Let’s Get the Most Out of Existing Wells

Closing the gaps between current output and productive capacity is one of today’s best opportunities to quickly enhance production and improve recovery. A unique service initiative and focused engineering well reviews help tap into potential productivity and increase oil and gas asset value.

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Established fields are the most likely places to find additional oil and gas output. Improving the performance of wells that are already producing is a cost-effective way to offset natural decline, extend field life and improve hydrocarbon recovery. Production enhancement (PE) efforts are aimed at evaluating wells and recommending ways to increase productivity. Effective well interventions and recompletions, therefore, are essential elements of this endeavor.

But how can oil companies and service providers work together to identify suitable candidates for production enhancement from among thousands of wells? One method is by prospecting—searching in well files for opportunities to get more oil and gas from existing wells. And modern computers combined with new oilfield technology, tools and services are facilitating this effort.

In daily operations, E&P companies often require specific production and reservoir engineering recommendations. Service companies can meet this need by helping to identify underperforming wells and then assist by providing customized solutions to improve production. Within Schlumberger, there are two approaches to production enhancement: candidate recognition and field support (above). Schlumberger Wireline & Testing, Dowell and Anadrill solve field operational problems, and perform well construction and single-service candidate recognition (CR) through field support. Requests for integrated solutions, optimized well designs, specialized well construction services and production engineering assistance are addressed by ad hoc teams that are tailored for each situation.

Generally, candidate recognition is a means of identifying opportunities as they arise, not merely solving problems in the field. But rather than wait for opportunities to present themselves, proactive candidate recognition (PCR) actively seeks out ways to improve production, takes full advantage of oilfield technology and integrated services, and concentrates on producing and shut-in wells. The best engineering answers and most appropriate well interventions are the targets for PCR, which is the top priority of the Schlumberger Production Enhancement Group (PEG).

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ClientLink, DESC (Design and Evaluation Services for Clients), Dual-Burst, ELAN (Elemental Log Analysis), Enerjet, FoamMAT, NODAL, Pivot Gun, RAPID (Reentry and Production Improvement Drilling), SPAN (Schlumberger Perforating Analysis), TDT (Thermal Decay Time) and WellWatcher are marks of Schlumberger.
Specifically, the PEG mission is to optimize well productivity and increase oil and gas output at a pace that exceeds historic industry trends. As prospectors, PEG engineers do not stop to make “jewelry” from the “gold” that is found. Instead, they keep looking for new “nuggets” of opportunity. Design and implementation of specific services are turned over to one of the Oilfield Services companies or an integrated solutions group. This article discusses this focused and aggressive initiative to improve production from client wells.

How PEG Works
Candidate recognition began in the late 1980s in response to customer needs and requests. In 1990, the first co-located Dowell engineers were placed in oil company offices along with the necessary computer and communications tools to fulfill client requirements. At the same time, an integrated PEG was formed in Houston, Texas. These were among the first steps toward building new business and working relationships in the oil industry. With more than 200 engineers posted in client offices, the DESC Design and Evaluation Services for Clients program continues to grow, facilitating cooperation and providing intimate contact with daily operations. Today, there are also more than 20 PEG locations in key markets worldwide, some with multiple teams in place (below). More are planned for 1998 and beyond.

The Production Enhancement Group works outside of traditional transactions, interactions and work flow between operators and service companies. With permission and cooperation from clients, production specialists look at well files and identify opportunities to increase production—they recognize candidates—acting and moving forward instead of reacting and waiting to fill phone-in orders or direct requests. This approach achieves production rates beyond levels that the industry traditionally expects and that result from clients initiating a call to a service company.

The PEG engineers evaluate well and production histories using the latest computer software, applying openhole, cased-hole and production logs or interpretation as needed. Current well performance is analyzed. Pressure, net pay, permeability and skin, or formation damage, are determined. Potential well output is calculated and the best services are recommended. Results of these well interventions are then systematically evaluated after implementation.

Experts from Schlumberger Wireline & Testing, Dowell, Anadroll and, when required, GeoQuest Reservoir Technologies make up a typical PEG. As a team, they cooperate with operating company asset managers to develop well intervention strategies that increase production. In addition, through the ClientLink initiative, the extensive Schlumberger intranet provides direct access to research, technology and innovative solutions tailored to meet specific client, field and well requirements.

Proactive candidate recognition does not involve extensive field studies or exhaustive reservoir evaluations. The heart of these efforts is an engineering calculation and innovative methodology based on single-well NODAL production system analysis from outer reservoir boundaries to the wellbore sandface, across the perforations and up the production tubing (see “Production System Analysis,” next page). Any restrictions, such as safety valves, choke, surface facilities and flowlines, can be included in this type of analysis.

The PEG engineers perform detailed technical and economic analyses of single wells, groups of wells or fields, and recommend actions with input and support from internal and client experts. There is no charge for this well review, evaluation and engineering function. Compensation for production enhancement recommendations comes from providing customized solutions and performing value-priced services for clients (see “Turning Cost into Revenue,” page 20). In some cases, recommendations to optimize well output involve simply modifying the wellbore flow conduit—tubulars or artificial lift. Except for coiled tubing completions and scale removal, recommendations to change wellbore mechanical configurations—replacing tubing, resizing chokes and adding or modifying artificial-lift methods—are considered an extra benefit of the candidate recognition process.


PEG Locations

The PEG teams. At this time, there are PEG offices located in key markets around the world and more are planned. Some of these areas, like Venezuela with six in place, have multiple teams. Proactive integrated efforts by PEG specialists recommend actions to improve client production without regard to specific company or individual service considerations within the Schlumberger Oilfield Services group.
Production System Analysis

NODAL analysis is used to optimize well production systems (below). This technique couples the capability of reservoirs to produce fluids into a wellbore with the capacity of tubulars to conduct the flow to surface, including facility piping if applicable. The name of this technique reflects discrete locations—nodes—where independent equations describe inflow and outflow from reservoirs to stock tanks by relating pressure losses and fluid rates. This engineering methodology allows calculation of the rate that a well is capable of delivering and helps determine the effects of perforations, stimulations, wellhead or separator pressure and tubing or choke sizes. Future production can also be estimated based on anticipated reservoir and wellbore parameters.¹

Computer software based on NODAL analysis is often used to diagnose and identify system bottlenecks—completion, perforation and piping limitations or formation damage—that restrict production or injection. These calculations are also used to quantify the production increases that can be expected if restrictions are removed. The estimated production can then be used in economic models.

The reservoir section is described by inflow performance relationship (IPR) curves. Wellbore tubulars and surface pipes—the flow-conduit section—are described by vertical or inclined multiphase flow correlations for tubing outflow, or intake, performance. The most common approach is to start at one end of the system, the reservoir node for example. Subtracting all the pressure losses at various rates from the reservoir pressure defines an IPR curve for fluids flowing into the wellbore. Pressure at the wellbore node facing the reservoir bottomhole pressure declines as production rates increase.

Starting from the separator and adding pressure losses encountered in surface pipes and wellbore tubing gives the pressure for various rates at the IPR reservoir node. This calculation results in a tubing intake, or flow-conduit, curve with bottomhole pressure increasing as production rate increases. The equilibrium point where IPR and flow-conduit curves have the same pressure and rate—intersection of the two curves—represents anticipated production and downhole pressure for the specific conditions being modeled. Output from NODAL analysis can be two curves or a set of curves for sensitivity analysis.

For example, this type of plot can be used to determine the effect of increasing choke and tubing sizes. A larger flow diameter moves tubing curves down and to the right, increasing the flow rate. In production enhancement, IPR curves are most often used to evaluate the impact of increasing effective borehole radius by perforating, acidizing, fracturing or drilling horizontal or lateral drainholes (above). These remedial well interventions move IPR curves up and to the right.

When operators allow a local PEG to diagnose production gaps and initiate design, execution and evaluation of services, both parties focus on production and results. This unique interaction ensures optimal recommendations to close productivity gaps and application of the right services. Focusing on production generates more revenue for both clients and the service company. In today’s new business relationships, operators are agreeing to share some of this added value, and service companies are accepting some downside risk. Having a vested interest in the outcome of remedial actions helps the service provider better understand and meet customer needs and expectations.

**Producing Wells**

Existing assets have several distinguishing characteristics, both positive and negative, in the context of production enhancement. On the upside, because established fields have wells and facilities in place, production increases can generate cash flow without adding infrastructure, which reduces lead and cycle times. There are also fewer unknowns. Fluid properties, reservoir drive and recoverable reserves are, in most cases, well understood. On the downside, available information is older, perhaps out of date; data were gathered using possibly obsolete technology, tools and techniques; and completion strategies may be outdated. But these negatives also present potential opportunities to increase production.

Single-well production enhancement involves moving reservoir inflow performance relationship (IPR) curves up and to the right, or moving flow-conduit performance curves down and to the right. The objective is to recommend solutions and services that will close identified gaps between current well output and potential production. To achieve this goal, the components that contribute to a production gap must be identified and understood (see “Production Gaps: Well Performance Components,” right). The total production system includes reservoir, completion, flow-conduit and artificial-lift components plus surface flowlines and facilities, which are assumed to be a constant in most individual oil and gas well analyses.

Based on what is known about a field, well files and data can be examined with an eye for likely opportunities from among these components. A model of the well production system is then developed using this information and, if required, confirmed by well tests or additional wireline logs to determine net pay, reservoir pressure, permeability, skin and saturations—oil, gas or water. Once a model is validated, wells are chosen for further evaluation using the PEG methodology. Remedial interventions are recommended, costs are estimated and viable options are compared based on estimated well productivity and operator economic constraints.


**Production Gaps: Well Performance Components**

Engineering optimum production rates requires that reservoir deliverability, well stimulation, recovery efficiency, wellbore hydraulics and surface constraints be addressed. Elements of the well production system are interrelated, and performance of the entire system is often a function of the weakest links. During the production enhancement process, various screening methods and well-analysis techniques are used to examine reservoir, completion, flow-conduit—wellbore tubulars or plumbing—and artificial-lift system performance (next page).

Reservoir performance—A production gap exists if reservoirs do not effectively deliver hydrocarbons into a wellbore. The result is low flow rates at high-drawdown pressures. This problem may be overcome by increasing effective borehole radius—fracturing, acidizing or high-performance perforating. Lateral or horizontal drainholes are another solution. Nearby injectors or producers may also affect the region around a well. A possible solution might be to squeeze off zones in injectors using cement. Controlling water influx and mitigating the production of formation fines are also alternatives.

Single-well inflow performance relationships (IPR) are a function of time and original oil in place. Near-wellbore effects and mechanical physical description, Darcy’s law and pressure-volume-temperature (PVT) behavior affect an IPR. Diagnostics, including transient testing, artificial-lift or permanent monitoring, saturation logging, production logging, sonic imaging and economic analysis, can be performed to obtain needed information. Remedial actions include high-performance perforating, stimulations, drilling laterals, squeeze cementing, water control and fines mitigation.

Completion performance—The completion, which includes perforations, liner slots, the cement-by-borehole annulus, sand-control screens, gravel packs and any zone of formation damage, dictates fluid movement from reservoirs to wellbores. Pressure drawdown at the completion is a function of flow rate. Factors that influ-

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**Closing single-well performance gaps.** The objective of production enhancement is to identify and close gaps between current well output and productive potential. This goal is accomplished by applying solutions and services that move reservoir inflow performance curves (IPR) up and to the right, and move flow-conduit performance curves down and to the right.
ence completion performance are perforation entrance-hole diameter and depth of penetration into a formation, sand control, stimulation, zonal isolation and damage, or partial formation penetration. Drawdown through a completion is reduced by reperforating or acidizing and by perforating a larger interval to reduce classical skin, resulting from a limited perforation interval. If not in place, a gravel pack or other sand-control method may be required. A cement squeeze may be needed if some zones produce unwanted water and gas, or take fluids that crossflow from another zone. Poor cement may also allow communication behind casing.

Tools used for evaluation include perforation-analysis programs, saturation logs, ultrasonic imaging tools, production logs and economic analysis. Services that improve completion performance include high-performance reperforating, sand control—gravel or fracture-packing sand-control jobs, squeeze cementing and acidizing.

**Flow-conduit performance**—Wellbore hydraulics may also limit flow if tubulars are improperly sized, and if there are unnecessary mechanical restrictions like tapered strings and profile nipples, or scale buildups inside the tubing and casing. Flow efficiency is a function of restrictions or leaks in wellbore tubulars. Tubing type, traps, restrictions, erosional velocity and crossflow can also limit performance efficiency. Required information may be obtained from calipers, ultrasonic imaging tools, production logs, water-flow logs and economic analysis. Solutions include acidizing, scale removal with coiled tubing, coiled tubing completions and early production systems.

**Artificial-lift performance**—Since flowing bottomhole well pressure is a function of artificial-lift efficiency, lifting system problems can impact well performance. Data useful for performance evaluation may be obtained from production logs, artificial-lift monitoring and economic analysis. Services to pull and replace or redesign rod pumps, gas-lift valves or electric submersible pumps can remediate performance problems.
Production Enhancement

Opportunities to enhance production—untapped primary, secondary and tertiary recovery—are abundant. On average, less than 35% of original hydrocarbons in place are recovered from millions of wells worldwide. These remaining reserves represent one of the best opportunities for operators to improve production. And this potential oil and gas output is fertile ground for prospecting (above). The PE portion of this prize, realizing an incremental 5% increase nominally from just one out of ten wells for example, could yield billions of barrels in additional production and reserves.

Because porous formations act as filters, most wells become damaged, or develop a significant “skin,” at some time during the drilling and production life cycle. Skin is a zone of reduced permeability around the wellbore that causes an excessive pressure drop across the completion face and limits fluid flow from the reservoir. Formation damage is a natural consequence of well drilling, completion activities and production flow. Drilling mud, completion fluids, crude oil, gas and formation water deposit clay particles, formation fines, asphaltenes, paraffin and scales that can block rock pore spaces and reduce matrix permeability. Damage can also result from mechanical crushing and compaction of the near-wellbore region as a result of pressure drawdown.5

Unlike our automobiles, however, most wells do not have their filters checked regularly. Recall any number of stories, from the mid-1980s until today, about oil companies that sold mature fields to other operators who then significantly improved production from these supposedly unprofitable, marginal or poor assets. Situations like these—success for one company, disappointment for another—are not unique.

Untapped reserves, formation damage and wells that need modern, full-service tune-ups are the factors that combine to make many assets, some with significant remaining reserves, ripe for auction blocks or abandonment (see “New Life for a North Sea Field,” page 10). There are even more wells and reservoirs that still produce economically which have additional potential waiting to be identified. These opportunities prompt operators and service providers alike to ask such questions as: In any theater of petroleum operations, from the Permian Basin of west Texas with over 100,000 wells to the North Sea with more than 2000, how many wells have skin effects that can be eliminated; or could oil and gas output be improved using new technology, modern techniques, improved tools and better fluid systems? Answers to these questions are the basis for production enhancement.

Because of this industry’s preoccupation with drilling and production operations, the many recent improvements in well services, and today’s powerful computers and modern software, operators can now take full advantage of PE opportunities for the first time.

Recently as well as in the past, the industry concentrated primarily on exploration, drilling, well construction and field operations, assigning lower priorities to production engineering and well performance optimization. Initial flush production, limited production quotas and government-regulated allowables meant that many wells were produced at rates far below their true potential.

Completions did not have to be optimized if wells were producing their allocated volumes. The only way to obtain higher allowables and increase production was to drill more wells. As a result, optimal completions were not always a priority. With few exceptions, however, the days of drilling into giant, prolific, near-darcy-permeability reservoirs are gone. Allowables, quotas and production limits are becoming a thing of the past; target reservoirs are more complex, smaller and tighter—lower permeability; many existing fields, large and small, are in mature stages of their production life cycle; and older fields need more attention to maintain output and identify overlooked opportunities.

