Reducing Exploration Risk

With energy demand rising and production from mature fields on the decline, oil and gas companies are expanding their exploration activities into increasingly challenging areas—deep water, beneath salt and basalt, and in carbonate reservoirs. These environments often yield murky seismic images, but innovative marine-seismic technology can now provide high-quality results to reduce risk in these settings.
Exploring for oil and gas is a risky business. By increasing the likelihood of drilling success, 3D seismic surveys have probably done more than any other modern technology to mitigate this reality. In the 1970s and 1980s, before the use of 3D surveys, the exploration drilling success rate in the USA was approximately 25%. Once E&P companies started using 3D surveys widely, the success rate for exploration wells increased to almost 50% by 2005, and for development wells the rate reached 88%. While advances in other technologies such as drilling, LWD, visualization and real-time data delivery have also contributed to these success rates, explorationists credit 3D seismic methods with having the greatest impact.

While three-dimensional seismic applications have led to an improvement in overall exploration drilling success, in some situations, the success rate is still low. For example, in 2006, of 119 Gulf of Mexico exploration wells drilled in deep water—water deeper than 1,000 ft [300 m]—only 11 hit pay. This 10% success rate is typical of deepwater exploratory drilling in the Gulf of Mexico in the last decade. With deepwater wells costing up to US$ 100 million, it is not surprising that oil and gas companies are looking for ways to reduce the frequency of dry holes.

Many companies consider the current level of risk unacceptable. From 1996 to 2000, oil and gas companies bought 3,000 leases in the Gulf of Mexico. Of these, only 8% have been drilled. Because high rig demand will keep drilling costs from declining in the near future, operators await additional advancements in technology to increase their likelihood of success.

The 3D seismic surveys that did so much to improve drilling success rates on land and in shallow water are not always adequate for exploration in deep water and other problematic areas, such as beneath hard sea floors, salt, basalt and carbonate layers. Complex geology and highly refractive layers cause ray bending that leaves portions of the subsurface untouched by seismic waves. Also, noise from near-surface reflectors can mask the weak signals returning from deep formations.

Deepwater subsalt prospects have been particularly difficult to image properly. While several fields have been discovered in the Gulf of Mexico in the past decade using 3D seismic technology—Atlantis, Mad Dog, Neptune, Puma, Shenzi and Tahiti are a few that together hold many billions of barrels of oil—only a small part of the total resource is under development (above). In some cases, the quality of seismic data may have served exploration purposes, but it may not be good enough to create accurate models for reservoir development.

Recent improvements in seismic data acquisition and analysis may be the answer to achieving seismic images that are good enough to reduce the risk of drilling wells in these difficult areas. This article explains how new practices in survey acquisition and data analysis are improving the information gained from 3D marine seismic surveys. We describe innovations in seismic illumination made possible by probing seismic targets from several angles, and discuss new vertically aligned configurations of sources and receivers that are increasing signal quality in hard-to-image areas. Advances in imaging have also helped reposition development wells in an offshore carbonate reservoir and in a deepwater heavy-oil field. Examples from the Gulf of Mexico, West of Shetlands, and offshore Mexico show how improvements in seismic technology are reducing drilling risk.

**Typical Marine Seismic Surveys**

A typical 3D marine seismic survey is acquired by a ship towing airgun seismic sources and streamers, or cables instrumented with receivers. The ship “sails” in a predetermined direction above a subsurface target, the airguns emit seismic energy, and the receivers record signals that propagate from the sources down to

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subsurface reflectors and back. The process is repeated at defined spatial increments until the requisite number of seismic traces has been recorded (below).

The current standards in seismic acquisition have evolved from towing a single streamer in the 1970s and waiting 10 minutes between dynamite shotpoints to the highly efficient operations of modern surveys. Now, vessels tow eight to ten streamers at a time, separated by 50 to 150 m [160 to 490 ft]. Each streamer may be from 6 to 8 km [4 to 5 miles] long. The source consists of an array of 12 to 18 airguns, and may be fired every 10 to 20 seconds. These general values apply for many 3D surveys, but the exact acquisition parameters will vary depending on the survey plan, which balances geophysical objectives and economic constraints.

The survey plan also specifies the depth at which the sources and streamers should be towed to minimize noise and maximize signal. Towing streamers at a shallow depth—less than 8 m [26 ft]—better preserves the high-frequency content of the signal, but affects the low-frequency content and also increases the noise from waves and weather. Deeper towing better retains the low-frequency content, and so increases depth of penetration, but at the expense of high-frequency content. A typical towing depth for streamers is less than 10 m [33 ft].

Similar trade-offs must be considered when determining the tow depth of the source. Airgun source arrays typically are towed at a depth of 5 to 10 m [16 to 33 ft], depending on the required frequency bandwidth.

