Applications of texture attribute analysis to 3D seismic data

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In this study, texture attribute analysis application to 3D surface seismic data is presented. This is done by choosing a cubic texel (texture element) from the seismic data to generate a gray-level occurrence matrix, which in turn is used to compute second-order statistical measures of textural characteristics. The cubic texel is then successively made to glide through the 3D seismic volume to transform it to a plurality of texture attributes. Application of texture attributes to two case studies from Alberta confirm that these attributes enhance understanding of the reservoir by providing a clearer picture of the distribution, volume, and connectivity of the hydrocarbon-bearing facies in the reservoir.

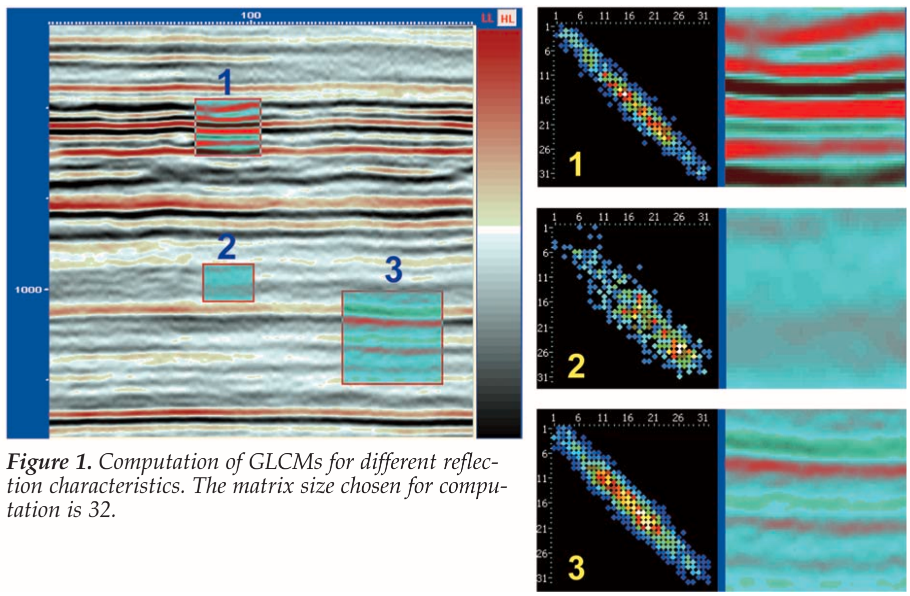

Figure 1. Computation of GLCMs for different reflection characteristics. The matrix size chosen for computation is 32.

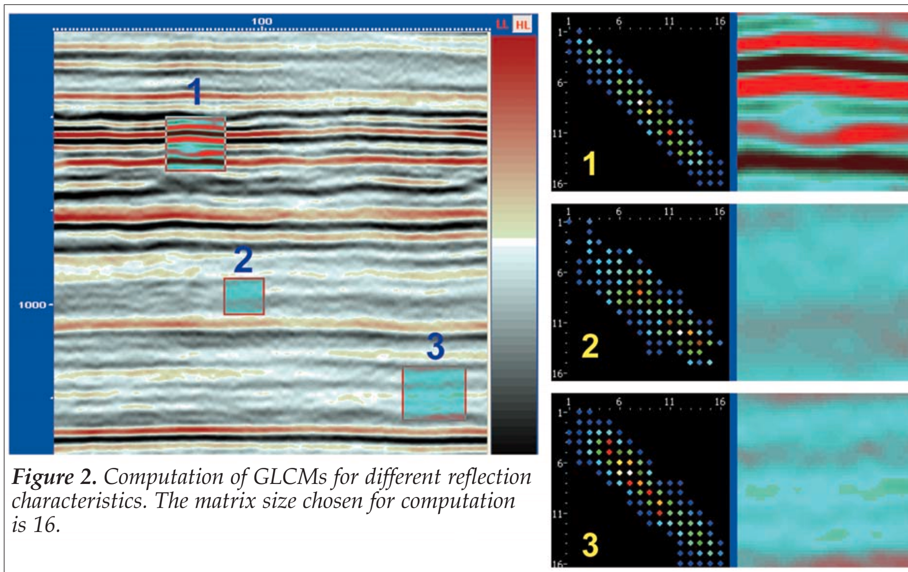

Figure 2. Computation of GLCMs for different reflection characteristics. The matrix size chosen for computation is 16.

