Eagle Ford Solutions: Critical Log Data, Solutions and Conclusions*

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Abstract

The Eagle Ford Formation presents a unique set of challenges to geologists and reservoir engineers attempting to define the reservoir and understand the characteristics that contribute to production. From a conventional standpoint, the formation cannot be adequately described by traditional measurements of triple combo logs. General relationships can be established, but attempts to predict advanced reservoir properties, such as permeability, fluid type, and the ability of the formation to accept effective fracture treatments, do not conform well to correlations.

Nuclear magnetic resonance (NMR) logs added to logging suites provided a portion of the required solutions. Direct permeability transforms from relaxation, or T_2, provided the first reservoir properties independent of any other log measurement. Permeability from well to well and even within a vertical section in a given well can now be established using the Bray-Smith permeability equation.

Dipole sonic logs provided another important element of discovery. When these logs are run in vertical pilot holes, values for vertical and horizontal closure stress can be calculated. These, combined with permeability from NMR, enable the operator to precisely target the interval in the Eagle Ford that provides the best opportunity for enhanced production. When these logs are run in horizontal wells, anisotropy can be included to select intervals for fracture treatment that will have a greater ability to break down and retain the geometry of the fracture treatment.

This study of enhanced logging techniques considers the application of each of these devices in the Eagle Ford Formation. NMR responses for permeability and fluid type are combined with data from dipole sonic logs to select the best landing horizon. Dipole sonic logs are used to establish rock mechanical properties and anisotropy to determine the best fracture treatment locations and the best treatment designs. The combination possibilities of all of these devices are explored as a recommended best practices review.

Method and Theory

The Eagle Ford Formation is similar to other unconventional reservoirs in one important way: if the rock surfaces in the formation can be well exposed to conduits to the wellbore, good production will result. This conduit is established by efficiently placed fracture treatments that retain some flow path geometry to keep these induced treatments in contact with the productive components of the reservoir.

In thought processes and in design procedures, this process is envisioned as a fairly simple process. The overwhelming approach to the Eagle Ford, or to any other unconventional reservoir, is to stimulate with a large treatment with the expectation that it will grow to fill the formation from top to bottom and extend for a considerable distance laterally into the reservoir.

Figure 1 shows beginning point for the discovery of the validity of this presumption in this outcrop of the Eagle Ford. A horizontal well that would penetrate the reservoir was superimposed on this outcrop photo. The photo also includes locations of fracture treatment stages, spaced periodically along the horizontal wellbore at distances consistent with conventional practices. The section of rock exposed in this outcrop appears to be very consistent horizontally away from the incursion point of the well. The horizontal scale of the outcrop is around 1,000 feet, which is approximately one-fifth of the horizontal distance normally drilled in the reservoir.

The rock is also known to be vertically inconsistent. The layers highlighted in yellow are known boundary effects to any treatment pumped into the reservoir. When a horizontal well is spotted in the location shown, any efficient completion of this formation requires breakdown through these horizontal boundary conditions and further planning to ensure that this incursion enables fluids to flow from the reservoir to the wellbore. This basic treatment problem is not unique to the Eagle Ford, but a solution can be critical to maintaining long-term production from this reservoir.

The solution to increased production requires a method that is capable of determining useful solutions for the specific portion of the reservoir that is encountered. The first critical solution that can be established is from NMR measurements in the reservoir. The evaluation that was applied used a derivative of the Bray-Smith permeability equation (Smith et al., 2008). This equation provides useful estimates of permeability, without external inputs, in many different conventional reservoirs that are in the millidarcy range. The equation has been adapted to derive estimates of shale permeability in the nanodarcy range in unconventional reservoirs. The equation takes the form (Smith et al., 2013):

$$kbin-Perm = \left[(MPHI)^{p} * \left(\sum_{T2Bphi0ms}^{T2Bphi8000ms} wf * T_2 Bphi / BVI \right) \right]^{S}$$

Where:

kbin Perm = shale permeability

MPHI = NMR effective porosity
wf = weight factors
T_2 Bphi = segmented bin porosity
BVI = bulk volume irreducible water
Factors *p* and *s* are empirically derived constants

The form of this equation is the same as that used for conventional reservoirs. Changes in weight factors and exponents have been derived to accommodate the earlier time arrival of relevant data. When pore sizes are smaller, as they are in shale, all data occurs earlier in time. Cores, evaluated by laboratory NMR measurements, can then be used to focus on the critical bin times to estimate permeability in the shale. As these values were determined, they were applied to the weight factors to provide a shale permeability solution consistent with the laboratory NMR data.

