3D Seismic Survey Design

There's more to designing a seismic survey than just choosing sources and receivers and shooting away. To get the best signal at the lowest cost, geophysicists are tapping an arsenal of technology from integration of borehole data to survey simulation in 3D.

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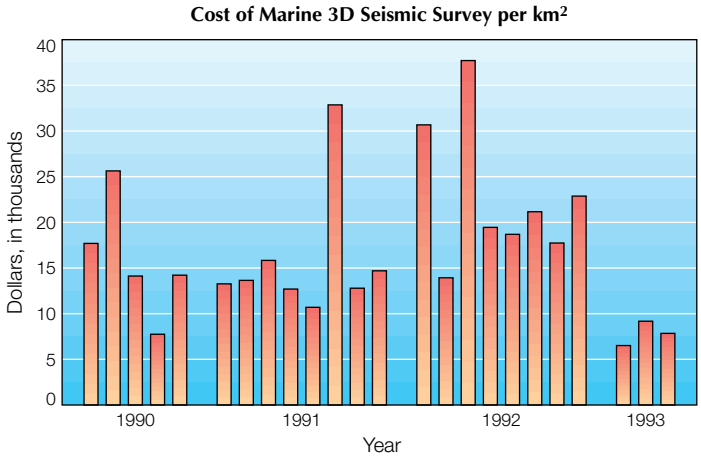

Cost of marine 3D seismic surveys for one oil company. Since 1990, the cost of a marine 3D survey has decreased by more than 50%. *(Courtesy of Ian Jack, BP Exploration, Stockley Park, England.)*

Increased efficiency has brought the cost of marine three-dimensional (3D) seismic data to its lowest level ever, expanding the popularity of 3D surveys (*above*). In the past five years, oil companies have increased expenditures on seismic surveys by almost 60%, to $2.2 billion.[1] However, an estimated 10% of surveys fail to achieve their primary objective—some because the technology does not exist to process the data, some because the surveys are improperly planned.[2] Careful planning can result in more cost-effective acquisition and processing, and in data of sufficient quality to benefit from the most advanced processing.

But before the first shot is fired or the first trace recorded, survey designers must determine the best way to reveal the subsurface target. As basics, they consider locations and types of sources and receivers, and the time and labor required for acquisition. Many additional factors, including health, safety and environmental issues, must be taken into account. This article investigates the objectives and methods of seismic survey design and reviews field examples of state-of-the-art techniques.

The ideal 3D survey serves multiple purposes. Initially, the data may be used to enhance a structural interpretation based on two-dimensional (2D) data, yielding new drilling locations. Later in the life of a field, seismic data may be revisited to answer questions about fine-scale reservoir architecture or fluid contacts, or may be compared with a later monitor survey to infer fluid-front movement. All these stages of interpretation rely on satisfactory processing, which in turn relies on adequate seismic signal to process. The greatest processing in the world cannot fix flawed signal acquisition.

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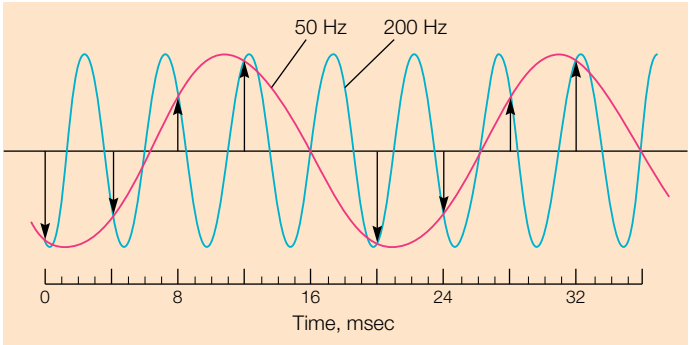
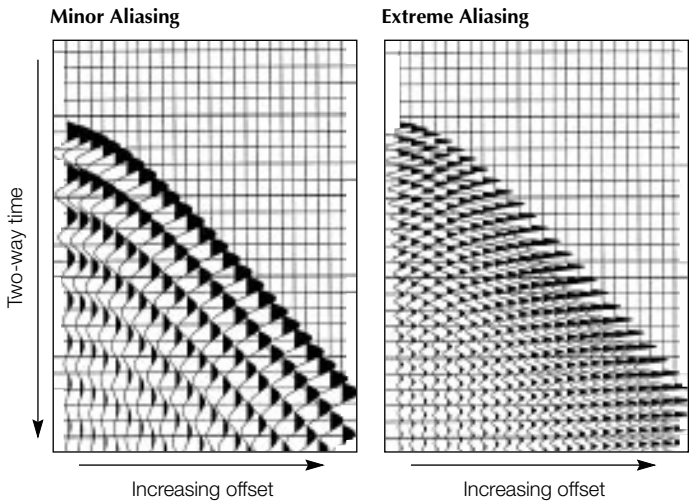
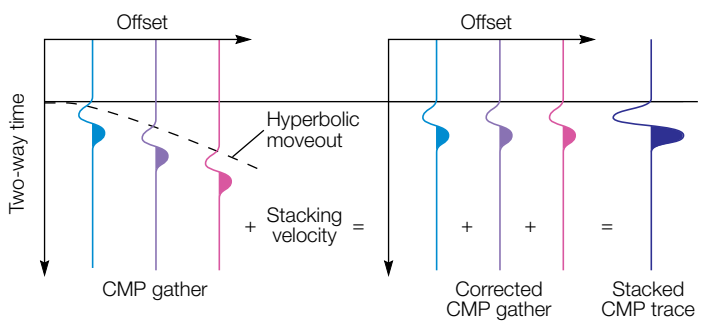
Appreciation is expressed to Qatar General Petroleum Corporation (QGPC) for its consent to the release of data.

1. For the most recent worldwide figures:
   Riley DC: "Special Report Geophysical Activity in 1991," *The Leading Edge* 12, no. 11 (November 1993): 1094-1117.
2. Personal communication: Thor Sinclair.

Temporal Aliasing







☐***Better stacking from a wide and evenly spaced set of offsets. Reflection arrival times from different offsets are assumed to follow a hyperbola. The shape of the hyperbola is computed from the arrivals. Traces are aligned by flattening the best-fitting hyperbola into a straight line, then summed, or stacked. Perfect alignment should yield maximum signal amplitude at the time corresponding to zero offset. A wide range of evenly spaced offsets gives a better-fitting hyperbola, and so a better stack.***

☐***Temporal and spatial aliasing caused by sampling less than twice per cycle. Temporal aliasing*** *(top)* ***occurs when insufficient sampling renders a 50-Hz signal and a 200-Hz signal indistinguishable (arrows represent sample points). The 50-Hz signal is adequately sampled, but not the 200-Hz.*** *(Adapted from Sheriff, reference 4.)* ***Spatial aliasing*** *(bottom)* ***occurs when receiver spacing is more than half the spatial wavelength. With minor aliasing*** *(left)* ***arrivals can be tracked at near offsets as time increases, but become difficult to follow at far offsets. With extreme aliasing*** *(right)* ***arrivals even appear to be traveling backwards, toward near offsets as time increases.*** *(Adapted from Claerbout, reference 6.)*

Elements of a Good Signal

What makes a good seismic signal? Processing specialists list three vital requirements—good signal-to-noise ratio (S/N), high resolving power and adequate spatial coverage of the target. These basic elements, along with some geophysical guidelines (see "Guidelines from Geophysics," *page 22*), form the foundation of survey design.

High S/N means the seismic trace has high amplitudes at times that correspond to reflections, and little or no amplitude at other times. During acquisition, high S/N is achieved by maximizing signal with a seismic source of sufficient power and directivity, and by minimizing noise.[3] Noise can either be generated by the source—shot-generated or coherent noise, sometimes orders of magnitude stronger than deep seismic reflections—or be random. Limitations in the dynamic range of acquisition equipment require that shot-generated noise be minimized with proper source and receiver geometry. Proper geometry avoids spatial aliasing of the signal, attenuates noise and obtains signals that can benefit from subsequent processing. Aliasing is the ambiguity that arises when a signal is sampled less than twice per cycle (*left*). Noise and signal cannot be distinguished when their sampling is aliased.

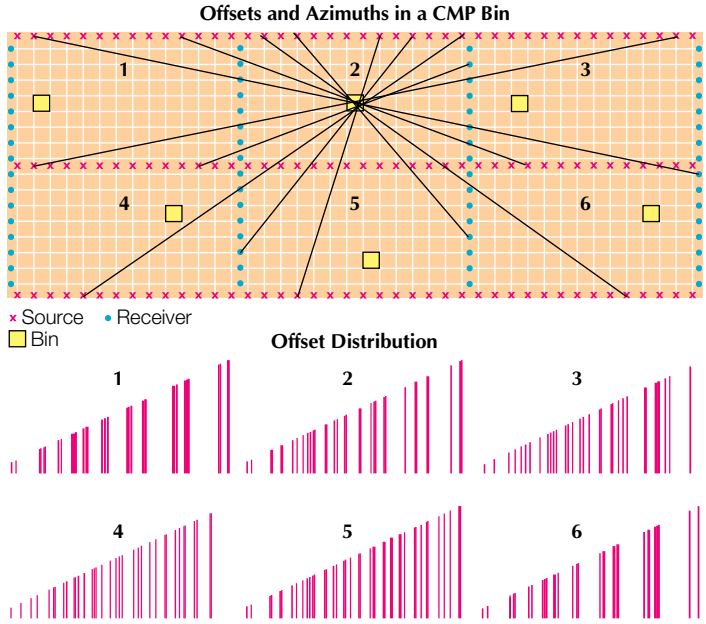
A common type of coherent noise that can be aliased comes from low-frequency waves trapped near the surface, called surface waves. On land, these are known as ground roll, and create major problems for processors. They pass the receivers at a much slower velocity than the signal, and so need closer receiver spacing to be properly sampled. Planners always try to design surveys so that surface waves do not contaminate the signal. But if this is not possible, the surface waves must be adequately sampled spatially so they can be removed.

