Seismic Attributes – A Historical Perspective

Satinder Chopra[†] and Kurt J. Marfurt[*]

[†]Arcis Corporation, Calgary, Alberta, Canada

[*]Allied Geophysical Laboratories, University of Houston, Houston, Texas, USA

ABSTRACT

A seismic attribute is a quantitative measure of a seismic characteristic of interest. Analysis of attributes has been integral to reflection seismic interpretation since the 1930s when geophysicists started to pick travel times to coherent reflections on seismic field records. There are now more than fifty distinct seismic attributes calculated from seismic data and applied to the interpretation of geologic structure, stratigraphy and rock/pore fluid properties. The evolution of seismic attributes is closely linked to advances in computer technology. As examples, the advent of digital recording in the 1960s produced improved measurements of seismic amplitude and pointed out the correlation between hydrocarbon pore fluids and strong amplitudes ("bright spots"). The introduction of color printers in the early 1970s allowed color displays of reflection strength, frequency, phase, and interval velocity to be overlain routinely on black-and-white seismic records. Interpretation workstations in the 1980s provided interpreters with the ability to interact quickly with data to change scales and colors and to easily integrate seismic traces with other information like well logs. Today, very powerful computer workstations capable of integrating large volumes of diverse data and calculating numerous seismic attributes are a routine tool used by seismic interpreters seeking geologic and reservoir engineering

information from seismic data. In this review paper celebrating the 75th anniversary of the Society of Exploration Geophysicists, we reconstruct the key historical events that have lead to modern seismic attribute analysis.

INTRODUCTION

The goal of seismic exploration is to map geologic features associated with hydrocarbon deposition, generation, migration, and entrapment. The goal of seismic exploitation is to characterize the static and dynamic characteristics of subsurface reservoirs. Cosentino (2001) lists these parameters as structure (horizon depth, reservoir thickness, faults, …), internal architecture (heterogeneity), petrophysical properties (porosity, permeability, …) and hydrocarbon properties (product, thermodynamics, …). Conventional logging programs provide sparsely sampled one-dimensional (or ‘vertical’) measurements; indeed, many of the above properties are not measured at all in a well but rather need to be estimated. A good seismic attribute either is directly sensitive to the desired geologic feature or reservoir property of interest, or allows us to define the structural or depositional environment and thereby allows us to *infer* some feature or properties of interest. While bright spots (high reflectivity) are an obvious example of an attribute that is directly related to a parameter of interest, the inference of structure or stratigraphy began with the first reflection seismology recordings in the 1930s. The first attribute is simply the picked two-way travel time of a reflection event.

After scanning through his or her data, a good seismic interpreter develops one or more geologic hypotheses on which to identify leads and build plays. While science (particularly that based on geologic principles) plays a role, much of the actual identification of features is done intuitively. Many would define seismic interpretation to be a mix of 'art' and 'science'. Once an interpreter has identified a seismic feature or pattern that is associated with successful wells (whether the scientific underpinning is valid or not!), he or she can rapidly find more of the same. This 'pattern recognition' by experienced interpreters is mind-boggling to younger geophysicists who often come armed with a great deal more formal mathematics.

One of the goals of seismic attributes is to somehow 'capture' this expertise, by quantifying the amplitude and morphological features seen in the seismic data through a suite of deterministic calculations performed on a computer. For instance, the coherence attribute developed in the mid 1990s captures the same discontinuities seen in the seismic data and interpreted as faults by workers such as Rummerfeld (1954) some 40 years earlier.

If we use multiple attributes, Barnes (2000b) advises that we use attributes that are independent of each other. Kalkomey (1997) warns that in order to avoid false positive correlations, we should only use those attributes that are associated with physical properties and features of interest to our play or reservoir. Bob Sheriff laments 'mindless interpretation' where geoscientists search through a suite of attributes and stops when they find one that shows a feature they want to see. If possible, we recommend that each attribute only capture one type of physical property or feature, which can then be combined intelligently through geostatistics or other multiattribute analysis tools.

In the most general sense, seismic attributes encompass all quantities derived from seismic data; thus, we consider interval velocity, inversion for acoustic impedance, pore pressure prediction, reflector terminations, as well as complex-trace attributes and AVO to be ‘attributes’. By assigning the name ‘attribute’ to a quantity based on very sophisticated calculations such as impedance inversion and pore pressure prediction, we recognize that these estimates are somehow flawed, and thus amenable to calibration to well data via geostatistics or other data integration techniques.

Classification of attributes

As seismic attributes grew in both their number and variety over the last three decades, many authors have attempted to classify them into families, with the ultimate goal of better understanding and application. To put this growth in perspective, Bob’ Sheriff’s 1984, 1991, and 2004 editions of his Dictionary of Geophysics increases from 9 through 15 to 69 lines devoted to attributes.

Taner et al (1994) divide attributes into two general categories, ‘geometrical’ and ‘physical’. The objective of geometrical attributes is to enhance the visibility of the geometrical characteristics of seismic data: they include dip, azimuth, and continuity. Physical attributes have to do with the physical parameters of the subsurface and so relate to lithology. These include amplitude, phase, and frequency. The classification may be further divided into post-stack and pre-stack attributes. Brown (1996, 2004) classified attributes using a tree structure comprising time, amplitude, frequency and attenuation as the main branches, which further branch out into post-stack and pre-stack categories. Time attributes provide information on structure while amplitude attributes provide information on stratigraphy and reservoir. Chen and Sidney (1997) provided a classification based on wave kinematic/dynamic categories and geologic reservoir feature categories. Barnes (1997) developed a classification of complex-trace attributes depending on the relationship amongst different attributes and seismic data. Recognizing amplitude and phase as fundamental attributes from which all others are derived, attributes are classified as 1-D, 2-D or 3-D, as time or depth, and as instantaneous or local. Such classifications have been attempts at developing an intuitive understanding of the different attributes and this has helped in the application of attributes or combinations of attributes in discriminating subsurface features.

We prefer Liner et al.'s (2004) classification into *general* and *specific* categories. Liner et al's *general* attributes are measures "of geometric, kinematic, dynamic, or statistical features derived from seismic data". They include reflector amplitude, reflector time, reflector dip and azimuth, complex amplitude and frequency, generalized Hilbert attributes, illumination, edge detection/coherence, AVO, and spectral decomposition. These general attributes are based on either a physical or morphological character of the data tied to lithology or geology and are therefore 'generally' applicable from basin to basin around the world. In contrast, 'specific' attributes have a less well-defined on physics or geology basis. While a given specific attribute may be well correlated to a geologic feature or to reservoir productivity within a given basin, these correlations do not in general carry over to a different basin. There are literally hundreds of specific attributes. We add a third category to Liner et al.'s classification, that of 'composite' attributes (also called 'meta' attributes by Meldahl et al. (2001)). Many of the specific attributes cited in the literature are sums, products, or other combinations of more fundamental 'general' attributes. The authors prefer two types of composite attributes – those used to display more than one attribute at a time (a composite display such as shown in Figure 4) and those combined using geostatistics, neural nets, or other classification technology (such as Meldahl et al.'s (2001) meta attributes). Given the dangers of false correlations, we prefer when possible to use attributes that correlate to only one physical or geologic variables of interest, followed by geostatistics, neural networks, clustering, or visualization to combine multiple attributes in a meaningful manner.

Outline of this review paper

In this sixth of a suite of ten papers celebrating the 75th anniversary of the Society of Exploration Geophysicists, we attempt to reconstruct the key historical events that lead to modern seismic attribute analysis tools and workflows (Figure 1). While the foundations of attribute analysis evolved during the development of the seismic exploration, attribute analysis, as we now know it, had to wait until modern digital recording. We do not feel we have the proper perspective to cover the most recent developments, including volumetric estimation of Q, volumetric curvature, and prestack attributes. We also do not cover the extensive literature on AVO attributes, which we feel will be better covered in a paper addressing rock physics. Geostatistics and multiattribute classification also would require a paper as long as this.

1950-1960

Attributes from analog data

Some of the most important seismic attributes appeared long before digital recording, during the time of paper records. Roy Lindseth (2005) remembers the early 1950s as the time when reflections were inked by hand on seismic records and reflections were graded by labels in terms of consistency and character. Zones of no reflection would be labeled *NR* to signify recordings so poor that reflections could not be distinguished from the unruly background noise. Lindseth remarks: 'Demonstrating the true doodlebug spirit of turning adversity into advantage, Ben Rummerfeld (1954) correctly predicted in one area that NR gaps correspond to faulting. This predecessor of semblance was perhaps the first documented use of seismic attributes to find oil.'

Nigel Anstey (2005) recollects that the main reason for adopting magnetic analog recording in 1954 was to provide frequency analysis making it possible to plot corrected cross-sections which directly correlated to rock interfaces in the earth – a significant development at the time that even convinced geologists that it was possible to associate geological meaning with those wiggles. Bob Sheriff doesn't disagree with this technical advantage, but remembers the justification of magnetic recording to his management was the ability to evaluate alternative analog filters and mixing on the field records, rather embedding it directly in the recording process. Reflector picks were made manually, transferred to a map, and hand contoured in order to evaluate closure about potential hydrocarbon traps. During the same time period, maps of reflector dip were commonly created. Isochors (time thickness maps) were calculated directly from the seismic data or occasionally, computed from the mapped horizons. Faults were recognized by discontinuities and (more commonly) the presence of diffractions, and also posted on maps, but the correlations between lines was a source of error. While tedious to generate, these measurements were clearly ‘attributes’ of the seismic data. While all four of these attributes: structural elevation, dip, thickness, and discontinuities, have been greatly improved with the advent of digital data, one of the most important attributes – amplitude – had to wait for digital recording and would not appear until 1972.

1960-1970

Digital recording and bright spot detection

Until 1963, explorationists relied on inaccurate, low-resolution analog data in planning their exploration investments. Nigel Anstey recalls that in the mid 1960s, with useful contributions pouring in from Milo Backus and Bill Schneider, and the development of the velocity spectrum by Tury Taner and Fulton Koehler – multifold data began to help with the interval velocity computations. Bob Sheriff recalls interval velocity estimation as a serendipitous by product of the original goal of producing seismically derived time to depth conversion. In the context of Peterson et al.’s (1955) synthetic seismogram and its implied convolutional model, the velocity is arguably the most fundamental of attributes. By the late 1960s, a few geophysicists had started noticing the strong isolated reflections and changes in reflection character on seismic sections which in 1975 would form the foundation of seismic stratigraphy based on onlap, offlap, and other morphological patterns (Forrest, 2000). Initially it was thought that some of these reflections were caused by ‘hard streaks’, and people were skeptical that these observations were meaningful. But gradually, when some of these strong events on drilling encountered gas-zones, interpreters started taking them seriously. These streaks of high-amplitudes seen on seismic sections were christened ‘bright spots’ and gave birth to the ‘bright spot’ technology.

Searches of worldwide technical literature at the time revealed that some of the Russian research papers had already reported ‘direct detection’ of hydrocarbons by seismic means. This search revealed concerted efforts in carrying out correlation studies of bright spots with well data and field studies. It was found that reflections from hydrocarbon charged reservoir rocks showed much larger amplitudes than reflections from adjacent oil or water-saturated zones. Bob Sheriff recalls that no one was interested in finding gas during this period – bright spots were sold as a means of finding oil. It was only later that we realized that these bright spots were due to gas, or the effect of gas dissolved in oil, causing a low impedance anomaly. Even if initially poorly understood, the revelation that anomalously higher amplitudes seismic events in young clastic basins could indicate hydrocarbons gave a new level of importance to the seismic exploration method. By 1970, oil companies were successfully using ‘bright spot’ phenomena to identify gas-saturated reservoirs (Forrest, 2000).

