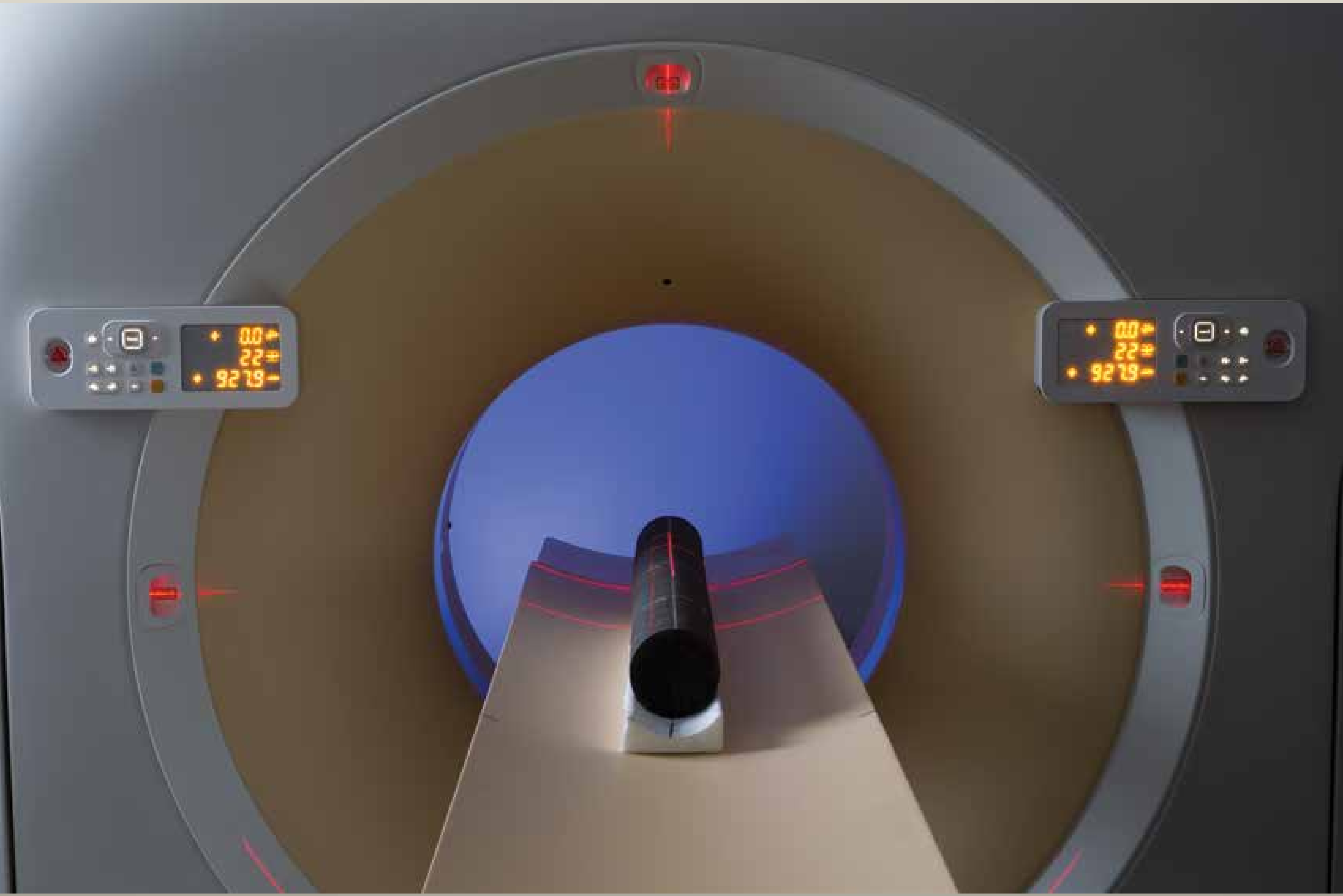
InSite

CWLS Magazine
Spring 2015



Inside…

InSite

CWLS Magazine Spring 2015

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The InSite is an informal magazine with technical content. The material is not subject to peer review. The opinions expressed are those of the individual authors.

Table of Contents

Cover Photo: Medical grade CT Scanner used for core analysis. Also provides high resolution density and PEF curves.

Photo Credit: Courtesy of Schlumberger Reservoir Laboratory. Calgary Alberta

Photos: If you have photos that the CWLS can use in its next InSite please send a high resolution jpeg format version to Doug.Kozak@Halliburton.com or maboud@slb.com. Include a short description of the photo with your submission.

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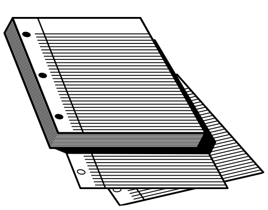

Call for Papers

The CWLS is always seeking materials for publication. We are seeking both full papers and short articles for the InSite Magazine. Please share your knowledge and observations with the rest of the membership/petrophysical community.

Contact publication Co-chair:
Manuel Aboud – maboud@slb.com or
Doug Kozak – doug.kozak@halliburton.com

The President Report

2014 was a remarkable year for the CWLS despite our industry facing recent economic challenges, falling oil prices, drilling activity reductions and a global industry downturn through the last half of the year. This recent downturn has many people wondering about the future and what it may hold. I am confident that the CWLS will continue to thrive, because we have built a solid foundation through our members and are well positioned for the future and its challenges.

I am very proud that we have seen significant accomplishments this past year - from the new CWLS.org website, increased use of LinkedIn social media as an alternate forum and communication tool, the continued success of GeoConvention and vastly improved student and junior industry professional involvement. I am truly enthusiastic about what we accomplished over the last year, improvements that will continue into 2015 and I remain extremely confident in a very strong future for the CWLS.

New Website and Social Media

The transition to a new website provider has been a longer and rockier road than we had initially anticipated. Early in the 2014 term, the Executive became aware of the technical limitations of the old website, so we decided to redesign the website from scratch, building on a platform that would allow future enhancements and functionality and allow the website and society to evolve together. After several months in development, the new-look CWLS.org launched in late 2014. The Executive continues to work closely with the developer to rebuild the new CWLS.org website into a fully functional petrophysics and log analysis resource site. These will include the return of online resources, such as the Rw catalog and core database, as well as improved features - simplified online purchases of Technical Luncheon tickets, Membership renewal and electronic receipt generation.

We are also continuing with our social media offerings. LinkedIn continued to be a valuable tool for the CWLS to broadcast updates and other communications to our members. LinkedIn also continued to evolve as a technical hub of petrophysical activity with regular discussions covering well log analysis. Special thanks to Dustin Menger and William Parrales for continuing to represent the CWLS and the executive on LinkedIn.

2014 GeoConvention

GeoConvention continues to be single-largest annual revenue generator for the CWLS and continues to evolve through our Joint Partnership Agreement with the Canadian Society of Petroleum Geologists (CSPG) and the Canadian Society of Exploration Geophysicists (CSEG). The three societies will continue to split the proceeds 45/45/10 among the CSPG, CSEG and CWLS, respectively. This agreement ensures a solid future for the GeoConvention and continued involvement from the CWLS.

The 2014 GeoConvention again featured amazing representation from the CWLS. In total, we offered 39 technical talks this year, filling the three days with CWLS content and representing a 39% increase from an already extremely successful event in 2013. In late 2014, Dustin Menger stepped up to help lead GeoConvention as Executive Director and William Parrales has been appointed to the GeoConvention board, ensuring that the CWLS is well represented within GeoConvention for the future.

Students and Sponsorship

We worked closely in 2014 with various student groups and junior industry associations to increase awareness of the CWLS within the industry's newest members and had particular success with the Young Professionals groups of the SPE, CSPG and CSEG, the U of C's Rundle Group of Geology and PES (Petroleum & Energy Society), the Joli Fou Geological Society at MRU, the P.S. Warren Geological Society at U of A and CSEG's GIFT (Geophysical Industry Field Trip). The CWLS' commitment to sponsorship of these events saw our student participation grow throughout 2014 as a result.

Acknowledgements

On behalf of the CWLS, I wish to acknowledge and thank APEGA for their continued support. Ashley Pessell and Anita Denton continue to be key members of the CWLS team and were invaluable as we transitioned to our new website this past year.

Closing

It has been both an honour and a privilege to serve as your elected president for 2014. I am extremely grateful to all the volunteers that stepped up this year for the CWLS. The executive team was an amazing and diverse group and I would like to reiterate my thanks for all of your hard work, dedication and patience over the last year. I would also encourage all of our members to consider volunteering in one capacity or another; it may not be easy to fit time in with our busy schedules, but the rewards are considerable.

To the incoming 2014-2015 Executive, I offer my congratulations on volunteering to be a part of this unique and vibrant community. I wish you all continued success for the coming year.

James Ablett
2014-2015 Canadian Well Logging Society President

Thaimar Ramirez (2014 – 2015 SPWLA President-Elect) and James Ablett (2014 CWLS President)

The Vice-President's Report

Dear members and executive team at CWLS, thank you for your continued support and patronage over the last year, our 60th consecutive year of operations. In 2014, we continued our efforts to deliver a valuable program of high quality events and monthly technical luncheons.

The monthly luncheon talk's attendance was large and received very positive feedback. We aimed to deliver content focusing on geomechanic, petrophysics and log analysis of conventional and unconventional plays. This included technological innovation, new methodologies and integration of other disciplines including pulsed neutron logging, spectroscopy, geomechanics and microseismic. Thanks to the speaker evaluation forms, collected on every event, we gather intuitive feedback to the executive and speakers on topics that are the most valuable for CWLS members.

As in previous years, one of our goals for 2014 was to continue to take the message of the CWLS to other global sister societies including the SPE, SPWLA and AAPG. We will continue to reach out to different societies in USA and Canada to further increase the recognition of petrophysics as a profession and its vital role in the continued development of the oil and gas industry. We will continue strengthen the synergy among the societies by means of speaker exchange and several other activities.

On the technical facet, we must continue to explore new methods of data acquisition through new technology and well data as the industry becomes progressively more complex and influenced by the downturn in oil prices. Our role must be centered in deliver knowledge and expertise to produce a positive impact in the industry to optimize resource recovery.

The following is a summary of the 2014-2015 Technical Luncheon speaker and topics:

Date	Speaker	Topic
February 11, 2015	**Dr. Zhangxing John Chen** Foundation CMG	Meeting the Challenges in the Post-Steam Era
December 17, 2014	**Andrew C Newson** Moose Oils 2014 Ltd	Using Wireline Logging Dipmeter Data To Support The Seismic Interpretation Of LOFF 8
November 19, 2014	**Mark G. Kittridge** HESS Corporation	Investigating The Influence of Mineralogy and Pore Shape On The Velocity Of Carbonate Rocks – Insights From Global Data Sets
October 15, 2014	**Ahmed Reda** Petroleum Development Oman (Shell Oman)	Methodology for Determination of Three Phase Saturations Using Sigma Mode Pulsed Neutron Logging
June 18, 2014	**Murray Reynolds** Ferus Inc	Optimizing Fracture Fluid Selection for Multiple Fractured Horizontal Tight Oil and Gas Wells
May 21, 2014	**Gregory Berko** Ana-min	Application of Fourier Transform Infra Red Spectroscopy [FTiR]
April 16, 2014	**Amy D. Fox** Canadian Discovery	The Value of Geomechanical Data – Examples from the Second White Specks in Pine Creek
March 19, 2014	**Sam Green Ikon** GeoPressure	Need for Accurate Onshore GeoPressure Analysis and Prediction

We thank all of our speakers for their continued support of petrophysics and the CWLS over the past year. We also sincerely thank our sponsors and volunteers, to whom we owe a great debt of appreciation.

The CWLS Executive polled the membership with online surveys on a variety of topics ranging from membership (fees and value), technical luncheons (ticket cost/value, venue, and topics) and the CWLS website. Based on the responses and in line with the Legacy Committee's previous findings on similar topics, the CWLS executive will be addressing several of these subjects next term.

Last year was also signed by the revamp of the website, becoming on an improved resource for members. The newly website functionality includes: electronic luncheon tickets, improved membership renewal and e-voting and electronic receipt generation. We are excited to work with our new provider to make the CWLS website a valuable resource for members in years to come.

The 2014 CWLS-Fall Social was held this year at "Local 522" in Downtown on October 2nd and was another successful and well attended event. We hope to continue this tradition, as it is a welcome social event prior to our industry's busy winter season and gives us all a chance to network and catch-up with old friends and colleagues.

In conclusion, 2014 and early 2015 marked another successful year for North America's premier Formation Evaluation Society. Special thanks to Ashley Pessell and all the APEGA office staff for their diligent efforts, Emma MacPherson from CSPG (webcasts) and Jennifer Seguin, Sarah Freisen and Andras Kiss-Parciu (Fairmont Palliser events team). We owe a great deal of thanks to all of them for helping to keep the CWLS and its events running smoothly.

William Parrales
2014-2015 Canadian Well Logging Society Vice-President

A Multidisciplinary Approach for Improving Microfrac Results in Steam Assisted Gravity Drainage Caprock Integrity Tests

Peter Lywood, Munazzah Afzal, and Kazim Malik, Schlumberger

Overview

This paper presents an integrated approach to improve wireline formation tester (WFT) microfrac stress testing in caprock by using the advanced borehole image sand count technique and sonic data.

The in-situ measurement of caprock geomechanical properties and stress has been an integral part of a steam assisted gravity drainage (SAGD) asset evaluation (see Figure 1). The caprock geomechanical properties and stress are essential information in determining maximum steam injection pressure, which plays a critical role in formulating the economic viability of an SAGD asset and obtaining regulator project approval.

The three principal rock stresses consist of ?1, the greatest stress, ?2, the intermediate stress, and ?3, the smallest magnitude stress. In a normal stress regime, the overburden or vertical stress (Sv) is ?1, the maximum horizontal stress (SH) is ?2, and the minimum horizontal stress (Sh) is ?3. Under these conditions, an induced fracture will open against Sh and propagate vertically in the direction of the SH.

When the objective is to test the strength of the barrier cap rock a vertical fracture must be induced, opened, propagated and then allowed to close against the minimum horizontal stress. Identifying and analyzing the pressure value and the time at which this induced fracture closes, called "closure pressure", provides an estimation of the minimum horizontal stress.

Wireline Stress Measurements

Normally a wireline formation testing tool (WFT) is used to measure formation pressure, similar to a drill stem test (DST). The WFT can also be used to create and propagate fractures in a formation; this process is called a microfrac. The tool comprises a dual packer system deployed on wireline into the open or cased hole section of a wellbore. The dual packers are inflated and seal the borehole annulus from the formation or perforation in the casing. Fluid is injected between the packers to a sufficient pressure that initiates and propagates a fracture, the injection is then stopped and the pressure allowed to falloff and the fracture closes. A downhole pressure gauge records the pressure change throughout the microfrac process allowing for real time surface analysis of the data, providing an estimate of the in-situ formation minimum stress.

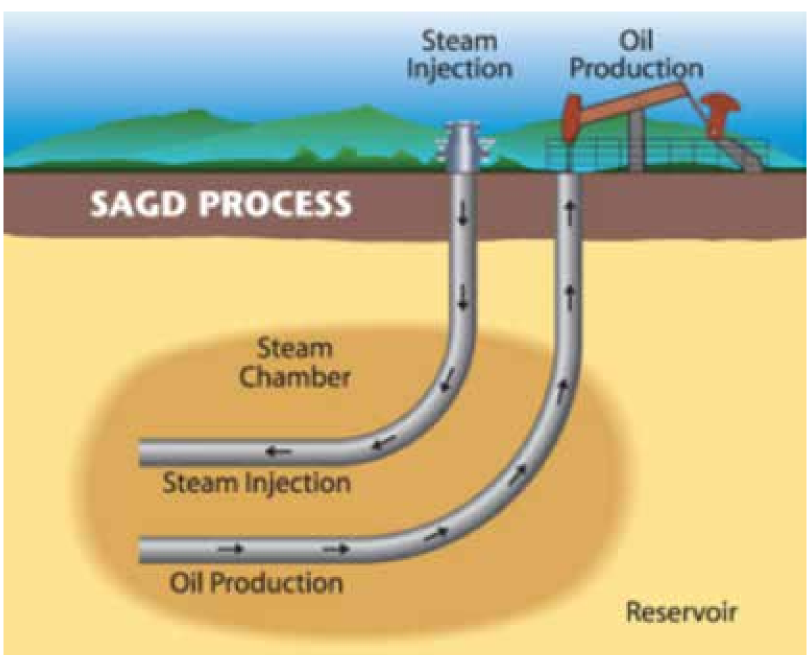

Figure 1: Basic SAGD well configuration with a producer and injector well combination (Source, Google).

The Sv can be reliably calculated using wireline density logs, the Sh and SH can also be calculated using sonic wireline logs but require calibration. The in-situ measurement of Sh can be accurately determined with the wireline formation testing tool by performing a microfrac test. This in-situ measurement of Sh is then used to calibrate the wireline sonic calculated Sh and SH.

The Problem

Under normal stress conditions (Figure 2) where Sh < Sv, it is expected that a vertical fracture would be induced when fluid is injected between the dual packers of the WFT and then reaches the breakdown pressure of the formation. Monitoring the propagation and closure pressure would then allow for a direct measurement of the minimum horizontal stress (Sh). It has been shown in some cases that microfrac testing in shallow formations has created and propagated a horizontal fracture even though the Sh is thought to be less than the overburden stress (normal stress or strike/slip regime). This theory is based on the observation of several acquired microfrac stress values that appear to have measured Sv even though Sv should be greater than Sh, in other words a vertical fracture should have opened against the Sh stress as opposed to the Sv stress. For the Sh to equal the Sv, the formation must be in a thrust fault regime or typically less than a depth of 350 m in Alberta (Bell and Babcock, 1986). Because most of these observed tests are deeper than 350 m and not considered in the vicinity of a thrust fault regime, an alternate explanation is required. It has been shown that shale tensile strength can be anisotropic in nature with a vertical axis of symmetry (VTI), the tensile strength normal to the bedding can be less than half of the tensile strength parallel with the bedding (Sierra, Tran, Slatt, 2010). So it is theorized that the rock between the thin layers is weak and failing in tension; therefore, during the microfrac injection, the weak cohesion between the horizontal layers allows for the creation of a horizontal fracture before a vertical fracture is created. Based on borehole image data, it has been observed that this phenomenon occurs in thin interbedded zones. If these thin beds can be clearly identified prior to the microfrac process, we can avoid testing in these zones.

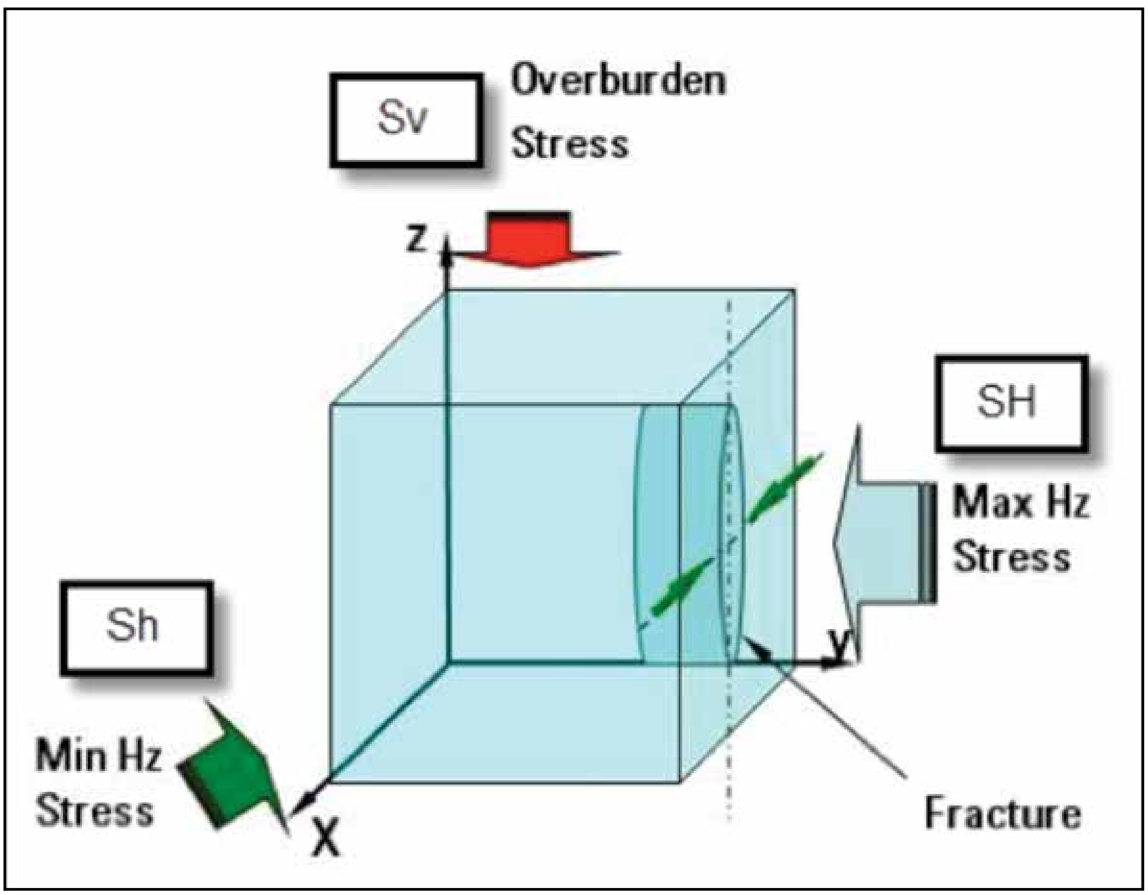

Figure 2: Principal stresses under a normal stress regime

The Way Forward

An integral element of this testing process is the pre-frac gathering of open hole borehole data, which includes gamma ray, resistivity, density, porosity, sonic slowness, and fracture information. The identification of (natural or drilling related) formation fractures prior to microfrac testing using the interpretation of borehole image data provides the operator with valuable information. This information allows the operator to select micro-frac test points that avoid pre-existing fractures; therefore, only the zones that can provide the fresh in-situ geomechanical information required for asset evaluation are tested. In addition to the basic fracture interpretation from borehole image data, there are some advanced techniques such as sand count analysis which can provide valuable information to the operator for identifying the microfrac test intervals. The sand count method allows us to separate borehole image resistivity into 10 classes by defining cutoff values to determine the percentage of values at each depth in each class and to generate a lithology (or class) flag curve and accumulated curves for each class. The sand count technique provides detailed lithology information based on resistivity and has a resolution of 5.0 mm.

An example from a SAGD well is shown in Figure 3. In this example, three microfrac tests were performed in thin-bedded sections at x63, x85, and x90-m MD. The brown line in track 6 from the left, is the density derived overburden gradient; the triangles are the microfrac test points and the blue line is the sonic calculated Sh. The sand count analysis in track 9 shows thin interbedded zones (separated by black lines). The mea-

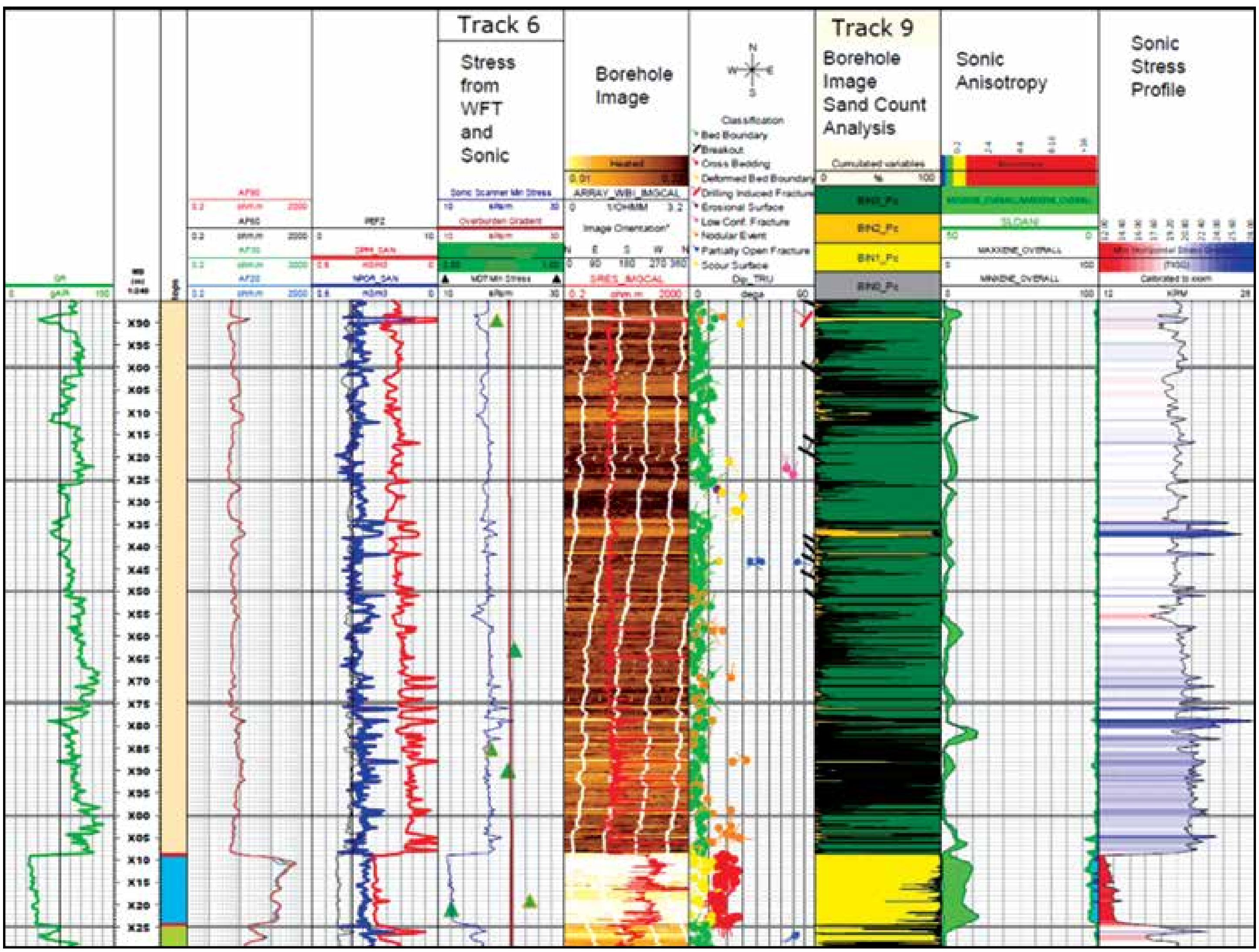

Figure 3: Sand count analysis example.

sured microfrac pressure gradient for the tests at x65 and x90 clearly falls on the overburden gradient line indicating a horizontal fracture was created. The sand count analysis indicates these tests were performed in thin interbedded zones.

