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Pressure Prediction Helps Guide Drilling

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THE WOODLANDS, TX.–Methods have been developed to enable robust pressure prediction in the presence of multiple pressure mechanisms, including undercompaction, unloading processes (secondary pressure mechanisms), and at great depth, the onset of secondary chemical compaction.

These models utilize geological and geophysical information to constrain the calibration models and the depths at which they must be applied to develop a multilayer pressure calibration model that will predict pressures accurately for prospect-level analysis and predrill prediction. These models then are integrated with the velocity field, and the geological and geophysical information, to predict pore pressures and fracture pressures at greater depths than previously have been feasible.

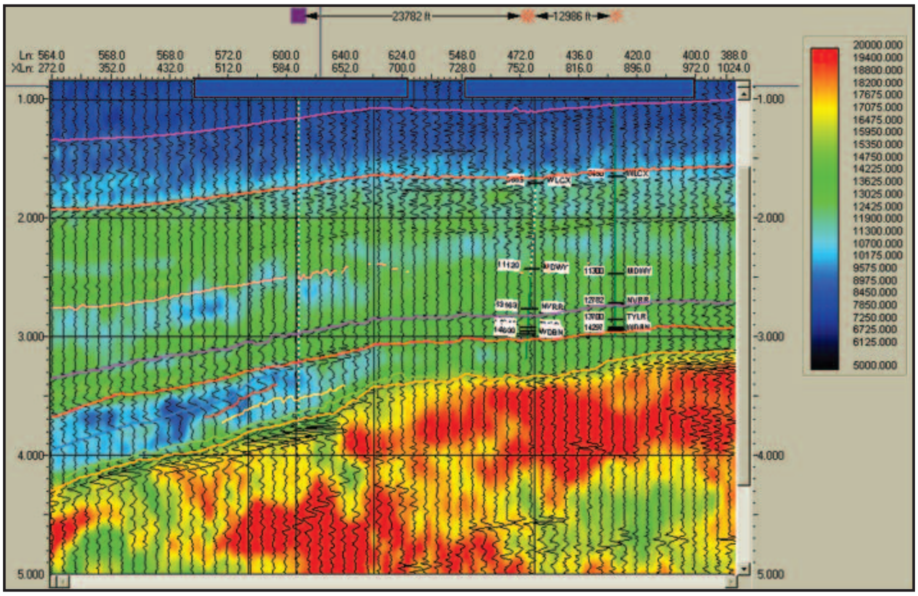
This methodology has been proven effective in multiple basins in helping drilling engineers improve well performance through more effective mud and casing program designs that significantly reduce well costs and rig time.

Applying elastic and acoustic inversion in complex carbonate environments also has proven effective for predicting pressures in environments where the shales can be separated from the carbonates. The approach requires that the inverted data be separated into the shale and carbonate velocity trends to allow the shales to be used for effective stress prediction while the complete velocity field is used for time/depth conversion. These studies have revealed that pore pressure prediction from mixed-lithology (carbonate and shale) environments is feasible using advanced inversion methods.

Applying 3-D pressure prediction methods in shale plays also has proven effective for differentiating actively maturing shales that are generating hydrocarbons from immature shales that are not as prospective. The resulting pressure volumes can be integrated with other seismic attributes to identify sweet spots in the shales, and also can be integrated with attributes such as brittleness to estimate fracture properties.

In the case where the shale target has internal stratigraphy with higher and lower total organic carbon intervals, the inversion method can be used to assess the pressure variations in the formation. This is demonstrated by an example from the Woodbine Shale where strata-bound pressures indicate the level of maturity.

