Porosity prediction from seismic inversion, Lavrans Field, Halten Terrace, Norway

David M. Dolberg, Mobil Exploration Norway, Stavanger, Norway
Jan Helgesen, Tore Håkon Hanssen, Ingrid Magnus, Girish Saigal, and Bengt K. Pedersen, Saga Petroleum ASA, Sandvika, Norway

Lavrans Field lies offshore Norway on the western extreme of Halten Terrace, 15 km south of Smørbukk Field (Figure 1). Exploration in this area has been extremely active, yielding two large gas and condensate discoveries within Petroleum License 199—Lavrans Field to the east and Kristin Field to the west. Combined reserves are approximately 1200 million barrels oil equivalent of gas and condensate. Unique conditions have come together to provide hydrocarbons and preserved porosity at depths greater than 5 km.

Hydrocarbon-bearing sandstones at Lavrans have a thickness of 600 m. These reservoirs consist of shallow-marine deposits of Jurassic age. Although the facies can be laterally extensive, the overprint of diagenesis makes prediction of reservoir quality difficult. Seismic inversion provides insight to porosity variations away from limited well control. Thus, seismic inversion can be a valuable tool for reservoir characterization prior to field development. This study developed out of a need to better understand the significance of seismic amplitude variations over the crest of Lavrans Field (Figure 2). Hypotheses examined to explain amplitude variations were fluid effects, porosity, pressure changes, or processing and illumination artifacts.

Seismic inversion. One method chosen to better understand the amplitude variations was 3-D seismic inversion. This was carried out using CGG's 3-D inversion package TDROV (Gluck et al., 1997), which combines seismic information with an a priori model. Acoustic impedances are produced in thin microlayers. For the inversion to be as accurate as possible the 3-D seismic volume ideally would be multiple free, zero-offset, migrated, and (preferably) zero-phased. The seismic wavelet is extracted from the data via a matching filter between the synthetic trace derived from the impedance log and the seismic trace at the well location. The a priori model is then constructed from well-log information combined with interpreted horizons. The a priori model attaches time and impedance values to the primary interpreted horizons. The output seismic inversion is brought back into the workstation, where consistency with input horizons and well-derived acoustic impedances serves as quality control. Figure 3 shows the inverted acoustic impedance along the same conventional seismic line as in Figure 2. Note that the amplitude anomaly identified below the Top Ile reflector in Figure 2 corresponds to a low-acoustic impedance anomaly in Figure 3. Figure 4 illustrates both input and inverted acoustic impedance responses for the two well locations. Due to drilling restrictions, the lower part of well 6406/2-1 was left open for several months. This led to extensive cave-ins and poor log measurements. Well 6406/2-2 had the best log data quality and was therefore used for wavelet estimation. The best match between input and modeled results lies in the interval between the Top Ile and Top Tilje markers. This interval includes two of the most important reservoir units at Lavrans, Ile, and Tofte formations. The third important reservoir unit is the heterolithic Tilje Formation. However,

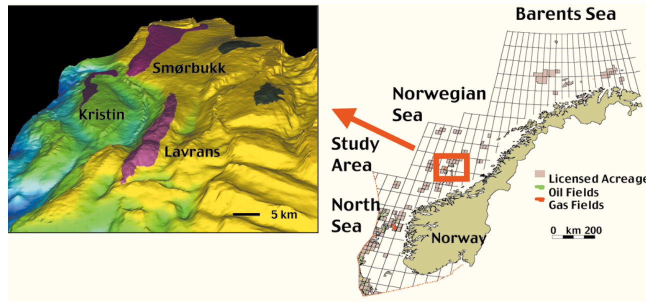

Figure 1. Lavrans and Kristin fields relative to Smørbukk. Field outlines (rose) are drawn on the map of the Base Cretaceous Unconformity. View is to the north.