This relationship has been applied in many of the shale reservoirs in North America. To date, absolute permeability has proven to be elusive. The response from NMR tools is consistent, but nanodarcy results from laboratory core analysis cannot be replicated from laboratory to laboratory. Individual laboratories appear to provide repeatable results, but comparisons of results between laboratories are not always exact. Therefore, shale permeability is presented by evaluation from this equation. It is a very useful property, nevertheless. If order of magnitude differences in permeability can be evaluated, order of magnitude changes in production can be achieved if the well is placed in the correct portion of the reservoir.

Figure 2 (Smith and Menendez, 2011) shows permeability to evaluate a shale reservoir. Track 2 presents both conventional permeability in yellow and kbin, with shale permeability shown in red. This demonstrates the great difference between conventional Bray-Smith permeability and kbin shale permeability. This log shows many areas of divergence and demonstrates how micro-porosity can contribute to permeability in a much different manner than textural features in a conventional reservoir. The scaling for conventional permeability is in millidarcy units, whereas the scaling for shale permeability is a qualitative (not absolute) scale in nanodarcy units.

The log shows that the highest permeability segment is located at 9,630 feet. When that thin section is compared to the reservoir segment at 9,690 feet, the calculated permeability differs by two orders of magnitude, which implies that the higher permeability section will produce at a rate that is 100 times greater than the low permeability section. Even in nanodarcy rock, this difference can be significant.

A large portion of the reservoir near the high permeability streak is relatively high permeability. The rock at 9,640 feet is nearly one order of magnitude less than the highest permeability portion of the reservoir. It is still an order of magnitude greater permeability than the rock at 9,690 feet. As shown in this section, relative quality of the reservoir can be inferred from the NMR measurement in a vertical pilot hole through the section.

Because the productive capacity of unconventional reservoirs depends on the quality of the stimulation treatment, the real question to be addressed is whether or not this permeability difference has any significance in the production. If the reservoir can be treated in such a manner that the entire reservoir produces fluid to the wellbore, the permeability is not an issue. The fracture treatment connects the entire reservoir to the wellbore.

For this Eagle Ford reservoir, as well as many other conventional and unconventional reservoirs, an assumption of treatment connection to all portions of the reservoir may be presumptuous. As shown in Figure 1, vertical boundary conditions exist that may limit the growth of the treatment to the desired areas of the reservoir. A method of quantifying that limitation must be used to enhance the value of the completion by placing it in the correct portion of the reservoir to achieve the maximum effect of the treatment.

This need to place the horizontal well in the optimum reservoir location has special significance in shale reservoirs. Bedding sources may differ significantly, creating compositional and textural differences in reservoir layers. Significant elapsed time can also exist between the deposition of a single horizontal horizon and the section of rock directly above or below. Drying or wetting events may exist that alter the rock and cause additional variation and contrast.

Logs that can identify rock mechanical values of all portions of the reservoir would be invaluable for this solution. For many years, the industry has evaluated sonic logs to derive compressional and shear waves as they propagate through the reservoir. These values are used in well-known relationships to establish Young’s modulus and Poisson’s ratio along the wellbore, which are then used to determine the height growth of any fracture treatment. Historically, this practice has worked well for vertical growth from a vertical fracture initiation point. The solution of migration of a fracture treatment vertically through a reservoir from an initiation point in a horizontal well requires another solution. Vertical closure stress does not supply this answer; a horizontal closure stress is required.

To achieve a solution of rock mechanics in three dimensions, additional information must be measured and unique analysis techniques applied to the resulting data. Dipole sonic logs enable the measurement of oriented shear data in different directions. When the orientations of the measurements are established through directional information, the phases in the vertical and horizontal component directions can be separated, examined, and evaluated.