Borehole images also provide clues about the stress state by identifying the direction of maximum and minimum stress based on borehole breakout and drilling-induced fractures. Identifying existing natural fractures is also required; a fresh fracture is desired for measuring the in-situ stress.

Another method that can help improve the success of a microfrac test and the selection of WFT microfrac test points is the sonic-derived HTI anisotropy analysis (Alford, 1986). If the WFT microfrac test point is in a zone having high HTI anisotropy (possible horizontal stress magnitude contrast) and does not contain natural fractures or breakout, the likelihood of breakdown in the maximum stress direction is greater than in a zone of low anisotropy. Furthermore, a quick dynamic mechanical property calculation using sonic data can be used to identify zones of low Poisson's ratio, which are more likely to fracture.

By identifying zones of natural and induced fractures, anisotropy, and thin interbedded formations, we can optimize rig time and save operation costs for the operator by testing only those zones that have a higher probability of fracturing vertically. If the WFT can create vertical fractures that propagate in the direction of maximum horizontal stress, we can then achieve the objective of measuring the in-situ minimum horizontal stress.

Additionally, calculating the minimum horizontal stress and determining its direction can be achieved using the data acquired by the sonic tool. This minimum horizontal stress can then be calibrated to the WFT-measured minimum horizontal stress and a continuous stress profile over the logged interval can be obtained. A WFT calibrated stress profile can be used to identify stress boundaries for fracture treatment, used as an input for 3D geomechanical models (Higgins et al., 2008), and as input for SAGD design to determine maximum operating pressure.

Conclusion

Applying a multidisciplinary approach to caprock integrity testing can improve the likelihood of obtaining the data required to estimate the in-situ minimum horizontal stress. Using borehole image data helps to avoid thin interbedded zones and decrease the probability of initiating a horizontal fracture (vertical stress measurement). This multidisciplinary approach also identifies zones that contain existing fractures, helping to avoid testing natural and induced fractures. With the outputs of the sonic tool data processing, the information can be used to identify zones of horizontal stress contrast. Testing in these zones increases the possibility of creating a vertical fracture under normal stress conditions. With the propagation of a vertical fracture under these conditions, achieving the objective of estimating the in-situ value of the minimum horizontal stress of a caprock becomes possible.

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ChromaStratigraphy®
Quantitative Analysis of Geologic Samples Using Color

William "Bill" Ellington Jr

Abstract

The use of color as a descriptive tool for geologic samples has traditionally relied upon qualifying modifiers such as "light" or "dark" to describe the varied range of rock Values and Hues. Attempts at more systematic methods have introduced complex descriptive systems, such as Munsell Soil Color Charts. While these efforts represent improvements, they remain highly qualitative and fail to remove the primary source of poor accuracy and precision: human error. Moreover, these descriptors are not readily converted into a useful tool for visual interpretation and analysis (e.g., well logs). Here we present ChromaStratigraphy®, a quantitative technique for the rapid, reproducible characterization, and correlation of chromatic data in well log format and demonstrate its application to conventional and unconventional resource plays.

Using proper protocols, quantitative chromatic data can be rapidly and reproducibly gathered from rock cuttings (interval samples), Core, or outcrop (spot) samples from any region and age. Saturated slurries of pulverized sample and distilled water are photographed under tightly controlled conditions. Raw color data is extracted from each sample via software and used to calculate an average color for that depth or interval, and can be equally collected in the laboratory setting or at the rig site for near real-time results. Here we focus on the RGB and HSV color systems, though others remain suitable. Color data can be displayed in color-component form (e.g., Red, Value) to identify absolute deviations, or relative changes through component ratios [e.g., Red/Blue, Red/(Red + Green + Blue)]. When plotted in well log format, these curves form systematic and predictable changes that can be interpreted and correlated, as with wireline data. A key component of the ChromaLog® is a graphical display of the reconstructed color from the measured samples, similar to viewing a core or outcrop. This powerful image allows for the immediate recognition of facies and formation changes, especially in well studied settings. When integrated with a suite of independent data, a robust Chromastratigraphic framework can be developed allowing the ChromaLog® profile to be confidently utilized as an interpretative tool. For example, by combining chromatic data with stratigraphic markers (e.g., biostratigraphy), ChromaStratigraphy® can be used to confirm lithostratigraphic correlations and, under certain circumstances, create chronostratigraphic tie-lines.

Background, Procedures, and Objectives

Color is one of the first observed physical traits of any geologic sample, but has always been described subjectively. At first glance color can relay considerable information about geologic significance ranging from the inherently intrinsic (e.g., mineralogy) to the inferred (e.g., stratigraphic succession).

Factors that influence the color of a geologic sample include – but are not limited to:

- Mineralogy
- Lithology – including:
  - – Grain size
  - – Cementation
- Geochemistry – including:
  - – Inorganic (e.g., iron oxides)
  - – Organic compounds (e.g., TOC),
  - – Chemical alteration (e.g., redox conditions)
- Thermal history

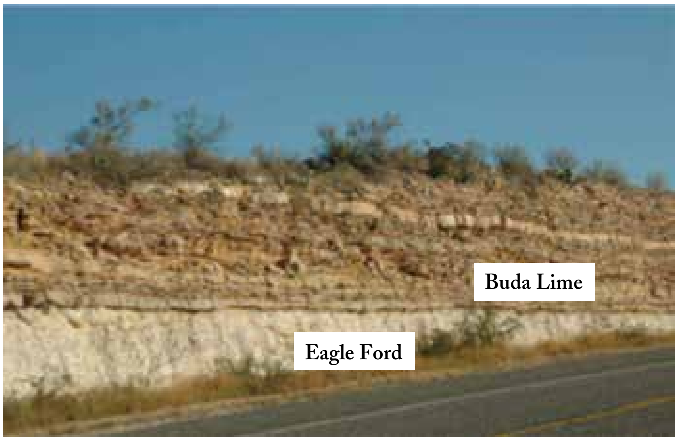


Figure 1: Photograph of an outcrop road cut in Texas featuring the contact between the Eagle Ford and Buda formations. The contact is readily identifiable. (Photo: Peschier & Lock, SIPES 2010)

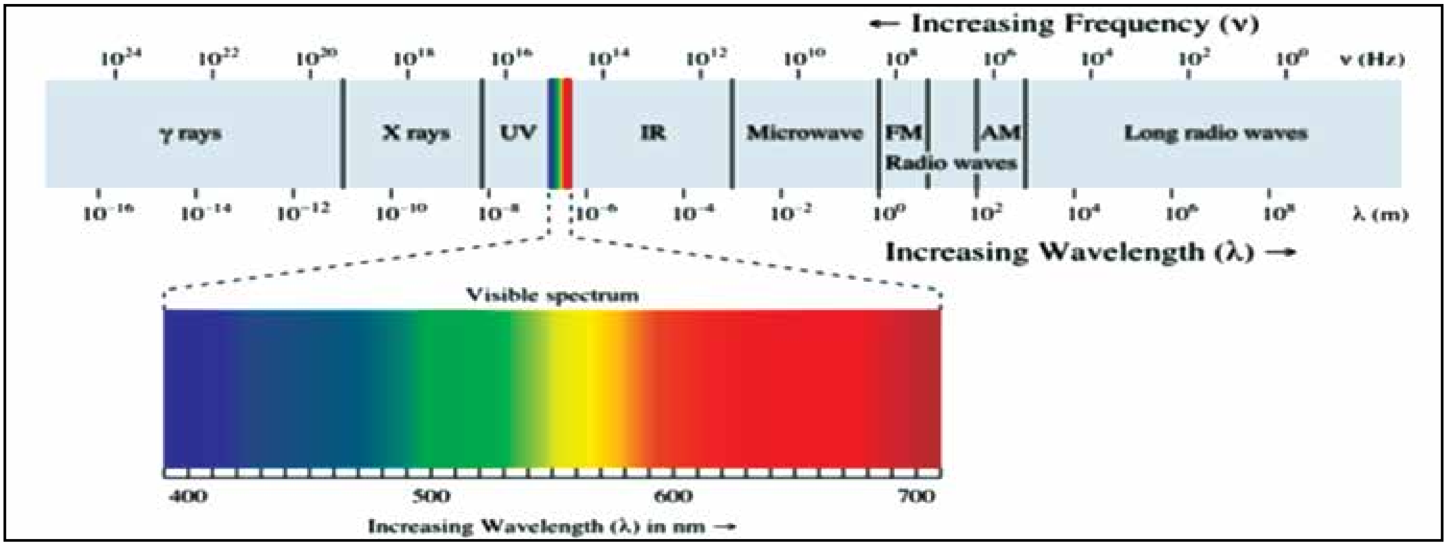


Figure 2: Position of visible light within the electromagnetic spectrum.

Variations in human perception require a new rigorous approach before the application of color analysis to geologic samples. Physiologically, the color is a merging of the spectral sensitivities of the eye's three cone cells types. These signals constitute perceived visible light (over the short range of near-infrared to near-ultraviolet, 390-750nm) (Figure 2).

Graphical display of color has traditionally focused on additive models, such as the RGB (Red-Green-Blue) model common in consumer electronics. Other color systems, including the HSV (Hue-Saturation-Value) and CIELAB 1976, are mathematical transformations, and are fully reversible. Here, we apply scientific rigor using the RGB and HSV color systems, with emphasis on ratios of the RGB components, and Value.

Through extensive experimentation, we have refined our methodology for capturing chromatic data from a geologic sample into a simple, rapid and consistent technique.

A representative sample (1g) is mixed with distilled water (20ml) and pulverized to create a saturated slurry. This slurry is photographed with a digital camera mounted in a custom-built photo cabinet under tightly controlled conditions. Using proprietary software, the average color for each sample is calculated and extracted for post-processing analysis and interpretation. This data is then transformed into well logs, and other advanced metrics for quantifying color changes.

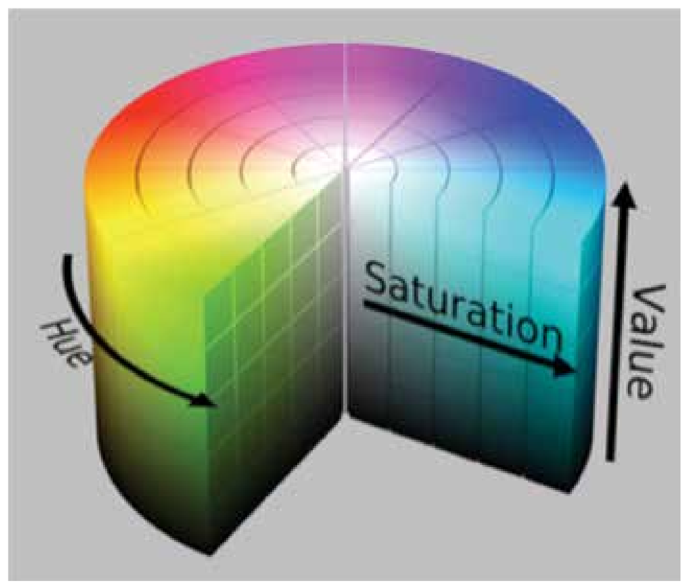


Figure 3: The HSV color system illustrated in cylindrical form. Hue (0-360) is radial, and analogous to the color wheel; Saturation (0-100) is color purity, and Value (0-100) is color intensity. (Wikipedia).

Figure 4: Example of saturated sample slurries illustrating the readily observable changes captured by our sampling methodology. Even in a seemingly homogenous section of black and neutral colored samples, significant changes and gradations are evident. Here, downhole depths increase top to bottom and left to right.

Our research demonstrates that while the preparation method for the measured sample (i.e., raw cuttings, saturated slurry, or slide) can significantly alter the magnitude of the chromatic response, each preparation shows consistent shifts. For most samples, the saturated slurry demonstrates a more dynamic response to the range of observed colors (Figure 4).

Our objectives for this technique are twofold:

- Use of digital technology to capture the inherent spectral information in geologic samples.
- Use quantitative techniques to display and correlate this information in an effective and useful manner (i.e., well logs, multidimensional plots) to aid in geologic exploration, production and understanding.

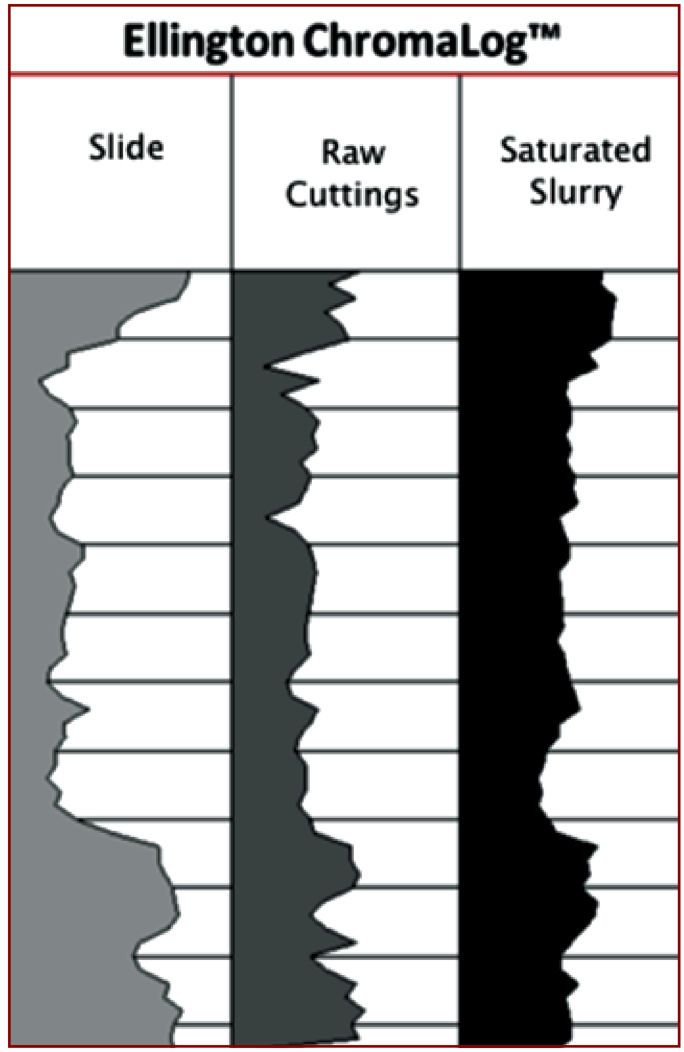


Figure 5: Value data for (L to R) saturated slurry, raw cuttings, and slide preparations. Slurries are preferred for their dynamic range across the observed colors and saturations.

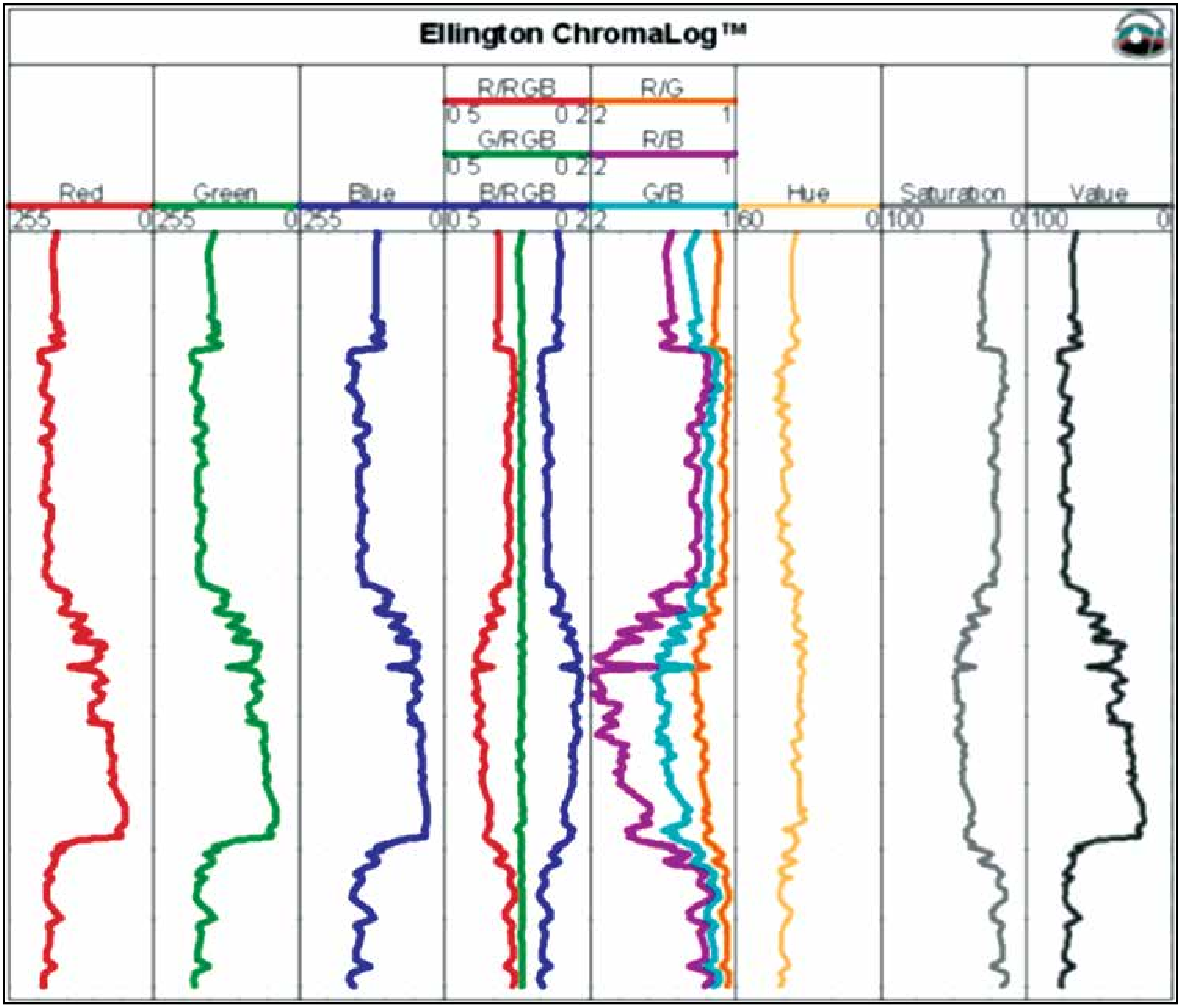


Figure 6: Well log of chromatic components and ratios from the RGB and HSV color systems. Individual Red, Green, and Blue components from the RGB system are strongly coherent, with intensity related to overall sample darkness. Ratios of the components (where the 'RGB' represents the summation of the R, G, and B components) isolate relative differences between the components. In contrast to the similarity of each component in the RGB system, the Hue, Saturation, and Value components each respond differently. The shape of Value mirrors those of the RGB components.

From rock sample to well log

ChromaLog® well logs are constructed from individual chromatic components and component ratios. Chromatic logs are read similar to other logs from downhole tools, where shifts correspond to changes in geologic properties and significance.

ChromaLog® analysis allows for the rapid identification and assessment of changing geologic conditions using a visual recreation of the sampled rock section.

Multiple wells allow for detailed ChromaStratigraphy® correlation on a local to regional basis using quantitative data. Superior results are attained when integrated with supplementary data streams.

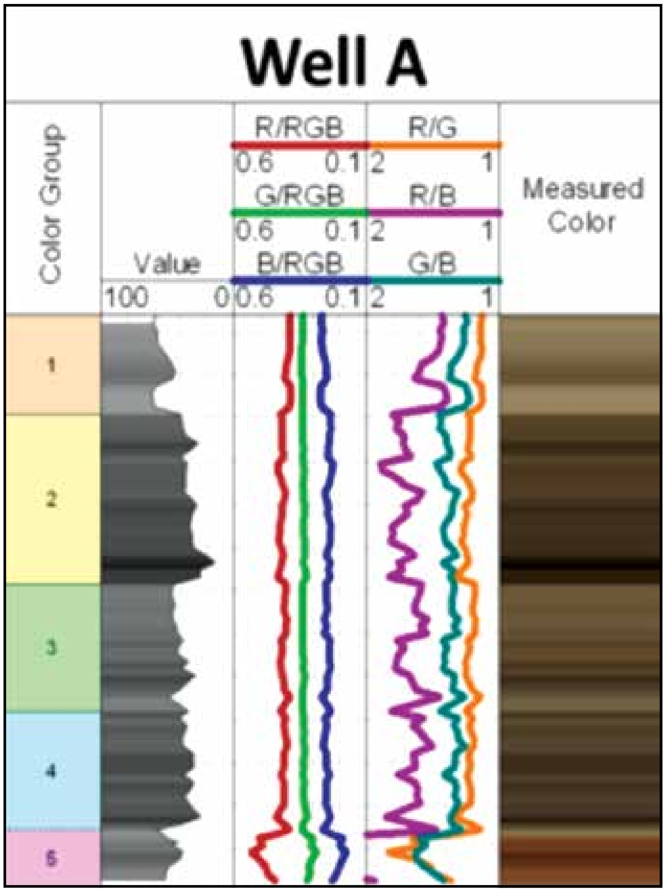
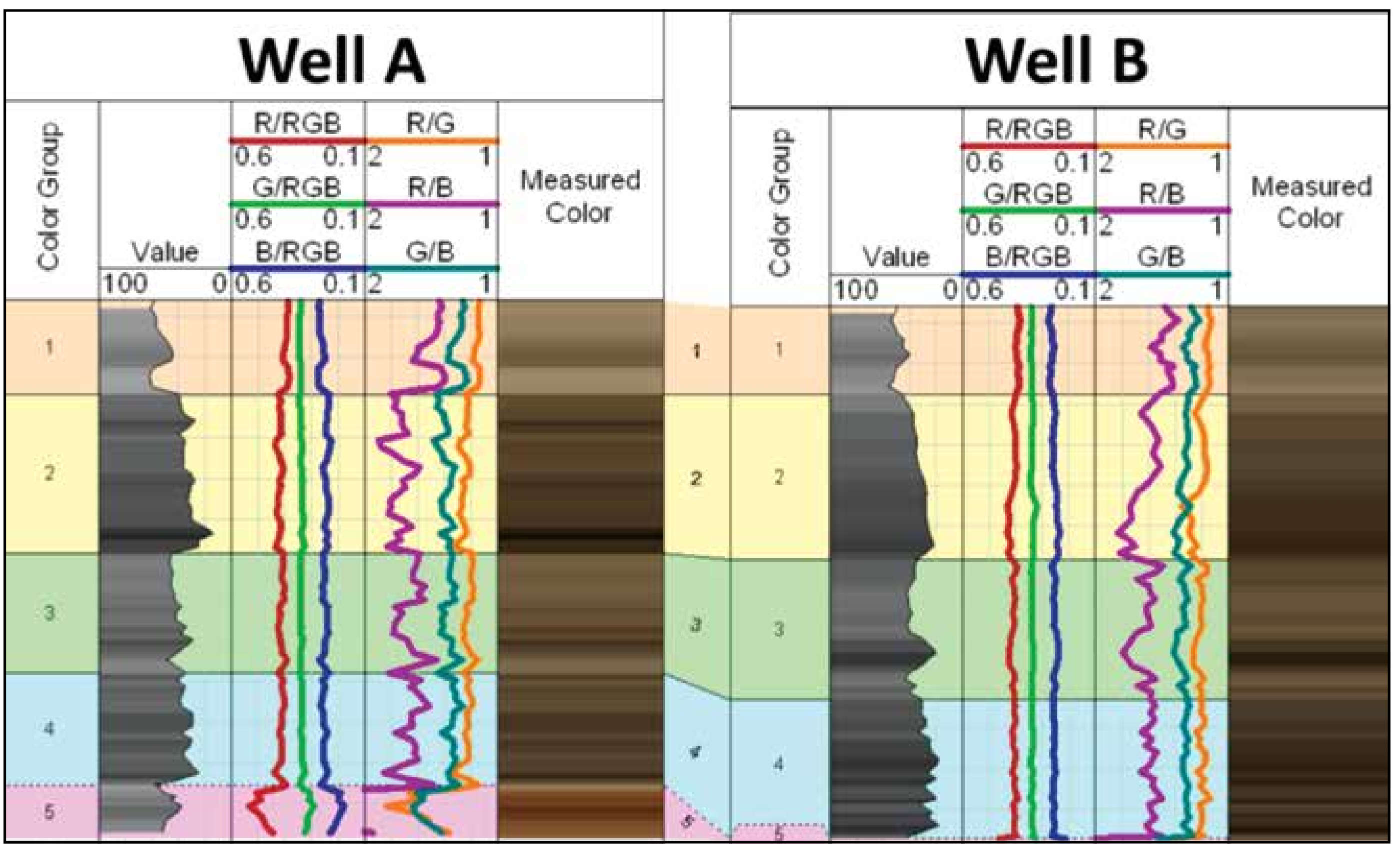


Figure 7: ChromaLog® with chromatic changes

Figure 8: ChromaStratigraphy® correlation of two ChromaLog® plots.