A plethora of seismic attributes have been derived from seismic amplitudes to facilitate the interpretation of geologic structure, stratigraphy, and rock/pore-fluid properties. *Complex trace analysis* treats seismic amplitudes as analytic signals and extracts various attributes to aid feature identification and interpretation. Computations for these attributes are carried out at each sample of the seismic trace and so have also been dubbed *instantaneous attributes*. Another class of attributes utilizes the 3D nature of the seismic data by using an ensemble of traces in the inline and crossline directions and using time samples in the computation as well. Coherence attribute computation is done this way. More information on all these attributes can be found in the 2005 article by Chopra and Marfurt. These different attributes have been used for different purposes and have their own limitations.

Texture analysis of seismic data was first introduced by Love and Simaan (1984) to extract patterns of common seismic signal character. This inspiration came from the suggestion that zones of common signal character are related to the geologic environment in which their constituents were deposited. These and other similar attempts enjoyed limited success as the outcome was dependent on the signal-to-noise ratio and also because the stratigraphic patterns could not be standardized. A more recent development of the use of statistical measures to classify seismic textures by using gray-level co-occurrence matrices (GLCMs) (West et al., 2002; Gao, 2003) has been introduced.

The idea behind texture analysis of surface seismic data is to mathematically describe the distribution of pixel values (amplitude) in a subregion of the data. Texture analysis has been extensively used in image processing (remote sensing), where individual pixel (picture element) values are used in the analysis. The term *texel* is usually used for reference to the smallest set of pixels (planar for 2D) that characterize a texture. For 3D seismic data, a *cubic texel* is used for texture analysis. The technique used to quantify involves a transformation that generates GLCMs. The GLCMs essentially represent the joint probability of occurrence of gray levels for pixels with a given spatial relationship in a defined region. The GLCMs are then used to generate statistical measures of properties like coarseness, contrast, and homogeneity of seismic textures, which are useful in the interpretation of oil and gas anomalies.

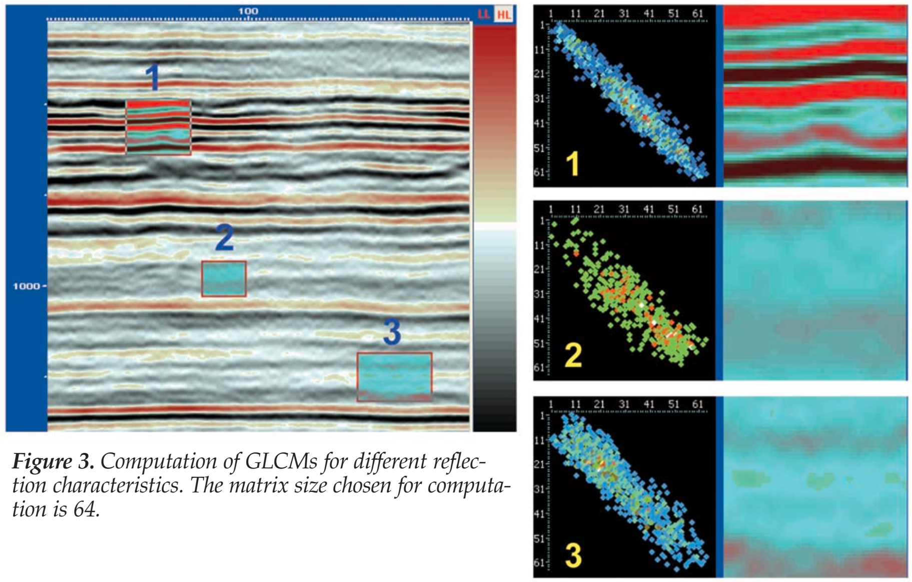

Figure 3. Computation of GLCMs for different reflection characteristics. The matrix size chosen for computation is 64.