By using a long window AGC the high-amplitude anomalies associated with hydrocarbon accumulations became more obvious but then some were visible but some of the detailed structural information was lost. Thus, usually two sections were plotted – a bright spot section and a conventional section (Anstey, 2005).

Digital recording greatly improved the quality of seismic data and by 1975 nearly all seismic recording was digital. With digital recording came an awareness about preserving relative amplitudes. After early successes, ‘bright spot’ technology rapidly evolved in the early 1970s. Bright spot technology involved efforts to quantify the seismic amplitude changes and to calculate pay-sand thicknesses and had a major impact on bidding in offshore Louisiana shelf and the Gulf of Mexico. Time/structure, velocity and seismic amplitude are the most fundamental attributes in use today.

Bright spot technology included more than amplitudes, but also included flat spots, frequency loss, time sags, time shadows, polarity reversals, and dim spots – features identified by the interpreter that will form the motivation for later seismic attribute developments. Encouraged by the success of the bright spot technology application, especially for reducing risk in high-cost environments, geophysicists now started looking at these other hydrocarbon indicators. (Taner et al, 1979) observed ‘low frequency shadows’ below hydrocarbon reservoirs (which we now know to be due to gas sands and condensates). No adequate explanation was provided to explain this phenomenon, although several possible contributing reasons were proposed, nor has much has been published on this topic since. (Recently, Ebrom (2004) has listed at least ten mutually non-exclusive mechanisms for this effect.)

Reflector dip

While binary gain digital recording inspired amplitude-analysis techniques, it also enabled developers to improve structural interpretation techniques. Picou and Utzman (1962), used a 2-D unnormalized cross correlation scan over candidate dips on 2-D seismic lines to estimate dip at every sample and every trace on a seismic section (Figure 2). The result of this process was a suite of dip vectors, which was plotted on the seismic section using specialized hardware. Further work on estimating reflector dip was driven by contemporaneous developments in map migration, which is summarized by Bednar's (2005) 75th SEG Anniversary review paper on seismic migration. The computer was being used as a means of enhancing the display of seismic data.

1970-1980

Introduction of color in seismic displays

In 1971, A. H. Balch developed a computer-graphic-photographic system, called the color sonogram, to display the frequency spectra of seismic events simultaneously with their time varying waveforms. In this display, the waveforms are displayed using a conventional variable area scheme, but with the positive lobe now colored to represent the frequency spectra of the wavelet. The lateral changes in rock attenuation, or the loss of high frequencies due to slight lateral changes in move-out velocity, etc. could show up as color shifts on such displays. Balch's 1971 paper is credited with being the first published in *Geophysics* to display seismic data in color. His work heralded the beginning of an era where color, with the enhanced dynamic range that it offers, was used for meaningful analysis of seismic data.

The rise of seismic attributes

At around the same time (1968-69), Nigel Anstey at Seiscom Ltd was working on innovative seismic displays and playing a key role in introducing color on seismic sections. Experimenting with the first laser plotter (developed by SIE) installed in their office in London, Anstey and his team (Ron O'Doherty, Peter Ferrer, Judy Farrell, and later Lloyd Chapman) developed several programs to display two variables on the seismic section: the normal seismic trace to give the geological picture, and an auxiliary modulation to show interval velocity, reflection strength, frequency content, or anything else that might prove useful. The overlay of the color attributes on the black and white seismic sections resulted in displays that provided more information — with the conventional black and white seismic display providing structural information, and the seismic attribute providing more subtle stratigraphic information. Since this was the time of the 'bright spot' revolution, the most popular of these displays were those of reflection strength (the amplitude of the envelope).

Anstey published his innovative work on attributes in two internal reports for Seiscom Ltd (Anstey, 1972, 1973a) and also presented at the 1973 SEG annual meeting (Anstey, 1973b). The high cost of printing in those early days of color processing prevented Anstey's reports from being widely circulated. However, they do represent an important landmark for the introduction of both color and attributes into the seismic world. As Anstey puts it, 'the real advance lay in the simultaneous display of an attribute *in its geological context*; the color was just a way of doing this' (Anstey, 2005).

In Figure 3 we display one of Seiscom Ltd's conventional (but still high quality) seismic displays of the early 1970s — a variable density plot of the seismic data showing the most positive values of the seismic data as black. The use of variable density (commonly called variable intensity on modern interpretation workstations) allowed interpreters to plot data in 'squash-plot' form, with the horizontal scale greatly compressed, thereby emphasizing subtle structural trends. In contrast, conventional variable area plots lost progressively more dynamic range as the trace width was compressed. In Figure 4 the interval velocity, obtained using Dix's equation, is superimposed on these seismic traces. In Figures 5-9 we show several other of the earliest attribute plots — reflection strength (Figures 5 and 8), apparent polarity (Figure 6), and high frequency loss (Figure 7). In Figure 9 we show reflection strength displays from a 2-D grid of data, combined to form an isometric fence diagram. The displays could be rotated to optimize the view, 'sculpted' down to reservoir level and supplemented by a superposed contour map (Anstey, 2005).

Complex-trace analysis

After Anstey left Seiscom in 1975, two of his colleagues at Seiscom in Houston, Turhan Taner and Fulton Koehler, advanced these developments, and gave them a sound mathematical basis. Turning their attention to seismic wave propagation, they interpreted the recorded seismic waveform on geophones sensitive to particle velocity to be the kinetic energy component of the total energy flux. Under this assumption of simple harmonic motion, they felt it should be possible to compute the potential energy component as well. Thus, Koehler developed an energy-based procedure and computed the envelope of a seismic trace in this manner.

Norman Neidell, also working as a research geophysicist at Seiscom, came up with the suggestion that the Hilbert transform approach might be a useful way of achieving the same result. The Hilbert transform served as a starting point for the complex-trace analysis we now use routinely. Taner and Koehler continued this work and developed a single mathematical framework for attribute computation. The seismic trace amplitude is treated as the real part of the (complex) analytical signal while the imaginary part of the signal is computed by taking its Hilbert transform (Figure 10). The envelope is computed by taking the square root of the sum of the squares of the real and imaginary components, while the phase is computed by taking the double argument (ATAN2) inverse tangent of the imaginary and real components. Finally, the frequency is computed as the rate of change of the phase. These computations were carried out at each sample of the seismic trace and have since been dubbed *instantaneous* attributes. By 1975, three principal attributes, envelope, phase and frequency were established:

- *Instantaneous envelope* (reflection strength) is sensitive to changes in acoustic impedance and thus to lithology, porosity, hydrocarbons, and thin bed tuning,
- *Instantaneous phase* is useful for tracking reflector continuity, and therefore, for detecting unconformities, faults and lateral changes in stratigraphy, and
- *Instantaneous frequency* is useful in identifying abnormal attenuation and thin bed tuning.

Seismic stratigraphy and complex-trace analysis

Taner presented his complex-trace analysis at the 1976 SEG meeting The timing for the development of this work proved to be opportune. Exploration activity was in full swing, driven by the energy crisis of the 1970s, while the principles of seismic stratigraphy were being introduced by Peter Vail and his colleagues at Exxon (Figure 11). As Taner remembers, ‘One day as I displayed the instantaneous phase for a seismic profile, I was amazed to see the many different depositional patterns. I immediately called Peter and showed him the results I had. He was very impressed and said, ‘That’s the kind of section I would like to have for stratigraphic interpretation.’’ (Taner, 2005).

Bob Sheriff recalls the 1976 AAPG meeting in Dallas where much of these advances were presented: “The presentations on seismic stratigraphy at the convention made such an impact that there was a request that the entire meeting be re-presented for those who had missed it. Instead, it was decided that a week-long seismic stratigraphy school would be more effective. This was only the 2nd school ever, and the AAPG continuing education coordinator was most effective in finding delightful off-season venues at delightful resorts around the country and internationally. This school was conducted for 7-8 years, with the AAPG Memoir 26 (Payton, 1977) serving as the textbook".

While Peter Vail showed that seismic stratigraphy could be used as a measure of depositional processes, seismic attributes gained in popularity and respect. Taner, along with his colleagues Fulton Koehler and Robert Sheriff (who at the time was a member of the research team), published this work in two seminal papers (Taner and Sheriff, 1977; Taner et al, 1979) that helped geophysicists gain a better understanding of complex-trace analysis and its applications. In Figure 12 we display some of Taner's early displays of complex attribute analysis of different lightologies.

Color plotting of seismic data

Alongside the theoretical evolution of complex-trace analysis, the hardware and software needed to do efficient color plotting were also developing during this time. Thus, by the late 1970s color plotters had invaded the market and as a result time was right for the application of complex-trace analysis to aid seismic interpretation. Color plotting is thus an important piece of history, as the theoretical development would have had much less impact if there had been no good way to display attributes in color.

Jamie Robertson recalls that seismic stratigraphy was an application that picked up and justified the expense of color plotting at Arco. Seismic stratigraphers saw the new color displays as tools to help pick event terminations, unconformities and other fundamental inputs of seismic stratigraphy. In many oil companies, part of the justification for buying expensive plotters at the time was to plot seismic attribute sections and seismic stratigraphic analysis. In other companies, the expense was justified by the advent of 3-D seismic data and the ability to display horizontal slices.

Seismic impedance inversion

During the mid 1970s, another significant seismic attribute contribution was inversion of post stack seismic amplitudes into acoustic impedance, an important physical property of rocks and an aid in studying the subsurface. The inverted impedance sections yielded useful information about the lateral changes in lithology and porosity. The conversion of seismic traces into acoustic impedance and velocity pseudo logs was first reported by Lavergne (1975) and Lindseth (1976, 1979), and they quickly became popular, mainly due to the ease and accuracy of interpretation of impedance data and also the stratigraphic interpretation framework that picked up at that time. Figure 13 shows an inverted seismic section from the Swan Hills Devonian reef bank that Lindseth used for prediction of Carbonate porosity. Notice at the time Lindseth used a transit-time scale rather than a velocity scale and he also used a lithological color scale to highlight the changes in transit-time, which distinguished carbonate from clastic sections on the inverted acoustic impedance sections.

Seismic inversion for acoustic impedance is routinely used today. We lump acoustic impedance in with other ‘attributes’, to be calibrated with well log data. Because of its early use of color overlays, impedance inversion was thought by many (especially management that didn’t want to pay for expensive plotters) to be no more than pretty colored wiggle traces. Indeed, 20 years later, Rebecca Latimer (2000) still felt it important to correct this misconception.

Some shortcomings

A significant reality of the 1970s in many companies was that seismic data were interpreted by geophysicists rather than by geologists. The geophysicists engaged in processing at the time did a good job with structural imaging, arriving at noise free, continuous reflections on the final processed sections. Unless schooled in the concepts of seismic stratigraphy, subtle discontinuities and fine detail associated with what we now know interpret as slumps, turbidites, and other 'chaotic' features could be lost. In general, the resolution of the seismic data in the 1970s was poor. Since not many geologists were trained as geophysicists (Ravenne, C., 2002), the geological input to interpretation would be missing, resulting in an erroneous product. There would often be disagreement on the final results, with geologists arguing over geological input and the geophysicists arguing about the uncertainty associated with the interpretations based on reflections following a complex path as they travel in the subsurface. Thus, by the end of the 1970s, even though the concepts of seismic stratigraphy were developing, there were few well established workflows - it was simply too difficult to estimate key lithologic parameters directly from trace data (May and May, 1991).