Formation Identification in Unconventional Plays

Unconventional resource plays (i.e., shale gas and shale oil) are highly productive and have demonstrated the effectiveness of new technologies to optimize efficiency, especially in the placement and steering of the wellbore through long horizontals. ChromaLog® analysis has proven advantageous as a new quantitative technology for formation identification, as a predictive technique for organic content that can be readily integrated with other data sets, and is suitable for detailed correlations and interpretations using our ChromaStratigraphy® analysis.

Color changes are readily and consistently recorded in the chromatic data. Key formation identifiers remain distinct with little or no smearing of the formation boundaries as sample interval increases. As observed in the Eagle Ford shale, discrete markers can be identified even in seemingly homogeneous sequences.

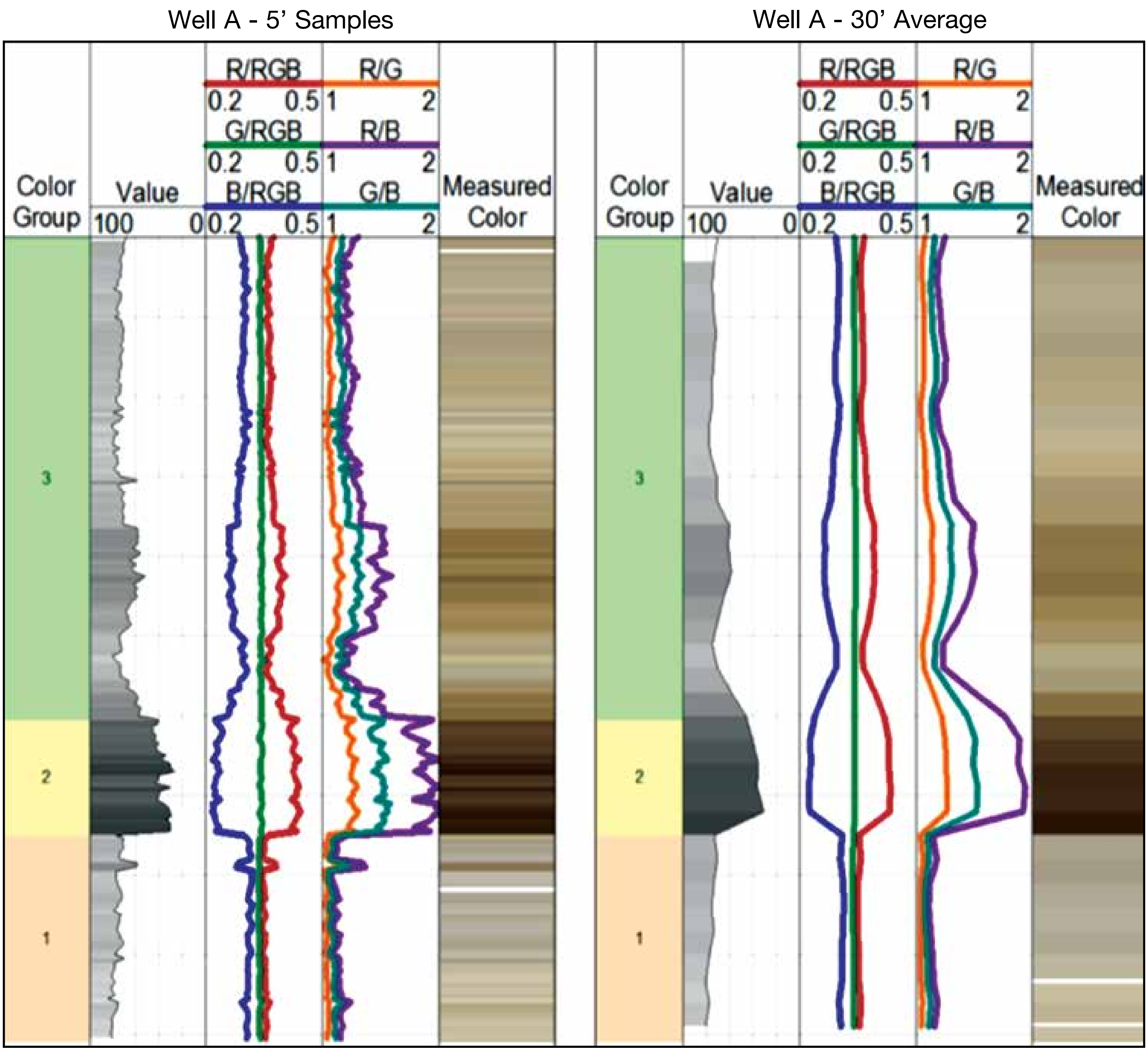


Figure 9: (L) High-resolution 5-foot interval ChromaLog®. (R) High-res data averaged to 30-foot interval representative of typical cuttings sampling. Very little vertical "smearing" is evident in the samples averaged to 30-feet. Formation tops appear to be largely independent of sampling density, though some detail is lost.

Multiple ChromaLog® analyses can be linked for local and/or regional interpretations through ChromaStratigraphy®.

When integrated with other data types, the interpretative ability of chromatic data expands. Above we illustrate color coding the data, based on a number of biostratigraphic tie points. Fields of data with known lithologic identity were isolated, allowing 'uphole' samples with chromatic measurements to be tied to formations with increased confidence.

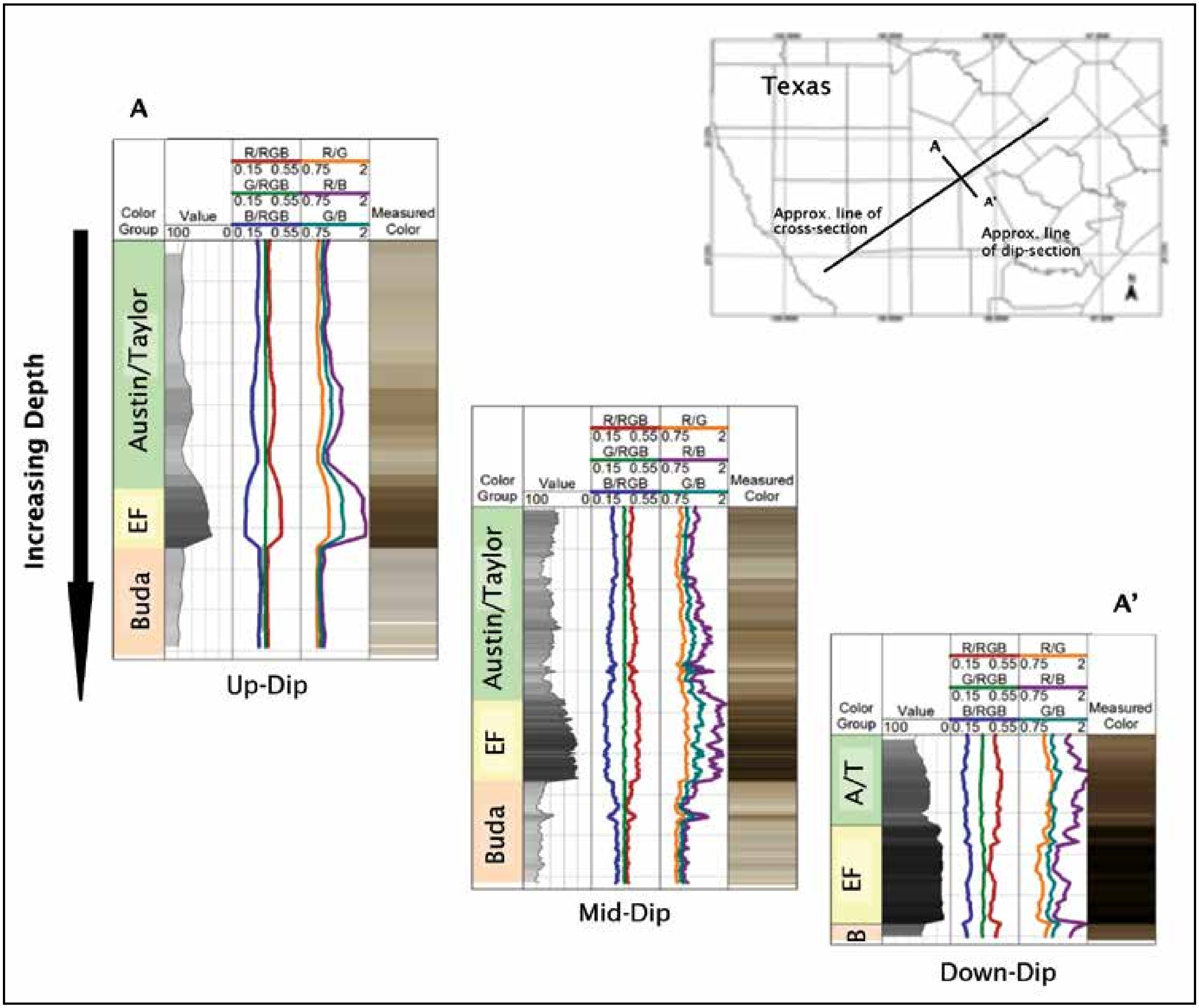


Figure 10: Chromastratigraphy® dip-section in the Eagle Ford play through Live Oak and Atascosa counties, Texas. Logs are hung on depth, and illustrate the ease of down-dip correlation of the Buda, Eagle Ford, Austin and Taylor formations.

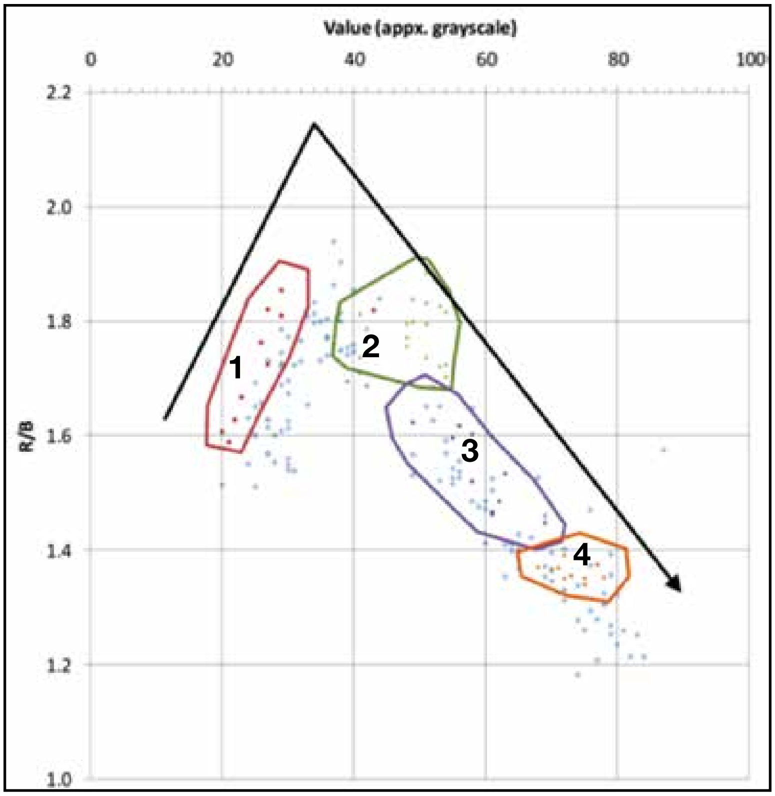


Figure 11: Chromatic data plotted as R/B vs Value. Colored fields (and points) illustrate the relative position of chromatic data from each formation member as determined by biostratigraphy. Numbers correspond to those in Figure 12. Black arrow represents the direction of drilling along lateral leg. Blue points depict data from pilot hole. The kink in the R/B data separates the lower and upper Eagle Ford, fields 1 and 2 respectively.

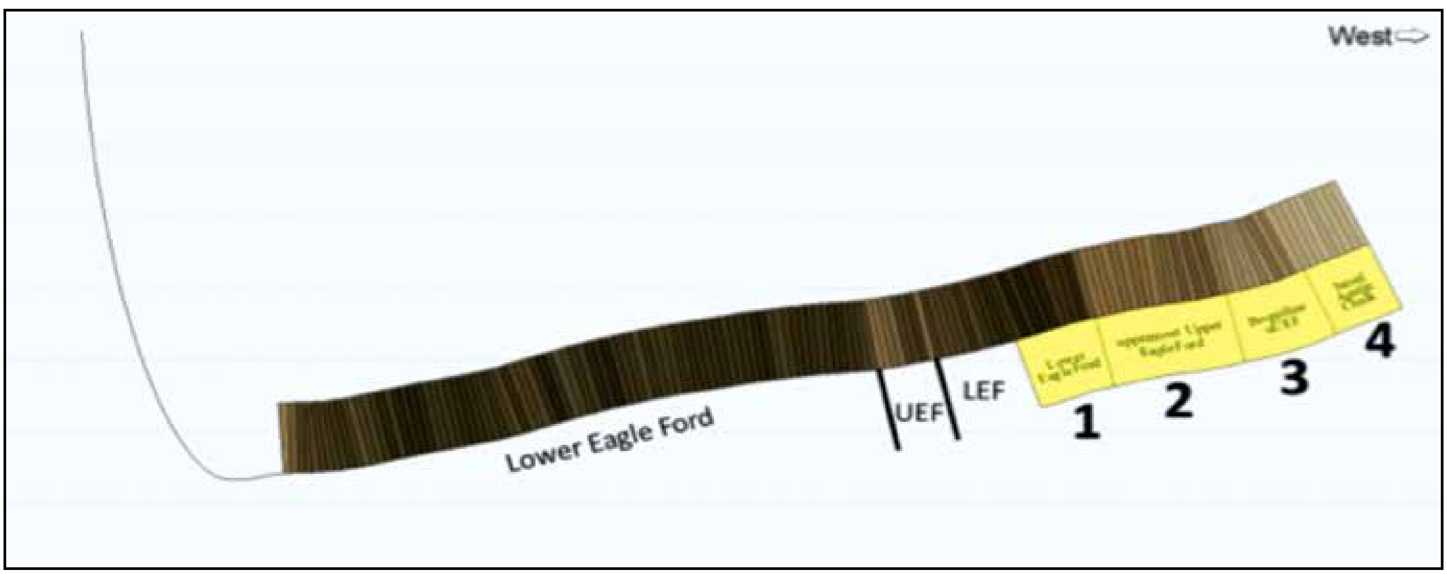


Figure 12: (Measured color and lithostratigraphy (from nannofossil data) along the horizontal well in the Eagle Ford. Numbers correspond to those in Figure 11. Labeled fields represent interpreted formations from ChromaLog® analysis.

Surface Mapping

Using only ChromaStratigraphy®, surface maps of plays can be rapidly produced to ascertain local or regional variations in surface depth, unit thickness, etc.

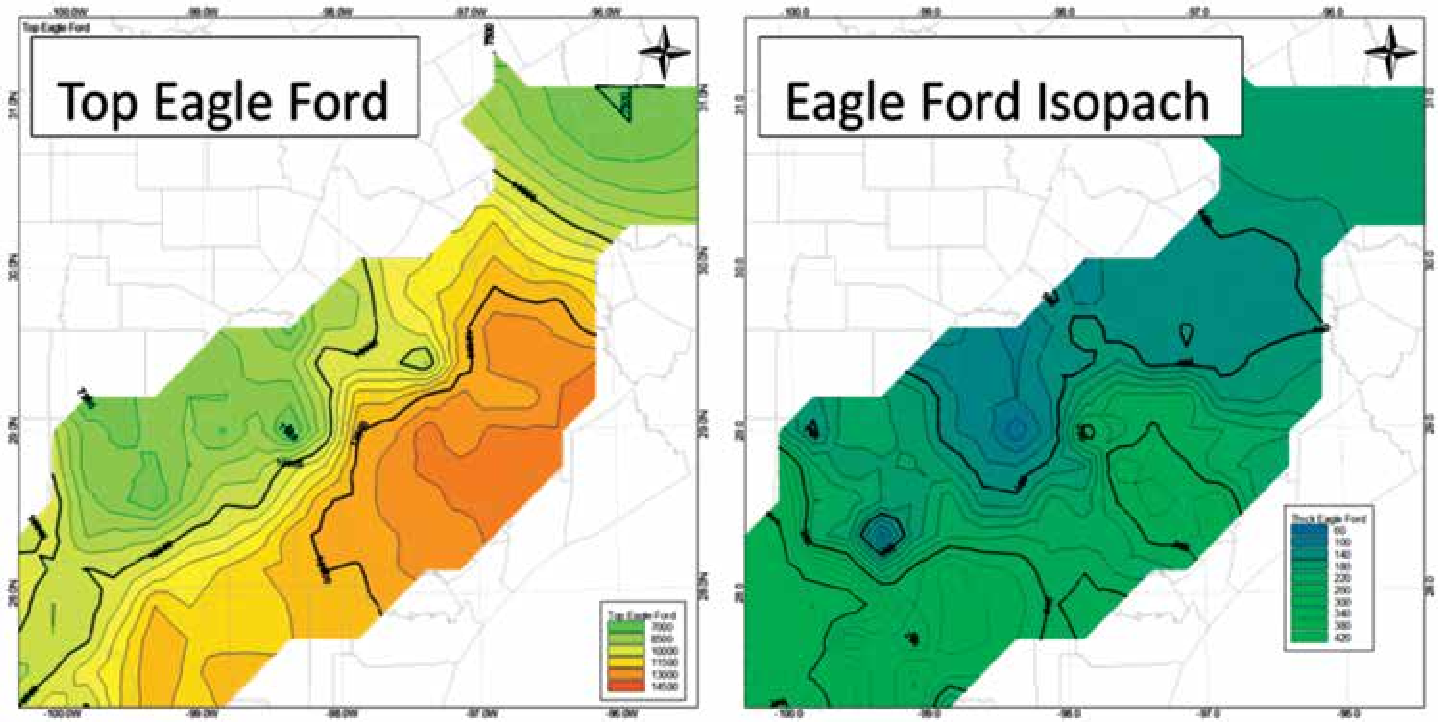


Figure 13: (L) Top surface of the Eagle Ford shale, as interpreted by ChromaLog® analysis. (R) Isopach (thickness) map of the Eagle Ford shale, as interpreted by ChromaLog® analysis. Both maps are constructed from chromatic data of 41 wells. Texas counties shown for geographic reference.

Predictive Tool

Value is a successful predictor of TOC content, generally with a non-linear relationship. Exact TOC-Value relationships are formation and lithology specific.

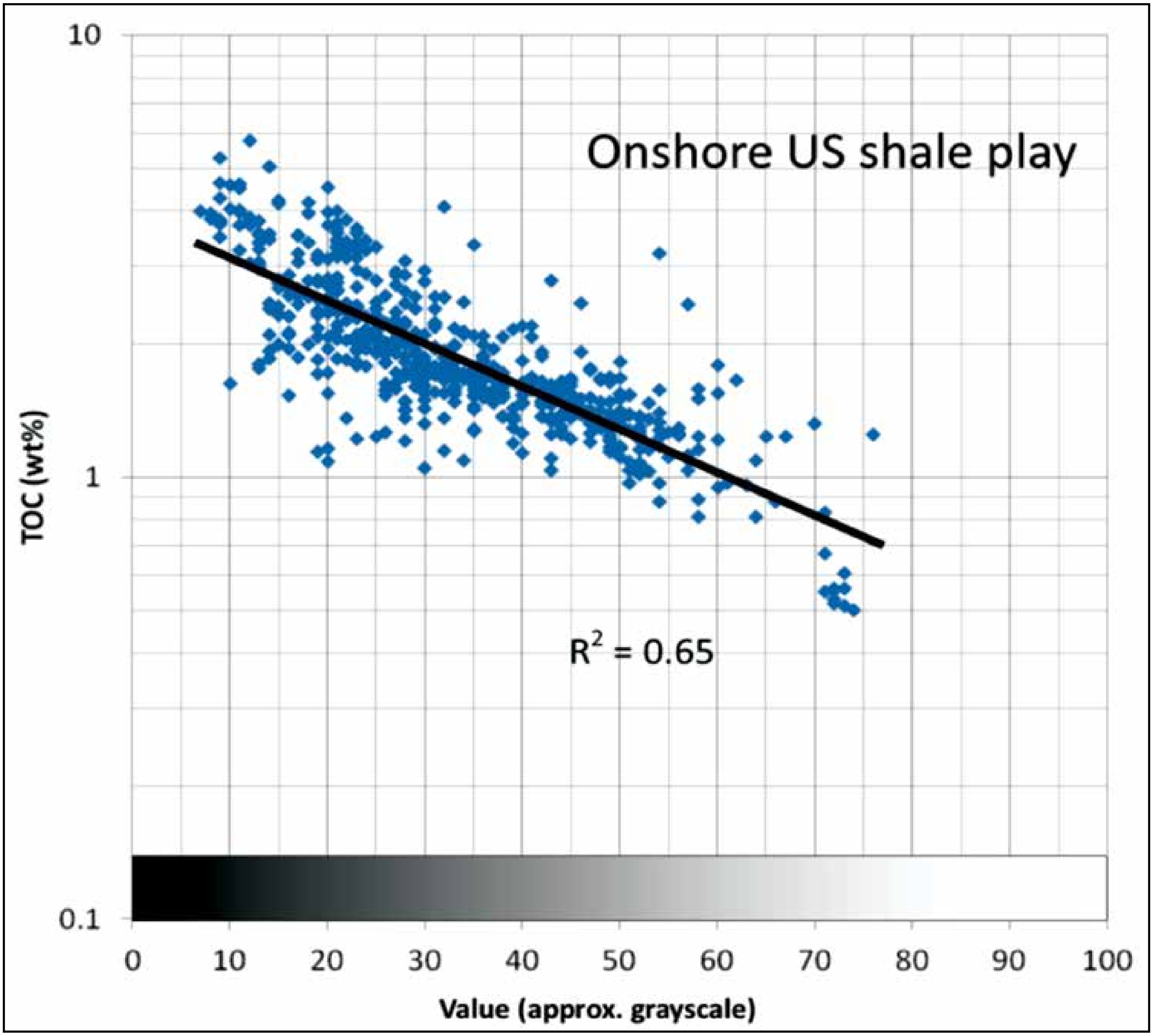


Figure 14: Semi-log cross-plot illustrating non-linear relationship between Value and TOC content. Here, an exponential relationship provides the highest degree of correlation for this onshore shale play.

Integrated Results

Chromatic data and ChromaLog© analysis can easily be integrated with any type of well log data, measured down-hole or taken from cuttings and/or core samples.