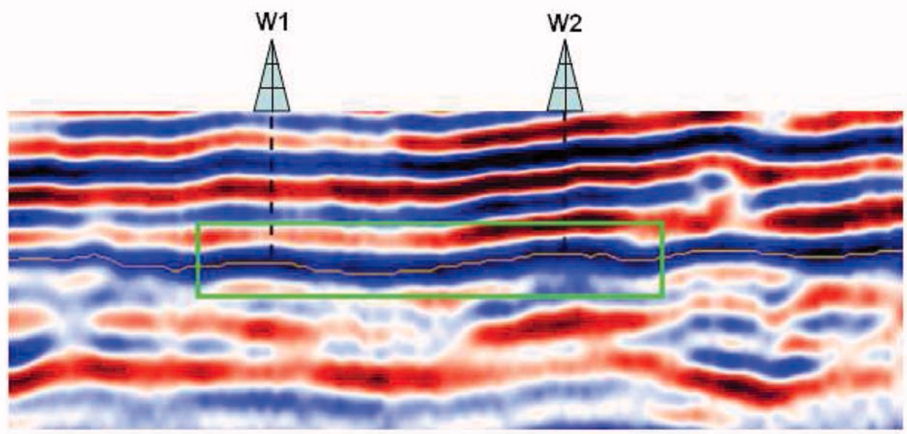

Figure 4. Seismic section showing the level of the producing reservoir (dark blue portion in the highlighted area).

GLCMs for seismic data. A computed gray-level co-occurrence matrix has dimensions $n \times n$, where n is the number of gray levels. For application to seismic data, the gray levels refer to the dynamic range of the data. For example, 8-bit data will have 256 gray levels. A GLCM computed for these data would have 256 rows and 256 columns (65 536 elements). Similarly, 16-bit data would have a matrix of size $65536 \times 65536 = 429\ 496\ 720$ elements, which could be a little overwhelming even for a computer. Usually, the seismic data is rescaled to 4-bit (16×16 matrix) or 5-bit (32×32 matrix) and in practice it has been found that this does not result in any significant differences in the computed properties.

The structure of GLCMs as applied to seismic data can be easily understood. Figure 1 shows regions 1, 2, and 3 selected for GLCM computation. The computed GLCMs are shown to the right. For strong continuous reflections, the GLCM exhibits a tight distribution along the diagonal. The matrix size chosen is 32, and the parameters chosen are 4, 3, and 4 in the inline, crossline, and time directions. Low-amplitude regions exhibit values near the center. Discontinuous or incoherent reflections have more occurrences farther away from the diagonal (view 3 in Figure 1). View 2 has lower amplitudes as well as incoherent reflections and so the GLCM shows a scatter about the diagonal. For a matrix size 16, we see smaller number of elements in the GLCM (Figure 2) and for a matrix size 64, there is a higher population of points (Figure 3).

While GLCMs give us all this information, they are not accurate enough to make quantitative interpretations. They need to be matched by extracting a number characteristic of the property of each matrix. In other words, texture features can be generated by applying statistics to co-occurrence probablilities. These statistics identify some structural aspects of the arrangement of probabilities within a matrix indexed on i and j, which in turn reflects some characteristic of the texture. There are various types of statistics that can be used. Haralick et al. (1973) demonstrated the derivation of 14 different measures of textural features from GLCMs. Each of these features represents certain image properties (e.g., coarseness, contrast, or texture complexity). However, due to redundancy in these statistics, the following four measures generate the desired discrimination without any redundancy: energy, entropy, contrast, and homogeneity.

Energy: a measure of textural uniformity in an image. Mathematically, it is given as

$$\text{Energy} = \sum_i \sum_j P_{i,j}^2$$

Energy is low when all elements in the GLCM are equal and is useful for highlighting geometry and continuity.

Entropy: a measure of disorder or complexity of the image.

$$\text{Entropy} = \sum_i \sum_j P_{i,j} \log P_{i,j}$$

Entropy is large for images that are texturally not uniform. In such a case many GLCM elements have low values.

Contrast: a measure of the image contrast or the amount of local variation present in an image.

$$\text{Contrast} = \sum_i \sum_j (i-j)^2 P_{i,j}$$

Contrast or inertia is high for contrasted pixels while its homogeneity will be low. When used together, both inertia and homogeneity provide discriminating information.

Homogeneity: a measure of the overall smoothness of an image.

$$\text{Homogeneity} = \sum_i \sum_j \frac{1}{1+(i-j)^2} P_{i,j}$$

Homogeneity measures similarity of pixels and is high for GLCMs with elements localized near the diagonal. Thus, homogeneity is useful for quantifying reflection continuity.

For 3D seismic volumes, computing GLCM texture attributes at one location yields the localized features at that point. Repeating the computation of these attributes in a sequential manner throughout the volume transforms the input seismic volume into the above four texture attributes, which we discuss below.