FIGURE 1



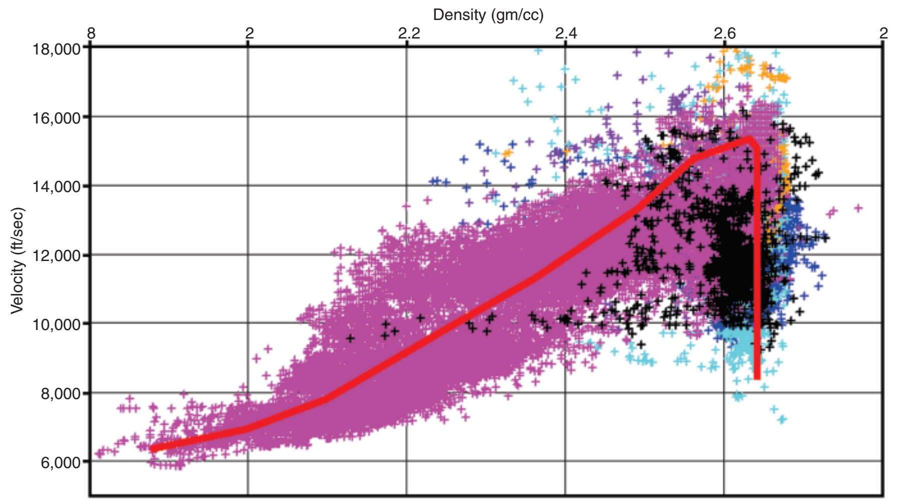
Seismic velocities across the study area show the strong reversal within the Woodbine formation. The top of the Woodbine is denoted by the red horizon and the base of the Woodbine is denoted by the gold horizon.

Basic Approach

Pressure prediction typically is performed using time-migrated gathers along with well logs and bore-hole geophysical data from local well control. The method requires detailed velocity analysis on the seismic gathers and some conditioning of the well data, followed by calibrating the seismic with the well data and predicting fluid pressures on whatever grid was picked on the seismic data.

The final velocity picks from the seis-

FIGURE 2



Well velocity and density data from offset wells in the study area show the abrupt velocity decrease at constant density in the Woodbine formation, which is directly correlated to the decrease in effective stress resulting from hydrocarbon maturation.

mic data are calibrated using well control, and a velocity-effective stress transform is determined that honors the well and seismic data at the control well locations. The overburden for the prediction area is calculated by integrating the density log data to obtain a vertical stress versus depth relationship referenced to the mud line or land surface.

This equation usually takes the form of (vertical stress = $a*Z^b$) where Z is depth, a is a coefficient and b is an exponent.

For this study, a Bowers-type relationship was used to create calibrations for velocity-effective stress. The Bowers equation is a power law relationship between velocity and effective stress that has been proven very effective worldwide for interpreting stress and predicting fluid pressure.

The basic equation is of the form ($V = V_0 + A\sigma^B$) where V is the velocity, σ is the effective stress, A is a coefficient and B is an exponent.

The vertical stress and effective stress then are combined to calculate the pore pressure using Terzhagi's basic relationship: vertical stress = fluid pressure + effective stress.

The last item to be calculated is the fracture pressure and fracture pressure gradient. The fracture pressure usually is determined with offset well calibration using a constant percentage of overburden, or using a Matthews and Kelly approach where the fracture pressure is defined as ($P_f = P_p + K*(OB-P_p)$), where P_f is the fracture pressure, K is the stress ratio, P_p is the fluid pressure and OB is the overburden (vertical stress). For this study, a Matthews and Kelly approach was employed.