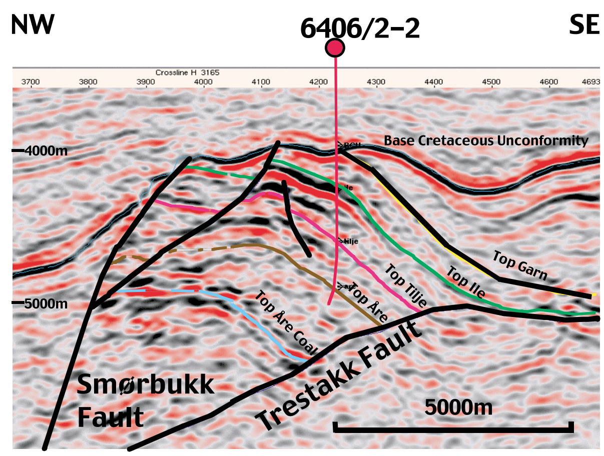

Figure 2. Cross-line 3185 is a dip line through well 6406/2-2. Seismic anomalies are seen below the Top Ile Formation. Understanding the meaning of these amplitudes was a primary motivation for this study.

small acoustic impedance separation between poor and good reservoir in this formation limited the potential of seismic inversion here.

Rock physics. To understand the effect of porosity, pressure, and fluid type on seismic velocity, 3 core plugs were taken from well 6406/2-1 and 11 from well 6406/2-2. Measurements of porosity, permeability, grain volume, grain density, and ultrasonic V_P and V_S were made in the laboratory. Interpretation of *P*- and *S*-wave sonic logs, and log estimates of porosity, shale velocity, density, and saturation were also done. Acoustic impedance is a function of both density and velocity. Density variations have some impact on acoustic impedance, but velocity variations are much more significant. Lab data indicate that at depths greater than 4000 m, velocities are most sensitive to changes in porosity. Velocity changes resulting from changes in fluid type or pressure are small in comparison. Figure 5 shows ultrasonic V_P and V_S versus porosity at 20 megapascals (MPa). This graph illustrates that a V_P reduction resulting

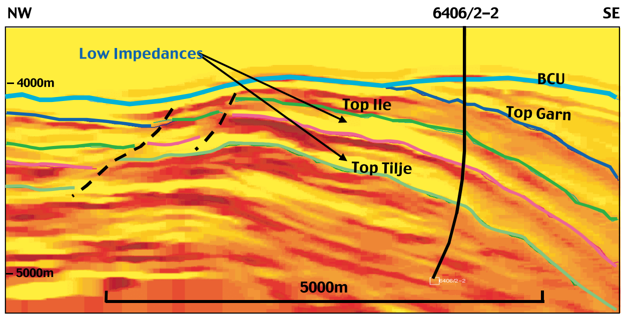

Figure 3. Cross-line 3185 through well 6406/2-2 showing acoustic impedance. The high amplitudes in Figure 2 are in yellow and represent low acoustic impedances. The rock physics study showed that this indicated higher porosities.

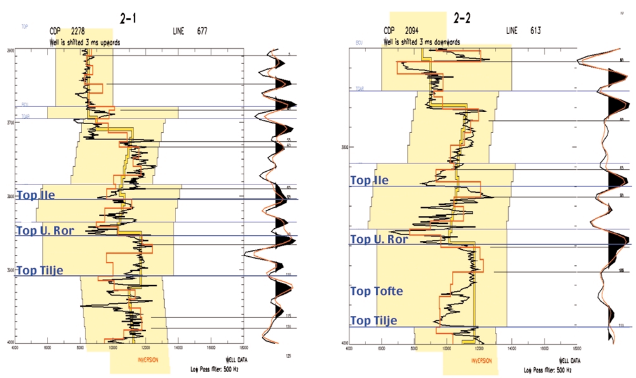

Figure 4. Final inversion results for wells 6406/2-1 (left) and 6406/2-2. Black curves within the yellow band represent log-measured acoustic impedance. Red, blocky curves represent the modeled acoustic impedance response. The double line dark yellow curve is the modeled low frequency at each well. The yellow band defines an area where no penalty is applied in the error function for the inversion. Outside the yellow corridor, soft constraints are applied. The seismic response at each well is on the right. The red curve on the right is the synthetic modeled trace.