During processing, S/N is enhanced through filters that suppress noise. Coherent noise is reduced by removing temporal and spatial frequencies different from those of the desired signal, if known. Both coherent and random noise are suppressed by stacking—summing traces from a set of source-receiver pairs associated with reflections at a common midpoint, or CMP.[4] The source-receiver spacing is called offset. To be stacked, every CMP set needs a wide and evenly sampled range of offsets to define the reflection travel-time curve, known as the normal moveout curve. Flattening that curve, called normal moveout correction, will make reflections from different offsets arrive at the time of the zero-offset reflection. They are then summed to produce a stack trace (*left*). In 3D surveys, with the

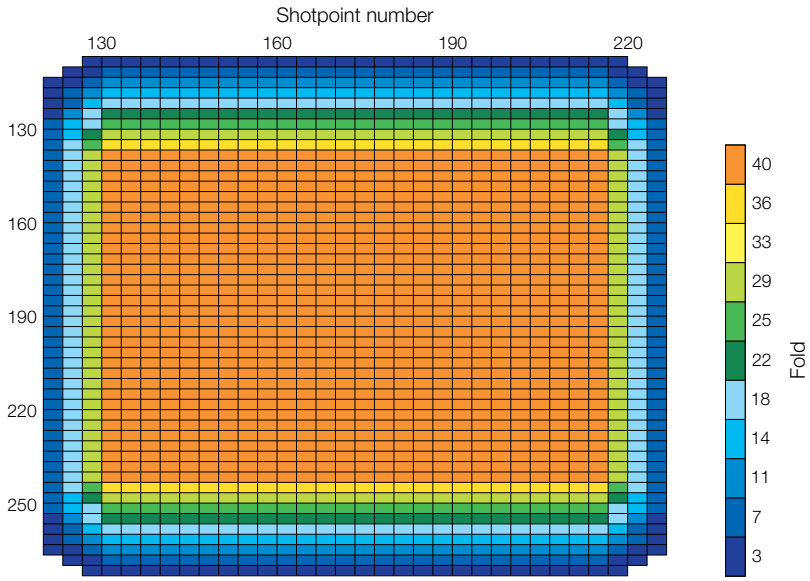
advent of multielement marine acquisition—multistreamer, multisource seismic vessels—and complex land acquisition geometries, reflections at a CMP come from a range of azimuths as well as a range of offsets (*right*).[5] A 3D CMP trace is formed by stacking traces from source-receiver pairs whose midpoints share a more or less common position in a rectangular horizontal area defined during planning, called a bin. The number of traces stacked is called fold—in 24-fold data every stack trace represents the average of 24 traces. Theoretically, the S/N of a survey increases as the square root of the fold, provided the noise is random. Experience has shown, however, that for a given target time, there is an optimum fold, beyond which almost no S/N improvement can be made.

Many survey designers use rules of thumb and previous experience from 2D data to choose an optimal fold for certain targets or certain conditions. A fringe—called the fold taper or halo—around the edge of the survey will have partial fold, thus lower S/N, because several of the first and last shots do not reach as many receivers as in the central part of the survey (*below, right*). Getting full fold over the whole target means expanding the survey area beyond the dimensions of the target, sometimes by 100% or more. Many experts believe that 3D surveys do not require the level of fold of 2D surveys. This is because 3D processing correctly positions energy coming from outside the plane containing the source and receiver, which in the 2D case would be noise. The density of data in a 3D survey also permits the use of noise-reduction processing, which performs better on 3D data than on 2D.

Filtering and stacking go a long way toward reducing noise, but one kind of noise that often remains is caused by multiple reflections, "multiples" for short. Multiples are particularly problematic where there is a high contrast in seismic properties near the surface. Typical multiples are reverberations within a low-velocity zone, such as between the sea surface and sea bottom,



☐*Reflections from source-receiver pairs bounce in a bin, a rectangular, horizontal area defined during planning. In a 3D survey a CMP trace is formed by stacking traces that arrive from a range of azimuths and offsets (top). The distribution of offsets is displayed in a histogram within each bin (bottom). The vertical axis of the histogram shows the amount of offset, and the horizontal axis indicates the position of the trace in offset.*

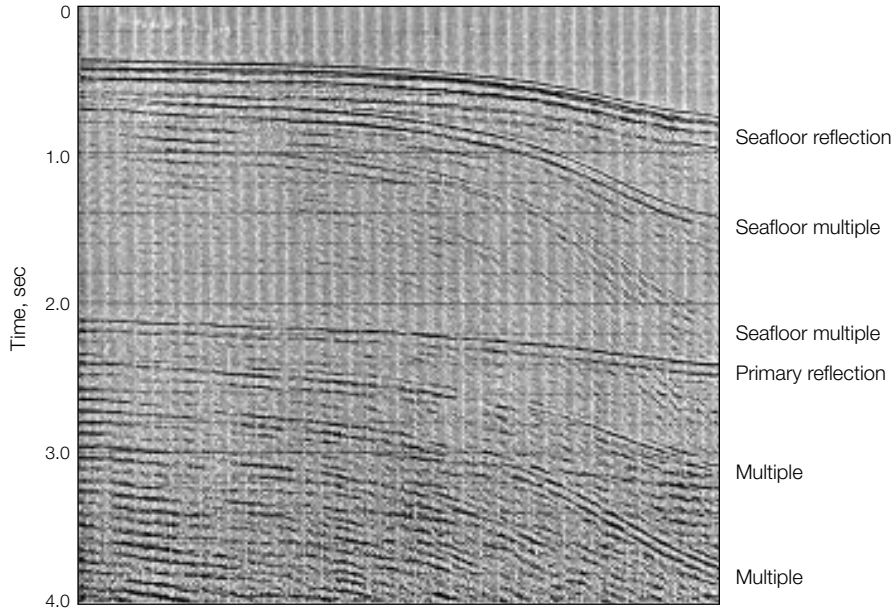


☐*A fold plot showing 40-fold coverage over the heart of the survey. The edge of the survey has partial fold because several of the first and last shots do not reach as many receivers as in the central part of the survey.*

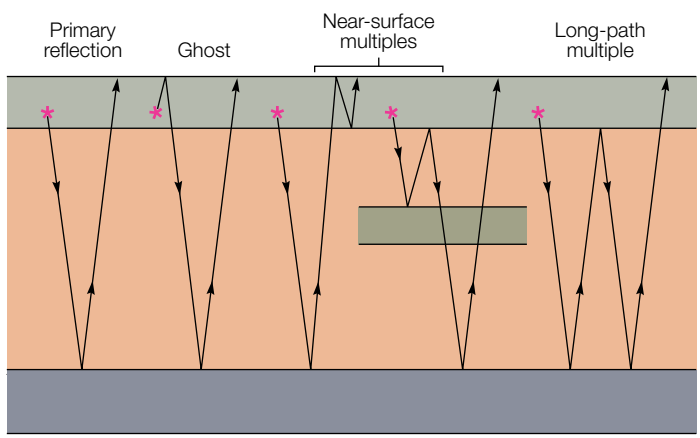
3. Directivity is the property of some sources whereby seismic wave amplitude varies with direction.

4. For a full description of terms used in seismic data processing see Sheriff RE: *Encyclopedic Dictionary of Exploration Geophysics*. Tulsa, Oklahoma, USA: Society of Exploration Geophysicists, 1991.

5. Streamers are cables equipped with hydrophone receivers. Multistreamer vessels tow more than one receiver cable to multiply the amount of data acquired in one pass. For a review of marine seismic acquisition and processing see Boreham D, Kingston J, Shaw P and van Zeelst J: "3D Marine Seismic Data Processing," *Oilfield Review* 3, no. 1 (January 1991): 41-55.



☐***Seismic section with strong multiple noise. Multiples can appear as a repetition of a shallower or deeper portion of the seismic image.*** *[Adapted from Morley L and Claerbout JF: "Predictive Deconvolution in Shot-Receiver Space," Geophysics 48 (May 1983): 515-531.]*



☐***Multiple reflections. After leaving the source, seismic energy can be reflected a number of times before arriving at the receiver.***

or between the earth's surface and the bottom of a layer of unconsolidated rock (*below, left*). Multiples can appear as later arrivals on a seismic section, and are easy to confuse with deep reflections (*left*).[6] And because they can have the same characteristics as the desired signal—same frequency content and similar velocities—they are often difficult to suppress through filtering and stacking. Sometimes they can be removed through other processing techniques, called demultiple processing, but researchers continue to look for better ways to treat multiples.

