisdom suggests that surge flow from a reduction in near-wellbore pore pressure mitigates crushed-zone damage and sweeps some or all of the debris from perforation tunnels.

Schlumberger scientists analyzed transient perforating pressures during laboratory tests and found that static underbalance alone does not ensure clean perforations. Results indicated that previously neglected fluctuations in wellbore pressure immediately after shaped charges detonate, not the initial pressure differential, actually govern perforation cleanup.

Researchers applied this improved understanding of dynamic wellbore pressures to develop the patented PURE Perforating for Ultimate Reservoir Exploitation process. This new technique is applicable for wireline- or slickline-conveyed charge carriers, or guns; and coiled tubing or tubing-conveyed perforating (TCP) systems in either vertical or high-angle completions, including horizontal wellbores.

The PURE process uses customized perforating designs, specialized shaped charges and fit-to-purpose gun configurations to generate a large dynamic underbalance from modest static underbalanced or overbalanced pressures. This proprietary technique significantly improves well productivity or injectivity. The PURE perforating process also improves well-completion operational efficiency.
Eliminating the need for large static pressures differentials makes well preparations prior to underbalanced perforating more straightforward. Controlling surge flow limits produced fluid volumes during perforation cleanup, which reduces the risk of sand influx that can result in stuck guns. Small acid jobs, or perforation washes, that are often required to remediate perforating damage may not be needed.

In addition, dynamic underbalanced perforating increases the number of open perforations, thereby enhancing the effectiveness of larger acid and fracturing treatments. A higher effective shot density, or number of shots per foot (spf), also optimizes pumping operations by decreasing horsepower requirements. Another benefit is the reduction in perforating shock intensity, which minimizes disruption of the cement-sandface hydraulic bond and helps ensure zonal isolation after perforating.

This article describes innovative perforating and completion design methods, gun systems and associated hardware designed specifically to control dynamic underbalanced pressure. Case histories from North America and the North Sea demonstrate results from PURE perforating designs based on specific reservoir properties and well configurations.


^ Perforating and perforation damage. Shaped charges consist of four basic elements—primer and main explosives, conical liner and a case. The conical cavity and metal liner maximize penetration through steel casing, cement and rock. As charges detonate, the liner collapses to form a high-velocity jet of fluidized metal particles. Perforating shock waves and high-impact pressure shatter rock grains, break down intergranular mineral cementation and debond clay particles, creating a low-permeability crushed zone in the formation around perforation tunnels. Perforating damages in-situ permeability primarily by crushing formation material impacted by the jet and reducing pore-throat sizes. Photomicrographs show undamaged rock and microfractures in the crushed zone.
Underbalanced Perforating

In the 1970s, completion engineers recognized the potential of underbalanced pressure for improving perforated completions. Research during the 1980s and 1990s confirmed that a high static pressure differential between wellbore and formation often yielded more effective perforations. These studies concluded that rapid fluid influx was responsible for perforation cleanup and recommended general underbalanced perforating criteria.⁷

Research focused on two primary assumptions: first, that wellbore pressure remains essentially constant during perforating and perforation cleanup; and second, that the static underbalanced pressure prior to gun detonation is effective across the perforation tunnels of an entire completion interval. Research concentrated on establishing specific underbalanced pressure criteria and predicting the degree of underbalance needed to ensure clean perforations.

A 1985 Amoco study correlated results from 90 wells that were acidized after perforating with tubing-conveyed guns and a range of underbalanced pressures.⁵ Results did not imply that all perforation damage could be removed, but suggested that acid stimulation was not necessary or as effective when sufficient underbalanced pressure was achieved.

In 1989, researchers calculated underbalanced pressures in gas wells based on sand-production potential determined from sonic logs.⁸ Their study combined new data with data from the prior Amoco project to develop equations for the minimum underbalance required to eliminate the need for acid stimulation.⁹ Another study indicated that flow and surging after perforating were less critical in damage removal, but might sweep debris and fines into the wellbore.⁹

Until recently, scientists believed that the magnitude and duration of surge flow after underbalanced perforating dominated perforation cleanup.⁷ Immediately after charge detonation, pore pressure drops and reservoir fluids decompress around new perforations, causing a sudden fluid influx. This instantaneous surge minimizes pore-throat invasion by completion fluids and solids, loosens damaged rock, and cleans some loose material out of the perforation tunnels (top right).

Laboratory tests indicate that turbulent flow is not required to remove perforating damage. One theory suggests that perforation cleanup is related more to viscous fluid drag during surge flow. However, most data suggest that higher underbalanced pressures than those commonly used in the past are required to effectively minimize or eliminate perforating damage.¹⁰ A less than optimal underbalance can result in variable flow rates per perforation and different degrees of damage removal.

Dynamic forces—pressure differential and drag—that mitigate permeability damage by eroding and removing fractured formation grains from perforation walls are highest immediately after perforating. This is the starting point for developing semi-empirical equations for underbalanced pressure and perforation damage, or skin, from historical datasets. The key factors are maximum transient pressure differential and subsequent drag from slightly compressible radial flow, either laminar or turbulent.

Behrmann proposed equations to calculate the optimal underbalance for zero-skin perforations, or conversely, to calculate the skin if underbalanced pressure is less than optimal.¹¹ Now the most widely accepted underbalanced-pressure criteria, these equations were the result of more than a decade of perforating research. This technique recommends underbalanced pressures that are two to four times greater than those used in previous methods (above).
A static pressure underbalance alone does not necessarily deliver consistent results. Well productivity after static underbalanced perforating can be disappointing, while results from perforating with initially balanced or over-balanced pressures sometimes are surprisingly good. Until recently, researchers focused little attention on exactly how much pressure underbalance actually occurs. That changed with the advent of pressure gauges that have extremely fast sampling rates. These new gauges provide more detailed, higher resolution data about wellbore pressure variations immediately after perforating.13

More recent investigations indicated that shear failure of the crushed zone, not erosion due to surge flow, removes perforation damage.13 Shear failure depends on rock strength and effective formation stress. In turn, shear forces are related to the magnitude of the pressure differential during underbalanced perforating. Therefore, underbalanced pressure control cleanup, but the required magnitude depends on the rock strength rather than its permeability.

For sandstone formations, rock strength and permeability are somewhat related, although no such relationship exists for carbonates.

**Experimental Investigation**

Laboratory tests indicate that wellbore pressure oscillates for a few hundredths of a second as the explosive detonation, high-velocity jets and shock waves pass through wellbore liquids. Detailed studies of these transient phenomena are performed in the Productivity Enhancement Research Facility (PERF) at the Schlumberger Reservoir Completions (SRC) Center, Rosharon, Texas, USA (above).

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Bartusiak et al., reference 9.
In contrast to previous studies, recent testing at SRC varied perforating configurations to investigate transient, or dynamic, pressures during single-shot tests. Researchers collected microsecond-resolution—fast—and millisecond-resolution—slow—pressure data under simulated downhole conditions to better understand the resulting pressure transients.

In the first series of tests, researchers perforated four standard Berea sandstone cores with identical shaped charges and an initial underbalance of 1000 psi [6.9 MPa] (left). In another series of tests, three Berea cores similar to the first four were perforated with a 500-psi [3.45-MPa] static overbalanced pressure (below left). Results confirmed that wellbore pressure varies significantly immediately after shaped-charge detonation.

In each test, simulated wellbore pressure increases after extremely rapid transients associated with shock-wave propagation and then decreases as wellbore liquids enter spent guns. Wellbore pressure increases again as reservoir fluids flow into the wellbore and far-field wellbore fluid decompresses. Under certain conditions, wellbore pressure can change from underbalance to overbalance to increased underbalance within the first half-second.