Another aspect of typical marine seismic acquisition is the collection of signals from a group of receivers into a single recorded trace. Standard streamers carry hundreds of hydrophone receivers spaced 0.5 to 1 m [1.6 to 3.3 ft] apart, with groups of 12 to 24 hydrophones feeding to a single recording channel. In principle, summing the traces in a group before recording enhances signal-to-noise ratio. But this process can irreparably damage signal fidelity and reduce the effectiveness of noise-reduction processing.

![Diagram of marine seismic acquisition](image_url)
The two main advantages of this arrangement of sources and receivers are efficiency in acquiring data over most subsurface targets—the marine seismic industry has built itself around this method—and the ability to obtain adequate images through standard processing. The disadvantages become clear when surveying in problematic areas or under suboptimal circumstances. Images may be faint or impossible to interpret. Noise generated in the streamers from weather and sea conditions can contaminate the seismic record at all levels. To make matters worse, platforms and other structures can obstruct the path of survey vessels, creating gaps in coverage that must be filled by additional shots and survey time. And close alignment between source and receiver arrays limits azimuthal coverage, meaning the reservoir is illuminated from only one direction.1

The Q-Marine single-sensor marine seismic system, introduced in 2000, has overcome several of these limitations.2 Instead of recording signals from grouped receivers, the Q-Marine system records signals from individual receivers. This improves spatial sampling of both the noise and the desired wavefield, leading to several advantages over conventional acquisition. Q-Marine surveys have, on average, broadened bandwidth by 40% compared with grouped-receiver technology, thus increasing the resolution of seismic images. Streamer noise can be adequately sampled, allowing signal-processing techniques to suppress it without harming signal bandwidth. This allows high-quality seismic data to be acquired even in poor weather, thereby reducing weather-related downtime.

Additional enhancements, such as repeatable, calibrated sources, and the ability to position streamers and steer them with high accuracy and repeatability, have led to seismic images with greater resolution. However, in some areas, further improvements are required.

New Directions in Seismic Surveys
Most marine seismic surveys—including Q-Marine surveys—acquire data along a narrow azimuth, and so illuminate the target from essentially one direction. If all subsurface layers were flat and smooth, narrow-azimuth surveys would deliver adequate images. However, in areas of E&P interest, subsurface targets and their overburden are rarely flat and smooth. The disadvantage of narrow-azimuth illumination in these cases can be shown by analogy. Shining a beam of light on an irregular landscape produces shadows behind mountains and within canyons. But, if the light shines from a different direction, areas that were in shadow become illuminated.

Although they are called narrow-azimuth surveys, most marine surveys acquire seismic data at a range of azimuths depending on the offset, or source-receiver distance. For a few short offsets, the azimuth can be quite large, but for most offsets, azimuths fall within a narrow range—about 10° on either side of the sail line. Because the short-offset, large-azimuth traces are not acquired in great number, they do not contribute much to the image computed using standard processing. Thus, a target covered by such a survey is essentially illuminated by rays from a narrow range of azimuths, causing poor signal-to-noise ratio and suboptimal seismic resolution. Most narrow-azimuth survey designs attempt to compensate for the lack of azimuthal range by redundant sampling of the same subsurface point, or bin.3 Increasing the fold, or the number of traces per bin, is one way to increase signal-to-noise ratio.

A particular type of noise that plagues all seismic surveys is called a “multiple.”4 Multiples are reverberations between interfaces with high acoustic-impedance contrasts, such as between the sea surface and sea bottom, or between the Earth’s surface and the bottom of a layer of unconsolidated rock (above). They appear as later arrivals on a seismic section, and thus are easy to confuse with deep reflections. Because multiples have velocities that can be slower than, the same as, or faster than the desired signal, and can have frequency content higher than that of the desired signal, they are difficult to suppress through filtering and stacking.5 Significant efforts in surface-related multiple elimination (SRME) have led to processing techniques that improve data quality, but modeling has shown that even greater improvement in multiple attenuation can be realized by increasing azimuthal coverage.6

7. Azimuth is the bearing from the source to the receiver.
9. A bin is the area on the target surface, typically 25 m by 25 m (82 ft by 82 ft), to which seismic traces are assigned according to their common midpoint (CMP).
10. Stacking is the summation of signals, and is performed to enhance signal-to-noise ratio.
The azimuthal coverage of a survey can be increased in several ways. One way is to repeat a standard survey at one or more azimuths, creating a multiazimuth survey (above). Multiazimuth surveys acquired in this way increase fold as well as azimuthal coverage. One such survey has been acquired over the Nile Delta in the Mediterranean Sea.12

Wide-Azimuth Surveys
Another way to increase azimuthal coverage in a wider swath above the target is to displace the seismic source from the sail line of the streamer vessel, in a wide-azimuth survey (WAZ). Wide-azimuth surveys require at least two source vessels in addition to the streamer vessel, and some may be acquired with multiple streamer vessels to improve acquisition efficiency.