**It Begins With “Where are the Files?”**

A unique new interaction between operator and service provider begins when PEG representatives are allowed access to relevant well files by an oil and gas company. The goal is to collect and analyze data quickly so that additional information needs can be determined or specific service proposals can be made (previous page, bottom). This phased approach with short cycle times—look at well files, recommend and execute services, evaluate results, then re-analyze and make improvements based on new data—reduces operator exposure to risk while providing timely feedback about the effectiveness of production enhancement. When proprietary client information and well data are being used by a local PEG, complete confidentiality is maintained at all times.

Proactive candidate recognition using the prospecting methodology and PEG analysis function is an iterative cycle (right). Data on a given field, reservoir or well are collected, cataloged and evaluated; and any production anomalies are noted. The best screening techniques and software are then used to thoroughly diagnose and assess well productivity in order to identify prospective candidates for remedial actions. The PEG software tool box—Production Enhancement Analysis Kit (PEAK)—includes Schlumberger and available industry programs, but PEG engineers are not limited to any particular software. They can use software that is preferred by a client or other programs with which they are familiar.

A minimum amount of information is needed to perform PCR; and there are usu-
Decline-curve projections indicated that production from the Amoco N.W. Hutton field would fall below the break-even economic limit of 6000 BOPD [950 m³/d] in 1996, and signal the beginning of decommissioning for 1997 (right). This would have been the first North Sea field to be completely abandoned, not a comforting prospect in light of environmental controversy surrounding other field abandonments and proposed disposal of their platforms.

Reservoir studies, however, indicated that factors other than natural decline could have caused the poor performance of this field. Most wells demonstrated significant declines within the first year of production. Although declines were initially believed to be the result of reservoir complexity, further investigation indicated that formation damage and scale in the immediate wellbore region of productive zones might be a more likely cause. Productivity also declined after well or field shut-downs. There was no flush production from recharging when wells were brought back online; productivity losses were permanent; and gas/oil ratios (GOR) remained constant during the initial decline phase, which was not consistent with structural compartments. Production below bubblepoint pressure should cause the GOR to increase, so drastic declines could not be attributed to pressure depletion of small drainage areas.

The field production platform was designed to handle 120,000 BOPD [19,070 m³/d], but actual production peaked at 83,000 BOPD [13,190 m³/d] for only a short time. The initial 280 million bbl [44.5 million m³] estimate of recoverable reserves had been reduced over the life of the field and production averaged 7000 BOPD [1112 m³/d] in 1996. Only about 120 million bbl [19 million m³], or 24% of the 487 million STBO [77 million m³] estimated to be in place originally, had been recovered. Most of the area’s Brent fields have recovery factors of at least 40%. Amoco wanted to determine if the suspected damage mechanisms could be successfully treated and if new technology—sidetracks, conformance control, injection management or stimulation—might improve oil recovery.

GeoQuest Reservoir Technologies for reservoir technical expertise, Schlumberger IPM for project coordination and the PEG Production Enhancement Group located in Aberdeen, Scotland, conducted a technical review of the field. This evaluation indicated a high probability of significant additional mobile oil, possibly 20 to 50 million bbl [3 to 8 million m³], remaining to be exploited. The operator was willing to share incremental value in return for engineering and services that would address limited resources, reduce uncertainty and risk, and facilitate project implementation.

An action plan and commercial proposal were presented to Amoco and the field partners. Schlumberger would risk intervention and engineering revenue to enhance field production, manage production and development operations, and optimize reservoir performance. In return, as the integrated service provider, Schlumberger would recover costs plus a gain-share compensation component from incremental oil. For each dollar invested, an agreed-upon multiple would be paid back. After the gain-share cap is reached, all revenue reverts to the N.W. Hutton field owners. This proposal was accepted and the project was initiated in the fall of 1996. The scope of work includes coiled tubing operations, matrix acidizing, water shutoff, fracturing, scale management, wireline logging, testing, perforating, lateral drilling and reservoir modeling. IPM manages the project, which is now generating incremental oil revenue.

A three-phase redevelopment plan was proposed with each phase dependent on the success of the previous work. Investments were staggered and to some degree self-funding. The first phase involved rate maintenance and data acquisition. Scale inhibition was initiated, up-time improvements were made and a production logging program was performed. Phase two involved fracture and diagnostic matrix stimulations to address skin damage. Conformance and gas-lift optimization were also initiated. The goal of the third phase is to generate high-risk, high-reward opportunities to add reserves through a full reservoir study.

The first and second phases of this project are under way. Production enhancement stimulations were undertaken to generate positive cash flow, demonstrate the potential to produce this field economically and instill confidence in the project’s future. These efforts are also providing data to supplement reservoir studies that are targeting options for extending the productive life of the N.W. Hutton field.

Skin, reservoir description, reserves, pressure and water chemistry data were used to generate intervention proposals—candidate recognition. Four intervention techniques to remove or bypass near-wellbore damage have been proposed:
scale dissolver treatments to address barium sulfate deposition in the rock matrix, diverted acid stimulations to treat calcium-carbonate scale and fines migration, tip screenout hydraulic fracturing and short coiled tubing drilled laterals to bypass skin damage.

Three of the four proposed well interventions to remove or bypass skin—scale inhibitor, acid and fracturing—have been applied, resulting in significant improvement in well productivity. Prior to fracturing, one candidate well produced at a rate of 700 BOPD [111 m³/d]. Three weeks after the stimulation treatment, the well was producing about 3200 BOPD [510 m³/d]. Scale dissolver and acid treatments have also been successful. More than 500 BOPD [80 m³/d] of additional oil production were realized from one well. The criterion to begin phase three, a goal of 6000 BOPD incremental production, was achieved and surpassed.

The Amoco and GeoQuest Reservoir Technologies team is revising N.W. Hutton reservoir descriptions and evaluating development scenarios that will increase the value of this field by improving productivity. The proposed redevelopment includes production enhancement, well construction and project management efforts aimed at improving production and increasing reserves through application of leading-edge technologies. It will be managed and coordinated by IPM working in conjunction with the Schlumberger Oilfield Services companies.

The organization and process were developed jointly by Amoco and Schlumberger to create an alliance structure and contractual provisions that are equitable and beneficial to all parties. The alliance approves budgets and proposals consistent with the strategies of both the operator and the service company. Sharing financial risks and rewards through value-pricing results in a high degree of alignment between companies and refocuses efforts and resources on achieving common goals.


Allied enough data in the well files. Ideally, available data should include formation evaluation logs, buildup or production tests, and a well history. In addition to well logs, or if logs are not available, field net-porosity and net-hydrocarbon-thickness maps may be used. Ideally, both logs and maps should be used, and in some cases, seismic data may be helpful. New wireline formation evaluation logs may be needed to verify production potential. When there are no production or well-test data, new pressure buildup or production well testing are often recommended. If well data are incomplete, it may be possible to “back into” well and reservoir unknowns by iterating through a NODAL analysis until a good fit with known parameters is obtained. This type of analysis can best be described as reverse, or inverse, engineering. Typically, relevant data are gathered and compiled in a spreadsheet or database.

Candidate recognition may include calculating skin and damage effects, determining production potential at a reduced skin, quantifying available reserves, running economic evaluation and making recommendations based on risk versus return or cost versus benefit. Current well output is analyzed along with production history and the effects of various PE options. Additional formation evaluation logs may help verify productivity before economic and risk analyses are performed.

Analyzing current performance using the best available data establishes the most likely reservoir parameters for a well. If build-up or drawdown tests are available, transient-pressure-analysis programs help calculate pressure, permeability, skin and reservoir boundaries. Four-point and backpressure tests can be used to determine initial reservoir pressure. Iterative NODAL analysis can also be used to match pressure and permeability, and obtain skin at a given time. The most useful skin information comes from recent time. “Snapshots” of a well production system can be obtained at the start of production, before a well is put on gas lift or rod pump, after a well is put on artificial lift, and at current rates. These reference points include reservoir pressure, wellhead pressure, production rates—oil, gas and water—skin and cumulative production.

Since the objective is to predict future output, only production rates at the present skin value are important. This means that cumulative production since the last significant event that altered the skin is all that needs to be examined. Data are normalized by selecting this event as the initial time. Cumulative time and oil, gas and water production can be calculated from this point. Initial pressure—reservoir pressure at the time of that event—is derived from material balance programs.

Production history analysis is used to verify the current performance analysis. General material balance programs with single-layer model solutions for homogeneous reservoirs quickly evaluate reservoir performance and obtain reliable initial pressure estimates, pore volume and average aquifer-water influx rate. Sensitivity analysis can be performed with these models to evaluate drainage area, initial pore pressure and the influence of water influx on reservoir pressure history. Once a satisfactory production history match is obtained and unknown parameters are determined, these models can help forecast future well performance and recovery by extrapolating from previous production to an average reservoir pressure or time using conventional rate-decline relationships.

Other programs and production-history analysis are also used to model wells and check values obtained using NODAL analysis and material balance programs. Programs that provide a continuous production picture, rather than just a few snapshots over time, can be particularly helpful. NODAL analysis software is used to match production at several times during the productive life of a well, and these reference points are used to verify the production history model. Excellent matches between estimates and real data provide confidence in well model validity and the accuracy of their predictions.

At this stage, it may be evident that more data or full reservoir simulation are needed to determine candidate economic viability. Not all production gaps can be addressed through candidate recognition with the prospecting methodology. Some problems do take weeks or months to solve, and PEG engineers must recognize these problems and refer them to reservoir study groups for evaluation.

Once required well data are compiled, the next step is to study enhancement options, which establishes viable PE alternatives, and the production increases and economic benefits associated with them. After all of these steps are applied to the wells being considered, PE candidates are prioritized in terms of risk versus net-present-value (NPV) economics, and appropriate recommendations and well interventions are selected, designed and executed. The final step in this process is...
to compare actual results to predicted outcomes and carefully analyze the details of this feedback. Results—successes and failures—are evaluated, reviewed with the client and then used as additional input in another cycle of the PEG analysis process. Out of 100 wells, for example, a PEG evaluation might find as many as 10 potential candidates. Successful interventions on these wells may then generate additional PE opportunities.

The PEG process, which is always applied on one well at a time, is used for individual single-well evaluations, but is perhaps most successful when employed to analyze groups of wells or a field. This allows engineers to look at a statistically significant number of wells, which can compensate for some unsuccessful jobs and help ensure overall project success. Wellbore mechanical modifications on some of the wells being evaluated may also improve production and contribute to overall production enhancement success.

**Why Proactive?**

Candidate recognition performed proactively is the antithesis of chance occurrence—waiting until wells go off line or drop below economic limits before initiating action. Another reason to take advantage of PCR is synergy, those actions taken jointly to increase overall effectiveness beyond the sum of their individual effects. Production enhancement efforts create a partnership, or team, often based on a handshake agreement, consisting of the client and a local PEG organization working together with Schlumberger Oilfield Services companies (above right). Cooperation between these groups, in concert with advanced technologies and well servicing methods, can be effectively employed to improve production from existing wells.

With the exception of tubulars, downhole equipment and other stock warehouse parts, Schlumberger provides services from discovery to depletion, including seismic surveying, data processing and interpretation, drilling, well logging, perforating, well testing, cementing, acidizing, fracturing, and coiled tubing or abandonment services. And many of these applications—cleaning out fill, perforating or reperforating, logging, interpreters and evaluating data to find more pay, acidizing to remove damage, fracturing to create conductive flow paths, water and gas control, and infill, directional, horizontal or lateral drilling—are directly related to moving IPR curves and increasing productivity.

The style of proactive PEG evaluations is quick—hours and days, not weeks and months—and action oriented, generating specific recommendations to be implemented, not reports or studies to be read and reviewed. In most cases, these “action” plans are a simple list of wells, or sometimes a single spreadsheet page, with recommendations to gather more data or apply a specific solution, technology, service or integrated application (next page).

Among the short-term benefits of production enhancement, PCR generates candidates for well interventions, demonstrates production potential for added confidence in well or field viability and provides additional cash flow for funding further production enhancement. The long-term upside potential includes maintaining profitability, increasing asset value and extending well or field productive life.

But why are operators allowing PEG representatives access to their prized well files? One answer lies in leveraging the best mix of knowledge, experience and technical resources to address production engineering. Another reason is that E&P company personnel have a limited amount of time, which can often be taken up by higher priorities like drilling new wells and maintaining their more prolific producing properties. It can be difficult to consistently maintain effective surveillance, perform production engineering and identify opportunities across an entire asset portfolio, and still keep up with the latest techniques and technological advances. In addition, it is helpful to have input from experts who look at production enhancement opportunities and potential well productivity from different points of view.

Unlike the period following oil price collapses in the 1980s, experienced service personnel are now available to undertake PE projects. Over the past several years, service companies, including Schlumberger and Halliburton, have been among the top recruiters of petroleum engineers. In addition to filling entry-level technical positions, these companies are also adding mid-career professionals, many with oil company and consulting backgrounds, that expand the service sector experience base.
### Proactive Candidate Recognition Screening: West Texas

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<th>Well</th>
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<th>Comments and PE recommendations</th>
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<td>Clean out fill and acidize or fracture stimulation</td>
</tr>
<tr>
<td>106</td>
<td>Upper</td>
<td>Yes, Yes</td>
<td>Clean out fill and water control</td>
</tr>
<tr>
<td>148</td>
<td>Lower</td>
<td>Yes</td>
<td>No additional potential</td>
</tr>
<tr>
<td>201</td>
<td>Lower and middle</td>
<td>Possible, Possible</td>
<td>Evaluate stimulation and rod pump performance</td>
</tr>
<tr>
<td>204</td>
<td>Lower and middle</td>
<td>Possible, Yes</td>
<td>Water control and evaluate stimulation</td>
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</table>

### Phase 1 Candidate Recognition: Gulf of Mexico Acid Treatments

<table>
<thead>
<tr>
<th>Well</th>
<th>Reservoir</th>
<th>Zone</th>
<th>Buildup analysis</th>
<th>Current production</th>
<th>PEG prediction</th>
<th>Comments and recommendations</th>
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</thead>
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<tr>
<td></td>
<td>Reservoir pressure, psig</td>
<td>Permeability, mD</td>
<td>Wellhead pressure, psig</td>
<td>Oil rate, B/D</td>
<td>Water rate, B/D</td>
<td>Gas rate, Mscf/D</td>
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<tr>
<td>1</td>
<td>A</td>
<td>1844</td>
<td>60</td>
<td>250</td>
<td>70</td>
<td>2</td>
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<tr>
<td>2</td>
<td>A</td>
<td>1640</td>
<td>180</td>
<td>—</td>
<td>250</td>
<td>62</td>
</tr>
<tr>
<td>11</td>
<td>B</td>
<td>1844</td>
<td>60</td>
<td>250</td>
<td>50</td>
<td>26</td>
</tr>
<tr>
<td>21</td>
<td>C</td>
<td>35</td>
<td>Partially collapsed tubing</td>
<td>0</td>
<td>121</td>
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<tr>
<td>31</td>
<td>D</td>
<td>1844</td>
<td>60</td>
<td>250</td>
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<tr>
<td>32</td>
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<td>170</td>
<td>375</td>
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<tr>
<td>33</td>
<td>D</td>
<td>1715</td>
<td>226</td>
<td>550</td>
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<tr>
<td>34</td>
<td>D</td>
<td>Based on well production history</td>
<td>40</td>
<td>117</td>
<td>—</td>
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</tbody>
</table>

**Action plans.** The final product of a PEG analysis is often a simple, one-page list of wells, sometimes in spreadsheet format, with specific solutions and recommendations about actions, services or integrated applications that need to be performed to enhance production.
Current PEG teams include the talents, expertise and experience of petroleum engineers with PhD degrees, and some top experts and specialists in key production engineering disciplines. Schlumberger Oilfield Services also recently acquired S. A. Holditch & Associates, Inc., College Station, Texas, a worldwide petroleum engineering company that offers consulting services in well stimulation, completion design and reservoir analysis. This acquisition broadens the range of production enhancement activities and reservoir engineering services that can be provided to operators.