Computed tomography (CT) provided X-ray images of each core after single-shot perforate and flow tests. These CT scans provided a qualitative analysis of perforation lengths and conditions. Researchers at SRC believe that the amount of debris remaining in perforations is indicative of variable levels of surge flow immediately after perforating. In addition, core flow efficiency (CFE) was analyzed to quantitatively evaluate the effects of dynamic underbalanced pressure (next page). The resulting consistent perforation length and shape are indicative of high-quality shaped charges and consistent Berea core targets.

$$\text{CFE} = \frac{\text{steady-state flow through a perforated core}}{\text{theoretical flow through a drilled hole with the same dimensions as the perforation}}$$

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These results indicated that effective dynamic underbalanced pressures could be achieved starting from an initial static overbalance.
Although crushed-zone damage is not visible on CT scans, its magnitude can be inferred from CFE ratios. A CFE of about one suggests that there was no flow impairment from injected debris and fines nor crushed-zone damage because surge flow occurred.

The estimated underbalance required to completely remove induced perforation damage is about 2400 psi [16.5 MPa] for Berea cores under these test conditions. Therefore, the 0.67 average CFE for the first three tests is reasonably close to expectations for a 1000-psi underbalance.

The high dynamic underbalance—more than 2400 psi—achieved during Test 7, which started with a 500-psi static overbalance, resulted in a CFE of 0.92. This level of perforated core productivity was better than in any of the static underbalanced tests.

Many industry experts believe that static overbalanced perforating cannot be effective because it precludes effective surge flow and potentially carries fine particles into formation pore throats. Indication of surge flow during two of these static overbalanced perforating tests surprised investigators and was counter to conventional wisdom.

Perforation damage cleanup now appears to be directly related to both the maximum dynamic underbalance and the rate of instantaneous surge flow, not the initial static wellbore—underbalanced, balanced or overbalanced. This new concept helps explain occasional poor results from underbalanced perforating and unexpected good results from balanced and overbalanced perforating.

Results and conclusions from this project suggested a new approach to perforation cleanup and provided the basis for a new perforating technique. This PURE process specifies unique wellbore and gun configurations to optimize the sharp drop in pressure, or dynamic underbalance, that occurs after charge detonation. The next step was to apply the techniques in field trials.

Enhancing Productivity

ChevronTexaco performed the first trials of this new technique in the East Painter field near Rock Springs in southwestern Wyoming, USA. Previously, the company perforated these wells, which were completed with cemented casing, using tubing-conveyed guns and moderate static underbalanced pressures—300 to 600 psi [2.1 to 4.1 MPa]. The wells typically required small coiled tubing perforation acid washes to establish flow after perforating.

Large foam-diverted acid treatments followed these perforation washes to establish commercial production rates. Moderate economic success provided an incentive to evaluate other options. Engineering studies suggested that greater underbalanced pressure differential was required to improve perforating effectiveness and enhance well productivity.

Output from SP AN Schlumberger Perforating Analysis software based on designs using the Behrmann criteria suggested that an underbalance of about 4000 psi [27.6 MPa] was needed to achieve zero perforation skin in the Nugget sandstone reservoir with permeabilities ranging from 0.01 to 100 mD. However, the existing 4600-psi [31.7-MPa] reservoir pressure required an extremely low initial wellbore pressure to achieve this large static underbalance, while conventional practices in this field did not provide sufficient underbalance to achieve clean perforations.

The PURE perforating process solved this problem by generating a high dynamic underbalance from a modest initial underbalance or overbalance. Two single-shot perforate and flow tests performed in the PERF laboratory at SRC simulated conventional and PURE perforating using actual Nugget outcrop cores (right).

The first test simulated conventional perforating with an initial 4000-psi static underbalance and the wellbore open to the atmosphere. The next test modeled PURE perforating starting from a 500-psi static overbalance and the perforated zone shut-in below a packer. Schlumberger proposed a PURE perforating system based on Test 2 that started with an initial 500-psi overbalance. This design required a retrievable packer with a closed string above tubing-conveyed perforating (TCP) guns and a fast-opening production valve below the packer. However, the requirement for a profile nipple in the production tubing eliminated this option.

Engineers redesigned the gun system to generate a 2400-psi dynamic underbalance from a 400-psi [2.8-MPa] static underbalance. Based on previous laboratory tests, the resulting dynamic underbalance would result in a well productivity similar to that of Test 2.

PURE planning software helped engineers specify the appropriate gun system, including PowerJet deep-penetrating shaped charges, shot densities and specific charge configurations for each well to achieve an adequate dynamic underbalance. Gun lengths ranging from 15 to 20 ft [4.6 to 6.1 m] were chosen based on formation permeability. Short intervals used PowerJet 3406 charges at 6 spf; long intervals used PowerJet 2906 charges at less than 6 spf; intermediate-length intervals used PowerJet 2906 charges at 6 spf.

Four out of five of wells completed with these PURE designs resulted in successful completions without additional stimulation. The first PURE completion attempt required an acid...
treatment to establish production after a mechanical failure resulted in post-perforating damage to the formation. The application of PURE technology saved more than $150,000 per well compared with previous completions that were perforated conventionally.

Increasing Injectivity
Nederlandse Aardolie Maatschappij (NAM) drilled the Borgsweer 4 well in The Netherlands during 2001 as a water injector for the giant Groningen gas field. Water disposal is critical to continuous operations in this field, and collapsed casing in an existing injector required that well construction be fast-tracked. The Borgsweer 4 targeted the Rotliegend sandstone reservoir, which has a porosity of 18 to 22%, a permeability ranging from 40 to 400 mD and a formation pressure of 2530 psi [17.4 MPa].

NAM typically perforates water-injection wells and establishes injectivity by pumping cold water to thermally fracture the formation. Completion engineers initially planned to establish a static underbalanced pressure before perforating by circulating nitrogen from about 1000 m [3281 ft] with coiled tubing. As an alternative, Schlumberger proposed the PURE technique using wireline-conveyed guns to generate an effective dynamic underbalance with static wellbore pressure initially equal to the formation pressure—balanced.

An initial perforating run with a conventional gun punctured the casing to allow wellbore pressure and formation pressure to equalize. This left the well in a hydrostatically balanced condition. These perforations were not expected to clean up completely, but they could potentially contribute some injectivity. For the two subsequent PURE perforating runs, engineers designed gun configurations to create a dynamic underbalance starting from balanced pressure conditions. Both perforating runs achieved dynamic underbalanced pressures (left).

However, the initial injection rate after perforating was lower than expected because of slow initiation of thermal fractures in the formation and possible injection of fines into the formation pore throats. The cyclical pressure oscillation, or water-hammer effect, that occurred after achieving a dynamic underbalance could have contributed to perforation damage and impaired injectivity. The perforating string was subsequently modified to include PURE charges and PURE chambers that alleviate unwanted pressure increases by increasing the gun volume open to flow.

This was the first field trial of dynamic underbalanced perforating in continental Europe. Borgsweer 4 operations proved that PURE systems could achieve an effective dynamic underbalance starting from balanced hydrostatic conditions. It also showed that gun configurations could be modified to alleviate adverse fluctuations in wellbore pressure, such as the water-hammer effect.

Candidate Selection and Applications
All wells, producers and injectors alike, should be considered potential PURE candidates. Evaluating rock type, fluid types, and formation porosity and permeability, and performing simulation using SP AN software help determine if a well will benefit from the PURE technique. In most areas, many new and existing well completions will benefit from the application of PURE dynamic underbalanced perforating.

Most injection wells are excellent PURE candidates because clean perforation tunnels are essential for optimal injectivity. Achieving an adequate dynamic underbalance ensures sufficient surge flow to remove loose material from perforation tunnels before injection begins. It also prevents debris and fine formation particles from being injected and sealing off formation pore throats.

The PURE technique has been particularly effective in low-permeability formations that require extremely high underbalanced pressures for perforation cleanup. Such large pressure differentials are often difficult to achieve during conventional perforating operations with static underbalanced pressures.