High-amplitude continuous reflections, generally associated with marine shale deposits, have relatively low energy, high contrast, and low entropy. Low-amplitude discontinuous reflections generally associated with massive sand or turbidite deposits have high energy, low contrast, and high homogeneity (Gao, 2003). Low-frequency, high-amplitude anomalies, generally indicative of hydrocarbon accumulation, exhibit high energy, low contrast, and low entropy, relative to nonhydrocarbon sediments.

Application of texture attribute analysis. Sometimes gas-bearing formations are not characterized by very high-amplitude bright spots on the prestack-migrated seismic data. Besides, seismic reflection amplitudes are influenced by other parameters such as thickness, lithology, porosity, and fluid content and so even if bright spots were present, they would be ambiguous. To resolve such ambiguities we use texture attributes, and these provide a detailed and accu-

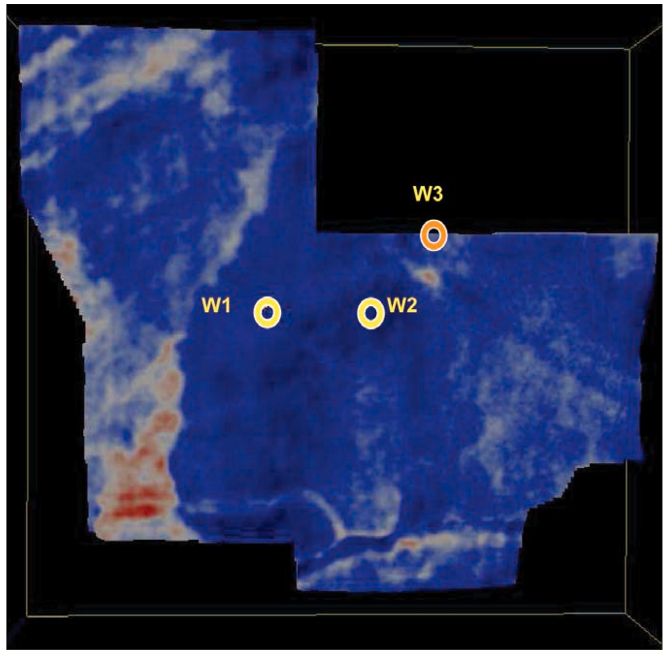

Figure 5. Strat-slice at the reservoir level from the seismic volume. There is not enough information from the seismic slice that could improve understanding the distribution of the producing sandstones at this level.

