Facilitating technologies for permanently instrumented oil fields

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It is a commonplace of technological advances that each improvement in technology relies on a host of enabling, or facilitating, subtechnologies. In pursuing a lofty goal (such as putting a man on the moon or monitoring fluid flow in a petroleum reservoir), a large number of intermediate problems must be overcome. In the case of the space race, enormous numbers of supporting technologies were created to solve problems ranging from keeping pumps operating (while passing liquid oxygen!) to keeping small objects from floating free in the capsules. Unfortunately, the oil business cannot afford the NASA strategy—funding multiple technology paths and picking the most appealing result. Instead, the best "fit for purpose" technology must be prudently chosen from the field of possible contenders.

At Texaco, we have installed a set of four-component receivers on the ocean floor at Teal South Field in the Gulf of Mexico. An earlier *TLE* article (October 1998) provides some background on this experimental time-lapse test site. The project has been passed on to a not-for-profit research group (Energy Research Clearing House) and is open to both industrial and academic research partners.

Time-lapse analysis at Teal South was facilitated by a number of support technologies, but we will confine ourselves to the most prominent facilitating technologies in the three traditional specialties of seismology—acquisition, processing, and interpretation.

Acquisition. Low-cost computing and semiconductor manufacturing are, not surprisingly, affecting the way we do business in seismic reservoir monitoring. The development of reliable and inexpensive solid-state microprocessors and memory makes possible the severing of functions traditionally linked to one contractor (e.g., providing integrated sensor, telemetry, recording equipment, and seismic source). This can be accomplished through remote recording buoys and platform recording stations that take advantage of the benefits offered by permanently emplaced sensor grids (Figure 1).

In the Teal South phase I configuration, four east-west cables were laid on the seafloor. Each was temporarily connected to a recording buoy during acquisition. We stress the temporary aspect of connection, because the truly expensive part of the recording system (the recording buoy) is required on-site only during the shooting of the seismic data. The relatively inexpensive (analog) cables are detached from the buoys after shooting is finished and then "put to sleep" on the seafloor to await awakening for the next seismic survey. Only three cables were put to sleep after phase I because one had been damaged in postsurvey experiments.

At Teal South, during the 18 months between the first phase I acquisition (August 1997) and a trial "wake-up" cruise (January 1999), two cables were lost, presumed to have been dragged away by fishing activities. Obviously, other support technologies were needed to ensure cable safety

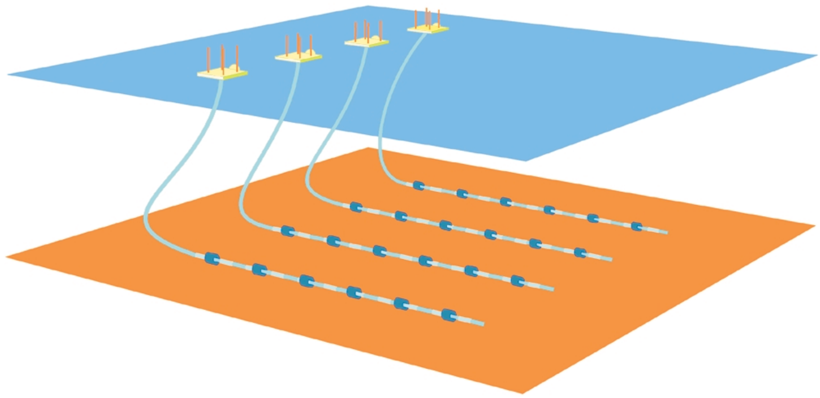

Figure 1. Schematic of distributed data acquisition system. Expensive recording buoys are attached to inexpensive seismic cables for the duration of the survey. The buoys are then detached and used at other survey sites, while the cables are put to sleep until the next survey. (Courtesy of Western Geophysical.)

Figure 2. The front of the Oceaneering ROV in its aluminum holding cage on deck. Black manipulating arms can be clearly seen. This picture does not capture the grace and power of the ROV as it moves underwater, autonomous save for its telemetry umbilical.