The second characteristic of a good seismic signal is high resolution, or resolving power—the ability to detect reflectors and quantify the strength of the reflection. This is achieved by recording a high bandwidth, or wide range of frequencies. The greater the bandwidth, the greater the resolving power of the seismic wave. A common objective of seismic surveys is to distinguish the top and bottom of the target. The target thickness determines the minimum wavelength required in the survey, generally considered to be four times the thickness.[7] That wavelength is used to calculate the maximum required frequency in the bandwidth—average seismic velocity to the target divided by minimum wavelength equals maximum frequency. The minimum frequency is related to the depth of the target. Lower frequencies can travel deeper. Some seismic sources are designed to emit energy in particular frequency bands, and receivers normally operate over a wider band. Ideally, sources that operate in the optimum frequency band are selected during survey design. More often, however, surveys are shot with whatever equipment is proposed by the lowest bidder.

Guidelines from Geophysics

Many of the rules that guide 3D survey design are simple geometric formulas derived for a single plane layer over a half-space: the equation describing the hyperbola used in normal moveout correction is one example. Others are approximations from signal processing theory. Sometimes survey parameters are achieved through trial and error. The following formulas hold for some simple 3D surveys:

Bin size, $\Delta x \Delta y$, is calculated to satisfy vertical and lateral resolution requirements. For a flat reflector, bin length, Δx, can be the radius of the Fresnel zone or larger. The Fresnel zone is the area on a reflector from which reflected energy can reach a receiver within a half-wavelength of the first reflected energy. For a dipping reflector

$$\Delta x = \frac{V_{rms}}{(4 f_{max} \sin \vartheta)} \quad ,$$

where V_{rms} is the root mean square average of velocities down to the target, f_{max} is the maximum nonaliased frequency required to resolve the target, and ϑ is the structural dip. Normally $\Delta y = \Delta x$.

3D fold is determined from estimated S/N of previous seismic data, usually 2D. 3D fold must be greater than or equal to

$$\text{2D fold} \sqrt{\frac{\Delta x \Delta y}{2 R_f \, dx}} \quad ,$$

where R_f is the radius of the Fresnel zone and dx is the CMP interval in the 2D data.

Maximum offset, X_{max}, is chosen after considering conflicting factors—velocity resolution, normal moveout stretch and multiple attenuation.[1] For a velocity resolution $\Delta v/v$ required to distinguish velocities at time T,

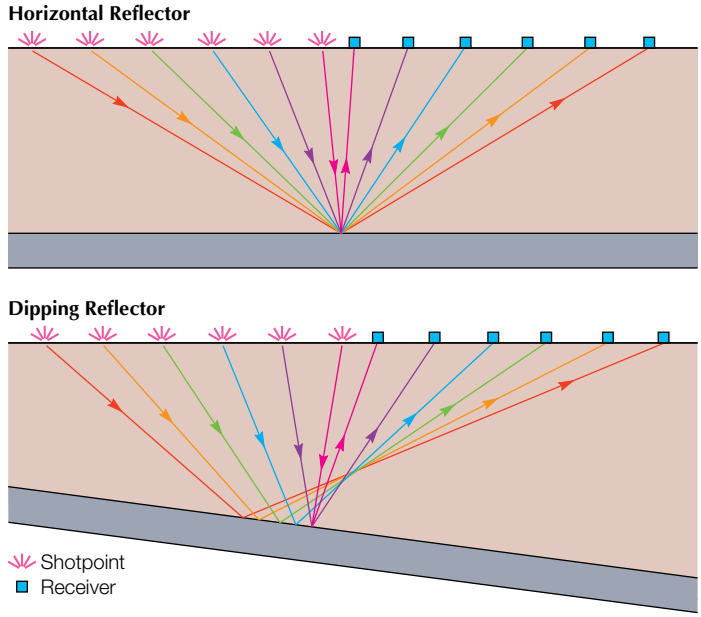
$$X_{max} = \sqrt{\frac{2Tv^2}{\Delta f \left(\frac{\Delta v}{v}\right)}} \quad ,$$

where Δf is $f_{max} - f_{min}$, or the bandwidth. As X_{max} increases, $\Delta v/v$ increases, or improves. But with long offsets, normal moveout stretch increases and multiples can become worse.

1. Normal moveout stretch is the distortion in waveshape caused by normal moveout correction.

Another variable influencing resolution is source and receiver depth—on land, the depth of the hole containing the explosive source (receivers are usually on the surface), and at sea, how far below the surface the sources and receivers are towed. The source-receiver geometry may produce short-path multiples between the sources, receivers, and the earth or sea surface. If the path of the multiple is short enough, the multiple—sometimes called a ghost—will closely trail the direct signal, affecting the signal's frequency content. The two-way travel time of the ghost is associated with a frequency, called the ghost notch, at which signals cancel out. This leaves the seismic record virtually devoid of signal amplitude at the notch frequency. The shorter the distance between the source or receiver and the reflector generating the multiple, the higher the notch frequency. It is important to choose a source and receiver depth that places the notch outside the desired bandwidth. It would seem desirable to plan a survey with the shallowest possible sources and receivers, but this is not always optimal, especially for deep targets. On land, short-path multiples can reflect off near-surface layers, making deeper sources preferable. In marine surveys, waves add noise and instability, necessitating deeper placement of both sources and receivers. In both cases, survey design helps reach a compromise.

The third requirement for good seismic data is adequate subsurface coverage. The lateral distance between CMPs at the target is the bin length (for computation of bin length, see "Guidelines from Geophysics," *previous page*). Assuming a smooth horizontal reflector, the minimum source spacing and receiver spacing on the surface must be twice the CMP spacing at the target. If the reflector dips, reflection points are not CMPs (*above, right*). Reflected waves may be spatially aliased if the receiver spacing is incorrect. A survey designed with good spatial coverage but assuming flat layers might fail in complex structure. To record reflections from a dipping layer involves more distant sources and receivers than reflections from a flat layer, requiring expansion of the survey area—called migration aperture—to obtain full fold over the target.



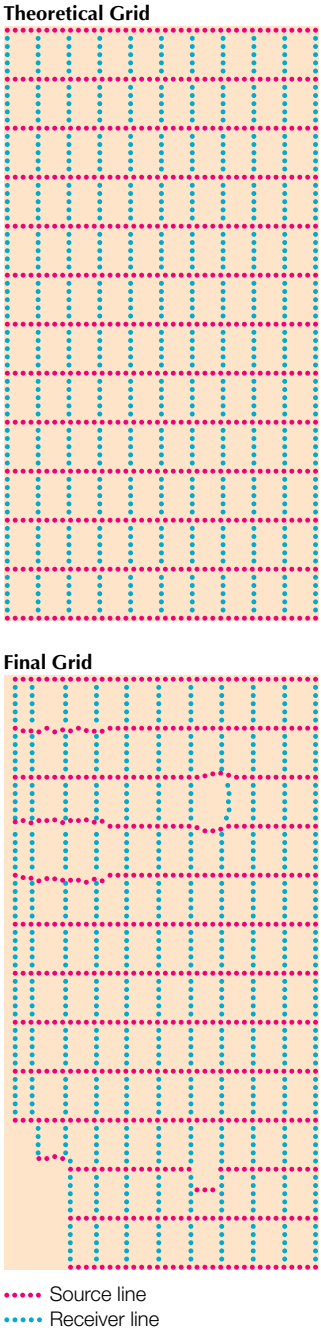
Effect of reflector dip on the reflection point. When the reflector is flat** (top) **the CMP is a common reflection point. When the reflector dips** (bottom) **there is no CMP. A dipping reflector may require changes in survey parameters, because reflections may involve more distant sources and receivers than reflections from a flat layer.

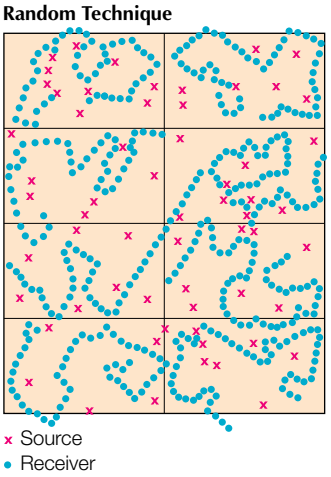
In general, survey planners use simple trigonometric formulas to estimate optimal CMP spacing and maximum source-receiver offset on dipping targets. As geophysicists seek more information from seismic data, making the technique more cost-effective, simple rules of thumb will no longer provide optimum results. Forward modeling of seismic raypaths, sometimes called raytrace modeling, provides a better estimate of subsurface coverage, but is not done routinely during survey planning because of cost and time constraints. An exception is a recent evaluation by Geco-Prakla for a survey in the Ship Shoal South Addition area of the Gulf of Mexico (*page 31*).

Balancing Geophysics with Other Constraints

Acquiring good seismic signal is expensive. On land or at sea, hardware and labor costs constrain the survey size and acquisition time. The job of the survey planner is to balance geophysics and economy, achieving the best possible signal at the lowest possible cost.[8] On land, source lines can be aligned with receiver lines, or they can be at angles to each other. Different source-receiver patterns have different cost and signal advantages, and the planner must

6. Claerbout JF: *Imaging the Earth's Interior.* Boston, Massachusetts, USA: Blackwell Scientific Publications (1985): 356.
7. This is the criterion for resolving target thickness visually. By studying other attributes of a seismic trace such as amplitude or signal phase, thinner layers can be resolved.
8. Survey design and survey planning are sometimes used interchangeably, but most specialists prefer to think of planning as the part of the design process that considers cost constraints and logistics.