Figure 3 (Warpinski et al., 1998) shows some of the boundary conditions that may restrict fracture treatment growth in any shale reservoir. The red initiation point of the fracture treatment encounters different types and textures of rock as it migrates. In the condition on the left, the mechanical contrast between the reservoir sections is great. As the initiation progresses, rock that is remote to the initiation point begins to crack. When the initiation pressure wave strikes that plane, the treatment diverts to that flow path and additional extension is hindered. The center figure shows a weak plane within a section of the rock. The pressure actually separates layers within the softer rock and diverts the initiation pressure into the horizontal plane because it provides the least resistance. All treatment energy then migrates horizontally and has no further positive effect on creating surface area in the formation. Finally, the image on the right shows a condition in which a particular rock horizon is extremely ductile. When the pressure system encounters this portion of the reservoir, the rock deforms in a plastic manner. All of the pressure is expended deforming this plastic rock. When the pressure is removed, the deformation caused by the pressure is expended by a quick flow back to the wellbore. In all three of these cases, the energy used and paid for is, at best, inefficient; at worst, it is entirely useless in creating flow paths for production. Reduced effectiveness of fracture treatment directly results in reduced flow during production. An engineering technique that could identify these adverse reservoir conditions would have great value. The use of that information in a treatment design would result in better production and greatly improve the economics of any completion.

Figure 4 (Bray et al., 2010) exemplifies the problem of layered reservoirs. In homogeneous reservoirs (left), sonic measurements may be made in any direction with the same result. When the same signals are introduced into a layered reservoir, as indicated in the center figure, measurements in the vertical direction may be significantly altered as the signal migrates through layers of rock with varying ability to transmit that signal. Signals in the horizontal direction are more representative of a single geologic unit and may provide valuable information related to the absolute and relative rock mechanical stresses of these layers.

Dipole sonic logs are capable of making multiple measurements that provide a solution for these layered events. They measure dipole signals in two different oriented directions that are orthogonal to one other along with compressional arrivals and Stonely waves, both of which are omnidirectional. This data can be organized and evaluated in vertical and horizontal planes. The vertical component is directly measured and calculated. The horizontal component can be separated and evaluated by matrix techniques that provide a unique solution. The data thus organized can be presented in a visual scale that represents relative brittleness of the formations involved.

Figure 5 shows how this solution of vertical and horizontal closure stress may be applied to a completion. In this image, the left log track is vertical closure stress. The right log track is the horizontal closure stress. The color palette on the log is arranged to present the most brittle rock as bright red and the least brittle rock as blue. The other colors are across the color spectrum in between. Green events are close to blue while yellow events are closer to red.

The known ductile portions of the reservoir, highlighted in yellow in the outcrop, are evident as green representations on the log. The top horizon trends into the blue spectrum. These results indicate that it will be difficult for the hydraulic fracture treatment to break through and maintain wellbore connection to the fractures as they attempt to migrate through these horizons. Because these conditions are known, they can now be incorporated into the treatment size, content, and pressure requirement planning.

An additional complication in the treating equation is variation along the horizontal well path. As drilling progresses laterally away from a pilot hole, the well does not remain within a single depositional horizon. Any traverse up or down in the section will result in changes of rock strength as different depositional and compositional events are encountered. Anisotropy from a dipole sonic run in the horizontal well can provide a solution.

Figure 6 (Bray et al, 2010) shows a combination of data from an open hole log in a vertical pilot hole and a cased hole log in a horizontal well. This combined data set identifies the best landing horizon within the reservoir. The stimulation of the well can also be designed because of this enhanced data set. Track 4 of the vertical log shows the horizontal closure stress calculated from the dipole sonic in a vertical pilot hole. Bright colors (red) indicate brittle rock, or rock that is easy to break down. Cool colors (blue) indicate less brittle areas. In this vertical section, a green horizon exists between 11,979 and 11,983 feet, which indicates an area that should be avoided in a well drilled horizontally from this starting point.