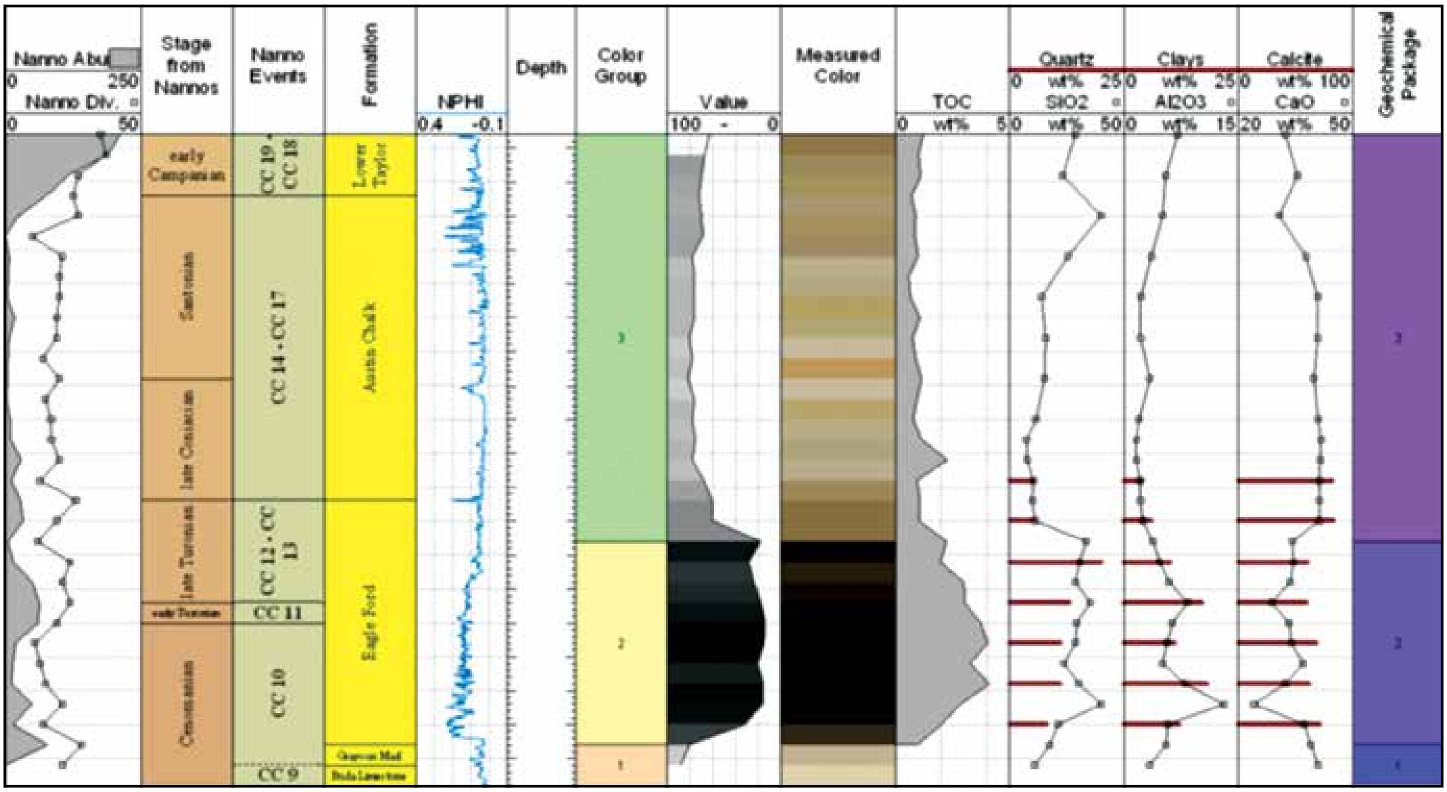


Figure 15: Example of an integrated Eagle Ford report, illustrating relationships between chromatic, electronic log, biostratigraphic, organic, mineral and elemental data. Note the distinct darkening with TOC and mineralogical shifts at the top of the Eagle Ford formation. The highest TOC values are in the lower Eagle Ford, denoted by the darkest values consistent with the Cenomanian-Turonian boundary (global extinction event and Oceanic Anoxia Event2 [OAE 2]).

ChromaStratigraphy® in Conventional Plays

Conventional plays are also appropriate for ChromaLog® analysis. Even in structurally complex and highly localized basins, ChromaStratigraphy® proves to be a successful correlation technique.

ChromaStratigraphy® analysis conducted in 2011 of the above wells effectively resolved a conflict in biostratigraphic interpretations between nannofossil and foraminifera data (foram data not shown). Original samples collected c. 1990.

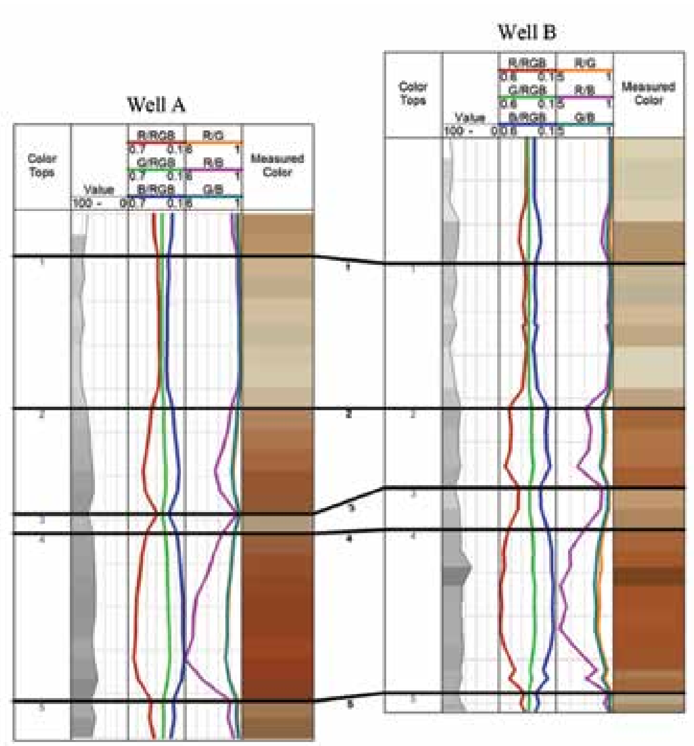


Figure 16: ChromaLog® analysis of two wells from a conventional offshore U.S. Gulf of Mexico play. The wells are located approximately 10 miles apart, and are within the same mini-basin. Five tops suitable for ChromaStratigraphy® were readily identified within the two wells. ChromaLog® analysis was conducted on large interval (500 ft.) cuttings samples. Original cuttings samples from these wells date to circa 1990, illustrating the practicality of applying ChromaLog® analysis to old wells and/or wells without available logs or other data. Wells are approximately 10 miles apart.

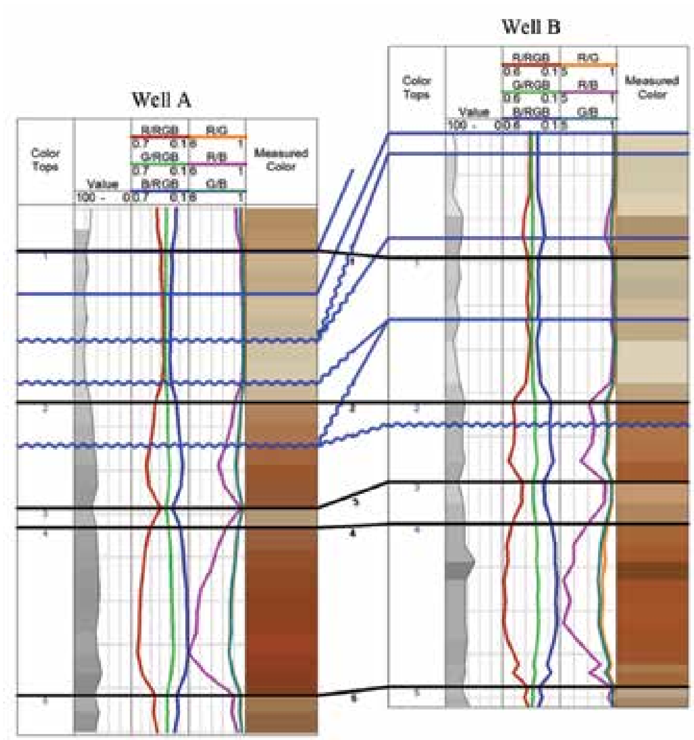


Figure 17: ChromaLog® analysis with integrated biostratigraphic tops (shown in blue) for the two wells above. Nannofossil analysis was conducted on the same cuttings. Correlation tie lines between chromatic and biostratigraphic analysis cross, indicating conflicting correlations and interpretations. ChromaLog® tie lines (shown in black) were later demonstrated to be correct from foraminifera data analyzed at more frequent intervals (data not shown). Wells are approximately 10 miles apart.

Conclusions

This document demonstrates the numerous applications of ChromaLog® analysis and ChromaStratigraphy® in both conventional and unconventional plays, and illustrates some of the capabilities of the techniques.

Based on the analysis and interpretation of the more than 100 wells, the authors have confidence in the identification and correlation ability of ChromaLog® analysis. Precision testing has confirmed the repeatability of the technique, ensuring client confidence in correlations and measurements made across multiple projects.

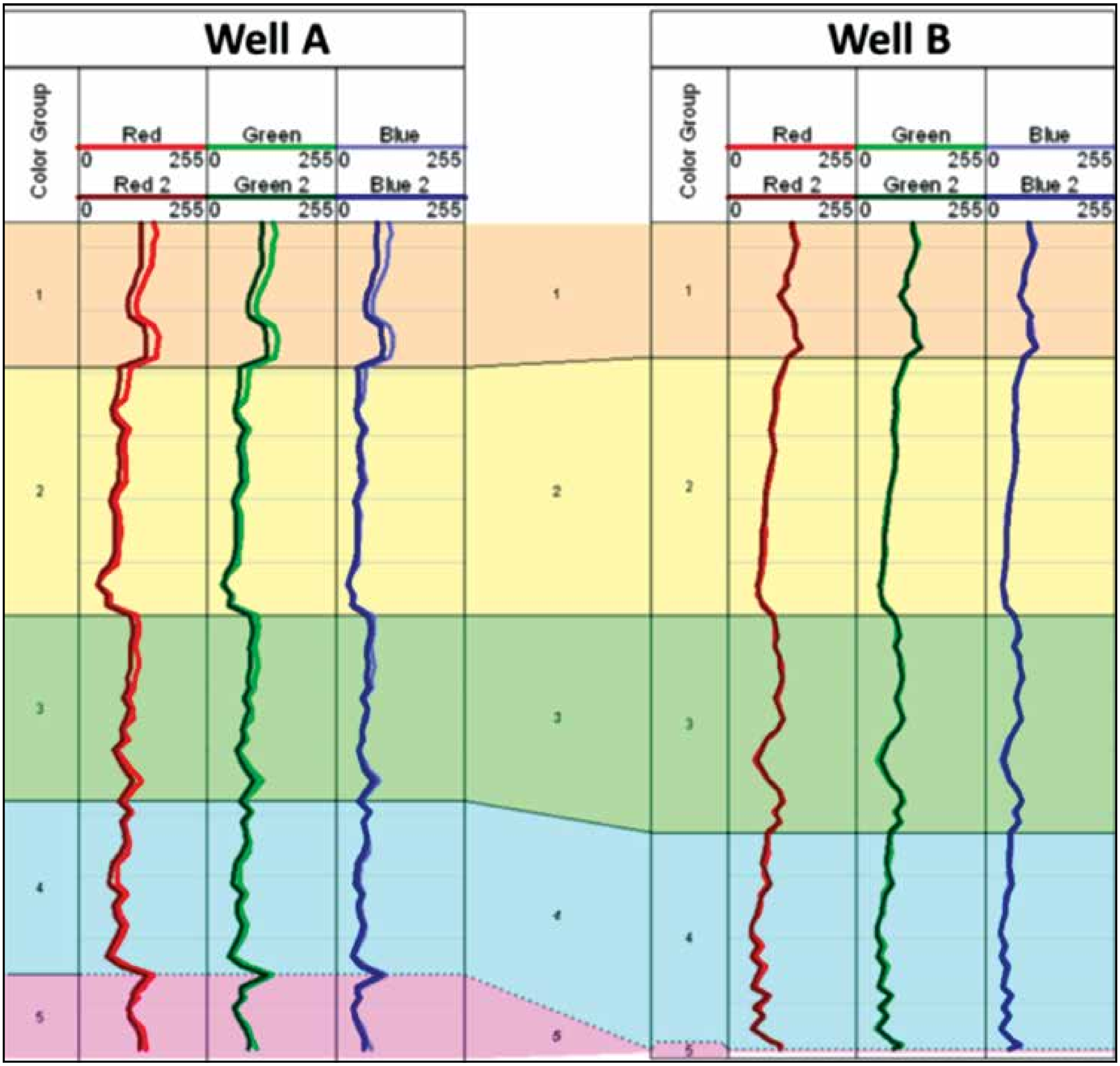


Figure 18: Results of repeatability testing for the methodology and measurements of ChromaLog® analysis. Repeat measurements were conducted on saturated slurries from wells A and B. New slurries were prepared from the same set of washed cuttings samples on different days, by different technicians. Minor differences are observed in the upper reaches of well A, though all patterns remain consistent and correlatable between the two wells. Observed variations in well B are insignificant.

Integrating data from the ChromaLog® and ChromaStratigraphy® techniques with conventional wireline and other analytical techniques establishes the control points necessary to extrapolate chromatic data into areas with limited or nonexistent data.

Ellington is currently testing integrated well site applications of near real-time ChromaLog®, TOC, XRF (elemental), and XRD (mineral) analysis in a joint venture with ALS Empirica.

ChromaLog® analysis and ChromaStratigraphy® are revolutionary techniques that:

- Bring scientific rigor to traditionally subjective lithologic descriptions.
- Present results in a standard well log form.
- Apply to all geologic settings.
- Quantify variations and color changes in cuttings, cores (whole & sidewall), and outcrop samples.
- Produce highly repeatable measurements in the lab or at the well site.

Reference

Moore, J.C., Engelhardt-Moore, N.L., Dubinsky G.L., and Ellington, W.E., Jr. 2012

Quantitative Analysis of Geologic Samples with ChromaStratigraphy: Applications to Conventional and Unconventional Resources; AAPG 2012 Annual Convention & Exhibition Poster – EMD-AAPG; President's Certificate for Excellence in Presentation Award.

Three Methods for Log-Derived Mineralogy: Part Two …primarily used for Shales (Silts) & Tight Formations and also applicable to High Porosity Formations

R.V Everett, Robert V. Everett Petrophysics Inc.

Abstract

This is the second of a series of articles designed to explain the three methods for determining mineralogy. As mentioned in the previous article, we prepare reliable data before entering the calculation programs in order to:

- correct for washouts affecting density
- predict missing log curves
- determine Rw from the SP
- calculate total organic carbon (TOC).

This data can be interpreted using one of the following three methods to obtain porosity, permeability and mineralogy of the formations:

- Nuclear Spectroscopy (NS) with core mineralogy – a spreadsheet recently converted to a Java-based program.
- Element prediction program when NS is absent. Reconstruction can substitute for lack of core, otherwise X-ray Fluorescence (XRF) core measurements are used to check our predictions.
- NS with core mineralogy and XRF chemistry, where all are combined in a program called Robust Element to Minerals (ELM).

Why involve mineralogy? We can use mineral attributes such as cation exchange capacity and grain density to aid in the solution of Sw, porosity and permeability.

Is core always valid? The method to check core validity is:

1. Do the XRF elements match the log elements? If not, which is incorrect? Interpretation must stop here until this is resolved as incorrect log measurements result in incorrect mineralogy.
2. If there is no core XRF but there is core XRD, the elements can be derived from the core XRD assuming an element to mineral transformation.
3. If there is no core at all, a strip log can at least tell if one is inidentify a carbonate or clastic environment.
4. Geological local knowledge is important.

We honour core when we have reasons to believe it is valid, even when our log-only interpretation program produces a different result.

In summary, valid mineralogy from logs can improve the interpretation and calculation of porosity, water saturation and permeability.

In this second article, we will show four examples of the results using the Java-based program.

The logs are from Central Alberta in high porosity zones. ECS measurements are predicted from an offset model well.

The purpose of this article is to illustrate that a computer interpretation program must be flexible so that when core provides different yet valid results, the program can be modified to fit the core. Hence we call the procedure Petrophysics Designed to Honour Core (PDTHC). However, when no core is available using an ECS (TM Schlumberger) or other NS set of measurements, GEM (TM Halliburton), FLEx (TM Baker) or LithoScanner (TM Schlumberger)) from a model well are our best choice. In this article the use of the term ECS refers to any NS measurement. We acknowledge there are differences amongst the service company measurements.

Steps involved in using Nuclear Spectroscopy

The following steps are part of the calculations before admittance to the log interpretation program:

1. Prepare the log data.
2. Calculations in the program.
3. Outline Rw and TOC.

Petrophysical Summary

A Log Interpretation Method, not commonly available, is designed to incorporate and be calibrated by core. When no core is available, the well containing an ECS (NS) log is used as a guide to the elements.

Our interpretation starts with the most basic inputs that can be correlated to core measurements in every step of the interpretation. For example, we start with predictions of the elements, (Ca, Fe, Si, S, Ti, Gd, U, and K & Th) from the offset well containing both nuclear and natural gamma spectroscopy.

We invoke an element to mineral model from the PDTHC to separate the common minerals from the input elements. While this may seem an obvious strategy, there are more unknowns than knowns involved. We meet our goal using a normalization procedure where the elements act as constraints. Alternatively, a normalization procedure has also been developed that uses the core minerals as constraints. When extensive core mineralogy is not available, as is the case in these wells, we begin with element-constrained mineralogical analysis.

Log derived mineralogy attributes are used to derive cation exchange capacity, grain density and permeability and could be compared to RCA permeability measurements as well as core porosity, Sw and permeability on all wells.

When porosity and permeability were computed from the predicted ECS and compared to core results, close agreement was expected but could not be verified as core was not available.

We studied four wells but will focus on the ECS well for this summary. The other wells used elements predicted from the ECS model well.

Summary of predicted and measured logs

P=predicted RCA=ROUTINE CORE ANALYSIS

well	KEY WELL? (HAS ECS)	ECS	NGS	CMR-CMRP	KSDR-CMR	CORE	PEF	RESISTIVITY	DENSITY	HDRA	NEUTRON	GR	MDT-TESTS	DTCO	DTSH	COMMENT	DLIS	STEP
well 1 PROVOST 8-20-37-3w4		P	P	P	P	no	PDPE	RILD	RHOB	DENCOR	NPRS	GR	0	DT	P	WEATHERFORD	NO	0.1
well 2 ET AL PROVOST 15-17-37-3		P	P	P	P	no	PDPE	RILD	RHOB	DENCOR	NPRS	GR	0	DT	P	WEATHERFORD	NO	0.1
well 3 PROVO 16-32-38-3w4		P	P	P	P	no	PEFZ	ILD	RHOZ	DRHO	NPOR_SAN	GR	0	DT	P	SCHL	NO	0.04
well 4 ECS model well PROVOST 8-9-41-8w4	KEY WELL	MEAS	MEAS	MEAS	MEAS	no	PEFZ	AT90	RHOZ	HDRA	NPOR_SAN	GR	0	DT4P	DT2	SCHL	NO	0.0254

Table 1: Summary of Predicted and Measured Logs

00/08-09-041-08W4/0

Short Name	TVD (m)	MD (m)	Subsea (m)	Isopach (m)	Por Int (m)
LEAPRK	320.0	320.0	412.5	60.0	
MILKRV	380.0	380.0	352.5	102.0	
COLRAD	482.0	482.0	250.5	148.0	
2WSPK	630.0	630.0	102.5	48.0	
BFSC	678.0	678.0	54.5	57.0	
VIK	735.0	735.0	-2.5	9.0	
JOLIFU	744.0	744.0	-11.5	34.0	
MANN	778.0	778.0	-45.5	9.5	
MCLRNSS	787.5	787.5	-55.0	15.5	5.0
WASECASS	803.0	803.0	-70.5	18.0	
SPRKYSS	821.0	821.0	-88.5	9.0	
GPETESS	830.0	830.0	-97.5	12.0	3.5
REXSD	842.0	842.0	-109.5	8.0	
LLOYDSS	850.0	850.0	-117.5	15.0	
CUMMGSS	865.0	865.0	-132.5	15.0	1.0
DINASD	880.0	880.0	-147.5		13.5

Production
00/08-09-041-08W4/0

00/08-09-041-08W4/0

#	Perf Date	Perf Type	Upper Depth (m)	Lower Depth (m)	Shots/Me	Treatmen	Description
1	3/17/2006	JET PERFO	742.0	745.0	17		
2	3/17/2006	JET PERFO	734.0	738.0	17		
3	2/15/2007	TREATMEN	724.0	732.0	0	BRIDGE PLUG CAPPED W/CEMENT	
4	2/15/2007	JET PERFO	643.0	645.0	17		
5	2/15/2007	JET PERFO	640.0	642.0	17		
6	2/15/2007	JET PERFO	631.0	633.0	17		
7	2/22/2007	TREATMEN	631.0	645.0	0	FRACTURED	
8	11/19/2007	JET PERFO	674.0	676.0	14		
9	11/19/2007	JET PERFO	588.0	591.0	14		
10	11/19/2007	JET PERFO	489.0	491.0	14		
11	11/21/2007	TREATMEN	674.0	676.0	0	FRACTURED	
12	11/21/2007	TREATMEN	588.0	591.0	0	FRACTURED	
13	11/21/2007	TREATMEN	489.0	491.0	0	FRACTURED	

Table 2: Perforations on the well with ECS log

Plot of entire well is shown next. Shorter, more readable plots will follow:

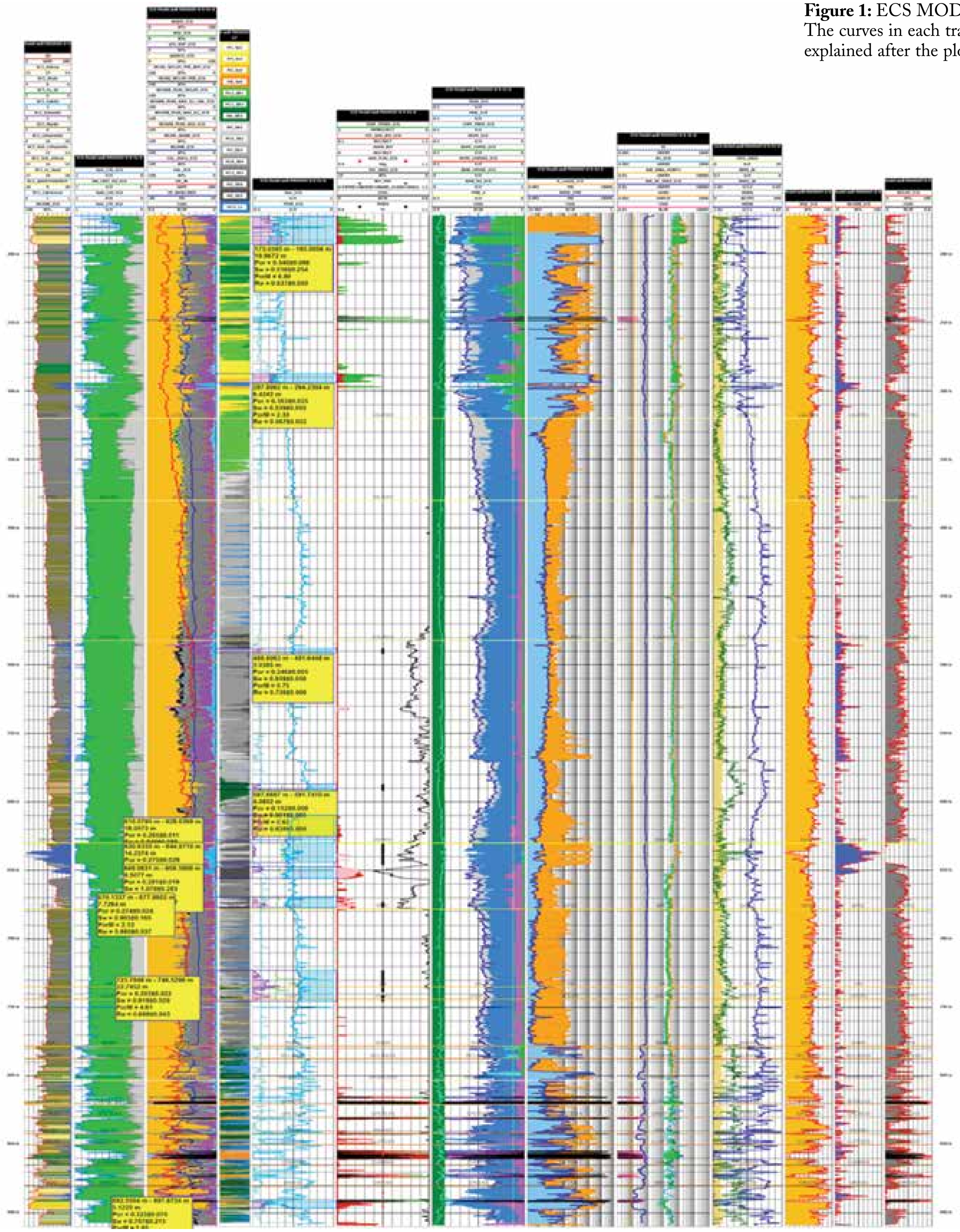


Figure 1: ECS MODEL WELL. The curves in each track are explained after the plots are shown.