1980 – 1990

Incremental improvements

The 1980s saw a proliferation of seismic attributes with the development of the cosine of instantaneous phase, dominant frequency, average amplitude, zero-crossing frequency, and many others. The cosine of instantaneous phase was developed since it is a continuous parameter, unlike the phase itself which has a discontinuity at ± 180 °. Such a continuous attribute could be interpolated, smoothed, processed, and even migrated. It also saw the introduction of interval and formation attributes which measure an average property in a user-defined window about a picked horizon, or alternatively, between two picked horizons. Such 'windowed' attributes are frequently used when the seismic reflections associated with a reservoir is sufficiently heterogeneous to preclude tracking a consistent peak or trough on all traces. Interval and formation attributes are often more statistically meaningful, just as in well log correlation, where we combine a number of thin discontinuous sand units to generate a net-to-gross sand ratio map rather than maps specifying individual unit thicknesses.

A noteworthy observation was made by Robertson and Nogami (1984), that the instantaneous frequency at the peak of a zero-phase seismic wavelet is equal to the average frequency of the wavelet's amplitude spectrum. That is to say there are points on a conventional instantaneous frequency trace where the instantaneous frequency directly measures a property of the Fourier spectrum of the wavelet. For the same reason, the instantaneous phase corresponds to the wavelet's true phase at these points. These physically meaningful measurements occur at a small number of points. The remaining instantaneous attribute measures provide little additional information about the seismic wavelet. Interpreters were frustrated when they attempted to do so and quantify reservoir properties. Later on, White (1991) showed that Robertson and Nogami's (1984) relationship between instantaneous frequency at the reflector peak and average spectrum does not statistically hold in practice due to noise and waveform interference.

Response attributes

The most stable of the instantaneous attributes was the envelope and could always be counted on to provided accurate interval thicknesses. Bodine (1984,1986) examined the instantaneous frequency and phase in terms of the reflection event seen between minima on the instantaneous envelope. He argued that since most of the signal energy in a trace is found in the vicinity of envelope peaks, the reflection event's phase and frequency could be more accurately described by assigning them to the value seen at peaks. While Bodine called these 'response' attributes, we prefer Taner's more descriptive term of 'wavelet' attributes. Thus, response (or wavelet) phase is the instantaneous phase at the point at which the envelope is maximum. One value is computed for each lobe and is applied to the width of the energy lobe from trough to trough. This phase is independent of the amplitude and measures phase variations between successive energy lobes. Similarly, response frequency is the value of instantaneous frequency at the point at which the envelope is maximum and a single value is returned for the width of the energy lobe between two successive troughs. Since the response frequency is calculated at envelope peaks, it avoids the singularities seen where seismic events interfere, which is worst at the envelope troughs. (Later on, Hardage et al. (1998) advocated using these discontinuities in instantaneous frequency for interpretation, while Taner (2000) developed a thin-bed indicator based on the difference between the instantaneous frequency and the envelope weighted instantaneous frequency.

These singularities will also form the basis of Liner et al.'s (2004) SPICE attribute). These peak values will also be the ones mapped later by Bahorich and Bridges (1992) in their seismic sequence attribute mapping effort. Additional discussion of response attributes can be found in Robertson and Fisher (1988).

Early Texture Analyis

Inspired by the Sangree and Widmier's (1976) suggestion that zones of common seismic signal character are related to the geologic environment in which their constituent sediments were deposited, Love and Simaan (1984) attempted to extract these patterns using texture analysis. If a given signal character can be represented in the form of a 2-D amplitude template, then it would be possible to classify every pixel by matching its local texture with the template of each feature. Further improvements to this template matching process were made by incorporating artificial intelligence into the classification process. While such efforts were supposed to help with automatic analysis of large amounts of 2-D surface seismic data in a regionally consistent manner, they enjoyed very limited success. Part of this lack of success was due to the low S/N ratio of the data and out-of-the-plane artifacts on 2-D data. However, we feel the biggest handicap was that the 2-D stratigraphic patterns could not be standardized. 20 years later, with 3-D data routine, we now realize the main problem was due to the limitations of 2-D seismic stratigraphy. Seismic patterns classified alternatively as 'parallel', 'sigmoidal', or 'hummocky clinoforms' could all describe the same fan system – but the appearance depending on the orientation of the 2-D acquisition over the over the fan, not on the geology.

Interpretive workstations

The 1980s saw the advent of interpretive workstations. Workstation development started within each of the major oil companies, first on mainframes, then on dedicated minicomputers, then on the PCs, and finally on UNIX workstations. The hardware costs were initially high but then plummeted rapidly. The 2nd author remembers paying $120,000 for a dedicated PC system (that was less powerful than his current cell phone!). More interestingly, the dedicated workstation table (with 3 translational and 2 rotational degrees of freedom) cost $110,000! The 1980s saw a major shakeout in the interpretive workstation arena. The ever-increasing spiral of new computer 'standards' burnt out the not-so-nimble beginning-to-age geophysicists. Old software 'standards' like the multi-user 'Uniras' standard justified by the 2nd author in the 1980s for $2,000,000 at Amoco, had too many legacy applications to keep up with the evolving hardware. Most companies gave up internal development and during the low price of oil that occurred in the later half of the decade, 'outsourced' workstation development and maintenance to vendors such as Scitex, Landmark, and Geoquest.

There were two main benefits of the interpretive workstation that beneficially impacted attributes. First, the use of color became pervasive and (unless you wanted a hardcopy!) economical. Second, a great many attributes became interactive. The benefit here was more one of risk reduction rather than of speed. The daring interpreter could simply try out an idea in the dead of night and show favorable results to his or her boss the next day if it enhanced the map. If it failed, it was just one more computer file to be erased. There was no paper trail, and more importantly, no internal plotting costs, and no external contractor costs to explain to management.

There was one major disadvantage of this shake out. The diversity of more than 20 research groups following their intuition and local business drivers within oil company labs were replaced by 3 or 4 software groups being driven by customer demands and marketing constraints. Many good ideas were put in a 'job jar' and died during this shakeout. We show one of these ideas in Figure 14, which is patterned after a presentation made by Knobloch (1982) while working on interpretation workstation software and workflows at Conoco. In it we show an image of seismic data, of instantaneous envelope, instantaneous phase, and a composite of instantaneous phase and envelope using a 2-D color bar. 25 years later, such a 2-D color bar is still not provided by the three main workstation vendors.

More colors and shaded relief maps

The number of colors expanded rapidly in the 1980s. The 2nd author remembers many arguments about whether 8 or 16 colors were sufficient to display the information content of seismic data, primarily phase, frequency, envelope, and velocity. Those who were older (management!) and poor dressers (also management!) felt that 8 colors were sufficient. Interpreters favored 16. To analyze the sensitivity of the human eye, Knobloch (1982) displayed an image of Cheryl Tiegs (the cover girl of the era) in 2048 colors. Everyone agreed that Cheryl was a beautiful woman. He then dropped the display to 1024 colors. The 5% of the audience that were women all smiled – Cheryl had become pasty looking. By 512 colors the men noticed too, with poor Cheryl suffering from a bad case of acne. Knobloch's point was that of pattern recognition – the interpreter can see a great amount of detail through the use of colors if he or she has the experience or training.

Because of computer memory and I/O constraints, most of the commercial workstations settled on an 8-bit color display. Typically, 5 of these bits were used for color display of the seismic (giving 32 colors), while the remaining 3 bits (8 colors) were used to display the interpretation. In this manner, an interpreter could toggle horizon and fault picks on and off by simply changing the color lookup table. While 24 bit color became widely available with UNIX-based workstations in the late 1980s, the cost of updating legacy applications forced most vendors to continue to provide only 32 or 64 colors to the user until quite recently. With the recent market push to rewrite these legacy software applications for use on Linux and PC systems, these vendors now provide 256 colors.

The 1980s also saw the adoption of shaded relief maps (Batson et al., 1975), which became widely dispersed through the application to geophysical (SEASAT) measurements by Bill Haxby working at Lamont Doherty of Columbia University. Shaded relief maps of seismic data, including draped shaded relief maps with a 3-D perspective, are now part of nearly all 3-D seismic interpretation and visualization packages.

Auto trackers

Fortunately for practitioners, a few companies soldiered on with internal research and development. One of note is the work initiated by Naaman Keskes at the French National Robotics and Computer Lab (INRIA), supported in part by Elf Acquitaine.

Keskes and his colleagues used a suite of attributes, including instantaneous dip, semblance, amplitude, phase, and frequency to track 'seeded' picks around a grid of 2-D seismic lines. Keskes later joined Elf Acquitaine in Pau, where he was one of the key designers of their internal 'Sismage' product (Keskes et al., 1982, 1983; Sibille et al., 1984). A derivative of Sismage was commercialized 15 years later under the name 'Stratimagic', which is now one of the more popular attribute analysis applications.

As a side note, a contemporary in the French university system, Evgeny Landa, was also sponsored by Elf Acquitaine. While their focus was velocity analysis for prestack depth migration (Landa et al., 1989), their tools consisted of complex-traces, semblance, and dip. Scheuer and Oldenburg (1988) also used complex-trace analysis for velocity analysis. Their work formed the basis for 2-D (and later 3-D) dip and azimuth computation by Barnes (1996), who at that time was collaborating with Taner. Taner also addressed the auto-tracking problem, but with an emphasis on first break picking for refraction statics.

In summary, the 1980s saw a rapid expansion in the seismic processing and display capabilities necessary for the explosion of attribute techniques that would occur in the mid 1990s. However, attribute usage in the 1980s actually decreased over that in the late 1970s.

Attributes fall out of favor

Complex-trace attributes suffer from waveform interference that can obscure subtle trends in the data. In particular, instantaneous frequency estimates can fall outside the seismic bandwidth and even generate negative values. Although a few workers understood this phenomenon, and could use it as an unconformity or thin bed indicator, the impact of waveform interference was not published, such that interpreters attempting to associate physical meaning with such attributes were frustrated by such artifacts. They also found it difficult to relate these attributes directly to logged reservoir properties like porosity and thus they could not be used to quantify reservoir properties. As the 1980s passed, seismic attributes lost credibility with the interpreters. This loss was probably coupled with a loss of faith in seismic stratigraphy as well, as numerous dry holes were drilled based on seismic stratigraphic predictions. Robertson (2005) lists some the contributing factors as follows:

1. Given the limited resolution of the seismic data available in the 1980s coupled with the lack of geological input to interpretation, interpreters lost sight of what seismic data could really resolve, compared to the stratigraphic resolution they were seeking. Numerous interpretations of geological detail simply were unjustified by the resolution of the seismic data. When geologists attempted interpretations of seismic attributes, they often did not have a sound understanding of the limitations of seismic data, and their geophysicist teammates did not do a good job of educating them in the pitfalls of the seismic resolution.
2. 3-D seismic surveying began in the early 1970s and by the mid-1980s emerged as a beneficial technique in many onshore and offshore areas around the world. It improved resolution enormously and contributed effectively fewer dry wells. Even though it was considered expensive at the time, 3-D seismic interpretation proved to be much better at making successful exploration predictions than seismic stratigraphic analysis of 2-D seismic data. This had a dampening effect on the use of 2-D seismic

stratigraphic interpretation of attribute sections. Use of attribute techniques only re-emerged after workstation tools were developed to apply the technology to 3-D data.

3. After the energy crisis of the 1970s and the accompanying oil price rise, oil companies in the early 1980s scrambled to drill prospects and were not careful to drill only the good ones. Exploration management in essence allowed too many poor prospects to be drilled, and seismic stratigraphy/attribute analysis took the blame for failure when the blame really should have gone to poor exploration management judgment.

Other experts at the time also voiced their concerns about this state in which seismic attributes were found and Barnes (2001) lists their excerpts from the literature.

Seismic stratigraphy faced an additional problem with 3-D data. One of the more common workflows on 2-D data was to generate ‘A-B over C’ interpretations on seismic sections and then post them manually on maps, which were then contoured. 3-D data precluded posting such dense alphanumeric information. It was not uncommon for the ‘stratigrapher’ member of the team to extract several key 2-D lines and go off to do hardcopy interpretation while the rest of the team was deeply immersed in the digital world.