The dipole sonic was also logged in the horizontal section of this well. Again, the palette is bright for easily broken down and blue for difficult to break down. The red numbers on the top of the horizontal log indicate the vertical depth of this section. The section shown is from 11,969 to 11,977 feet. In comparison to the vertical log, this is inclining into the green horizon identified in the vertical well. The shading on the horizontal log is trending toward the cool colors and will be more difficult to treat. Perforation points for entry in this section should be selected to correspond to the bright colors. Although this process will not guarantee an efficient initiation and propagation of the treatment, it provides the best potential opportunity for success.

Figure 7 shows how this information may be brought together for optimal completions in the Eagle Ford reservoir. The logs shows NMR with time measurement of porosity in track 1, calculated permeability in red in track 2, and horizontal closure stress in track 3. All of these logs were captured in a pilot hole.
An analysis of the logs indicates good permeability above and below the horizontal closure stress boundary at 9,652 feet. The majority of completions in the area were placed below that closure feature with good results. The calculation of permeability/thickness of the section actually indicates that better permeability was above that closure stress, but the completion decision was based on experience with past completions.

After the horizontal landing horizon decision is made, the horizontal well is drilled; the only remaining decision point is where to place perforations to maximize treatment and production. In Figure 7, the anisotropy measured in the horizontal at this placement point is not ideal. Most of the palette presented appears as a cool color, or difficult range for stimulation. At this point, nothing can be done to alter the economic effect of the location of the landing horizon. Improvement in production rates can still be achieved by maximizing the value of any decisions made going forward.

Three thin sections of brittle material are evident in the horizontal log image. Perforations should be placed in these locations. This example shows how, even with good planning to place a horizontal well in an optimal position vertically, there can still be variations within the various rock strata that can create significant problems with completion. These difficult conditions can still be overcome with a collection of meaningful data and intelligent decisions made by evaluating that data.

Conclusions

The permeability of the Eagle Ford Formation can be qualitatively evaluated by using NMR logs and an adaptation of the Bray-Smith permeability equation. This data, collected in a pilot hole, can be used to identify the best portions of the reservoir for horizontal landing positions.

Dipole sonic logs, also run in the pilot hole, identify the vertical and horizontal closure stress conditions within the reservoirs. The horizontal closure stress becomes a boundary condition from any fracture treatment that initiates from a horizontal wellbore. The exact location that these conditions occur must be considered in a decision about the targeted horizontal landing horizon.

Dipole sonic logs, run in cased hole conditions, can be evaluated for anisotropy along the horizontal well path. When these logs are compared to the vertical pilot hole, the vertical location of the well path can be understood in relation to the rock mechanical values of the particular section of the reservoir being evaluated. Reference of the horizontal well back to the pilot hole can be extended away from the pilot hole as long as significant alterations are not observed in texture or composition of the reservoir.

The application of each and all of these technologies will result in decreased completion costs and increased production. The economics of any project will be improved.

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Figure 1. Eagle Ford outcrop and superimposed horizontal well with fracture treatment stages.