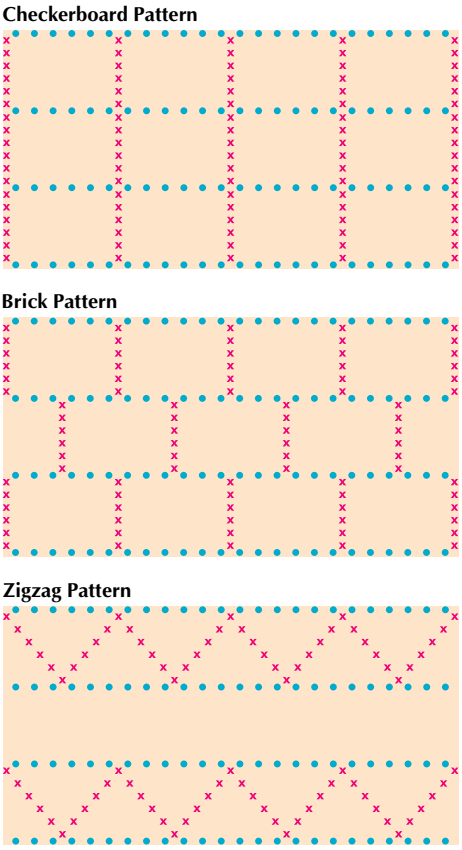




Planned versus actual surveys. A survey planned in West Texas, USA *(top, left)* **calls for a checkerboard of receiver lines** *(blue)* **and source lines** *(red)*. **The actual survey shot** *(bottom, left)* **came very close to plan. Other cities present acquisition challenges. A survey in Milan,iItaly** *(right)* **used a random arrangement of sources and receivers.** *(Adapted from Bertelli et al, reference 9.)*

choose the one that best suits the survey (*right*). Once a survey pattern is selected, subsurface coverage can be computed in terms of fold and distribution of offset and azimuth. If the coverage has systematic holes, the pattern must be modified.iIn complex terrain, planned and actual surveys may differ significantly (*left*).[9]

Land acquisition hardware can cost $5 million to $10 million for recording equipment and sources—usually vibrating trucks or dynamite—but labor is the major survey cost. Cost can be controlled by limiting the number of vibrator points or shotpoints, or the number of receivers. But limiting receivers limits the area that can be shot at one time. If a greater area is required, receivers must be picked up and moved, increasing labor costs. The most efficient surveys balance source and receiver requirements so that most of the time is spent recording seismic data and not waiting for equipment to be moved. Land preparation, such as surveying source and receiver locations and cutting paths through vegetation or topography, must be included on the cost side of the planning equation. In countries where mineral rights and land surface rights are separately and privately held, such as in the US, landowners must give permission and can charge an access fee. Other constraints that can affect survey planning include hunting seasons, permafrost, population centers, breeding seasons, animals migrating or chewing cables, and crops that limit vibrator source trucks to farm roads.



Common source-receiver layouts for land acquisition. The checkerboard pattern *(top)*, **sometimes called the straight-line or cross-array pattern, is preferred when the source is a vibrator truck, because it requires the least maneuvering. The brick pattern,** *(middle)* **sometimes called staggered-line, can provide better coverage at short offsets than the checkerboard, but is more time-consuming, and so costlier. The zigzag pattern** *(bottom)* **is highly efficient in areas of excellent access, such as deserts, where vibrator trucks can zigzag between receiver lines.**

Marine survey planners consider different constraints. Hardware is a major cost; sources and recording equipment are a sizable expense, but additionally, seismic vessels cost $35 to $40 million to build, and

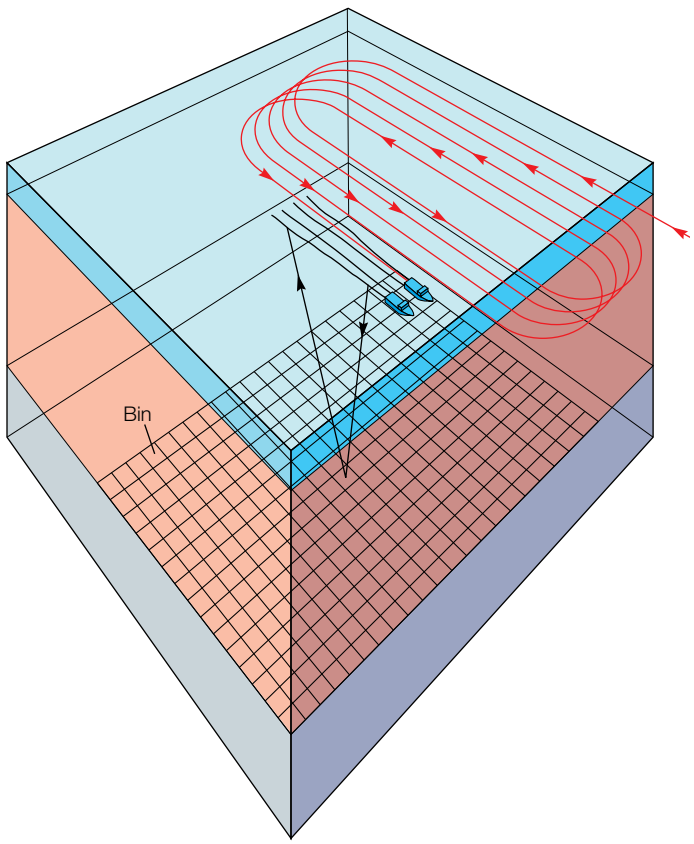
tens of thousands of dollars per day to operate. Sources are clusters of air guns of different volumes and receivers are hydrophones strung 0.5 m [1.6 ft] apart in groups of up to 48, on cables up to 6000 m [19,680 ft] long. Sources and receivers are almost always towed in straight lines across the target (*below, right*), although other geometries are possible. Circular surveys have been acquired with sources and receivers towed by vessels running in spirals or concentric circles.[10] Geco-Prakla's QUAD-QUAD system tows four receiver cables and four source arrays simultaneously, acquiring 16 lines at a time. Currents and tides can cause the long receiver cables to deviate by calculable amounts—up to 30°—from the towing direction. Spacing between shotpoints is a function of vessel speed, and can be limited by how quickly the air guns can recover full pressure and fire again. Access is usually limited only by water depth, but drilling rigs, production platforms and shipping lanes can present navigational obstacles. Environmental constraints also influence marine surveys: the commercial fishing industry is imposing limits on location of, and seasons for, marine acquisition.[11] For example, planning in the Caspian Sea must avoid the sturgeon breeding season or seismic surveys would wipe out caviar production for the year.

Transition zones—shallow water areas—have their own problems, and require specialized equipment and creative planning.[12] Transition zones are complex, involving shorelines, river mouths, coral reefs and swamps. They present a sensitive environment and are influenced by ship traffic, commercial fishing and bottom obstructions. Survey planners have to contend with varying water depths, high environmental noise, complex geology, wind, surf and multiple receiver types—often a combination of hydrophones and geophones.

One thing all surveys have in common is that planning must be done quickly. The clock starts ticking once acreage is licensed. Exploration and development contracts require oil companies to drill a certain number of wells, spend a certain amount of money, or shoot a certain amount of seismic data before a given date. There is often little time between gaining approval to explore or develop an area and having to drill. In some cases, oil companies plan every detail of the acquisition before putting the job out to bid. In other cases, to increase efficiency, oil companies and seismic service companies share the planning. In many cases, service companies plan the survey from beginning to end based on what the oil company wishes to achieve. In the quest for cost savings, however, seismic signal is often compromised.

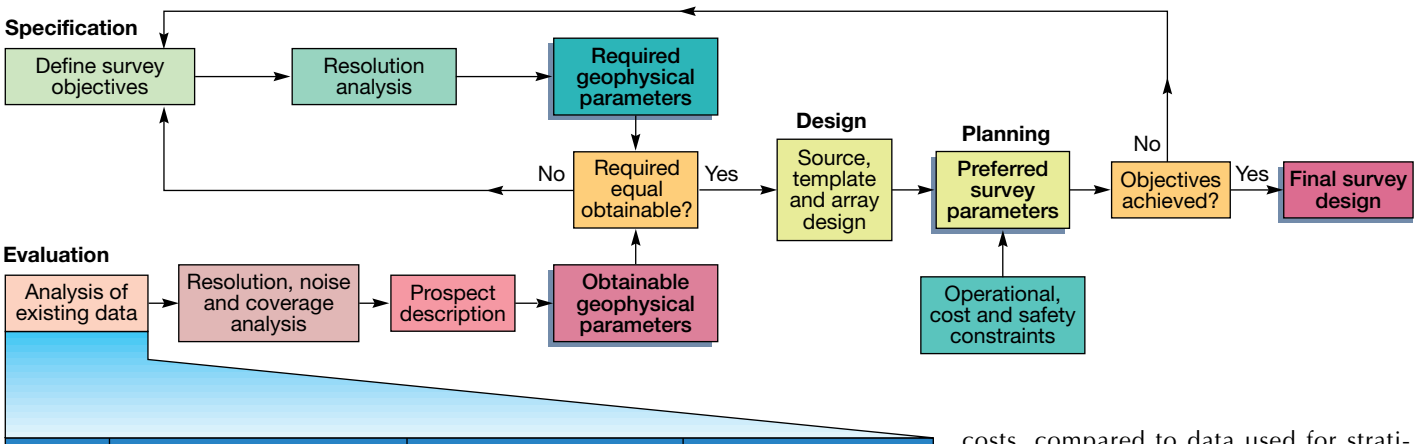
Cost-Effective Seismic Planning

How would 3D seismic acquisition, processing and interpretation be different if a little more emphasis were given to survey design? Geco-Prakla's Survey Evaluation and Design team in Gatwick, England, has shown that by taking a bit more care, signal can be improved, quality assured and cost optimized simultaneously. There are three parts to the process as practiced by Geco-Prakla—specification, evaluation and design (*next page*). Specification defines the survey objectives in terms of a particular depth or target formation, and the level of interpretation and resolution required. The level of interpretation must be defined early; data to be used solely for structural interpretation can be of lesser quality, leading to lower



Marine acquisition geometry showing seismic vessels looping in oblong circuits. The length of straight segments is calculated from fold plots, and must include additional length—"run in" and "run out"—to allow cable to straighten after each turn.