Prediction Methodology

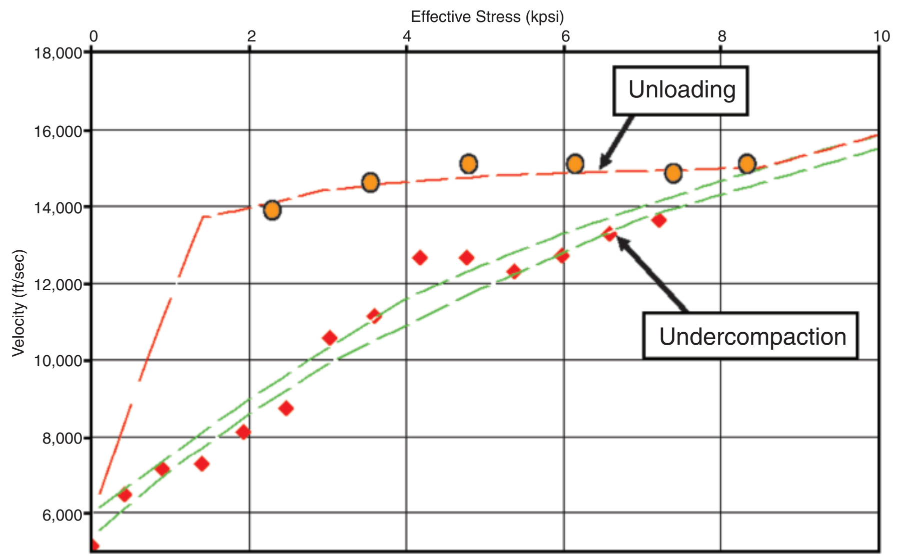
Predicting geopressure starts with quality control of the well data, seismic gathers and velocity data. The initial seismic gathers are conditioned using a proprietary data conditioning workflow. Dense velocity analysis is performed on the 3-D data around the proposed drill location, and these velocity picks are used as the input to residual velocity analysis.

Residual velocity analysis using an amplitude-variation-with offset phase-mismatch methodology is performed on the seismic data using a spatial smoothing of a predetermined number of common depth points and a temporal smoothing to stabilize the variations in the velocities without distorting the variations across faults and other primary structures.

The fluid pressure prediction is developed by generating vertical stress and seismic velocity/effective stress models from control wells. Pressure data including mud weight, repeat formation tester, modular formation dynamics tester and leak-off test data are employed in the calibration procedure to estimate overburden, pore pressure and fracture pressure.

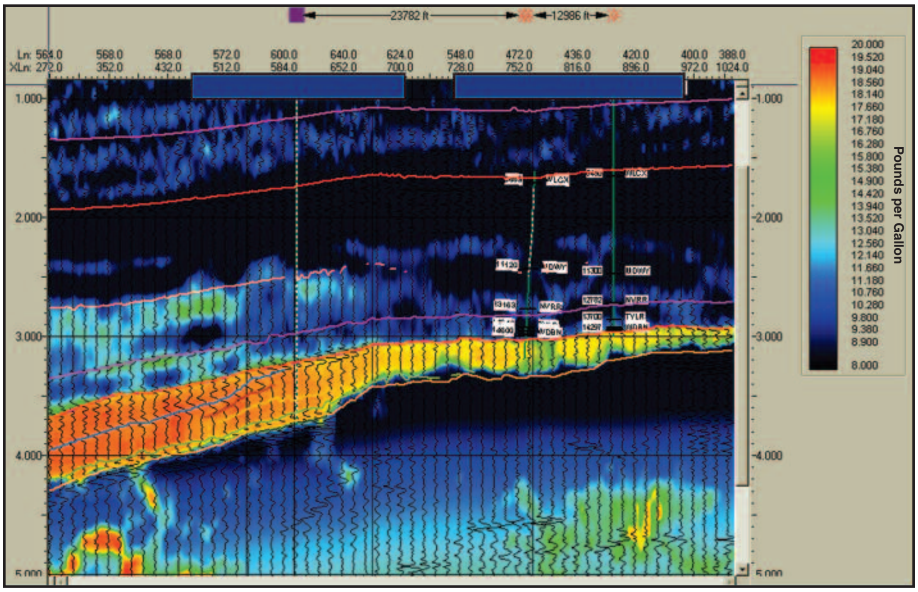
Density-log curves from a control well are integrated to estimate the vertical stress (Figure 1). The red points in the left-hand track indicate a representation of the density data. The points in the right-hand track indicate the calculated vertical stress (overburden) from this density model. The red curve indicates a mathematical model of the calculated vertical stress: (vertical stress = overburden

FIGURE 3



Effective stress calibration for the Woodbine formation and overlying strata show the relationship between the Bowers compaction curve for the area and the Woodbine unloading.