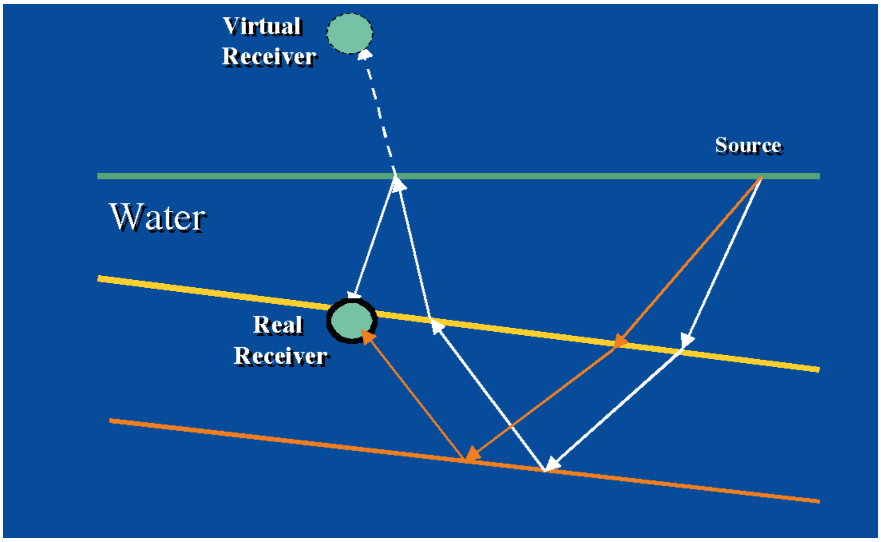

Figure 3. Fundamentals of mirror migration.

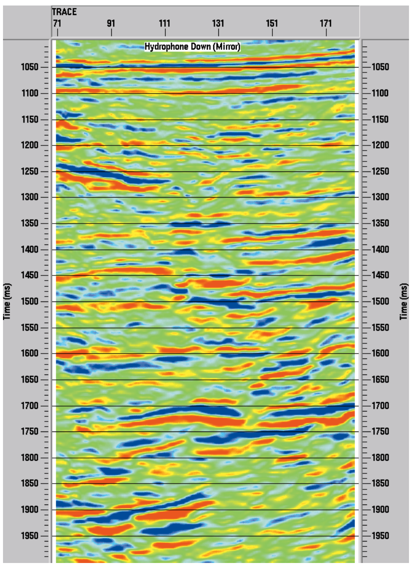

Figure 4. Hydrophone data after mirror (downgoing) migration.

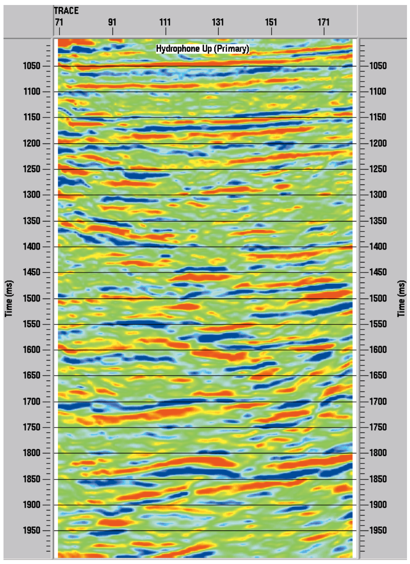

Figure 5. Hydrophone data after conventional (upgoing) migration.

during "sleep." Acoustic positioning of the sole remaining cable at Teal South indicated it had been snagged and dragged from the end of another cable attached to the acoustic pop-up buoy. Because the pop-up buoy stands proud in the water column, an obvious strategy was to reduce the profile of the pop-up buoy. Trawler-resistant mounts were constructed to allow nets to pass over future-deployed pop-up buoys without snagging.

Seven new cables were constructed for deployment prior to phase II acquisition. However, the possibility remained that a net would grab the cables themselves. A company with experience in trenching telecommunications cables (Oceaneering) volunteered to entrench about 6 km of the seismic cable system before the phase II acquisition. The trenching involved use of a sophisticated remotely operated vehicle (Figure 2), roughly the size of a large U.S. sport-utility vehicle (and only a few dozen times more expensive!). The initial plan was to use visual observation of the cable to guide trenching. Fortunately, a backup plan had been included; it turned out that the seafloor was covered by 20 ft of turbid water, and visibility was less than 2 ft. The backup plan, which worked flawlessly, involved using a differential magnetometer to detect a lightly magnetized chain taped to the cables.

Processing. Conventional processing (i.e., redatuming, CMP stacking, and poststack migration) could be applied to the data from a permanently instrumented offshore survey, but this strategy usually will not yield the best result. Due to the cost of instrumentation, receiver intervals are larger than in a conventional survey. This produces irregular offset distributions throughout the image area and a strong acquisition footprint in the shallow part of the subsurface image.