The improvement that WAZ acquisition brings to subsalt illumination can be seen in a modeling example, in which a flat, horizontal target beneath a complex salt structure is probed by both narrow- and wide-azimuth surveys (next page). In the narrow-azimuth case, the number of hits, or times that seismic energy reaches a point on the target, is everywhere lower than in the wide-azimuth case. In both cases, some portions of the target are not hit at all, but there are fewer of these misses in the wide-azimuth case. In addition to this basic ray-tracing method, finite-difference and wave-equation modeling are also used in illumination studies.

In 2001, in the Norwegian North Sea, BP and Petroleum Geo-Services (PGS) tested the wide-azimuth concept including high fold and using multiple vessels; earlier surveys had acquired data in multiple directions.13 The results of the 2001 survey showed improved noise attenuation with increased azimuthal coverage. Since then, the method has grown in complexity and has seen practical application. BP conducted the first Gulf of Mexico WAZ survey with seismic contractor Veritas over the Mad Dog field in 2004 and 2005.14

In 2006, Shell Exploration acquired a WAZ towed-streamer survey with WesternGeco over a deep objective below a complex salt structure in a deepwater area of the Gulf of Mexico.15 The prospect is located in 3,800 ft [1,160 m] of water, and the discovery well was drilled to a total depth of 29,414 ft [8,965 m].

The survey design attempted to satisfy several seemingly conflicting objectives: full illumination, optimal noise suppression, easy processing and low cost. Achieving these required a wide range of azimuths to illuminate targets under the salt, relatively uniform sampling, minimization of inefficiencies—such as over-redundancy in sampling—and consideration of practical limitations, such as the number of vessels available for the survey and the number of streamer passes.

Four parameters are critical for WAZ survey design. First is the maximum crossline offset, which is the greatest separation between source and receiver in the crossline direction—
perpendicular to the inline, or streamer, direction. Second is the source-line interval, which is the distance between adjacent source lines. Third and fourth are survey size and number of vessels. The maximum crossline offset and the source-line interval are determined from synthetic modeling and migration of synthetic data. Illumination of the target and successful attenuation of multiples are the main criteria for assessing the modeling results, which must also include deterioration of the image caused by gaps created when the streamers avoid surface obstructions, and feathering, or streamer deviation caused by strong currents.

After evaluating several survey geometries, Shell selected a program comprising two dual-source vessels and one streamer vessel towing eight receiver cables spaced 150 m apart, for an effective streamer swath of 1,200 m [3,937 ft].

One source vessel sailed alongside the streamer vessel, but offset 100 m [328 ft] from the outside streamer, while the second source vessel sailed


Effect of narrow-azimuth and wide-azimuth acquisition on subsalt illumination. A complex but realistic salt body (top), defined by its top (gold) and bottom (pink), overlies a target horizon (purple). Salt overhangs are in green. Shotpoints for both surveys are in the black rectangle. The narrow-azimuth acquisition hit map (middle) shows the number of traces that reach the target horizon. The wide-azimuth hit map (bottom) shows more seismic traces reaching the target horizon, with fewer areas of no illumination (white).
behind the streamers, offset from the first source vessel by 450 m [1,476 ft] (above). Then, while the source vessels repeated the same source lines, the streamer vessel performed additional passes at 1,400-m and 2,600-m [4,593-ft and 8,530-ft] offsets from the original source line, and repeated those offsets again on the other side of the source line. Each source line was acquired six times. After this coverage for one source line was completed, the entire process shifted 900 m [2,952 ft] to the next source line, and was repeated. The azimuth-offset plot for this wide-azimuth survey displays a much broader distribution than for a narrow-azimuth survey (next page, top). Data from this wide-azimuth pilot survey underwent initial processing, consisting of only coherent-noise attenuation and common shot-gather migration using a preexisting velocity model. This dataset, with only basic processing applied, was compared with more fully processed WesternGeco narrow-azimuth data from a multiclient survey covering the same area (next page, bottom). The narrow-azimuth survey processing included coherent-noise attenuation, SRME multiple suppression and the same wave-equation migration as the WAZ survey. Even without additional multiple suppression, the WAZ survey produced a clearer subsalt picture than the narrow-azimuth survey, leading to more confident assessment that the reflections were coming from subsalt layers rather than multiples. The improvement in clarity is most obvious on the left side of the section, where sediments truncate against the salt keel in the middle of the section. The WAZ data convinced interpreters that significant subsalt events continue updip toward the salt keel, and that these events are not multiples.

Shell concluded that while not all areas below the salt were illuminated, the WAZ survey improved the image of subsalt sedimentary structure in most places. The dominant multiples were removed without specific processing. Depopulation tests to see if adequate results could be achieved with less data showed that in...
the deep subsalt areas, images acquired by removing every other source line were almost as good as the full dataset. These tests also indicated that data acquired from sources in front of the streamers provided better subsalt imaging than data acquired from the sources behind the vessel, where streamer feathering has greater negative impact. This information could help in the design of future WAZ surveys.