In horizontal or deviated wells, displacing drilling or completion fluids to obtain the required static underbalance is often difficult. Dynamic underbalanced perforating helps avoid costly and inconvenient displacement of wellbore fluids with a lighter liquid or inert gas to achieve the required pressure underbalance. Conventional static overbalanced perforating with potentially damaging fluids in a wellbore may cause damage that only near-wellbore acid treatments can remove.

The highest priority well candidates, those that provide the most value to operators, are wells with significant potential for productivity improvement. Also included are well conditions that require expensive operations to establish an adequate static underbalance, wells that typically require near-wellbore acid perforation washes after perforating and those that require high underbalanced pressures.

The PURE candidate-selection process focuses on improving the ratio of crushed-zone permeability to formation permeability ($K_c/K$) to increase well performance (left). Dynamic underbalanced perforating achieves high productivity levels with fewer (6 spf) perforations (middle). Clean PURE perforations ($K_c/K=1$) improve productivity more than increasing shot density (12 spf) or perforation length (bottom).
Perforating Tight, Low-Pressure Formations

In 2002, Anadarko Petroleum Corporation applied dynamic underbalanced perforating in the Brady gas field of Wyoming. In addition to containing high concentrations of H₂S, the Weber formation comprises about 600 ft [183 m] of interbedded sand, shale and dolomite stringers. Permeability ranges from 0.5 to 1.5 mD with a current reservoir pressure of less than 2800 psi [19.3 MPa] at 14,000 ft [4267 m].

The 18 existing well completions in this field used wireline-conveyed guns and static overbalanced perforating techniques, which resulted in minimal flow. Anadarko performed perforation-wash treatments using hydrochloric-hydrofluoric [HCl-HF] acid to establish commercial production. After acidizing, these wells typically flowed 1 to 5 MMcf/D [28,640 to 143,200 m³/d] of gas. Three of the wells required fracture stimulations.

Anadarko chose the PURE perforating technique to recomplete the Brady 38W well in an upper section of the Weber formation. Cement-squeeze perforations above the target zone made remedial acidizing and hydraulic fracturing difficult if perforating did not achieve desired results. Dynamic underbalanced perforating provided the best chance for a successful completion without additional stimulation.

A prejob NODAL production system analysis indicated that the well should produce about 3.85 MMcf/D [110,260 m³/d] with zero perforation damage (above). However, completion skin historically exceeded 20 after perforating overbalanced and before acidizing. The PURE technique achieved a sustained flow rate of 5.2 MMcf/D [148,930 m³/d] just hours after perforating with an initial 3250-psi [22.4-MPa] overbalance. The estimated perforation skin was negative 1.17, or slightly stimulated.

Later in 2002, Anadarko drilled the 56W well, the first new Brady field well in more than 17 years. The success of the Brady 38W recompletion convinced Anadarko to use the PURE technique again. Both wells used permanent TCP completions (above right).

A NODAL analysis indicated that this well should produce about 3 MMcf/D [85,920 m³/d] with zero perforation skin. The well actually flowed at a stabilized rate of 4.2 MMcf/D [120,290 m³/d], indicating a negative 1.2 perforation skin. The low bottomhole pressure (BHP) resulted in a static overbalance of 3750 psi [25.9 MPa]. The 56W well would have required additional stimulation if perforated conventionally.

After perforating, the 56W well unloaded slowly because of a lower than expected BHP—2300 psi [15.9 MPa]. The low-permeability, low-pressure reservoir required immediate flowback and cleanup after perforating to avoid further completion damage. The TCP assembly consisted of 2¾-in. PURE HSD High Shot Density gun systems designed to create a dynamic underbalance, a fast-acting SXPV production valve, mechanical and backup hydraulic-delayed firing heads, a sliding sleeve and a packer.

The TCP assemblies were run with the wellbores full of completion fluid and the sliding sleeves open. The sliding sleeve was closed after setting the packer, trapping pressure at 6050 psi [41.7 MPa] around the guns. Fluid level in the tubing was swabbed down to about 12,000 ft [3658 m], 1000 ft [305 m] above the packer. The initial wellbore condition in both wells was a pressure overbalance.

A drop bar released from surface initiated the mechanical firing head. The guns detonated and the production valve opened after a dynamic underbalance was generated. With the tubing open and previously swabbed to underbalanced fluid level, the well instantly flowed into the surface production system. If the drop bar malfunctioned, gas pressure on the tubing could activate the backup hydraulic firing head. The gas would be bled off during the firing delay to evacuate the tubing.

These PURE designs were also adjusted to account for the final wellbore pressure in case the SXPV valve failed to open. PURE charges and internal gun volume had to be designed correctly based on wellbore volume and pressure, otherwise perforating pressure could go from initial overbalance to an dynamic underbalance and back to overbalance, causing perforation damage. The 56W well required additional PURE chambers to ensure that wellbore pressure remained underbalanced or balanced after achieving a dynamic underbalance.

Dynamic underbalanced perforating eliminated the need for near-wellbore perforation washes with acid. Both wells flowed naturally after perforating. Completion operations were more efficient, resulting in relatively safer, quicker gas sales in this sensitive H₂S, or sour-gas, environment. The success of these two wells further confirmed the potential of PURE perforating.

Optimizing New Completions
In the southern South Sea, NAM also drilled a high-angle well along the eastern margin of the Broad Fourteens basin. The well targeted a 140-m [459-ft] gas-bearing reservoir in the Rotliegend sandstone. Formation porosity ranged from 5 to 15% and permeability varied from 0.2 to 20 mD. Reservoir pressure obtained from an MDT Modular Formation Dynamics Tester tool was 46 MPa [6672 psi].

Because of the low permeability in these reservoirs, NAM planned to use coiled tubing-conveyed perforating in conjunction with a CIRP Completion Insertion and Removal under Pressure system to achieve a high static underbalanced pressure and retrieve the long gun string without killing the well. Because of the
completion configuration, NAM chose 2 7/8-in. HSD guns with PowerJet shaped charges loaded at 6 spf for conventional perforating. Acidizing the well would finalize the completion.

Prejob modeling indicated that this well could benefit from dynamic underbalanced perforating. In addition, the Borgsweer 4 injection well results and an ongoing field test of PURE gun systems in other NAM gas wells had provided encouraging results. As a result, the NAM team agreed to perforate this well using a specifically designed PURE gun system with charges loaded at 4 spf. The 195-m [640-ft] PURE gun string with a 7-m [23-ft] PURE chamber was run on 1 1/4-in. coiled tubing and fired with an initial 700-psi [4.7-MPa] underbalance (previous page).

The well flowed about 2.5 million m³/d [87 MMcf/D] of gas after PURE perforating, exceeding the expected flow rate of 0.5 to 1.5 million m³/d [17 to 52 MMcf/D]. Because of this unexpectedly high flow rate, a planned acid treatment was cancelled. NAM is currently evaluating PURE designs for future gas-completion applications.

Dynamic underbalanced perforating is gaining acceptance throughout the North Sea and operators are applying the technique with equal success in other fields of the region. In mid-August 2003, CNR International performed two PURE jobs in the Ninian North field in the North Sea UK sector. The company perforated two wells designated N-41 and N-42 in the Ninian North field during shoot-and-pull operations with a drillstem test (DST) assembly.

To achieve a PURE perforation design, the DST string for these two wells created a closed system and the gun system was configured to achieve a dynamic underbalance (right). Pressure gauges with slow 1- and 5-s sampling rates recorded the pressure response at the bottom of each DST gun string.

In the first application, CNR perforated eight zones totaling 992 ft [302 m] of net pay across a 2200-ft [671-m] gross interval in the N-41 well. The TCP test string included 3 3/8-in. HSD guns designed to generate a dynamic underbalance...
1.54 MMcf/D [44,110 m³/d] gas.  

conventional perforating.  