One important feature of such data is that the first multiple (downgoing) has the same amplitude as the primary reflection (upgoing). Such a multiple is usually treated as coherent noise to be eliminated. However, many projects at Texaco indicate that water-column reverberations can be useful. If treated properly, downgoing reverberations provide better imaging than upgoing reflections because of better coverage of the subsurface area, especially in deep water. Others (Godfrey et al., 1998) also report this.

Prestack depth migration in the common receiver domain (which allows shots and receivers to be placed at different datums) provides a convenient way of imaging both the primary reflection and first multiple. Primary reflections can be imaged by treating the receiver as being on the seafloor ("upgoing image"). The first multiple can be imaged ("mirror migration") by treating the receiver as being above the water surface, at the virtual position of the actual location if "mirrored" by the water surface (Figure 3).

Using the multiple will increase fold and improve the footprint situation. The increased processing time associated with adding mirror migration is not significant, because it shares the same input data as normal migration. How much we can benefit from using the downgoing image of the multiple depends on the water depth. For shallow water, where traveltime differences between primary and multiple are small (relative to the wavelet duration), mirror migration will be of little value. In deeper water, where traveltime differences between primary and multiple are large, mirror migration can substantially improve the final migrated image.

3-D prestack depth migration was performed on both the Teal South hydrophone and geophone data. The mirror migration image of the hydrophone data (Figure 4) is slightly better than the conventional migration (Figure 5). The real improvement comes via stacking these two images (Figure 6), which results in an image with a fold effectively twice that of Figures 4 and 5. Then the process is repeated for the geophone data, and all four images (conventional and mirror migration of hydrophone and geo-

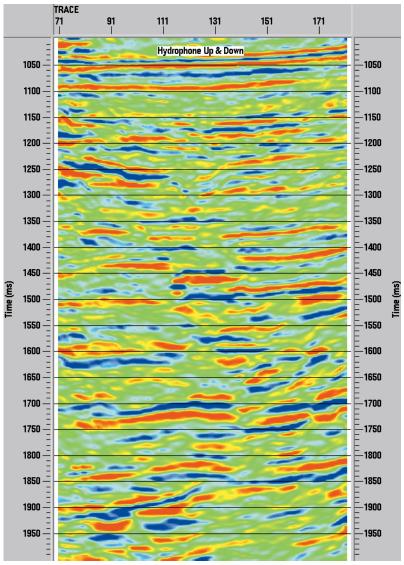

Figure 6. Hydrophone data after summation of conventional and mirror migration images. Fault resolution is substantially improved relative to either conventional or mirror images alone.

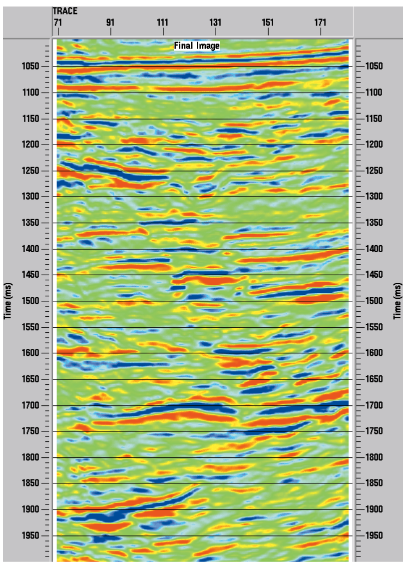

Figure 7. Hydrophone and geophone data summed after conventional and mirror migrations. The result is even better fault resolution than the hydrophone-only summation of conventional and mirror migrations in Figure 6. This image has an effective fold four times that of Figures 4 and 5, and twice that of Figure 6.

phone data) are summed to produce a final image (Figure 7). Fault resolution can be seen to have substantially improved in Figure 6 (hydrophone summation of conventional and mirror migration) relative to either Figure 4 or Figure 5. And Figure 7, the summation of conventional and mirror