FIGURE 4



Predicted pore pressure gradient is shown in ppg for the seismic section seen in Figure 1.

= a*d^B) where stress is in thousands of pounds per square inch (kpsi) and depth is in meters below mud line.

This mathematical model is applied at all locations throughout the velocity volume. The fluid pressure measurements or mud weights for a well may be combined with the overburden curves to calculate effective stress values as a function of depth. This procedure underestimates the effective stress if the mud weight is greater than the fluid pressure. In the study, there were four wells available for calibrating the pressures in the target formation.

The mud weight curve for the calibration wells can be combined with the overburden model and the velocity data to calculate an effective stress for each mud weight/depth pair. The same process can be applied to the modular formation dynamics tester and drill stem test data. When the fluid pressure approximates the mud weight, this approach provides a good interpretation of the fluid pressure/effective stress relationship. When mud weight exceeds the fluid pressure–the most common situation–the mud weight approach tends to overestimate fluid pressure.

Prediction And Drilling

In the study, the velocities through the area show a distinct reversal in the Woodbine formation, as shown in the log data from the offset wells (Figure 2). This reversal varies across the study area, and the magnitude of the velocity reversal increases with depth of burial, as would be expected in the case where thermal maturity is increasing with increases in temperature (Figure 1).

In this case, the paleo-shelf environment showed higher relative velocities than the paleo-slope, which was buried more deeply. The Woodbine formation, by virtue of its strong velocity reversal, required a separate calibration based on unloading of the effective stress in the formation that was related to the active generation of hydrocarbons within the formation.

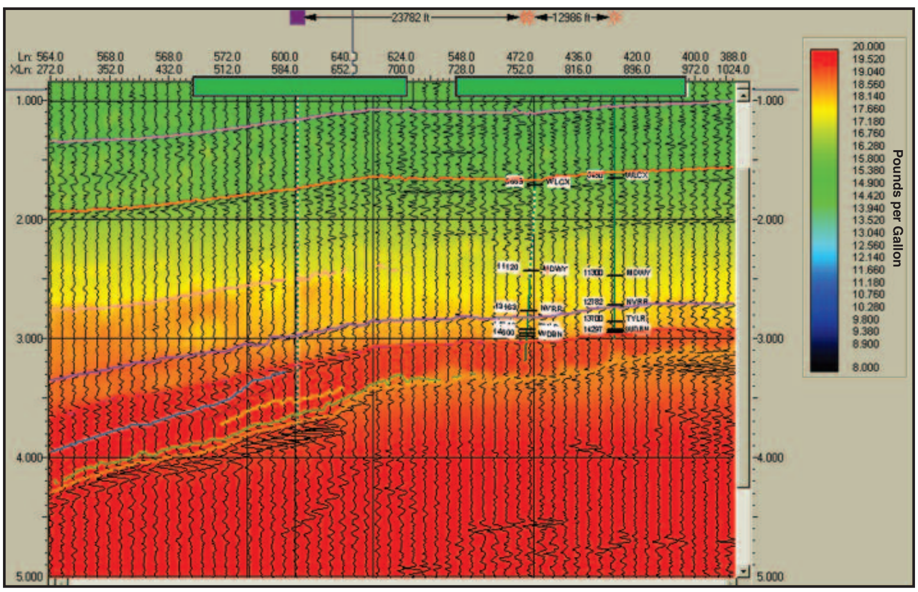
The pressures in the overlying rocks were calibrated with a consistent regional Bowers compaction curve (Figure 3) that represented the compaction behavior of the rocks above the Woodbine. Within the Woodbine, a separate Bowers unloading curve was applied to correctly predict the unloaded conditions in the target formation.

The prediction process was applied in 3-D and volumes for pore pressure gradient (Figure 4) and fracture pressure gradient (Figure 5) that could be used in planning a proposed well. The pore pressure gradient data show very nicely the severe pressure onset that characterizes the Woodbine formation in the study area.

