Exploration Technology in an Era of Change

Improvement in the tools of exploration is redirecting the search for oil and gas. Bypassed pay is discovered. Higher productivity is coaxed out of marginal reservoirs. Inaccessible reserves come within reach. A group of leading geoscientists compares notes on how the evolution of exploration tools affects how and where they look for hydrocarbons.

**Moderator**

**WOODY NESTVOLD**

The search for hydrocarbons and tools for the search are changing. In the 1970s and 1980s, the hunt practically covered the earth. Many large fields were found and some giants. Today is different. We still explore new basins, but both the risk and failure rate are high. We also explore by adding new reserves in or near known fields. I'd like to understand the interplay between exploration strategy and the tools of exploration—how the tools of exploration affect where you explore. To narrow down what exploration tools we need to discuss, how are your exploration efforts divided between virgin territory and mature fields?

**ELWYN GRIFFITHS**

Today the industry is in a transition phase. Five years ago, most companies were hunting for elephants—meaning a field of more than 100 million barrels. American companies especially were emphasizing this hunt through expansion outside the US. Now it's a mixed bag. We still look for elephants to enrich our portfolio and add growth for the long term. But we also look for satellite features in mature basins, and in what I call emerging, or semimature, basins—where hydrocarbons have been discovered and the hydrocarbon system is known but not fully evaluated and exploited.

**WILLIAM FISHER**

I think we can still find elephants, but perhaps not economic elephants that can sustain oil companies at their historic level of infrastructure. Contrary to a common perception, there are still significant exploration opportunities in the US. We consistently add 2.5 billion barrels to reserves each year, about 20% of which is new field discoveries. The emphasis, however, is shifting from rank wildcat to re-exploitation. Between 1974 and 1982, Texas reserves increased by 6.5 billion barrels of oil, but only 10% of that—about 600 million barrels—was from new fields. The overwhelming majority was from existing fields.
GRIFFITHS
We’ve got to be careful how we define economic. Advances in technology make what is uneconomic today economic tomorrow. Take deep water development. Five years ago we would have said a water depth of 4000 ft [1220 m] in the Gulf of Mexico is a no-no. Now, no problem. So when we talk about economic elephants, we are often talking about waiting for development technology to catch up to make those elephants economic. And the technology is catching up rapidly.

NAHUM SCHNEIDERMANN
These days, our industry faces many opportunities for reserve additions. We have access to opportunities like the Tengiz supergiant in Kazakhstan, which was discovered but not developed. Here, technology is needed to overcome production problems and reduce operational cost. Elsewhere in the Commonwealth of Independent States, in Venezuela and Algeria, we face opportunities to add production in mature fields—again, with the help of production technology and more efficient reservoir management, such as 3D seismic, geostatistics and horizontal drilling.

In Chevron, even the exploration department isn’t just looking for reserves, but rather for reserves that will add value. In other words, we’re not driven as much by the size of the prospect as by the ability of the production department to develop it. Regardless of whether the prospect will be an elephant in a frontier or a satellite of a mature basin, if the production department will not be able to develop it rapidly and at a low operating cost, we will not drill it.

RICHARD HUBBARD
Our approach is to always look for high volumes of low-cost hydrocarbon. This means a finding cost of about $1 per barrel and a combined finding and development cost not exceeding $5 per barrel. Our overall target is to increase reserves by 600 million barrels per year, which is slightly more than our annual production. We achieved this goal the last couple of years and to repeat it for the next few years, we are looking for both extensions of proven basins and what we call “new geography.” Our new geography can be the result of technical advances, such as drilling in thrust belts or deep water, or the opening of areas following political change, such as in the former Soviet Union and Vietnam. We think that the greatest potential for success will come mostly from new geography.
The fundamental thrust of our company is to get better technologically than other people. Anyone who can harness integrated technology in a sophisticated fashion will move ahead of 99% of the competition.

Our competitive advantage comes mostly from integration of technology that has emerged in the last 5 to 10 years. We don’t view technology itself as a driving force for corporate strategy. Most majors are more willing to share technology today—realizing that there will not be as many scientific breakthroughs as in the past—and certainly don’t rely on them to the same degree as in the past.

I agree. We think of multidisciplinary integration as a core competency—we are only as good as our ability to develop options based on our multidisciplinary evaluation of data. Accessing Technology, with a capital “T,” we do mainly by looking to the outside world.