We should note that while complex-trace attributes of seismic traces that otherwise often went unnoticed, they did not create any new information. While attribute analysis produces additional sections which tend to point out certain aspects of geology that were masked on the variable-area/wiggle-trace seismic sections, a skilled interpreter with sufficient time could extract all the necessary details using conventional interpretation techniques. Seismic sequence attribute mapping (or simply stated, the mapping of extracted attributes much like picked travel times) developed by Bahorich and Bridges (1992) would change this impediment for 2-D data. Time slices, horizon slices, and arbitrary vertical traverses would change it for 3-D data.

We should also recall that during this time that seismic data was expensive to collect and process. 50% of geophysicists were involved in acquisition and processing, with the remainder making maps (interpretation). Today, fifteen to twenty years later, the vast majority of geophysicists are interpreters – we have become so buried in seismic data that most seismic lines may never be touched by a human being!

Two-dimensional attributes

By the mid 1980s considerable improvements in recording and processing techniques had enhanced the information content of seismic data that is required for stratigraphic interpretation. During this time a number of two-dimensional continuity and dip attributes were also developed that were employed in procedures for defining and analyzing seismic facies (Contcini, 1984; Vossler, 1989). Finn (1986) anticipated the need for 3-D estimates of dip and azimuth by applying a 2-D semblance estimate of apparent dip on surveys of 2-D intersecting lines. Though novel and interesting, these procedures did not evoke an enthusiastic response. The results could be subjective and 2-D surveys simply contained too many artifacts from out of the plane.

Horizon/interval attributes

Towards the middle of the 1980s and later, horizon attributes (Dalley et al 1989) and interval attributes (Sonneland et al, 1989) were introduced which demonstrated that interpreted horizons exhibited reflector characteristics not easily observed on the vertical seismic sections. The areal variation in reflection characteristics could be related to paleogeographic elements (Brown and Robertson, 1985) while the amplitude extractions of seismic horizons revealed features directly related to stratigraphic events. These amplitude extraction maps were used to interpolate/extrapolate reservoir properties from well control (Thadani, 1987). The most important of the references establishing these work flows is Alistair Brown's (1986) AAPG Memoir 42.

1990-2005

Industry adoption of 3-D seismic

The 1990s brought new life to seismic attribute analysis. The main reason for this was that the industry had by now embraced 3-D technology – by far the most successful new exploration technology of several decades. By it's very nature, 3-D required computer-aided interpretation and the decimation of images that were presented to the interpreter and drilling decision teams. Perhaps the single most important contribution at this time was the concept of 3-D attribute extractions. One of the earliest publications is by Dalley et al. (1989) and his colleagues at Shell, Rijks and Jauffred (1991), who introduced two concepts that are now commonplace in the interpretation workplace – dip/azimuth maps and amplitude extractions. In Figure 15 we reproduce a suite of images from Rijks and Jauffred (1991), including a vertical section through the seismic data showing the picked top and bottom of the formation in Figure 15a, a dip magnitude map of the upper horizon in Figure 15b, a shaded relief map of the same horizon in Figure

15c, and amplitude extractions from both the upper and lower horizons in Figures 15d and e. These images not only showed the value of 3-D seismic data, they also established standard workflows that are still accepted as best practices today.

The association of attributes with 3-D seismic breathed new life into attribute analysis, moving it away from seismic stratigraphy and towards exploitation and reservoir characterization. Contemporaneous developments in rock physics research provided the quantitative basis of how rock properties affect seismic data, allowing us today to directly relate attributes to rock properties in a much more credible way that was possible in the 1980s (Robertson, 2005).

Seismic sequence attribute mapping

It is somewhat surprising that making maps of attributes generated on 2-D surveys followed making similar maps (attribute extractions or horizon slices) directly from 3-D data. While complex-trace analysis numerically quantified subtle changes in envelope, amplitude and phase, these same ‘attributes’ of the data could be readily seen by an experienced interpreter from the original seismic data itself. However, such human interpretation could not readily be turned into a map. The basic concepts of such mapping were first presented by Sonneland et al. (1989), followed later by Bahorich and Bridges (1992) and Bahorich and van Bemmel (1992) who presented this concept as the “seismic sequence attribute map” (SSAM). Interestingly, Amoco’s involvement in this effort took place out of its Denver exploration office rather than its research center in Tulsa. Having unwillingly given up internal workstation development in the late 1980s, Amoco’s research efforts (like most other companies) were focused on ‘more important’ technologies, including prestack depth migration and AVO. Bahorich proselytized the value of SSAM so strongly that eventually he was 'punished' and sent to dwell with the technology misfits in Tulsa, thereby solving both 'problem' groups. This fortuitous occurrence soon lead to Amoco's development of seismic coherence.

3-D seismic exploration comes of age

By the mid 1990s 3-D seismic technology became affordable. Whereas by 1980 only 100 3-D seismic surveys had been done, by the mid 1990s an estimated 200-300 3-D surveys were being conducted annually. Good 3-D interpretation workflows on interactive workstations were being perfected. Complex-trace analysis was performed on full 3-D seismic volumes and used in the interpretations. However, most 3-D interpretation was performed on vertical in-lines and cross-lines and then projected onto a time slice. Though this worked well, it lead to ambiguities in the lateral resolution of faults, especially where faults join together, cross or simply end as a result of changes in geologic stress.

Seismic coherence

Although 3-D was routinely used for exploitation, Amoco still primarily used 2-D for exploration in early 1990s. Bahorich, now imprisoned with (and accused of being one of!) Amoco's researchers, was faced with the problem of making his seismic sequence attribute mapping workflow produce useful results in multiple overlapping 2-D surveys. Since the data had radically different amplitude, phase, and frequency, there was little that could be done in an interpretative workstation – phase and spectral matching required reprocessing. Instead, working with programmer Steve Farmer, Bahorich evaluated several alternative attributes that were relatively insensitive to the source wavelet (Unbeknownst to the Amoco team, this was Finn's (1986) M.S. thesis, though Finn did not have a ready means of posting his data in map view). Faults were easily seen and could be tracked on the 2-D section. Within a week, John Lopez, a structural geologist member of the team working out of Amoco's New Orleans office, applied it to a large 3-D data set. The results were astounding. Seismic coherence was born

Bahorich and Farmer (1995) state that this was the 'first published method of revealing fault surfaces within a 3-D volume for which no fault reflections had been recorded.' Their volume of coherence coefficients computed from the seismic amplitudes on adjacent traces using a cross-correlation technique, portrayed faults and other stratigraphic anomalies clearly on time and horizontal slices. The coherence images showed up distinctly buried deltas, river channels, reefs, and dewatering features. The remarkable detail with which stratigraphic features show up on coherence displays, without any interpretation bias, and some unidentifiable even with close scrutiny, appealed to the interpreters. They had a new view of their data. The Amoco team followed their original three-trace cross-correlation algorithm with semblance and eigen-decomposition coherence estimates (Marfurt et al, 1998; Marfurt et al, 1999; Gersztenkorn and Marfurt, 1999) which provided improved clarity and lateral resolution (Chopra, 2002). According to the SEG, 'this significantly changed the way geophysicists interpret 3-D seismic data and the way oil industry management views geophysicists' contributions to the industry.'

Figure 16 depicts an example from offshore East Coast of Canada, where NW-SE faults and fractures, apparently difficult to interpret, show up clearly on coherence time slices. Overlaying coherence on a seismic time slice provides the interpreter with the capability to more easily name and link master and antithetic faults.

Spectral decomposition

Another Amoco misfit cried for attention by his research colleagues in Tulsa, this time from Calgary. Again, the proselytizer and miscreant were soon cellmates in Tulsa and forced to live in harmony. The 2nd author of this article, prescient as he thinks himself to be, was one of these miscreants and soon found himself as Partyka's supervisor. He was familiar with the recent work by Okaya (1995) and thought he understood the work by Amoco alumni Kallweit and Wood (1984) on the limits of lateral resolution. All of Partyka's examples were 2-D lines from Canada having poor vertical resolution. Partyka displayed his images using an innovative ribbon plot, since made available in Stratimagic. Poor dresser that he was then, Marfurt didn't like these images. Fortunately, Amoco supervisors in their research center wielded precious little power or influence, such that Partyka charged ahead. He partnered with the signal analysis team (Gridley) and interpreters (Lopez in New Orleans and Peyton in Denver) and applied his technique to 3-D data, where like many other attributes in 3-D map and horizon slices, it made a significant interpretational impact (Partyka et al., 1999; Peyton et al., 1998). Spectral decomposition was born. This work continues actively today, with most workers preferring the wavelet transform based approach introduced by Castagna et al. (2003) over the original discrete Fourier transform.

Seismic inversion revisited

The original recursive or trace-integration seismic inversion technique for acoustic impedance also evolved during the late 1980s and 1990s, with developments in model-based inversion, sparse-spike inversion, stratigraphic inversion, geostatistical inversion, providing accurate results (Chopra, 2001). The earlier techniques used a local optimization method that produced good results when provided with an accurate starting model. Local optimization techniques were followed by global optimization methods that gave reasonable results even with sparse well control.

Connolly (1999) introduced elastic impedance, which computes conventional acoustic impedance for non-normal angle of incidence. This was further enhanced by Whitcombe (2002) to reflect different elastic parameters such as Lamé's parameter λ, bulk modulus κ, and shear modulus μ.

Crossplotting of attributes

Crossplotting of attributes was introduced to visually display the relationship between two or three variables (White, 1991). Hilterman and Verm (1994) used crossplots in AVO analysis, which have been used since as AVO anomaly indicators. When appropriate pairs of attributes are cross-plotted, common lithologies and fluid types often cluster together, providing a straightforward interpretation. The off-trend aggregations can then be more elaborately evaluated as potential hydrocarbon indicators, keeping in mind the fact that data that are anomalous statistically are geologically interesting - the essence of successful AVO crossplot analysis. Extension of crossplots to three dimensions is beneficial as data clusters 'hanging in 3-D space' are more readily diagnostic resulting in more accurate and reliable interpretation.

In Figure 17 we illustrate the use of modern crossplotting software of three attributes that help identify a gas anomaly – Lambda-Rho on the x-axis, Mu-Rho on the y-axis and fluid stack on the z-axis. In Figure 17a, we indicate a gas anomaly on a time slice through the Lambda-Rho volume by a blue patch. We then draw a red polygon on the time slice to select live data points to be displayed in the crossplot. The red cluster of points in Figure 17b corresponds to the red polygon and five time slices (two above and two below the one shown). As the crossplot is rotated toward the left on the vertical axis, the fluid stack shows the expected negative values for the gas sand (Figure 17c)

Automated pattern recognition on attributes

The attribute proliferation of the 1980s resulted in an explosion in the attribute data available to geophysicists. Besides being overwhelming, the sheer volume of data defied attempts to gauge the information contained within those data using conventional analytical tools, and made their meaningful and timely interpretation a challenge. For this reason, one school of geophysicists examined automated *pattern recognition* techniques, wherein a computer is trained to 'see' the patterns of interest and then made to sift through the available bulk of data seeking those patterns. A second school of geophysicists began combining attributes sensitive to relevant geological features through *multi-attribute analysis*.

Neural network application for multi-attribute analysis

One attempt at automated pattern recognition took the form of neural networks (Russell et al, 1997), wherein a set of input patterns is related to the output by a transformation that is encoded in the network weights. In Figure 18 we show an example on how multivariate statistical analysis can be used in determining whether the derived property volumes are related to gas saturation and lithology (Chopra and Pruden, 2003). For the case study from southern Alberta, it was found that the gamma ray logs in the area were diagnostic of sands, and there was a fairly even sampling of well data across the field. A non-linear multi-attribute determinant analysis was employed between the derived multiple seismic attribute volumes and the measured gamma ray values at wells. By training a neural network with a statistically representative population of the targeted log responses (gamma ray, sonic, and bulk density) and the multiple seismic attribute volumes available at each well, a non-linear multi-attribute transform was computed to produce gamma ray and bulk density inversions across the 3-D seismic volume.