Proactive candidate recognition can be performed solely by PEG specialists, but perhaps works best as an operator-Schlumberger team approach. Oil company personnel are most familiar with the overall production history and reservoir view, but integrated service providers invest time and money for research to commercialize new technology and, therefore, are knowledgeable about specific applications of the tools, methods and services that are developed. As a result, PEG engineers review well files and data from a fresh perspective and may recognize opportunities to apply specific techniques, unique combinations of technologies or an integrated solutions approach that might otherwise be overlooked.

**Result-Based Experience**

Typical well interventions for production enhancement include jobs that address the full range of performance-gap components. Reservoir- and completion-related interventions, however, usually represent most of the jobs and dominate the mix (above right). The remaining well productivity gaps are the result of artificial lift and tubing performance. Reservoir IPR curves can be moved and productivity gaps can be closed by:

- finding bypassed pay
- perforating
- acidizing
- fracturing
- drilling laterals.

Since being established in 1990, the PEG organization has worked to improve production and increase reserves for clients through PCR and the production enhancement process using these types of well interventions.7

Recompletions can tap bypassed hydrocarbons. In one case, an old electric log was reviewed to identify possible zones of interest. Through-casing potential was determined by running a Dual-Burst TDT Thermal Decay Time log and performing an ELAN Elemental Log Analysis evaluation. A previously undiscovered gas zone was perforated with a through-tubing Enerjet gun. The new zone produced 770 Mscf/D [22 Mscm/d] and paid out in eight days (next page, bottom).

Several PE activities help identify additional pay or bypassed productive intervals. Surveillance methods, like net-porosity mapping and hydrocarbon indexing, can be used to locate behind-pipe production potential in existing fields (next page, top). Older logs can be reevaluated or interpreted using new techniques, or modern wireline logs can be run to acquire more information. Recompletions can tap bypassed hydrocarbons. In one case, an old electric log was reviewed to identify possible zones of interest. Through-casing potential was determined by running a Dual-Burst TDT Thermal Decay Time log and performing an ELAN Elemental Log Analysis evaluation. A previously undiscovered gas zone was perforated with a through-tubing Enerjet gun. The new zone produced 770 Mscf/D [22 Mscm/d] and paid out in eight days (next page, bottom).

![Typical well candidates. The majority of PE well interventions in North America fall into the reservoir and completion performance gap categories.](image)

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Reservoir surveillance. Methods like porosity mapping and hydrocarbon indexing help locate behind-pipe production potential in existing fields.

Finding new pay zones. New formation evaluation techniques—logs and processing software—also locate bypassed oil and gas. A previously undetected zone produced 770 Mscf/D [22Mscm/d] and paid out in eight days.
Adding perforations. Additional perforations improved production from this offshore Louisiana well. Increased gas production also improved flow-conduit lifting performance. The 12-day payout for this PE job was less than the initial estimate, resulting in a 30% price premium.10

In another example, reperforating with high-performance charges can increase production and realize the predicted production potential of wells. Deep-penetrating perforations or larger entry holes reduce drawdown across the completion. Analysis of a well in a dolomite oil reservoir in Texas indicated a 6-in. damage zone with a 0.85-mD permeability. The 1.6-mD dolomite reservoir was 20 ft [6 m] thick with an 8500-psi reservoir pressure. The well was completed by perforating with a casing gun and tested at 55 BOPD [8.7 m³/d] rate. When reperforated using an expendable through-tubing gun, the well produced 148 BOPD [23.5 m³/d]. NODAL analysis predicted that this well should be capable of making 270 BOPD [43 m³/d] (next page, top). A recommendation to shoot the well with a Pivot Gun perforator resulted in a rate of 277 BOPD [44 m³/d].
Acidizing—Stimulation technologies have been improved as well. Today’s acid systems remove damage more effectively, and these matrix treatments can be designed, placed and diverted with greater efficiency. Matrix acid jobs reduce skin and improve well productivity. In south Texas, a matrix acidizing treatment was used to stimulate an Edwards Lime well with 40 ft [12 m] of 1-mD gas pay and 2200-psi bottomhole pressure. Gas production before acidizing was 750 Mscf/D [21 Mscm/d], but NODAL analysis predicted that production potential from this well was 1270 Mscf/D [35 Mscm/d] (right). Actual production after a FoamMat acid treatment was 1400 Mscf/D [40 Mscm/d], almost a two-fold increase.

Reperforating. NODAL analysis predicted that this well could produce 270 BOPD. After perforating with a Pivot Gun perforator the well tested at a 277-BOPD rate.

Acidizing. A south Texas gas well produced 1400 Mscf/D after a FoamMat acid treatment. Before acidizing, production was 750 Mscf/D. NODAL analysis estimated potential production at 1270 Mscf/D.
Drilling lateral drainholes. A well in Lake Maracaibo, Venezuela, had not produced since 1986 because of mechanical wellbore problems—junk in the hole. NODAL analysis predicted 275 BOPD from a 70-ft lateral sidetrack. The well actually produced 250 BOPD and paid out in 13 months.

Fracturing. A low-permeability gas well was shut in. NODAL calculations estimated post-fracture stimulation potential to be 550 Mscf/D. After fracturing the well produced 600 Mscf/D.
Fracturing—Today’s fracture stimulations use cleaner fluids and more effective props to provide the most conductive path possible from the formation to the wellbore.13 Retained fracture permeabilities, for example, have been increased from less than 10 to several hundred darcies.

Fracture stimulation treatments create conductive paths from the formation into the wellbore. In low-permeability reservoirs, propped fractures serve as a highway for hydrocarbons. NODAL production system analysis for another South Texas well predicted that the Wilcox formation could produce 550 Mscf/D [16 Mscm/d] at a 2600-psi wellhead pressure after fracturing (previous page, top left and right). This well penetrated 45 ft [14 m] of 0.09-mD formation and had a reservoir pressure of 4500 psi. The well would not produce initially, but made 600 Mscf/D [17 Mscm/d] after the fracture stimulation.

Drilling laterals—Reentry drilling technology, such as RAPID Reentry And Production Improvement Drilling, has also developed to the point where horizontal and multilateral wells provide options for tapping bypassed reserves from existing wellbores.14 And modern coiled tubing techniques can unlock the potential of these high-angle or horizontal wells, not only through drilling but also by efficiently conveying logging tools and placing stimulation fluids.15

In Lake Maracaibo, Venezuela, NODAL analysis forecast that a 70-ft [21 m] sidetrack would produce 275 BOPD [44 m³/d] (previous page, bottom and below). This well had been shut in since 1986 because of mechanical wellbore problems—a lost fish or junk in the hole. After the sidetrack was drilled, this well produced 250 BOPD [40 m³/d]. The payout for this production enhancement intervention was 13 months.

Computer and communications capabilities have advanced as well. A little more than 10 years ago, personal computers were used almost exclusively for word processing. Today, these computers provide the computational horsepower for engineering programs that help select, design and evaluate well interventions. Previously, reservoir and production calculations were time consuming, made by hand or on massive mainframe computers. Now, service company representatives can quickly forecast the effects of completion and stimulation actions with portable laptop computers while sitting across the desk from clients in their offices. Reservoir surveillance capabilities, data management and information technology have also improved.16

In most PEG evaluations, the overall reservoir development plan is fixed, but production enhancement may be an integral part of more extensive reservoir management projects that are directed at optimizing field, production and reservoir performance. Data and results from the PE process also provide insights and input for further detailed reservoir studies and simulation. On larger, complex projects, like the Amoco N.W. Hutton field, production enhancement during early stages can jump-start oil and gas production and boost income to help generate funds for initial remedial efforts. Efforts to improve productivity should not be directed solely at marginal wells, completions on the structural flanks of fields or areas with limited pay or potential. Like fracture stimulation well candidates, the best producers often make the best PE prospects. Each well should be evaluated to determine if it is producing at its full potential.

Turning Cost into Revenue

An important aspect of production enhancement and the PEG function, in addition to actively prospecting for well candidates, is undertaking projects on a contingency, risk-reward or value-price basis. Until recently, charges for well services were usually based on service cost or prevailing market rates. But compensation for integrated, solution-based services that deliver an incrementally greater return can also be based on performance, benefits or the extra value generated—value pricing (right). Value pricing makes sense when customized solutions result in measurable savings or increased income that is quantifiable and differentiated from other products, services or methods.

Helping clients meet incremental production targets is the foundation for customized solutions and contingency payments or result-based rewards (below right). For risking some service revenue down to a lower cost limit, Schlumberger receives a fair share of the added value generated by PEG recommendations. Operators share this additional value, up to a reward cap, in return for reduced financial exposure, technology and service resources, and a mutual working arrangement that helps overcome risk and technical obstacles, resistance to applying new technology and pricing fixations that are left over from the low-bid days and industry downturns of the past decade. This approach focuses on generating, measuring and sharing greater value.

Payment for PEG recommendations could, for instance, be calculated based on incremental production. The operator might share 50% of incremental production, after paying taxes and royalties, for a mutually agreeable period of time. In short, to the extent that services provide two dollars of extra value, the client shares some amount less than a dollar. Compensation can also be based on job success using a sliding scale. Payments for services can be determined by multiplying market or alliance price rates by a predetermined percentage (next page, top left). The operator could agree to pay market rates or less for services that are unsuccessful or for marginal production increases. Successful jobs that return large increases in production would be invoiced at higher percentages.

Cost and market-driven pricing

![Cost and market-driven pricing diagram]

Value pricing

![Value pricing diagram]

- Costs versus solutions. Value pricing moves customers and solutions forward in the service process. Customized solutions emphasize production not low-bid jobs and can generate greater value for both operators and an integrated service provider like Schlumberger.

- Sharing risk and value. In value-pricing arrangements, operators share the rewards, up to a cap, from projects that enhance production, add reserves, improve efficiency or increase service quality. For risking some service revenue, down to a limit, Schlumberger gets a fair share of this value. Value pricing makes sense if customized solutions, differentiated from other products and services, deliver measurable savings or increased revenue.
Value-based pricing and contingent payment philosophies help buyers and service providers think, act and make decisions in terms of value rather than price, and therefore concentrate on optimum solutions and results instead of the lowest price tools and services. When Schlumberger as an integrated service company is given the task of helping operators achieve a target incremental production, NPV or return-on-investment (ROI) in exchange for a fair share of incremental production costs are more effectively turned into revenue. The result is a new focus on the outcome, production to be generated and value that is provided instead of the cost, or expense, of services. Focusing on production generates more revenue and, as a result, additional value for both the client and the integrated service company.

The service sector, now more than ever, is able to assume more responsibility for production operations. A complete range of Schlumberger service capabilities is available to deliver customized solutions, and manage well construction, production enhancement interventions, field operations, major projects and reservoir performance (above right). But the blurring of traditional boundaries between clients and service providers can be complicated. Schlumberger believes that service companies should be independent, maintaining consistent relationships with all clients. Actions that might result in overlap, confusion and potential conflicts of interest are avoided even when sharing risks and rewards.

Integrated service providers should be compensated for service quality, performance and the value that is delivered, but without taking an equity position in oil and gas assets. Value-pricing ensures that the service provider is fairly compensated for integrated skills and services, such as production enhancement, project management and reservoir optimization, and ensures that the extra value generated by customized solutions is distributed equitably.

**What Does the Future Hold?**

In the arsenal of services available to oil companies, production enhancement is rapidly gaining acceptance. The future for PEG includes expansion into more markets and continuing advances in computer capabilities and data management. Candidate recognition, including well monitoring and evaluation, will become more automated. Real-time data measurement, communication and management tools—like the WellWatcher system—will help track surface and subsurface parameters, such as temperature, pressure, flow rate and fluid densities, and then transmit this information to operator offices continuously or on command.

The Production Enhancement Analysis Kit (PEAK) will be further developed into a tightly integrated reservoir and production engineering software support package. And finally, production enhancement efforts will be further integrated with future well construction, project management, reservoir enhancement, field study and reservoir management processes.

Increasingly, efforts by PEG teams may also be an integral element in larger projects. As a logical next step in new business relationships between clients and service companies, production enhancement can be a starting point to further expand integrated production management and customized service solutions. Operators benefit from improved production, reduced risk and more effective use of service sector knowledge and experience. As the integrated service provider, Schlumberger gets an improved return for services rendered and an expanded market for solutions, services and tools, in addition to more opportunities to prove new technologies and ideas, demonstrate integrated services concepts and gain experience.

On a daily basis, oil and gas operating companies must deal with many existing wells and reservoirs while trying to improve or maintain output from an increasing number of new wells. Proactive efforts to optimize the productivity of client-operated wells through production enhancement are helping to get the most value out of existing wells. This engineering methodology breaks down traditional barriers between petroleum disciplines as well as producers and integrated service companies, providing a more open exchange of information that results in additional production, increased recoveries and the sharing of value. —MET
Information delivery is a business of balance. With too little information, problems remain unsolved. With too much, the relevant parts may go unheeded. Too early may not be possible, but too late might just as well be not at all. And giving confidential information to the wrong party is unacceptable. Creating the perfect balance requires knowing what is needed: which data and how much, where and when to send data, and to whom. And of course, no data transfer is possible without a means of conveyance.

For the oil and gas industry, the scale of the information-delivery challenge is global. Rigs, crews and vessels are able to acquire log and seismic data at nearly every coordinate on the globe, but the decision-makers and end-users of these data are usually far from the acquisition site and often removed from data-processing operations.

The availability of the WorldWide Web, satellites and high-speed transmission lines makes delivery of distant oilfield information possible, but other elements of the balancing act must be weighed before the problem is completely solved—before the hard-won data make their utmost contribution to the resource optimization puzzle. Each discipline within the industry has specific requirements for data type and amount. Even within a discipline, needs may vary with urgency and end use.
In terms of seismic data, the demands for information can be classified according to the stage of a survey. The two stages with the greatest needs for time-sensitive data, and that lend themselves well to the constraints imposed by real-time transfer of information, are survey acquisition and data processing. In this article, we examine the data requirements for these two crucial stages in the imaging of a reservoir and describe a new Internet-based system that allows operators to monitor in real time the progress of their data acquisition and processing.

**Required While Acquiring**

Until a well is drilled, the most reliable information available for identifying targets is gleaned from seismic data. Getting a high-quality seismic survey at a cost-effective price is crucial. To achieve this, operators need details about survey progress during seismic acquisition, whether on land or at sea. This may be for health, safety and environmental reasons, contract conditions, or for monitoring and assessing data quality. In some cases, timely operator response or input is essential to the success of the survey.

Some of the information operators require is contained in the party chief’s log, which is a record of all significant events; the navigation log, which documents the positioning process; and the daily production log, which is a listing of the lines that were acquired and whether they passed established quality acceptance criteria.

Also vital, from a data-quality point of view, are Quantified Quality Assurance (QQA) reports that contain detailed analyses of the data acquired and comparisons of these to quality standards that were set in the survey planning stage. Quality parameters have traditionally been based on simple analysis of background noise levels, but are increasingly based upon the measured quality of recorded data. Quality acceptance levels for parameters such as signal-to-noise ratio, source power, frequency content and coherence between adjacent traces are set prior to a survey after a detailed evaluation of their impact on the ultimate objectives of the survey.

