Recent advances in geophysical technology: introduction and review

P. A. F. CHRISTIE1 and E. ROBEIN2

1 Schlumberger Cambridge Research, High Cross, Madingly Road, Cambridge CB3 0EL, UK (e-mail: pafc1@slb.com)
2 Total Exploration Production UK plc, 33 Cavendish Square, London W1G OPW, UK

Abstract: In many basins and especially those in NW Europe, 3D seismic data have become a necessary prerequisite to development, appraisal and, almost routinely, exploration drilling, but equally they are rarely seen as being sufficient. Why is this, when the majority of industry analysts recognize the value of 3D seismic data to an oil company’s exploration portfolio: are geophysicists too successful at marketing? Are we victims of promising too much, or should we see this hunger for ever more subsurface information as encouragement to refine existing technologies further and to develop new ones?

In September 2002, the Geological Society meeting on exploration in volcanic margins heard about a successful strategy of ‘drilling the bumps’, which led to the discovery of the Marijaun hydrocarbon accumulation, the first in Faroese waters. Peter 2002 was told that the biggest UK North Sea discovery for a decade had not used ‘geophysical malarkey’. Is seismic technology inadequate, or has it reached its limits as the targets get ever tougher?

Evidently, as the remaining basins become covered by seismic surveys, the easy finds are becoming fewer. Having consumed roughly half the world’s proven reserves, new reserves must be found using ever more imaginative geological hypotheses, and remote sensing technologies will need to give access to ever more information and provide discrimination to test the hypotheses and reduce the risk.

The quest for resolution is unrelenting and finer spatial sampling is providing significant improvements in imaging. Honouring well information requires more realistic, anisotropic velocity models for pre-stack depth migration which furnish images that are better representations of the drillable geology. The need to qualify the data in a seismic survey has resulted in so many auxiliary measurements of the acquisition system itself that the subsurface data are almost in a minority, but this brings improved, quantified repeatability, with the potential to drive down time-lapse seismic noise and reveal subtle, production-related reservoir changes. Qualified amplitudes and careful control during processing allow inversion for elastic parameters of the subsurface. With good petrophysical and geomechanical models, elastic inversions can benefit both the reservoir engineer and the driller and offer further potential for multi-component acquisition in reservoir characterization. Salt, basalt or complex tectonic overburdens pose their own challenges to imaging and encourage potential field measurements to complement seismic data in velocity model building and the prediction of reservoir rocks or fluids. Very long offsets and very low seismic frequencies may also have a rôle to play in these environments. Breakthroughs in data handling and visualization technology allow us to take full benefit of these improvements.

The stimulus for innovation is as strong as ever and, even if the immediate economic context is uncertain, the industry is responding. This paper will review several of the current technology trends and offer some speculation on the road ahead.

Keywords: seismic imaging, time-lapse data, multi-component, borehole, wide angle, remote sensing, electromagnetic, gravimetry, rock physics, uncertainty

The BP Statistical Review of World Energy (BP plc 2003), covering the calendar year 2002, shows that while primary energy consumption increased by 2.6% in 2002 compared to a global, ten-year average of 1.4%, oil consumption worldwide grew by only one-tenth of one percent. The above trend in consumption was largely due to China’s rapidly growing economy, driving increases of 5.8% in oil, 8.0% in gas and 27.9% in coal. This meant that while the world’s coal consumption in 2002 was up almost 7%, beating a relatively strong rise in gas consumption of 2.8% and outstripping the rise in oil consumption which, according to the BP Statistical Review, has been largely flat for three years. Global coal consumption outside China rose 0.6%, as many OECD (Organization for Economic Co-operation and Development) countries continued to switch power generation to gas, resulting in an OECD gas consumption increase of 2.4%, close to the global average, even though OECD economic activity was weak. OECD oil production rose by 0.8%, but reduced economic activity caused a fall in consumption of 0.6%, representing a much larger volume since OECD oil consumption exceeds production 47 fold. In 2002 world oil production fell 0.7% but, since the USA and OECD countries managed to increase oil production by 0.3% and 0.8%, respectively, it was reduced production by the Organization of Petroleum Exporting Countries (OPEC) – down 6.4% – which contributed towards price stability, with Brent crude averaging $US 25.19 per BBL compared to $US 24.77 per BBL in 2001. With the relative stability and firmness of the oil price over the past 2–3 years, one might expect that the upstream oil industry would be very active in the quest for replacement reserves. However, a perceived fragility to that apparent firmness and a recent folk memory of $US 10 per BBL, engendered corporate caution, exemplified by BP’s switch in 2002 from production growth to net earnings as the metric with which to judge their corporate success. It is admittedly difficult to base a business model over a full economic cycle on geopolitical factors which restrain global economic growth.

production and which are outside corporate control, even if the current phase of the cycle is proving very beneficial to oil company cash flows.