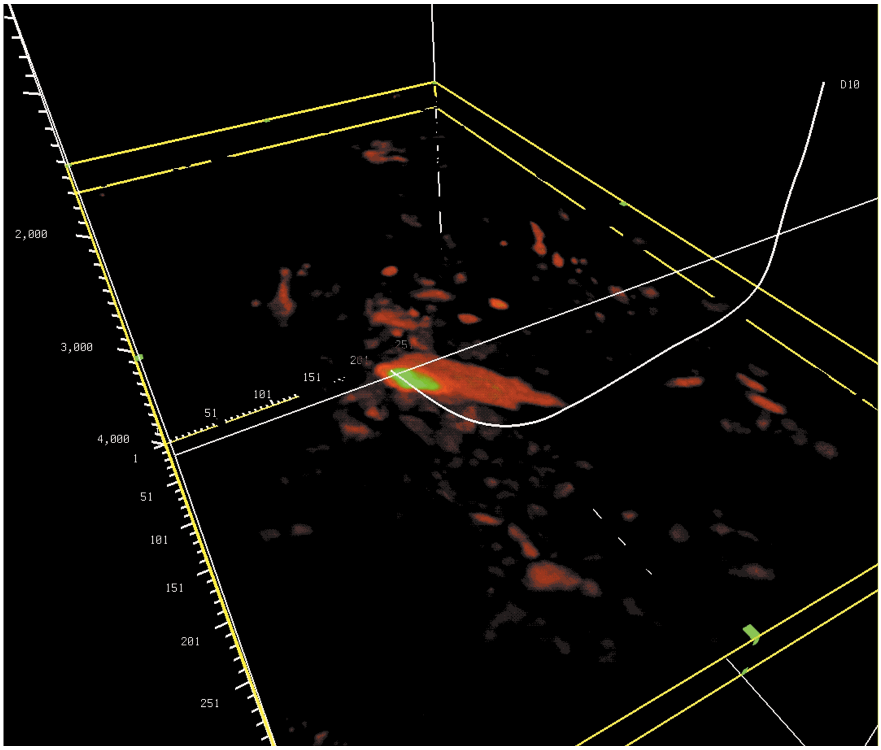

Figure 8. Visualization of difference cube looking west. Well track of D10 well is also shown intersecting with the southern end of the difference anomaly.

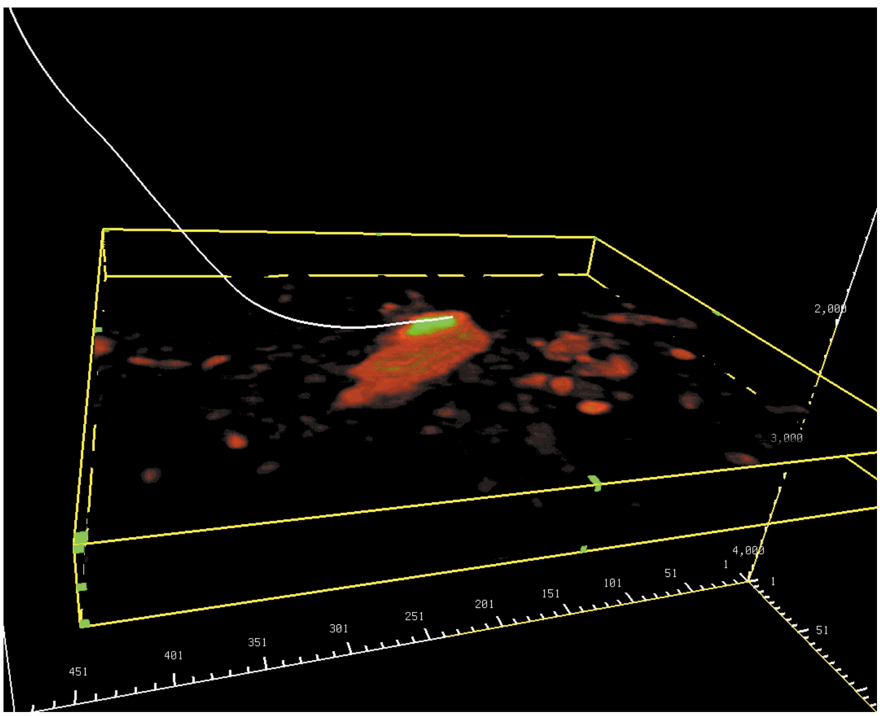

Figure 9. Visualization of difference cube looking south. Note shallow dip on top of difference anomaly.

migration for both hydrophone and geophone, has the best fault resolution of all.