In the course of a survey, some shots or lines may not meet quality specifications, requiring a reshoot of the offending lines. Or conversely, some lines that do not initially appear to meet specifications based on background noise levels may, in fact, be adequate after some processing, and not require reshooting. The operator, usually someone in an office, decides whether the data are fit for the processing and interpretation that follow. For maximum acquisition efficiency and economy, making the decision that a line need or need not be reshot requires up-to-date information, so shooting can be done before the acquisition crew leaves the site.

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In addition, periodically, a coverage map—a plot showing the geographic area of the survey and the density of seismic energy recorded at every “point” on the map—is analyzed to verify that the subsurface target is being covered sufficiently by seismic data (previous page). The points are actually small areas called bins. As the survey comes to a close, if holes are detected in the coverage, infill shooting is required. Infill shooting, which entails redeploying sources and receivers to areas already traversed in the survey, can represent up to 30% of overall survey cost.

In the past, the party chief’s log, navigation log and daily production log were printed on paper and sent or faxed to the oil company. Data quality control (QC) analyses and coverage plots were also printed and sent by fax or surface mail if color plots were produced. Decisions would be made based on the paper output, and relayed as soon as possible back to the service company contractor. Unfortunately, delays often occurred, and seismic crews were kept waiting or had to return to the site later for costly reshooting.

### Input to Processing

Data acquisition is not the only stage of a seismic survey that requires timely input from the operator. Data processing—whether run after acquisition, or as is now more common, concurrently with acquisition—can benefit from real-time client involvement.

The two processing steps that most typically receive client attention are deconvolution and velocity analysis. Deconvolution is a filtering technique that removes certain types of noise and produces seismic traces with features that more accurately correspond to the reflectors encountered. As a test, various deconvolution filters are applied to a small amount of the seismic data. The filter that gives the best result is then applied to all the data. The choice is usually made visually from a plotted series of deconvolution panels. Expert knowledge about the expected geology is important in choosing deconvolution parameters.

Velocity analysis is part of the stacking process. Stacking is the summing, for the purpose of enhancing the signal-to-noise ratio, of seismic traces acquired by different source-receiver pairs. On these traces, echoes originating from the same location on a reflector appear at different times. The time difference across traces is directly linked to the velocity at which seismic waves travel through the subsurface. Most velocity analysis schemes rely on picking the maximum in a velocity-versus-time plot (above). Several velocities are tested on small portions of the data. The velocity that produces the greatest coherence is selected.

A 3D seismic survey typically requires velocity analysis at several thousand locations, between which the selected velocities are interpolated to enable optimum stacking over the whole survey area. Selection of the velocity function that maximizes coherence can be done automatically by computer, but quality control must be performed visually by a geophysicist who can recognize a physically realistic velocity function. Quite frequently clients participate directly in velocity quality control, or pick the velocity functions themselves. This practice can sometimes lead to scheduling delays in the project.

In a growing industry trend, more surveys are being shot and processed concurrently, reducing overall cycle time of the project and speeding access to an interpretable result. This drives the need for even faster decision-making, which in turn requires faster access to real-time acquisition and processing information by oil company office personnel.
Monitoring from Afar

The SuperVision project monitoring service from Geco-Prakla delivers acquisition and processing updates that allow oil company decision-makers to participate in projects in real time (above). This new initiative uses off-the-shelf Web-browser software and the explorationist’s own PC or workstation to access a project “home page.” The client can monitor and comment on project progress from an office or portable PC, anywhere in the world and at any time of day or night.2

Connection between client sites and the SuperVision system is through one of a small number of servers from the TWS Trusted Web Service offered by Omnes. The TWS server is linked to the Schlumberger intranet through a security firewall (below). Actual transmission of data can be through the Internet or through dedicated high-speed integrated services digital network (ISDN) lines. Project monitoring data destined for client view are collated onboard or at the field location, transferred on a regular basis via satellite to a master server, then sent to the TWS server. Through the appropriate authentication mechanism, authorized personnel log into the home page of that survey, and use commercially available Internet tools, such as Navigator or Internet Explorer to view and browse the Web site.

Network security is obviously of paramount importance. The security technology that controls SuperVision access was designed by Geco-Prakla to work in the security-unfriendly environment of the public Internet. The goals of the security measures are privacy, authentication and robustness. Privacy means there is no unauthorized access to confidential information over the public network. Authentication means that steps are taken to ensure that users are who they say they are and that information originates from the source it claims. Robustness means that a server will not fail by attack from someone with physical or network access.

Extending client connectivity with the SuperVision system. Seismic data from acquisition units (left) are transferred on internal Web servers to data-processing centers on the Schlumberger intranet. Data are then archived on a TWS Trusted Web Service server. To access data, oil companies (right) may use the Internet or direct ISDN lines, following strict authentication measures to access the TWS server.
The TWS service relies on three technologies—fire wall, Netscape Enterprise server and secure socket layer—to ensure properly controlled connectivity. The fire wall restricts physical access and monitors traffic to detect unauthorized access attempts. It also restricts the electronic communication between two different machines, or Internet protocol (IP) addresses, to a certain class of conversations, or port numbers. For example, machine A might be allowed to access Web pages on machine B, but not be able to do a remote login. The Netscape Enterprise server manages access control. The secure socket layer manages certified access and relies on public key encryption, digital certificates and personal smart cards to assure security.\(^1\) Digital certification for access to the Geco-Prakla TWS server is administered by trusted third-party authorities called certificate authorities.

The certificate authority currently certifying access to the TWS server is Verisign, Inc. of Mountain View, California, USA. Verisign is the leading provider of digital authentication services and products for electronic commerce and other forms of secure communications. Verisign installs a unique fingerprint, or digital certificate, on the hard disk of the computer that will be used to access the server. The certificate is registered with the Web site at the time the authorized client user is issued a password. Certified access to the TWS server requires identification of that user with that password on that machine with that digital certificate. Unless each of these is authenticated, there is no access. If multiple machines are to access the Web site, each must have a certificate registered with the TWS server.

Once the authorized user has accessed the SuperVision home page, the gateway is open to a wealth of information. A tour of the home page set up for the fictitious XYZ Oil Company reveals the types of information available on acquisition and processing projects.

The first stop is the party chief’s log, an exact replica of its paper-copy ancestor. Also on record here in chronological order are all the logs for each day of the survey.\(^2\) The recent log selected—highlighted in the left column—chronicles details of the survey. Annotations include the party chief’s name.

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weather conditions, number of sources, streamers and channels, streamer length, total number of points shot, comments on streamer modifications made during the survey and notes on the day’s events. In this case, the difficult weather conditions precluded a rendezvous with a supply boat.

As a type of update, the coverage plot, presents several panels with information about how effectively the survey is covering the subsurface target (above). The main screen shows each traverse of the vessel as a vertical swath. Black indicates full coverage, according to the specifications of the survey, and lighter colors flag zones of lower coverage. An inset panel explains the color legend and describes the details of the groupings of shots within each vertical swath of the plot. The white step-like areas at the bottom of each swath are zones left without coverage at the beginning of each line. The white areas in the middle of a black area are gaps in coverage created by obstacles in the survey area. The inset panel describes in more detail the four vertical subdivisions of each swath. The leftmost division of any swath shows the coverage for the near-offset traces, with offsets between 180 and 1630 m. The second division gives coverage for the near-to-mid offsets, from 1630 to 3080 m. The mid-to-far offsets (3080 to 4530 m) follow, and the rightmost division shows coverage for the far offsets (4530 to 6100 m).

Unlike the party chief’s log and coverage plot, which are generated at regular intervals, quality control plots are generated as exception reports, and appear only when a parameter threshold has been surpassed. With this information available in real time, clients can evaluate the impact of the noisy shots on the final outcome of the processed survey. For this survey, such conditions occurred in isolated shots on two lines, as indicated in the left window.

Acquisition updates are also available for land seismic surveys with the SuperVision service. In a fictitious example over the city of Amsterdam, the survey acquisition geometry with locations of sources and receivers has been plotted on a basemap of the local countryside (next page, bottom left). This shows the locations of obstacles and other constraints on the acquisition. During acquisition, coverage can be monitored. For example, an area dominated by a lake exhibits some low-coverage spots because source positions were limited. Adequate coverage is plotted in red and orange, while lower coverage shows up as yellow, green and blue (next page, bottom right).
Planning a seismic survey over Amsterdam. Taking into account natural and man-made obstacles, a grid of source (red) and receiver (purple) positions has been laid over a map of the city.

The coverage expected for the Amsterdam survey in one area dominated by a lake. Coverage decreases from red and orange through yellow to green and blue.

Exceptions to the rule. When survey noise parameters exceed established thresholds, a QQA Quantified Quality Assurance exception report is generated. In this case, the signal quality recorded in the port streamer shows a noise level spike (center panel) near shotpoint 2600.
Several steps in the data-processing chain can also be monitored. The processing status report gives an overview of the processing project (below). This display plots the processing tasks in chronological order, the time interval allotted for completion and a snapshot of processing status. This excerpt from an output for a TQ3D Total Quality 3D marine survey indicates that the early tasks, including priority-area processing concurrent with acquisition, prestack testing and data merging, have been completed. Milestones, such as completion of acquisition, delivery of navigation data, meetings and steps requiring client input, are marked by diamonds. A typical processing project will have 20 to 40 tasks, many of which overlap. The final steps in this project, not plotted here, include velocity field QC and data migration.

The crucial phase of velocity analysis for stacking requires several iterative steps and exchanges of data between service company and operator. The SuperVision system allows these exchanges to be performed in a fraction of the time previously required for fax and courier delivery of paper outputs. The SuperVision page houses a record of velocity-analysis panels, and updates the archive with all communications and data analyses pertaining to the velocities that will be used for stacking and migration (next page). The multipanel display is standard output from the Geco-Prakla SEISMOS data-processing system. The velocity-depth panel on the left shows coherence maxima picked as blue, red and black squares. The center panel plots the seismic data with the current velocity field applied. The seven panels on the right show the results of applying seven different constant-velocity fields to the data.

**The Vision**

SuperVision project monitoring delivers higher quality seismic results than previous methods, and does so more efficiently. The fast turnaround in communication promotes client input at crucial stages, producing an improved seismic product. Efficiency is gained because the Web site takes less effort to update and to read. The data are available when needed, and there is a unique, shared version that can be accessed by teams working in different locations. The digital project archive can be stored and managed with the seismic data themselves, from acquisition through processing and interpretation. Certified access to multiple locations allows operator experts and partners, as well as contractor offices and field sites, to participate in creating a high-quality seismic dataset.

Because information is updated rather than replaced, an information archive is built up over the duration of a survey, allowing a complete retrospective view of the job to date. An added benefit is that by the end of a project, most of the final report already exists in a standard and accessible format.

The SuperVision service aims to deliver project monitoring to customer desktops, usually a personal computer, and to provide any display that would normally be seen on a workstation in the instrument room of a seismic vessel or land acquisition unit, or in a processing center. An immediate benefit is better leverage of experienced personnel: monitoring a survey no longer requires absence from the office for two or three months. Supervising a project via the Web...
eliminates days, weeks, and potentially months of dead time, postage costs and risk of misdirected packages.

With the desktop goal and speedy access in mind, data available through the SuperVision system are limited by their size. Raw seismic data and large 3D cubes occupying hundreds of gigabytes are not suitable for delivery to the oil company interpreter’s desktop PC. But through the SuperVision page, for example, a request can be made for the data to be delivered through a different path to a large machine down the hall, with the option of using high-fidelity compression techniques to shorten transmission times.

The near-term goal is to have every seismic project accessible to clients through the SuperVision system. This would be the next step toward the longer-term vision of comprehensive management of oil and gas resources from the office desktop. —LS
Extended-Reach Drilling: Breaking the 10-km Barrier

Geosteering, torque reduction and casing flotation have all contributed to record-breaking extended-reach drilling achievements. The limits of directional drilling continue to be pushed back as horizontal reservoir sections greater than 2500 m are being drilled, cased, cemented and completed to tap reserves at extreme distances from surface wellsites.

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ADN (Azimuthal Density Neutron), CDR (Compensated Dual Resistivity) and GeoSteering are marks of Schlumberger.
Extended-reach drilling technology recently achieved a new milestone with the drilling and completion of a 10-km [33,000-ft] stepout well, some 2 km [6,600 ft] longer than the previous world record. The main technical hurdles to the success of this well were reducing torque and drag, controlling fluid circulation and maintaining directional control. Solutions were not simple because methods to mitigate technical challenges in one area often had adverse consequences in others. One factor, drillstring rotation, repeatedly surfaced as part of the solution to all the major problems in this extended-reach well.

Guiding a wellbore accurately through the pay zone at such extreme distances would be virtually impossible without geosteering (previous page). Geosteering involves taking petrophysical measurements at or near the bit and relaying the information in real time to the drilling team. The team can then adjust the bit direction to aim the wellbore optimally through the formation. The result is that smaller targets at greater distances can be drilled successfully. Geosteering has been a success in terms of both the technical practicalities and the productivity benefits in extended-reach wells.

This record extended-reach well, M-11, at the BP Exploration Operating Co. Ltd. Wytch Farm development in southern England, has a horizontal displacement of 10,114 m [33,182 ft] at a true vertical depth (TVD) of only 1,605 m [5,266 ft]. Well M-11 is the second extended-reach record well at Wytch Farm (above). Both wells used Anadrill logging-while-drilling (LWD), measurements-while-drilling (MWD) and GeoSteering...
The M-05 well had set a displacement record of 8035 m [26,361 ft] in 1995 (right). The M-05 record was broken last year by Phillips China, Inc., which drilled the Xijiang 24-3 in the South China Sea to a horizontal displacement of 8063 m [26,446 ft]. Horizontal displacement, also called stepout or departure, is the farthest horizontal distance from a vertical line below the surface location to the tip of the well.

The total measured depth of Well M-11 is 10,658 m [34,967 ft], a remarkable achievement that puts this well second among the longest wellbore paths drilled in the world. In comparison, the world’s deepest well at 12,869 m [42,226 ft] measured depth is a vertical well, SG-3, drilled by the Ministry of Geology of the former Soviet Union for scientific exploration on the Kola Peninsula.

The stepout ratio (horizontal displacement divided by TVD at total depth) is 6.3 for Well M-11 (below). Generally, a well is defined as extended reach if it has a stepout ratio of 1 or more. A horizontal well is loosely defined as having a final segment at an 85° to 90° inclination from true vertical. An extended-reach well may also be a horizontal well, but this is not a requirement.

### Top 20 extended-reach wells worldwide.

<table>
<thead>
<tr>
<th>Rank</th>
<th>Horizontal displacement, ft</th>
<th>Measured depth, ft</th>
<th>TVD, ft</th>
<th>Operator</th>
<th>Well</th>
<th>Location</th>
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* Directional drilling, MWD, LWD or GeoSteering services provided by Anadrill

**Industry comparison of extended-reach wells.** What was once considered the envelope of extended-reach drilling now merely indicates the difference between standard and advanced technology. That envelope continuously enlarges as companies push technology to the limit.
Drilling the “10-km challenge,” as Well M-11 had been nicknamed throughout planning and operations, was driven by environmental and economic as well as technical objectives. Simply put, the well was drilled because it economically tapped additional reserves more than 10 km from the surface wellsite. These reserves lay in a section of the Sherwood reservoir which extends offshore beneath Poole Bay on the southern coast of England. Wytch Farm is western Europe’s largest onshore oil field, but roughly one-half of its 467 million bbl [74 million m³] of oil extends offshore. The Wytch Farm oil field comprises three major reservoirs, the shallower Frome Limestone at 800 m [2625 ft], the Bridport reservoir at 900 m [2900 ft] and the larger, more productive Sherwood reservoir at 1600 m [5200 ft]. The Bridport has been on production since 1979 and was the first stage of Wytch Farm development. The second stage consisted of the onshore Sherwood reserves, and third stage the offshore Sherwood (above left).