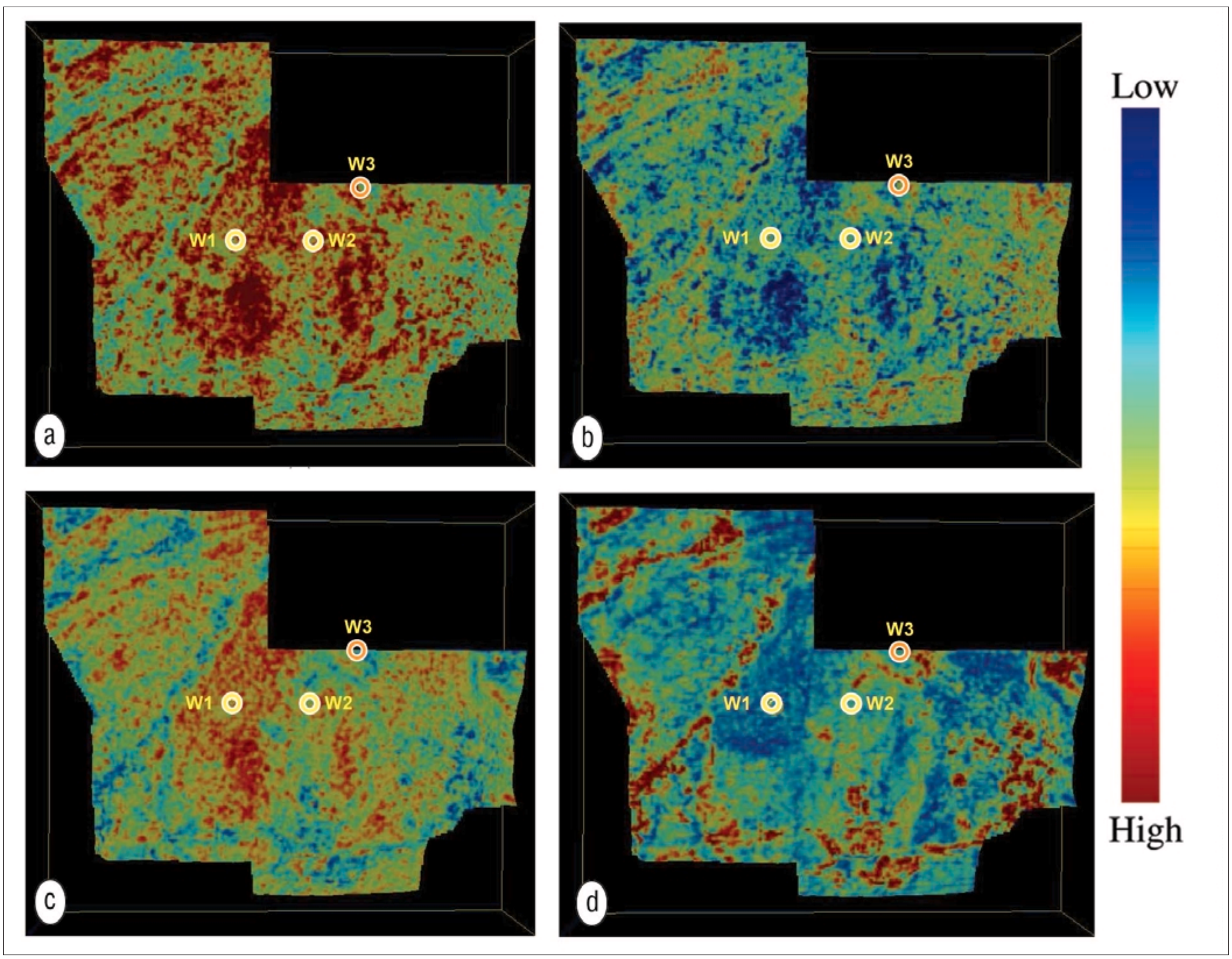

Figure 6. Strat-slices at the reservoir level showing texture attributes defining sandstone distribution: (a) represents the energy attribute showing high values of energy corresponding to the producing sandstone. These high values of energy are associated with low values of entropy (b) and high values of homogeneity (c). (d) represents the contrast texture attribute indicating high contrast ring around well W3.