Major companies use a lot of technology, but very few base their competitive position on utilization of technology alone. Most base their advantage on access to large reserves and economies of scale.

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We think about exploration Technology in broad terms. We line up our technology under three banners: (1) techniques that reduce finding and development costs, (2) those that shorten the time between discovery and production, and (3) those that
improve fluid recovery. For us, 3D seismic plays a role in all three categories and increasingly is routinely integrated with other data. I have an example of this multidisciplinary integration, in which our geoscientists worked with our reservoir engineering, drilling and production people on development of a field in offshore Gulf of Mexico.

In a lease 25 miles [40 km] off the Louisiana (USA) coast, we started drilling extended reach wells but penetrated the reservoir at a fairly high angle. We realized we needed to define the upper and lower boundaries of the reservoir and drill horizontally along it. We had a 2D survey that showed what we thought were faults. To map these “faults” and the limits of the reservoir, we acquired a 3D survey (previous page).

This is a 3D seismic plot of acoustic impedance, in which the higher impedance is red. The darker the red, the higher the sand porosity. Well data and seismic mapping tell us this reservoir, a 50-foot-thick sand, consists of a series of prograding clinoforms. The breaks in the red are breaks in the reservoir. From the interpretation, we believe we’re looking at penecontemporaneous slumping that, in places, has compartmentalized the reservoir. In other places, the clinoforms create baffles along the length of the reservoir. This limits production to the fluid that can be drained between clinoforms. To overcome this, and get higher productivity per well, we drilled into the deepwater pay sand horizontally, skewer-fashion, through several clinoforms. Critical to this interpretation was overlaying the resistivity on the seismic, to find the high-resistivity pay zones. There’s no rocket science in this, but it’s a good example of how a multidisciplinary approach made this interpretation possible.

GRIFFITHS

This hits on an excellent point—the availability and reduction in cost of 3D surveys give us seismic resolutions not possible with 2D. Today we have an onshore Gulf of Mexico project in which our production geologists and geoscientists are using 3D data to better image seismic attributes, looking for amplitudes and sedimentary packages that help them target deviated wellbores. Attribute analysis used to be the domain of explorationists, but has been made accessible to our production people through the increasing power of workstations.

SCHNEIDERMANN

At Chevron, we are leveraging our technology to gain more understanding of the reservoir by integrating information from various disciplines. With the computer power now at the fingertips of our earth scientists and engineers, it is important to enhance the flow of information between workstation applications. This allows easy combining of complementary information. The results from one computer analysis, such as 3D seismic interpretation, can therefore be passed on to the next, such as reservoir simulation.

We’ve used this interdisciplinary approach in the Bay Marchand field, offshore Louisiana. Our “net sand” map, although simple in concept and appearance, results from significant manipulation and integration of well and seismic data (above). Other parameters can be similarly integrated to estimate other reservoir characteristics, such as variations in porosity, fluid type and permeability barriers. These data become the input to subse-

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1. A clinoform is an underwater landform analogous to the continental slope of the oceans. Clino deposits are formed on the sloping part of the floor of a body of water, extending from wave base to deeper water.
quent analysis, such as net pay calculations or reservoir simulations (above).

The Bay Marchand 3D survey dramatically increased our understanding of the field’s structure and stratigraphy. This new knowledge, coupled with focused effort in development and secondary recovery, allowed us to reverse the decline, and increase recoverable reserves. Production has been maintained at a steady 40,000 barrels per day for the last eight years.

MODERATOR
Elwyn, seismic is proved in clastics, but what role does it have in carbonates?

GRIFFITHS
Carbonates are very important for us. For instance, we are using 3D seismic to trace cavern and cave deposits in the Ellenberger formation of West Texas (USA). We have very dense well control and think we can see caverns [karst topography] that cut through various units of the Ellenberger. What amazes me is that it’s not like imaging a typical reef—there appears to be more of a density contrast between the cave wall and cave fill than a velocity contrast. We’re continuing to refine our model for application elsewhere.

HUBBARD
We are also using mostly 2D seismic in carbonates in Abu Dhabi to look at the density and fluid contrasts in producing fields. This allows us to make inferences about reservoir dynamics and helps in optimization of drainage.