The knock-on effects of perceived price fragility are a focus on cost control, continuing consolidation to enhance reserves inventories through mergers, a cautious approach to exploration, and cost-effective ways to increase recovery factors from existing assets. Booked oil reserves fell by 0.25% in 2002 and it was only the greater fall in oil production (0.7%) which resulted in a slight increase in the global reserves/production ratio to 40.6 years, the first since 1990. It seems that for now, oil companies are placing less emphasis on finding new oil, partly due to the lack of unexplored basins, and more emphasis on getting more oil out of the ground, more cost effectively: a switch from exploration to production optimization which requires new tools and technologies to help achieve the new objectives. Upon this global canvas, the regional picture of NW Europe has oil production from the UK and Norwegian Continental shelves going past their peaks, although Norwegian gas production is still expected to grow. The statistics challenge the industry to consider some longer-term questions: for how long will a reserves-replacement strategy based on improved oil recovery be sustainable? What will happen if China tries to switch its energy mix from coal to hydrocarbons? Can we do anything about the environmental impact if China does not move away from coal?

For the time being, there is anecdotal evidence of the new mind-set: in September 2002, the Geological Society meeting on exploration in volcanic margins heard about a successful strategy of ‘drilling the bumps’, which led to the discovery of the Marjun hydrocarbon accumulation, the first in Faroese waters (Smallwood & Kirk, this volume). Petex 2002 was told that the biggest UK North Sea discovery for a decade, the Buzzard Field found by EnCana (Doré et al., this volume), had not used ‘geophysical malarkey’. Is seismic technology inadequate, are the targets getting ever tougher, or is it that the geophysical expertise is being siphoned off from the exploration groups and applied to the production teams? Perhaps the anecdotes on testing good geological hypotheses simply reflect the discoverers’ determination to show that exploration plays can be successful without geological de-risking. Evidently geophysicists have a challenge to show that, properly applied, there are tools and techniques which can help to reduce risk, to enhance production and to address some of the environmental issues in the current business context. The session on Innovative Geophysics at the 56th Petroleum Geology Conference responded to that challenge by considering technologies in four, interrelated sub-sessions:

- time-lapse seismic data;
- improving imaging and interpretation;
- complementary remote sensing;
- integrating with borehole data.

This paper serves as an introduction to the section by reviewing selected topics within these areas and identifying some further issues.

Time-lapse seismic technology

Arguably the most successful new geophysical technology being applied to reservoir management is that of 3D time-lapse seismic (also called 4D seismic) technology and its prominence was reflected in seven presentations in the session, three of which are included in this volume (Chadwick et al., Kristiansen & Waggoner, Vejbeak et al.). Several case studies were cited by oral and poster presenters (Stammeijer et al. 2003; Jones & Folstad 2003; Gosselin & Williamson 2003) and covered all the phases of a reservoir cycle from before first oil (Foinaven) to carbon dioxide sequestration in Sleipner, a crucially important environmental project which may well continue even after the ultimate cessation of hydrocarbon production. Some of the issues and challenges facing time-lapse seismic technology will be reviewed using Foinaven as an example.

The time-lapse seismic concept already has quite a long history, with experimental accounts in the literature as early as 1983 for using the differences between successive seismic surveys over a producing field to interpret production-induced changes in the reservoir (Greasves et al. 1983). However, although there was experimental activity for many years, commercial projects did not really develop momentum until the late 1990s. A useful distinction between ‘experimental’ and ‘commercial’ may be found in contrasting the technical success of a geophysicist in observing 4D seismic changes some time after the production event asserted to have caused them, to the timely use of 4D results by a reservoir engineer in his/her workflow for production management. Quoting the late Drummond Matthews in the context of seismic wiggles that cannot be hit with a geological hammer, the former may have a high ‘Coo’ factor (as in ‘Coo, look at that! ’), while the latter demonstrate the interpretability of the seismic data for useful reservoir information.

FARMinG yesterday

An example of technical success leading to commercial application is the Foinaven Active Reservoir Management (FARM) pilot project undertaken in the Foinaven Field, the first field to come on-stream in the UK Atlantic margin. Operated by BP, then in partnership with Shell and, more recently, with Marathon, the Foinaven Field lies in 500 m of water, 190 km west of Shetlands. Details of the time-lapse project may be found in a number of papers (Cooper et al. 1999a, b, c; Bouska & O’Donovan 2000). Foinaven was the first 4D project launched before first oil, since the dedicated 4D baseline surveys were acquired in 1995 as references before production start-up. Two baseline surveys were shot, comparing towed streamer with permanently installed, seabed sensors, in a bid to evaluate the two technologies. The Foinaven reservoir rocks are largely clean, turbidite, Tertiary sandstones with good porosity and permeability. Since an amplitude versus offset (AVO) signal had already been linked to hydrocarbon presence and quantification – no ‘malarkey’ here – Foinaven made an excellent time-lapse laboratory.

Foinaven original oil was near full saturation, with free gas caps in places, and the reservoir pressure was close to bubble point. Pre-survey modelling suggested that the replacement of oil by water following production should be visible on the time-lapse seismic data as a dimming of the far-offset reflection strength at the oil rim.

At the baseline survey in 1995, there was practically no free gas in the FARM reservoir compartment under study. In the 1998 repeat surveys after ten months of production, the amplitudes were much brighter: instead of water replacing oil to dim the far-offset reflection, it was inferred that gas had come out of solution, due to falling pore pressure following production (Cooper et al. 1999c), significantly increasing the rock compliance. Up to the time of the repeat surveys, no water injection had been available to manage voidage and evidently there was insufficient aquifer support to maintain pressure in most parts of the studied compartment, even to the oil—water contact. Where time-lapse amplitudes increased, the reservoir was interpreted to be in pressure communication with the producer wells. No increase in amplitude meant no pore pressure drop, which could be due either to isolation from the producers, or to local aquifer support maintaining pressure and avoiding gas evolution. The time-lapse seismic amplitude maps were interpreted in terms of pressure connectedness and fault seal, instead of changes in water saturation. Consistency of features such as minor faulting in both time-lapse surveys also added confidence to a detailed structural interpretation.