In 1990, BP began analyzing methods of producing offshore reserves from the Sherwood reservoir, including evaluation of setting a platform or constructing an artificial island (left). The field sits near a nature preserve and is in an area of outstanding natural beauty frequented by tourists. Thus, any development plan had to be aesthetically pleasing with minimal effect on the area. The development plan also had to adhere to stringent environmental regulations. The initial plan called for construction of an artificial island with conventional directional wells at a cost of £180 million [$330 million]. In contrast, development of the offshore reserves with extended-reach wells would cost less than half as much at an estimated £80 million [$150 million] and would better protect the environment. Furthermore, the use of extended-reach wells accelerated production by three years.

Wytch Farm Development

Daily production forecast. The third-stage development of Wytch Farm comprises extended-reach wells drilled from two onshore sites to produce reserves that sit offshore. More than 80% of the current field production comes from extended-reach wells. The extended-reach program increased reserves from 300 million bbl before the program to 467 million bbl now.

Well M-11 is the fourteenth extended-reach well drilled in the third stage of Wytch Farm development (below). A significant factor in the decision to use extended-reach drilling (ERD) was the success of other companies, particularly Unocal Corp., in the Point Pedernales field in southern California, USA. In the late 1980s, collapsing oil prices prompted Unocal to design and drill extended-reach wells from an existing platform rather than set a second platform. For Unocal, extended-reach wells achieved several objectives: they eliminated the high capital cost of a second platform, intersected more of the formation with near-horizontal wellbores and demonstrated conclusively that such difficult wells could be drilled and completed economically. These wells were relevant to Wytch Farm because of the shallow TVD of 1350 m [4420 ft]. Many other wells had been drilled with long stepouts, but none at such shallow depths. The base requirement for further field development was the capability to drill and complete wells at up to 6000-m [20,000-ft] departure from onshore well sites, which BP felt to be a reasonable extension of existing technology.

The use of extended-reach wells results in less surface disturbance because fewer wells are needed and surface sites have a smaller footprint. In developing Wytch Farm field, BP sought to maximize oil recovery as economically as possible with the least disturbance to the environment and the surrounding community. Drilling from small surface sites instead of an offshore location helped accomplish this goal. BP established a partnership with local communities and regulatory authorities to ensure that the natural beauty of the Poole area remained unspoiled. More than 300 formal meetings and countless informal discussions were held with local authorities, government departments, environmental and conservation organizations and the general public to ensure that the views of area residents be considered in the development of the field. The area around the oil field forms part of the Dorset Heritage Coastline and includes areas of special scientific interest, a wildlife special protection area, a wetland birds site and a national nature reserve. The surface site is designed to blend into the

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**Geological cross section. The world’s longest extended-reach well has a stepout of 10,114 m and a total measured depth of 10,658 m.**
environment, and equipment is painted in earth-tone colors to minimize visual impact. All lighting is judiciously placed and pointed downward. Strict noise regulations are imposed and ensure minimal disturbance. An extensive impermeable containment ditch surrounding the site can hold any fluids from potential accidents.

**Teamwork and Planning**

An extended-reach well requires extensive planning and involves the commitment and direct participation of the operator, rig contractor and all service providers. The evaluation, design and planning of Well M-11 lasted more than a year, from March 1996 until drilling began in May 1997.

Close cooperation and a smooth working relationship were essential for such a challenging, high-profile project as Wytch Farm. Contractors were paid on a day-rate basis with total well performance incentives to be shared among all participants, further encouraging teamwork and ensuring alignment of goals. Anadrig supplied directional well planning and drilling engineering support, directional drillers and equipment, surveying, MWD/LWD, mud logging and coring services. Baroid provided mud supplies, mud engineering, and drill-cuttings and waste fluids disposal. BJ Services provided cementing services. Deutag Drilling supplied the drilling rig, crews, drillstring tubulars, tubular running services and fishing tools. Lasalle designed, installed and commissioned completion and electrical submersible pump equipment. Schlumberger Wireline & Testing supplied openhole logging services, cased-hole logging services, drillstem test and tubing-conveyed perforating and well testing; and Dowell supplied coiled tubing services.

The focus during the early part of the third stage of development was to build multidisciplinary teams, with contractors working in close proximity to the operator’s staff. Contractor senior representatives have offices close to one another within the operator’s office complex in Poole. This setup fosters a close but informal “roundtable” arrangement. Communication barriers have disappeared, and everyone on the project has the same goals—to drill the wells efficiently, correctly and economically. Decisions are made and involve both the operator and contractors. For such a system to work effectively, a high degree of trust and openness is necessary among personnel of all rank. This working environment has provided the opportunity to obtain excellent benchmark data for drilling subsequent extended-reach wells, leading to the record-setting 10-km target.

At the onset of third-stage development, two of the least known factors were the increased time and cost for extended-reach compared to conventional wells. Typically, the first one or two wells of any project incur the greatest time and cost as the learning curve begins. Efficiency and performance improve rapidly on subsequent wells as team members work together more efficiently, and technology is applied more effectively. Generally, each well at Wytch Farm has been drilled farther than the previous wells, allowing for incremental learning through experience. Had such an incremental learning process not been used, many problems would undoubtedly have occurred on the M-11 well.

Every aspect of the M-11 well plan underwent a rigorous peer review to identify potential pitfalls and develop contingency plans. Experts from BP and its partners thoroughly analyzed key risks and processes in reservoir issues, well placement, drilling mechanics, hydraulics and safety. Having outsiders analyze the well plan provided a useful check against existing contingency plans.

**Profile Design**

The reservoir section targeted by Well M-11 lies between 8- and 10-km [26,000- to 33,000-ft] departure from the M site (previous page, bottom and below). For this length departure, the relatively shallow depth of the Sherwood reservoir posed some special drilling challenges not present at greater depths. There was limited scope in the trajectory design to allow the target to be

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reached optimally.7 The majority of wells at Wytch Farm have been drilled with 80° to 82° tangent angles and were controlled by choice of kickoff point and build rate in the upper section.

This well was planned to have a shallow kickoff point to allow inclination angle to be built to 82° in the 17¾-in. hole. The 13¾-in. casing was to have been run to about 1400 m [4600 ft] measured depth, and then the 12¾-in. hole was to be drilled as a 7500-m [24,600-ft] tangent section into the top of the Sherwood reservoir. The length of the 8½-in. hole section was kept to a minimum because reservoir drilling is three to four times more expensive than in the 12½-in. section due to reservoir drilling is three to four times more expensive than in the 12½-in. section due to extra bottomhole assembly equipment, mud losses and slower penetration rates. In addition, the mudstone above the reservoir would be exposed to a low-weight mud, leading to concerns about borehole stability.

A tangent angle of 82° was used to keep torque levels manageable, maximize the likelihood of being able to run casing to a 10-km departure and permit oriented drilling in the 8½-in. section (above and next page, top). The final double build and hold trajectory was similar to that on other wells, except that steering would be further limited in the 8½-in. section. This trajectory would allow the well to build angle to horizontal starting at the 9½-in. casing shoe. Previous wells used an instrumented positive displacement motor, LWD tools and an adjustable stabilizer to geosteer in the reservoir.

Because steering capability would be limited, Well M-11 was designed to be drilled as geometrically as possible through the reservoir, with some geosteering performed by rotary steering drilling tools.

The key to success would be performing every phase of the well plan flawlessly. Directional control, hole cleaning, torque and drag, and casing flotation each played a role. The rest of this article describes how they come together in the drilling of this record-setting 10-km well.

**Directional Control**

Steering by slide drilling is impossible at extreme horizontal distances. Experience on Wells M-05 and M-09 indicated that slide drilling would be practically impossible beyond 8 km. Drilling in the sliding mode results in several inefficiencies that are compounded by extreme distances. The motor must be oriented and maintained in a particular direction while drilling to follow the desired path. This orientation is achieved through a combination of rotating the drillstring several revolutions and working the pipe to turn it to the desired direction. At 8 km or more, the pipe may need 15 to 20 turns at surface just to turn the tool once downhole, because the drillstring can absorb the torque over such a long distance. For the directional driller, this technique is as much art as it is science. After the tool is positioned, drillstring torque is required to hold the motor in proper orientation against reverse torque created by the motor as the bit drills.8

This situation is beneficial in wells with low frictional drag because adjusting weight on bit changes reactive torque, changing toolface direction. Thus, small changes in orientation can be made by varying weight on bit, giving the directional driller better control. In high-drag situations like Well M-11, however, it is difficult to keep torque constant in the lower part of the drillstring, causing difficulty in maintaining toolface orientation. Another problem with slide drilling in high-angle wells is that cuttings removal suffers from the lack of drillstring rotation. In wells with high drag, the drillstring cannot be lowered smoothly and continuously, which prevents the motor from operating at optimal conditions. In combination, these factors result in a lower penetration rate compared to that during rotary drilling (next page, bottom). For extended-reach wells, not only does penetration rate suffer, but there is a point at which slide drilling is no longer possible.

The M-11 trajectory was designed to minimize the amount of sliding directional work in the 8½-in. reservoir section. In some of the earlier Wytch Farm wells, a new technique was pioneered to overcome these...
Sidetrack cross section. When the original borehole (M-11z) reached 9 km, the well was sidetracked to access a better part of the reservoir. The sidetracked lower bore (M-11y) was cased and completed, and the upper borehole left open. The tip of the well veers upward to stay away from the oil-water contact and to penetrate additional formation layers for added geological information.

Rotary and sliding penetration rates. In offset Well M-05, rotary drilling penetration rates were several times greater than slide-drilling penetration rates. Conventional slide drilling techniques were ineffective at extreme stepout distances because of difficulty controlling downhole torque and weight on bit.
problems with conventional sliding for directional control. The combination of the GeoSteering tool near-bit inclination measurement and a downhole variable-gauge stabilizer positioned above the motor enabled drilling the wells almost entirely in rotary mode.

Standard steerable-motor directional drilling equipment is generally based on the tilt-angle principle. A bend between 0.5° and 3° in the motor provides the bit offset necessary to initiate and maintain changes in course direction. Three geometric contact points (bit, near-bit stabilizer on the motor and a stabilizer above the motor) approximate an arc that the well path will follow, and thus the curve rate or dogleg severity for the system. This curvature is formed and built by holding the entire drillstring still so that the bend can work in a preferential direction or in sliding mode.

Conventional practice is to drill in rotary mode, rotating the drillstring from the surface to drill a straight path. If a change in direction is needed, the drillstring is stopped with the bent housing or tilt on the steerable system oriented in the desired direction. This orientation is called the toolface angle and is measured downhole by MWD systems. When drilling in this oriented mode, the entire drillstring has to slide. Drillstring drag problems become acute in extended-reach wells and cause problems in setting the toolface angle and applying weight to the bit. Rate of penetration suffers. Techniques are needed to provide greater directional flexibility with rotary drilling in extended-reach wells.
The primary components of the GeoSteering tool are a steerable motor with an instrumented section and a fast wireless telemetry system that passes data to the MWD system higher up in the BHA. The instrumented sub is built into the motor near the bent housing which is typically about 1.5 m [5 ft] above the bit. Packaged in the sub are directional and petrophysical sensors, electronics for control and telemetry and batteries for power. Three inclinometers provide inclination data at the bit in both a survey and continuous mode. A GeoSteering tool, a stabilizer with an adjustable gauge allows the directional driller to change the directional characteristics of the BHA in rotary mode. Unfortunately, rotary directional tendencies are not as predictable as those in sliding mode. The inclination-at-bit measurement from the GeoSteering tool is critical to judge the cause-effect relationship from gauge changes to well path curve rate. Minor directional changes can be made reliably with rotary drilling, using the steering mode for larger or more difficult changes (previous page).

The first three extended-reach wells at Wytch Farm, Wells F-18, F-19 and F-20, were designed based on a reservoir characterization developed from the onshore reservoir, 2D seismic surveying and more recent 3D seismic acquisition, outcrop studies and offshore appraisal wells. The basic design in each case was to traverse the reservoir section at a constant angle of 86°. A well encountering a 50-m [160-ft] oil column could then be drilled 20 m [65 ft] above the oil-water contact. These wells were successful and had departures of about 5 km [16,000 ft]. With the additional reservoir information from these wells, subsequent wells were designed with an even larger standoff from the oil-water contact. Wells from the M site accessed poorer-quality sands in the Sherwood reservoir and needed even longer reservoir sections for sufficient well productivity. BP decided to drill the next wells with 7- to 8-km [23,000- to 26,000-ft] ERD steeps and vertical depth control tolerance of 1 m [3 ft].

At such distances, orienting the pipe in sliding mode would be difficult and time-consuming. Penetration rates would suffer because of the frictional losses reducing the amount of weight reaching the bit. Minimizing the amount of sliding was critical. The nature of the Sherwood reservoir complicated the picture, since it has many distinct zones separated by near-horizontal shales. Previous directional drilling had shown the formation response to be erratic, with rotary mode performance of a BHA varying suddenly and unpredictably from holding angle, to building angle, to dropping angle.

During drilling of the early wells, the MWD survey measure point was typically 20 to 25 m [66 to 82 ft] behind the bit face. The typical BHA consisted of the bit, motor, stabilizer, CDR Compensated Dual Resistivity tool, MWD, and ADN Azimuthal Density Neutron tool (above). A simple geometrical calculation showed that if the build rate were to change by 4°/30 m [4°/100 ft], the true vertical depth of the well would be altered by 0.75 m [2.5 ft] before the problem could be detected. With this BHA design, the deviation from plan could be quite large, and only a rapid response with sliding mode drilling would allow the well to stay within the tight tolerances required. Even with


sliding, it would be difficult to keep the well within the 1-m vertical tolerance. The solution was to use the GeoSteering tool to provide near-bit inclination data and give immediate warning of any change in BHA response. Gamma ray and resistivity data could also be checked for any unexpected changes in geology. Another drilling equipment change for these long wells was the inclusion of a downhole-adjustable, variable-gauge stabilizer. If the GeoSteering tool identified deviations from the required well path early, then the trajectory could be altered in the rotary mode by adjusting the stabilizer. This BHA design drilled the reservoir sections successfully in Wells M-02, M-03 and M-05.

In Well M-02, with a stepout of 6760 m (22,180 ft) and a reservoir vertical tolerance of 2 m (7 ft), 15% of the reservoir section was drilled in sliding mode, and the stabilizer gauge setting was changed 16 times in drilling 891 m (2923 ft). The sliding penetration rate was low—only one-third the rate achieved during rotary drilling. BHA performance in Well M-03 was similar, but even better in the M-05 Well. In each case, without the flexibility provided by this set up, considerably more time would have been spent in sliding mode to adjust the well path, with a corresponding decrease in penetration rate.

The highly variable gauge stabilizer has six possible settings between 7/4 in. and 8½ in. The stabilizer blade position is controlled from the surface by applying mud-flow sequences that are interpreted by a microprocessor in the tool. This adjustable stabilizer allowed some degree of build and drop during rotary drilling and worked adequately in previous wells at Wytch Farm, but it did not provide azimuth control.

To drill out 8 km and then on to 10 km, rotary steerable directional systems were tried for even greater control of inclination and azimuth. It was clear that a new type of directional drilling tool would be needed to control direction and azimuth adequately while rotating in the Sherwood at great departures. Several designs were nearing commercialization, each with a different approach to achieving vertical and lateral steering while the drillstring is rotated.