9. Bertelli L, Mascarin B and Salvador L: "Planning and Field Techniques for 3D Land Acquisition in Highly Tilled and Populated Areas—Today's Results and Future Trends," *First Break* 11, no. 1 (January 1993): 23-32.
10. Hird GA, Karwatowski J, Jenkerson MR and Eyres A: "3D Concentric Circle Survey—The Art of Going in Circles," EAEG 55th Meeting and Technical Exhibition, Stavanger, Norway, June 7-11, 1993.
11. Gausland I: "Impact of Offshore Seismic on Marine Life," EAEG 55th Meeting and Technical Exhibition, Stavanger, Norway, June 7-11, 1993.
12. Petersen C, Brakensiek H and Papaterpos M: "Mixed-Terrain 3D Seismics in the Netherlands," Oilfield Review 4, no. 3 (July 1992): 33-44.



Data Type	Parameters to be Determined	Means to Determine Parameters	Process or Output
VSP	•Maximum frequencies attainable •Reflection response of target •Identification of multiples origin •Source peak amplitude •Peak-to-bubble ratio •Source volume •Source depth •Resolution attainable •Noise levels	•VSP processing •Source modeling •Apply losses to source signatures	•Loss modeling •Frequency dependent losses •Source signature for various depths •Bandwidth at target •Target wavelet
Logs or 1D Models	•Estimate spatial and temporal resolution •Shooting direction •Primary/multiple velocity discrimination •Required streamer length •Stack fold, offset and group length for optimum multiple moveout discrimination	•Build geological 2D model and apply appropriate target wavelet •Analysis of 2D synthetic CMP gathers	•Modeled section •Synthetic CMP gathers •Synthetic shots •Migration aperture •Long-offset analysis •Normal incidence stacks •Statics model
2D or 3D Surface Seismic	•Signal-to-noise ratio •Establish noise mechanisms •Near trace offset •Useful offset with time, stack and S/N relationship •Group interval •Crossline spacing •Spatial frequency •Spatial resolution •Shotpoint interval •Migration aperture •Shooting direction •Record length	•Analysis of existing surface seismic •Analysis of migration requirements	•FK plots, filter tests •Refraction velocities (near surface) •Noise records •Amplitude versus time plots •Mute, stack, fold tests •Migration of synthetic zero-offset data •Migration of existing 2D data •Ambient noise estimation

☐*Survey evaluation and design scheme.*

costs, compared to data used for stratigraphic interpretation, analysis of amplitude variation with offset (AVO) or seismic monitoring.[13] Specification quantifies the geophysical parameters needed to meet the interpretation objectives: frequency content and signal-to-noise ratio of the recorded signals, and spatial sampling interval—the familiar requirements for good signal.

Evaluation of existing data, which can be done independently and concurrently, tells which geophysical parameters are obtainable—sometimes different from those stipulated by specification. The types of data evaluated include logs, vertical seismic profiles (VSPs) and 2D or existing 3D data. Existing data can provide models for simulating the effects of the geophysical parameters on new seismic data. If the required parameters are not obtainable, the survey objectives are reexamined, or respecified. The loop is repeated until a set of geophysical parameters is found that is both desired and obtainable.

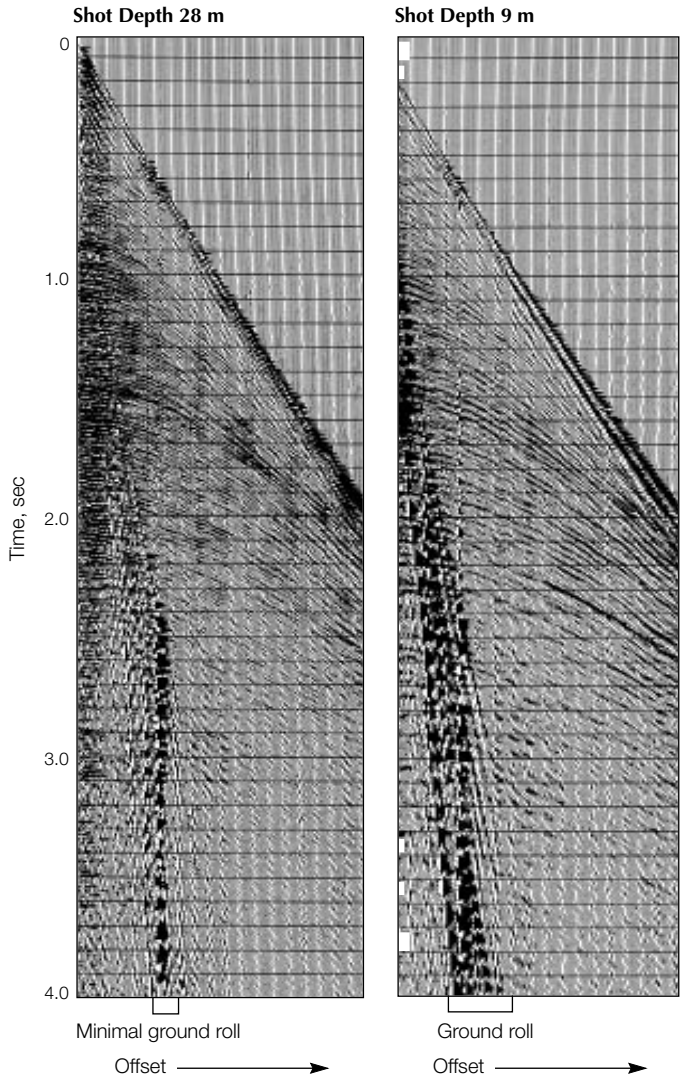
In the third step, design, the geophysical parameters are weighed against other constraints. Keeping in mind the understanding gained from evaluation of existing data, survey planners select the source and receiver configuration and choose the shooting sequence and type of seismic source. These preferred survey parameters are tempered by cost, safety and environmental constraints.

Putting Planning into Practice

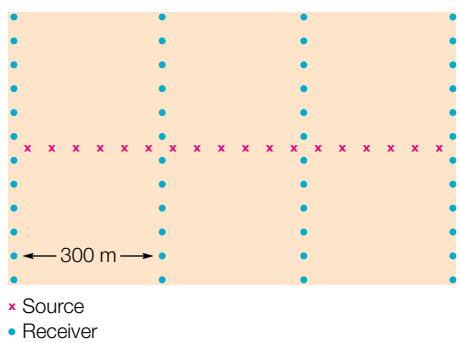
In 1991 Elf Petroleum Nigeria Limited put out for tender a 160-km² [62-sq mile] land survey in the Niger Delta. Working with the Seismic Acquisition Service of Elf Aquitaine Production in Pau, France, the Survey Evaluation and Design group evaluated sources and geometries for optimal acquisition. The primary target is the structure of the Ibewa oilfield at 3500 m [11,480 ft], at or below 3 sec two-way time, with secondary deeper objectives. Signal-to-noise requirements, based on previous experience, suggested the data should be 24-fold. Resolution of the target required signal bandwidth of 10 to 60 Hz and 25 m by 25 m [82 ft by 82 ft] bins. The source was specified to be dynamite, which would be fired in shotholes drilled and cased or lined to 25 m, again based on previous experience. Constraints on the survey included the high population density, potential damage to personal property and the many oil pipelines that cross the area. A roll-along acquisition pattern similar to a checkerboard was suggested in the bid, with four receiver lines to be moved as the survey progressed (*below, right*).

Evaluation of existing data—2D seismic lines and results from seismic source tests—warned of potential problem areas. Source tests compared single-source dynamite shots to source patterns, and tested several source depths.[14] The tests indicated the presence of ghost notches at certain depths, leading to a reduction in signal energy within the desired frequency band of 10 to 60 Hz (*above, right*). The source tests also indicated source patterns were ineffective in controlling ground roll in this prospect area. Deployment of the source at 9 m [30 ft] gave a good S/N ratio at 25 to 60 Hz, but produced very high levels of ground roll. Deployment of the source below 40 m [130 ft] gave a good S/N ratio from 10 to 60 Hz and low levels of ground roll. However, such deep holes might be unacceptably time-consuming and costly.