The FARM pilot project demonstrated that 4D seismic technology ‘worked’ West of Shetland and provided reservoir-related interpretation. The technical success of the project
motivated the extension of 4D surveys to other BP West of Shetland assets (Part et al. 2000). Many case studies can now be found in the literature and were presented at the Conference (Gosselin & Williamson 2003; Stammeijer et al. 2003) showing how time-lapse seismic technology is being integrated into a reservoir management workflow, but the FARM project has stimulated further questions germane to the future direction of the technology.

Towed streamers or permanent installation?

FARM compared time-lapse technology using towed streamer and permanent seabed sensors, looking at relative repeatability, fitness for purpose and cost. It was found that the permanent system could indeed provide more repeatable data than the towed streamer (Kristiansen et al. 2000). Once the initial emplacement cost is covered, repeat surveys should have a lower unit cost than a towed streamer survey, allowing subsequent ‘snapshots’ at times determined by the reservoir process being monitored. FARM data from the first permanently installed seabed array highlighted both issues and benefits of this technology.

Sparse seabed sampling provided interesting challenges to the data processors, especially as a strong multiple overlies the reservoir in much of the area. Because multiples generally do not repeat (another lesson learned from FARM), due for instance to small changes in the water velocity between the surveys, the multiples had to be attenuated in each volume before differencing the data. Godfrey et al. (1998) showed that the strong multiple could be used for imaging but, at the time, careful interpolation allowed successful demultiplexing (Probert et al. 2000) using algorithms which relied on conventional spatial sampling. Receiver-side, free-surface demultiplex is greatly facilitated by the processing together of the hydrophone and vertical-component geophone on a multi-component, seabed sensor (Barr & Sanders 1989; Barr 1997), housed either in a cable (ocean bottom cable; OBC) or in individual ocean bottom seismometers (OBS). Such sensors also permit direct access to both compressional (P) and shear (S) wavefields, assisting the separation of lithology fluid and pressure effects, so it seems likely that future permanent installations will be multi-component. Their higher cost puts further pressure on reducing sensor density and, while the receiver-side, free-surface multiples may be addressed by sensor combination, the source-side multiples remain. Recent research, such as Calvert & Wills (2003), seeks to address the issue of demultiplex and imaging using sparse, permanently installed systems.

The FARM seabed data were seen to have an extra octave of bandwidth at low frequencies when compared with the towed streamer data, believed due to the absence of a streamer ghost notch (Cooper et al. 1999b). This extra bandwidth was found by Wagner et al. (2003) to benefit the inversion of the data to impedance and is also a feature of the hydrophone–geophone combination in OBC data.

Because of cost, it may be tempting to target areas where reservoir changes are expected. However, the value of 4D data may, arguably, be found in cases where it reveals changes unpredicted by the reservoir model: if flow predictions were always accurate, there would be no need for time-lapse seismic technology. If complete sensor coverage is too expensive then the siting of a more limited number of sparse sensors poses an optimization challenge, trading off fold, coverage, signal-to-noise ratio and cost in a variety of flow scenarios. Is it cost effective to install a multi-component sensor array over a complete field with sufficient sensor density to enable interpretable data to be acquired on demand using a low-cost source vessel? A positive answer to this question opens the way to ‘Life of Field Seismic’ and may be provided by the experimental seabed array over Valhall (First Break 2003).

Seismic to reservoir parameters

The time-lapse signal is the differential seismic response of the subsurface caused by production affecting saturation, temperature, pore pressure, fracture compliance and fill, compaction, subsidence and reservoir and overburden stress fields. These reservoir changes can impact seismic measurable such as travel time, velocity, amplitude, polarization, AVO and anisotropy for both compressional (P) and shear (S) waves and a crucial area of 4D research lies in developing appropriate rock physical models to relate changes in seismic observables to changes in reservoir parameters. Vejbaek et al. (this volume) present one such study of modelling time-lapse saturation changes in carbonates. The separation of time-lapse signal due to pore-pressure changes from that due to changes in saturation is a key goal which appears to be addressed best by estimating changes in shear modulus as well as bulk modulus. A natural approach is to use both P and S waves from multi-component sensors but their cost and the difficulty of ensuring high repeatability (except from permanently installed systems) has prompted the study of time-lapse, AVO anomalies from towed streamer data as an indirect estimator of the shear modulus. Stammeijer & Landro (2003) have suggested ways of estimating compaction from time-lapse data, especially in Chalk reservoirs where production and associated water-injection have resulted in collapse of the rock matrix. Compaction drive is a valuable production mechanism but its time-lapse signal overlaps that due to saturation changes and invalidates the commonly held assumption that the overburden is invariant under production. Even without matrix collapse, the notion that pore-pressure changes in the reservoir will impact effective stress in the overburden will be familiar to those who have seen the effect of stress release in a mining gallery on the seismic velocity field in the overburden. It is evident that the reservoir, aquifer and overburden are coupled through flow, stress and strain and that flow simulation is a driver for the geomechanical evolution of the system. In some reservoirs, coupled simulators may be needed to interpret the time-lapse signal and it would seem at least prudent that these sensitivities be assessed in both the design and interpretation of 4D surveys. Although much of the value of 4D data to date has been realized in identifying first-order controls to flow (baffles and channels), the combination of flow, geomechanical and seismic simulation – held together by the glue of rock physics – will help 4D technology to go far beyond the qualitative ‘Coo factor’ and turn it into a quantitative tool for reservoir optimization. Examples of this more quantitative approach were presented on a North Sea field by Gosselin & Williamson (2003) and Stammeijer et al. (2003).