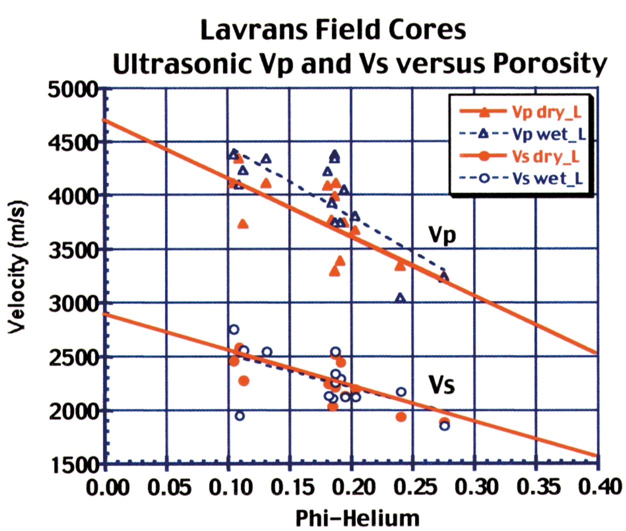

Figure 5. Velocity changes resulting from a porosity increase of 0 to 35% are greater than 1500 m/s.

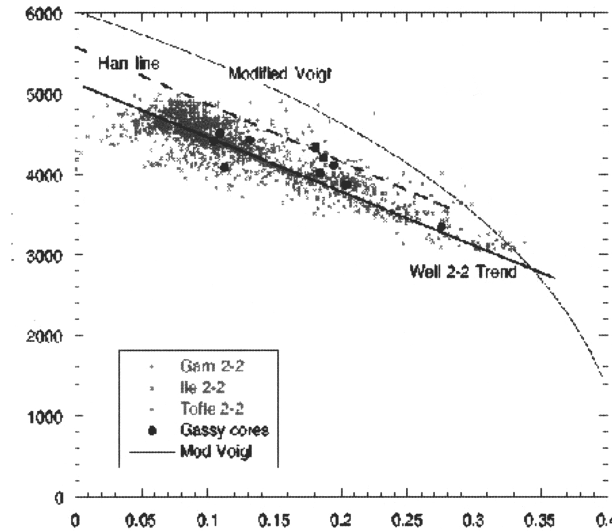

Figure 6. V_P versus porosity from Lavrans core and log data plotted with trends found in other studies.

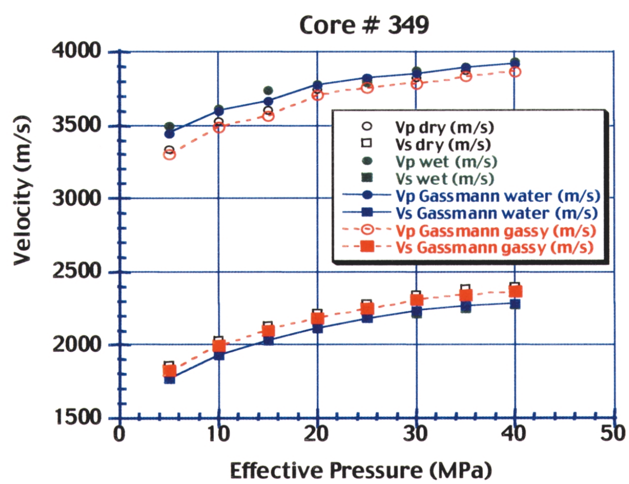

Figure 7. Velocity is plotted against effective pressure for various fluid states for one sample. Results are similar for other samples. There is increasing separation between water-saturated and gas-saturated samples as pressure decreases. At 10 MPa, the maximum velocity change is 100-150 m/s. At Lavrans Field the effective pressure is at 50 MPa. Thus, porosity's effect on velocity is at least 10 times more significant than velocity change related to fluid and pressure.