SCHNEIDERMANN
We have used 3D seismic to look at carbonates in some conventional ways and some not-so-conventional ways. In West Africa, 3D seismic plays a vital role in understanding the complex struc-
A model for understanding petroleum systems. In these schematics, a system and its prospects are characterized in both space and time. Spatial relationships for one system are shown here as a 3D cube, and for another in plan view. The cube shows migration paths, the plan view shows maturity of hydrocarbon-bearing bodies in relation to a sealed reservoir and geologic structure, with wells drilled at the crests of anticlines. For each of the four categories of temporal relationships, a degree of risk is qualitatively assigned so that the overall confidence of temporal characterization can be evaluated. Characterization of spatial and temporal relationships leads to reconstruction of basin evolution, here highlighting preservation of a reservoir sand.

- **Spatial relationships**
  - Gas
  - Oil
  - Reservoir
  - Source rock
  - Prospects
  - Migration direction

- **Temporal relationships**
  - Tectonic and thermal events
  - Deposition of source rock, reservoir and seal
  - Hydrocarbon generation and migration
  - Hydrocarbon entrapment and alteration
  - Past — Present

**Critical reconstructions**
- Past
- Present

- **A model for understanding petroleum systems.** In these schematics, a system and its prospects are characterized in both space and time. Spatial relationships for one system are shown here as a 3D cube, and for another in plan view. The cube shows migration paths, the plan view shows maturity of hydrocarbon-bearing bodies in relation to a sealed reservoir and geologic structure, with wells drilled at the crests of anticlines. For each of the four categories of temporal relationships, a degree of risk is qualitatively assigned so that the overall confidence of temporal characterization can be evaluated. Characterization of spatial and temporal relationships leads to reconstruction of basin evolution, here highlighting preservation of a reservoir sand.
Use of reservoir geochemistry to reevaluate complex structure and fluid distribution in the Bay Marchand field, offshore Louisiana. The composition of oils from several wells (1 through 6) was evaluated with gas chromatography to determine the lateral continuity of hydrocarbon in a sand at 7700 ft [2350 m]. In the polar plot of chromatographic data, each letter on the periphery represents the ratio of one oil component to another, such as pentane to iso-pentane. Oil groups identified did not support earlier mapping of the reservoir based on 2D seismic data. Results from the oil correlation study were combined with new 3D seismic data to produce a revised interpretation of reservoir structure. (From Kaufman RL, Ahmed AS and Elsinger RJ: “Gas Chromatography as a Development and Production Tool for Fingerprinting Oils from Individual Reservoirs, Applications in the Gulf of Mexico,” in Schumacher D and Perkins BF (eds) Gulf Coast Oils and Gases: Their Characteristics, Origins, Distribution, and Exploration and Production Significance. Proceedings of the Ninth Annual Research Conference, Society of Economic Paleontologists and Mineralogists. Austin, Texas, USA: Earth Enterprises (1990): 263-282.)
mature and frontier areas. Several years ago we bid on the most popular block in Norway, and even though it was in a mature basin, we had the humbling experience of drilling a dry hole. Someone said “the fault leaked.” That’s not good enough anymore. We’ve got to model the evolution of the geologic basin and prospect through time and space to better define migration and entrapment. In the case of this Norwegian prospect, overlying shales may have formed an insufficient seal, or the migratory route of hydrocarbons may have bypassed the prospect altogether. At Mobil, we now go through all the critical reconstructions of the petroleum system in detail because we realize it’s fundamental to our business. Now, because of the power of the subsurface to find lost production, and to see whether we are re-injecting in the right place, we run the models to predict the tops of the oil and gas windows, timing of migration, and maximum expulsion.

This leads into my favorite exploration topic, geochemistry. We’ve been doing a lot of work with geochemical biomarkers that allows us to do two things, what I call exploration geochemistry in the exploration setting, and reservoir geochemistry in the development setting.

In the exploration setting, when we don’t have access to source rock, we look at the geologic history of source rocks by examining the biomarkers of available liquids, either seeps or shows. We don’t have to spend money to access the source rock. The analysis of biomarkers tells us about the source rock—whether it’s carbonate or clastic, its age, maturity and environment of deposition.

In reservoir geochemistry, we use the composition of reservoir fluids to look for horizontal and vertical compartments in the subsurface to find lost production, and to see whether we are properly draining the reservoir (previous page). We also have data that provide us with a qualitative sense for commingling of reservoirs and whether different zones are producing at different times on these.