The two-phase wide-azimuth study was designed to demonstrate the value of WAZ technology in exploring complex subsalt settings. Following the successful imaging results from the first phase, the second phase was cancelled and Shell Exploration moved to underwrite acquisition of a large multiclient WAZ exploration survey in the Gulf of Mexico.
Using knowledge gained from modeling and earlier WAZ surveys, WesternGeco has designed and acquired two large WAZ surveys for multiclient use (left). These surveys incorporated design improvements such as crossline reciprocity—sail lines in opposing directions—and source vessels at the forward rather than aft end of the streamers. They also use wider crossline offsets for better signal-to-noise ratio, multiple attenuation and illumination.

The first survey, completed in 2006, covered 222 Gulf of Mexico blocks, or 5,183 km² [2,002 mi²], and deployed three single-source vessels. Ten 7,000-m [22,967-ft] streamers were used in a 1,200-m [3,936-ft] spread width, and sail lines were run in reciprocal directions. The second survey, completed in 2007, covered 252 blocks, or 5,895 km² [2,278 mi²], and deployed four single-source vessels, including single sources on two streamer vessels interleaving in two opposing directions.

The first multiclient WAZ survey provides improved images compared with narrow-azimuth surveys acquired over the same area. With minimal processing, the new images show enhanced clarity and illumination, especially in areas beneath salt overhangs (below).

The third and fourth phases of the multiclient Gulf of Mexico WAZ project will cover more than 10,000 km² [4,000 mi²] starting in May, 2007. The goal is to produce a quick-look wave-equation migrated volume through onboard processing, allowing customers to meet lease sales deadlines.
Rich-Azimuth Surveys

Azimuthal coverage can be further enhanced by combining the multiazimuth and wide-azimuth concepts in what is called a rich-azimuth survey (RAZ). BHP Billiton first implemented this type of acquisition in 2006 over the Shenzi field in the Gulf of Mexico, a 2002 discovery in water depths up to 4,300 ft [1,300 m] approximately 120 miles [190 km] from the coast of Louisiana (right). The field comprises Green Canyon Blocks 609, 610, 653 and 654. Development drilling will assess recoverable reserves, which are estimated at 350 to 400 million bbl [56 to 64 million m³].

Coventurers in the project are Hess Corporation and Repsol YPF.

The Shenzi discovery well was drilled to a target identified by 3D seismic data, but the first appraisal well encountered subsurface layers at unexpected depths. New seismic data with higher signal-to-noise ratio and resolution were required to build a more reliable subsurface model that would reduce the risk of future drilling. A survey design and evaluation study helped BHP Billiton and WesternGeco geophysicists conclude that a rich-azimuth survey was the best choice for the Shenzi reservoir. Important factors in this decision were the reservoir structural complexity, strong currents, rig activity and platforms.

The RAZ survey, the world’s first, was acquired with one streamer vessel equipped with a source and two source vessels shooting along three azimuths, 30°, 90° and 150° (below). The survey plan allowed each shot location to be repeated at least three times.

In another world’s first, the streamer vessel continued recording during tight vessel turns. Shooting and recording while turning improve

operational efficiency and reduce nonproductive
time. Typically, vessels extend their sail lines and
turn well outside the boundary of the survey, so
that the streamers are straight and at the proper
separation by the time the vessel reenters the
boundary. This practice adds time to the survey
acquisition—an extra two hours per turn (below). Usually, no data are acquired during the
turn, because the streamers do not track cleanly
around the turn and the receiver positions are
not accurately calculated. Also, towing through a
curve causes too much noise for usable data to be
acquired.

With the Q-Marine system, streamers can be
positioned and steered so that they maintain
spacing throughout the turn. Also, recording data
from individual hydrophones, instead of grouping
before recording, allows removal of noise from
turning, which resembles bad-weather noise.
These features promote acquisition of valuable
data during periods that would normally be
nonproductive. Acquiring additional data on the
edges of the Shenzi survey increased the area
that could be imaged effectively and improved
the images of the target near the boundary of the
survey area.

Comparison to a fully processed conventional
narrow-azimuth survey showed that the
Q-Marine rich-azimuth survey with basic
processing reduced noise artifacts and produced
clearer illumination of the base of the salt, and
subsalt reflections, than the fully processed
narrow-azimuth survey (next page, top). Reflections could even be identified within the
salt. However, the greatest improvement was in
reflections deep below the salt. BHP Billiton
geophysicists are now able to interpret
structures in zones that are better illuminated.