from a change in porosity from 0 to 35% would be more than 1500 m/s. Figure 6 illustrates that V_P values taken from logs are similar to V_P values from cores in well 6406/2-2. The data are also plotted against trend lines from previous work (Han, 1986; Nur et al.,1991). Han's trend line was derived from many formations at various depths and locations in the Gulf Coast. The mechanism of porosity reduction seen in Han's data is believed to be due to compaction and diagenesis. This plot illustrates that the Lavrans' log and core data are consistent with observations from other formations in other locations. This plot further supports the hypothesis that the V_P-porosity relationship at Lavrans is controlled by diagenesis. V_P-porosity slopes tend to be steep when porosity is controlled by diagenesis and flat in areas when porosity is controlled by grain size (Mavko, 1998).

Figure 7 plots V_P against effective pressure for various

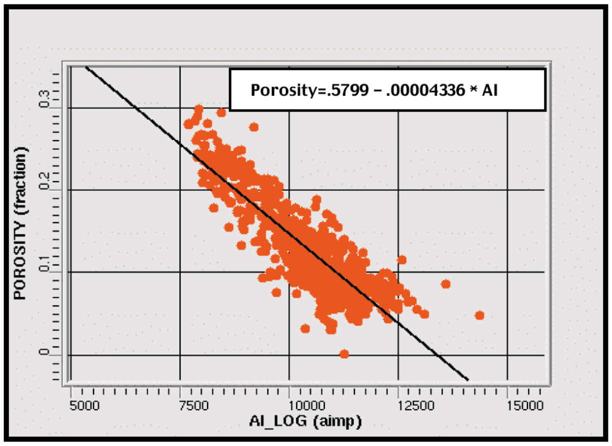

Figure 8. Relationship of acoustic impedance to log-estimated porosity for Ile Formation in wells 6406/2-1 and 6406/2-2. Samples with water saturation greater than 65% have been filtered out.

fluid states. At Lavrans Field, initial effective reservoir pressures are more than 50 MPa (500 bars). As effective pressure decreases, there is a slight increase in velocity separation between water-wet samples and gas-filled samples. This increase in separation can be as large as 100-150 m/s at 10 MPa. As production starts, effective pressures at Lavrans will increase, further decreasing the velocity effect. With these conditions, it is unlikely that initial pressure anomalies or changes in pressure due to production could be monitored with seismic. These rock physics results suggest that neither pressure nor fluid effects have significant impact on seismic response. Differences in acoustic impedance are essentially correlated to variations in porosity.

Satistical analysis and implementation. From the rock physics results, it is clear that a relationship between acoustic impedance and porosity should also exist within the well information. Log porosity data was tied to overburden-corrected core data. These porosity results, density, sonic, gamma ray, Vshale and other log-derived data were imported into SigmaView for bivariate analyses. Crossplotting shows that acoustic impedance is strongly correlated to porosity. Figure 8 shows the relationship of acoustic impedance to porosity for Ile Formation using the two wells from Lavrans Field. Sensitivity analysis shows that maximum correlation between well and seismically derived acoustic impedance occurs at a vertical scale of 15-30 m. At this scale, seismic data predicts porosity with a maximum correlation (R) of .70. The uncertainty in this relationship increases when sampling seismic below this vertical resolution. Therefore, it is important to understand at which scale the seismic can be measured with the least uncertainty (smallest residual). The effectiveness of porosity mapping using acoustic impedances is maximized in sand-prone intervals. Because acoustic impedance values from shales can be similar to those of sands, an understanding of how the stratigraphy correlates to a typical diagnostic vertical acoustic impedance profile is required before acoustic impedance values can be exported from between two horizons. At Lavrans Field, the Ile sandstone reservoir is overlain by the Not Shale, which always exhibits very low acoustic impedance values. The underlying Upper Ror Shale exhibits high acoustic impedances. The acoustic impedance derived from the seismic is plotted against the acoustic impedance encountered within the 6406/2-2 well