1600 ft [488 m] were perforated with a dynamic 

[277 m] of net pay across a gross interval of 

String. Three zones encompassing about 910 ft 

configured for PURE perforating in the DST 

ing up, the N-42 well produced 421 B/D [67 m³/d] gas. 

much higher than the 5300 psi [36.5 MPa] 

pressure of more than 6100 psi [42.1 MPa], 

pressure after perforating indicated a reservoir 

of 9500 B/D [1510 m³/d]. Well output stabilized 

(right). This well produced at an initial oil rate 

of 9500 B/D [1510 m³/d]. Well output stabilized 

at 7500 B/D [1192 m³/d] oil, 50% higher than the 

original projection of 5000 B/D [795 m³/d] for 

conventional perforating.  

For the N-42 well, CNR used 3½-in. HSD guns 

configured for PURE perforating in the DST 

string. Three zones encompassing about 910 ft 

[277 m] of net pay across a gross interval of 

1600 ft [488 m] were perforated with a dynamic 

underbalance (next page). The initial surface 

pressure after perforating indicated a reservoir 

pressure of more than 6100 psi [42.1 MPa], 

much higher than the 5300 psi [36.5 MPa] 

encountered in the N-41 well. While still cleaning 

up, the N-42 well produced 421 B/D [67 m³/d] oil, 2633 B/D [419 m³/d] water and 

1.54 Mmcf/D [44,110 m³/d] gas. 

Tubing pressure applied at the surface actuated 

a hydraulic-delay firing (HDF) head. During 

the time delay before gun detonation, an 

Intelligent Remote Dual Valve (IRDV) tester 

valve was closed, trapping hydrostatic pressure 

around the guns—about 8000 psi [55.2 MPa] 

in the N-41 well and about 8600 psi [59.3 MPa] 

initially in the N-42 well. 

In both wells, the high static overbalance 

and a gun-to-wellbore volume ratio combined to 

create a dynamic underbalanced pressure estimated to exceed 4000 psi immediately after the 

guns were detonated. A slow leak from 8600 psi 

to 7500 psi [51.7 MPa] occurred during the N-42 

firing delay. But with the tester valve closed, 

initial wellbore pressure remained high enough to 

achieve the required dynamic underbalance. 

These data-acquisition rates were not fast 

enough to capture detailed transient pressures, 

but did indicate a dynamic underbalance imme-

diately after the guns fired. The rapid pressure 

buildup in the two wells to the reservoir pres-

sure of 5300 psi in the N-41 well and 6100 psi in 

the N-42 well indicated clean perforations 

with minimal induced damage. The N-42 well, 

originally drilled as an injector, produced for a 

short period before being recompleted. CNR has 

also applied PURE perforating techniques in 

five other wells, including a Ninian South field 

producer and a Murchison field injector. 

What's Ahead for Dynamic Underbalance? 

The use of static balanced and overbalanced 

pressures for well-completion operations has 

declined, except for niche applications such as 

extreme overbalanced perforating. In contrast, 

underbalanced perforating continues to expand 

and evolve. As a result of ongoing research and 

development efforts, the prevailing static under-

balance concept is being replaced by the new 

dynamic underbalance technique. 

Innovative PURE technology optimizes gun 

designs, charge types and completion configura-

tion to deliver clean perforations. The PURE 

technique provides control over the true level of 

underbalance by taking reservoir properties, 

completion parameters and gun configurations 

into account. This approach helps operators 

achieve the most effective dynamic under-

balance and perforating conditions. 

Well-completion and perforating parameters 

must be carefully designed to achieve a dynamic 

underbalance and generate zero-skin perfora-

tions. The degree of fluid-surge control possible 

with PURE perforating designs aids in avoiding 

stuck guns and associated fishing costs. In some 

applications, improved perforation conductivity 

and lower completion skins may avoid the need 

for near-wellbore acid washes to clean up 

perforating damage.


Behrmann L, Huber K, McDonald B, Couët B, Dee J, 

Folsie R, Handren P, Schmidt J and Snider P. “Quo Vadis, 

Extreme Overbalance,” Oilfield Review 8, no. 3 


19. Stutz and Behrmann, reference 17.
In addition to eliminating remedial perforation washes, PURE perforating improves stimulation and pumping efficiency by increasing effective shot density. The PURE technique controls downhole pressure transients, resulting in less intense perforating shocks to wellbore and completion equipment. In some applications, this degree of control makes it possible to reduce the chance of cement-sheath damage and unwanted water flow behind casing.

Dynamic underbalanced perforating does not replace matrix acidizing and chemical treatments to remEDIATE near-wellbore damage from drilling or completion fluid losses, organic deposits and mineral scale. The PURE technique is not a replacement for larger acid and hydraulic fracture treatments that address deeper damage and stimulate production and increase reserve recovery from low-permeability carbonate and sandstone reservoirs.

Dynamic underbalanced perforating also appears to minimize the degree of pressure differential required to achieve clean perforations. This advantage leads to safer operations in sensitive environmental areas and in dangerous well conditions, such as reservoirs that contain hydrogen sulfide. Conventional underbalanced criteria do not apply for the dynamic underbalanced system and, in fact, sometimes overestimate the pressure differential required for optimal results with dynamic underbalanced perforating.

Laboratory tests are being conducted to confirm these findings and address underbalanced pressure requirements. Clearly, additional wellbore and reservoir physics related to gun detonation and pressure responses need to be considered to better understand perforation cleanup and to improve dynamic underbalanced perforating simulations.

Even at this early stage of application, the major physical processes that lead to dynamic pressure variations are becoming clearer. Detailed modeling and analysis are likely to be difficult because of the complexity of these processes, but first-order predictions of dynamic underbalance and subsequent perforation cleanup are close to realization.

A mathematical model of transient wellbore dynamics, currently under development, will be included with the PURE planning software to incorporate laboratory observations in perforating designs and support the application of dynamic underbalanced operations. This software complements the SPAN design program to help design optimal PURE perforating systems.

Downhole gauges with extremely fast sampling rates can now be run with PURE systems to further optimize dynamic underbalanced perforating. Capturing transient pressure data in the field helps verify the maximum pressure differential and provides a more detailed picture of early-time pressure events during actual perforating jobs. When applied, this capability will improve our understanding of wellbore physics during perforating.

To date, more than 100 wells, ranging from wireline and TCP to coiled tubing-deployment and permanent completions, have been completed successfully using PURE perforating techniques. For the first time, operators can obtain effective new perforations in wells with existing open perforations.

This technique has tremendous potential—clean perforations even with multiple gun runs, elimination of high static underbalance requirements, a lower risk of wireline guns being blown uphole, reduced perforating shocks and wellbore damage, and potentially less need for remedial near-wellbore damage-removal treatments. —MET

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**Pressure-Up to Initiate HDF and Delay Period**

**Dynamic Underbalance after Perforation**

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^Transient pressure response while perforating the N-42 well in the Ninian North field. The slow sampling rate of pressure gauges in the N-42 perforating string did not record the maximum dynamic underbalance during this PURE job, which was designed to achieve a 4000-psi underbalance. However, available data indicate a dramatic drop of 2246 psi [15.5 MPa] from 7480 to 5234 psi [51.6 to 36.1 MPa]. After perforating, wellbore pressure quickly increases to the reservoir pressure of 6100 psi [42 MPa], indicating clean perforations. —MET
**Contributors**

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**Mark Brady**, Schlumberger GeoMarkets Technical Engineer based in Doha, Qatar, is involved with increasing the matrix stimulation business by transferring key technologies to the field. He is responsible for providing direct support to field organizations and developing and tailoring new technology to specific markets. His most recent projects were the successful introduction of VDA Viscoelastic Diverting Acid service to US land carbonate acidizing and the growth of matrix acidizing for clients in the Gulf of Mexico. Since joining Schlumberger in 1994, he has played a key role in introducing many new technology applications. Prior to assuming his current position in 2004, he worked in Sugar Land, Texas, as senior matrix stimulation support engineer for the North and South America. He also served as development engineer for the sand management group. Mark has published numerous papers and articles and is the holder of many patents. He earned BS and PhD degrees in chemistry, both from The Queen’s University, Belfast, Northern Ireland.