Evaluation of existing 2D lines revealed the frequency content that could be



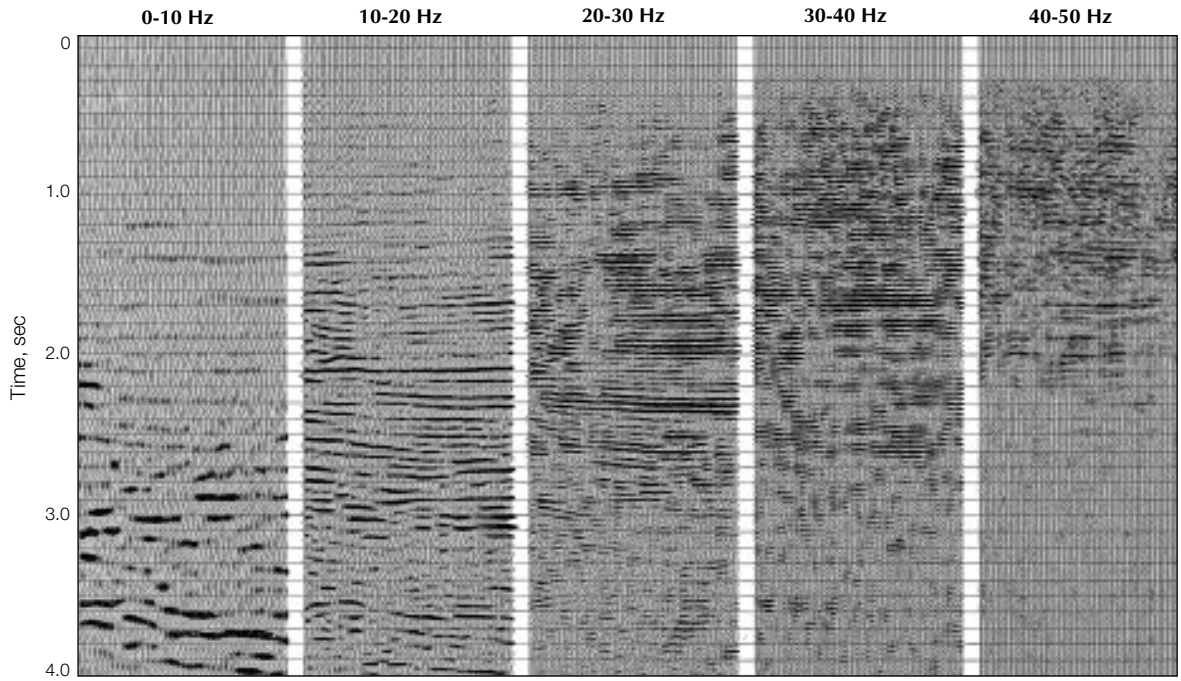
□*Tests with dynamite sources at different depths. Traces recorded from the shot at 28 m [92 ft] (left) show less low-frequency noise—ground roll—than from the shot at 9 m (right). In general, the deeper the source, the less ground roll generated.*



□*Original roll-along geometry proposed for Elf Petroleum Nigeria survey. Four receiver lines would be laid at 300-m intervals. Each line would have 144 receivers with 50-m spacing. Shots would be fired at 50-m intervals in a line perpendicular to the receiver lines, and then the four receiver lines would be rolled along to the next position.*

13. For a review of AVO see:
Chiburis E, Franck C, Leaney S, McHugo S and Skidmore C: "Hydrocarbon Detection With AVO," *Oilfield Review* 5, no. 1 (January 1993): 42-50.
For more on seismic monitoring see:
Albright J, Cassell B, Dangerfield J, Deflandre J-P, Johnstad S and Withers R: "Seismic Surveillance for Monitoring Reservoir Changes," *Oilfield Review* 6, no. 1 (January 1994): 4-14.

14. Source patterns are groups of dynamite charges in separate holes at the same depth, fired simultaneously. The goal is to cancel low-frequency noise that travels laterally, called ground roll.



Filtered 2D data showing frequency content variation with depth. Each panel has been filtered to allow a different band of frequencies, called the passband, to pass. As the passband rises, the maximum depth of penetration of seismic energy decreases. Lower frequencies** (left) **penetrate deeper. Higher frequencies** (right) **do not propagate to deeper levels. At the target level of 3.0 sec there is still some 50 Hz energy left.

expected from seismic data in the area (*above*). Resampling along the 2D line at the sampling interval planned for the 3D survey confirmed that the 50-m [165-ft] receiver and shot spacings initially recommended were appropriate. Fold-reduction simulations performed on the 2D sections showed that 24-fold would be appropriate for the survey. However, a brick pattern would give better fold and offset distribution than the roll-along pattern, potentially improving the survey results. The brick pattern would also reduce the lateral offset between source and receiver line, thus reducing the potential for ground roll arriving at the same time as the reflection from the target and making the ground roll easier to handle in processing.

The complete survey evaluation and design took two months and reached the following conclusions.

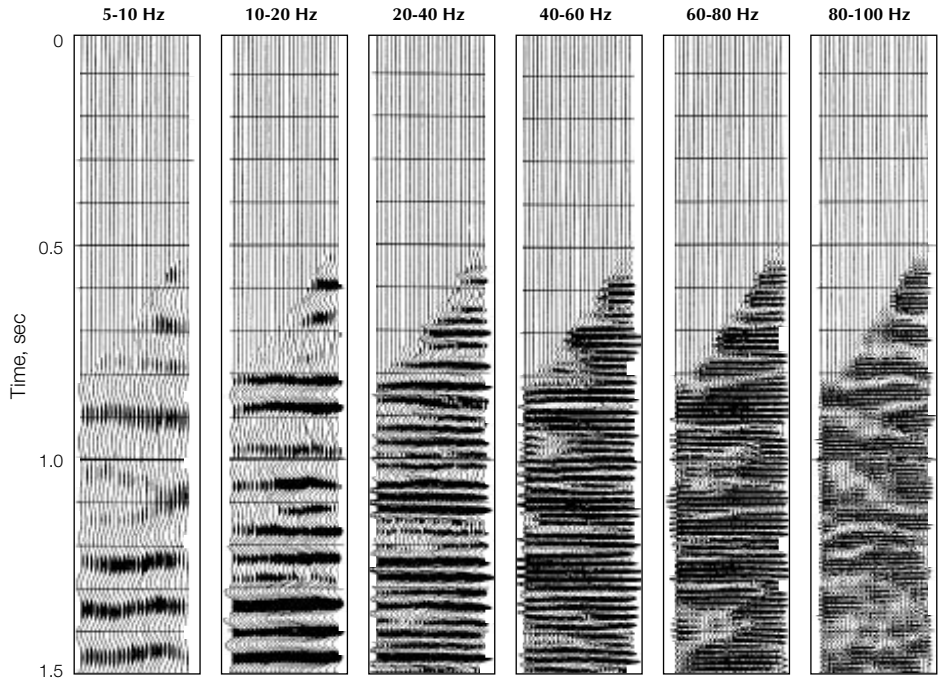
1. A target bandwidth of 10 to 60 Hz is a reasonable acquisition objective.
2. Placement of sources deeper than 40 m would avoid complex processing problems and high levels of ground roll in the 3D data set. If logistics prevent locating the sources at this depth, then a fallback deployment of sources at 9 m would meet the target bandwidth criterion with minimal notching but higher levels of ground roll. Field quality control should verify there is no notch between 10 and 60 Hz.
3. A 144-trace brick pattern with 300-m [984-ft] receiver line spacing and 300-m shot line spacing would give the best offset distribution.
4. Shot and receiver intervals should be no more than 50 m.

Drilling 40-m holes for each source location was deemed impractical. Optimizing costs and logistics, the company obtained satisfactory results with a 24-m [79-ft] source depth, single-shot dynamite, and brickwork acquisition pattern.

Evaluation and design can be different in the marine setting. A case in point is the Al Shaheen location in offshore Qatar, under development appraisal by Maersk Oil Qatar AS, according to an agreement with Qatar General Petroleum Corporation (QGPC). Maersk Oil had only eight months to design and acquire a 3D survey that would provide a 25 km^2 [9.6 sq mile] image, requiring about 49 km^2 [18.8 sq mile] of full fold data, and to spud a vertical development appraisal well. Given the tight schedule—processing alone normally takes a year—Maersk Oil contracted a survey evaluation and design study based on existing VSPs and 2D surveys. This study was more extensive than the previous example, with more preexisting data, particularly well data.

The objective of the 3D survey was to produce a stratigraphic image of the Kharaib limestones and a thin 13- to 15-ft [4- to 4.6-m] thick overlying oil-filled sand. The seismic data were to be analyzed for porosity-related amplitude variations along with small-scale faulting and fracturing to help in planning the trajectory of future horizontal wells. The acquisition vessel had already been contracted, limiting the seismic source to a 1360- or 1580-in.^{3} [22,290- or 25,900-cm^3] air gun.