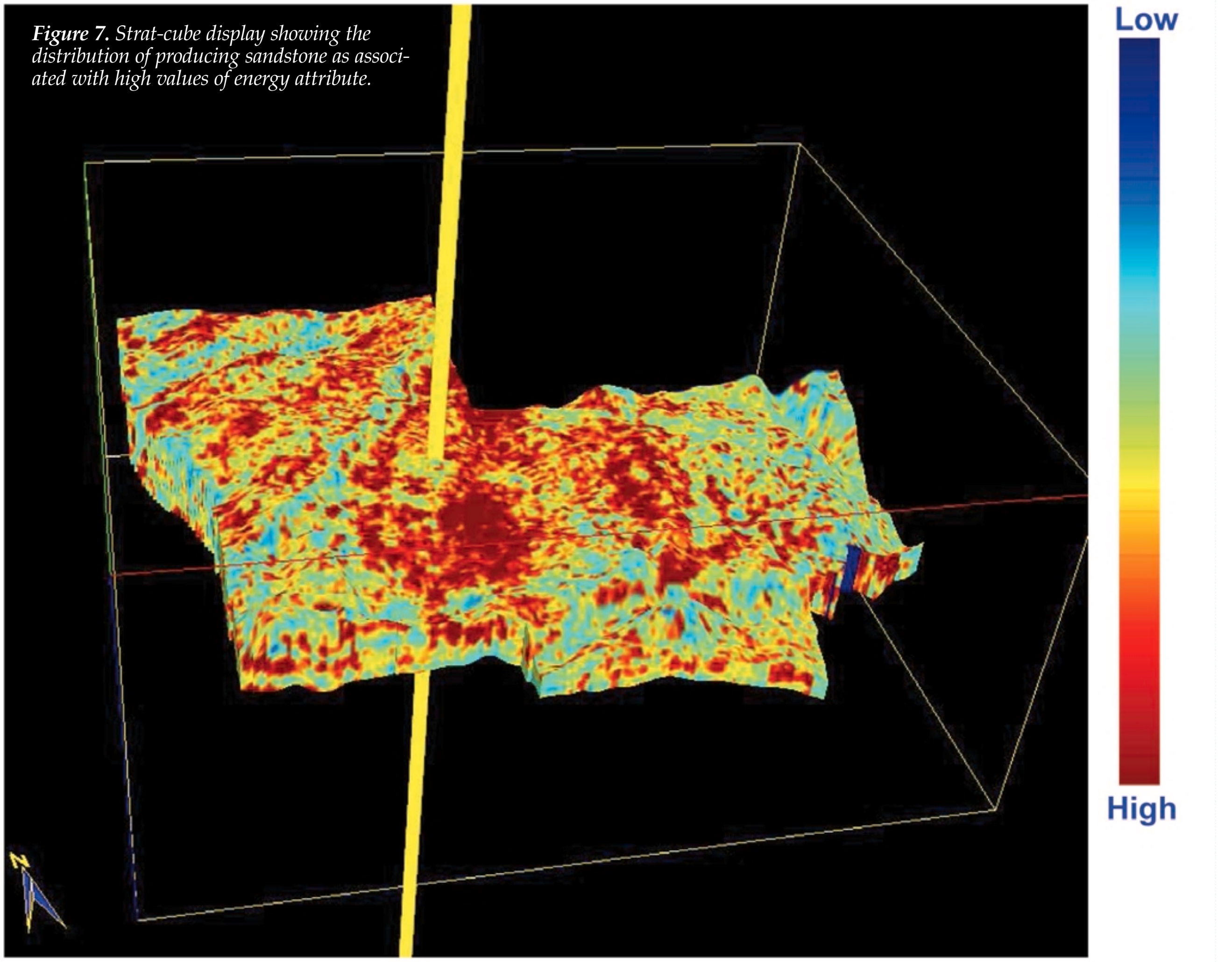

Figure 7. *Strat-cube display showing the distribution of producing sandstone as associated with high values of energy attribute.*

rate estimate of distribution of reservoir sands in the zone of interest. In the two cases under study here, based on the log correlation, the amplitudes corresponding to sands were somewhat pronounced as seen in Figure 4, but not conspicuous enough to be picked up as representing anomalies.

Case study 1. This study focuses on an area in southern Alberta. The target zone is Lower Cretaceous glauconite-filled fluvial deposits that have been productive in the area. A 3D seismic survey was acquired to create a stratigraphic model consistent with the available well control and matching the production history. Wells W1 and W2 produce hydrocarbons from the same formation, while well W3 (to the northeast of W2) has a different pressure and apparently does not share the same producing formation with wells W1 and W2. The ultimate goal was to locate the undeveloped potential within the fluvial deposits.

As the objective was stratigraphic in nature, the seismic data were processed with the objective of preserving relative amplitudes. Prestack time migration improves our ability to resolve stratigraphic objectives and extract high-quality seismic attributes and so was run on the data. It resulted in an improvement in the stacked image in terms of frequency and a crisper definition of features as it contributes to energy focusing and improved image positioning prior to stack (Reilly, 2002). Figure 4 shows a segment of a seismic section indicating the reservoir level and the producing sandstone (seen as dark blue) as enclosed in the box.

Strat-cube displays (of amplitudes or their attributes) are useful for seismic interpreters as they provide new insights for studying objects in a 3D perspective, which in turn shed light on their origin and their spatial relationships. Strat-cubes are subvolumes of seismic data, either bounded by two horizons which may not necessarily be parallel, or covering seismic data above and below a given horizon. A strat-slice of amplitudes from the migrated stack at the reservoir level is shown in Figure 5. There is an apparent indication of channels to the southern part of the slice as well as the northwest corner, and a slight indication of a broken ring-like feature around well W3 but the data are inconclusive about faults/fractures controlling production from W3. Besides, there is no indication of the distribution of the productive sands around W1 and W2.

Texture attribute analysis was done on the subvolume covering the broad zone of interest, and Figures 6a–d depict the energy, entropy, homogeneity, and contrast attributes. Figure 6a shows high values of energy associated with the fluvial deposits, not only for wells W1 and W2 but also for some channel sands seen to the northeast part of the slice. However, high energy for fluvial deposits needs corroboration with other texture attributes, before they can be used with any confidence. In Figures 6b and 6c, we see high energy associated with low entropy and high homogeneity, respectively, as we expected. Interestingly, the areal distribution of productive sands seen on texture attribute displays matched very well with the geologic mapping of these producing sands done independently and before the texture