The predrill prediction was used to plan a wildcat well that targeted zones of permeability within the Woodbine formation. The calibration of the predrill velocities to vertical seismic profiling data from the offset wells was used to accurately predict the top of the Woodbine formation. The quality of the velocities was sufficient that the casing point just above the Woodbine was picked within 100 feet of the formation top.

This allowed the drilling operation to get a maximum leak-off pressure before increasing the mud weight to penetrate the Woodbine. The predrill prediction indicated that the mud should be increased from 12 to 18 pounds per gallon at the top of the formation.

FIGURE 5



Fracture pressure gradient is shown in ppg across the seismic section seen in Figure 1.

The actual pressures within the Woodbine were measured at 17.6 pounds per gallon, which was within the 0.5 ppg error margin of the predrill prediction and enabled safe drilling of the high-pressure Woodbine interval. The well was drilled safely and efficiently for $1 million less than the $12 million authorization for expenditure assumed for the well. By comparison, several other wells drilled in the same area experienced significant drilling and operational problems at the top of the Woodbine in the absence of similar predictions, including at least one major blowout that resulted in the loss of a drilling rig.

Conclusions

Predicting pore pressure and fracture pressure using seismic velocities has a proven track record in complex geologic settings such as the Woodbine play and other shale-dominated unconventional plays. Integrating seismic and well data with robust multilayer earth models for compaction, diagenetic unloading, and chemical compaction can enable safe and efficient drilling in these plays, and also can be used with other seismic techniques to predict reservoir properties and plan hydraulic fracturing programs.

The pressure prediction process also can be combined with elastic inversion methods to predict Young's Modulus, Poisson's Ratio, and brittleness, which then can be integrated with the pore pressure and fracture pressure data to calculate fracture heights and closure stresses in unconventional reservoirs.

Effective use of these integrated geophysical and petrophysical tools in unconventional reservoirs enables operators to improve drilling results and safety dramatically, while reducing drilling costs by 10-15 percent, on average. Combining the technologies to predict rock mechanical properties also can reduce the cost of hydraulic fracturing and stimulation processes, which can help operators get significantly better production from fewer wells with fewer fracs, and avoid areas where fracturing will be ineffective because of suboptimal rock properties. ❒

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Alan R. Huffman is chief technology officer for SIGMA^3 Integrated Reservoir Solutions, and also chairman and chief executive officer of Fusion Petroleum Technologies Inc., which was acquired by SIGMA^3 in early 2011. Huffman was responsible for Fusion's strategic growth since 2003. He also was the 2003-04 Lyssa & Cyril Wagner professor of geology and geophysics at the University of Oklahoma. With more than 25 years of experience in international exploration and production, Huffman was manager of Conoco's Seismic Imaging Technology Center from 1997 to 2002, and served at Exxon Corporation from 1990 to '97 as a technology specialist on exploration and production projects in the United States, West Africa and the Far East. In 1986-87, he performed the seismic hazard analysis for the superconducting supercollider in Waxahachie, Tx., and in 1989-90, he was science manager for the U.S. continental drilling program of the Drilling, Observation and Sampling of the Earth's Continental Crust (DOSECC). Huffman holds a B.S. in geology from Franklin & Marshall College and a Ph.D. in geophysics from Texas A&M University.

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Jeffrey S. Meyer is responsible for characterizing petrophysical and elastic rock properties associated with AVO modeling and pore pressure analysis at SIGMA^3 Integrated Reservoir Solutions. Meyer joined SIGMA^3 as part of its acquisition of Fusion Petroleum Technologies Inc., where he served as vice president of petrophysics and geopressure prediction. Prior to FPTI, he specialized in bore-hole geophysics with the Crosswell Seismic (Tomoseis) Division of CoreLab (1997-2004). Meyer began his career with Western Atlas (1987-1997) as a field engineer in Texas, transferred to California, and worked with the VSP-while-drilling development group and finally as a senior analyst in the Log Analysis Center in Jakarta, Indonesia. He has a B.Sc. in petroleum engineering from Texas A&M University.