Time-lapse metrics

The detection of production changes, and eventual quantitative interpretation, depends on the ratio of time-lapse signal to time-lapse noise. 4D noise results not just from the ambient noise level in a given seismic snapshot but also from the non-repeatability of the parameters of successive seismic surveys, including survey location, source and receiver geometry, source signatures, different acquisition equipment and different versions of processing software. The need either to control, or to correct for, such aspects of the seismic acquisition has led to the development of sophisticated systems for controlling and monitoring seismic acquisition parameters. However, estimating comparative repeatability of seismic data requires metrics. Kristiansen et al. (2000) applied two metrics to the FARM data and their differing sensitivities to aspects of trace repeatability (gain, phase and time-shift) were pursued by Kragh & Christie (2002) who demonstrated their link to underlying signal-to-noise ratio and proposed their combined use for monitoring the processing impact on the time-lapse signal. While a good rock physics model can help to relate trace non-repeatability to the minimum detectable
reservoir change, and to estimate confidence in a given signal estimate, further work is probably required, especially where noise is correlated. However, the benefits of such an understanding could also provide a better prior assessment of the potential value of a time-lapse survey (e.g. Waggoner 2002).

With or without prior estimates of value, the track record for time-lapse technology is developing strongly with statements of actual value, representing significant returns on investment, for example by Stammeyer et al. (2003).

Improving imaging and interpretation

Improving seismic imaging is a continual process. A comparison of seismic image quality over the past 15–20 years, even the past five years, shows remarkable gains in definition. A new acquisition, or a reprocessing of an earlier survey, is often considered at intervals of three years or less. The success of time-lapse seismic technology is testament to our ability to obtain sufficient signal-to-noise ratios and to control the repeatability of amplitudes through acquisition and processing. Imaging improvements can result from better acquisition technology, greater reductions in both coherent and incoherent noise, more accurate earth models for migration and more accurate migration algorithms. The continued demonstration of Moore’s law allows more accurate implementations of existing algorithms or new methods previously considered too expensive. The section saw examples of improved imaging and interpretation, from broader bandwidth data (Egan, this volume; Connolly et al., this volume), from simultaneous interpretation of P- and S-wave volumes from multi-component sensors (Kristiansen & Waggoner, this volume) and from pre-stack depth migration (PreSDM) using more accurate subsurface models of complex geology (van der Burgh & Douma, this volume) and/or anisotropic overburden (Hawkins et al. 2003; Jones et al. 2003; Sutter et al., this volume). Angerer et al. (2003) also presented a poster paper using azimuthal anisotropy as part of a fracture characterization workflow, integrating across scales of measurements from cores to logs to seismic data. Since the topic has been well covered in the section material, a snapshot of some of the issues and directions is presented.

Increasing bandwidth

The Earth acts as a low pass filter, whose characteristics vary markedly with location. Where these characteristics are favourable for seismic propagation, it is possible to increase the centre frequency of a marine source signature by towing the source and streamer shallow. This shortens the delay between primary signal and the ‘ghost’ of the primary in the free-surface mirror, pushing the spectral notch due to this dipole to higher frequencies. The peak enhancement from the ghost occurs at the frequency for which the source/streamer depth is a quarter-wavelength and the overall octave bandwidth of spectral enhancement is 2.32, irrespective of the tow depth (Ziolaowski et al. 2001). However, the bandwidth of enhanced frequencies increases with decreasing depth and, provided the received energy is above the noise level, the wider frequency bandwidth results in a shorter wavelet with higher resolution. Connolly et al. (this volume) describe a successful, high-resolution survey offshore Angola, in which source and streamers were both towed at 4 m, resulting in ghost notches at about 180 Hz and a generated signal frequency almost flat over three octaves from 15 Hz to 120 Hz in the shallow part of the section. The resulting images display very good resolution and the increased swell noise which would be expected from a such a shallow tow was removed by a 5 Hz, low-cut filter.

In other regions, sea-states often cause too much swell noise to allow a shallow tow with conventional streamers, but Egan (this volume) describes how swell noise may be attenuated with moveout-based filters, provided it is finely sampled with point sensors to avoid spatial aliasing. Such an approach avoids low-cut filtering, maximizing the signal bandwidth. There is a current debate about whether signal processing for swell noise removal is more or less effective than alternative streamer designs to reduce sensitivity to cross-flow, but Connolly et al. (this volume) present convincing evidence that high resolution data are, indeed, achievable and worth pursuing, provided the Earth allows good signal penetration, as is often the case in deep offshore. As noted earlier, seabed recording avoids the low-frequency cut of the streamer ghost, while the combination of hydrophone and vertical geophone data enables up/down wavefield separation in the water column, broadening the bandwidth at both ends. Wavefield separation may also be achieved in towed streamer data by using twin streamers in an over-under configuration, enabled by dynamic streamer steering, although the technical and commercial viability of this approach remains to be shown.