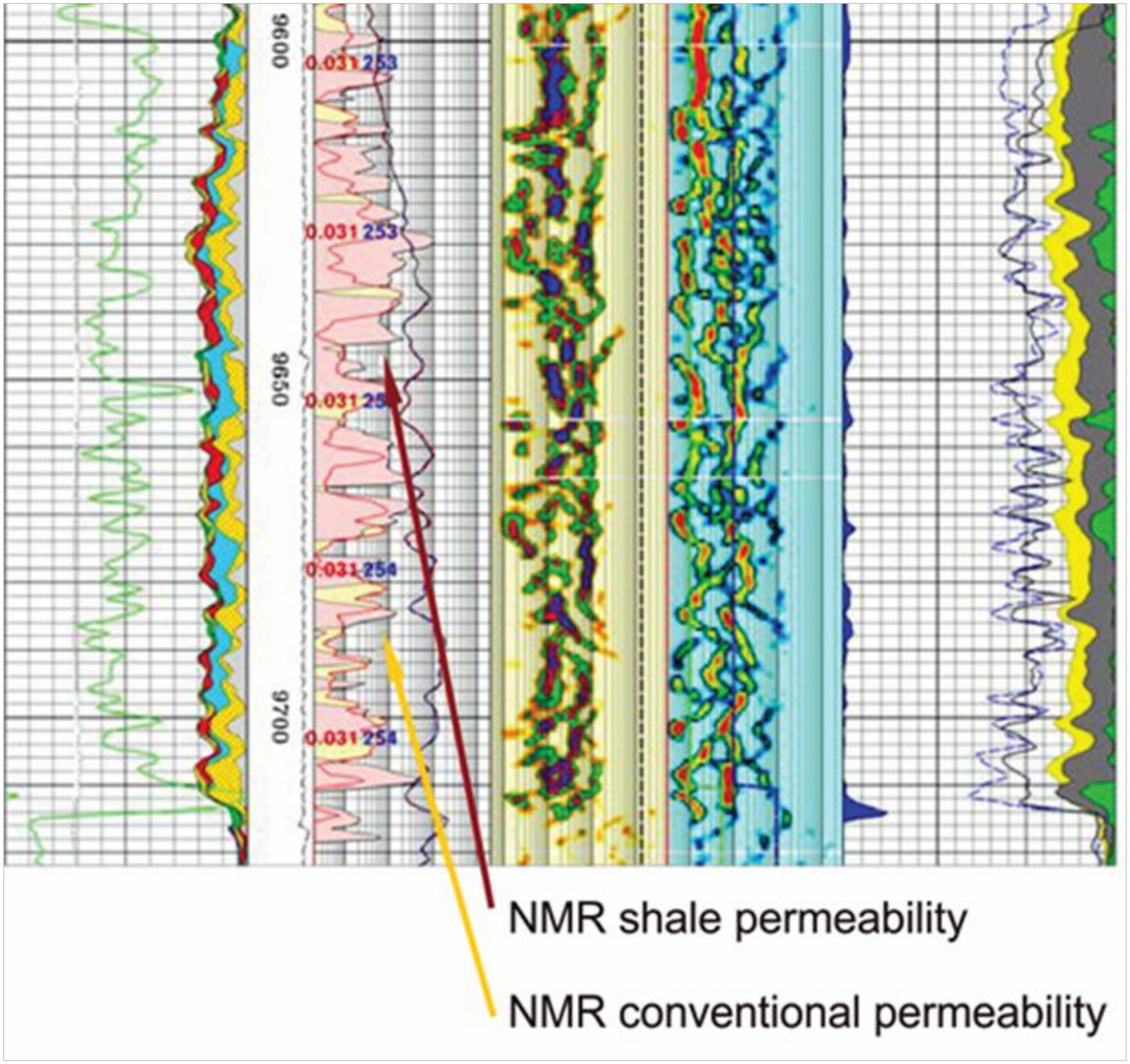

Figure 2. Comparison of conventional permeability calculation with shale permeability.