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Lee Francis, who is president of Cimarron Engineering Inc., founded the company in 1987 in Tulsa, Oklahoma. Prior to that, he worked in engineering and management with KCS Medallion, Conoco and Williams companies. He earned a BS degree in industrial engineering and management from Oklahoma State University in Stillwater and is a Registered Professional Engineer in the state of Oklahoma.

Chris Fredi, North and South America (NSA) Stimulation Products Manager for Schlumberger, is based in Sugar Land, Texas. He provides technical support for field operations and clients and manages the NSA Stimulation Client Support Laboratory. He focuses on solving client-related problems, addressing competitive issues, evaluating and introducing new technology and supporting service quality standards. He is also responsible for providing technical training to laboratory and field personnel. Chris joined Dowell Schlumberger as a staff engineer in 1987, working on improved cleanup of fracturing fluids and evaluation of acidizing technology. He later worked as an area laboratory manager for district laboratories in south Texas. He received a BS degree from Clarkson University, Potsdam, New York, and a PhD degree from University of Michigan in Ann Arbor, USA, both in chemical engineering.

Dan Fu, Project Manager for Matrix Stimulation in the Oilfield Chemical Products department, works at the Schlumberger Technology Center in Sugar Land, Texas. There he leads a team in the development of stimulation fluids and techniques for acid stimulation applications. He joined Schlumberger in 1997 as a development engineer and has worked on oilfield chemical products and matrix stimulation research. Prior to assuming his current position in 2003, he was involved in the development of VDA fluids, OilSEEKER® and ClearFRAC™ technologies. Dan has a BS degree in chemistry from Peking University, China; a PhD degree in chemistry from University of Southern California, Los Angeles, and an MBA degree from Colorado State University in Fort Collins, USA.

Nayelli Garcia Esparza Tapia is a general field engineer working on fracturing treatments in the Chicontepec field in Veracruz, Mexico. She joined Schlumberger in 2001. After training in Maurice, Louisiana, she became a field engineer on the DeepSTIM® fracturing vessel in the Gulf of Mexico. In 2002, she moved to Reynosa, Mexico, where she was in charge of a pumping crew. Nayelli joined the team working on optimizing stimulation in the Chicontepec field in 2002. She has a degree in chemical engineering from the Instituto Tecnológico y de Estudios Superiores in Monterrey, Mexico, where she also studied environmental systems and biotechnology.

Gretchen Gillis is a senior editor of the Schlumberger Oilfield Review and coordinator of the Oilfield Glossary project. Before joining Schlumberger in 1997, she worked as a geologist for Maxus Exploration Company and Oxy Energy Company in Dallas, Texas. Chairman of the American Association of Petroleum Geologists (AAPG) Publications Committee since 2002, Gretchen holds a BA degree in geology from Bryn Mawr College, Pennsylvania, and an MA degree in geological sciences from The University of Texas at Austin.

Lee Hornsby, Drilling Superintendent for the East Region, Gabot Oil & Gas Corporation (COGC), is based in Charleston, West Virginia, USA. Since 2002, he has managed drilling and completion activities for COGC’s East Region, which drills more than 100 wells in the Appalachian basin each year. Lee joined COGC in 1990 and has had various assignments as engine assistant, district engineer, production engineer, measurement engineer and drilling engineer. Prior to COGC he was employed as a mining engineer for six years and also managed a coal analysis laboratory. He obtained a BS degree in mining engineering technology from West Virginia University Institute of Technology in Montgomery.

Efrain Huidobro is the engineering well design department chief leader of the PEMEX Veracruz Drilling Operation Unit in Veracruz, Mexico. He has held various PEMEX engineering positions with responsibilities in drilling, completion and stimulation operations. He has a BS degree in petroleum engineering from Instituto Politecnico Nacional in Mexico City, Mexico.

Haitham Jarouj, who is Schlumberger field services manager for land cementing operations, handles all cementing functions including design, logistics, personnel and execution for the Abu Dhabi Company for Onshore Oil Operations (ADCO) at Abu Dhabi, UAE. After joining Schlumberger in 1985, he served as cementing supervisor, Deir Ez Zor, Syria, until 1986 when he assumed his present position. At ADCO he was involved in the introduction of the new cementing technologies including CemCREP®, CemSTONE® and CemNET® services. He was a major contributor to the installation and field testing of the SFM® Solids Fraction Monitor system and is currently involved in a blending project. Haittham earned a BS degree in geology from Damascus University, Syria.

Mohamed Jemmali, Schlumberger Account Manager since 2002 for the northern area of Saudi Arabia, is based in Al-Khobar, Saudi Arabia. He is currently working on introducing VDA stimulation technology to the area. Since joining the company in 1991, he has worked in various positions including field engineer, field service manager, technical engineer and sales engineer with numerous client companies in Nigeria, Congo, Tunisia, Kuwait and Saudi Arabia. Mohamed received a BS degree in civil engineering from the University of Texas at Austin.

Hendri Junaidi is a graduate of the Bandung Institute of Technology (ITB), Indonesia, with a degree in petroleum engineering. He joined P.T. Caltex Pacific Indonesia, in June 1998 as a drilling representative working in the Duri field. In 2009, he moved into operations where his current responsibilities include monitoring drilling operations.

Bernhard Lungwitz is a senior engineer in the Schlumberger Client Support Laboratory in Sugar Land, Texas. He is responsible for client and field support for stimulation including field implementation of new technologies. In 1997, he joined Schlumberger as a development engineer. He was part of the ClearFRAC fluid development team and also worked on several applications of viscoelastic surfactant (VES) fluids including coiled tubing cleanout fluids, gravel-pack fluids and foamed VES fluids. Bernhard has an MS degree in chemical engineering from Technical University in Munich, Germany, and a PhD degree in organometallic chemistry from Humboldt University, Berlin, Germany. He was also a research fellow in chemistry at Massachusetts Institute of Technology, Cambridge, USA.
Steve McCraith, Senior Well Engineer for the Shell Brent Delta drilling platform, is based in Aberdeen, Scotland. He is the team leader for drilling well engineering operations on that installation. He joined Shell in 1989. Before assuming his current position in 2003, he spent eight years as offshore drilling engineer and drilling engineer based in The Netherlands, and as drilling supervisor on jackup rigs, platforms, and mobile rigs in the UK and The Netherlands. Before joining Shell, he worked briefly in mining operations for Asarco in Western Australia on exploration drilling for gold, and in Navan, Republic of Ireland, at the Tara lead and zinc mine. Steve earned a BS degree (Hons) in exploration and mining geology from University College of Cardiff, Wales, and an MS degree in drilling engineering from Robert Gordon’s University, Aberdeen. He is also a Charterd Engineer and member of the Institute of Mining Engineers.

Jesus Mendoza Ruiz, Schlumberger Business Development Manager for the Caribbean and Mexico, is based in Mexico City. After receiving his BS degree in geology in 1979 from Instituto Politecnico Nacional in Mexico City, Mexico, he joined Schlumberger Wireline & Testing, where he worked on interpretation and sales of geological logging products. In 1995, Jesus became a sales engineer, and in 1998 he moved into marketing to promote key services. He assumed his current post in 2002.