According to the survey plan, the RAZ survey
would have taken 105 days, compared with a
conventional survey that would have taken
72 days to cover the same area. As shot, the
Shenzi RAZ survey took just 88 days, plus 12 days
in mobilization, and delivered six times the data
of a conventional survey. The time savings arose
from several factors. Shooting in three directions
with the wide-azimuth acquisition made it
unnecessary to undershoot obstacles, and
minimized the time required to shoot infill lines.
The vessel crews experienced almost no weather
downtime, because the streamer cables were
towed deep, at 12 m [39 ft], and the Q-Marine
single-sensor recording adequately sampled any
weather-related noise. Following the success of
the first RAZ survey, BHP Billiton is preparing to
acquire another.

WesternGeco experience in WAZ and RAZ
surveys demonstrated several benefits of wide-
azimuth and rich-azimuth acquisition. Improved
attenuation of multiples and other coherent
noise provides increased signal-to-noise ratio of
subsurface events. Raypaths from different
azimuths result in better reservoir illumination,
and repeatability of shots in the same location
makes migration processing highly efficient.
Additionally, acquiring data while turning
increases efficiency, and is a practice that
WesternGeco expects to extend to conventional
3D Q-Marine surveys.

Shooting and recording while turning, for improved operational efficiency. In traditional surveys
(top left), each sail line (dashed line) is extended to make sure the streamers are straight for all
shots. This additional line length at the beginning and end of each turn adds hours to the turning
time. The Q-Marine system allows streamers to stay in position throughout the turn (green line), so
data acquisition during turning is possible. The quality of data acquired while turning is comparable
to that acquired along sail lines (top right). Data acquired in the turns contribute to the overall image
of subsurface reflectors and fit smoothly with data acquired by straight streamers (bottom).
A completely different approach to improving seismic signal involves deploying sources and streamers differently to more fully sample both the noise and desired energy fields. As outlined earlier, acquiring marine seismic data typically involves towing sources and receiver cables at constant depths specified by the survey design. Selecting the depths calls for consideration of several factors. One of these is the limiting effect of the source and receiver depths on the frequency content of the seismic energy that can be recorded. Understanding how source and receiver geometry affects signal-to-noise level and frequency content requires examining the way energy propagates from the towed source to the receiver cable, and especially how near-surface multiples add noise and reduce signal.

Because of this polarity reversal, the wave reflected at the sea surface, called the source ghost, and the direct, downgoing, wave destructively interfere to the extent that at certain frequencies, the amplitudes cancel. The result is a downward propagating wavefield that is deficient in energy at certain frequencies. The frequencies at which these deficiencies occur—at which amplitude falls to zero—are called the source-ghost notches, and are related to the depth of the source. The greater the depth of the source, the lower the first, nonzero source-ghost notch frequency.


25. Polarity of a seismic signal refers to the direction of its amplitude in a recorded seismic trace. Negative and positive amplitudes have opposite polarity.
Similarly, energy returning from a deep reflector travels upward toward the receiver cable and also reflects off the sea surface, interfering destructively with energy traveling directly from the deep reflector to the receiver. This interference causes cable-ghost notches at several frequencies (middle right). The combination of the source- and cable-ghost notches leads to a complex amplitude spectrum that produces gaps in the available seismic signal. The maximum frequency used in processing is usually limited at the frequency corresponding to the first receiver notch, and the minimum frequency is limited by the acquisition filter, which is typically 3 Hz.

Because the objective is to acquire data of the greatest bandwidth and highest frequency possible, the source and streamer are usually towed at shallow depth, pushing the first, nonzero notch frequency higher. However, shallow towing has disadvantages. Wind, waves and shallow currents add noise to the acquired signal, and the need to keep noise to a minimum can restrict acquisition to seasons with good weather. Also, shallow towing attenuates the extremely low frequencies needed for inversion, a processing technique that extracts acoustic impedance and other rock properties from seismic data.

Another disadvantage to the lack of low frequencies is the diminished probing power of seismic waves. Because depth of penetration is related to seismic wavelength, the lack of low frequencies limits the depth to which seismic energy propagates.

Increasing the towing depth allows data acquisition in a quieter environment, extends the acquisition season and extends the bandwidth to lower frequencies. This allows imaging at greater depth, but decreases the maximum frequency of data that can be recorded, and so decreases the overall image resolution.

Until recently, survey planners had to sacrifice resolution and high frequencies for depth of penetration and a quiet acquisition environment, or vice versa. They were forced to choose between towing shallow, deep, or at some intermediate depth. However, a reemerging acquisition technology called "over/under" allows companies to enjoy the advantages of both shallow and deep towing without the drawbacks.

Over and Under
The idea of towing one shallow streamer along with one deep reflector—one over and one under—has been around for more than 50 years. Practical application of the method was attempted in the 1980s to reduce weather-related noise and downtime. A key benefit of the over/under method is the increased bandwidth obtained from the ability to fill the nonzero ghost notches through combination of the over and under streamers, while still retaining the low-frequency benefit of deep towed streamers. Also, in theory, the vertical separation of two linear arrays of receivers allows the upgoing seismic wavefield to be separated from the downgoing waves, facilitating the suppression of surface-related multiples.