Improving image resolution

If one can generate and record broader band data then one also needs to retain the bandwidth in the image. Trace summation processes, such as stacking and migration, are robust in reducing random noise but easily destroy the high frequencies that have been so hard won in acquisition through inappropriate time shifts applied to the time samples before summation. This can be due to inaccurate parameters in structurally complex Earth models used to derive the travel time trajectories for summation, or even to inappropriate physical models, such as the use of isotropic models in anisotropic media. Time domain processing remains the imaging tool of first resort, despite its intrinsic limitations. However, it has recently evolved quite significantly with the emergence of ‘full Kirchhoff Pre-Stack Time Migration’ (Kirchhoff PreSTM), for both marine and land data. PreSTM is much more computer intensive than the decreasingly used Dip Moveout (DMO) or ‘Moves’ approaches. There are no longer limitations in accounting for vertical heterogeneity in the subsurface, but PreSTM still makes severe approximations in the presence of lateral velocity variations. However, its use is now quite widespread, probably because of (1) its ability to allow velocity analysis in a migrated position, which facilitates the task of velocity pickers and interpreters involved in processing; and (2) the final Residual Moveout (RMO) process. In effect, the final RMO process allows a cost-effective, high resolution/high density fine-tuning of the velocity field and subsequent optimization of the stack, almost on a bin-by-bin basis. The RMO also accommodates so-called higher-order move-out effects, whether due to heterogeneity or anisotropy, or artefacts such as residual statics.

The availability of high-density, seismically derived velocities offers potential for making efficient use of velocity attributes, which are probably underexplored today. These may find conventional application in velocity model building (van der Burgh & Douma, this volume), but also in facies description, lithology studies and a low frequency background model for amplitude inversion. One example presented in the session (Jones & Folstad 2003) examined the use of continuous, high-resolution velocity as a 4D seismic attribute (Jones 2002).

There are various strategies to perform velocity analysis in the PreSTM domain, from iterative methods to scanning methods and, increasingly, a combination of both. Interestingly, building the PreSTM velocity field is becoming more elaborate, including layered modelling and ray tracing; the boundary between PreSTM and PreSDM is getting fuzzier. However, it does not solve other pre-stack issues such as multiples and statics, which often represent the main headache for the seismic processor. The PreSTM method can also be extended to PS mode-converted waves, sometimes called C-waves. Although there is still limited experience in this application, promising early results were reported by Kristiansen & Waggoner (this volume).
When the subsurface geology varies significantly within the length scale of a seismic cable, time processing, including PreSTM, reaches its limits and there is no choice but to use PreSDM. PreSDM requires the building of an explicit and fairly accurate model of the propagation velocity field in the subsurface. Unfortunately, the more complex the subsurface, the more detailed the model should be and the more difficult it is to build! PreSDM is a standard imaging tool, run almost in parallel with PreSTM in favourable cases (e.g. Gulf of Mexico, where there are salt bodies with very complex geometries but with a well-defined velocity, embedded into sediments which are fairly well behaved in terms of velocity). It remains the ultimate, expensive tool in the North Sea, where the model building is much more difficult (complex shapes/overthrusts/salt, shale or mud diapirism/strong velocity contrasts – chalk against clastics; clastics against evaporites). The high cost is mainly the result of the number of iterations required and the interpreter’s and processor’s time to build and update the model at each iteration. Model-building technology again converges towards two classes: layer- and grid-tomography and scanning. The former is more efficient and allows a high density of results; the latter permits more interpretative input at each iteration.

Results can be impressive (van der Burgh & Douma, this volume), but the bad news with PreSDM is that with there may be flat events within the aperture of the Common Image Gathers (the objective criterion of a good seismic image), the resulting image may still not tie with the wells: there is non-uniqueness. Hence, the necessity of incorporating other information into the interpretative, model-building process from complementary sources such as borehole seismic, electromagnetics, gravimetry, core measurements, geological background, section balancing and wide-angle seismic data. The more prior information, the more chance there is of reducing the non-uniqueness. Complex subsurface models result in multi-pathing which poses a problem for Kirchhoff migration algorithms and, with the availability of greater computing power, has re-ignited interest in wave extrapolation approaches, typically using phase-shift methods and, sometimes, the more time-consuming finite-difference formulations. However, the benefits of the Kirchhoff approach have also stimulated research into the multi-pathing problem and a number of possible solutions are helping to extend its applicability by allowing multiple arrivals and using ray attributes to select the appropriate ray paths for imaging.

On the model side, more accurate physical representations of the overburden must be developed. This often means introducing velocity anisotropy into the model to reconcile both depth and time. While the velocity model is increasingly complex, the way anisotropy is parametrized is still very crude: a pair of Thomsen 1986 parameters per transversely isotropic (TI) layer, 10 or 12 parameters for a whole 3D cube! Recent refinements allow a variable tilt to the TI symmetry axis but a major difficulty with anisotropic model-building remains the estimation of anisotropy parameters: this is barely possible from surface data alone, and well data or borehole seismic data must normally be used jointly with surface data to determine the anisotopic model parameters, and even then only at the well locations (Hawkins et al. 2002, 2003; Sui ter et al., this volume).