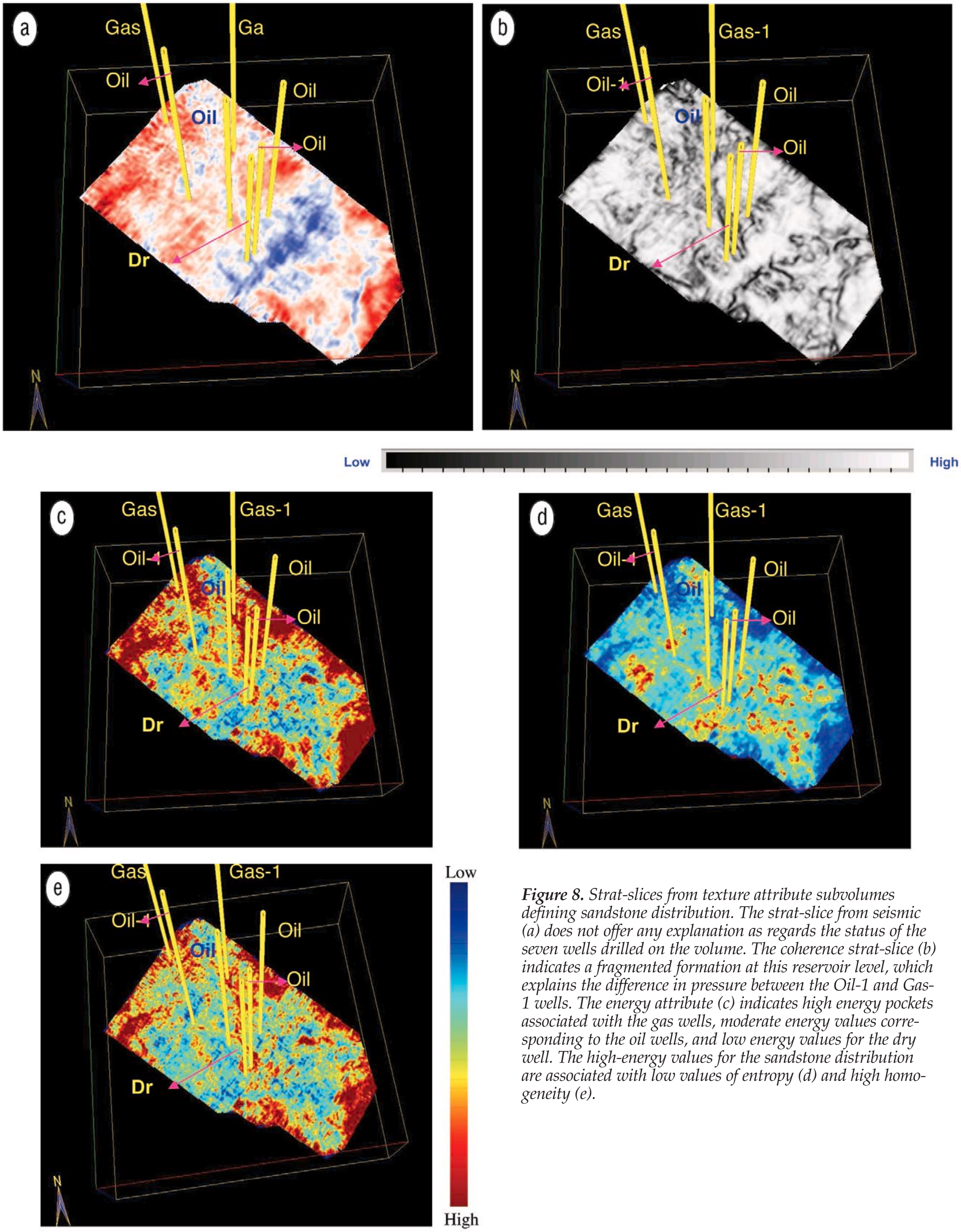

Figure 8. Strat-slices from texture attribute subvolumes defining sandstone distribution. The strat-slice from seismic (a) does not offer any explanation as regards the status of the seven wells drilled on the volume. The coherence strat-slice (b) indicates a fragmented formation at this reservoir level, which explains the difference in pressure between the Oil-1 and Gas-1 wells. The energy attribute (c) indicates high energy pockets associated with the gas wells, moderate energy values corresponding to the oil wells, and low energy values for the dry well. The high-energy values for the sandstone distribution are associated with low values of entropy (d) and high homogeneity (e).

analysis was done. The contrast attribute (Figure 6d) indicates a ring-like feature surrounding well W3. This feature is more crisp and focused, indicative of a discontinuity ring around W3 as if it were sitting on a separate fault block, in contrast to the broken feature indication seen in Figure 5.