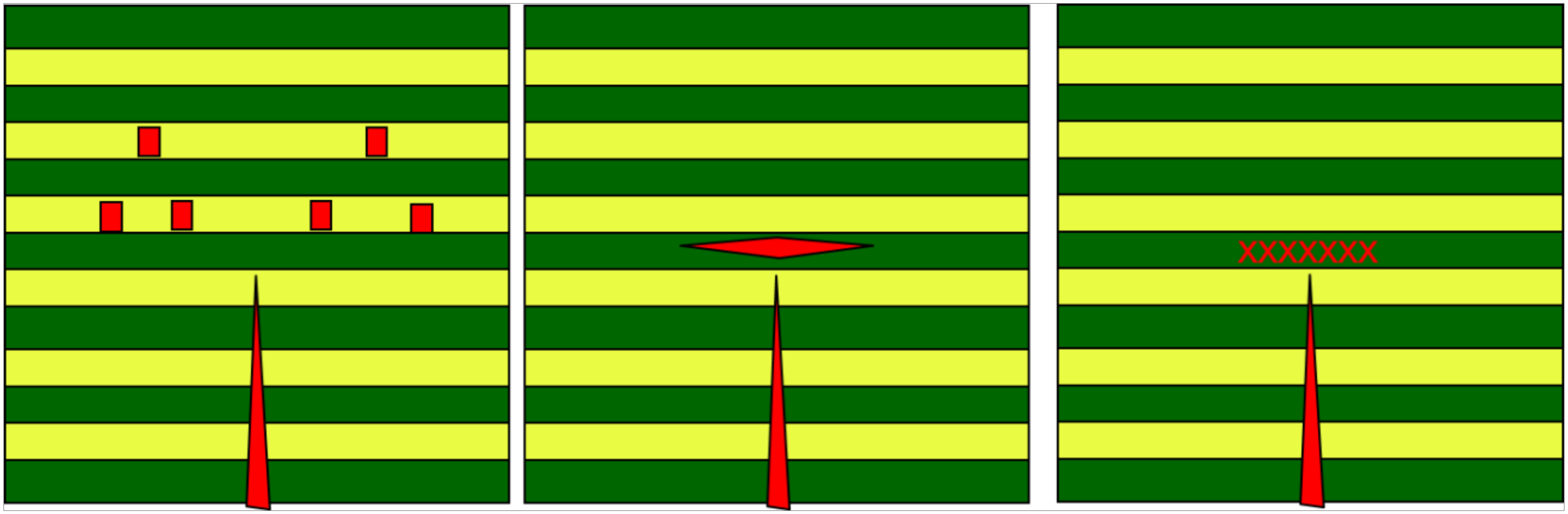

Figure 3. Potential boundary conditions for fracture initiation migration in horizontal wells.

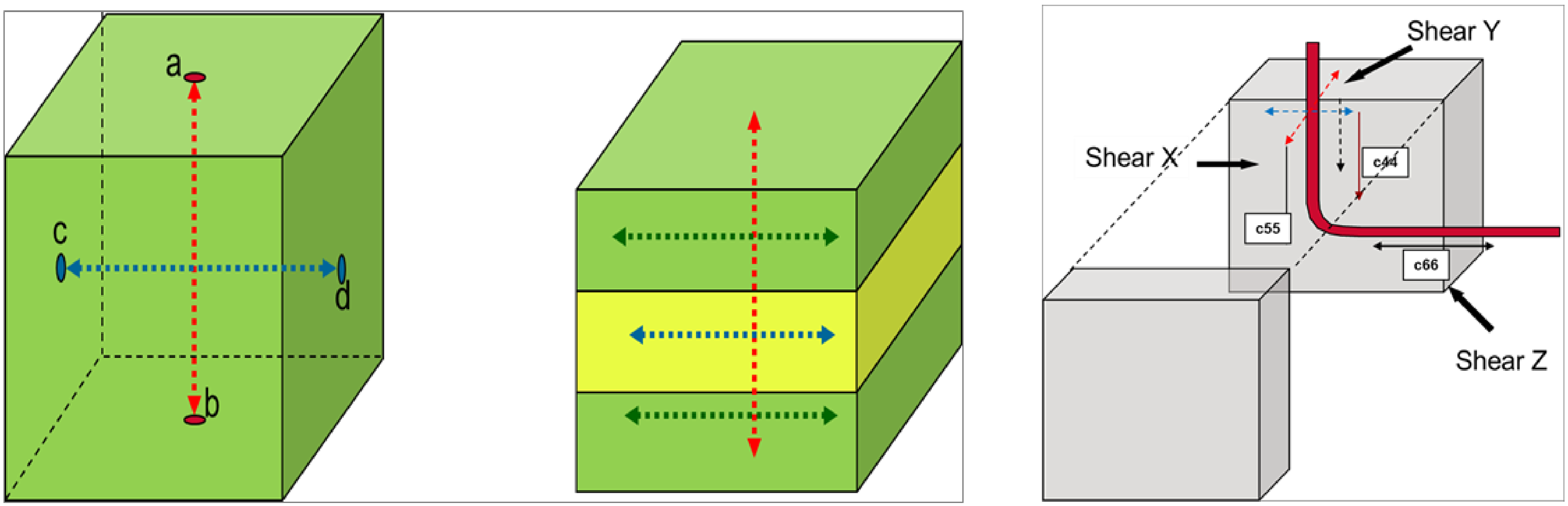

Figure 4. Solution of vertical and horizontal closure stress from dipole sonic logs.