A prototype from Camco Drilling Group Ltd. had been tried on Wells M-08, M-09 and M-10 at Wytch Farm to encourage and accelerate their development and test the feasibility of using these tools to drill the 10-km well. These tools further reduced the amount of time spent on slide drilling. This rotary steerable system synchronously modulates the stabilizer blade extension and contact pressure as a particular blade passes a certain orientation in the wellbore. By applying hydraulic pressure each time a rotating blade passes a specific vertical or lateral orientation, the near-bit stabilizer forces drilling away from that direction. Continuous rotation of the drillstring results in reduced torque and drag and improved hole cleaning.

These improvements led to more efficient weight transfer to the bit and higher penetration rates. Hole direction and dogleg were controlled from the surface during drilling operations by sending information to the downhole tool using a sequence of mud pulses. This coded sequence specified steering commands from the multiple command set preprogrammed into the tool on surface. The BHA at total depth included the bit, steerable rotary system, stabilizer, MWD and LWD. The steerable rotary drilling system was instrumental in cutting sliding time to less than 5% on the M-11 well and was critical to drilling the well beyond 10 km.

**Hydraulics and Hole Cleaning**

Selection of a drilling fluid must balance a number of critical factors. The fluid must provide a stable wellbore for drilling long openhole intervals at high angles, maximize lubricity to reduce torque and drag, develop proper rheology for effective cuttings transport, minimize the potential for problems such as differential sticking and lost circulation, minimize formation damage of productive intervals, and limit environmental...
To meet such rates, an existing rig may need to increase the number of mud pumps from two to three, increase the power rating of the pumps from 1600 hp to 2000 hp or more, and increase the pressure rating of the pumps and surface system from 5000 to 7500 psi. A downside to these changes is the increase in capital cost for additional pumps and a doubling of maintenance costs for the higher-pressure equipment. At higher surface pressures, parts replacement will occur more frequently, but having an extra pump results in less disruption to the drilling program during pump repairs.

To maintain sufficient flow rates on the Wytch Farm wells, Deutag’s T-47 rig used a 5000-psi surface system and three 1600-hp triplex pumps electronically controlled to increase efficiency. If the three pumps worked independently, there would be potential for synchronization of the cylinders in each pump. In such a case, the pumps could produce pressure surges up to 750 psi, much more than could be handled adequately by the pumps’ pulsation dampeners. In effect, this electronic control system worked like a camshaft, keeping the cylinders 40° out of phase with each other. The three pumps worked as one nine-cylinder pump.

In addition to reducing pressure surges, this system reduced surface vibrations, decreasing the wear and tear on the pumping system, and detected impending pump failure to reduce downtime. A further benefit was an improvement in the quality of the MWD signal. With a smooth, regular pump signal, the MWD pulses were much clearer and easier to read at the surface, improving data quality.

Increasing the pumping capacity of the rig required sufficient capacity in the solids-control equipment, particularly the shale shakers, to handle the increased flow rates. Removing the maximum amount of solids at the shale shakers reduces the need for further solids-control equipment. The T-47 rig had four state-of-the-art, linear-motion shale shakers. One of these shale shakers was outfitted with larger-mesh screens to salvage and reuse lost-circulation material. Two centrifuges, in line after the shakers, removed fine low-gravity solids.

Pipe rotation is another critical factor in hole cleaning. The objective of the hole-cleaning program is to improve drilling performance by avoiding stuck pipe, avoiding tight hole on connections and trips, maximizing the footage drilled between wiper trips, eliminating backreaming trips prior to reaching the casing point and maximizing daily drilling progress. The more an extended-reach well can be drilled in the rotary mode instead of sliding, the better the hole cleaning. Pipe rotation helps prevent cuttings from accumulating around stabilizers, drillpipe protectors and tool joints. Rotating pipe helps disturb any cuttings that may settle to the low side of the wellbore, keeping the cuttings suspended in and transported by the mud. Faster rotational speeds of the pipe improve hole cleaning, but there are some drawbacks to very high rotational speeds. Although good for hole cleaning, excessive rotational speed can increase the severity of downhole vibration and shocks, putting directional drilling and LWD equipment at electronic and mechanical risk. Furthermore, excessive rotary speeds may increase drillpipe and casing wear.
Torque levels have been closely monitored throughout the extended-reach development program. In extended-reach wells, torque levels are generally more dependent on wellbore length than on tangent angle. Higher-angle wells do, however, tend to reduce overall torque levels, as more of the drillstring will be in compression, and consequently, tension and contact forces around the top build section are reduced.

In Wytch Farm extended-reach drilling, three sizes of grade S135 drillpipe were used. In the Well M-11 12½-in. hole, the drillstring configuration consisted of 8000 m [26,000 ft] of 6⅝-in. drillpipe—a length dictated by the racking capacity within the derrick—on top and 5⅝-in. pipe below. The larger pipe at the top provided strength to resist torque loads. The main factors in drillstring design in this part of the hole included pump pressure limitations, torque capacity and hole cleaning. In the 8½-in. hole, the drillstring configuration consisted of 4500 m [14,700 ft] of 5-in. S135 drillpipe on bottom and then 5⅝-in. S135 pipe to surface.

The considerations in drillstring design for the 8½-in. hole included fishing capability, equivalent circulating density and torque capacity. The 5⅝-in. drillpipe had double-shoulder, high-torque tool joints, and the 5-in. drillpipe joints underwent stress balancing and used high-friction-factor pipe dope to increase the torque capacity to match that of the topdrive. Nonrotating drillpipe protectors were run in trials on earlier wells and helped reduce torque somewhat, but there was a trade-off because they caused an increase in annular pressure drop and therefore in equivalent circulating density. The drillpipe protectors also suppressed drillstring buckling.
In drilling extended-reach wells, drillpipe is rotated not by the rotary table but instead by the topdrive, which travels the length of the derrick and permits drilling with an entire stand of pipe. The topdrive also provides backreaming capacity and the capability to push casing down the well when high drag is encountered. Maximum output from the top-drive system is closely related to the maximum torque capacity of the drillpipe used. The Deutag T-47 rig has a continuous top-drive output of 45,000 ft-lbf and a maximum intermittent rating of 51,000 ft-lbf. Inevitably there will be some torsional variation, so the top-drive torque rating needs to be sufficiently high to accommodate these peak values.

The use of MWD tools that measure downhole torque, rotational speed and downhole weight on bit in real time helps identify conditions that lead to stick-slip, which can produce detrimental torque variations in the drillstring. During stick-slip, the bit will alternately stop rotating (stick) and then accelerate (slip) while the drillstring rotates at a constant speed. The long drillstring can wind and unwind when this occurs, leading to excessive torque on connections, drillstring failures, premature bit wear, BHA failures and inefficient drilling. Fluctuations in drillpipe torque from downhole stick-slip can be minimized by adjusting drilling parameters—weight on bit, pump rate or rotational speed—provided fluctuations in downhole torque are detected early.

Changing design parameters to control surface torque is not necessarily beneficial in minimizing drag. Overcoming axial drag in these high-angle wells is a significant challenge (previous page, top). The critical operations, in particular, are running the 9 5⁄8-in. casing inside the 12 1⁄4-in. hole and drilling the 8 1⁄2-in. hole in an oriented mode. Experience to date has shown that running the liner and completion tubing is less difficult yet still requires close monitoring of drag.

Extensive reviews of previous wells helped predict surface torque for the 12 1⁄4-in. section of Well M-11. Two independent methods were used to analyze these data. The first method, composite forecasting, is a plot of surface torque from all previous Wytch Farm extended-reach wells with upper and lower trend lines used to predict torque ranges for the section. The second technique uses a drillstring simulator program to examine torque values from the most recent wells and calculate upper and lower bounds for the section. This determination of friction factor has proven remarkably consistent for the 12 1⁄4-in. section (previous page, bottom). These analyses uncovered a strong correlation between wellbore length and torque in the 12 1⁄4-in. hole.

Similar analyses were performed on the 8 1⁄2-in. hole to predict likely torque values. Composite plots from previous wells showed a trend of increasing torque with measured depth (above left). Close assessment of each well generated some unexpected results: torque levels tended to flatten after a certain length of openhole section was drilled, resulting in low openhole friction factors.

These low-friction factors reflect good hole-cleaning practices and controlled addition of fibrous lost-circulation material. Crushed almond hulls helped control fluid loss in the reservoir section, and this lost-circulation material had a beneficial side effect in that it reduced drillstring torque in openhole sections during rotary drilling. These materials apparently form a low-friction layer between the drillstring and formation. Once this relationship was discovered, a recovery system was added to the rig shale shakers to collect and reuse the lost circulation material continuously as part of the torque-reduction program. The effect of hole cleaning on torque is significant in the 8 1⁄2-in.
Casing Flotation

One of the major hurdles to overcome in drilling and completing a 10-km well was running 9\(\frac{5}{8}\)-in. casing to a departure beyond 8000 m. Experience on other Wytch Farm wells showed that running the 9\(\frac{5}{8}\)-in. casing became increasingly difficult with greater departures. Casing design analyses using friction factors from offset wells indicated that drag would be too high to run the planned 8800 m of casing conventionally in Well M-11, even with full weight from the travelling block. Various options, such as a tapered casing string, altered fluid properties and casing flotation, were tried on intermediate-length wells to identify the best approach for Well M-11. Of the options tried, casing flotation proved to be the only method with sufficient potential to get the casing to total depth. In principle, casing flotation is a simple technique. Essentially, casing is not filled as each joint is run into the wellbore, so it becomes virtually weightless in the mud, and drag is minimal.

On Well M-03, the entire 9\(\frac{5}{8}\)-in. casing string was floated into the well to observe the actual running weight compared to predictions. This exercise was important because it indicated that the mud weight as measured at the surface needed to be slightly lower than calculated to reduce positive buoyancy and allow the casing to sink. The mud rheology had to be reduced as much as possible prior to running the casing because of the high surge pressure caused as the casing was pushed into the well.\textsuperscript{21}

\textsuperscript{21} Cocking et al, reference 13.
In a long extended-reach section, an entire air-filled casing string can become positively buoyant and resist being pushed farther into the well. In such cases, the technique is altered by partial casing flotation, during which the casing string is divided into two sections with the lower portion filled with air and the upper section filled with mud. The section filled with mud is in the near-vertical section of the well and provides weight to help push the lower, buoyant casing into the well. A shear-out plug separates the air-filled and mud-filled sections of casing. The plug holds the mud in the upper section but can be opened with applied pump pressure to circulate fluid through the entire casing string.

In a further prelude to Well M-11, the 9 5/8-in. casing was partially floated on Well M-08. The mud weight and rheology were decreased prior to running the casing. The first 2000 m [6600 ft] of casing were run with air. A shear-out plug was run in the casing at that point, and the remaining 1500 m [4900 ft] to surface was run and filled conventionally. In addition to flotation, the casing was also rotated at various times during the operation. Rotating the casing on Well M-08 was merely a test of the procedures before they had to be used on Well M-11. Once the casing begins to float in the well, the actual torque required for rotation is small. In fact, the actual running weight and torque closely matched predicted values, proving that these techniques could be used effectively on the extreme-departure well.

This flotation method was used again on Well M-09 to run 9 5/8-in. casing to 6580 m [21,589 ft]. This flotation method was eventually deployed on Well M-11 to run 9 5/8-in. casing to 8890 m [29,162 ft] measured depth (below). The casing was floated to 7080 m [23,228 ft] prior to installation of the flotation collar. The casing was run into the openhole for another 20 stands prior to filling the upper section of casing to achieve the additional running weight.

To handle positive casing buoyancy safely, a push-tool was installed below the topdrive on the rig. This tool engaged over the box connection of the casing and allowed the full weight of the topdrive and blocks to be applied to the string. A set of bidirectional, hydraulic, flush-mounted slips held the buoyed casing in the hole. The slips were anchored to the rotary table and provided the necessary hold-down force on the casing.

A Look at the Future
Well M-11 was completed with an electrical submersible pump and brought into production on January 12, 1998, at a rate of 20,000 BOPD [3200 m³/d]. Wytch Farm production currently averages more than 100,000 BOPD [16,000m³/d], 80% of which comes from extended-reach wells.

The design of Well M-11 took more than a year, and its completion provided an excellent test of the industry’s capabilities. The success of this well has opened up even more targets and the potential to access reserves that would have remained out of reach or required huge capital outlays just a few years ago. The current focus at Wytch Farm is to drill 5-km stepout infill wells faster and cheaper than previous wells. Another extreme well, with a stepout of some 11 km [36,000 ft], is in the initial planning stages. Also under consideration are several 6- to 8-km multilateral wells.

All aspects of extended-reach technology have to move forward. The next step will be in completions and interventions, where wellbore workovers and maintenance will be critical.

The future for GeoSteering technology and rotary steerable tools is bright. Currently, these steerable systems are used primarily on relatively expensive extended-reach wells where they can provide a technical capability beyond the limit of standard motor-driven systems. Here, these systems can be run economically even if their cost is high. Further work will focus on increasing the reliability, upward telemetry systems and operating time of these tools while cutting costs.

—KR

![Partially floated 9 5/8-in. casing. Casing flotation experiments on Wells M-03, M-08 and M-09 proved the concept for the extreme test in Well M-11. The bottom section of casing, containing air, remained neutrally buoyant to allow the casing to slide more easily along the well path. The mud-filled upper section provided the weight necessary to push the entire string to bottom. Once the casing was landed, pump pressure was applied to shear the plugs in the flotation collars and allow circulation.](image-url)
Exploring for Stratigraphic Traps

There was a time when exploration consisted simply of following surface signs such as seeps, creek beds and salt domes, and drilling where the party boss poked his stick; but those days are gone. Petroleum seismology has revolutionized the search for hydrocarbons and brought about a period of remarkable discoveries. Seismic exploration has expanded dramatically with the tandem advent of 3D seismic technology and powerful computer capabilities. Exploration has been a race at sea and on land for ever greater efficiency. The current limits of contemporary technology were apparently reached last year, however. In marine seismic acquisition, eight streamers formed 750-meter [2460-ft] wide swaths and 10,000-meter [32,800-ft] offsets, and in land seismic acquisition, very large-channel capacity, 24-bit recording systems and three-component sensors were employed. Computing power has also grown exponentially, with massively parallel computers such as the CM-5 (576 nodes and over 74 gigaflops of power) cutting processing time to a tenth of what it was just ten years ago. Sophisticated software systems are now integrating the processing flow so seamlessly that engineering, petrophysical, geological and geophysical data can be merged at the explorationist’s workstation to facilitate interpretation.

Despite these tremendous technological strides, easy discoveries have become a thing of the past. All of the world’s more obvious reservoirs have been found, and most have been tapped and put into production. Those in accessible areas that have been the easiest to identify, the hydrocarbons trapped in structural faults and anticlines that manifest themselves so readily in 2D and 3D seismic data, are almost all in production, as are the stratigraphically entrapped reservoirs that revealed themselves as bright spots in otherwise lackluster seismic data.