In PreSDM, amplitudes are handled in a model-based, deterministic way. This remains a difficult issue (e.g. acquisition footprints), which has implications when amplitudes are important, for example in AVO inversion, reservoir characterization or 4D technology. The pragmatic, ‘statistical’ approach to amplitude handling in the time-domain processing is quite robust, if less than exact. However, when PreSDM is really necessary, overburden and reservoir complexity make it a major challenge to get meaningful amplitudes because of caustics, multi-pathing and even post-critical reflections: seismic reservoir characterization and quantitative 4D surveying below salt will remain a dream for some time to come.

After having taken some time to mature, anisotropic PreSDM is now a tool at our disposal to derive a sharper and more accurate structural image of the subsurface in depth. It is still quite an expensive processing route involving iterations and borehole seismic workflows. However, PreSDM is also the natural domain for processing pure shear and PS mode-converted waves, since depth is unique and independent of wave type, which is not true of the time domain. Our understanding and estimation of anisotropy also needs to be improved in the future, since anisotropy has much greater impact on S-waves than on P-waves at incidence angles typically employed. Conversely, the greater sensitivity of shear waves to anisotropy, and the fact that anisotropy couples P- and S-waves may allow us to develop better tools which can scan both P and S volumes in estimating anisotropy parameters more accurately. What can already be done (Sui ter et al., this volume; Blanco, this volume) and should be done more systematically, is to put error bars on depth maps and the lateral positions of geological features, especially faults. In the future, error bars will be included on the seismic images in depth as well, a by-product from stochastic depth imaging, although a few more years of Moore’s Law may be needed to achieve this. One may look forward, as well, to multi-directional acquisitions for a more complete, 3D illumination of the subsurface for imaging and anisotropic interpretation of multi-component data below complex structures with applications to fracture evaluation, lithology and fluid prediction and reservoir monitoring.

Seismic and uncertainty

Error bars on structural features have been mentioned, but, in fact, uncertainty analysis is a rapidly expanding field that has focused primarily on addressing the range of possibilities for reservoir volumetrics and flow rates in order to optimize topsides and reservoir plumbing. This form of risk assessment is becoming a standard tool but the distributions sampled to create multiple flow realizations have usually derived from geostatistical analyses. Since most reservoir models are built on top of a seismic interpretation, it is evident that uncertainty in the seismic image and amplitudes can have an impact on uncertainty in the geological model, its properties and, once upscaled, the flow model. Although Parkes & Hatton (1984) showed the effects of velocity errors on migrated images and proposed a Monte-Carlo approach to estimate structural uncertainty, it is only relatively recently that uncertainty in 3D seismic data is beginning to be estimated and visualized. Careful evaluation of actual outcomes will be needed to determine whether seismically derived uncertainty estimates are able to provide more accurate risk assessments than current techniques which focus on well logs or outcrop analogues. From a purely philosophical viewpoint, it surely behaves a scientific discipline, as geophysics asserts to be, to put an error bar on its measurement.

Complementary remote sensing

Gravity-gradiometry

Such is the recent dominance of reflection seismic data as a tool for subsurface exploration that one may fall into the trap of calling other techniques ‘non-seismic techniques’. This sub-session covered a broad and fascinating set of methods for complementary remote sensing; with new developments described in gravity-gradiometry (Smit et al., this volume), controlled source electromagnetics (Mullis et al. 2003) and wide-angle imaging (Barton et al. 2003). The first of these, as mentioned above, has been demonstrated to aid velocity model-building for PreSDM, but one may conjecture that this is the first of many possible applications of measuring the gradient of the gravity vector in all three Cartesian coordinates, taking advantage of the higher spatial resolution that can be achieved from measurements...
of the gravity gradient when compared to gradients derived from measurements of gravity. While attributes derived from gravimetric data are useful in structural interpretation, a widespread adoption of the technique is still some way off, possibly reflecting a combination of acquisition cost and relative inexperience in interpretation of gravity gradients. Nevertheless, examples such as those presented in this section should help to stimulate further case studies and, indeed, there is active research into alternative, cost-effective ways of measuring gravity gradients without differencing.

**Controlled-source electromagnetics**

Mulilis et al. (2003) gave an introduction to the principles of controlled-source, deep-tow, electromagnetic sounding, a technology which has hitherto been applied in the identification of magma chambers (e.g. MacGregor et al. 1998) but which has recently emerged as a complementary method to seismic investigation, reducing exploration risk as a non-seismic, direct hydrocarbon indicator (DHI). DHIs are derived from seismic amplitudes distinguished hydrocarbon pore fluids from connate water using the seismic response to the contrasts in pore fluid compliance and density, a signal which gets progressively weaker with decreasing porosity and increasing bulk modulus of the dry rock matrix. By contrast, controlled-source electromagnetics (CSEM) respond to the resistivity contrast between a highly-resistive, hydrocarbon-saturated reservoir rock, embedded in a conductive shale, and its conductive, water-saturated counterpart. The technique, which is well adapted to deep-water exploration, breaks all the rules about mixing electricity and water by using a high-current, horizontal electric dipole source to generate a low-frequency, diffusive field in the subsurface. This field is modified by the resistivity distribution in the deep subsurface in such a way that the radial and transverse components of the electric field detected at the seabed are also affected by the presence or absence of resistive reservoir rock. The diffusive field is rapidly attenuated by conductive sediments, but a resistive, hydrocarbon layer allows lateral propagation of the field, with significantly less attenuation than in the overlying sediments. Field energy leaks from the hydrocarbon layer into the overburden and back to the seabed detectors. At an offset comparable to the depth of burial, the guided energy is stronger than the field directly coupled through the overburden, significantly modifying the amplitude and phase of the radial field component in comparison both to the radial component in the absence of the resistive layer and to the transverse component with the resistive layer. Modelling studies suggest that the lateral edges of a resistive body are, perhaps surprisingly, quite well defined and, consequently, there are two recently launched commercial groups who are undertaking a number of proprietary studies on behalf of oil companies to evaluate the applicability of this new form of DHI (Ellingsrud et al. 2002; Eidesmo et al. 2002; Rasten et al. 2003).