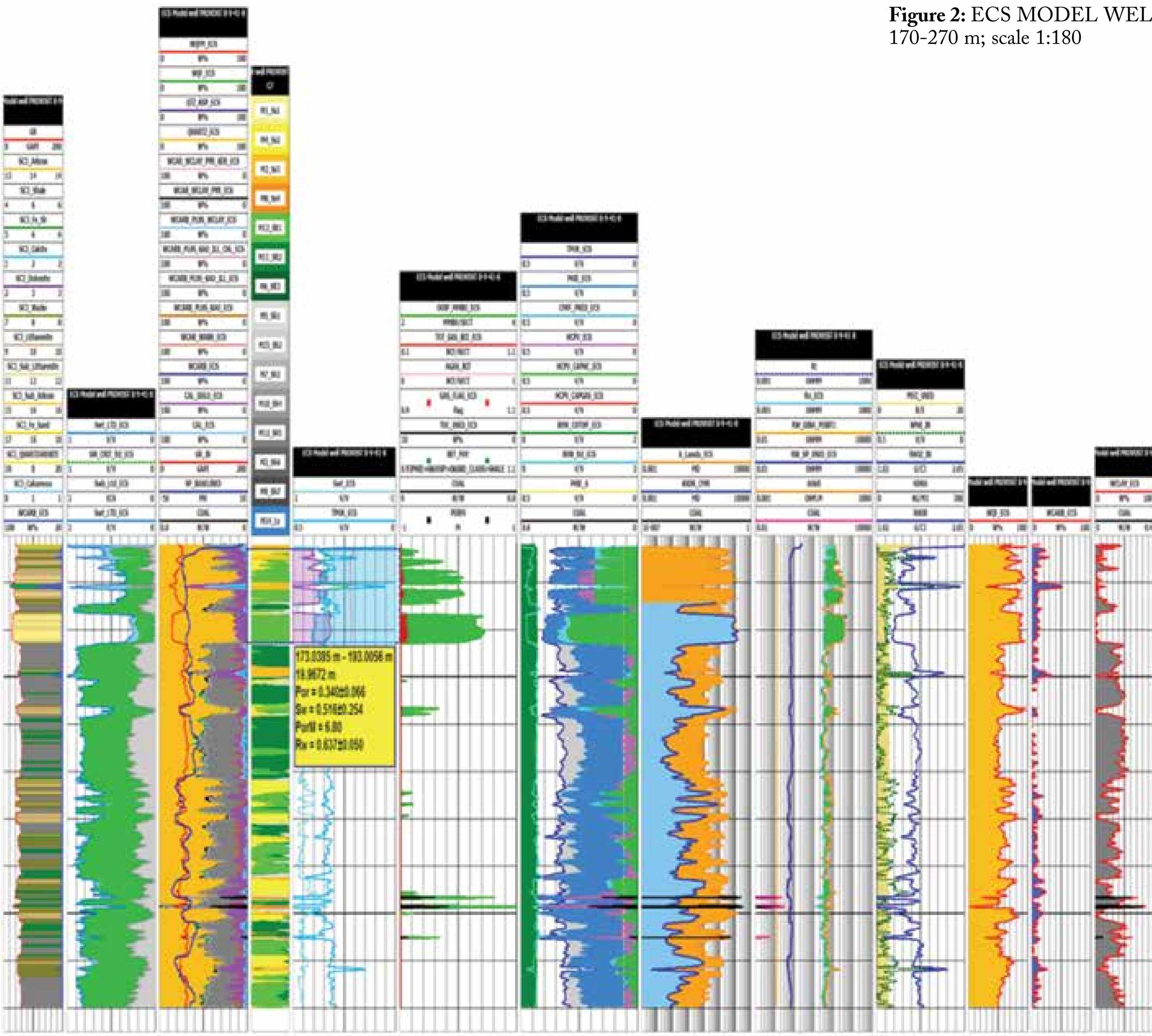
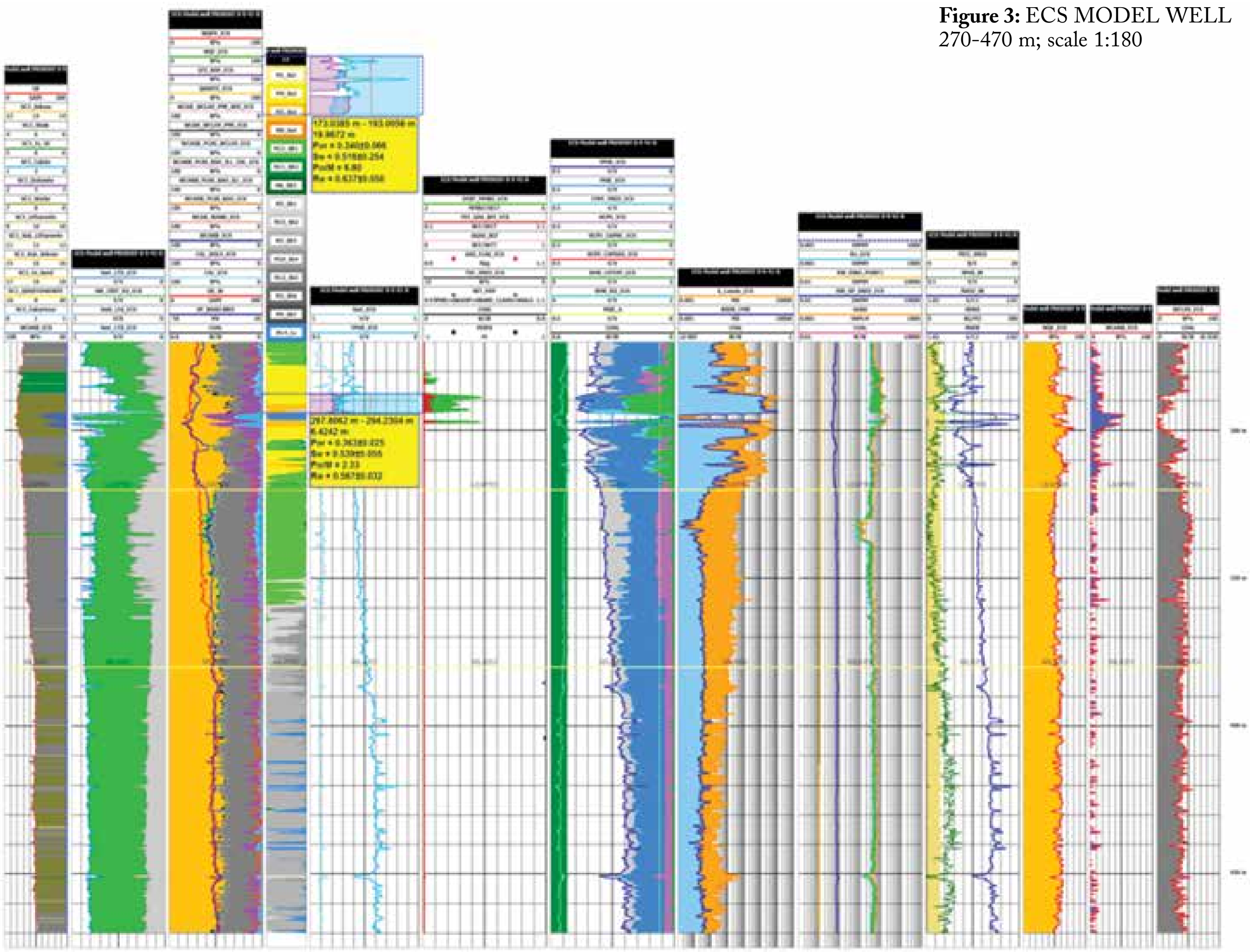


Figure 2: ECS MODEL WELL
170-270 m; scale 1:180

Figure 3: ECS MODEL WELL
270-470 m; scale 1:180



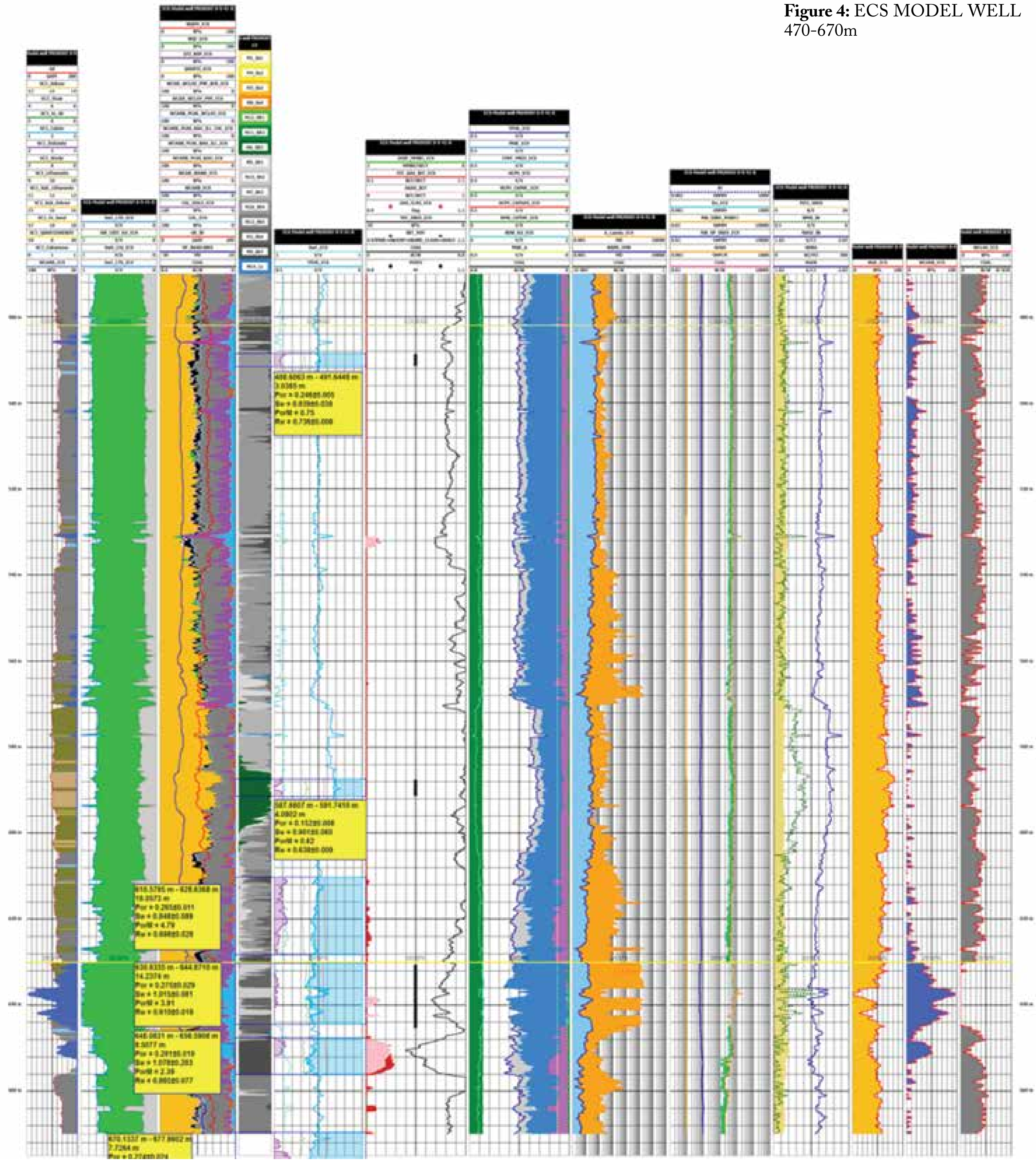


Figure 4: ECS MODEL WELL 470-670m

Note the carbonate in the 2nd White Specks over the perforated interval shows a slight increase in resistivity but not enough. Interpretation agrees with results of zero production.

Perhaps the zone above or below would have been better? The zone below shows a high TOC, so adsorbed gas (light pink) is high. However, Sw is still too high, so no pay flag shows up.

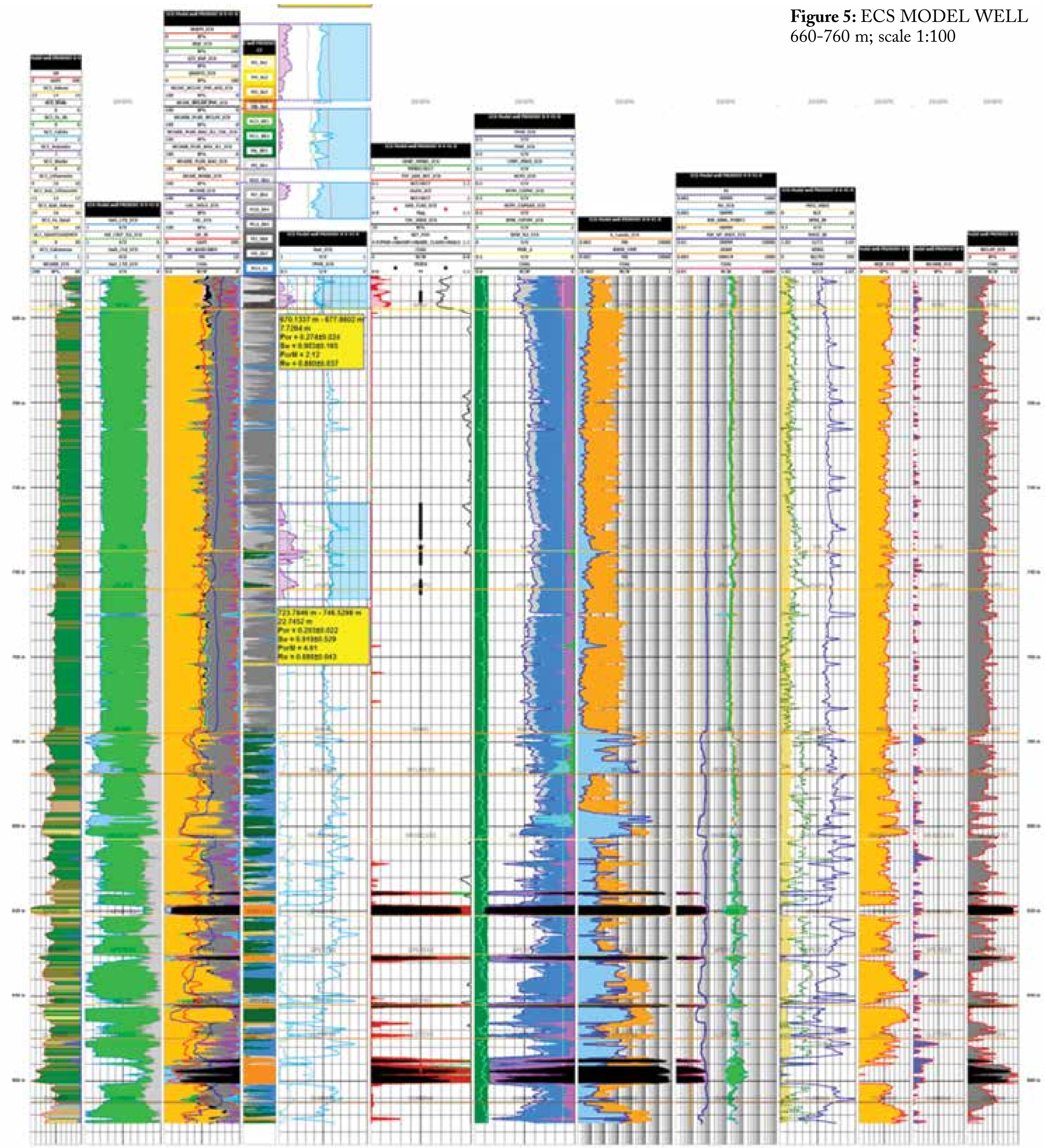


Figure 5: ECS MODEL WELL 660-760 m; scale 1:100

Perforations and fracturing just above BFSC, bottom of BFSC Viking and Joli Fou. Only the zone above the BFSC has high TOC. No hydrocarbon production is expected as Sw is too high, hence, no pay flag.

SP (predicted) deflects to the left in the top of the Dina; the Dina is wet, but has a show just below the coal, albeit water-productive. It was not tested. No pay flag but looks like it was worth a test.

Tracks descriptions are:

1. Sand class to right of GR curve. The darker the colour, the higher the GR. The name of the curve defining the classifications is SC3_log_SiO2plusCaO_Al2O3. This means the logarithm of the ratio (SiO2+CaO) over Al2O3. It is a curve that shows the classification of the rock from quartz arenite to shale. Most of the interval is Sub_lith to Arkose. One can see the stacking of sands of different classification within the sand package defined by the GR

2. Water saturation: the medium blue is water that will probably be produced with a frac job but is located in the small pore-space capillaries (micro-pores) so will not normally produce. We will see that the Sw_Crit from the CMR shows that some water will be produced when Sw_Crit is less than Swt. This will be discussed later. The top of the well is the only good zone in the well but was not completed. None of the perforated zones made hydrocarbons. The well was abandoned. It does provide an excellent well to model elements and mineralogy for other wells via prediction software (Geological Analysis by Maximum Likelihood System (GAMLS) is the software used by the author.) Comments:

   a. If a green Sw_CRIT_ltd_ECS curve is shown, and is less than Swt, some water may be produced, as shown in the top sand, 186-193m.

   b. If a grey Swb curve is presented, this represents the bound water saturation of the clay water.

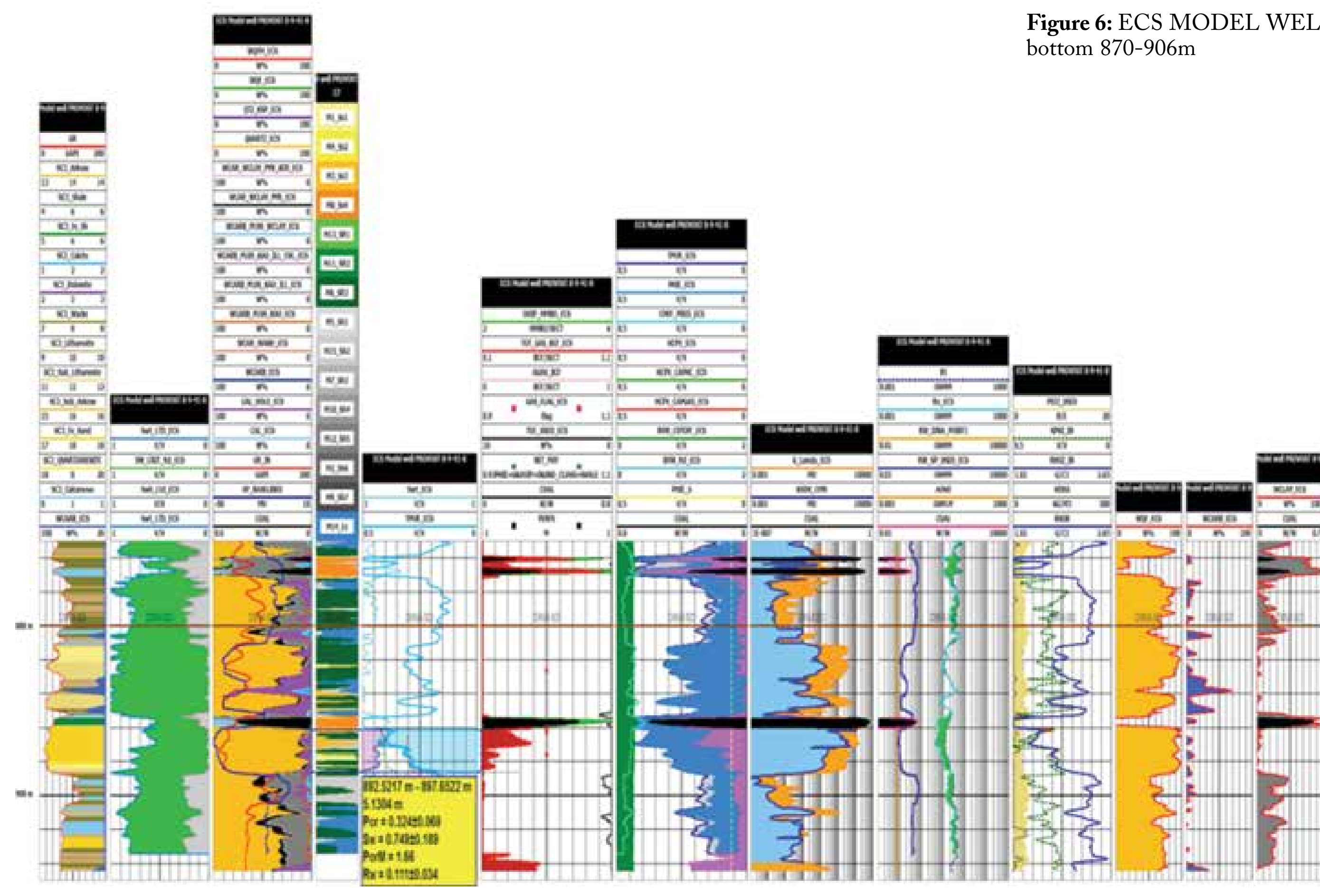


Figure 6: ECS MODEL WELL bottom 870-906m

c. Since the Sw_Crit is derived from the CMR, I rely on the CMR if it is a measured curve, as it is in this ECS model well. Note that CMFF is not recorded below the Waseca sand but is predicted from there to TD. In the other three wells the CMR was predicted.

3. Mineralogy shows quartz in orange, kerogen in plum (very little), pyrite in black, chlorite in plum (none), illite in grey, kaolinite in dark orange, dolomite in purple and calcite in blue. Coal is not in the model but shows up as clay (sum of mineral groups =100; when coal present, SiO2 + CaCo3 = 0, so result ends up as clay). Coal is shown when the density log (RHOB < 1925 kg/m3) is low.

4. Clustered Lithology: shales are white to grey to black; dolomite is in purple, calcites in blue, anhydrite in salmon (none). The darkness of the colour is proportional to the GR and density. Clusters will change with increased or different data input. All four wells were clustered at the same time so that the cluster colours mean the same lithology for each well. Note that this is lithology derived from the neutron, density, GR, DT and Pe, as opposed to a sand classification shown in track 1. The sand classification is based on Si, Ca and Al as described in Reference, Herron, 1986.

5. The next track is special. There are three curves in the track that do not get shown in the heading as they are from an internal plotting program with fixed scales. The plotted curves are our ECS-calculated Sw in dotted blue; ECS-Calculated TPOR in solid blue. When the hydrocarbon quick look program is called up, a dashed box appears (as shown) and Sw and porosity are automatically plotted. The trick is to modify the a, m and n in the Archie equation until the purple Sw fits on top of the dashed Swt_ECS. See screenshot below to see the parameters for the top zone. Modifying the grain density for each of the three cluster groups(sand, carbonate and silt-clay) provide a computed grain density for the porosity calculation from the density log.

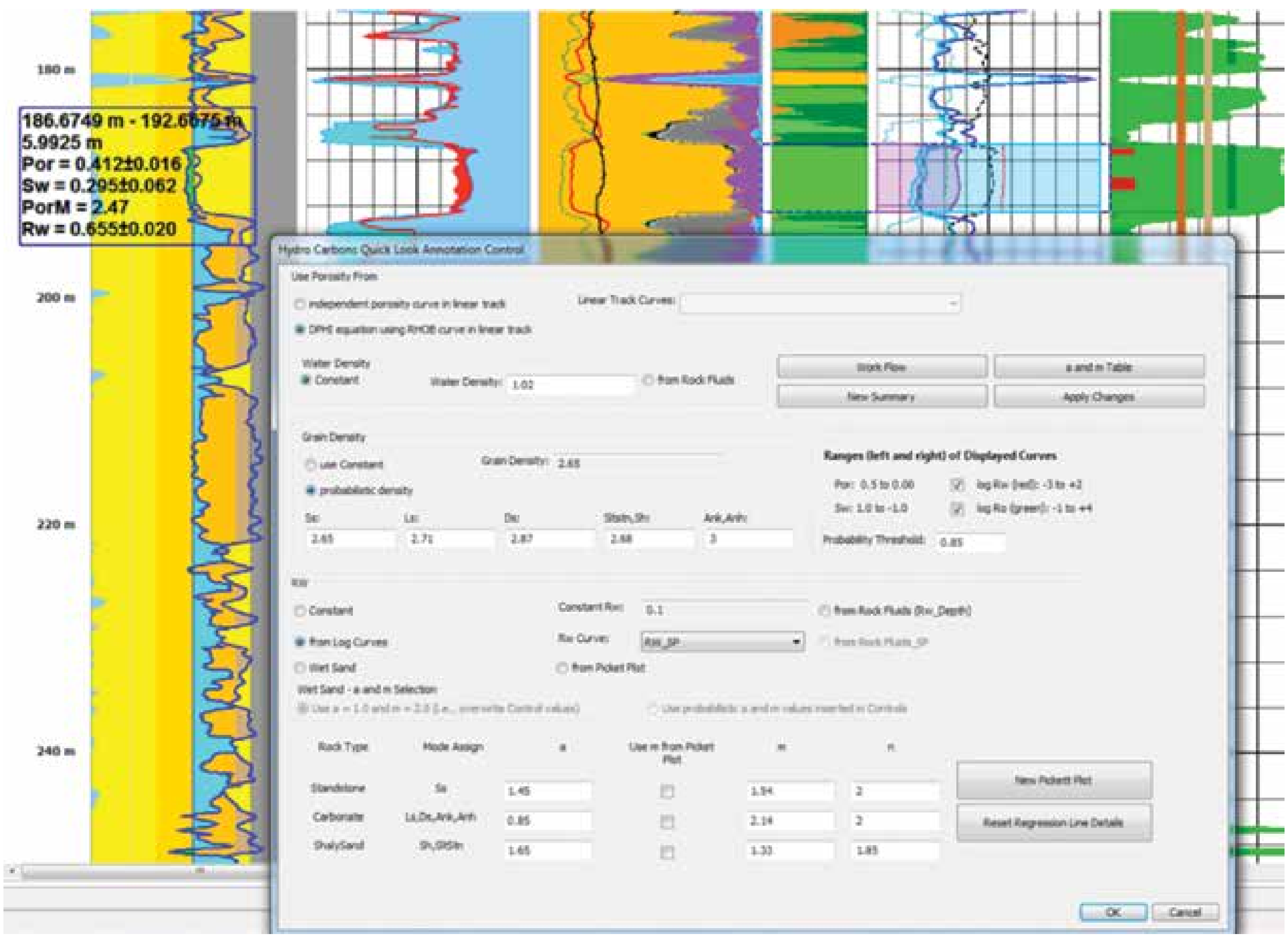


Figure 7: Quick Look Annotation Control

6. The next track shows Original oil in place (OOIP) as green and gas as red. Since gas is plotted on top of the OOIP, one will only see the red on top of the green coding as oil is expected to be produced, if anything (no gas flag). Both the OOIP and the Total Gas are computed from the same starting point of hydrocarbon pore volume (HCPV). The brown bars are the resulting bed thickness from all the curves used in the cluster. The green net pay flags show the zones one should perforate. No zones in the well have a green net pay flag.