Jean-François Mengual, Petrophysics Domain Champion for Latin America-South, is based in Rio de Janeiro, Brazil. Before that, he held the same position for Mexico and Central America, where he promoted nuclear magnetic resonance logging and helped develop and implement integrated log-interpretation strategies for optimizing completions in the Burgos basin and Chicontepec fields. He began his career in 1987 as a Schlumberger field engineer in South America, then transferred to the North Sea. From 1991 to 1993, he worked in land seismic processing for Western Geophysical in South America, and then acted as deputy project manager for a YPF-Repsol project on underground gas storage. He returned to Schlumberger in 1998. Jean-François has a bachelor’s degree from Institut National des Sciences Appliquées in Toulouse, France, and a master’s degree from Université Paul Sabatier, Toulouse, both in physics.

Eric Messier is a drilling engineer and superintendent responsible for work planning, scheduling, licensing and preparation of drilling programs for wells in British Columbia, Canada, for Devon Canada Corporation. He is currently managing an underbalanced drilling project in Helmet, British Columbia. Prior to joining Devon in 2001, Eric was a drilling engineer for PanCanadian Petroleum Ltd. in southern Alberta, Canada. There he was responsible for engineering support, scheduling and preparation of drilling programs for more than 1200 oil and gas wells drilled using conventional, directional, slant and coiled tubing methods. Eric holds a BE degree from McGill University, Montreal, Quebec, Canada.

Phil Milton is a consultant senior well engineering contractor to CNR International Ltd. in Aberdeen, Scotland. He is responsible for the planning, equipment identification and execution of all well services operations on CNR North Sea assets. He served an apprenticeship with Halliburton beginning in 1987 and also worked for Wellserv Plc. before founding his own company, Milmar Wellservices Ltd., in 2000. Since then, he has been a well services operations consultant to both Kerr-McGee and CNR. He was involved in the abandonment of the Hutton tension-leg platform in the North Sea and is the coauthor of an SPE paper on that operation. Phil holds a diploma in mechanical engineering from Angus College in Arbroath, Scotland.

Trevor Munk, New Technology Implementation Manager for Cementing, is based at Schlumberger Riboud Product Centre in Clamart, France. There he manages the deployment of technologies to the field and provides internal and client training and support. He began his career in 1985 as a process technician with Petro-Canada. He held various project-management positions with Canadian Western Natural Gas, Home Oil and the Canadian Institute for Petroleum Industry Development. He served as business development engineer for Imperial Oil before joining Schlumberger in 1988 as well services cell leader in Gabon, Africa. Before taking his current post, he was sand-control business development manager in West and South Africa. Trevor earned an honors diploma in petroleum engineering technology from Northern Alberta Institute of Technology in Edmonton, Canada, and a BS degree in petroleum engineering and an MS degree in engineering management from the University of Alberta in Edmonton.

Hisham A. Naser-El-Din, Senior Research Consultant and Group Leader of the Stimulation Group, is at the Research and Development Center at Saudi Aramco. He holds BS and MS degrees in chemical engineering from Cairo University, Egypt, and a PhD degree from the University of Saskatchewan, Canada. His research interests include well stimulation, formation damage, two-phase flow, flow in porous media, enhanced oil recovery, rheology, conformance control, interfacial properties, adsorption and nondamaging fluid technologies. He has played a key role in the introduction of VFD technology and the extension of the VES technology to acid fracturing and fluid-loss control in the Middle East. He has several patents and has published more than 200 papers. He is adjunct professor with the University of Alberta, Canada, and has supervised several PhD students. He is a member of SPE and serves on the SPE steering committees on corrosion and oilfield chemistry, and is a technical editor for SPE Production & Facilities. He has received numerous awards within Saudi Aramco for significant contributions in stimulation- and treatment-fluid technologies, stimulation design, and for his work in training and mentoring.

Nils Nedland, Discipline Leader, Cement, for Statoil ASA in Stavanger, Norway, oversees all aspects of well cementing. He began his career in 1980 with BJ Services in Tananger, Norway, in stimulation and cementing engineering and also worked for Norsk Hydro in Stavanger and Bergen, Norway, in cementing and drilling engineering. He joined Statoil in 1982. Nils has a degree in petroleum engineering from Rogaland Distrikshøyskole in Stavanger.

Luis Roca Ramisa is marketing manager for the Schlumberger Mexico GeoMarket region, based in Mexico City. He has been a researcher and has held academic positions in several research centers in the USA, Europe and Venezuela. He has also published many technical articles in the fields of petrophysics and geomechanics. Luis received BS and MS degrees in engineering geology from the South Dakota School of Mines and Technology in Rapid City, USA, and a PhD degree in geomechanics from the University of Missouri at Rolla, USA.

Alan Salsman, Schlumberger Product Champion for the PURE* Perforating for Ultimate Reservoir Exploitation system, is based in Rosharon, Texas. After completing two years towards a degree in business administration at Acadia University in Wolfville, Nova Scotia, Canada, he joined Schlumberger in 1977 working as an operator and field engineer in Canada. After postings in Aberdeen, Scotland, and Bas Shuikheir, Egypt, he became a tubing-conveyed perforating (TCP) coordinator in the Middle East. He served as wireline country manager in Qatar, manager of TCP and drillstring testing operations in Balikpapan, Indonesia, and technical staff engineer for Southeast Asia. From 1993 to 1996, he was marketing manager for the Schlumberger Perforating and Testing Center in Rosharon. Before assuming his current position in 2003, Al was the business development manager for Cased Hole Wireline Services in Canada.

Mathew Samuel, Stimulation Business Development Manager and Fluid Specialist for the Middle East and Asia, stationed in Al-Khobar, Saudi Arabia, is responsible for the marketing and introduction of new technologies for Schlumberger Well Production Services and for all products, chemistry and fluids. He is advisor to the stimulation group at the Dhahran Carbonate Center and to Saudi Aramco and other operating companies. He joined Schlumberger in 1996 at the Tulsa, Oklahoma Product Center where his polymer cleanup project led to the development of ClearFraC polymer-free fracturing fluid. He served as the project manager for VES fluids from 1998 to 2000 and was responsible for developing and introducing the VES family of products and OISEEKER, VDA, ClearPAC and ClearPLL technologies. Before joining Schlumberger, he was an assistant professor at New York University in New York City. He has BS and MS degrees from Kerala University, India, and a PhD degree from the University of Pennsylvania in Philadelphia, all in chemistry. Mathew holds 11 patents and has written 55 publications.

Depinder Sandhu, who is based in Cairo, Egypt, has been business development manager, Coiled Tubing and Matrix Acidizing Services, for the Schlumberger East Africa and East Mediterranean region since 2002. His current focus is on the growth of the well services business in Syria. Since beginning his career with Schlumberger in 1996 as a field engineer trainee, he has held a variety of engineering, project management and field service management positions throughout the Middle East. Depinder holds a BTech degree in marine engineering from Marine Engineering and Research Institute in Calcutta, India.

Nigel Shuttleworth, Shell U.K. Exploration and Production (EXPRO) Senior Well Engineer for the Sedco 711 Mobile Rig since 2003, is based in Aberdeen, Scotland. He has complete responsibility for the delivery of wells drilled in a safe and cost-effective manner. He joined Shell International in 1980 as a trainee in Holland and worked in a variety of positions including driller, drilling supervisor and operations engineer. His career with Shell has included assignments in Brunei and The Netherlands before becoming senior well engineer for the Brent Charlie platform in 1998. Nigel obtained a diploma in mechanical engineering from Barrow-in-Furness College, Cumbria, England.
Andrés Sosa Cerón is a petroleum engineer with more than 25 years of experience. He joined Petróleos Mexicanos (PEMEX) in 1976, and worked with the Well Drilling Design and Engineering Team for 16 years. He is currently drilling submanager of the Services per Contract department, North Region. Andrés studied in the Engineering and Architecture College at the Instituto Politécnico Nacional, Mexico City, Mexico, and he did research in oilfield engineering at the Universidad Nacional Autónoma de México, also in Mexico City, graduating with honors from both institutions. He is an active member of the Society of Petroleum Engineers (AIPM) and the Petroleum Engineer’s College (CIPM) in Mexico.