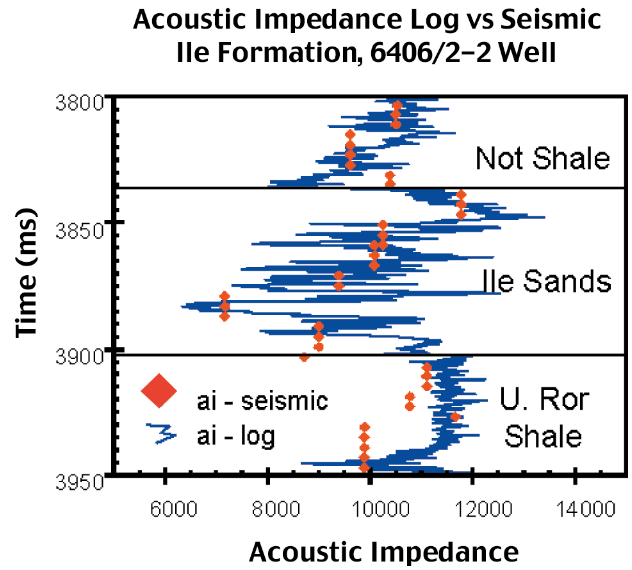

Figure 9. Seismically derived acoustic impedances are plotted beside those derived from well information. The figure indicates that, at Lavrans, acoustic impedance is not a good indicator of lithology. Ile sands are overlain by low-impedance shales and underlain by high-impedance shales. At Lavrans, partitioning reservoir units assures that acoustic impedance values can be correlated to calibrated porosities. Within the Ile package, low impedances mark sands with good porosity.

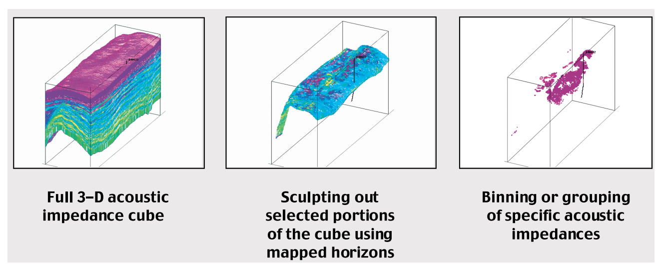

Figure 10. By understanding the acoustic impedance vertical profile, Ile Formation can be partitioned through detailed mapping of acoustic impedance interfaces. These horizons are used to sculpt intervals of interest for determining average acoustic impedance. Additionally, binning or grouping of specific acoustic impedances can isolate reservoir of a specific quality.

to verify that the correct interval is being extracted (Figure 9). Thus, with this understanding, Ile Formation interval can be identified and sculpted out (Figure 10). VoxelGeo outputs average acoustic impedance values for specific sculpted seismic intervals. At Lavrans, the approximate thickness of extracted acoustic impedance zones were on the order of 60 m. 2-D average acoustic-impedance horizons were combined with porosity transforms from the statistical analyses (Figure 8) to yield 2-D pseudoporosity maps. Figure 11 shows how grouping specific acoustic impedance ranges can identify areas with a particular reservoir quality. In this example, only lower acoustic impedances (higher porosities) were selected. Seismic trend data (pseudoporosity) yielded important information for the reservoir engineer, with respect to lateral reservoir quality, and helped the geologist to validate and modify geologic models. Additionally, seismic inversion and pseudoporos-

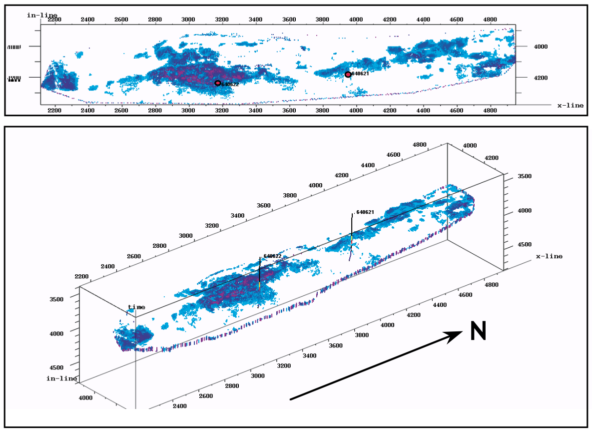

Figure 11. Grouping acoustic impedances into specific bin ranges allows an areal assessment of reservoir quality. In this example from Lavrans, both the 2-D map view (top) and 3-D perspective show impedances of 5500-8800.