7. Porosity: light grey is bound clay water; blue is water in the small capillaries, which is normally not producible unless stimulated hydraulically; plum is hydrocarbon in the small capillaries which is not producible unless heavily stimulated hydraulically; green is oil in the larger macro pores and red is gas in the larger macro pores. Comment:

    a. When the CMR shows free fluid, no frac is needed for production as these are the macro pores.

    b. When the CMR shows cyan blue fluid, production is water. This is the case for the Dina sand. It is also the case for the top sand. So the top sand will produce water plus oil, according to the CMR. Ideal place for a Modular Formation Tester before perforating top sand. Nothing like a test to tell for sure.

8. Permeability: if the zones had core they would be shown as black dots. There are none on this well. For ease of colour coding, the permeability curves are stacked:

    a. K-Lamda_ECS is the intrinsic permeability from the Herron Paper.

    b. KSDR_CMR is calculated in the program from T2LM and TCMR. The recorded KSDR did not go as deep as the well, so the calculated value filled the bottom of the hole.

    c. KSDR is the permeability from the CMR recorded at the wellsite, using the formula derived by Schlumberger-Doll Research.

    d. Coal is turned on when the density is less than 1.925 g/c3. This value was selected by inspection of the density and DT curves.

9. Resistivity: the field Rw of 0.1@77F (@25C) is the yellow vertical line. This value was gleaned from inspection. The green shading between Ro and RT is an indication of oil saturation. One might ask why the SP is used to calculate the Rw? Why not just used the field average for all formations? The answer is the Rw varies from zone to zone, with the unflushed zones having a different Rw than the flushed zones. Once certain challenges are met, the SP is an excellent measurement to delineate the differences. It must be baselined, bed-thickness corrected, hydrocarbon-corrected and it must have one calibration zone where the Rw is known. Clay and invasion effects help to provide permeability distinctions.

10. Neutron Density: the density is high (low porosity) in the carbonate zones. The separation of the neutron and density is increased by clay and reduced by light hydrocarbons and changed by input matrix effects (sandstone, limestone, dolomite function formers).

11. The matrix-adjusted neutron and density is the last track. Since no zones have cross-over, we assume that no gas is present (or little).

12. TABLE OF RESULTS is in the TOPS and SUMMARY csv files that are available for each well. Part of the summary for the ECS model well is shown below. The summary is also on the output LAS file.

# TOPS & SUMMARY		WELL:	ECS MODEL	DATE:	2014-06-26 15.08.03													
# STRT:	149.5048	STOP:	925.8304															
# Formation Name	Top	Bottom	Interval	NET_PAY_PHIE>PAY1 &HCPV	Porous_PHIE >PAY2	Gross_PHIE >PAY3	POR_AVG	PHIE_STOR_ CAPACITY	kh-FLOW-CAPACITY	DELIV_SPEED	Sw_AVG_nc _cutoffs	HCPV	ADS_GAS _BCF/SEC	FREE_GAS _BCF/SECT	HCPV &Net	HCPV& Porous	HCPV& Gross	OOIP_MMBBL /SECT
# TOP OF WELL	149.5048	320	170.4952	0	138.3792	140.1572	0.43081394	14.9935946	722.1207	34174.45263	0.7420427	1.117917361	0.268346	8.2563013	0	1.0712	1.0722	5.550593849
# LEAPRK	320	380	60	0	51.181	51.181	0.269164275	3.01581787	15.32029	435.6660631	0.80612C	0.264113982	0.106663	3.1683916	0	0.2148	0.2148	1.311357612
# TOP OF WELL	149.5048	320	170.4952	0	138.3792	140.1572	0.43081394	14.9935946	722.1207	34174.45263	0.7420427	1.117917361	0.268346	8.2563013	0	1.0712	1.0722	5.550593849
# LEAPRK	320	380	60	0	51.181	51.181	0.269164275	3.01581787	15.32029	435.6660631	0.80612C	0.264113982	0.106663	3.1683916	0	0.2148	0.2148	1.311357612
# MILKRV	380	482	102	0	80.6704	99.7712	0.204854969	4.26876676	5.869618	177.4232515	0.8185401	0.313765573	0.185857	4.6468019	0	0.2497	0.3063	1.557883719
# COLRAD	482	630	148	0	117.2718	142.8496	0.236562877	7.39019027	40.9636	842.1811143	0.8274234	0.499101577	0.492513	9.4339291	0	0.4032	0.4799	2.47809922
# 2WSPK	630	678	48	0	41.91	41.9608	0.270086915	2.77955348	51.38763	486.9015828	0.823509E	0.190958085	2.330175	4.1246416	0	0.1616	0.1621	0.948129807
# BFSC	678	735	57	0	50.3936	51.816	0.217913095	2.57075853	4.598913	170.5431273	0.778736E	0.22755988	0.096809	5.3331712	0	0.2031	0.2085	1.129862113
# VIK	735	744	9	0	7.7216	8.636	0.204341562	0.37767673	0.525116	19.95160508	0.7880462	0.032442454	0.015315	0.7928188	0	0.028	0.0311	0.161080678
# JOLIFU	744	778	34	0	31.4198	31.9532	0.226285852	1.59727417	3.375246	120.0591316	0.7792055	0.138958178	0.056786	3.4790433	0	0.1307	0.1327	0.689944027
# MANN	778	787.5	9.5	0	7.5438	8.9916	0.215788064	0.44191149	3.607699	27.00805436	0.8812777	0.019787004	0.015875	0.506753	0	0.0153	0.0186	0.09824485
# MCLRNSS	787.5	803	15.5	0	6.7056	12.5222	0.185896772	0.61231119	6.148931	27.81750497	0.8408393	0.034889685	0.026323	0.9091019	0	0.0085	0.0266	0.173231475
# WASECASS	803	821	18	0	11.938	15.3924	0.29260548	1.09100296	428.8231	16473.67624	0.69673C	0.188676073	0.028013	5.0411952	0	0.1566	0.1683	0.936799346
# SPRKYSS	821	830	9	0	3.5306	6.9088	0.177667774	0.32324876	1.704102	56.19396743	0.7855528	0.027311615	0.015371	0.7326137	0	0.0112	0.022	0.135605445
# GPETESS	830	842	12	0	7.9756	9.6012	0.264375325	0.68388699	44.67508	1502.83062	0.8074221	0.06970681	0.018995	1.8999336	0	0.0436	0.0461	0.346102676
# REXSD	842	850	8	0	6.8072	7.0612	0.310520704	0.56106978	72.59559	2372.452399	0.7867123	0.059450356	0.012124	1.6374251	0	0.0556	0.0565	0.29517815
# LLOYDSS	850	865	15	0	8.7376	10.922	0.357140765	1.14785208	319.5199	12897.06375	0.6322813	0.228949677	0.021955	6.3699536	0	0.1519	0.1577	1.136762621
# CUMMNG	865	880	15	0	10.033	13.6398	0.250904883	0.78646596	29.2264	851.3558798	0.7951322	0.079122522	0.023797	2.115192	0	0.0668	0.0756	0.392852816
# DINASD	880	925.8304	45.8304	0	21.3106	34.417	0.34479646	2.21840122	218.3586	6128.782464	0.825510C	0.273918117	0.738155	7.0839717	0	0.1265	0.2028	1.360036322

Table 3: Results Table

This summary provides the average Sw and porosity for input into your calculations. PHIE_storage capacity is porosity (v/v * cumulative metres.) It also provides hydrocarbon pore volume in three ways:

- HCPV at reservoir conditions. This is further divided into net pay, net porous and gross porous intervals.
- OOIP at reservoir conditions in MMBBL/section
- Total Gas at STP (adsorbed gas + free gas)

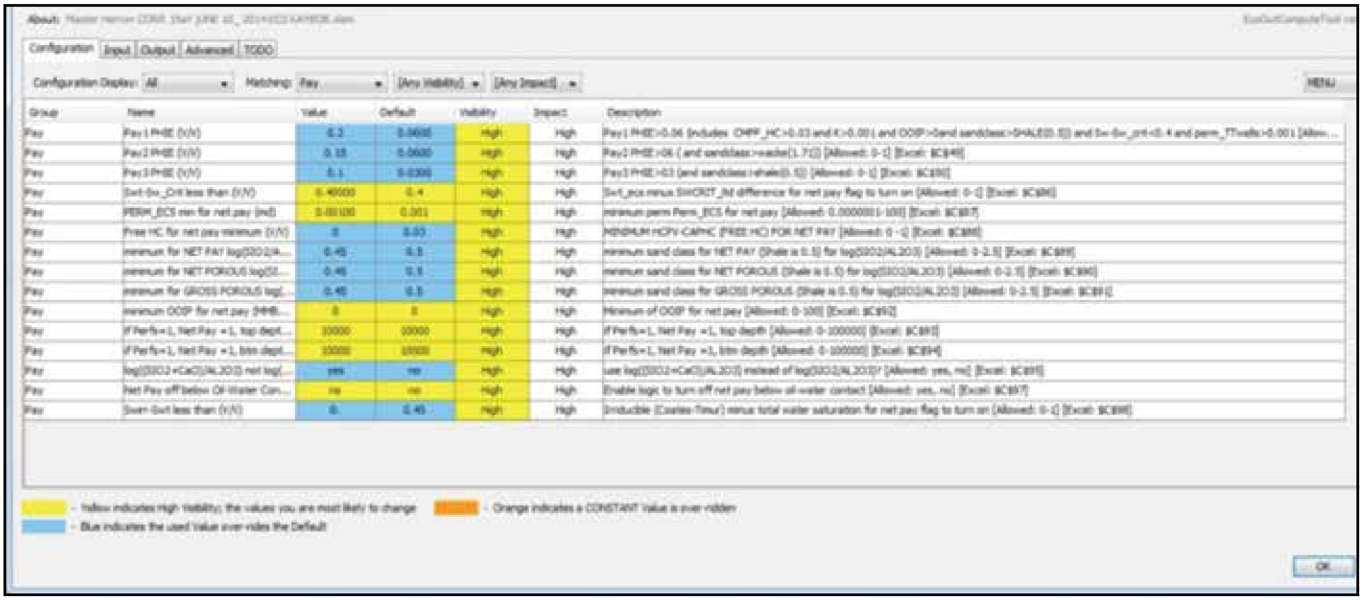


Figure 8: Pay Flag criteria used for initial computation

Figure 9: Input logs for the model well with the ECS log

The bottom line is that this type of interpretation generates alternatives when the target may not prove to be the best place to perforate.

Computation for each of three wells occurs with no ECS log.

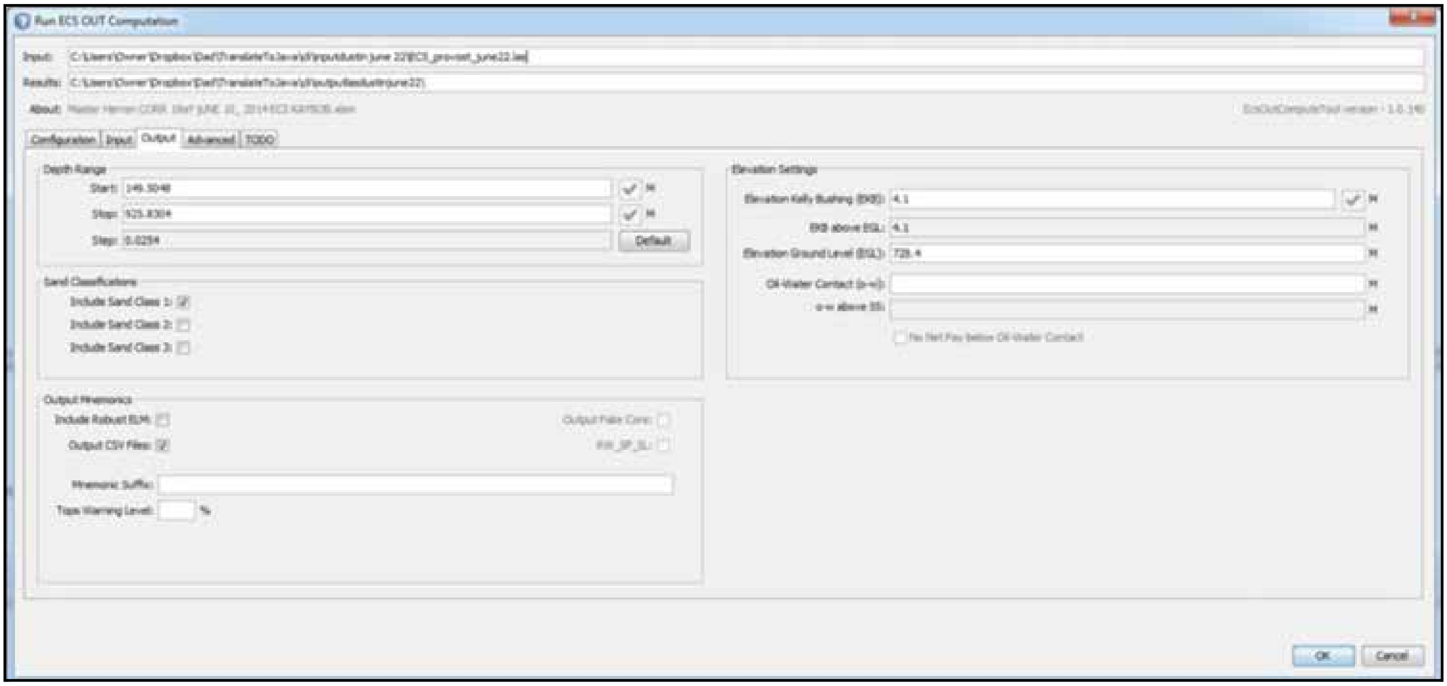


Figure 10: Output logs

Each of the next three wells has the ECS predicted from the model well.

The results in the Lloyd sand show the green net pay flag where the perforations are. We can also see that the top and the bottom perforations do not contribute hydrocarbons and therefore are sources of water. Note the sand classification in track 1 indicates different stacked sands with the best Arkose sands (lighter-coloured yellow, same as Dina) compared to the darker-tan-coloured litharenites. Note that one has to discount the pay flag when the black coding indicates coal.

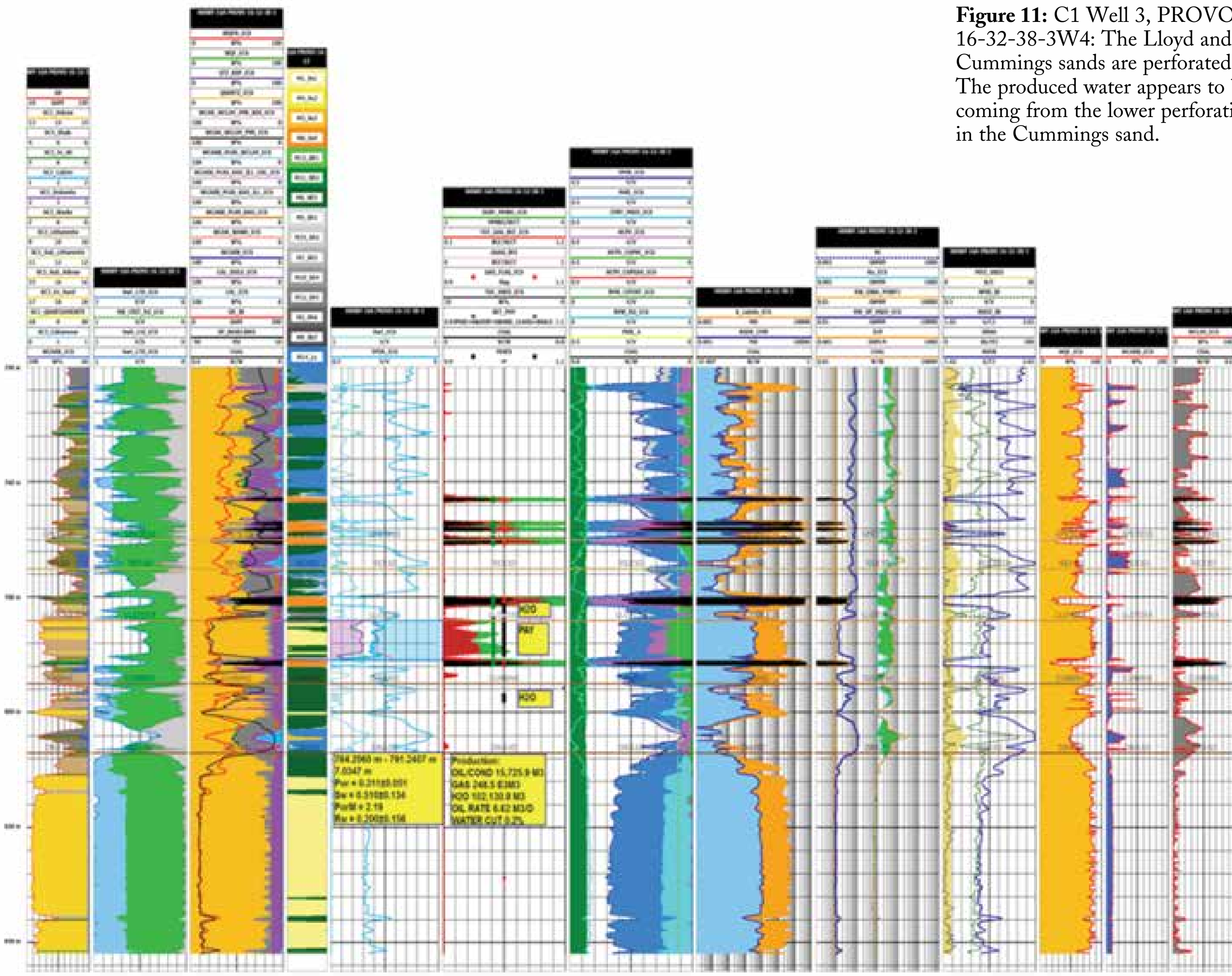


Figure 11: C1 Well 3, PROVO 16-32-38-3W4: The Lloyd and Cummings sands are perforated. The produced water appears to be coming from the lower perforations in the Cummings sand.

Inspection shows the best zones (highest porosity, most HCPV) were perforated. The General Petroleum zone appears to be the best (most red HCPV in Track 6). The Dina is interesting but will produce water in this well. The green shaded Sw_Crit curve in track 2 is less than Swt, indicating water would be produced. The yellow boxes refer to the summary immediately above them, except for the bottom one which refers to the Dina below.

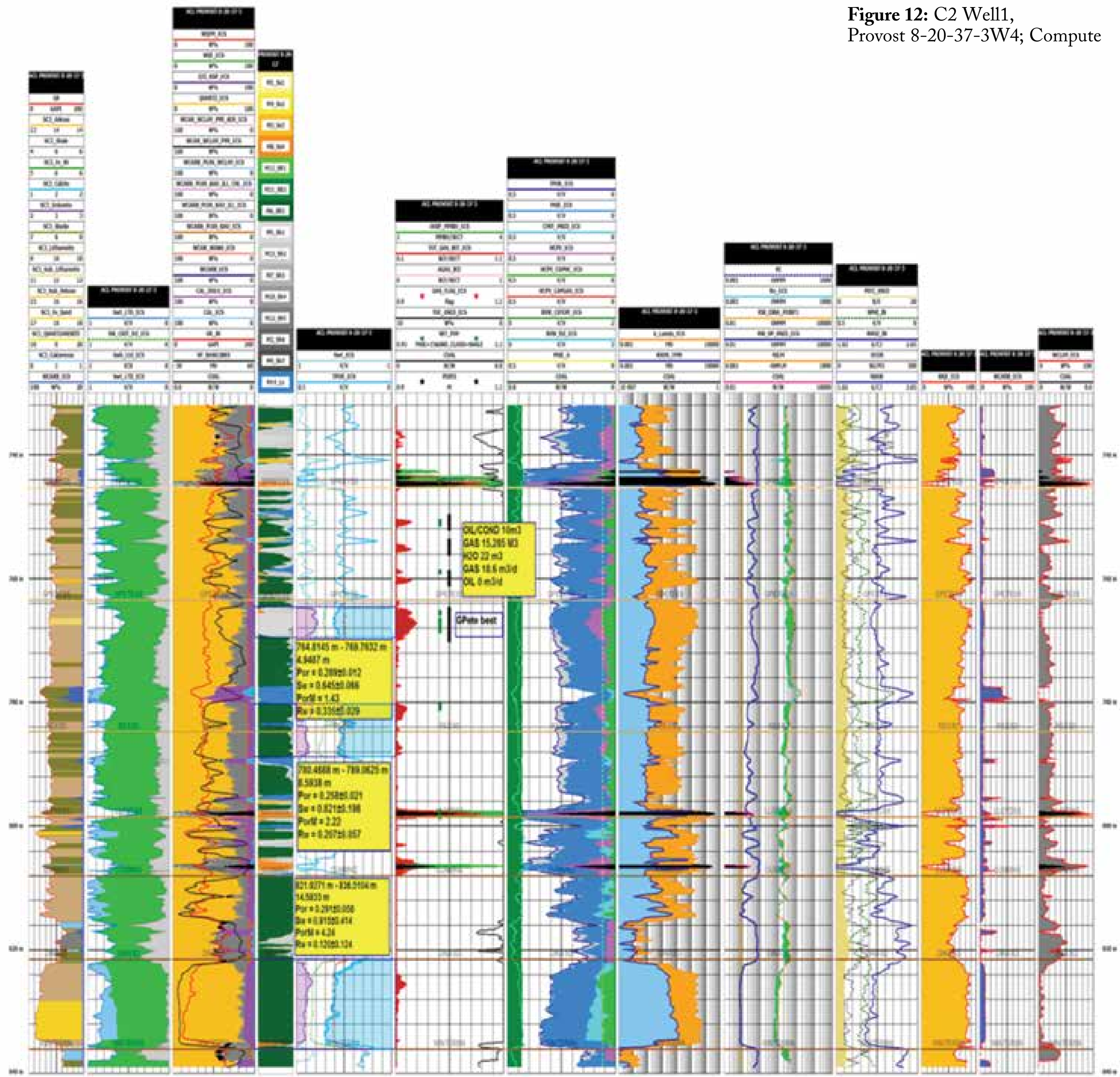


Figure 12: C2 Well1,
Provost 8-20-37-3W4; Compute

The zone at the top of the log shows moderate gas pay. In addition, the actual perforations are above the interval shown but we don't have the logs for the perforated interval, 742-756m. The recovery from the perforated interval was 8,846 m3 gas and 6m3 of H2O. Rate was 9.5E3m3/d.

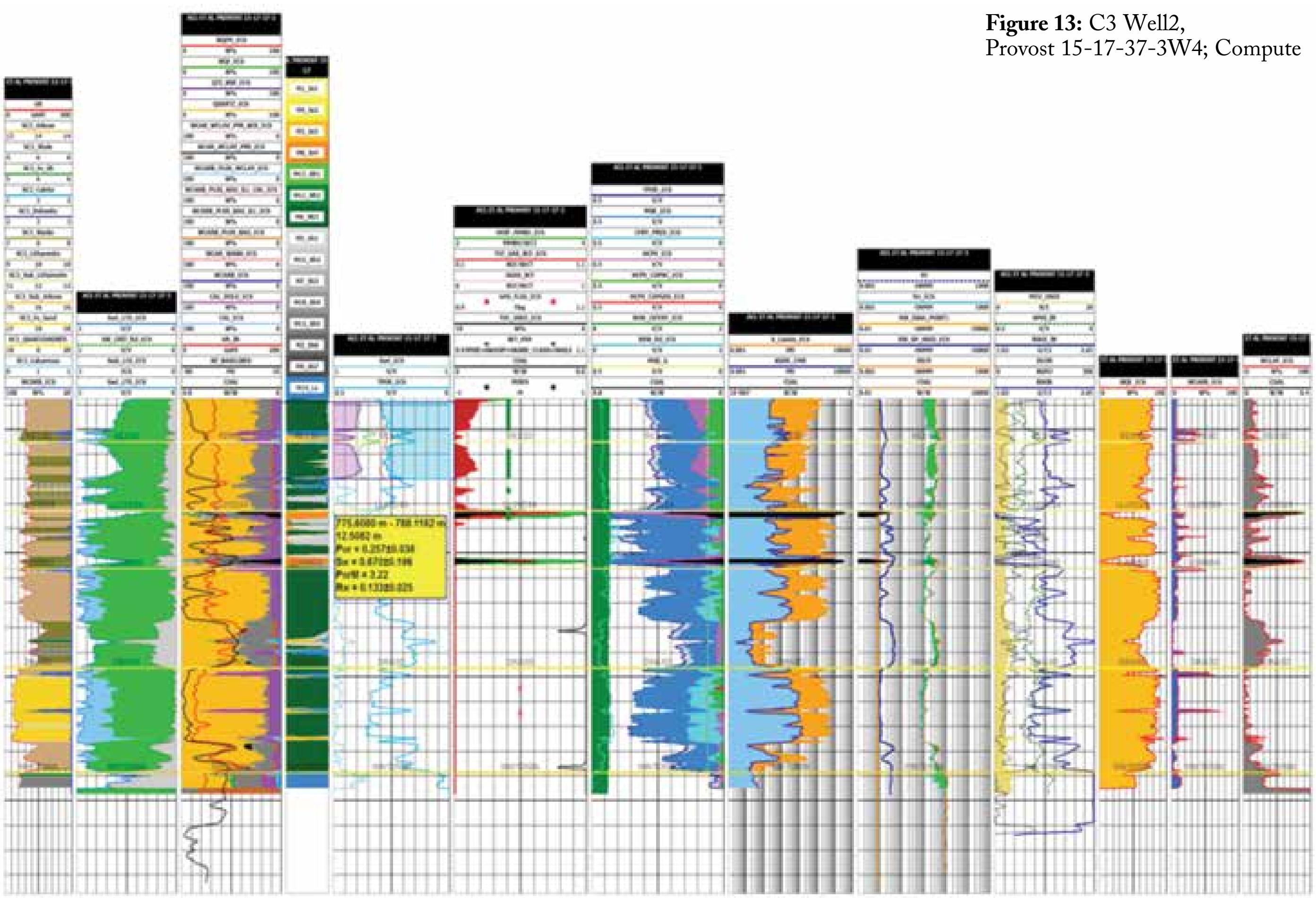


Figure 13: C3 Well2, Provost 15-17-37-3W4; Compute

Next, let's look at the final BVW and Pay parameters.