Sundaram (Sundy) Srinivasan, a Principal with the Schlumberger Oil and Gas Business Consulting Group, began his career with Schlumberger in 1985 as a drilling engineer and later was a district manager with Sedco-Forex. He worked as a district manager and division marketing manager for the Schlumberger Wireline division before joining the Integrated Project Management group as a project manager, country manager, and area business manager. Sundy managed startup offices for Schlumberger in Denmark and Vietnam, and has interacted with operating companies around the world. His BTech degree in mechanical engineering is from the Indian Institute of Technology in Delhi, India. He also earned an MBA degree from the Sloan School of Management at the Massachusetts Institute of Technology, Cambridge.

Gary Stirton is an independent consultant completing engineering contracts for CNR International in Aberdeen, Scotland. He is responsible for preparing and verifying completion designs and requirements for four northern North Sea platforms and also provides offshore support during operations and ensures internal and external regulatory compliance. Prior to becoming an independent consultant in 2000, Gary worked in Aberdeen for Halliburton Otis and Wellserv Plc. He holds a City and Guilds diploma in agricultural mechanics from Arbroath Technical College in Scotland.

Lloyd Stutz, Production and Completion Engineering Supervisor for Anadarko Petroleum Corporation’s Western Division and Project Manager for coiled methane development at Rock Springs, Wyoming, USA, is based in The Woodlands, Texas. There he supervises tight gas completions, coiled methane completions, high-temperature, high-pressure sour gas completions and carbon dioxide flood completions and construction in the Rockies area. Prior to joining Anadarko in 2000, Lloyd worked as production, development and exploration engineer for Champion Petroleum and Union Pacific Resources. Author of several SPE papers, he holds a BS degree in petroleum engineering from Texas A&M University in College Station.

R. Krister Svendsen, who is based in Bergen, Norway, is currently staff engineer, Schlumberger Well Cementing operations, on Norsk Hydro rigs in Norway. He began his career in the paper industry as a development engineer. In 1988, he joined Schlumberger as a field engineer in Perth, Western Australia. In 1999, he returned to the paper industry as a consultant in process engineering. He rejoined Schlumberger in 2001 to work on process engineering systems. He has been in his current position since 2002 and is involved in operational planning and design for rigs in the Tampen area of the North Sea, introducing FlexSTONE slurries and CemNET technology to the area. Krister earned an MS degree in chemical engineering from the Norwegian University of Science and Technology in Trondheim.

Salam Taoutaou, Shell Account Manager for Schlumberger, has been the DESC Design and Evaluation Services for Clients Engineer for Shell, overseeing operations for the Brent field and other northern North Sea fields since 2001. His responsibilities include well construction, cementing, technical, logistics and personnel services. He designed and executed the first cement application of expandable liner technology for Shell in the North Sea Brent Delta field. As a member of the Brent Loses Team, he introduced CemNET technology development. He is also a member of the integrated team for expandable liner technology development and implementation with Shell and Enventure Ltd. and a member of the casing drilling technology implementation team with Shell and Texaco. His experience in cementing began in Hassi-Messaoud, Algeria, on numerous land rigs using multiple types of cementing systems. As a DESC field engineer in 1999, he was responsible for complete job design and evaluation for BP and Sonatrach rigs in Hassi-Messaoud. Prior to beginning his career with Schlumberger in 1997, Salim taught mathematics at the University of Guelma, Algeria, where he earned a degree in mechanical engineering in 1993.

Emmanuel Therond, Schlumberger Field Service Manager for cementing operations, is based in Bergen, Norway. He began his career with Dowell Schlumberger in 1991 as a field engineer supervising cementing, matrix acidizing and sand control in Algeria, Nigeria and Kuwait. In 1995, he was appointed coiled tubing technology engineer in the North Sea. He also held a field service manager for cementing and completion fluids. Three years later, he was transferred to West Africa as well services operations manager. Before assuming his current position in 2002, he was an InTouch engineer at Schlumberger Eribon Product Center, Clamart, France, providing technical support to worldwide cementing operations. Emmanuel holds a degree in civil engineering from Ecole Nationale Supérieure des Arts et Industries de Strasbourg, France.

David Underdown, Technical Advisor for ChevronTexaco Energy Technology Company, is based in Houston, Texas. There he is responsible for completions engineering, focusing on sand control and perforating. He began his career with ARCO in Plano, Texas, as a completions engineer. He later worked as technical director for the Pall Corporation in Port Washington, New York, responsible for providing technical support to the Technology division. He joined Chevron in 1986. David earned a PhD degree in physical chemistry from the University of Houston. He was editor of SPE Monographs on Sand Control and on Completion Fluids, and a member of the SPE Awards Committee. He is currently chairman of the API Subcommittee on Perforating.

Klaas van der Plas, Senior Well Engineer, Concept Design, for Shell U.K. Exploration and Production (EXPRO) in Aberdeen, Scotland, is currently assigned to the Norway/UK Crossborder and Gannet Field Development group. He began his career with Petroleum Development Oman in 1989 working as a driller and drilling engineer and also drilling supervisor on land operations. He joined Brunei Shell Petroleum in 1985 and was involved as DSP and operations engineer for deepwater exploration, development drilling and high-pressure, high-temperature drilling and well engineering field development. He moved to Shell EXPRO in 2000 as a senior drilling engineer, new technology, and assumed his current position in 2003. Klaas received a degree in drilling and production technology from Hogere Technische School in Den Helder, The Netherlands.

Kees Veeken, Senior Production Technologist with Nederlandse Aardolie Maatschappij (NAM), a Shell Exploration and Production (E&P) operating company, is based in Assen, The Netherlands. There he is responsible for offshore gas-well completion design and production optimization. He joined Shell in 1985 to work in well technology research and development for six years and then served as a production technologist in Oman and Malaysia before assuming his current position in 2001. One of the highlights of his career was the introduction of big-bore gas-well completions in Shell Malaysia. Kees earned a PhD degree in experimental physics at the University of Nijmegen, The Netherlands.

Ian Walton is a scientific advisor and head of the Perforating Research department at the Schlumberger Reservoir Completions Center in Rossharon, Texas. He joined the company in 1987 as a senior research scientist at Schlumberger Cambridge Research following 11 years on the faculty of University of London and three years at the BP Research Centre in Sunbury, all in England. In 1991, he transferred to the Dowell Technology Center in Tulsa, Oklahoma, then moved to Rossharon in 1994 to work on coiled tubing applications. Four years later he moved to Perforating Research in Rossharon. He has been involved in projects on well control, cementing, production logging, sand control, various coiled tubing applications and perforating. He is an editor for the SPE and has authored or coauthored 47 technical papers. He holds a BS degree from University College, London, and a PhD degree from Manchester University, England, both in mathematics.

Helen Weeds is a lecturer in economics at the University of Essex, Colchester, England, where she conducts research in industrial organization and real options, and teaches industrial organization and finance. Previously, she was a principal at Lexecon Ltd, London, England, providing economic advice on antitrust, merger and regulatory proceedings. She has been a lecturer in economics at the University of Warwick, Coventry, England, and a junior research fellow at the University of Cambridge, England, also undertaking independent consultancy work. Helen has a BA degree (Hons) in philosophy, politics and economics (PPE), as well as a master’s degree and a doctorate degree in economics, all from the University of Oxford, England.

An asterisk (*) is used to denote a mark of Schlumberger.
Multicomponent Seismic Techniques. Multicomponent methods are improving seismic imaging results in regions obstructed by gas, low impedance contrast and salt, and are helping characterize reservoir lithology, fractures, fluid type, saturation and pressure. This article describes new technology designed to acquire high-fidelity multicomponent data, and includes case studies demonstrating the value of multicomponent results bring to exploration and production problems.