**Schneidermann**

In our basin modeling of frontier basins or extension away from producing areas, we create “pseudo-wells.” This involves detailed velocity modeling, conversion into a geologic model and development of an artificial well lithology. Using extensive calibration curves from neighboring wells and detailed analogs, we run the models to predict the tops of the oil and gas windows, timing of migration, and maximum expulsion.

Yes. In 3D, we map the specific time horizons to backstrip⁴ and model the evolution of the basin including the thickness of material deposited or eroded over time, and the timing of the formation of source and reservoir rocks and traps. For a case study including backstripping in the Stord basin, Norwegian North Sea, see: Bell DG, Snelshes H, Bjorøy M, Grogan P, Kilenyi T and Trayner P: “A New Technique for the Analysis of Commingled Oils and its Application to Production Allocation Calculations,” Proceedings of the 16th Annual Indonesian Petroleum Association Convention, Jakarta, Indonesia, October 20-22, 1987: 247-268.)

**Masters**

Are you using the 3D survey as a starting point for the structural picture?

**Griffiths**

Yes. In 3D, we map the specific time horizons to backstrip⁴ and model the evolution of the basin. We also map various kerogen types—such as marine or terrestrial—and run sensitivities on these.
rates (previous page). In one of our fields near New Orleans (Louisiana), a leak in a dual-string completion was traced through time (above). This led to an adjustment in booked reserves, which influenced subsequent drilling. In other fields with several shaly sands, previously unrecognized accumulations were discovered through analysis of reservoir rock extracts. In one case, this helped to identify about 50 ft [15 m] of new pay sand not seen on electrical logs.

HUBBARD
We use the same techniques, but for us the revolution in geochemistry came about another way. Some of our people reminded us that 100 years ago the search for oil involved locating seeps and drilling beneath them. Through the 1960s and 1970s, most of us forgot all that. We had one geologist who always booked a window seat on business trips to look for seeps. It was a long time before he was taken seriously, but now the conversion is complete—there’s no reason to think we can’t use seep detection, even offshore. Today we study satellite images, survey the sea surface from small planes and core the seabed. It’s not prospect specific, but as a first step, looking for seeps can send you to the right parts of the world.

SCHNEIDERMANN
I think the major change for us was the power of integrating geochemical with geological, reservoir geophysical and other kinds of data on the workstation and the linkage of many workstations and data bases. The interpreter or interpreting team has access to a variety of information and modeling software, including balancing geologic sections, basin modeling, palinspastic reconstructions\(^5\) and decompaction of sections. This approach requires more teamwork and further integration of staff specialists in the exploration and development process.
MASTERS
There’s a subtle difference between using technology to help you think and using technology as a substitute for thinking. This is why checks and balances have become important.

HUBBARD
The way we walk that knife edge is by constantly asking: Does this technology contribute to helping us make our $5-per-barrel finding and development cost? If not, we don’t use it. This is the only way we can be sure that our technology follows our business target rather than becoming a substitute for it and an end in its own right.

FISHER
Does more technology mean more or less manpower?

HUBBARD
I hope we will be able to work with smaller teams than in the past. Ultimately, when we can feed 3D seismic data into the reservoir simulator, petroleum engineers and reservoir engineers will be looking at the same terminal screen as geologists and geophysicists.

MODERATOR
So far, we’ve discussed the roles of 3D seismic, horizontal drilling, basin modeling, geochemical methods, and the importance of integration of various kinds of data on the workstation. Are other technologies influencing which basins we look at?

HUBBARD
Yes. Fold belts are a basin type made accessible by recent advances in drilling technology. We spent a long time avoiding fold belts because they are difficult to image seismically and to drill. BP’s work in the Cusiana field in Colombia is a case in point.\(^6\) We knew about the prospect since the 1970s, but we and the rest of the industry were unable to reach the target depths of 15,000 to 16,000 ft [4600 to 4900 m] (right). The main problems were borehole instability and stuck pipe, caused by the tremendous horizontal stresses. Drilling our first successful well in 1989 took 450 days and $30 million. Now we hope to show that we can drill those wells at half that cost. The key to our success in the Cusiana field was characterization of in-situ stresses and use of that knowledge to design a mud program that would maintain wellbore stability. We also used a topdrive to get the extra power to reach the deep target. In the end, our new knowledge—of drilling technology, stress field evaluation and mud management—made the fold belt accessible. This technological advance opens up exploration possibilities in several other fold belts around the world.