Figure 5. Eagle Ford outcrop with dipole sonic solution of vertical and horizontal closure stress.

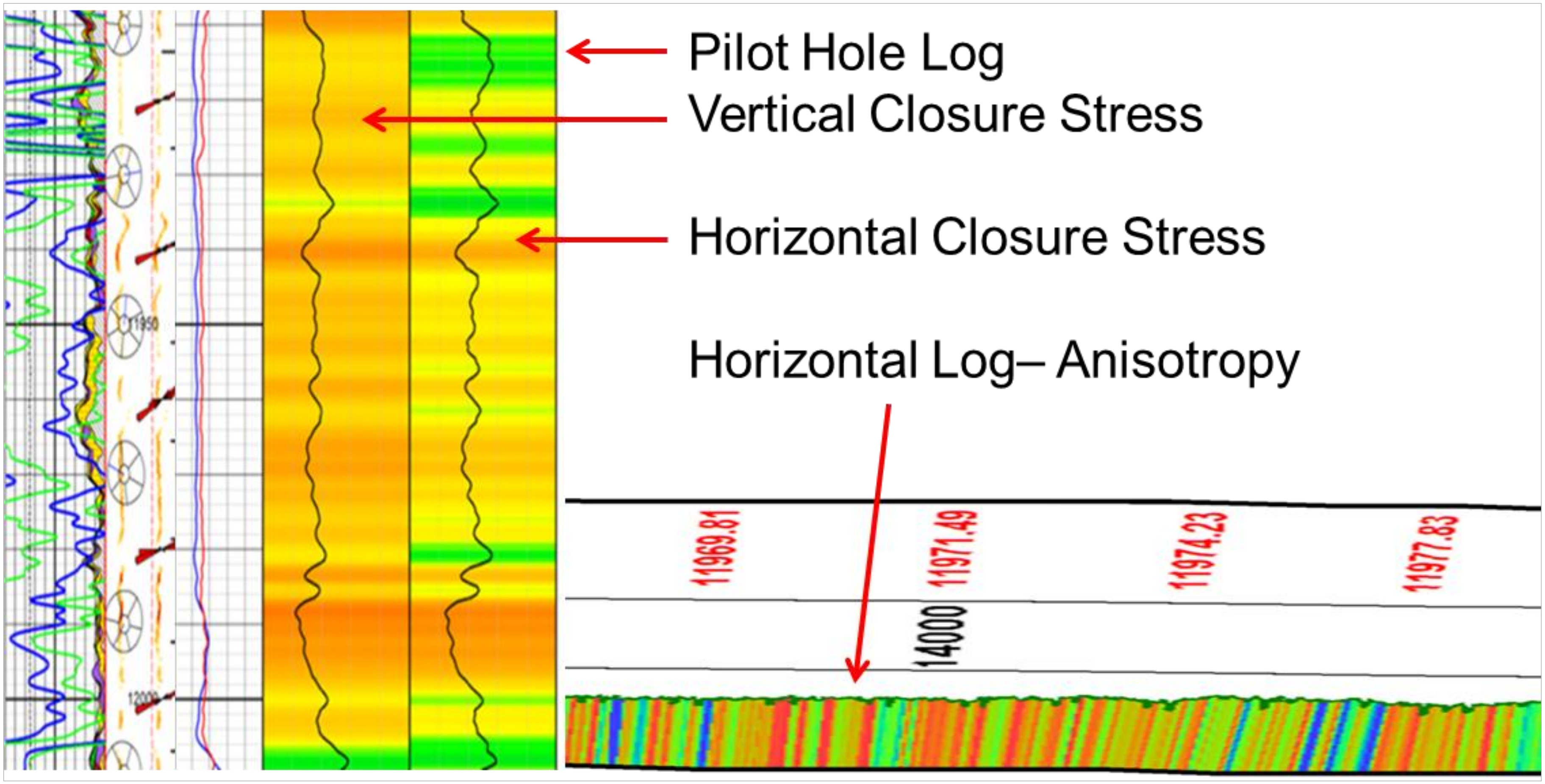

Figure 6. Pilot hole solution of vertical and horizontal closure stress, horizontal solution of anisotropy.