Recently, modeling the effect of streamer depth on frequency content of the recorded signal. Towing streamers at a shallow depth, 8 m (red dashed line), produces signals up to 93 Hz before the first nonzero-frequency notch cuts the signal amplitude to zero. Towing streamers deep, at 30 m (green), produces signals up to 25 Hz before the first notch cuts signal amplitude to zero. (Adapted from Moldoveanu et al, reference 27.)

Over and Under streamer configuration for the Chevron 2D survey in the Gulf of Mexico. An over/under pair of streamers (darker blue) was towed at 18 and 25.2 m, along with position-monitoring streamers at either side at 18-m depth, and an experimental-control streamer at 7.2 m. Sources were deployed at 5 and 10 m.
However, the success of this acquisition geometry in removing the ghost notches from the seismic data relies on keeping one streamer directly below the other, in one vertical plane all along the streamer length. Achieving this configuration was not feasible with the towed-streamer technology of the 1980s, and so the idea was not put into practice for many years. In spite of these practical limitations, scientists continued to develop wavefield-separation techniques for eventual application.\textsuperscript{31}

Recently, acquisition technology caught up with processing advances. The Q-Marine system is capable of steering pairs of streamers in a vertical plane with sufficient accuracy for the over/under method to succeed. To demonstrate the feasibility and promise of the method, Chevron and WesternGeco performed a 2D experiment over the Genesis field in the Gulf of Mexico in 2004.\textsuperscript{32}

The acquisition plan for the 2D line called for streamers to be towed at 18 and 25.2 m [59 and 82.7 ft]. However, to accurately calculate receiver positions, another two streamers were deployed, one on each side of the over/under streamers, at a depth of 18 m (previous page, bottom). One additional streamer was towed at 7.2 m [23.6 ft], directly above the over/under pair, to acquire conventional Q-Marine data as an experimental control. All five streamers were equipped with Q-Fin marine seismic streamer steering devices and a complete acoustic network to allow accurate positioning of the central streamers. The recording bandwidth was increased to record from 1.5 to 200 Hz to include the anticipated low-frequency response.

Throughout acquisition, monitoring of the vertical and horizontal separations of the streamers showed that variation in the 7.2-m vertical separation averaged less than 10 cm [4 in.], and the horizontal, or crossline, separation was always less than 6 m [20 ft]—believed to be adequate for separation of the upgoing and downgoing wavefields.

Comparison between the control dataset and the upgoing wavefield from the over/under line shows improved low-frequency response and higher signal-to-noise ratio for the over/under data (above right). The deep sediments in basins bounded by faults and salt diapirs are much clearer in the over/under line, as are the near-vertical flanks of the salt and highly dipping features throughout the section. The bandwidth extension to lower frequencies allows deeper penetration of seismic energy and better imaging of deep reflections than seen in the control dataset.

\textsuperscript{26} Low-frequency information is needed for inversion of seismic data because typically, the seismic data themselves provide only high-frequency information, such as relative changes in reflectivity or acoustic impedance at each layer boundary. Low-frequency information, typically derived from checkshots or integrated sonic logs, provides the baseline from which the high-frequency data vary. By combining both low- and high-frequency information, absolute changes in rock properties may be calculated. Because seismic inversion requires a combination of seismic and well data, it usually cannot be performed reliably in the absence of wells. However, if seismic data could be acquired with low-frequency content intact, inversion could be carried out in more areas.


Comparison of amplitude spectra from the over/under data and the shallow-streamer, reference dataset. Amplitude spectra from the upgoing wavefield obtained from the over/under data (black) show a wider bandwidth than the shallow-streamer, reference data (green), the data from the “over” streamer (red) and the data from the “under” streamer (blue). The upgoing wavefield also has a better high-frequency response than any of the individual streamers, and has a low-frequency response similar to that of the deepest streamer. (Adapted from Moldoveanu et al, reference 27.)

Spectral analysis of data acquired from all three central streamers demonstrates that the upgoing wavefield also has better high-frequency response than data from any of the streamers individually, and that the low-frequency response is similar to that of the deepest streamer (above).

Another innovation that was tested in this over/under survey was the concept of over/under sources.3 The airgun source arrays were towed at 5- and 10-m depths and their signals were recorded by the streamer towed at 7.2-m depth. After the over/under data were processed to separate the upgoing and downgoing wavefields, comparison between the migrated upgoing image obtained from the over/under source combination and the migrated image from the upper source alone showed an improvement in low-frequency content and in the signal-to-noise ratio at deep reflectors.

After these successful tests, Chevron decided to apply over/under streamer and source technology to a large project in the northeast Atlantic, east of the Faroe Islands and west of the Shetland Islands.4 Water depths in the Faroe-Shetland Channel exceed 1,000 m [3,300 ft], and weather can be harsh. Also known as the West of Shetlands, this offshore UK region has seen significant exploration success (above right).