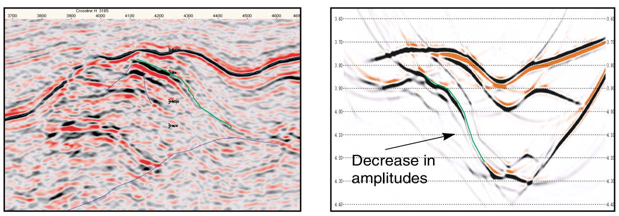

Figure 12. Simple processing of synthetic data from a common-shot survey shows that migration could be affecting amplitude strength.

ity maps provided a methodology for estimating porosity between wells, and helped to identify areas for future well placement.

Quality control. It is evident from Figure 2 that seismic amplitudes tend to decrease on the eastern flank of Lavrans Field. Using the relationships derived from the rock physics and well data, the decrease in reflector strength would be modeled as an acoustic impedance increase or a decrease in porosity. Results from this area became suspect because this increase in acoustic impedance seemed to lie further westward with each successively deeper horizon, was not located at a known hydrocarbon contact, and seemed to exist along a change in dip (Figures 2 and 3). Seismic modeling was designed to test whether some decrease in amplitude may be a result of processing artifacts. Map horizons and velocity layers were used to construct a velocity model. Synthetic seismic was generated, processed, and migrated (Figure 12). Reflector amplitude diminishes as dip increases. Thus, some amplitude decrease on the eastern flank of Lavrans Field may be related to illumination and processing. Another effect, often overlooked, is data degradation because of geometry. Due to the large burial depths (more than 4 s TWT), curvature also affects amplitude strength (Figure 13). Geometry irregularities may cause amplitudes to weaken or strengthen, depending on whether the reflected waves add constructively or destructively. In this example, concave reflectors focus and convex reflectors defocus seismic energy. Thus, modeling indicates that geometry may contribute to the uneven capture of 3-D amplitude data.

Making corrections to the seismic energy in these high-dip areas is possible, but devising a reliable methodology