GRIFFITHS
In addition to fold belts, another new frontier now opening is the subsalt environment, especially in the US Gulf Coast, Northern Europe and the Gulf of Suez. In shallow waters of the Gulf of Mexico, salt forms pillows, overhangs and steep dips. But in deep water the salt becomes sheet-like and develops a rugose undersurface that prevents clear seismic imaging. It’s logical to look at these salts, sometimes 20 miles [32 km] wide, and want to know what’s underneath. These deepwater Tertiary and Mesozoic terrains are the frontier of interest.

In Northern Europe—Germany, the Netherlands and parts of the southern North Sea—the salt is often deep. In Germany, the salt is around 15,000 ft [4600 m] and forms pillows and walls.

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5. A palinspastic reconstruction is a cross section in which features represented have been restored as nearly as possible to their original positions, before deformation by folding or thrusting.

6. For an introduction to the Cusiana field:
within the stratigraphy. The problem is getting the correct depth conversion on seismic imaging beneath some of the complex structure.7

MASTERS
There is another technical challenge that I alluded to earlier: finding all those now-invisible stratigraphic traps. Sequence stratigraphy is a key to some problems.8 For gas wells, an understanding of overpressure is essential:9 We classify rocks, based on porosity and permeability, into Types I, II and III. We find that overpressuring can move rock quality up a whole level. This allows us to produce from a rock that we normally would overlook. In the Washakie basin of Wyoming (USA), we’ve seen overpressure give excellent production from low-quality rock. As a result, we’re putting a new emphasis on layer-by-layer mapping of hydrodynamics to find the most promising intervals. Our input comes mostly from drillstem testing, sonic logs and some proprietary methods for deriving pressure from resistivity logs. In a basin like the Gulf of Mexico, pressure seals can be mapped with seismic. The pressure boundary moves up and down with the faults.

GRIFFITHS
John, I’d like to return to your comment on sequence stratigraphy. The intriguing part of sequence stratigraphy is that it can help explain play concepts and reservoir distributions locally, but also gives insight into the global picture. Mobil has formed a Global Themes Group, dedicated to linking sequence stratigraphy with paleo reconstructions and paleoclimates. This expands our understanding not just of this basin, but of the whole world. It allows us to set exploration priorities.

FISHER
Richard, does sequence stratigraphy withstand your $5-per-barrel criterion?

HUBBARD
Certainly. It’s the method we use. However, it always sends us back to extensions of proven oil provinces.

MODERATOR
Of the technical developments that have enhanced exploration, which three are contributing most to making formerly uneconomic areas attractive?

HUBBARD
I would list first our improved ability to drill extended reach and horizontal wells, and second, what I would call innovative development schemes, such as deepwater drilling, subsea completions and multiphase flow to reduce development costs. Third is improvement in subsurface imaging.

GRIFFITHS
I agree with those three, but I’d like to expand the list to add cost-effective integration of data bases, and cost-effective drilling, which would include slimhole drilling.

MASTERS
The foremost issue for me is not so much a technology, but an understanding made possible by technology—our recognition of low-resistivity pay in Tertiary and Mesozoic beds. We’ve got 150 wells with resistivity of 0.5 ohm-m, no spontaneous potential in low-resistivity pay. This doesn’t mean we go back to old electrical logs for reinterpretation. Often we can’t find anything in them. I think it means we’ve got to reexamine all our logs and production experience to find clustering of productive low-resistivity pay. This way, we can identify facies of the pay zone and drill structures that occur in that facies.

SCHNEIDERMANN
We bypassed several reservoirs in Nigeria and the US Gulf Coast because they were not recognized on the logs. We discovered them by doing reservoir geochemistry on cores. The methods don’t work so well on cuttings, so we are trying to collect more sidewall cores in problematic areas. The geochemistry itself is cheap—about $150 per sample.

FISHER
I would invert Richard’s list, and put geophysical methods at the top. We’ve seen leaps in the quality of resolution, but overall it’s gotten faster, cheaper and better. Second would be horizontal drilling and integration of drilling with geophysical and petrophysical information for geosteering. Third, I would list logging through casing. When we reexamine 30-year-old fields with modern logs, we can find a lot of bypassed gas. Right now, half the gas completions in the US Gulf Coast are recompletions, and in the last ten years the amount of gas added per recompletion has doubled. This success owes much to better cased-hole logging technology.