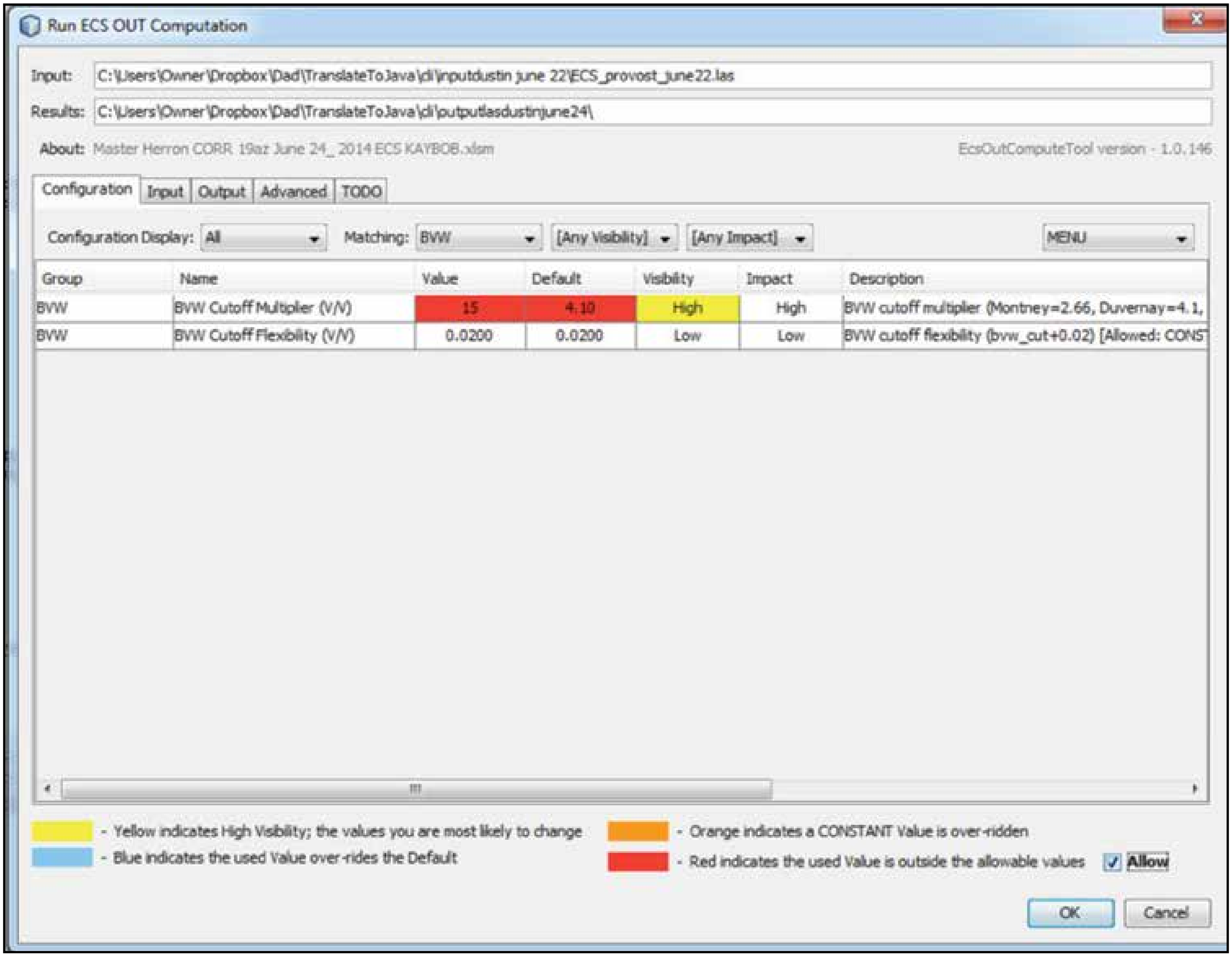


Figure 14: Final parameters used: BVW parameters

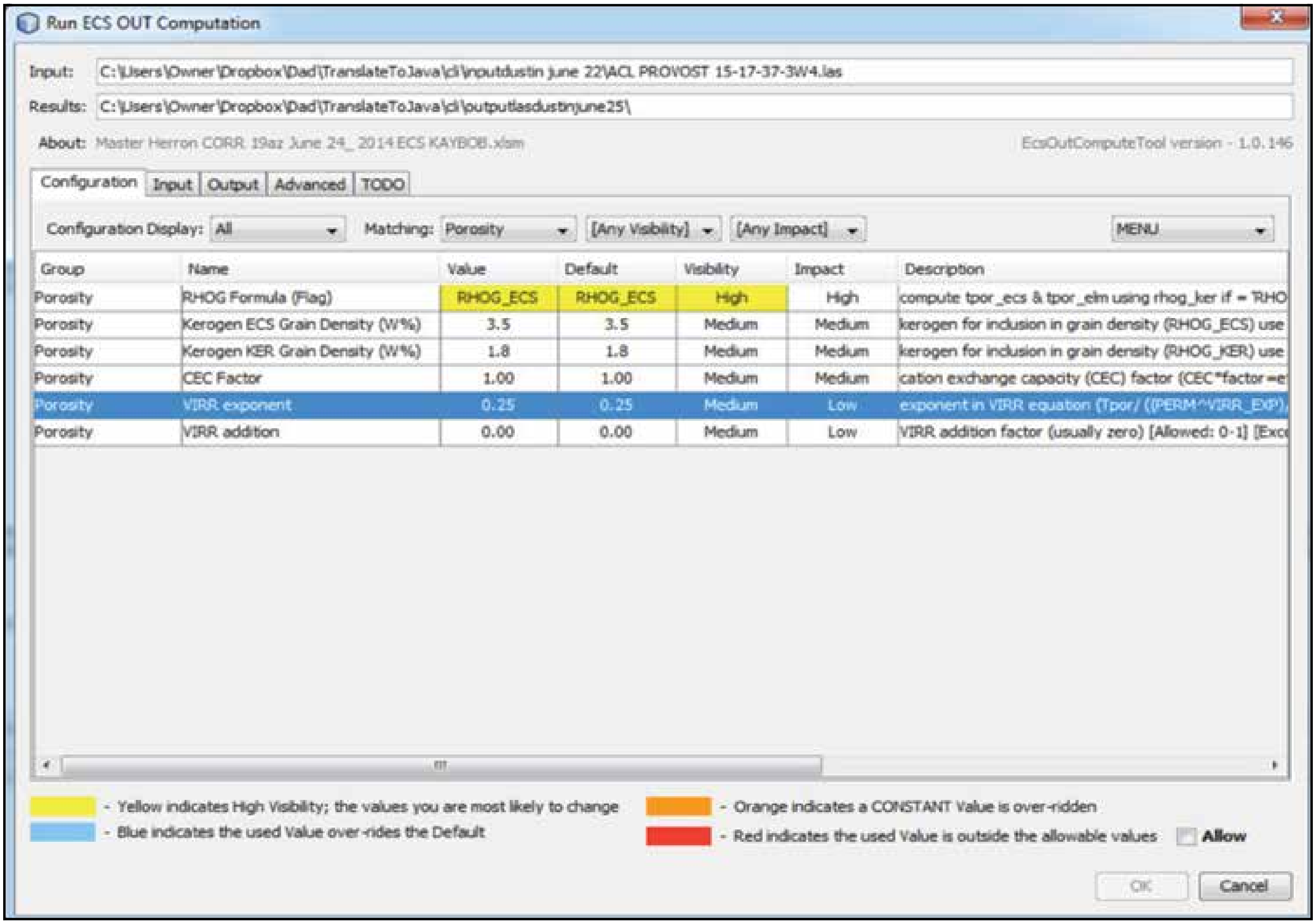
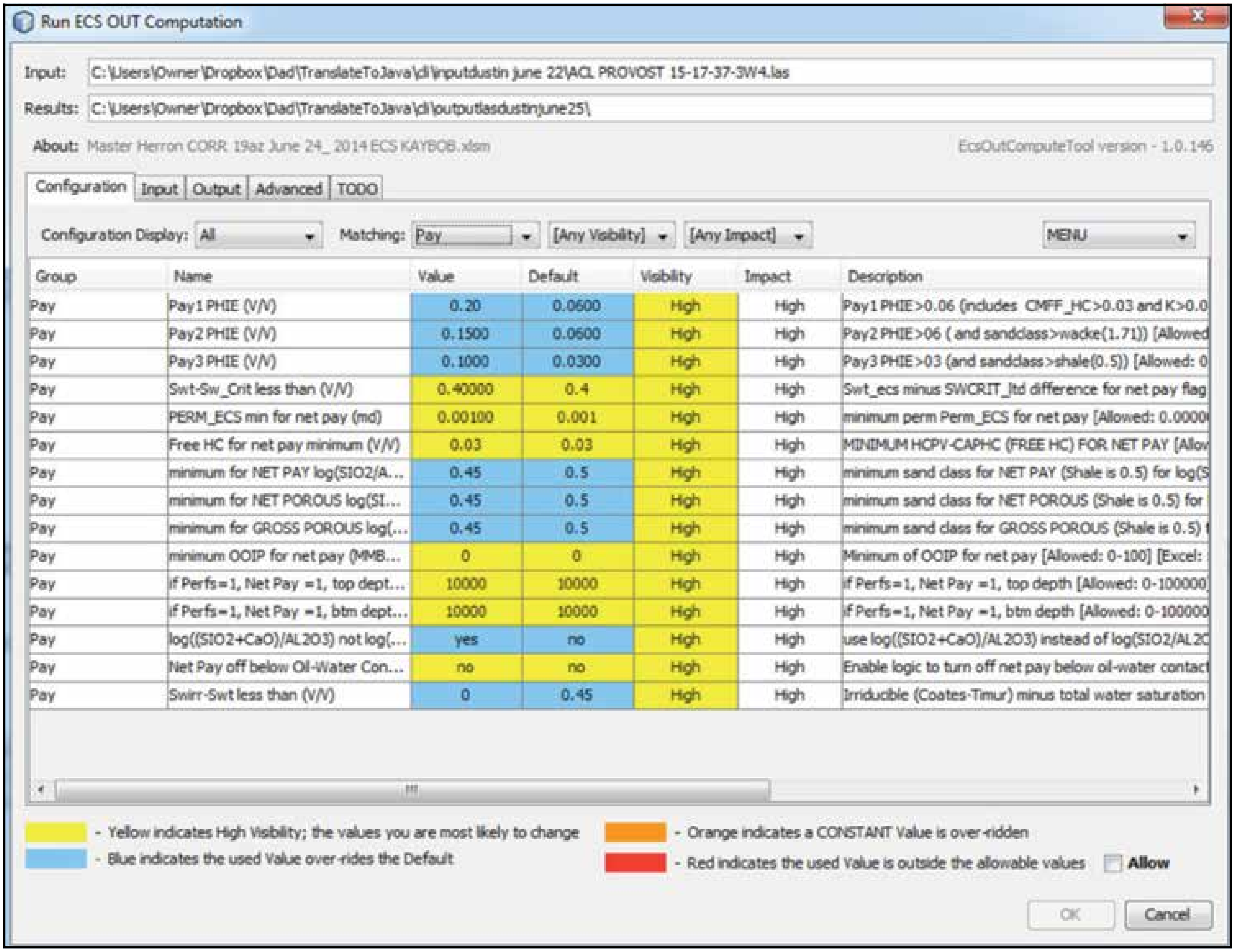


Figure 15: Final Porosity parameters; final Pay parameters are shown after porosity parameters.

The Virr permeability exponent is 0.25 for the wells 15-17 and 8-20. It was increased to 0.36 for 16-31 (increasing the exponent lowers the Swirr). For the ECS well, it was set to 0.5. This is important because the net pay flag will not turn on if Swirr<Swt. See conditions for net pay.



Group	Name	Value	Default	Visibility	Impact	Description
Pay	Pay1 PHIE (V/V)	0.20	0.0600	High	High	Pay1 PHIE>0.06 (includes CMFF_HC>0.03 and K>0.0
Pay	Pay2 PHIE (V/V)	0.1500	0.0600	High	High	Pay2 PHIE>06 (and sandclass>wacke(1.71)) [Allowed
Pay	Pay3 PHIE (V/V)	0.1000	0.0300	High	High	Pay3 PHIE>03 (and sandclass>shale(0.5)) [Allowed: 0
Pay	Swt-Sw_Crit less than (V/V)	0.40000	0.4	High	High	Swt_ecs minus SWCRIT_ltd difference for net pay flag
Pay	PERM_ECS min for net pay (md)	0.00100	0.001	High	High	minimum perm Perm_ECS for net pay [Allowed: 0.0000
Pay	Free HC for net pay minimum (V/V)	0.03	0.03	High	High	MINIMUM HCPV-CAPHC (FREE HC) FOR NET PAY [Allov
Pay	minimum for NET PAY log(SIO2/A...	0.45	0.5	High	High	minimum sand class for NET PAY (Shale is 0.5) for log(S
Pay	minimum for NET POROUS log(SI...	0.45	0.5	High	High	minimum sand class for NET POROUS (Shale is 0.5) for
Pay	minimum for GROSS POROUS log(...	0.45	0.5	High	High	minimum sand class for GROSS POROUS (Shale is 0.5) f
Pay	minimum OOIP for net pay (MMB...	0	0	High	High	Minimum of OOIP for net pay [Allowed: 0-100] [Excel:
Pay	if Perfs=1, Net Pay =1, top dept...	10000	10000	High	High	if Perfs=1, Net Pay =1, top depth [Allowed: 0-100000]
Pay	if Perfs=1, Net Pay =1, btm dept...	10000	10000	High	High	if Perfs=1, Net Pay =1, btm depth [Allowed: 0-100000
Pay	log((SIO2+CaO)/AL2O3) not log(...	yes	no	High	High	use log((SIO2+CaO)/AL2O3) instead of log(SIO2/AL2C
Pay	Net Pay off below Oil-Water Con...	no	no	High	High	Enable logic to turn off net pay below oil-water contact
Pay	Swirr-Swt less than (V/V)	0	0.45	High	High	Irriducible (Coates-Timur) minus total water saturation

Figure 16: Computations Table

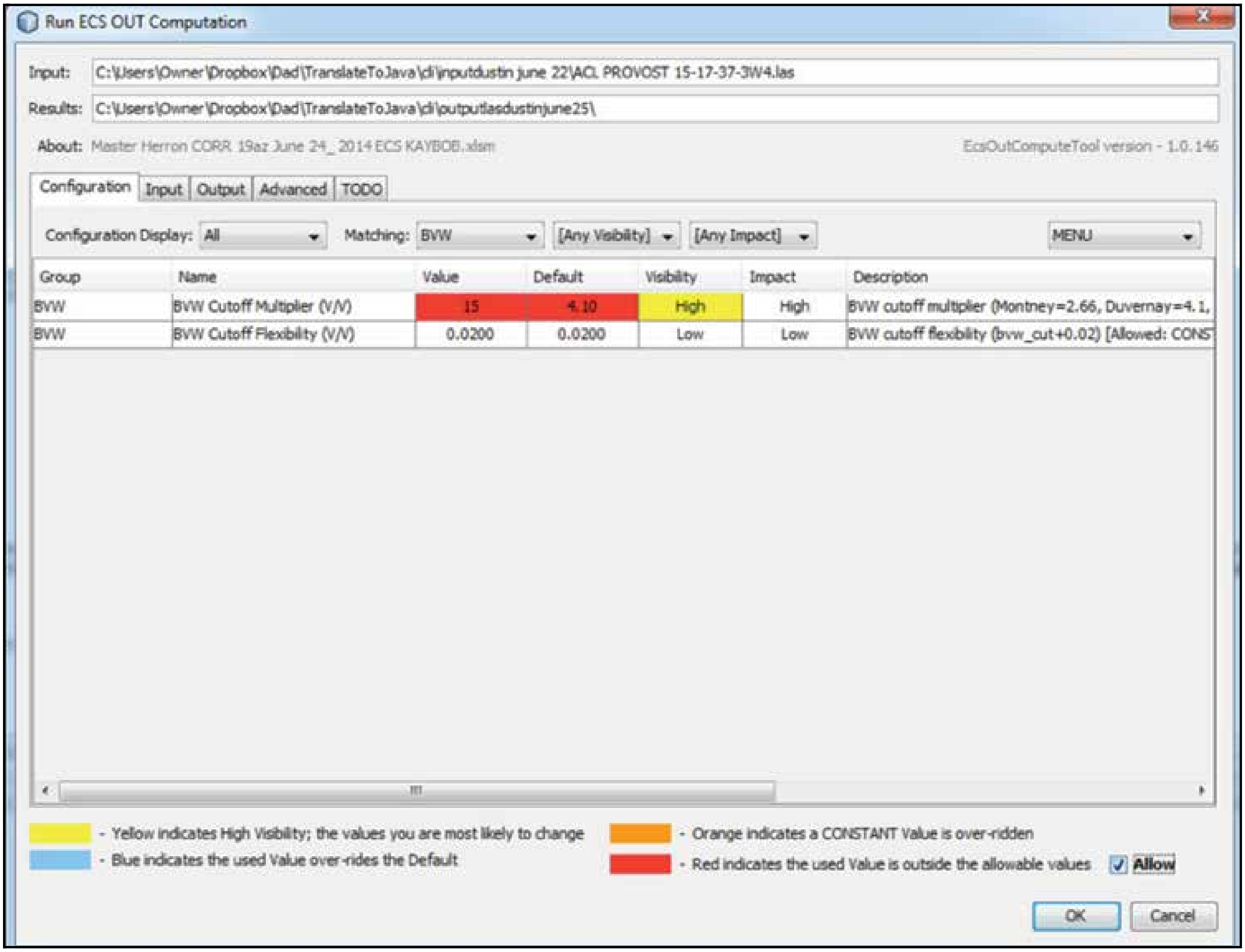


Figure 17: These parameters were run for all wells. The red flag refers to the multiplier for BVW_CUT which has an allowed range of 0-10 and we need to use 15 for these high porosity wells.

What have we learned?

Interpretation must use all available information to provide the best results. Using this method of interpretation we provide alternate zones to perforate when the target zone is not as good as expected.

Normalization

Logs from different vendors usually require normalization. However, one must be careful when applying normalization so that real differences are not removed. The basic question is why normalize at all? The neutron and GR are not used in calculations of porosity permeability and Sw, as they would be if one were using a volume of shale model.

The answer is we are predicting elements using the density, neutron and GR. So it is better to normalize these curves in order to get the correct prediction of elements.

However, one must be very careful and consider why one set of logs might be different from another.

An example is the GR raw curves below. The two SLB logs (red and orange) are similar. The green Weatherford log is within the window of the low end of the red SLB model well so it is OK, since it is only over the bottom of the well. On the other hand, the blue Weatherford well reads too high compared to the red model well. A shift is required for predictions to be valid.

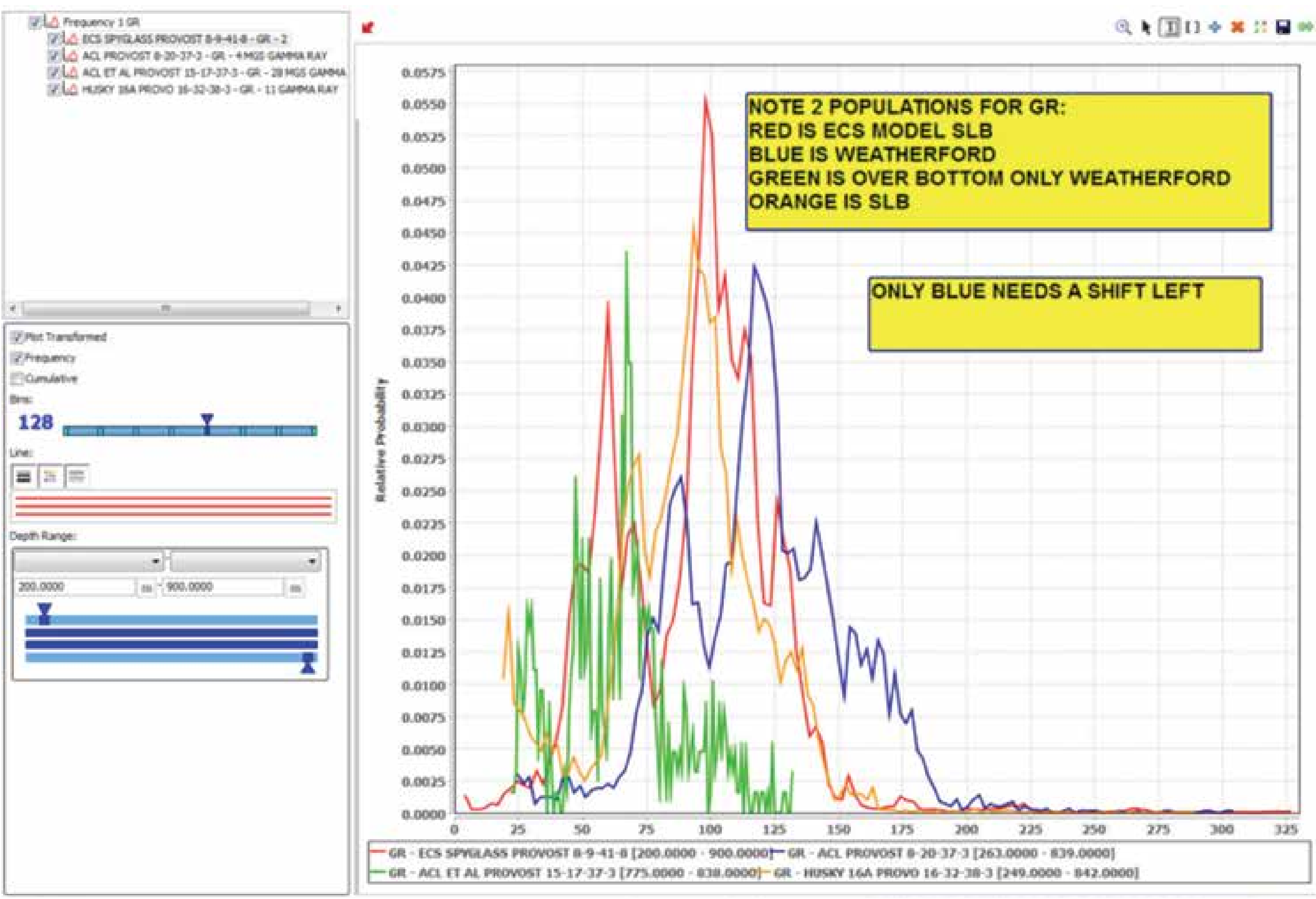


Figure 18: E1 Original GR

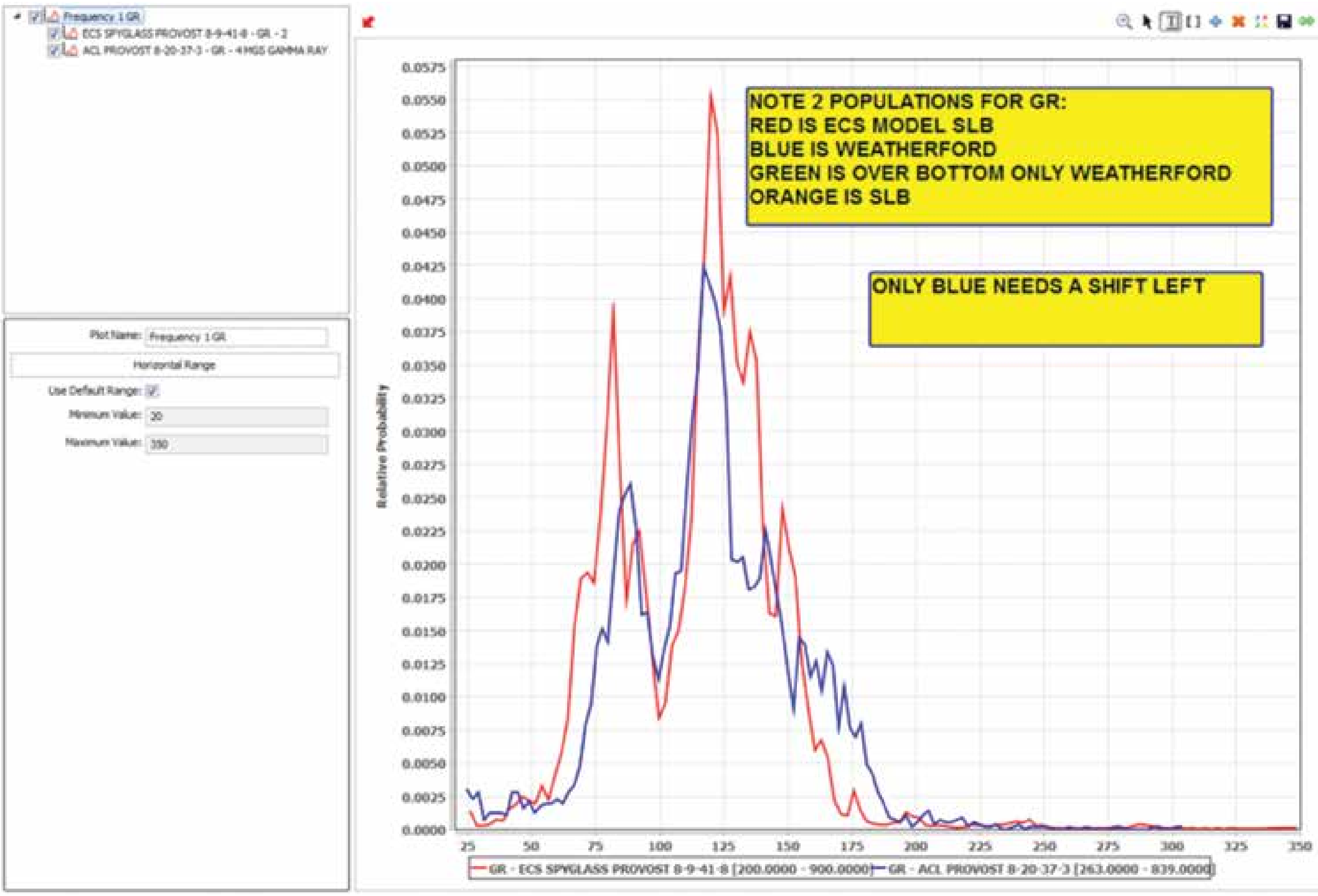


Figure 19: E2 GR after normalization of Blue: auto-normalization is used but only on one curve. One must be selective in what to normalize and what not to normalize.