However, some prospective areas await better delineation with seismic imaging technology that can see through basalt layers that obscure underlying structure.

Basalt is a highly attenuative medium, and although several geophysical methods have been proposed to improve imaging through it, basalt remains an obstacle to hydrocarbon exploration in many areas.5 Its high seismic velocity bends rays and prevents all but the lowest-frequency seismic energy from penetrating.

In 2005, the vessel Western Pride completed a regional 2D over/under survey in this area.6 The survey objective was to improve the subbasalt image compared with what could be produced from a single-source, single-streamer acquisition configuration. The two source depths were 12 and 20 m [39 and 66 ft], and the two streamer depths were 20 and 30 m [66 and 98 ft]. The combination of the “over” source at 12 m and the “over” streamer at 20 m was taken as the equivalent of what would have been recorded in conventional acquisition.

Compared with the image from the conventional acquisition, the over/under image shows far richer low-frequency information beneath the basalt (next page, top). This allows interpretation of subbasalt structure with greater confidence. Moreover, the deep-penetrating low frequencies are not generated at the expense of high frequencies. A comparison of shallow images shows that the over/under method produces sufficiently high frequencies to image shallower objectives.

The improvement in bandwidth associated with over/under acquisition can be seen in a comparison of amplitude spectra for both the signal and the noise extracted from a shallow and a deep window of the conventional and over/under datasets (next page, bottom). In the shallow window above the basalt, the over/under data display a signal bandwidth from 2 to 60 Hz, while the conventional-data bandwidth is 5 to 37 Hz, where the notch can be seen. In the deep window, below the basalt, the over/under data have a lower peak frequency than the conventionally acquired data. In general, the over/under data have greater bandwidth and greater separation between signal and noise.

The over/under technique has also been tested in 3D, with equally positive results.7 In this case, a 67-mi² [173-km²] survey was acquired with four pairs of over/under streamers over a subsalt play in the Gulf of Mexico. The 3D experiment demonstrated that the 3- to 55-Hz bandwidth achievable with conventional acquisition could be increased to 2 to 63 Hz with over/under acquisition. The resulting migrated images showed that the seemingly small extension in bandwidth produced significant results in imaging reflections below and within the salt.
More recently, over/under surveys have been acquired elsewhere for similar reasons. In the Barents Sea, salt outcropping at the seafloor creates a high acoustic-impedance contrast that attenuates seismic energy. Offshore India, the hard sea bottom and deep basalt have made imaging difficult in the past. The over/under method shows promise for imaging beneath and within carbonates and in other salt-prone provinces, such as offshore West Africa.


37. Moldoveanu et al, reference 27.

^ Over/under and conventional images from the Chevron West of Shetlands survey. This over/under survey towed pairs of both sources and streamers. The image produced from the resulting upgoing wavefield (top right) shows significantly more low-frequency information below the basalt than the conventional image (top left). The top of basalt is indicated by the yellow arrow. The generation of low frequencies does not decrease the high-frequency signal content, as seen in a close-up view (in yellow boxes) of a shallow section above the basalt. The shallow section of the over/under image (bottom right) shows a high-frequency content similar to that seen in the shallow section of the conventionally acquired image (bottom left). (Adapted from Hill et al, reference 34 (June 2006).)

^ Comparison of signal and noise amplitude spectra from over/under (top) and conventionally acquired data (bottom) from West of Shetlands. Spectral analysis of shallow data in a window from 2.9 to 4.0 s demonstrates the wider bandwidth of the over/under data (top left) than the conventional survey (bottom left). The over/under data exhibit a signal bandwidth from 2 to 60 Hz, while the conventional data contain signal from 5 to 37 Hz. Comparing signal content deeper, below the basalt, the over/under data (top right) show a peak at a lower frequency than the conventional data (bottom right). The greater bandwidth and larger separation between signal (blue) and noise (black) levels help produce higher resolution images with deeper penetration. (Adapted from Hill et al, reference 34 (June 2006).)
Targeting Carbonate Porosity

Carbonates pose another challenge to 3D seismic imaging. Like basalts, their high seismic velocities bend rays, hiding both their own internal structure and that of underlying formations.

After the 2003 discovery of the Lobina field offshore northeastern Mexico, Pemex needed a high-resolution 3D survey to assess and rank potential drilling locations. The Lobina field is adjacent to the Arenque field, a 1968 discovery that also would benefit from enhanced reservoir description. Low resolution caused by insufficient frequency content limited the usefulness of a 1996 3D survey.

A new survey, using the Q-Marine system, was designed to capture a wider bandwidth and preserve true amplitudes for inversion of reservoir properties. Obstructions and shallow water depths, ranging from 30 to 80 m [100 to 260 ft], presented design challenges, but the acquisition of the 320-km² [124-mi²] survey was completed in just two months.