Figure 7 shows the strat-cube display of the energy attribute and gives a realistic view of the distribution of the productive sands.

Thus the texture attributes provide convincing information not only for the distribution of the productive sands, but also furnish an explanation for the pressure of one well being different from the other two. While it is possible to interpret the productive sands on gamma-ray logs for wells W1 and W2 (having values less than 50 API units or so), the texture attribute displays provide a more intuitive presentation of the geology—the areal spread of these productive sands.

Case study 2. The second case study is from south-central Alberta. The field has been producing for about a year. Of the seven wells seen in the area (Figure 8), four are oil wells, two are gas wells, and one is abandoned. The objective of acquiring this 3D survey over the field was to help in understanding the status of the different wells in terms of the seismic amplitudes and also to explore the possibility of deciding on reservoir pockets that could be drilled. Yet another objective was to understand the difference in pressures between the Gas-1 and Oil-1 wells (Figure 8b).

The 3D seismic amplitudes were expected to indicate signatures consistently characterizing the different sandstone formations (two gas, four oil, and one dry). However, as seen in Figure 8a, the seismic data do not help much in this diagnosis.

The observed difference in pressures in the Gas-1 and Oil-1 wells necessitated the need to look for faults and fractures within the formations of interest. The coherence stratslice equivalent to that shown in Figure 8a indicates several discontinuities at the reservoir level of interest, showing that the reservoir-producing formations do not form a blanket but rather are fragmented by way of channels or sand edges seen as these discontinuities. This was taken as a plausible explanation for the pressure observations.

The texture attributes were generated next, and Figures 8c–e display the energy, entropy, and the homogeneity slices equivalent to the displays shown in Figures 8a and b. These displays indicate areas that calibrate well and are consistent with the status of the wells. While the two gas-bearing formations exhibit high values of energy (Figure 8c), the four oil wells indicate moderate values of energy, and the dry well is seen piercing a low energy pocket. As expected, the hydrocarbon-bearing formations indicate high energy, low entropy, and high homogeneity for fluvial formations.

It needs to be mentioned that GLCMs work well for seismic textures as long as the granularity of textures being examined is of the order of the pixel size, and for seismic application this is usually not an issue. Texture analysis depends on the resolution of the data and so the choice of parameters chosen will be important for bringing out patterns of interest.

Conclusions. Texture attribute study as presented here is different in that it is not usually associated with seismic attribute studies. Based on our analysis, we find the following:

- Texture attributes enhance the understanding of the reservoir by providing a clearer picture of the distribution, volume, and connectivity of the hydrocarbon-bearing facies of the reservoir.
- Texture attributes are a quantitative suite that aids the interpreter by defining the local geometry of the events.
- These attributes could potentially be utilized when analyzing the stratigraphic elements in a sequence stratigraphic analysis, similar to the rigorous methodology for two-dimensional seismic facies, known as the "A,B,C technique" presented by Ramasayer (1979).
- The sequential analysis utilized when generating the texture attributes gives insights into how the geology and geophysics and, in some cases, the engineering properties of the reservoir are linked.

Suggested reading. "Seismic attributes—A historical perspective" by Chopra and Marfurt (GEOPHYSICS, 2005). "Volume texture extraction for 3D seismic visualization and interpretation" by Gao (GEOPHYSICS, 2003)."Textural features for image classification" by Haralick et al. (*IEEE Transactions on Systems, Man, and Cybernetics*, 1973). "Seismic stratigraphy: a fundamental exploration tool" by Ramasayer (Offshore Technology Conference *Proceedings*, 1979). "3D prestack data mining to meet emerging challenges" by Reilly (SEG 2002 *Expanded Abstracts*). "Application of amplitude, frequency, and other attributes to stratigraphic and hydrocarbon determination" by Taner and Sheriff (in *Applications to Hydrocarbon Exploration, AAPG Memoir 26*, 1977). "Interactive seismic facies classification using textural and neural networks" by West et al. (*TLE*, 2002). "Segmentation of stacked seismic data by the classification of image texture" by Love and Simaan (SEG 1984 *Expanded Abstracts*). TLE

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