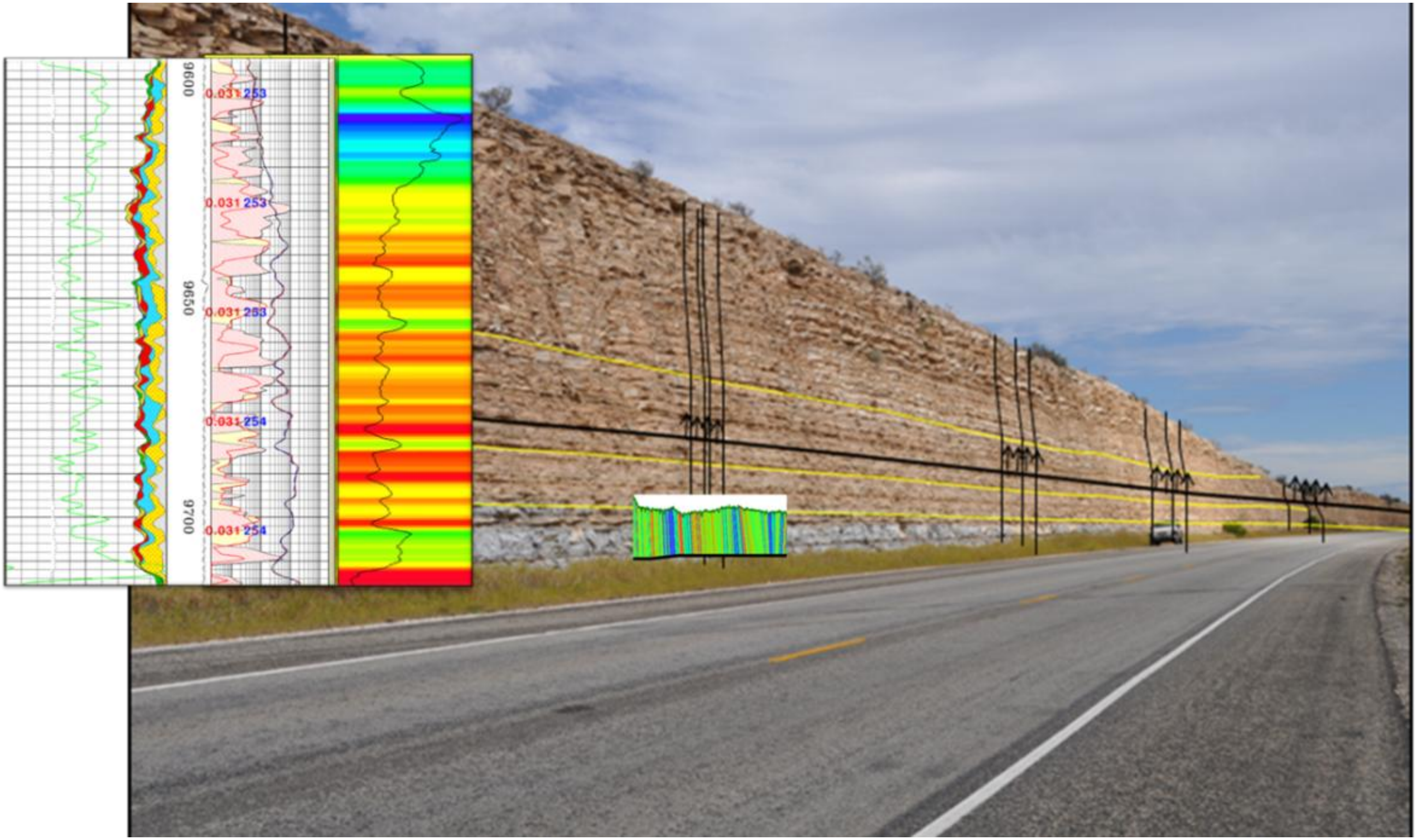

Figure 7. Permeability, horizontal closure stress and horizontal anisotropy considerations.