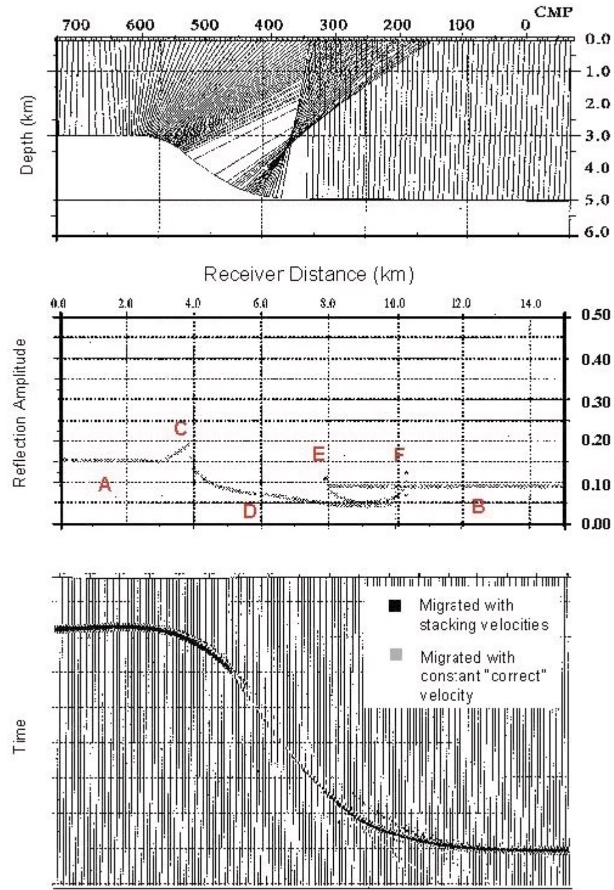

Figure 13. The top and middle figures illustrate how amplitude varies with geometry and distance from the reflector. Differences in amplitude between (A) and (B) are related to distance from the receiver, (C) is a modeling artifact due to irregularities in the geometry of the crest/shoulder, (D) decrease in amplitude due to steep dip (large distance from shot/receiver to reflector), and between (E) and (F) there is a spread of amplitudes related to the concave syncline. The bottom figure shows how migration changes the amplitudes and how the result varies with input velocities. The amplitude decrease seen from the slope is caused by illumination and processing deficiencies.

was considered difficult and costly. Thus, lateral variations noted in these suspect areas were used only for qualitative purposes and not included in trend extrapolations or quantitative reservoir description.

Conclusions. Seismic porosity prediction can improve reservoir characterization by providing information on the spatial variation of the reservoir away from existing well control. Seismically generated maps and volumes have vertical resolution in tens of meters. Thus, seismically derived porosity maps have the effect of averaging vertically, reducing variations in porosity that may be significant at reservoir characterization scale. Therefore, seismic porosities are more appropriately used as a steering component to derive trends, for larger-scale volumetric estimations, and to identify reservoir "sweet-spots." Finer vertical detail, which may be required for reservoir simulation, is perhaps better handled through simulation or stochastic techniques based upon residual distribution (see the following paper on Kristin Field). When applying seismic inversion for porosity prediction, the following procedures are vital to ensure robust and reliable conclusions:

1) Rock physics studies must be conducted to provide the physical basis for understanding how changes in rock and fluid properties will affect seismic response.
2) Statistical analysis of well and core information must show relationships consistent with rock physics studies. In this case, a relationship between porosity and acoustic impedance is documented.
3) Once a trend is established from well data, well information must be upscaled to seismic resolution. An assessment of how accurately seismic predicts well information is required before results can be accurately weighted and their impact understood.
4) Data quality must be assessed. Even though 3-D seismic should maintain absolute amplitude information, assessment of data quality is required to ensure that acquisition or processing problems have not altered amplitude response.
5) Identification of the implementation scale is necessary. Estimation is valid only when features can be resolved by the seismic.

When these procedures have been followed and the necessary conditions met, seismic inversion can add value:

- by providing information on reservoir quality away from the wellbore
- by providing input to geologic modeling
- by ensuring that lateral reservoir heterogeneities are included in reservoir simulations
- as a tool to high-grade well locations and reduce risk
- as a trend tool for porosity mapping

Despite vertical resolution limitations, seismic inversion provides powerful information for predicting lateral variations in reservoir quality, not accessible through well data.

Suggestions for further reading. *Effects of Porosity and Clay Content on Acoustic Properties of Sandstones and Unconsolidated Sediments* by Han (doctoral dissertation, Stanford University, 1986). "Wave velocities in sediments" by Nur et al. (in *Shear Waves in Marine Sediments*, Kluwer Academic Publishers, 1991). "High-resolution impedance layering through 3-D stratigraphic inversion of the post-stack seismic data," by Gluck et al. (*TLE*, 1997). *The Rock Physics Handbook* by Mavko et al. (1998). LE

Acknowledgments: The authors thank the Haltenbanken Sør partnership for permission to publish this paper. Thanks are also extended to CGG in Oslo, Norway, and Gary Mavko from Stanford University for their comments and suggestions.

Corresponding author: david_dolberg@email.mobil.com. Several authors have changed employment since this paper was written. Those authors and their new locations are: David Dolberg, Mobil Oil Canada, Calgary, Alberta, Canada; Jan Helgesen, CGG Norge, Høvik, Norway; Tore Håkon Hanssen, Fortum Petroleum, Oslo, Norway; Ingrid Magnus, Norsk Hydro ASA, Bergen, Norway; Girish Saigal, Norsk Hydro ASA, Oslo, Norway; and Bengt K. Pedersen, Norwegian University of Science and Technology, Trondheim, Norway.