In Figures 15a and b we show the Lambda-Rho and Mu-Rho sections with the anomaly enclosed in a yellow polygon. The cross-plots for these two attributes are also shown (Figure15c). The yellow dots on the cross-plots represent the values within the polygons on Figures 15a and b. The magenta polygon on Figure 19c indicates where we would expect to find gas sands in Lambda-Rho and Mu-Rho space in Figures 19a and b. The results of the gamma inversion are shown in Figure 20. The data are scaled to API gamma units in Figure 20a and converted to porosity in Figure 20b using the standard linear density relationship. From log data, the sand filled channels are interpreted as having gamma values less than 50 API units. This cut off value was used to mask out inverted density values for silts and shales. Analysis of Figures 17a and b shows three distinct sand bearing channels. Cubic B-spline curves (mathematical representation of the approximating curves in the form of polynomials) have also been used for determination of mathematical relationships between pairs of variables for well logs and then using them to invert attribute volumes into useful inversion volumes like gamma ray and porosity (Chopra et al, 2004). In Figure 21 we show spline curve inverted porosity

Enhanced visualization helps attribute interpretation

Gradually as geophysicists realized that the additional benefits provided by 3-D seismic were beneficial for stratigraphic interpretation of data, seismic interpretation methods also shifted from simple horizon-based to volume-based work. This provided interpreters new insights that were gained by studying objects of different geological origins and their spatial relationships. In Figure 22 we display strat cubes (sub-volumes bounded by two not necessarily parallel horizons,) generated from the seismic and the coherence volumes. The coherence strat cube indicates the N-S channel very clearly, the E-W fault on the right side as well as the down thrown side of the N-S fault on the left.

Of course with all this also came the complexity and the magnitude of identification work and the need for faster and more accurate tools. This brought about the significant introduction of techniques for automated identification of seismic objects and stratigraphic features. Keeping pace with such emerging technologies were the advancements in visualization and all this modernized the art of seismic interpretation. Starting at the seed voxels, a seed tracker will search for connected voxels that satisfy the user-defined search criteria, thereby generating a 3-D ‘geobody’ within the 3-D seismic volume.

While one given attribute will be sensitive to a specific geologic feature of interest, a second attribute may be sensitive to a different kind of feature. We can therefore combine multiple attributes to enhance the contrast between features of interest and their surroundings. Different methodologies have been developed to recognize such features. Meldahl et al. (2001) used neural networks trained on combinations of attributes to recognize features that were first identified in a seed interpretation. The network transforms the chosen attributes into a new 'meta-attribute', which indicates the probability of occurrence of the identified feature at different seismic positions. Such highlighted features definitely benefit from the knowledge of shapes and orientations of the features that can be added to the process.

Trace shape

While spectral decomposition and wavelet analysis compare seismic waveform to precomputed waveforms (typically windowed tapered sines and cosines), an important development was released by Elf Acquitaine in the mid 1990s – trace shape classification. In this approach, the interpreter defines a zone of interest pegged to an interpreted horizon, and then asks the computer to define a suite of approximately 10-20 waveforms that best express the data. The most useful of these classifiers is based on Self-Organized Maps (Coleou et al., 2003) that provides maps whose appearance is relatively insensitive to the number of classes. Although the results can be calibrated to well control through forward modeling, and although actual well classes can be inserted, this technology is particularly well suited to a geomorphology driven interpretation, whereby the interpreter identifies depositional and structural patterns from the images and from these infers reservoir properties.

Texture attributes

More recently the idea of studying seismic 'textures' has been revived. While the term was earlier applied to seismic sections to pick out zones of common signal character (Love and Simaan, 1984), studies are now underway to use statistical measures to classify textures using gray-level co-occurrence matrices (Vinther et al., 1995; Vinther, 1997; Whitehead et al., 1999; West et al., 2002; Gao, 2003, 2004). Some of the statistical measures used are energy (denoting textural homogeneity), entropy (measuring predictability from one texel or voxel to another), contrast (emphasizing the difference in amplitude of neighboring voxels) and homogeneity (highlighting the overall smoothness of the amplitude). Homogeneity, contrast and entropy have been found to be the most effective in characterizing seismic data.

Figure 23 shows a comparison of the amplitude and homogeneity horizon slice at the same stratigraphic level. Notice that the channel/levee deposits can be recognized, mapped and detected more effectively from the homogeneity volume than from the amplitude volume.

Curvature

With the wide availability of 3-D seismic and a renewed interest in fractures, we have seen a rapid acceleration in the use of curvature maps. The structural geology relationship between curvature and fractures is well established (Lisle, 1994) though the exact relationship between open fractures, paleo structure, and present-day stress is not yet clearly understood. Roberts (2001), Hart et al. (2002), Sigismondi and Soldo (2003), Massafero et al. (2003) and others have used seismic measures of reflector curvature to map subtle features and predict fractures. Curvature (a 3-dimensional property of a quadratic surface that quantifies the degree to which the surface deviates from being planar) attribute analysis of surfaces helps to remove the effects of regional dip and emphasizing small-scale features that might be associated with primary depositional features or small-scale faults. Figure 24 shows minimum curvature draped over a 'near-basement' reflection in part of the San Juan Basin. A prominent ~N-S trending incised valley is apparent, as are some faults that strike approximately NW-SE.

Figure 25a shows a time structure map of the top of a Tertiary incised channel-levee complex. Figures 25b and c shows the dip component of curvature overlain on a 3-D representation of the horizon with shaded relief to enhance features. Note how by changing the viewing angle, zoom and surface illumination angle, the definition of stratigraphic and structural features can be improved, compared to the time-structure map.

Examples of present-day workflows

(1) *Attributes used to generate sand probability volumes*: When attributes are tied to the available well control, they can be correlated to petrophysical properties, and this helps the interpreter to identify and associate high correlations with specific properties. For example, Figure 26 shows how attributes from prestack inversion of a high-resolution seismic dataset allowed mapping of sand bodies in a geologically

complex area. A key step in the workflow was the petro-elastic analysis of well data that demonstrated that seismic attributes derived from prestack seismic inversion could discriminate between sands and shales.

A multi-attribute classification approach, incorporating neural network training techniques, was used to generate sand probability volumes derived from P-wave and S-wave impedances estimated using AVO inversion. The study demonstrated that high-resolution seismic data coupled with targeted inversion can increase confidence and reduce uncertainty.

A crucial problem in any multi-attribute analysis is the selection and the number of seismic attributes to be used. Kalkomey (1997) showed that the probability of observing a spurious correlation increases as the number of control points decreases and also if the number of seismic attributes being used increases. A way out of such a situation is to withhold a percentage of the data during the training step and then later to use this hidden data to validate the predictions (Schuelke and Quirein, 1998).

(2) Time-lapse analysis

(a) Seismic attributes are being used effectively for time-lapse data analysis (4-D). Time-lapse data analysis permits interpretation of fluid saturation and pressure changes, and helps understanding of reservoir dynamics and the performance of existing wells.

Figure 27 shows an example from east of Schiehallion field West of the Shetlands (Parr and Marsh, 2000). The pre-production surveys in 1993 in (a) and 1996 in (b) show a high degree of similarity, but the 4-D survey (in (c)) shows large changes around producers and injectors. The poor production rates and low bottom hole-flowing pressures led to the conclusion that well C was located in a compartment that is poorly connected to injection support. The areal extent of this compartment could be picked by the amplitude increase seen on 4-D image and interpreted due to gas liberated from solution. This area is consistent with predictions from material-balance calculations.

Figure 27c from the 1999 survey suggested the possibility of a connection (marked by an arrow) between producers C and D. The existence of such a connection was also suspected from the material-balance analysis. Figure 28 shows a coherence display at the required level and depicts the expected connection (marked by a circle). While a plausible explanation for this is not known, it is postulated that the attributes on 4-D seismic provide a clue that a transmissibility barrier may have been broken between the injector and producer.

(b) Reservoir based seismic attributes are being used to help delineate anomalous areas of a reservoir, where changes from time-lapse are evident (Galikeev and Davis, 2005). As for example, reservoir condition due to CO_2 injection could be detected. They generate attributes that represent reservoir heterogeneity by computing short time window seismic attributes parallel to the reservoir. Such an analysis in short temporal windows ensures that attribute carries an overprint of geology (Partyka et al, 1999).

Figure 29 shows the dynamic changes within the Weyburn reservoir (Canada), due to the increased CO_2 saturation. This was done by computing the inverted impedance model of the reservoir on the differenced volume of the baseline (2000) and second monitor (2002) surveys. Figure 30 is a computed CO_2 saturation map, where the values do not represent absolute CO_2 saturation, but rather an estimation of part porosity occupied by CO_2 after irreducible water and oil were taken into account.

(c) 4-D seismic attributes together with 4-D rock and fluid analysis and incorporation of production engineering information, have been used for pressure-saturation inversion for time-lapse seismic data producing quantitative estimates of reservoir pressure and saturation changes. Application of such an analysis to the Cook reservoir of the Gulfaks field, offshore Norway (Lumley et al, 2003), shows that a strong pressure anomaly can be estimated in the vicinity of a horizontal water injector, along with a strong water saturation anomaly drawing towards a nearby producing well (Figure 31). This is in addition to strong evidence of east-west fault block compartmentalization at the time of the seismic survey.

(3) Attributes for detection of gas zones below regional velocity inversion:

Evaluation of gas distribution in the fluid system in the Wind River Basin where there are anomalously pressured gas accumulations is a challenge. Using the available logs and seismic data, the regional velocity inversion surface has been mapped in this area (Surdam et al, 2004b), which is the pressure surface separating the anomalously pressured rocks below from the normally pressured rocks above. Seismic attributes have been successfully used to evaluate the distribution of sandstone rich intervals within the prospective reservoir units. The Frenchie Draw gas field in the Wind River Basin is an example of an area where detecting and delineating gas zones below the regional velocity inversion surface is difficult. The stratigraphic interval of interest is the Upper Cretaceous-Paleocene Fort Union/Lance lenticular fluvial sandstone formations on a north plunging structural nose. The gas distribution pattern in the formations has been found to be complex, and so the exploitation proved to be risky. Surdam (2004a) has demonstrated that a good correlation exists between seismic frequency and gamma ray logs (lithology) in the lower Fort Union/Lance stratigraphic interval. The frequency attribute was used to distinguish sandstone-rich intervals from shale-rich intervals.

Figure 32 shows a frequency attribute section (with seismic data overlaid) covering the Fort Union/Lance stratigraphic interval intersecting the anomalously slow velocity domains (outlined by white dots). In addition to the north-plunging structural nose seen in the area, a shale rich sequence (seen in orange) is seen near the upper edge of the gas production. The important thing seen here is the lenticular distribution of the sandstone-rich intervals in blue that stand out against the shale-rich intervals in orange, yellow and green. This distributional pattern of lithologies corresponds well with the initial interpretations carried out by geoscientists who discovered the field.

2005 and beyond

The present

There are many areas in the attribute world where active development is underway and we mention here some of the prominent ones.

1. *Volumetric estimates of curvature*: Cracks or small discontinuities are relatively small and fall below seismic resolution. However, the presence of open and closed cracks is closely related to reflector curvature (since tension along a surface increases with increasing curvature and therefore leads to fracture). Until now, such curvature estimates have been limited to the analysis of picked horizons, which

previously may be affected by unintentional bias or picking errors introduced during interpretation. Volumetric curvature computation entails, first, the estimation of volumetric reflection dip and azimuth that represents the best single dip for each sample in the volume, followed by computation of curvature from adjacent measures of dip and azimuth. The result is a full 3-D volume of curvature values at different scales of analysis (al Dossary and Marfurt, 2005).