Today, fully 40% of the oil found in mature hydrocarbon provinces is being found in stratigraphic traps.1 In fact, most of the remaining oil and gas in these areas probably lie in such traps, making future exploration deliberate searches for these elusive geological units. Worldwide, except for those principally structural accumulations in Russia and the Persian Gulf, some 60% of known giant oil and gas fields (500 million bbl [79 million m³] oil and 3.5 Tcf [4.7 billion m³] of gas) are stratigraphic. These include Venezuela’s Bolivar Coastal with 30 billion bbl [4.9 billion m³], the 6 billion-bbl [1 billion-m³] East Texas field, and Mexico’s Poza Rica field, with 2 billion bbl [0.3 billion m³]. Furthermore, as exploration presses farther into the world’s deepwater provinces, the prospect is frequently a stratigraphic trap, too—the Shell Mars field, with 700 million bbl [111 million m³], for example, and Ram-Powell with 250 million bbl [38 million m³].
Regardless of the method of exploration, today's undiscovered stratigraphic traps are difficult to find and are frequently encountered purely by accident while drilling step-out wells to further delineate a field. That notwithstanding, with ever greater success, the technological advances in the geosciences that helped reveal so many of yesterday's hydrocarbons are now being put to the task of identifying these less discernible reserves. These lie in isolated depositional units beneath seismic data's hills and valleys, the pinchouts, unconformities, reefs and barrier bars collectively known as stratigraphic traps (above).

Structural Versus Stratigraphic Traps

Hydrocarbons migrate upward from their source through porous subterranean strata until their route is blocked by a layer of impermeable rock, and they accumulate beneath the sealing body, structure or trap. Geologists divide these traps into two types, structural and stratigraphic. Structural traps are formed by tectonic forces after the sedimentary rocks have been deposited. They generally fall into two categories: anticlines, where the rock has been folded or bent upward, and faults, where movement along a joint or fracture has driven an impermeable layer above a permeable layer.

Stratigraphic traps, on the other hand, are most often formed at the time the sediments are deposited. They fall into three categories: pinchouts, most common in stream environments where a channel through a flood plain has been filled with permeable sand that was then surrounded by less permeable clays or silts when the channel moved; unconformities, where a permeable reservoir rock has been truncated and covered by an impermeable layer following a nondepositional period or a time of erosion; and carbonate reefs, fossilized coral constructions and associated deposits that arose from ancient ocean shelves and were overlain by layers of both permeable and impermeable rock (see “Types of Stratigraphic Traps,” page 51).

Pinchout and unconformity traps are often found in sand-shale beds in basins that have experienced considerable tectonic activity, where there are unconformities and overlaps as well as marine, coastal and fluvial facies. Reefs, however, are frequently found either on stable shelves beside troughs containing fine clastic sediment or in evaporite basins. Since reef traps exhibit an anticlinal structural expression, their delineation with traditional seismic methods is ordinarily accomplished with relative success, unlike pinchouts and unconformities, whose physical subtleties have evaded explorationists until recently. For this reason, we are focusing mainly on nonreef stratigraphic traps. We examine why they have been so difficult to identify, and then describe the seismic acquisition and processing techniques that have been developed to bring these features to light.

Why Are They Difficult to Find?

Stratigraphic traps were first identified in Pennsylvania in 1880, but exploring for them remained a mystery until the mid-1930s, when seismology began to be applied in the petroleum industry. Explorationists find structural traps far easier to identify than stratigraphic traps in both 2D and 3D seismic data supported by 2. For background on early exploration for stratigraphic traps: Halbouty MT: “The Time is Now for All Explorationists to Purposefully Search for the Subtle Trap,” and other contributions to AAPG Memoir 32: The Deliberate Search for the Subtle Trap. Tulsa, Oklahoma, USA: American Association of Petroleum Geologists (1982): 1-10.
because structural traps are seen as highly
dipping reflections and discontinuities in oth-
erwise smooth reflections. Thus for years,
aquisition and processing techniques have
been tailored to accentuate these features,
allowing interpreters to concentrate their
efforts on faults, anticlines and reef forma-
tions rather than their more subtle stratigraphic
counterparts. Other methods, such as detect-
ing bright spots (reflections with anomalously
high amplitudes), are used with some success
on both structural and stratigraphic traps. Cer-
tainly, many bright spots do illuminate strati-
graphic traps, which make these traps so eas-
ily identified with today’s techniques that
experts say few await discovery (right). But,
until recently, the search for the more elusive
unconformities and pinchouts has been
thwarted by limitations in seismic data,
amely low resolution, noise and a multitude
of technological barriers—the need to expand
bandwidths, attenuate multiples (false reflec-
tions), reduce differences of scale between
seismic data and well logs, bring core and log
measurements into harmony, and improve
synthetic seismograms.

Stratigraphic traps are generally visually
subseismic, so thin or so conformable to
their surrounding geometry that their sub-
tleties are nearly invisible in traditional seis-
mic data. The detail that can indicate a
stratigraphic trap in seismic data may well
be just a small part of a single seismic trace,
perhaps only a small bump on an otherwise
smooth wiggle or a change of curvature or
slightly different wave shape that wasn’t pre-
sent earlier.

Detecting these subtleties requires data of
the highest possible quality. For these pur-
poses, high quality means large bandwidth
or a wide range of frequencies to resolve
small features, and low noise. Yet some
stratigraphic traps generate the very noise in
the seismic data that makes them hard to
see. For example, some stratigraphic traps
are associated with unconformity surfaces
or surfaces of major velocity contrast.
Reflections off these surfaces can reverber-
ate or reflect multiple times, giving rise to
the type of seismic noise called multiples.
The presence of these multiples in data can
conceal the trap and make it difficult to
define its exact depth. Frequently, however,
there is no strong reflection associated with
a stratigraphic trap. Instead, the trap is asso-
ciated with a gradual change in lithology
instead of an abrupt contrast. In these cases,
a more typical seismic signature would be
small changes in the character of a reflec-
tion from one trace to another (right).

A bright spot in the seismic record. A bright spot anomaly is a high-amplitude seismic
event. On the left panel, the bright spot shows up in the center as a black reflection of
positive amplitudes. On the right panel, the same bright spot shows up as a seismic
attribute, here in pink and red.

A channel-formed stratigraphic trap, the Flounder formation, in Gippsland basin, off-
shore Australia with diagnostic features indicated. Note the sigmoid pattern, the truncated
seismic events (arrow) indicative of an unconformity, and the amplitude changes from
one trace to another (between the chevrons).
Stratigraphic traps were first recognized in 1880 by Carll, but not so named until 1936 by Levorsen, who defined them simply as traps “in which a variation in the stratigraphy is the chief confining element in the reservoir which traps the oil.” He noted that, “the dominant trap-forming element is a wedging or pinching-out of the sand or porous reservoir rock, a lateral gradation from sand to shale or limestone; an uplift, truncation, and overlap, or similar variation in the stratigraphic sequence,” to differentiate them further from structural traps.1 Structural traps, conversely, are usually formed by tectonic forces after sedimentary rocks are deposited and include anticlines or folds and faults (right).

Stratigraphic traps include pinchouts, in which a lens of permeable sand is surrounded by less permeable silts and clays. These form in both land and submarine stream environments. Here sand is deposited in the stream channel and in coastal settings when beach sediments are covered by impermeable clays that are laid down if sea level rises. Unconformities represent a gap in the geological record due to erosion, nondeposition, or both (right). The reservoir seal may be created by alteration of the exposed portion of the reservoir rock itself, or by deposition of a later impermeable layer. Reefs, either mound or shelf-margin carbonate units, form by growth of coral and deposition of calcite precipitated from seawater.


The development of an unconformity. An unconformity is typically created through a process of deposition, uplift and tilting, erosion and redeposition.
Synthetics for a survey design in the Gulf of Mexico. A synthetic seismogram shows the correlation between log and seismic data and can indicate how well a stratigraphic target will be mapped. Here the most important tracks are tracks 3 and 4, representing the synthetic and the seismic data (repeated for clarity). The impedance log in track 2 is created from the velocity log in track 1 and the density log in track 8. Track 6 indicates the semblance, or accuracy, of the match between the synthetic and seismic data, with green representing high semblance. Track 5 is the recorded seismic line and includes the well trajectory (vertical red line)—which missed both red bright spots. SP and porosity logs are shown in tracks 7 and 8, respectively.

Fortunately, many reservoirs formed by stratigraphic traps also have a structural component that makes them easier to discover. They are found to have stratigraphic elements many years later, when cumulative production volumes surpass original estimates. In the North Sea, Gulf of Mexico, and Campos basin of Brazil, giant stratigraphic traps are only recently coming to light after decades of exploitation of smaller predominately structural traps, suggesting a bright future in exploration for stratigraphic traps in nominally mature provinces.

Because they are so hard to see, exploration for stratigraphic traps requires knowing where to look. It is fundamental to understand the structural setting and important, even if difficult, to recognize the depositional setting of a prospect to know where to anticipate the occurrence of stratigraphic traps. The application of seismic stratigraphy to existing seismic data and well logs aids in this understanding by providing needed information on the direction of sedimentary flow, whether the sea level was rising or falling, and other depositional conditions.

Designing for Discovery
Explorers don't select a drillsite based on intuition and the whim of the party boss any more. Nor are today's seismic shoots simple exercises in geometry; considerable geological and geophysical input goes into the planning of a modern survey.

To reduce the risk of an expensive dry hole, as much a priori knowledge of the location as possible is factored into the development of a stratigraphic model from which to design a new, comprehensive 3D seismic acquisition program. This preliminary model indicates not only the target depth for the survey, but when a stratigraphic trap is the target, provides an approximation of how large the trap is, so that the final survey can render the desired subsurface coverage. All known geological layers are included in the model, as are their velocities and densities. With ray tracing or, in the case of a targeted stratigraphic trap, applying the full-wave equation, a seismic survey can be simulated to optimize the measurements and fine-tune the survey design (left).

The technology for both onshore and offshore exploration for stratigraphic traps has been in existence for 20 years, beginning with sequence or seismic stratigraphy, then 3D acquisition and its higher resolution of the details in seismic data. Offshore, however, advances in technology have recently been changing the way acquisition is being performed in deep water and mature provinces. There, to alleviate the two most troublesome problems associated with exploring for stratigraphic traps, low-resolution data and related multiples, the survey is conducted in one of two ways. Towed multistreamer surface acquisition with long streamers (from 3 to 12 streamers, 5000 m [16,400 ft] to 10,000 m long) can yield wider bandwidths for higher resolution and obtain offsets long enough to attenuate multiples (next page, top). And, more recently, four-component (4C) ocean-bottom cable (OBC) acquisition has become feasible, which not only achieves greater resolution in the resultant seismic data, but provides more reliable information on the lithology and porosity of the target than can be obtained by towed streamers.

Shear Enlightenment
Although the resolution and signal quality achieved by towed acquisition have improved the ability to image stratigraphic traps, 3D seismic exploration is even further enhanced by employing the new technology of four-component seabed systems. Geco-Prakla took the concept of a seabed system with external hydrophones and geophones, originated by Statoil as SUMIC, and developed its new seabed system as an entirely self-contained cable with internal hydrophones and geophones, the Nessie 4C MultiWave Array system (next page, far right). The four components comprise three orthogonally mounted geophones and one hydrophone mounted within the ocean-bottom cables that are laid in direct contact with the seafloor.

This form of deployment allows measurement of rock properties that towed or vertical hydrophones cannot measure, since hydrophones record only compressional (P) waves. The vast majority of surveys, including those recorded on land, rely entirely upon P waves to obtain a seismic image, but appropriately deployed geophones, onshore...
or offshore, also record shear (S) waves, which react differently to the properties of the rock they penetrate (see “Full-Wave Spectrum: P and S Waves,” next page).

Because stratigraphic traps are not necessarily associated with structural events and are not domal in shape, they are often invisible in P-wave data, but are equally as often readily identified in combination P and S data. This is because shear waves have complementary information to that of the P waves, which allows more complete characterization of the elastic properties of the rock and fluid and allows identification of the subtle changes in lithology that come with stratigraphic traps.

Because shear waves do not travel through water, the cable must be in direct contact with the seabed to accomplish the 4C shoot, a deployment that requires precise positioning of the cables as they are laid from the back of the acquisition vessels. Once a seismic traverse has been shot, the cable is either dragged or taken in and redeployed in a new location; additional lines of seismic data are acquired until the entire area has been covered.

The information obtained in a four-component survey complements that from P waves in eight ways. First, because S waves are relatively unaffected by pore fluids, including gas, they can be used to obtain structural and stratigraphic information in areas where the presence of such fluids precludes coherent images from P waves only. Targets below gas chimneys and gas clouds are notoriously difficult to image with P waves, and S waves have been highly successful in this application.

Second, S waves yield independent information about rock properties, allowing more complete prediction of both fluid type and rock lithology. When only P waves are recorded in a seismic section, it is frequently difficult to discern whether a detected direct hydrocarbon indicator event is due to the presence of hydrocarbons or is simply due to lithologic changes. Shear-wave data lessen this difficulty considerably when acquired simultaneously with P-wave data. In areas where P-wave data produce amplitude anomalies and the S-wave data do not, the presence of hydrocarbons is likely. If the anomaly is observed in both S-wave and P-wave data, it is most likely either a diagenetic or lithological phenomenon. The ratio of P-wave to S-wave velocities, $V_p/V_s$, is often used to predict lithology, and the P-wave amplitude to the S-wave amplitude ratio may turn out to help predict fluid-saturation differences.

Third, in deepwater acquisitions, the triple-sensor nature of the geophone data provides a unique opportunity for demultiple processing. Shear waves contribute another velocity function to use in distinguishing between multiples. Since shear waves produce multiples themselves that are similar to those produced by P waves, this helps the interpreter sort the principal reflections from the multiples to image more accurately.

Fourth, by acquiring both P and S waves, explorationists expect to illuminate shadow zones beneath high-velocity salt structures. Because the raypaths bend at a boundary of two different velocities, and salt bodies often have irregular boundaries, shadow zones, areas with no reflections, are created. By using both P and S waves, some of the shadow zones of one are illuminated by the other. Therefore, better structural and stratigraphic images can be achieved beneath salt.

Fifth, variations in seismic velocities, both P-wave and S-wave, may help identify different lithologies. The use of interval travel-time ratios, $T_s/T_p$—related but easier to measure than interval $V_p/V_s$—over a relatively small time window in the seismic data, may indicate lateral or vertical changes in lithology and pore fluid type. Further, the use of these ratios, in conjunction with seismic facies interpreted from reflection patterns, provides a relatively powerful way to begin inferring lithologic information at a scale more detailed than most seismic velocity models.

Conventional seismic surveys use compressional or pressure (P) waves to penetrate the earth and sea and reflect back data on the strata and structures these energy waves encounter. When these waves become disturbances propagating through the body of a medium, they either remain compressional waves (P waves) or are converted into shear waves (S waves).

Compressional waves occur when a liquid, solid or gas is sharply compressed. The compression sets off small particle vibrations in the same direction that the compressional waves are traveling. Shear waves, on the other hand, are waves of shearing action and occur only in solids. In shear waves, the small rock particle motion is perpendicular to the direction of wave propagation. They may be generated by a seismic source in contact with a rock formation or by the non-normal incidence of P waves on rock. The generation of S waves from a reflected P wave is called mode conversion. It is slight for small incident angles and becomes more pronounced as the offset increases.¹

The velocity at which these waves travel is controlled by the mechanical properties of the rock, its density and elastic dynamic constants. In fluid-saturated rocks, these properties depend on the amount and type of fluid present, the composition of the rock grains and the degree of intergrain cementation, formation pressure and temperature. Soft, loosely consolidated rocks are generally less rigid and more compressible than hard, tightly consolidated rocks. As a result, P and S waves travel slower in soft rock than in hard. Extremely unconsolidated rocks support only weak shear-wave propagation.

P waves and S waves propagate through rock and reflect differently at interfaces (next page, top). A P wave reflecting as a P wave, called a P-P reflection, is symmetric about the point of reflection at the common midpoint (CMP) halfway between the source and receiver. A P-S reflection is asymmetric at the point of reflection, called the common conversion point (CCP), which is different from the CMP. The difference in reflection points must be taken into account through processing.