As with most new technologies there are a number of issues to be addressed. These include: reliable depth interpretation of the resistivity-interpreted anomalies; the relationship between CSEM and magnetotellurics (MT) in the context of seismic exploration (see, for example, MacGregor 2003); optimal survey design, given that the number of receivers is limited by the time and cost of deployment; the need to record, in a 3D sense, both radial and transverse electric field components from both inline and crossline orientations of the horizontal electric dipole source; the use of CSEM in shallower waters where the screening effect of the overlying conductive water layer is reduced, allowing coupling of source and detectors through the resistive atmosphere, and its possible application to time-lapse monitoring. The physics and implementation of CSEM have been studied and tested for two decades and this is an exciting time as its commercial viability is evaluated through field testing. If found to be successful, there will be no doubt that the development of the logistics and efficiency of deployment as a complementary measurement to seismic acquisition.

**Wide-angle seismic imaging**

Wide-angle seismic imaging may be considered complementary to exploration seismic surveying in that it focuses on the information content of the post-critical seismic wavefield which usually lies beyond the mute in conventional, sub-critical seismic processing. Barton et al. (2003) presented a review of wide-angle seismic technology and its role in increasing understanding of the structure of the North Atlantic margin, especially in areas where the pre-existing structures are obscured by extensive Tertiary basalt flows. In these regions, sub-critically reflected wavefields are dominated by scattering and geometrical spreading losses, multiples, diffractions and out-of-plane reflections. Whereas short-offset seismic data contain information on impedance contrasts, wide-angle data mainly contain information on the velocity structure. Long-offset wavefields have the merit that diving waves are often first arrivals with good signal-to-noise ratios and can be identified unambiguously as primary events. Although a velocity reversal does not give rise to a diving wave, high velocity (e.g. basalt) layer thickness can often be inferred from the offset termination of the diving wave and the resulting ‘step-back’ to the underlying basement reflector (e.g. White et al. 2003). Wide-angle reflections and diving waves may be tracked back in offset to identify sub-critical events. Their arrival times may also be picked and modelled with ray-tracing (Zelt & Smith 1992) to develop a velocity model in support of that derived from sub-critical velocity analysis. Although wide-angle events are typically low frequency and lack the resolution of conventional seismic data, when correctly imaged, they may be used to distinguish deep primaries from multiples on migrated sub-critical seismic sections.

Recent activity has focused on the generation and recording of low frequency seismic energy (Ziolekowska et al. 2001; Lunnon et al. 2003) which are less affected by scattering from basalt heterogeneities. This approach is motivated by the success of using low frequency seismic data in the Corrib reservoir, which lies beneath shallow extrusives, to develop images of sufficient quality to permit field development (Dancer et al., this volume). Roberts et al. (this volume) also report the acquisition of low-frequency OBS data together with low-frequency, long-offset, towed-streamer data, to image sub-basalt structure, including lower crustal reflectivity and the Moho. The integration of OBS and towed seismic data may also allow correlation of mixed-mode events from the OBS data with double-mode conversions on the towed streamer data, thereby establishing greater confidence in the method of mode-converted shear wave imaging proposed by Fruehn et al. (1999).

Barton et al. (2003) also presented two novel approaches of using long-offset data. Radon transformed into the intercept-time slowness (τ−p) domain, to develop both the velocity model and to achieve a stack. One approach extends the τ−p velocity inversion concept of Clayton & McMechan (1981) and generates a depth-migrated image from combined near- and far-offset data. A second technique applies constant move-out to the data in the time-offset domain and forms a stack of all the constant-moveout-corrected data which minimizes the event-stretching of conventional, hyperbolic move-out. The process offers the possibility of higher resolution imaging of wide-angle data, although issues such as anisotropy and the robustness to the assumption of one-dimensional structure, implicit in the velocity inversion, will be the subject of further research. As offsets and apertures increase, the effects of lateral velocity variations and anisotropy become increasingly important to take into account, which may require the use of anisotropic PreSDM discussed above.

The combination of OBS and towed streamers for wide-angle acquisition presents logistical challenges and integrated processing flows continue to be created and evaluated, but the prize of a
technique to access prospective acreage beneath the basalt carapace is a significant motivation in this last frontier of exploration in the NW European margin.