2. *3-D classifiers*: Supervised 3-D classification is being used for integrating several seismic attributes into a volume of seismic facies (Sonneland et al, 1994, Carrillat et al, 2002). Some of the most successful work is in imaging by-passed pay (Paddock et al., 2004) using attributes sensitive to amplitude and trace shape. Workers at deGroot-Bril, Paradigm, Rock Solid Images and many others have made progress in using geometric attributes as the basis to automatically pick seismic textures in 3-D.

3. *Structurally-oriented filtering*: Recently, several workers have used the volumetric estimates of dip and azimuth to improve the signal to noise ratio, yet preserve discontinuities such as faults and stratigraphic discontinuities. Hoecker and Fehmers (2002) use an anisotropic diffusion algorithm that smoothes along dip azimuth only if no discontinuity is detected. Luo et al. (2002) use a multiwindow analysis technique, smoothing in that window containing the analysis point that has the smallest variance. Duncan et al. (2002) built on this latter technique, but instead of a mean filter, applied a principle component filter in the most coherent analysis window. These structurally-oriented filtering (alternatively called edge-preserving smoothing) algorithms improve not only behavior of autotrackers but also the results of coherence and other attributes sensitive to changes in reflector amplitude, waveform, and dip.

4. *Volumetric estimation of Q:* The most common means of estimating Q is through sample by sample estimates of spectral ratios. Typical workflows use a smoothly varying estimate of Q to increase the spectral bandwidth at depth. Most workers have focused on intrinsic vs. effective Q, the later including effects such as geometric scattering and friendly multiples. The most promising work is done with the aid of VSPs and/or well logs. In these flows, one can interpret not only the spectral amplitude but also the spectral phase compensation necessary to improve seismic resolution.

5. *Pre-stack attributes:* In addition to AVO, which measures the change in reflection amplitude and phase as a function of offset at a fixed location, we can apply attributes such as coherence and spectral decomposition to common offset volumes to better predict changes in lithology and flow barriers. While the interpretation is entirely consistent with AVO analysis, the 3-D volumes tend to show discrete geologic features and the limits of hydrocarbon distribution. There is a similar relationship between amplitude vs. azimuth and geometric attributes applied to common azimuth volumes. In this latter case, we often find faults and fractures better illuminated at those acquisition azimuths perpendicular to structural trends.

Gazing into the Future

Given the current data explosion both of large regional 3-D surveys, but also of new time-lapse and multicomponent surveys, we envision an increasingly rapid evolution of seismic attributes and computer-aided interpretation technology. Some of the clear signs on the horizon are as follows:

1. We expect continued development of texture attributes that can quantify or enhance features used in seismic stratigraphy and seismic geomorphology leading to

computer-aided 3-D seismic stratigraphy. One of the major challenges is that due to tectonic deformation and sedimentary compaction, such patterns may be arbitrarily rotated from their original position.

3. We expect enhanced emphasis will be placed on time-lapse applications for delineation of flow-barriers, so that reservoir simulation provides more realistic estimates and information regarding the dynamic behavior of reservoirs.
4. We expect continued advances in 3-D visualization and multiattribute analysis including clustering, geostatistics, and neural networks to alleviate the problems interpreters face due to an overwhelming number of attributes.
5.

CONCLUSIONS

A seismic attribute is a quantitative measure of a seismic characteristic of interest. Good seismic attributes and attribute analysis tools mimic a good interpreter. Over the past decades, we have witnessed attribute developments track breakthroughs in reflector acquisition and mapping, fault identification, bright spot identification, frequency loss, thin bed tuning, seismic stratigraphy, and geomorphology. More recently, interpreters have used crossplotting to identify clusters of attributes that are associated with either stratigraphic or hydrocarbon anomalies. Once again, the attribute community has worked hard to first duplicate such human-driven clustering through the use of self-organized maps, geostatistics, and neural nets, and then to extend this capability beyond the three dimensions easily visualized by interpreters. Tentative steps have been made towards computer-assisted seismic stratigraphy analysis, whereby an interpreter trains the computer on a suite of structural or depositional patterns and asks the computer to find others like them. Progress has been made in automated fault tracking, though currently the technology requires an expert user. In the not too distant future, we can envision an interpreter seeding a channel on a time slice after which the computer paints it in 3-D. Although it may take decades, we expect computers will eventually be able to duplicate all the repetitive processes performed by an interpreter. In contrast we do not expect them ever to replicate the creative interpreter imagining depositional environments, structural evolution, diagenetic alteration, and fluid migration. The human interpreter is here to stay.

ACKNOWLEDGEMENTS

A review paper spanning over four decades cannot be a one/two man job. The authors therefore acknowledge the advice, support and suggestions given by many prominent individuals, some of whom were actually involved in the development of the attributes in the early years.

We thank and appreciate the effort Nigel Anstey and Turhan Taner put in, for going down their memory lanes and providing us with their memoirs and recollections to our historical perspective. Nigel very graciously provided Figures 3 to 9, which he had treasured since 1971, and honored our request by actually writing an article entitled '*Attributes in color: the early days*', which has been published in the March 2005 issue of the CSEG Recorder. Tury Taner allowed us to pick and choose from his vast selection of 35 mm slides, three of which are displayed as Figures 10 to 12.

A special word of appreciation goes to Jamie Robertson who provided very useful points of view and his reminiscent write-up.

We thank Alistair Brown for his advice, and the consultations with Roy Lindseth, Brian Russell, Roy White and Les Hatton are gratefully acknowledged.

Ever the Professor, Bob Sheriff not only corrected several of our historical misconceptions, but also carefully edited the entire manuscript, covering it in a sea of red ink. For some reason, Marfurt's students found great pleasure in this!

Finally, we thank Bruce Hart for providing Figures 24 and 25, Ronald Parr for Figures 27 and 28, Tom Davis for Figures 29 and 30, Mark Meadows for Figure 31, and Ron Surdam for Figure 32.

We have tried to cover almost all the prominent developments in this vast field of seismic attributes. However, in spite of our best efforts, it is likely we may have missed out on some. Hence any errors or omissions were unintentional and solely our responsibility.

One of the authors' (S.C.) expresses his appreciation to Arcis Corporation, Calgary for permission to use some of their data examples.

REFERENCES

Al Dossary, S. and Marfurt, K. J., 2005, 3-D volumetric multispectral estimates of reflector curvature and rotation: submitted to Geophysics.

Anstey, N., 1972, Seiscom 72 (Seiscom Delta internal report)

Anstey, N., 1973a, Seiscom 73 (Seiscom Delta internal report)

Anstey, N., 1973b, The significance of color displays in the direct detection of hydrocarbons: 43rd Annual International Meeting, Society of Exploration Geophysicists.

Anstey, N., 2005, Attributes in color: the early years: CSEG Recorder, **30**, March, xx-xx

Bahorich, M. and P. van Bemmel, 1994, Stratigraphic interpretation of seismic data on the workstation: 64th Annual International Meeting: Society of Exploration Geophysicists, 481-484.

Bahorich, M. S. and S. L. Farmer, 1995, 3-D seismic discontinuity for faults and stratigraphic features: The coherence cube, 65th Annual International Meeting, Society of Exploration Geophysicists Expanded Abstracts, 93-96.

Bahorich, M. S. and S. R. Bridges, 1992, The seismic sequence attribute map (SSAM): 62nd Annual International Meeting Society of Exploration Geophysicists, Expanded Abstracts, 227-230.

Balch, A. H., 1971, Color sonograms: a new dimension in seismic data interpretation: Geophysics, **36**, 1074-1098.

Barnes, A. E., 1996, Theory of two-dimensional complex seismic trace analysis: Geophysics, **61**, 264-272.

Barnes, A. E., 1997, Genetic classification of complex seismic trace attributes: 67th Annual International Meeting, Society of Exploration Geophysicists Expanded Abstracts, 1151-1154.

Barnes, A. E., 2000a, Weighted average seismic attributes: Geophysics, **65**, 275-285.

Barnes, A. E., 2000b, Attributes for automated seismic facies analysis: 70th Annual International Meeting of the Society of Exploration Geophysicists Expanded Abstracts, 553-556.

Barnes, A., 2001, Seismic attributes in your facies: CSEG Recorder, **26**, September, 41 - 47.

Batson, R.M., K. Edwards, and E. M. Eliason, 1975, Computer-generated shaded relief images: Journal of Research of the U.S. Geological Survey, **3**, 401-408.

Bednar, J. B., 2005, A brief history of seismic migration time: to appear in Geophysics.

Bodine, J.H., 1984, Waveform analysis with seismic attributes: 54th.Annual International Meeting Society Exploration Geophysicists, Session:S9.1.

Bodine, J.H., 1986, Waveform analysis with seismic attributes: Oil and Gas J., **84**, no. 23, 59-63.

Blumentritt, C. H., K. J. Marfurt and E. C. Sullivan, 2005, Volume based curvature computations illuminate fracture orientations, Lower-Mid Paleozoic, Central Basin Platform, West Texas: Submitted to Geophysics.

Brown, A. R. and J. D. Robertson, 1985, Focusing on SEG continuing education - Seismic interpretation for detailed exploration development and production: The Leading Edge, **04,** no. 10, 60-65.

Brown, A. R., 1986, Interpretation of three-dimensional seismic data (1st edition), Memoir **42**, American Association of Petroleum Geologists, Tulsa, OK, USA.

Brown, A. R., 1996, Interpretation of three-dimensional seismic data (4th edition), Memoir **42**, American Association of Petroleum Geologists, Tulsa, OK, USA.

Brown, A. R., 2004, Interpretation of three-dimensional seismic data (6th edition), Memoir **42**, American Association of Petroleum Geologists, Tulsa, OK, USA.

Brown, A. R., 1996, Interpreter's corner - Seismic attributes and their classification: The Leading Edge, **15,** 1090.

Carrillat, A., T. Randen, and L. Sonneland, 2002, Seismic stratigraphic mapping of carbonate mounds using 3-D texture attributes: 64th Annual International Meeting, European Association of Geoscientists and Engineers, Z-99.

Castagna, J. P., S. Sun. and R. W. Siegfried, 2003, Instantaneous spectral analysis: Detection of low-frequency shadows associated with hydrocarbons: The Leading Edge, **22,** 120-127.

Chen, Q. and S. Sidney, 1997, Seismic attribute technology for reservoir forecasting and monitoring: The Leading Edge, **16,** 445-456.

Chopra, S. and D. Pruden, 2003, Multiattribute seismic analysis on AVO-derived parameters: The Leading Edge, **22,** 998-1002.

Chopra, S. and O. Kuhn, 2001, Seismic inversion: CSEG Recorder: **26,** no. 1, 10-14.

Chopra, S., 2002, Coherence cube and beyond: First Break, **20,** no. 01, 27-33.

Chopra, S., V. Alexeev, and Y. Xu, 2003, 3-D AVO crossplotting - An effective visualization technique: The Leading Edge, **22,** 1078-1089.

Chopra, S., D. Pruden, and V. Alexeev, 2004, Multi-attribute seismic analysis – tackling non-linearity: First Break, **22**, no.12, p 43-47.

Coleou, T., M. Poupon, and K. Azbel, 2003, Unsupervised seismic facies classification: A review and comparison of techniques and implementation: The Leading Edge, **22**, 942-953.

Connolly, P., 1999, Elastic impedance: The Leading Edge, **18,** 438-452.

Conticini, F., 1984, Seismic facies quantitative analysis: New tool in stratigraphic interpretation: 54th Annual International Meeting, Society of Exploration Geophysicists, Session:S18.3.

Cosentino, L., 2001, Integrated Reservoir Studies: Editions Technip.