The combination of P- and S-wave data rather than P-wave alone can yield previously unavailable information about fluids in the pore spaces and improve the potential for identifying the prospect lithology. Because gas in a formation causes the compressional velocity to slow but has little effect on shear waves, the combination of compressional and shear measurements helps in identifying gas-related amplitude anomalies. In addition, S-wave data are also able, in some cases, to image structures that P waves cannot adequately portray, such as reservoirs with gas clouds in porous rocks above the reservoir (next page, bottom).²

Until recently, P and S waves could be acquired simultaneously only onshore, but with the advent of ocean-bottom cable (OBC), both can be obtained. Although the marine seismic source continues to generate only P waves, once those waves have reflected off deep strata, they may be converted and propagate upward as S waves. The new 4C seabed cable system is in contact with the ocean floor and can record both waveforms.

P and S waves. When P waves (red) reflect as P waves, they do so symmetrically about a common midpoint (CMP). When P waves convert upon reflection to an S wave (black), they do so asymmetrically, about a common conversion point (CCP).

Value of shear waves. Shear waves are useful for imaging beneath gas clouds, as they travel through this low-velocity zone relatively undisturbed. The lateral displacement of the CCP due to P-S reflection must be taken into account in processing.

Imaging through gas with shear waves. The lower panel shows an image created by migrating P-P CMP-stacked seismic data. The center of the image is weak and disrupted by a gas cloud obscuring the crest of the structure. The top panel shows migrated P-P CCP-stacked data. The reflectors are clearly imaged all the way across the panel.
Sixth, experience with a few situations in the North Sea has shown that some reservoirs have low P-wave reflectivity while having relatively high P-to-S mode-conversion capabilities. Therefore, these reservoirs, which cannot be seen at all on P-wave data, become visible using the mode-converted shear waves. An extension of this idea leads to the conclusion also that by acquiring both P and S waves, seismic information and log and core data can be correlated more convincingly, and perhaps explains why correlation has been difficult in some areas.

Seventh, a stationary acquisition system like the Nessie 4C MultiWave Array permits true 3D acquisition, meaning complete offset and azimuth distributions within the data. Towed 3D surveys, while providing coverage of a 3D volume, do so with a series of essentially 2D traverses, as the source is in line with the receiver cable. By acquiring P and S waves propagating in all azimuths, velocity anisotropy (the variation of a property with direction) of P and S waves may be determined. Velocity anisotropy can be especially pronounced in S waves, and depending on the type and amount, can be used to help

![Methodology Used by Geoscientists.](image)

![Depositional and termination patterns. Types of depositional and termination patterns sought in seismic data indicative of stratigraphic traps, including discontinuities.](image)
discriminate rock types, detect source rocks and identify principal fracture directions. For example, shales are often highly anisotropic, displaying transverse isotropy wherein the vertical velocity is different from the horizontal velocity. Sometimes this can be observed in 4C seismic data, and could indicate a shale, suggesting the existence of what is a common sealing formation for many stratigraphic traps. Velocity anisotropy is also an important consideration when processing surface seismic data for stratigraphic interpretation, as small errors in velocity can impact the resolution of the final seismic image.

An eighth benefit of acquisition with the Nessie 4C MultiWave Array is it allows for the calibration of AVO (amplitude variation with offset) analysis derived from streamer survey data. An AVO effect occurs when the reflection coefficient at an interface changes as a function of distance between source and receiver. When P-wave energy strikes a particular interface, some of it will be transmitted as P waves and some will be reflected as P waves, while some of the energy will reflect as S waves and be transmitted as S waves. Some lithology-fluid combinations generate dramatic AVO effects, and the observed AVO signatures, or anomalies, can be diagnostic of hydrocarbons. But these effects are not seen in conventionally processed seismic data, because the processing step of stacking averages amplitudes from traces at different offsets.

If an AVO effect is suspected, the seismic data can be processed to preserve and highlight rather than average amplitude variations. The data can also be visualized in 3D cubes in the same way stacked data are visualized. But in this case there would be multiple cubes: one for near-offset data, one for medium offsets and one for far offsets. A multitude of 3D cubes can be produced, limited only by how much offset information is captured in the analysis. Geco-Prakla scientists have created as many as 23 different offset ranges for a survey (previous page, top).

Once an AVO anomaly has been detected, it needs to be interpreted to identify the rocks and fluids that created it. This is done by generating models and comparing observed AVO effects to the modeled ones. Most models contain information from P waves alone, and the shear-wave velocities required for the model are extrapolated from distant well logs or inferred from empirical transforms relating P to S velocities. Shear-wave velocities extracted from Nessie 4C MultiWave Array data provide crucial input for construction of the models and allow for more reliable interpretation of lithology and fluids in the trap.

Processing
Geco-Prakla researchers have developed the SCT Seismic Classifier Toolbox software system for seismic stratigraphic mapping or inversion specifically for the identification of stratigraphic traps. The SCT methodology is based on work done by Peter Vail when he was at Exxon. An extension of the Vail technique, which was developed using 2D seismic data, the process begins by identifying depositional environments and their sequence boundaries in the 3D seismic data volumes and, within the sequence boundaries, identifying certain stratigraphic and geometric patterns that should be sought (previous page, bottom). Using advanced image processing algorithms that allow the geometry of interbed reflections between the sequence boundaries to be enhanced, primitives—computer templates—were developed to map these patterns automatically.

The goal is to determine the lithologic composition of the stratigraphic objects. The objects are defined by their boundaries, which may be subtle and difficult to delineate. Boundaries are sometimes identified implicitly by the way some of the seismic reflectors terminate against them. This is especially the case with submarine fan systems and their associated channels. For this reason, the Geco-Prakla SCT method includes reflection termination recognition systems (below).
The patterns produced by SCT processing of the 3D volume are then passed through classification, a type of generic inversion process wherein the desired stratigraphic pattern defines a set of attributes that are sought in the data. This produces either a catalog of patterns that the interpreter can use, or these patterns can go directly into the actual 3D volume following pattern enhancement.

At this point, the system is trained by the interpreter, who can simply point at a particular pattern and instruct the SCT system to recognize comparable patterns in the seismic dataset. The toolbox runs all of the seismic volume through the enhancement step and classifies based on the patterns that have been presented as the training data, either from the catalog or the identified patterns in the dataset. This produces a class volume, or voxel set, in the cube (above). Each voxel will have one value for each of the classes or stratigraphic patterns that were defined for the SCT process or it will have a value that indicates there is doubt in the pattern that has been identified.

At the end of the session, a set of voxel volumes is produced from the kinematic, or geometric, part of the seismic data, indicating the density of the bedding between the sequence boundaries and how the bedding terminates within the retaining system. At this point, the dynamic information is added, such as the reflection strengths of the various geometric patterns that were identified. These help discriminate between the types of lithology that may be lying between each of the stratigraphic objects.

Even if the 3D seismic data being processed through the set are solely acoustic or P-wave information from conventional towed streamers, there is some dynamic information that can be used to identify stratigraphic traps, including the same set of primitives. In addition, AVO methods can provide a fair understanding of lithologies. This is an implicit way of getting shear-wave information without the added cost of multicomponent acquisition.

Available well logs are now added to the process. To put the well and seismic data on the same scale, the log is used to construct a synthetic seismogram by convolving reflection coefficients from the sonic and density log with a band-limited seismic wavelet. This process achieves the same low resolution as that of the selected wavelet.

In a case study for Statoil in the Danish sector of the North Sea, for example, the Norwegian state oil company had a 2D line and two wells in which Geco-Prakla was able to identify two stratigraphic sequences with the SCT Seismic Classifier Toolbox system and map them in 3D. One of the wells showed hydrocarbons in the sands of a submarine channel system. The SCT approach, using fluid indicators from the ratio of P- to S-wave velocities, \( V_p/V_s \), measured in both the wells and inferred from the seismic data, made it possible to determine the reservoir’s fluid distribution.

To discriminate between hydrocarbon-bearing lithology and non-hydrocarbon-bearing lithology, it is essential to calibrate the lithological effect of the \( V_p/V_s \) ratio versus its fluid effect. If perturbations are present, they can be associated with fluid rather than lithology. The Danish example was a 2D traverse, not a 3D multicomponent OBC dataset, which would have allowed further identification of each layer of the stratigraphy with its full elastic field observations. Nevertheless, it was processed through a new set of software tools Geco-Prakla calls model-based processing, which assured consistency between the 3D geometric model of the dataset and its P-wave velocity models, and confirmed the identification of hydrocarbons in the stratigraphic trap in zones not tapped by the wells.
Visualization and Attribute Analysis

Looking for stratigraphic traps in seismic reflection data, the geophysicist searches for subtle variations within formations rather than the obvious structures. This requires analyzing the seismic attributes, or characteristics, of the seismic traces. Key attributes of the seismic data reveal whether the trap is structural or stratigraphic and provide additional characteristics that are helpful in determining the precise nature of the lithology.

In mapping sand channels, for example, the termination attribute is analyzed to determine the shape of the channel, where a reflector terminates against a particular channel. If there are channel complexes and high amplitudes are present, they will also be visible in the seismic data's texture and can be verified. The texture of the seismic traces, another attribute, the rough or smooth appearance of the data, serves as an excellent indicator of lithology. When the sediments are deposited under high-energy conditions, as are sands, the seismic data look chaotic; if quiet sedimentation, such as clays, then the data appear smooth (right).

Of the many different seismic attributes, the majority of which have arguable value in exploration, amplitude, the maximum departure of a wave from the average value, is the most important indicator of stratigraphic traps. This is because amplitudes can light up stratigraphic traps as bright spots, which in the amplitudes are dramatically greater or less than those of the adjacent layers. Even more important is when there is an updip drop in amplitude, because it can indicate a potential reservoir unit. In addition, when a stratigraphic interval thins with two beds coming together as happens in a pinchout, wavelets from these two beds merge causing reinforcement, or brightening of amplitude, and the location of that brightening is where the trap lies.

A great deal of information about the rock properties of the formation is available from amplitude. If true amplitudes are obtained, reflection coefficients derived from the data can be employed to compute acoustical impedance. This, in turn, can be related to density, velocity and porosity. Amplitude is also a major factor in estimating the net pay of the stratigraphic field, because amplitude changes with the amount of hydrocarbons present.

One useful attribute in identifying stratigraphic traps in 3D seismic data is amplitude versus azimuth, an aspect of anisotropy that combines both travel time and amplitude information and can indicate appropriate hydrocarbon reservoirs by whether the unit has closure and whether its amplitude is dim in the updip direction. Another use, in mapping fracture zones, from which primary production often comes, is that it indicates areas of weakened amplitude, which is caused by a poor coupling of S waves across fractures. Azimuthal coverage is typically 360° in a 4C survey, thus assuring the acquisition of this key attribute.

Accurate velocity measurement is also essential to correctly interpreting structures as stratigraphic traps, and particularly in gauging variations in the recorded velocities. Incorrect analysis can result from following the wrong reflecting wavelet. If the medium is 4C 3D seismic data, the measurement of shear information is much more reliable, permitting the use of the anisotropic effect and identification of both the P-wave layer velocity and the S-wave layer velocity, and adding to the discrimination power with respect to different lithologies, pore fluids and abnormal pressure regimes.

Although amplitude and velocity are integral to an accurate interpretation of 3D seismic data, different attributes are important in different aspects of the interpretation process. To determine which are more important, discrimination analysis is undertaken by compressing the seismic data into a set of attributes that might be relevant for the particular problem that has been identified, in this case the discovery of stratigraphic traps. From these attributes, a set of attribute transformations is selected.

In what is called attribute space in the model, points are defined for each position with several attribute values. These can be thought of as clusters. Separations between the clusters permit discrimination, because they show that there is no overlap between the two classes of attributes. If, for example, there are only two attributes, the attribute space is two-dimensional and appears as a crossplot, with each of the axes in that crossplot now an attribute parameter. If there are two separate clusters in that crossplot, then...

Stratigraphic features frequently are better imaged by Coherence Cube processing, a recently perfected methodology that may be applied either after or during the processing of 3D seismic data and utilized during the interpretation to further reveal the stratigraphic trap (below right). A nontraditional procedure, Coherence Cube processing, which was developed in the geophysical labs at Amoco and licensed exclusively to Houston-based Coherence Technology Company, processes 3D seismic data not for imaging reflections, but for imaging discontinuities by analyzing waveform similarity (below). Traces that are similar to each other are mapped with high-coherence coefficients, and when similarities end, discontinuities may be inferred. As a consequence, when visualized in a 3D volume or cube, coherence coefficients enhance the detection and understanding of stratigraphic features (as well as faults) that are often not visible in traditionally processed data.

Stratigraphic features are frequently difficult to see in seismic data due to the low level or chaotic nature of the seismic reflections they provide. Coherence Cube processing brings stratigraphic features into focus as it computes the variations in the waveform regardless of the amplitude of the reflectors (previous page, top). Lateral definition of these stratigraphic features frequently are better imaged by Coherence Cube processing, a recently perfected methodology that may be applied either after or during the processing of 3D seismic data and utilized during the interpretation to further reveal the stratigraphic trap (below right). A nontraditional procedure, Coherence Cube processing, which was developed in the geophysical labs at Amoco and licensed exclusively to Houston-based Coherence Technology Company, processes 3D seismic data not for imaging reflections, but for imaging discontinuities by analyzing waveform similarity (below). Traces that are similar to each other are mapped with high-coherence coefficients, and when similarities end, discontinuities may be inferred. As a consequence, when visualized in a 3D volume or cube, coherence coefficients enhance the detection and understanding of stratigraphic features (as well as faults) that are often not visible in traditionally processed data.

High- and low-coherence events. In a high-coherence event (top), waveforms are similar from trace to trace. In a low-coherence event (bottom), waveforms are dissimilar. (Images courtesy of Coherence Technology Co.)

Integration of conventional seismic line with Coherence Cube (Created by Coherence Technology Co. using GeoViz software from GeoQuest). Zones of low coherence (black) are interpreted as discontinuities.
features can be seen best in the horizontal or time domain. In areas of high dip or where stratigraphic features transit different stratigraphic horizons, flattening of key surfaces, horizon slices, may be beneficial in obtaining a greater understanding of the stratigraphy contained in the dataset. However, interpretive bias can enter the dataset when using horizon slices in tracing stratigraphic features, since a geoscientist is required to go through the difficult, time-consuming and subjective process of picking the horizon.

The Coherence Cube technique increases the probability of finding hydrocarbons by indicating stratigraphic (and structural) traps that were not visible with traditional procedures. Estimates of 3D dimensional seismic coherence are obtained by calculating localized waveforms within the regular grid of a 3D seismic dataset. A sharp discontinuity is produced by stratigraphic boundaries.

In areas such as the Gulf of Mexico, where high seismic amplitudes frequently indicate hydrocarbon accumulations, their stratigraphic milieu is more readily identified from coherence data because they provide a different perspective in combination with amplitude data.¹

Now, and in the years to come, the petroleum industry is relying on discovery of new resources in two areas: mature provinces and the deepwater offshore frontier. Both demand new technology to find the elusive hydrocarbons that lie beneath the earth and sea. Since stratigraphic traps may well hold the vast majority of the new millennium’s yet-to-be-discovered hydrocarbons, particularly when reefs are considered among them, “The time is now for all explorationists to purposefully search for the subtle trap,” in the words of Michel T. Halbouty. New acquisition technology now illuminates these stratigraphic traps as never before, and remarkable advances in processing and interpretation software and methodology reveal their attributes for analysis, visualization and verification. Difficult to find, yes, but as the giant stratigraphic traps around the world testify, well worth the search. —DG