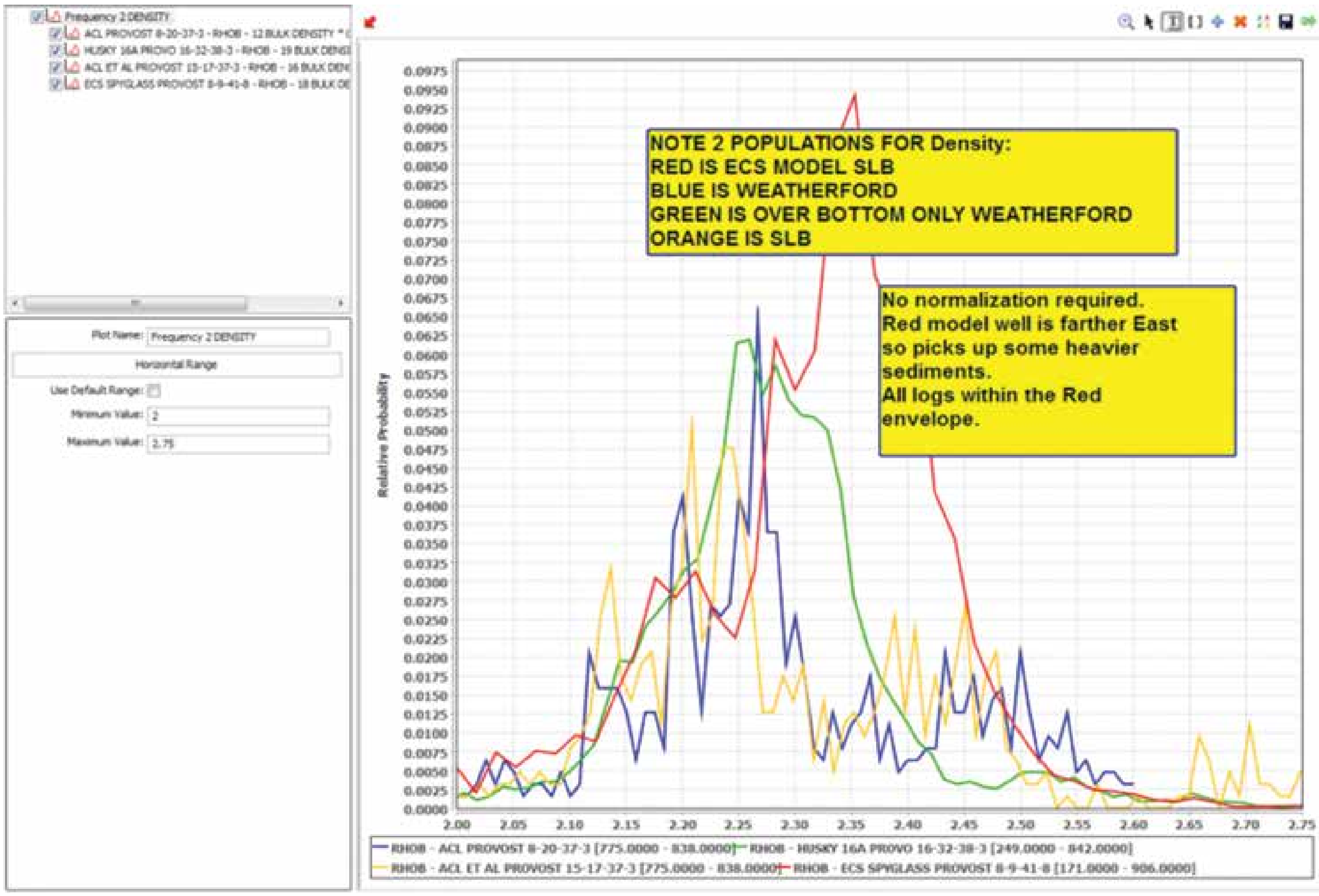


Figure 20: E3 Density before normalization

No normalization is required on the density logs because they all fall within the ECS model well envelope. The green curve is only over the bottom of the well so it is seeing the less dense formations. Note the coals are excluded by the selected scale starting at 2.0 g/c3 (coals are less than 1.925 g/c3).

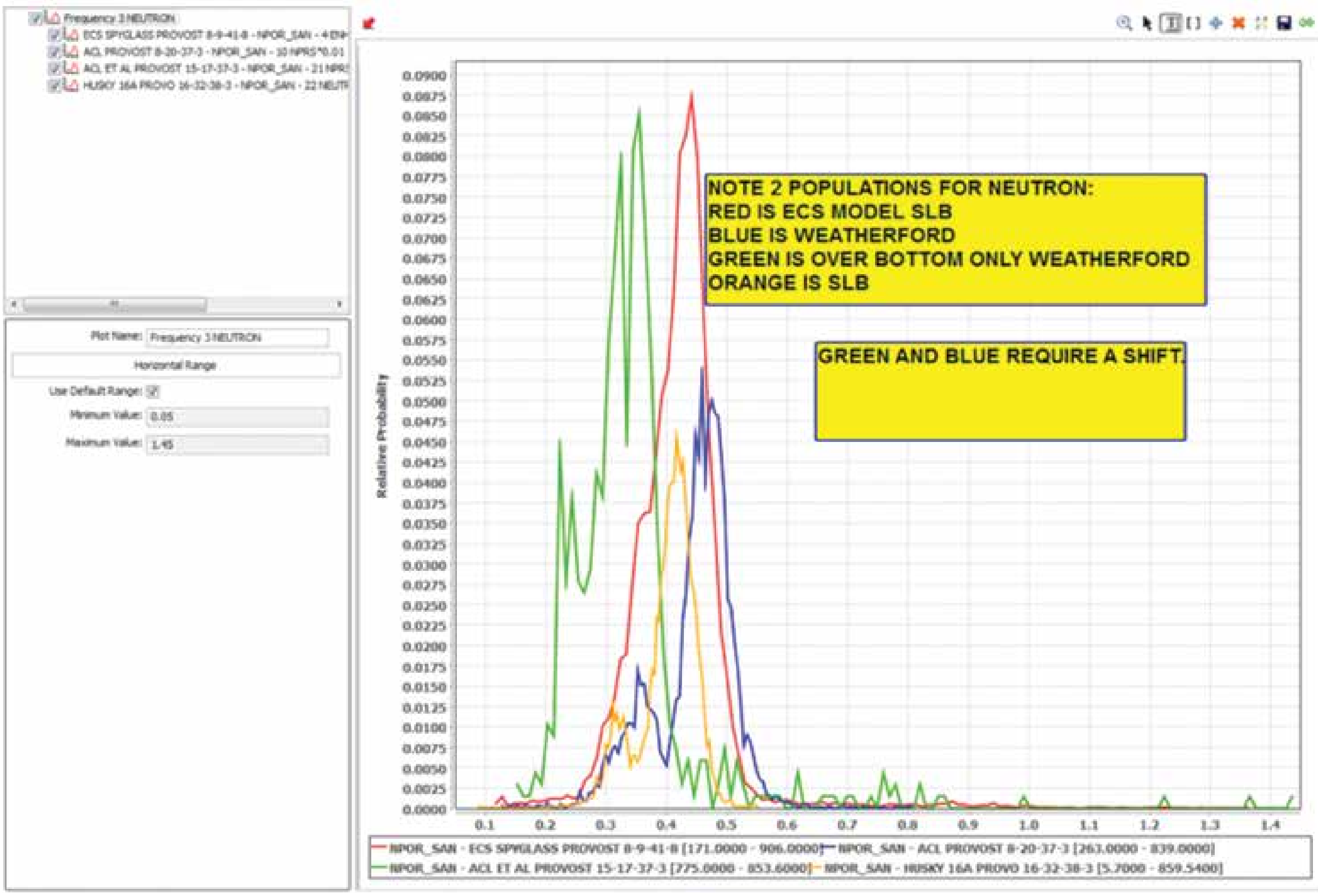


Figure 21: E4 Neutron before normalization

Bottom line: check curves for required normalization but do normalization selectively.

Point of Normalization: we are not implying that logs from one vendor are incorrect. We are just aware that logs from vendor A may not agree with logs from vendor B so normalization is prudent. Whether one selects vendor A or vendor B to normalize to is not important. What is important is that logs are normalized. A savvy consulting company president once told me that normalization was his secret weapon. Consistent interpretation requires normalization.

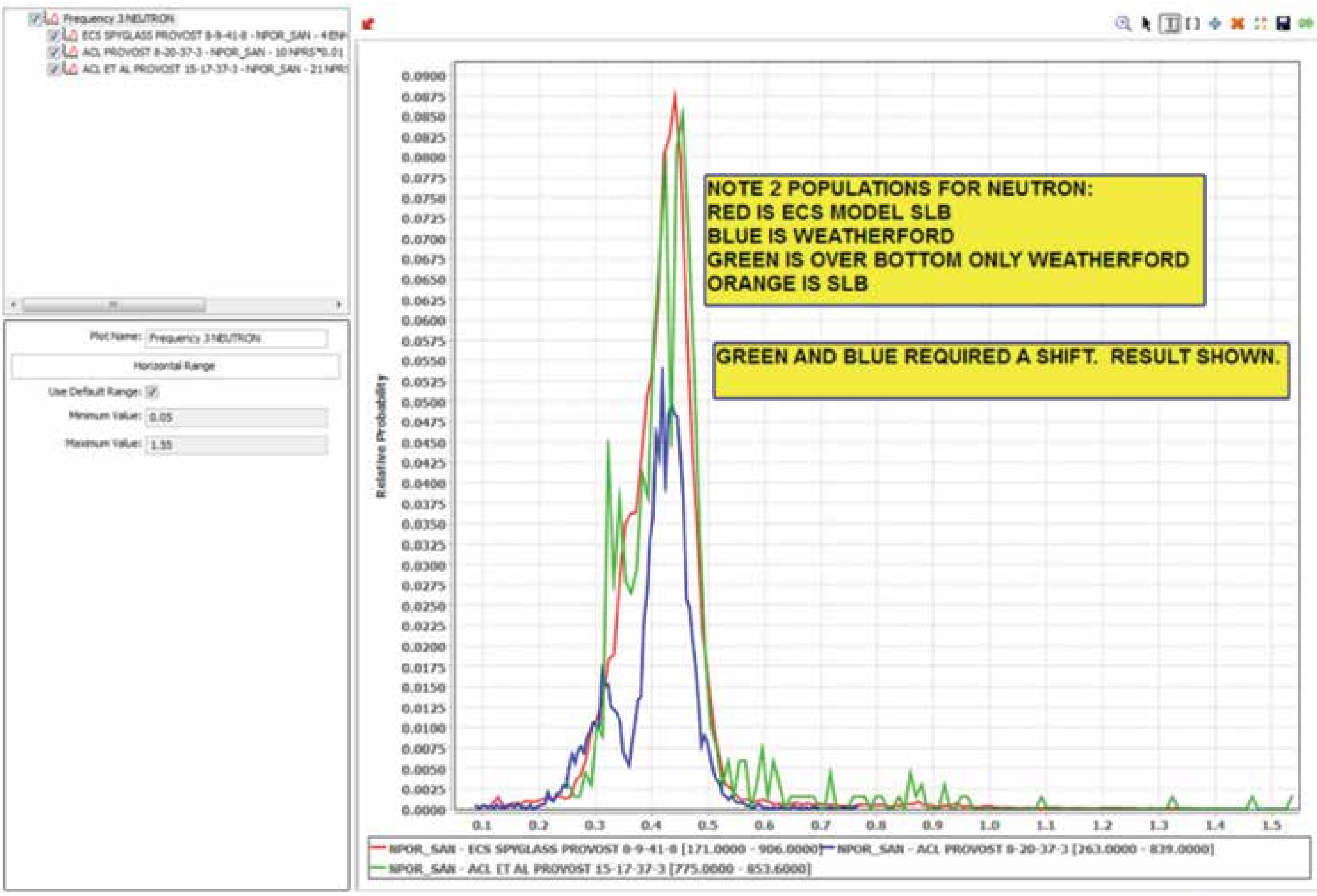


Figure 22: E5 Neutron after shift of green and blue (Weatherford to SLB)

Summary

In Part One, we walked through the steps for the results of the calculations of the mineral groups and their normalization process to convert the mineral groups to individual minerals. There are many parameters available to adjust, if the resulting minerals do not match quantitative mineral measurements.

Along the way, we calculated grain density, total porosity, permeability and CEC.

In Part Two, we've shown some examples of using the interpretation results to determine if there are zones in addition to the target zones that may be perforated.

We used magnetic resonance to determine the free porosity to make this water-free determination. If the formation is fractured, the water in the small capillaries of the effective porosity can also produce water, so we determine what effective porosity is, using the cation exchange capacity.

In the next instalment we will show both the results with core and the need to adjust results based on core. See you then.

References

1) Eslinger, E., and R. V. Everett, 2012, 'Petrophysics in gas shales', in J. A. Breyer, ed., Shale reservoirs—Giant resources for the 21st century: AAPG Memoir 97, p. 419–451.

2) Eslinger, E., and Boyle, F., 'Building a Multi-Well Model for Partitioning Spectroscopy Log Elements into Minerals Using Core Mineralogy for Calibration', SPWLA 54thAnnual Logging Symposium, June 22-26, 20131

3) M. M. Herron, SPE, D. L. Johnson and L. M. Schwartz, Schlumberger-Doll Research, 'A Robust Permeability Estimator for Siliciclastics', SPE 49301, 1998 SPE Annual Technical Conference and Exhibition held in New Orleans, Louisiana, 27–30 September 1968

4) Susan L. Herron and Michael M. Herron, 'APPLICATION OF NUCLEAR SPECTROSCOPY LOGS TO THE DERIVATION OF FORMATION MATRIX DENSITY' Paper JJ Presented at the 41st Annual Logging Symposium of the Society of Professional Well Log Analysts, June 4-7, 2000, Dallas, Texas.

5) Clavier, C., Coates, G., Dumanoir, J., 'Theoretical and Experimental Basis for the Dual-Water Model for interpretation of Shaly Sands', SPE Journal Vol 24 #2, April 1984.

About the Authort

Robert (Bob) Everett is the sole owner of Robert V Everett Petrophysics Inc. Bob works from his office in Merville, BC (Vancouver Island). He also works as a consultant for Eric Geoscience, using probabilistic interpretation methods. When living in Austin, Bob worked at the University of Texas at Austin on a Gas Research Institute tight gas project and consulted for UnoCal, Z & S Consultants and Baker Hughes in Houston.

After graduating from UBC in Mechanical Engineering in 1964, he worked 17 years with Schlumberger of Canada, 4 years at Schlumberger Doll Research (SDR) and 6 years with Schlumberger Well Services in New Orleans and Austin. While at SDR, he was a team leader tasked to build a better interpretation method than the prevalent volume of shale models that were common in the 1970s. The result of the work was the nuclear spectroscopy methods. Now tools such as the ECS, LithoScanner, FLEx and GEM provide element measurements, enabling the use of nuclear spectroscopy interpretation methods.

The methods can be applied to shales, clastics and carbonates. When combined with nuclear magnetic resonance, the combination of nuclear spectroscopy and nuclear magnetic resonance can be applied anywhere in the world to coax signals out of the rocks.

Appendix

Glossary

- Names used for output & description
  Alphabetical list & description

1. CAL: calcite abundance by weight.
2. CAL_DOLO: calcite plus dolomite abundance by weight.
3. CEC: cation exchange capacity summed from the CEC of each clay * abundance of each clay type.

4. CHL: chlorite abundance by weight.
5. DOL: abundance of dolomite
6. DWAL_WALK2_P: dry weight aluminum that was input to the program. This input may have been a predicted or measured value but the output is always with a '_P'.
7. DWCA_WALK2_P: dry weight calcium that was input to the program. This input may have been a predicted or measured value but the output is always with a '_P'.
8. DWFE_MINUS_14WAL: dry weight iron minus 14%*aluminum that was input to the program. This input may have been a predicted or measured value but the output is always with a '_P'.
9. DWFE_WALK2_P: dry weight iron that was input to the program. This input may have been a predicted or measured value but the output is always with a '_P'.
10. DWK_WALK2_P: dry weight potassium that was input to the program. This input may have been a predicted or measured value but the output is always with a '_P'.
11. DWSI_WALK2_P: dry weight silicon that was input to the program. This input may have been a predicted or measured value but the output is always with a '_P'.
12. DWSU_WALK2_P: dry weight sulphur that was input to the program. This input may have been a predicted or measured value but the output is always with a '_P'.
13. DWTI_WALK2_P: dry weight titanium that was input to the program. This input may have been a predicted or measured value but the output is always with a '_P'.
14. FELD: abundance of kspar plus plagioclase
15. GAS_FLAG: indicates that the neutron (PHIN_MAN) is less than the density porosity (PHID_MAD).
16. HFK_P: potassium either predicted or measured that was input to the spreadsheet program. Identical to DWK_WALK2_P.
17. ILL: illite abundance by weight%
18. KAO: Kaolinite abundance by weight%.
19. KAO_ILL: kaolinite plus illite abundance by weight% for plotting.
20. KAO_ILL_CHL: kaolinite plus illite plus chlorite abundance by weight%, for plotting.
21. KAO_ILL_CHL_MUSC: kaolinite plus illite plus chlorite plus muscovite abundance by weight% for plotting.
22. KAO_ILL_CHL_SME: kaolinite plus illite plus chlorite plus smectite abundance by weight% for plotting.
23. KSPAR: potassium feldspar abundance by weight%.
24. M_NPHI: modeled neutron reconstruction, based on a calculated neutron matrix based on a thermal neutron response for each mineral. The fluid response is based on the invaded zone of investigation of the thermal neutron with whatever fluids are in that zone. Its use is intended to be a quality control factor for the minerals. If the modeled and the measured neutron agree, then the minerals are feasible.
25. MUSCOVITE: the sum of the muscovite from the 'total clay plus muscovite' Herron calculation minus the illite, kaolinite, smectite and chlorite.
26. PERM_ECS: permeability derived from mineral surface area and total porosity, TPOR.
27. PHID_MAD: matrix-adjusted density porosity, where the matrix density is determined by elements.
28. PHIE: effective porosity, = TPOR*(1-SWB)
29. PHIN_MAN: matrix-adjusted neutron porosity, where the matrix is determined from elements.
30. PLAG: plagioclase, where the assumption is 60% Na-spars and 40% Ca-spar ~ oligoclase.
31. QTZ_KSP: abundance in wt. % of quartz plus Kspar for plotting.
32. QUARTZ: abundance in wt.% of quartz
33. RATIO_PEF_CAL_DOLO: ratio of calcite to dolomite from the Pef curve where Pef of 3 is dolomite and Pef of 5.5 is calcite.
34. RATIO_PEF_DOL_CAL: ratio of dolomite to calcite from the Pef curve where Pef of 3 is dolomite and Pef of 5.5 is calcite.
35. RHOG_ECS: grain density of minerals, including kerogen when < 3.5%, in g/c3, calculated from elements.
36. RHOG_KER_ECS: grain density of minerals, with kerogen above 1.5%, in g/c3, for calculating porosity_GRI. Calculated from elements and kerogen.
37. RO: wet resistivity.
38. RUTILE: TiO_2 from input titanium.
39. RW_SP_USED: formation water resistivity used in calculations of Sw_Archie, Ro and Swt_ECS.
40. SMEC: abundance of smectite in wt. %.
41. TOC_USED: selected TOC equation for calculations of adsorbed gas.

42. TPOR: total porosity calculated from the density log, using 1.0 for fluid and RHOG_ECS [FROM ELEMENTS with Ker<3.5%]
43. WANH: abundance of anhydrite, derived from sulphur.
44. WCAR_WANH: abundance of carbonate minus anhydrite for plotting.
45. WCARB_ECS: abundance of carbonate.
46. WCARB_MUSC_WCLAY: abundance of carbonate plus muscovite plus clay for plotting.
47. WCARB_PLUS_KAO: abundance of carbonate plus kaolinite for plotting.
48. WCARB_PLUS_KAO_ILL: abundance of carbonate plus kaolinite plus illite for plotting.
49. WCARB_PLUS_KAO_ILL_CHL: abundance of carbonate plus kaolinite plus illite plus chlorite for plotting.
50. WCARB_PLUS_KAO_ILL_CHL_SME: abundance of carbonate plus kaolinite plus illite plus chlorite plus smectite for plotting.
51. WCLAY_CM: weight fraction of clay + muscovite using the Herron clay-mica model.
52. WCLAY_HF: weight fraction of clay + muscovite using the Herron high feldspar model.
53. WCLAY_LF: weight fraction of clay + muscovite using the Herron low feldspar model. .
54. WMIN: used to estimate the fraction of each clay type from the separation of the neutron density porosity. Nominally water in the minerals WMIN = (NPHI_IN – DPHI_2.71)/ (1-DPHI_2.71)*2.71 Dimensionally correct calculation is: WMIN = (NPHI_IN – DPHI_2.71)/ (1-DPHI_2.71)*1/2.71
55. WQF: abundance of quartz plus plagioclase plus kspar.
56. WQFM: abundance of quartz plus plagioclase plus kspar plus muscovite.

UPCOMING EVENTS

Introduction to Log Analysis
March 9 – 11, 2015 Calgary, Alberta
Cost: $2195 + GST
Instructor: Gary Batcheller
www.progress-seminars.com/seminar/443/introduction-to-log-analysis/mar-9-15/

Hugh Reid - Practical DST Interpretation Course
March 23-26, October 5-8, 2015

Cement Log Evaluation – In High Angle to Horizontal Wells
March 12 – 13, 2015 Calgary, AB
Cost: $1895 + GST
Instructor: Gary Batcheller
www.progress-seminars.com/seminar/444/cement-log-evaluation-in-high-angle-to-horizontal-wells/mar-12-15/

Practical Quantitative Log Analysis
April 6 – 8, 2015
Cost: $1950.00 + GST
Instructor: E. R. (Ross) Crain, P. Eng.
www.spec2000.net\00-coursedates.htm

Analysis in Unconventional Reservoirs
April 9, 2015
Cost: $795 + GST
Instructor: E. R. (Ross) Crain, P. Eng.
www.spec2000.net\00-coursedates.htm

Hugh Reid - 16 ways to Identify Bypassed Pay from DST Data
April 9-10, 2015

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April 10, 2015
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