Dalley, R. M., Gevers, E. C. A., Stampfli, G. M., Davies, D. J., Gastaldi, C. N., Ruijtenberg, P. A. and Vermeer, G. J. O., 1989, Dip and azimuth displays for 3-D seismic interpretation: First Break, **07,** no. 03, 86-95.

Duncan, W., Constance, P. and Marfurt, K. J., 2002, Comparison of 3-D edge detection seismic attributes to Vinton Dome, Louisiana , 72nd Annual International Meeting Society of Exploration Geophysicists, 577-580.

de Figueiredo, R. J. P., 1982, Pattern recognition approach to exploration: *in* de Figueiredo, R. J. P., Ed., Concepts and techniques in oil and gas exploration: Society of Exploration Geophysicists, 267-286.

Ebrom, D., 2004, The low-frequency gas shadow on seismic sections: The Leading Edge, **23**, 772.

Finn, C. J., 1986, Estimation of three dimensional dip and curvature from reflection seismic data: M.S. Thesis, Univ. of Texas, Austin, TX.

Forrest, M., 2000, 'Bright' investments paid off: AAPG Explorer, July issue.

Galikeev, T., and T. Davis, 2005, Time-lapse seismic attributes and reservoir volumetric calculation: 67th Annual International Meeting, European Association of Geoscientists and Engineers, Z99.

Gao, D., 2003, Volume texture extraction for 3-D seismic visualization and interpretation: Geophysics, **68,** 1294-1302.

Gao, D., 2004, Texture model regression for effective feature discrimination: Application to seismic facies visualization and interpretation: Geophysics, **69,** 958-967.

Gersztenkorn, A. and K. J. Marfurt, 1999, Eigenstructure-based coherence computations as an aid to 3-D structural and stratigraphic mapping: Geophysics, **64,** 1468-1479.

Hardage, B.A., V. M. Pendleton, J. L. Simmons, Jr., B. A. Stubbs, and B. J. Uszynski, 1998, 3-D instantaneous frequency used as a coherency/continuity parameter to interpet reservoir compartment boundaries across an area of complex turbidite deposition: Geophysics, **63**, 1520-1531.

Hart, B.S., R. Pearson, R. Pearson, and G. C. Rawling, 2002, 3-D seismic horizon-based approaches to fracture-swarm sweet spot definition in tight-gas reservoirs: The Leading Edge, **21,** 28-35.

Hoecker, C, and Fehmers, G., 2002, Fast structural interpretation with structure-oriented filtering: The Leading Edge, **21**, 238-243.

Kalkomey, C. T., 1997, Potential risks when using seismic attributes as predictors of reservoir properties: The Leading Edge, **16,** 247-251.

Kallweit, R.S. and L. C. Wood, 1982, The limits of resolution of zero-phase wavelets: Geophysics, **47**, 1035-1046.

Keskes, N., A. Boulanouar, Y. Lechevalier, and P. Zaccagnino, 1982, Image analysis techniques for seismic data: 52nd Annual Meeting, Society of Exploration Geophysicists, Session:S16.7.

Keskes, N., P. Zaccagnino, D. Rether, and P. Mermey, 1983, Automatic extraction of 3-D seismic horizons: 53rd Annual Meeting, Society of Exploration Geophysicists, Session:S21.1.

Knobloch, C., 1982, Pitfalls and merits of interpreting color displays of geophysical data: 52nd Annual International Meeting Society of Exploration Geophysicists, Session:S8.8.

Landa, E., W. Beydoun, and A. Tarantola, 1989, Reference velocity model estimation from prestacked waveforms: Coherency optimization by simulated annealing: Geophysics, **54,** 984-990.

Latimer, R. B., R. Davison, and P. van Riel, 2000, An interpreter’s guide to understanding and working with seismic-derived acoustic impedance data: The Leading Edge, **19**, 242-256.

Lavergne, M., 1975, Pseudo diagraphics de vitesse en offshore profond, Geophysical Prospecting, **23**, 695-711.

Lindseth, R.O., 1976, Seislog process uses seismic reflection traces: Oil and Gas Journal, **74**, 67-71.

Lindseth, R.O., 1979, Synthetic sonic logs – a process for stratigraphic interpretation: Geophysics: **44**, 3-26.

Liner, C., C.-F. Li, A. Gersztenkorn, and J. Smythe, 2004, SPICE: A new general seismic attribute: 72nd Annual International Meeting of the Society of Exploration Geophysicists Expanded Abstracts, 433-436.

Lisle, R. J., 1994, Detection of zones of abnormal strains in structures using Gaussian curvature analysis: AAPG Bulletin, **78**, 1811-1819.

Love, P. L. and M. Simaan, 1984, Segmentation of stacked seismic data by the classification of image texture: 54th Annual International Meeting, Society of Exploration Geophysicists, Session:S7.3.

Luo, Y., al-Dossary, S., and Alfaraj, M., 2002, Edge-preserving smoothing and applications: The Leading Edge, **21,** 136-158.

Lumley. D., D. Adams, M. Meadows, S. Cole, and E. Ergas, 2003, 4D seismic pressure-saturation inversion at Gulfaks field, Norway: First Break, **21,** 49-56.

Luo, Y., W. G. Higgs, and W. S. Kowalik, 1996, Edge detection and stratigraphic analysis using 3-D seismic data: 66th Annual International Meeting, Society of Exploration Geophysicists Expanded Abstracts 324-327.

Marfurt, K. J., R. L. Kirlin, S. L. Farmer, and M. S. Bahorich, 1998, 3-D seismic attributes using a semblance-based coherency algorithm: Geophysics, **63,** 1150-1165.

Marfurt, K. J., V. Sudhaker, A. Gersztenkorn, K. D. Crawford, and S. E. Nissen, 1999, Coherency calculations in the presence of structural dip: Geophysics, **64,** 104-111.

Masaferro, J. L., M. Bulnes, J. Poblet, and M. Casson, 2003, Kinematic evolution and fracture prediction of the Valle Morado structure inferred from 3-D seismic data, Salta Province, northwest Argentina, American Association of Petroleum Geologists Bulletin, **87**, 1083-1104.

May, B. T. and S. L. May, 1991, Elastic inversion - The key to stratigraphic interpretation: 61st Annual International Meeting, .Society of Exploration Geophysicists Expanded Abstracts, 1098-1101.

Meldahl, P., R. Heggland, B. Bril, and P. de Groot, 2001, Identifying faults and gas chimneys using multiattributes and neural networks: The Leading Edge, **20,** 474-478.

Okaya, D. A., 1995, Spectral properties of the Earth's contribution to seismic resolution: Geophysics, **60,** 241-251.

Parr, R.S. and M. Marsh, 2000, Development of 4-D reservoir management West of Shetland, World Oil, **221**, no.9, 39-47.

Partyka, G., J. Gridley, and J. Lopez, 1999, Interpretational applications of spectral decomposition in reservoir characterization: The Leading Edge, **18**, 353-360.

Payton, C. E., ed, 1977, Seismic stratigraphy – applications to hydrocarbon exploration: Memoir **26**, American Association of Petroleum Geologists, Tulsa, OK, USA.

Peterson, R. A., W. R. Fillippoe, and F. B. Coker, 1955: The synthesis of seismograms from well log data: Geophysics, **20**, 516-538.

Peyton, L., Bottjer, R. and Partyka, G., 1998, Interpretation of incised valleys using new 3-D seismic techniques: A case history using spectral decomposition and coherency: The Leading Edge, **17**, 1294-1298.

Picou, C., and R. Utzmann, 1962, La coupe sismique vectorielle: Un pointé semi-automatique: Geophysical Prospecting, **4**, 497-516.

Randen, T., E. Monsen, C. Signer, A. Abrahamsen, J. Hansen, T. Saeter, and J. Schlaf, 2000, Three-dimensional texture attributes for seismic data analysis: 70th Annual International Meeting, Society of .Exploration Geophysicists Expanded Abstracts, 668-671.

Ravenne, C., 2002, Stratigraphy and Oil: A Review, Part 1, Exploration and Seismic Stratigraphy: Observation and Description, Oil and Gas Science and Technology – Rev. IFP, **57**, no.3, 211-250.

Rijks, E. J. H. and J. C. E. M., Jauffred, 1991, Attribute extraction: An important application in any detailed 3-D interpretation study: The Leading Edge, **10,** 11-19.

Roberts, A., 2001, Curvature attributes and their application to 3-D interpreted horizons: First Break, **19,** 85-99.

Robertson, J. D., 2005, Private communication.

Robertson, J.D. and D. A. Fisher, 1988, Complex seismic trace attributes: The Leading Edge, **7**, no. 6, 22-26.

Robertson, J.D. and H. H. Nogami, 1984, Complex seismic trace analysis of thin beds: Geophysics, **49**, 344-352.

Rummerfeld, B., 1954, Reflection quality, a fourth dimension: Geophysics, **19**, pp. 684-694.

Russell, B., D. Hampson, J. Schuelke, and J. Quirein,, 1997, Multiattribute seismic analysis: The Leading Edge, **16,** 1439-1443.

Sangree, J.B., and J. M. Widmier, 1976, Seismic interpretation of clastic depositional facies: AAPG Memoir **26**, 165-184.

Scheuer, T. E., and D. W. Oldenberg, 1988, Local phase velocity from complex seismic data: Geophysics, **53**, 1503-1511.

Schuelke, J. S. and J.A. Quirein,, 1998, Validation: A technique for selecting seismic attributes and verifying results: 68th Annual International Meeting, Society of Exploration Geophysicists Expanded Abstracts, 936-939.

Sibille, G., N. Keskes, L. Fontaine, and J. L. Lequeux, 1984, Enhancement of the perception of seismic facies and sequences by image analysis techniques: 54th Annual International Meeting, Society of Exploration Geophysicists, Session:S7.2.

Sigismondi, M. and J. C. Soldo, 2003, Curvature attributes and seismic interpretation: Case studies from Argentina basins: The Leading Edge, **22,** 1122-1126.

Sonneland, L., Barkved, O., Olsen, M. and Snyder, G., 1989, Application of seismic wave-field attributes in reservoir characterization: 59th Annual International Meeting, Society of Exploration Geophysicists, 813.

Sonneland, L., P. Tennebo, T. Gehrmann, and O. Yrke, , 1994, 3-D model-based Bayesian classification: 64th Annual International Meeting, Society of Exploration Geophysicists Expanded Abstracts, 510-511.

Stewart, S.A., and T. J. Wynn, 2000, Mapping spatial variation in rock properties in relationship to scale-dependent structure using spectral curvature: Geology, **28**, 691-694.

Surdam, R. C., Z. S. Jioa, and Y. Ganshin, 2004a, Reducing risk in low-permeability gas formations: understanding the rock fluid characteristics of Rocky Mountain Laramide Basins: DOE Final Technical Progress Report under contract no. DE-FC26-01NT41325, 39.

Surdam, R. C., Z. S. Jioa, and Y. Ganshin, 2004b, Reducing the risk of exploring for anomalously pressured gas assets: GasTIPS, Winter 2004, 4.

Taner, M. T., J. S. Schuelke, R. O'Doherty, and E. Baysal, 1994, Seismic attributes revisited: 64th Annual International Meeting, Society of .Exploration Geophysicists Expanded Abstracts, 1104-1106.

Taner, M.T. and R. E. Sheriff, 1977, Application of amplitude, frequency, and other attributes to stratigraphic and hydrocarbon determination: in Applications to hydrocarbon exploration, C. E. Payton, Ed., AAPG Memoir 26: Tulsa, American Association of. Petroleum Geologists, 301-327.

Taner, M.T., 2005, Private communication.

Taner, M.T., F. Koehler, and R. E. Sheriff, 1979, Complex seismic trace analysis: Geophysics, **44**, 1041-1063.