Integrating with borehole data

Suspicion of geophysicists is fostered by their historical reluctance to go to the depth domain. The fundamental measurements are in time, but wells are drilled and logged in depth. Borehole seismic data relate the two domains by utilizing surface seismic energy sources recorded by downhole sensors in a check-shot survey. Since both wireline depth and seismic one-way time are measured as data pairs, a local time–depth relationship can be established. After appropriate environmental editing and corrections for velocity dispersion, the compressional sonic log may also be used as a fine-scale interpolator between the check shots. Interestingly, although a large number of shear sonic logs are run, few are ‘calibrated’ by shear check-shot surveys. The borehole seismic traces are rich in events other than the direct first arrival from the source to receiver and, with adequate sampling in time and depth, triaxially recorded, vertical seismic profile (VSP) data may be separated into upward- and downward-travelling compressional and shear waves. Depending upon the acquisition geometry, these wavefields may be used to image geological structure within, below and beyond the well, often with a resolution better than that of surface seismic data because of the single passage through the attenuating near-surface. The common scaling in depth along the borehole uniquely allows correlation of compressional and mode-converted shear wave events, providing an invaluable tie point for multi-component surface seismic data. The recorded down-going wavefield provides access to the anisotropic elastic parameters of the local velocity model, effectively providing a measured Green’s function for use in PreSDM. When the geophone is just above a target horizon, up- and down-going wavefields have similar paths, allowing accurate estimates of offset-dependent reflectivity for AVO calibration in surface seismic data.

In this section, Blanco (this volume) described three case studies which demonstrate leading-edge applications of borehole seismic data, including early results of an experiment using permanently installed, fibre-optic borehole sensors for gas-well monitoring, which complement the concept of permanent surface seismic sensors, either on land or on the seabed, for field-wide reservoir monitoring. The proximity of borehole seismic sensors to the reservoir offers the intriguing possibility of recording and locating passive seismic events to monitor the response of the near-reservoir rocks to changes in effective stress due to production or injection. Because of their small magnitude, such microseismicity would not normally be detectable by surface arrays, so permanent downhole sensors may open a window on the geomechanical behaviour of the reservoir and neighbouring formations, as well as permitting more conventional time-lapse surveys using active seismic sources.

VSP is the measured seismic response of the Earth at or near the borehole and may be compared to the surface seismic trace to evaluate, enhance or complement the surface seismic processing/imaging. Despite being recorded in depth, the VSP, like the surface seismic trace, still needs to be tied to the geology. There is often a need, too, for a second opinion when the VSP and the surface seismic disagree. Both these functions are provided by constructing synthetic seismic traces and associated attributes by computing the modelled response of the Earth at the well, using the rock physical parameters logged along the borehole. Vejdek et al. (this volume) present a comprehensive study of modelling the seismic response of North Sea Chalk reservoirs, allowing for changes in burial depth and porosity by compaction and hydrocarbon saturation. Not only is accurate modelling necessary for a well-tie but reliable models are also required for interpreting changes in the seismic response away from the well in terms of the combined effects of compaction and fluid content. Also in this section, Japsen et al. (this volume) present initial results from a very ambitious project to acquire core, wireline log, borehole seismic and surface seismic data through two Faroes wells penetrating Middle and Upper Series basalts to complement the comprehensive dataset acquired in the Lower Series basalts in the Lopra-1/1A well. The characterization of the basalts will require careful integration of measurements over scale, where each data type will have its own environmental corrections for known systematic errors, together with estimated uncertainties. The results should help to feed back into guidelines for surface seismic acquisition and processing in basalt-covered, prospective areas.

The range of geometries available to borehole seismic acquisition is extensive, especially in highly deviated wells. One might argue that the technique is more general than surface seismic surveying, which is often restricted to acquiring data with sources and sensors on a common acquisition plane. It is also true that with cross-well geometries and real-time, seismic-while-drilling techniques, borehole seismic data have potential applications that are limited only by the imagination of the user. However, except for the conventional well-tie, there are so many possible applications that experience is needed in survey design to acquire the right survey for the task in hand, and to follow through the processing and interpretation to ensure that the information content is retained. There have been few geophysicists with this experience in the past, but the steady growth in borehole seismic surveys over the last few years suggests that the experience base is growing. Together with greater data quality and fold from new acquisition equipment, it seems likely that this growth will continue.

This overview began by citing the early 4D case study of Greaves et al. (1983), who used repeated 3D volumes to monitor a combustion front on land. Not only did they employ permanently buried, single sensors to assure good acquisition repeatability, but they also calibrated their seismic sections with VSP data to add confidence to the picks in travel time and wavelet character. Careful pre-survey modelling was carried out to assess the extent of the time-lapse signal and because the top and bottom of the sand units were required to be separately resolved, every effort was made to acquire high resolution data with a dominant frequency of 125 Hz or more. It seems that, after all, the geophysical goals remain pretty constant and even some of the means to achieve them have a familiar ring as well. Target depth and survey extent were relatively limited, as was the data processing and, today, geophysicists are carrying out surveys in more challenging environments with a high expectation of success, but the message remains that to seek the future innovations, one should not forget also to look into the past.

This account is largely seismic-orientated and reflects a paper, ‘Recent advances in seismic technology – can we deliver what the customer wants’, delivered by P. A. F. Christie at the 6th Petroleum Geology Conference.

References


Downloaded from http://pgc.lyellcollection.org/ by guest on July 26, 2021