Evaluation of existing data indicated areas where special care had to be taken to ensure a successful survey. For example, high-velocity beds at the seafloor promised to cause strong multiples, reducing the energy transmitted to deeper layers and

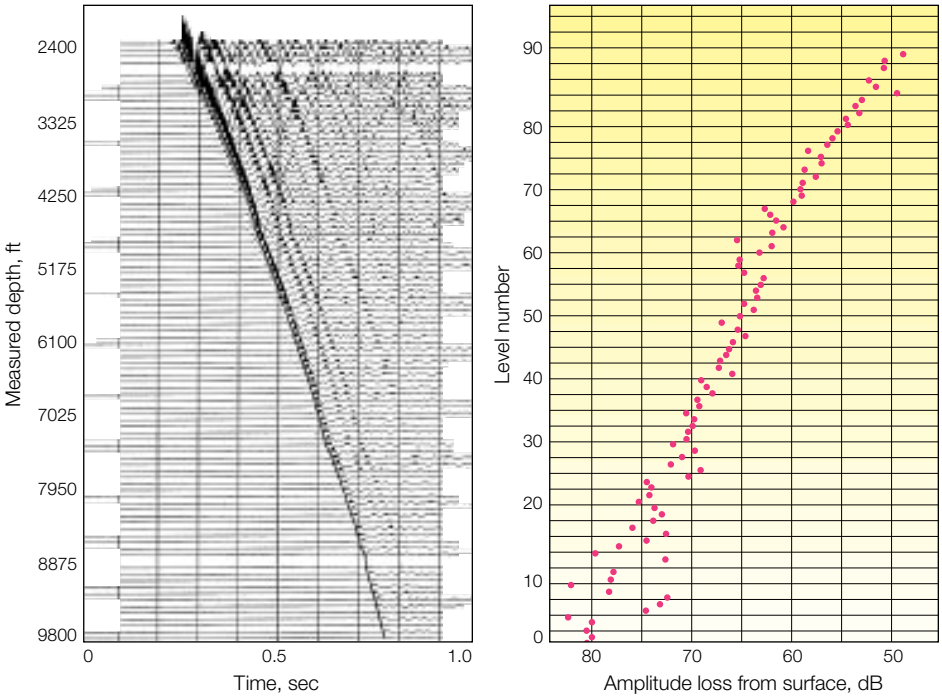


Bandpass filters on VSP data showing energy present up to 80 to 100 Hz at target. Each panel passes a different band of frequencies. Coherent energy up to 80 to 100 Hz reflects from the survey objective at 0.8 sec.

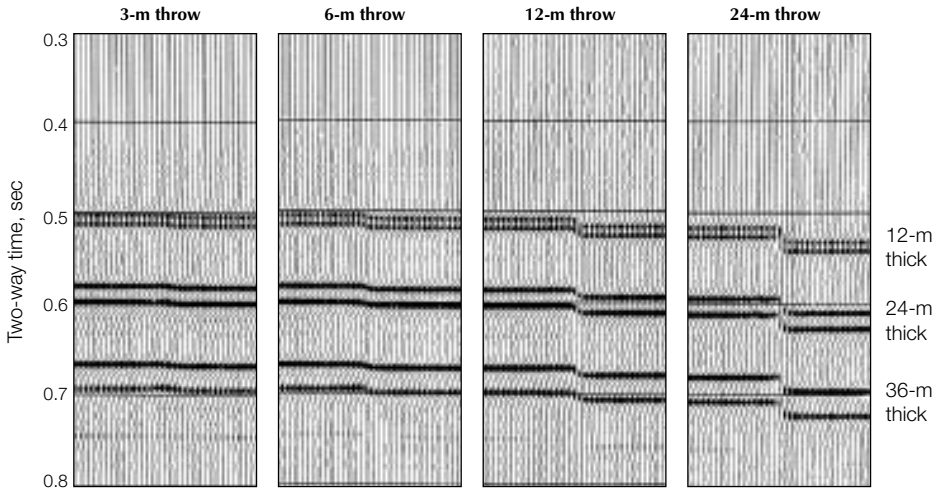
leading to strong reverberations in the water layer. A bandwidth of 10 to 90 Hz was required to resolve the thin sands above the target and the small faults within it.

Evaluation of existing borehole data offered valuable insight into the transmission properties of the earth layers above the target and the geophysical parameters that could be obtained at the target. Comparison of formation tops inferred from acoustic impedance logs with reflection depths on the two VSPs allowed geophysicists to differentiate real reflections from multiples. Identification of the origin of multiples allowed the acquisition and processing parameters to be designed to minimize their effect. Analysis of the amplitude decrease of the VSP downgoing first arrivals quantified transmission losses (*right*). Bandwidth studies on the VSPs showed that frequencies in the 80- to 100-Hz range were present and being reflected at the depth of the target (*above*). This meant the frequencies required for thin-bed resolution might be obtainable by the 3D survey.

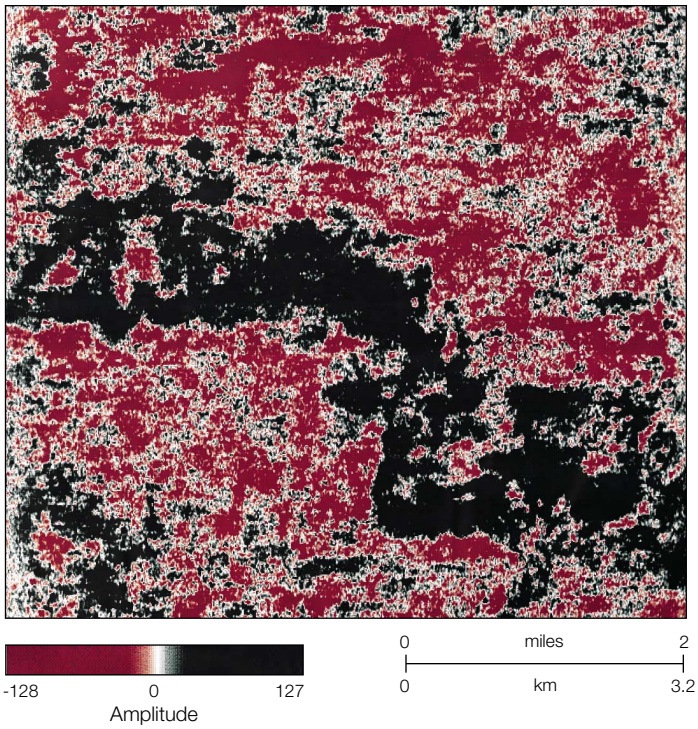
The study also looked into quantifying the seismic resolution of small-scale faulting (*next page, top*) and analyzed five different



Vertical seismic profile (VSP) traces** (left) **analyzed for amplitude loss with depth** (right). **Amplitudes of first arrivals recorded in a 92-level VSP are calibrated with amplitudes of a surface reference signal to account for changes in source amplitude from level to level. The amplitude ratio from one level to the next is plotted in decibels (dB). One dB is 20 times the log of the amplitude ratio. An amplitude ratio of 100 is equivalent to 40 dB. Amplitudes expected from a surface seismic survey would normally be 3 dB less than those from a VSP, and scaled by a reflection coefficient.



Resolution of thin beds and small-scale faulting. Each panel shows the modeled response of a seismic wave of 48-m [160-ft] wavelength (λ) to a different vertical fault displacing a series of thin beds of thicknesses 12 m, 24 m and 36 m. From left to right, faults with 3-m [10-ft], 6-m [20-ft], 12-m [40-ft] and 24-m [80-ft] throws correspond to $\lambda/16$, $\lambda/8$, $\lambda/4$ and $\lambda/2$, respectively. A fault throw of at least 12 m, corresponding to $\lambda/4$, can be resolved quantitatively. At less than that, existence of a fault can be detected, but its throw resolved only qualitatively.



A time slice from Maersk Oil Qatar 3D cube showing fractures and faults.

energy sources, source and streamer depth, spatial sampling and minimum and maximum offsets. Some of the early 2D lines were reprocessed to evaluate migration requirements and techniques for removing multiples.[15] Five recommendations were offered for survey acquisition:

1. A target frequency of 90 Hz is a reasonable objective and can achieve the desired resolution.
2. Multiples reverberating in the water will create severe problems. Offsets longer than about 1000 m [3280 ft] may not be useable because they will contain multiples indistinguishable from the target signal.
3. Of the available sources, the 1580-in.^{3} source would be preferred to the 1360-in.^{3} source because of its higher energy output at the important higher frequencies. This, however, is subject to the ability of the larger source to be cycled at a 12.5-m [41-ft] shotpoint interval.
4. Receiver intervals of 12.5 m and shotpoint intervals of 12.5 m should sufficiently sample the signal and the expected noise, allowing further reduction of noise during processing. These intervals provide sufficient fold to achieve the desired S/N within the 10- to 90-Hz bandwidth.
5. Because the primary reflection and multiples cannot be discriminated by differences in their velocities, stacking may not adequately attenuate multiples. Additional demultiple processing may be necessary.