Thadani, S. G., F. Aldabert, and A. G. Journel, 1987, An integrated geostatistical/pattern recognition technique for characterization of reservoir spatial variability: 57th Annual International Meeting, Society of Exploration Geophysicists, Session SEG1.2.

Vail, P. R., R. M. Mitchum, Jr. and S. Thompson, III S., 1977, Seismic stratigraphy and global changes of sea level, Part 4, Global cycles of relative changes of sea level: in Seismic stratigraphy applications to hydrocarbon exploration, C. E. Payton, C.E.(ed.), American Association of Petroleum Geologists., Tulsa, OK, Memoir **26**, 83-97.

Verm, R. W. and F. J. Hilterman, 1994, Lithologic color-coded sections by AVO crossplots: 64th Annual International Meeting, Society of Exploration Geophysicists Expanded Abstracts, 1092-1095.

Whitehead, P., J. Fairborn, and R. Wentland, 1999, Identifying stratigraphic units by seismic patterns, 69th Annual International Meeting, Society of Exploration Geophysicists Expanded Abstracts, 942-945.

Vinther, R., 1997, Seismic texture classification applied to processed 2-D and 3-D seismic data, 67th Annual International Meeting, Society of Exploration Geophysicists Expanded Abstracts, 721-724.

Vinther, R., K. Mosegaard, K. Kierkegaard, I. Abatzis, C. Andersen, and F. If, 1995, Seismic texture classification: A computer-aided approach to stratigraphic analysis, 65th Annual International Meeting, Society of Exploration Geophysicists Expanded Abstracts, 153-155.

Vossler, D. A., 1988, Automatic whole section seismic reflection mapping: 58th Annual International Meeting, Society of Exploration Geophysicists, Session:S2.2.

West, B., S. May, S., J. E. Eastwood, and C. Rossen, 2002, Interactive seismic facies classification using textural and neural networks: The Leading Edge, **21**, 1042-1049.

Whitcombe, D. N., 2002, Elastic impedance normalization: Geophysics, **67,** 60-62.

White, R. E., 1991, Properties of instantaneous seismic attributes: The Leading Edge, **10,** no. 07, 26-32. (* Discussion and reply in TLE-11-8-45-46 and TLE-11-10-10-12)

Xue, F., D. Paddock, K. Hemsley, 2003, 3D seismic classification - an efficient approach for prospect identification in asset evaluation: 73rd Annual International Meeting, Society of Exploration Geophysicists Expanded Abstracts, 1485-1488.

FIGURE CAPTIONS

Figure 1. A time line of seismic attribute development, and their relation to key advances In seismic exploration technology. (Modified from Barnes, 2001).

Figure 2. Perhaps the earliest example of a computer-generated seismic attribute: (a) Schematic of a device built to cross correlate seismic traces recorded on analog magnetic tape, which was then used to display (b) reflector dip and continuity. (After Picou and Utzman (1962).

Figure 3. A state of the art seismic display from the early 1970s. The variable density plot shows strong peaks as black, zero values as gray, and strong troughs as white. Variable density allowed the compression of the horizontal scale, generating 'squash plots' that enhanced subtle structure, onlap, offlap, and other stratigraphic features of interest. This image is the substrate for attribute images plotted in color in Figures 4-7. (After Anstey, 2005).

Figure 4. A composite attribute image from the early 1970s, showing interval velocities (estimated using Dix's equation) superimposed on the structural section of Figure 3. (After Anstey, 2005)

Figure 5. A composite attribute image from the early 1970s, showing reflection strength (in early days the most popular attribute) superimposed on the structural section of Figure 3. (After Anstey, 2005)

Figure 6. A composite attribute image from the early 1970s, showing the apparent polarity of reflections (positive as red, negative as blue) superimposed on the structural section of Figure 3. (After Anstey, 2005)

Figure 7. A composite attribute image from the early 1970s, showing the differential frequency content (the relative loss of high frequencies down the section) superimposed on the structural section of Figure 3. (After Anstey, 2005)

Figure 8. From the early 1970s, one of many bright spots identified in the North Sea. Display of reflection strength as in Figure 4. (After Anstey, 2005)

Figure 9. No substitute for 3-D work, but valuable in its day. From the early 1970s, an isometric fence diagram of reflection strength on a grid of 2-D lines over a gas field in the North Sea. (After Anstey, 2005)

Figure 10. The (a) real seismic trace, (b) quadrature, (c) instantaneous phase, and (d) instantaneous frequency from Taner et al. (1979). Note the envelope-weighted frequency indicated by the dashed line in (d). Also note the singularities seen in instantaneous frequency due to waveform interference. (e) A scanned copy of a slide used by Tury Taner in presentations made during the 1970s to explain complex-trace analysis.

Figure 11. Scanned copies of two slides used by Tury Taner in the 1970s to illustrate the value of complex trace analysis applied to (a) a hard streak lime buildup, and (b) a gas-charged reservoir. Note the differences in polarity.

Figure 12. Scanned copies of two slides used by Tury Taner in the mid 1970s-1980s in the AAPG-sponsored school on seismic stratigraphy. (a) Representative reflection characters seen on 2-D seismic lines. (b) Idealized characters used in seismic stratigraphy interpretation. These early interpretation workflows concepts provided the motivation for later developments in geometric attributes (including volumetric dip and azimuth, reflector parallelism, continuity, and unconformity indicators).

Figure 13. A 'seislog' inverted seismic section from the Swan Hills carbonate formation. (After Lindseth, 1979).

Figure 14. Combining (a) reflection envelope and (b) reflectio phase using (c) a 2-D color bar to form (d) a composite image. This technique, originally presented by Knobloch (1982), emphasizes the phase of the stronger reflection events and provides an effective tool for tracking waveforms across faults. The 2-D color legend (c) has been mapped to a more conventional 1-D color legend in (d) in order to use conventional plotting software.

Figure 15. (a) A vertical section through a 3-D seismic data volume with a picked top (blue dots) and bottom (green dots) of a formation. (b) A dip magnitude and (c) a shaded relief map of the top reflector. Amplitude extractions (a 'horizon slice' through the seismic data) corresponding to the (d) bottom and (e) top reflector. The white arrow indicates a small 10 m throw graben confirmed by seismic data that is seen in the shaded relief map. (After Rijks and Jauffred, 1991).

Figure 16: Time slices through (a) a seismic and (b) coherence data volumes. (c) Overlay of coherence on seismic. Note that the coherence slice not only reveals faults with clarity but also the intensively fractured region to the right. (After Chopra, 2002).

Figure 17: A Lambda-Rho section (with polygons selected) and corresponding clusters on 3-D crossplots. (a) Polygons selected on a time slice from the Lambda-Rho volume. The red-bordered polygon indicates the area being analyzed. (b) Points within the red, yellow and purple polygons show up as different clusters. The gas anomaly (blue on the time slice and enclosed by the purple polygon) shows up with negative values for the fluid stack. (c) 3-D crossplot seen from the fluid stack side (d) 3-D crossplot seen from the fluid stack side and including only points from the purple polygon. (After Chopra et al., 2003)

Figure 18. Time slices through (a) λ-ρ and (b) μ-ρ volumes. The suspected gas anomaly is indicated by low (blue) values in the λ-ρ slice and high (yellow) values of μ-ρ in the μ-ρ slice. (c) Cross-plot of lambda-rho vs. mu-rho. The red polygon encloses all the live data points on both time slices while the yellow polygon encloses the suspected anomaly. The cross-plot shows the yellow points

corresponding to low values of Lambda-Rho and high values of Mu-Rho that is expected of a gas anomaly. (After Chopra, 2003).

Figure 19. (a) Enclosing the high values of λ-μ and low values of μ-ρ in Figure 18c with the purple polygon highlights their corresponding spatial locations on the (b) λ-ρ and (c) μ-ρ time slices. The job of the interpreter is then to validate his seismic attributes with his or her interpretation of the depositional and structural setting. (After Chopra, 2003).

Figure 20. (a) Neural network inverted gamma ray response. Note the distinct separation of sand from silt and shale. (b) Neural network computed porosity from the inverted density response. The density values have been masked out for gamma ray values representative of silt or shale, giving a relative porosity indicator for the sands. (After Chopra and Pruden, 2003)

Figure 21. Spline curve inverted porosity corresponding to the time slices shown in Figure 19 and 20. (After Chopra et al., 2004).

Figure 22. Strat cubes (a subvolume of 60 ms thickness bounded by two not necessarily parallel horizons) of the (a) seismic b) coherence volumes. Notice the clarity with which the N-S narrow channel is seen on the coherence strat-cube and also the fault (seen with the help of relief). An E-W fault trend is also clearly seen on the coherence strat-cube.

Figure 23: A comparison between average absolute amplitude (a) and homogeneity (b) in a horizon slice at the same stratigraphic level. To avoid a biased comparison, the same processing parameters (texel size and dimension) and a normalized color

mapping function are used. Notice that the channel/levee deposits can be recognized, mapped, and detected more effectively from the homogeneity volume than from the amplitude volume. (After Gao, 2003).

Figure 24: This image shows minimum curvature draped over a "near-basement" reflection in part of the San Juan Basin. A prominent ~N-S trending incised valley is apparent, as are some curvilinear faults that strike approximately NW-SE. Tick marks are 1 km. Illumination from SW. (Image courtesy of Bruce Hart, McGill Univ.).

Figure 25: (a) A time-structure map of the top of a Tertiary channel-levee complex. (b) Dip component of curvature and (c) shaded relief overlain on a 3-D representation of the horizon to enhance features. Note the improved definition of stratigraphic and structural features compared to the time-structure map. (Images courtesy of Bruce Hart, McGill Univ.).

Figure 26. (a) A cross-section from the final processed seismic data volume. The dipping event in the center of the panel is interpreted as a sand injection feature. (b) The same cross-section from the sand probability volume derived from multi-attribute classification. The classification has predicted that the feature is sand being injected from the main sand body seen below. (c) The sand probability volume and amplitude data displayed using 3-D visualization. The figure shows seismic amplitude data in the background; the base reservoir surface is shown in blue and a possible sand injection feature mapped from the inversion results. Note the complexity of the injected sand bodies. *(Images courtesy: Steve McHugo, WesternGeco)*

Figure 27: An example from east of Schiehallion. The net sand maps based on seismic amplitudes on the Pre-production surveys (1993) in (a) and 1996 in (b) show a high degree of similarity. Comparison with the 1999 4-D survey (c) shows large changes around producers and injectors. (After Parr and Marsh, 2000).

Figure 28: A time slice through a coherence volume corresponding to Figure 27 and depicts the expected connection (marked by a circle) between the producers C and D. (After Parr and Marsh, 2000).

Figure 29. Position of the time-lapse impedance anomalies in depth relative to CO_2 injectors (black) and vertical water injectors (blue).

Figure 30. CO_2 saturation map computed from time-lapse (2000-2002 inversion of the difference) impedance values. Shown are: responded to CO_2 injection wells (white), horizontal injectors (black), unresponded to CO_2 wells (blue) and vertical water injectors (yellow).

Figure 31. Probability map on a scale of zero (blue) to 0.6 (white) that water saturation (left) and pore pressure (right) have increased within the Cook reservoir of the Gulfaks field, Norwegian North Sea. Note that there is a strong pressure anomaly surrounding the B-33 horizontal injector, along with east-west sealing fault compartmentalization. Water saturation change, however, is weak in most of the compartment since well B-33 injects into the water leg. The saturation change is stronger to the southeast of the compartment where water is drawn toward nearby producing well B-1. (After Lumley et al., 2003).

Figure 32. Seismic data display superimposed on a frequency attribute section at Frenchie Draw field. Shaded region shows anomalous velocity overlap. (After Surdam et al., 2004)