Initial processing indicated that the new survey doubled the maximum recorded frequency compared with the 1996 survey, recording up to 60 Hz compared with the 30-Hz maximum recorded in 1996. The increased frequency content significantly enhanced interpreters’ ability to map key reservoir layers.

The objective was to identify high-porosity zones within two carbonate layers, primarily a Jurassic limestone, and secondarily, a shallower Cretaceous carbonate target. The carbonate layers themselves are high-velocity layers, but in some zones, high porosity causes a marked decrease in seismic velocity.

Inverting the stacked seismic data allowed geophysicists to obtain a trace-by-trace quantitative measure of acoustic impedance. After calibration with acoustic impedances from sonic and density logs from 40 wells in the survey area, the seismic acoustic-impedance sections were converted to porosity sections, using an acoustic-impedance-to-porosity relationship from the wells.

The resulting porosity volume showed the internal architecture of the best reservoir units and allowed Pemex to optimize drilling locations in the Lobina and Arenque fields (left). Mapping maximum porosity between the top and base of the reservoir let Pemex calculate the volume of sweet spots. In this example, at the location of proposed Arenque Well B, the high porosity in the lower reservoir made this a high-priority target.

Another way to prioritize potential drilling locations is by comparing the product of porosity and height for gross reservoir intervals (left). Comparing the porosity-height product computed at several wells with the porosity-height product computed from the seismic data at the well locations shows a good correlation. These wells were not used in the inversion of the seismic data for porosity, and so the comparison is an excellent test of the qualitative power of the inversion.


Using the porosity-height attribute and maximum-porosity maps, Pemex reduced the priority of two drilling locations and gave higher priority to two others. The seismic results were available in time for a rig traveling to one location to be diverted to a preferred location. The Arenque Well B, drilled with the seismic-porosity results as a guide, produced oil and tested at 2,000 bbl/d [318 m³/d]. The seismically derived porosity results show excellent correlation with the measured porosity in the well (right).

Reducing risk in development drilling is an application in which high-quality seismic data play a vital role. Many fields that were discovered with the help of exploration 2D or 3D surveys have been further characterized by additional 3D surveys designed to identify optimal development-well locations. When 3D data are of superior quality, they can be used to map properties within reservoirs, increasing confidence in infill-drilling plans.

A Rich Future

The basic 3D marine seismic survey that revolutionized exploration in the 1990s has advanced in many ways. New acquisition methods that enhance azimuthal coverage, such as wide-azimuth and rich-azimuth surveys, have provided a step-change improvement in difficult subsalt environments. These surveys deliver increased signal-to-noise ratio and improved reservoir illumination. The examples in this article demonstrate the improvements possible with only basic processing. Full processing of the wide-azimuth data is in progress and is expected to significantly improve the results by applying multiple attenuation and an optimized velocity model for imaging. Through further application and experimentation, seismic practitioners expect even more from WAZ and RAZ surveys, such as extension to carbonate and subsalt exploration. Other potential benefits are improved velocity models for imaging, especially where anisotropy is involved, better characterization of fractured reservoirs, geomechanical studies around planned deepwater well locations and high-resolution imaging of shallow drilling hazards.

The improvement in signal bandwidth and penetration that comes with the over/under method of towing vertically aligned streamers and sources has helped illuminate deep structures that previously were hidden. The technique is a viable geophysical solution for boosting resolution and low-frequency content in areas where conventional seismic methods fail. One future challenge for the over/under method is to tow more streamers. In recent surveys, vessels have towed four pairs of streamers. Theoretically, a few WesternGeco vessels can tow eight pairs, but this has not yet been attempted. Researchers are investigating still other arrangements of streamers for next-generation over/under acquisition.

The ability to acquire high-fidelity seismic data with single-sensor technology ensures that companies have the optimal input data for inversion routines designed to output reservoir properties, such as acoustic impedance, porosity and other rock and fluid characteristics. This allows interpreters to look inside reservoirs and determine where to place development wells with greater confidence. Current inversion methods require low-frequency information from well logs or well seismic surveys. However, as surface seismic acquisition methods—such as the over/under technique—increase signal low-frequency content, inversion may become practical in areas far from existing wells.

As more companies reap the wealth of recent advancements in marine seismic technology, they will discover not only more oil and gas, but also how to use seismic data to reduce risk, replace reserves, lower finding costs, decrease the number of development wells, optimize well placement and accelerate development programs. –LS

Logging results from Arenque Well B, drilled to exploit the high-porosity zone identified by inversion of seismic data. Color-coding indicates seismically derived porosity in two carbonate reservoirs. Well B targeted the high-porosity zone in the lower carbonate (orange and yellow), just below the Csa marker (blue-green dot). The porosity calculated from well logs is projected along the well trajectory, and shows good correlation with the seismically derived porosity values in both reservoirs. During testing, the well flowed oil at a rate of 2,000 bbl/d. (Adapted from Salter et al, reference 38.)