Interpretation. Texaco's visualization team, led by Mike Zeitlin, has produced a "visionarium" in which seismic-derived volumes of data can be quickly analyzed. Much of its power comes from the ability of interpreters to develop a 3-D sense of the data in their "mind's eye." Because projections are 2-D, rotations of the data are essential to get a correct spatial sense. The visionarium's high-speed computing and software capabilities allow

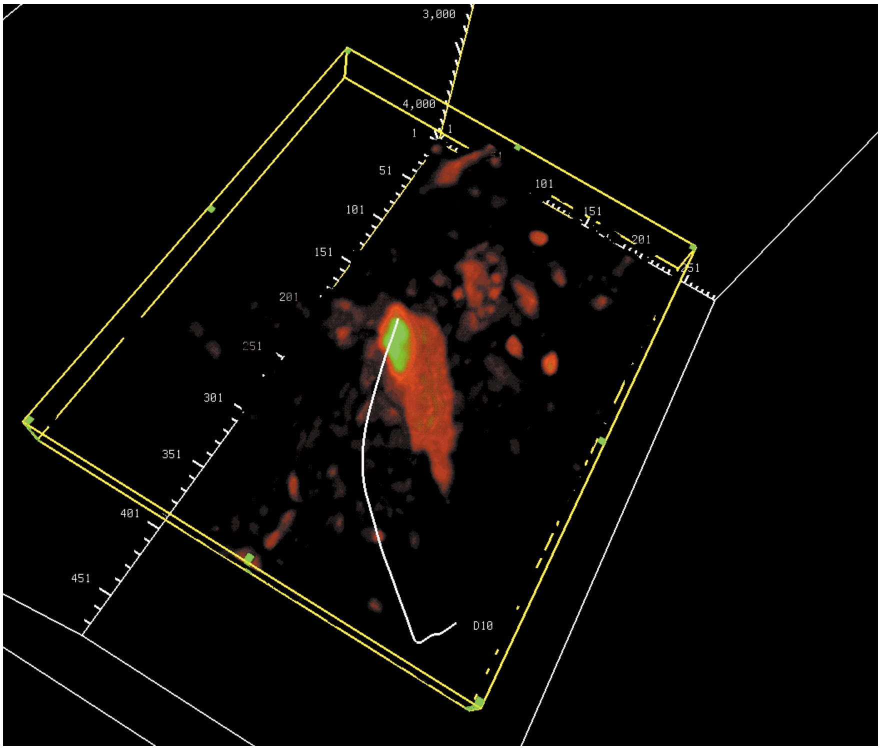

Figure 10. Visualization of difference cube looking down (southeast to the left).

images to be rerendered—under the control of the interpreter—several times a second, thus providing the illusion of real-time rotation.

Although no paper image can entirely capture the dynamic sensation of user-directed rotation, we include three images of a time-lapse difference cube from Teal South. (The difference cube shows the changes in *P*-wave seismic amplitude between the preproduction survey and the phase I OBC survey.) Additionally, the visualization software is able to superimpose the well track of the producing well (D10) over the difference cube. All data are in controlled opacity mode, where smaller data (difference) values are transparent and larger values are opaque. Figure 8, the difference cube looking to the west, shows the well intersecting the upper southern end of the difference anomaly. Figure 9, an oblique view looking south, gives a better sense of the shallow dip on the top of the difference anomaly zone. Figure 10, a bird's-eye view, captures the lateral geometric relationships of the well and the difference anomaly.

The future. Installation of permanent seismic receiving systems at offshore oil fields has been limited to date to BP's Foinaven Field in the North Sea and Teal South. However, most technical obstacles appear to have been addressed, and there is little question that permanent instrumentation can be installed and utilized successfully. A tougher question is the economic angle. Oil companies are driven financially by the need to produce oil as early in a field's life as possible. For smaller fields, depletion rates may make application of time-lapse seismic monitoring infeasible. The most likely candidates for permanent instrumentation, then, are the largest offshore oil fields. These "elephants," increasingly found in deep water, will provide the incentive to produce permanent instrumentation that can be deployed and utilized in increasingly deeper waters. The supporting technologies are in place, awaiting the right opportunities and the right champions to recognize those opportunities. LE

Acknowledgments: We thank Roger Entralgo of the Energy Research Clearing House for the photo of the ROV. Dan Ebrom thanks anonymous informants (the "Rotisserie for Beef and Bird" Five) who provided background information on the state of the industry as regards permanent seismic instrumentation at offshore oil fields. We thank Bob Tatham, formerly of Texaco EPTD and now the Shell Centennial professor of geophysics at the University of Texas, for continuing advice.

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