Sand Management. In many oil and gas assets, optimizing production depends heavily on preventing, delaying and properly managing the production of sand. A holistic approach to sand management is most successful. Experts, from multiple disciplines, now use powerful modeling software and advanced technologies to help predict, prevent, monitor and remedy sand production. This article discusses how a customized methodology helps define the sand-production problem and aids in the selection of the most appropriate technologies. Case studies highlight the success of this approach.

Coiled Tubing Update. Building on the technological resurgence of the 1990s, this unique well-servicing technique firmly established its place in mainstream oilfield operations. We review the latest advances in equipment and tools designed to improve operational safety and efficiency, enhance wellbore and reservoir remedial applications, and facilitate drilling and well completions.

NEW BOOKS

Practical Density Measurement and Hydrometry  
S.V. Gupta  
Institute of Physics Publishing  
The Public Ledger Building, Suite 1035  
150 South Independence Mall West  
Philadelphia, Pennsylvania 19106 USA  
2002. 352 pages. $115.00  
ISBN 0-7503-0847-8

This work provides information on mass metrology, highlighting the principles of physics involved and the technology needed for high-precision measurement of the density of solids and liquids to meet metrology industry standards. Starting with a look at national and international density standards, the book discusses methods for measuring solid and liquid density and their advantages and disadvantages, and gives a detailed treatment of thermal dilation of liquids. Also covered are interferometers used in dimensional measurements of solid-based density standards, phase change due to reflection and origins, and methods for density determination.

Contents:  
• Solid-Based Density Standards  
• Special Interferometers  
• Standard Mean Ocean Water (SMOW) and the Equipment for Measuring Water Density  
• Dilatation of Water and Water Density Tables  
• Mercury Density Measurement  
• Special Methods of Density Determination  
• Hydrometry  
• Density of Materials Used in Industry—Liquids  
• Density of Materials Used in Industry—Solids  
• Glossary, Index

The book is clearly written and easy to understand…. Listings of advantages and disadvantages of the different methods are very helpful.

Carbonate Reservoirs: Porosity Evolution and Diagenesis in a Sequence Stratigraphic Framework  
Clyde H. Moore  
Elsevier Science B.V.  
Sara Burgerhartstrout 25  
P.O. Box 211  
1000 AE Amsterdam, The Netherlands  
2001. 441 pages. $172.50 hardcover;  
$79.00 paperback  
ISBN 0-444-50838-4

This update of Moore’s 1989 book is an expansion of the core themes of diagenesis and porosity evolution. New topics such as microbial mediation of marine and meteoric diagenesis, deep-marine diagenesis of mud mounds and climate-driven diagenetic processes are included, along with emphasis on subaerial exposure processes, temperate water carbonates, basin hydrology, basin-wide diagenetic trends and tectonics.

Contents:  
• The Nature of the Carbonate Depositional System  
• Concepts of Sequence Stratigraphy as Applied to Carbonate Depositional Systems  
• The Classification of Carbonate Porosity  
• Diagenetic Environments of Porosity Modification and Tools for Their Recognition in the Geologic Record  
• Normal Marine Diagenetic Environments  
• Evaporative Marine Diagenetic Environments  
• Diagenesis in the Meteoric Environment

The book comes with an excellent CD-ROM supplement. This contains all of the diagrams and tables in the book, in colour.

... “would I buy this book.” The answer is definitely yes. It is an authoritative text, written by an academic with over 30 years of experience... a good overview of carbonate geology that will bring you up to date with some of the latest ideas....


Earthshaking Science: What We Know (and Don’t Know) about Earthquakes  
Susan Elizabeth Hough  
Princeton University Press  
41 William Street  
Princeton, New Jersey 08540 USA  
2002. 272 pages. $26.95  
ISBN 0-691-05010-4

The author, a research scientist at the US Geological Survey, offers a basic primer on a range of topics related to earthquake science and engineering. The book integrates state-of-the-art research with explanations of earthquake phenomena and discusses many of the current controversies.

Contents:  
• The Plate Tectonics Revolution  
• Sizing Up Earthquakes  
• Earthquake Interactions  
• Ground Motions  
• The Holy Grail of Earthquake Prediction
- Mapping Seismic Hazard
- A Journey Back in Time
- Bringing the Science Home
- Notes, Suggested Reading, Index

- Hough's writing style is easy and engaging, and she makes the subject matter entertaining, ... sidebars offer entertaining insights into the everyday lives of earthquake researchers.

- The illustrations (black-and-white maps, crude cartoons and line drawings) are disappointing. The quality of the figures in the chapter on ground motion is particularly poor.

- Probabilistic earthquake forecasts are now the standard technique for communicating earthquake information to the public, so it is important for readers to understand the methodologies used in such analyses—Paleoseismic data, earthquake recurrence models, long-term slip rates, fault segmentation and so on. These subjects are not as thoroughly discussed as they should be.

- This is a fine compilation of geology pertinent to petroleum in Libya and a great deal more. I recommend this excellent volume.

- This updated version of Aki and Richard's classic geophysical text deserves a place in every serious geophysicist's library.

- Quantitative Seismology is an excellent study and reference book for seismologists well-grounded in the methods of mathematical physics. This graduate-level textbook develops the theory of seismic wave propagation in realistic Earth models and supplements theoretical material with practical descriptions of how seismographs work and how data are analyzed and inverted. The book also includes new methods of detecting and recording seismic motions. This graduate-level textbook develops the theory of seismic wave propagation in realistic Earth models and supplements theoretical material with practical descriptions of how seismographs work and how data are analyzed and inverted. The book also includes new methods of detecting and recording seismic motions. Contents:

- History of Libyan Oil Exploration and Production
- Plate Tectonic History of Libya
- Stratigraphy: Precambrian and Palaeozoic
- Stratigraphy: Mesozoic
- Stratigraphy: Cainozoic
- Structure
- Petroleum Geochemistry
- Petroleum Systems
- Postscript: Where Are the Remaining Undiscovered Reserves?
- Notes, References, Glossary, Index

- This book examines the plate tectonics, structural evolution, stratigraphy, geochemistry and petroleum systems of Libya, and summarizes data on its oil fields, production and reserves. Hallett, a petroleum geologist, reviews the main structural provinces of Libya, and highlights the timing of the main tectonic events. Numerous maps and stratigraphic columns are also provided.

- Elastic Waves from a Point Dislocation Source
- Plane Waves in Homogeneous Media and Their Reflection and Transmission at a Plane Boundary
- Reflection and Refraction of Spherical Waves; Lamb's Problem
- Surface Waves in a Vertically Heterogeneous Medium
- Free Oscillations of the Earth
- Body Waves in Media with Depth-Dependent Properties
- The Seismic Source: Kinematics
- The Seismic Source: Dynamics
- Principles of Seismometry
- Appendix, Bibliography, Index

- This graduate-level textbook develops the theory of seismic wave propagation in realistic Earth models and supplements theoretical material with practical descriptions of how seismographs work and how data are analyzed and inverted. The book also includes new methods of detecting and recording seismic motions. Contents:

- Introduction: Overview
- A Brief History of Logging: The Petrophysical Approach
- Geological Measurements: Dipmeter; Electrical Borehole Imaging; Acoustic Borehole Imaging; Density Borehole Imaging; Optical Borehole Imaging; Nuclear Magnetic Resonance Logging; Nuclear Spectroscopy Logging; Paleomagnetic Logging; Core Sampling
- Applications and Case Studies: Structural Modeling; Bedding and Reservoir Zonation; Fractured Reservoirs; Well Correlation; Geological Drilling
- Conclusions
- Indexes

- These suggestions are minor in comparison with the large volume of excellent material provided.

- The book will be very useful for practicing geoscientists and graduate students to learn about, or update themselves on, the recent geological logging tools, their interpretation techniques and reservoir applications.

- Stefan M. Luthi