SCHNEIDERMANN
Although not a technical development, an important evaluation tool is an integrated approach to risk management, considering geologic, engineering and economic factors. Applying risk management before drilling identifies the key risk elements in the prospect. Knowing this, we decide what technology we need to mitigate or clarify geologic risk and uncertainty in volume distribution. Our focus on “value creation” also shortens our decision to test or abandon a play. After drilling is completed, the post-mortem identifies technologies we need to improve the process and further reduce risk. This kind of risk management ultimately lowers production cost by pointing us toward the best development strategy for the expected volumetric distribution.

Overall, we see an increase in communication between various contributors to the life cycle of the field, from discovery to abandonment. There is better alignment between users and providers of technology—whether in-house, contractors or academics—and more multidisciplinary teamwork. We are becoming more efficient, achieving lower operating costs and higher productivity from our fields.

GRIFFITHS
In risk assessment, the main lesson we are learning is to be able to walk away from a prospect. Today, we put great effort into evaluating the risk of our plays, but we don’t always apply what we learn. Even high-risk prospects we tend to drill. I expect that will change. Part of this risk reduction is the increase in strategic alliances, between oil companies and between oil and service companies. For the rest of the decade we’ll see an emphasis on these alliances, stressing practical application of technologies built up in the last five years. I’ve seen this coming for several years and, in a way, I envy the young geoscientists in the trenches today. We’ve got an exciting period ahead of us.—JMK

7. For an overview of structural imaging:
8. For a general introduction to sequence stratigraphy:
9. Overpressure is pore pressure that is higher than normally expected.
The overwhelming impression left by this discussion is that economics drives technology. Technology must reduce risks associated with exploration—but perhaps more importantly, technology has changed production costs so much that reexploration of known areas is now as much a part of exploration as the rank wildcat.

In mature areas, new techniques promise to find oil at low risk and minimal cost. Of increasing importance will be probing the limits of known fields through better evaluation of pressure and fluid distributions. Here, advanced formation testing will play a key role, and the MDT Modular Formation Dynamics Tester has introduced a new flexibility and capabilities in wireline testing.

New cased hole logging methods can shed light on bypassed oil. The through-tubing RST Reservoir Saturation Tool can detect untapped hydrocarbons behind casing with minimal problems of logistics (see “Saturation Monitoring With the RST Reservoir Saturation Tool,” page 29). RST technology integrates the advantages of conventional techniques and overcomes their limitations, such as tool diameter and sensitivity to salinity. Other new technologies can make formerly uneconomic discoveries viable. Tubing-conveyed perforating has already proved its value in this respect. Cheaper still, the Pivot Gun delivers big gun performance through tubing, and can make a marginal well or field profitable, without the cost of mobilizing a rig and crew.

Low-resistivity pay remains elusive, but our vision is now clearer. Thin layers of shale, silt and sand can be evaluated with high-resolution devices, such as the FMI Fullbore Formation MicroImager tool. Clays can be typed by geochemical logging. Permeability derived from low-frequency Stoneley and shear acoustic logs can help distinguish low-resistivity, nonproductive micropores from oil-producing macropores. By integrating these techniques, the exploration team can extend knowledge gained in key wells and propose exploration targets in other areas where similar deposition and facies patterns are likely.

In drilling, advances in several disciplines have made fold belts accessible. The contributors mentioned technologies that have helped overcome difficulties in drilling and mud management in areas such as Colombia. Technologies to add to this list are stress field quantification by minifracs, either with drillstem tests or wireline measurements; rock strength studies from cores and acoustic wave trains; and borehole deformation analysis from ultrasonic caliper measurements.

Explorationists have different styles but in their strategies and selection of targets, all have been influenced by technological advances. Today’s emphasis on low-risk, low-cost exploration does not necessarily mean a slowdown in the push for high technology. It means a more focused application of key technologies that will increase value not only of major fields, but of cost-sensitive areas as well.

Yves Boutemy
Yves Boutemy works on interpretation development for Schlumberger in Montrouge, France. He was previously marketing manager for wireline operations in the Middle East, based in Dubai. Yves also worked on evaluation of nuclear logging tools at Schlumberger-Doll Research, Ridgefield, Connecticut, USA and on interpretation development. In his 26 years with Schlumberger, he has worked throughout the Middle East, Africa, North America and Europe. Yves has a degree in physics from the University of Rennes, and an engineering degree from Ecole Supérieure d’Electricité de Paris, France.