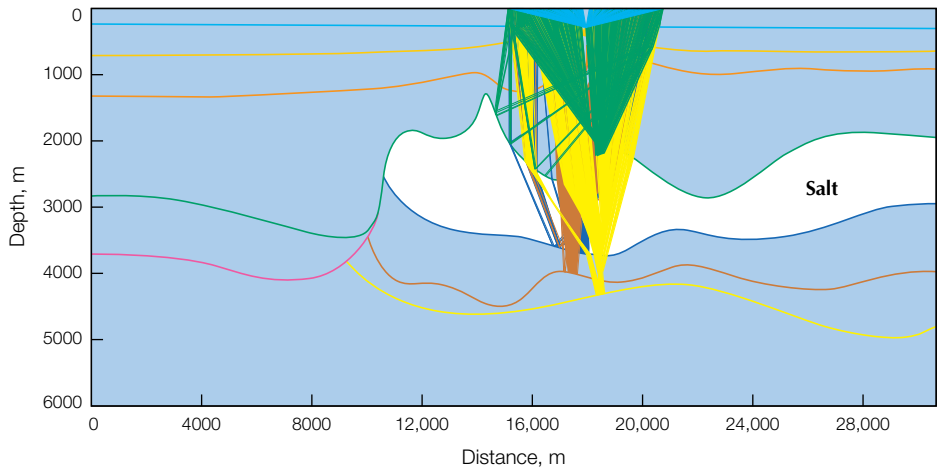
All the survey design recommendations were implemented except the larger source, which for technical reasons could not be towed as planned.

The survey acquired superb data. Maersk Oil Qatar drilled the vertical well on time and based on interpretation of the new seismic data, spudded two horizontal wells—one with a 10,200-ft [3120-m] long horizontal section. The 3D data show fine-scale faulting and two fracture sets (*left*). Fault location prediction based on interpretation of the 3D data was confirmed during

drilling. Faults with throws as little as 8 to 10 ft [2.5 to 3 m] interpreted in the seismic data were verified by on-site biostratigraphic evaluation of the reservoir limestones.

In addition to these two surveys, Geco-Prakla has conducted more than 30 other survey evaluation and design studies, sometimes with surprising results. In one case, analysis of tidal currents led the team to propose a change of 120° in shooting direction, which would add $150,000 to the processing cost, but cut 45 days and $1,500,000 off the acquisition cost, for a savings of $1.35 million. In another study, analysis of previous seismic data showed that coherent shot-generated noise was aliased at shot intervals of 37.5 m [123 ft]. Although it would increase acquisition and processing costs, a denser shot interval of 25 m would sample the noise sufficiently to allow removal during processing. The 37.5-m shot spacing was used in the survey, giving data that required extra prestack processing costs, which did not entirely eradicate the noise.

In a study with Schlumberger Technical Services in Dubai, UAE, data from a VSP acquired just before a marine 3D survey helped optimize planning.[16] In a deviated production well near the center of the survey, a slimhole TWST Through-Tubing Well Seismic Tool was run through tubing to the reservoir to record shots fired from the seismic source to be used in the 3D survey. The shot records allowed geophysicists to determine the effects at the depth of the target of source parameters such as air-gun volume, depth and pressure. The records also showed that at far offsets, high amplitude shear waves contaminate the traces. With a shorter receiver cable, a better survey was acquired in less time, and so for lower cost, than originally planned.



☐***Raytrace modeling showing strong changes in reflection paths through salt. Traces that would have a common midpoint in a flat-layered earth no longer bounce in the same bin. Salt, with its ability to deform and its high seismic velocity, creates complex structure and strong refraction, or ray bending.***

☐***Ship Shoal South Addition in the Gulf of Mexico.***

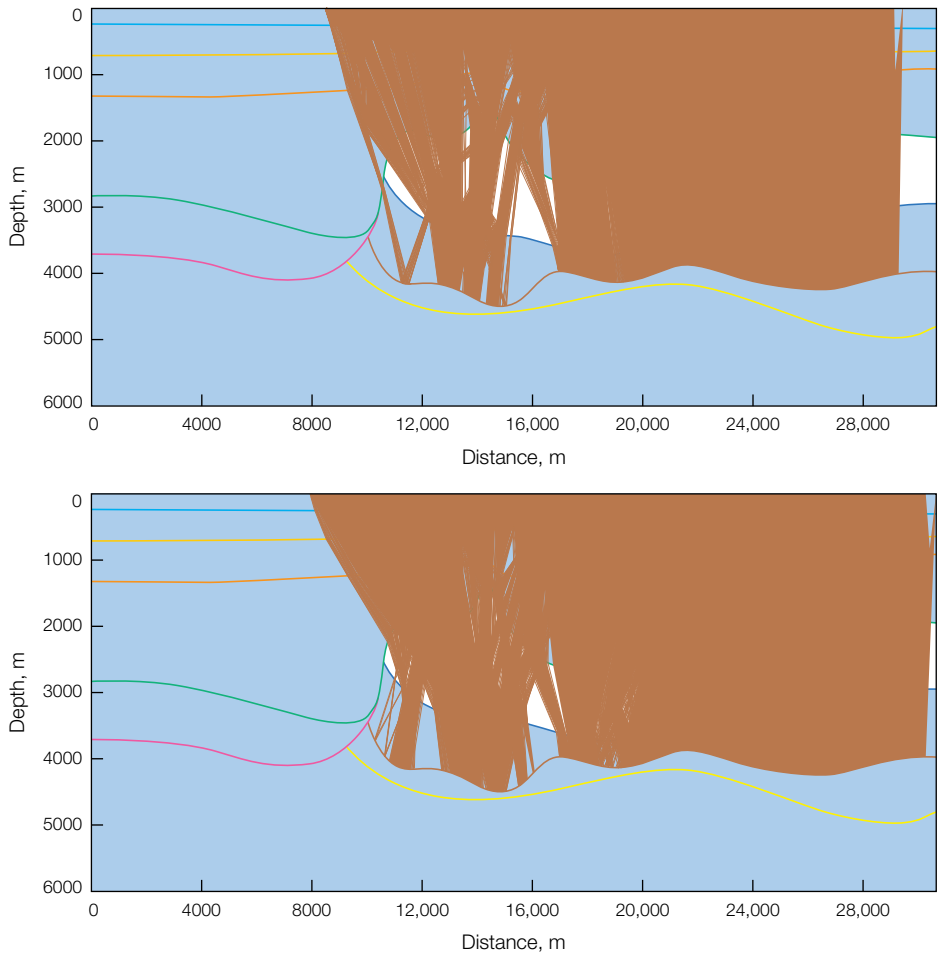
For the Future

Some of the advances to be made in 3D survey design have origins in other fields. VSP design routinely models seismic raypaths through complex subsurface structure, but rarely does surface seismic design account for structure. Despite considerable sophistication in 3D data processing, most 3D survey design assumes plane layer geometry in the subsurface to calculate midpoints and target coverage. But to estimate subsurface coverage adequately in complicated structure, survey designers recognize the need to model raypaths, and some are beginning to do this. Geco-Prakla has used raytrace modeling to determine coverage in a survey to image below salt in the Ship Shoal South Addition in the Gulf of Mexico (*left*).

Salt introduces large contrasts in seismic velocity, bending and distorting seismic rays along complex paths (*top*). Survey designers anticipated that a super-long receiver cable would be required to provide adequate coverage of the subsalt layers. They tested various cable lengths by shooting raypaths through a geologic model derived from 2D

15. Migration, sometimes called imaging, is a processing step that rearranges recorded seismic energy back to the position from which it was reflected, producing an image of the reflector.

16. Poster C: "Taking the Pulse of 3D Seismics," *Middle East Well Evaluation Review*, no. 13 (1992): 6-9.



Raytrace modeling to optimize cable length. Refraction through salt may mean a longer cable is required to image structure below. Two cable lengths, 8075 m** (top) **and 5425 m** (bottom) **were tested using the model on the previous page. Surprisingly, in this case both cables give similar coverage of subsalt horizons.

seismic data (*above*). Surprisingly, a standard 5425-m [17,794-ft] cable provides coverage similar to that of the proposed 8075-m [26,500-ft] cable.

Another advance may come through integration of survey design with acquisition, processing and interpretation into a single quality-assured operation. The aim is to maximize cost-effectiveness of the overall seismic survey, to supply quality-assured processed data with minimum turnaround time and optimal cost. Within Geco-Prakla, this idea is called Total Quality 3D, or TQ3D. Such surveys may be acquired on a proprietary (exclusive) or a speculative (nonexclusive) basis, or a combination of the two. For example, 75% of a 700-km^2 [271-sq mile] TQ3D survey in the southern UK continental shelf will be delivered as proprietary data to three oil companies. The remaining 25% is nonexclusive, and although sponsored in part by the current players in this area, the data will also be available to new players.

Defining the objectives of a TQ3D survey can be a difficult process. Rather than hazarding a guess at which reflectors in an area are the sought-after targets, Geco-Prakla planners involve proprietary and nonexclusive clients at early stages of the project. Over open acreage they examine a data base of nonexclusive 2D seismic surveys to learn about the targets.

Choosing acquisition parameters that will be optimal over the entire survey is also a challenge. It is not always practical to follow all the recommendations proposed by a survey evaluation and design study, but a judgment can be made of the impact that any decision will have on the quality of the data. Then, other options can be explored. For example, in a recent TQ3D survey, steeply dipping reflectors in 20% of the area would have been optimally sampled if the receiver spacing had been reduced from 25 m to 20 m [66 ft], but the 25% additional cost was unacceptable to clients. Having flagged this as an area where data quality could be improved, attention will be paid to processing that may help imaging of steep dips.

As oil companies and service companies strive for efficiency and acquisition of high-quality, cost-effective seismic data, more emphasis is being placed on survey design. The other pieces of the seismic puzzle—acquisition, processing and interpretation—have all benefited from advances in technology, and survey design is following the trend. Through powerful modeling and integration of log, VSP and surface seismic data, 3D survey design will become the foundation for all that follows. —LS