

# **Optimizing Placement of Laterals and Fracture Stages Using Downhole Geochemical Logging – an Eagle Ford Case Study\***

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## **Abstract**

This case study shows how Downhole Geochemical Logging was used to create a granular hydrocarbon profile throughout the well. This enabled identification of optimum selection for placement of the horizontal well. Additionally, cutting analysis from the lateral well enabled identification of lateral sweet spots containing higher porosity and hydrocarbon intensity as opposed to areas with limited porosity and lower hydrocarbon content. The data was also able to aid the client in determining the optimum number of fracture stages required for the lateral resulting in a savings of approximately \$600,000 while maintaining similar production.

A variety of logging technologies provide information during drilling as to the presence of hydrocarbons. However, these logging technologies do not measure hydrocarbons directly, but rather measure hydrocarbon proxies and infer hydrocarbon presence and phase based on this data. These technologies, while sophisticated can lack specificity and sensitivity when trying to accurately identify hydrocarbons.

Additionally, some new technologies can monitor hydrocarbons from n-C1 (methane) to n-C8 (octane) and expand the scope of hydrocarbon detection. These new technologies can clearly detect gas range organics and can infer light oils and condensates. However, all of these technologies lack the ability to measure the heart of the oil or liquid hydrocarbon fingerprint of n-C7 (heptane) to n-C15 (pentadecane). Thus, accurately characterizing and differentiating between multiple oil fingerprints becomes difficult, if not impossible, for current technologies. As such, these limitations negatively affect the ability of companies to properly assess and evaluate plays like the Eagle Ford that have numerous stacked liquid pays.

However, advances in well logging technology now provide the ability to analyze downhole cutting samples to directly characterize the composition of hydrocarbons vertically through the prospective section. This provides the unique ability to look at a broad compound range from C2 to C20, which is significantly more expansive than the limited traditional ranges of C1-C5 or C1-C8 of most well gas logging techniques. The result is the ability to not only characterize gas and condensate range hydrocarbons, but also characterization multiple liquid or oil phase hydrocarbons contained in the stratigraphic intervals.

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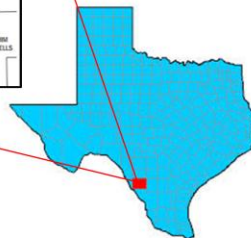
# Optimizing Placement of Laterals and Fracture Stages Using Downhole Geochemical Logging – an Eagle Ford Case Study



by Rick Schrynemeeckers  
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## Conventional Hydrocarbon Analyses



Geologic Column  
South Texas

CRETACEOUS	Gulfian	Escondido	
		Olmos	
		San Miguel	
		Anacacho	
		Austin Chalk	
	Comanchean	<b>Eagle Ford</b>	
		Buda	
		Del Rio	
		Georgetown	
		Edwards	Stuart City
		Glen Rose	
		<b>Pearsall</b>	
		Sligo	
	Sabbulian	Hosston	

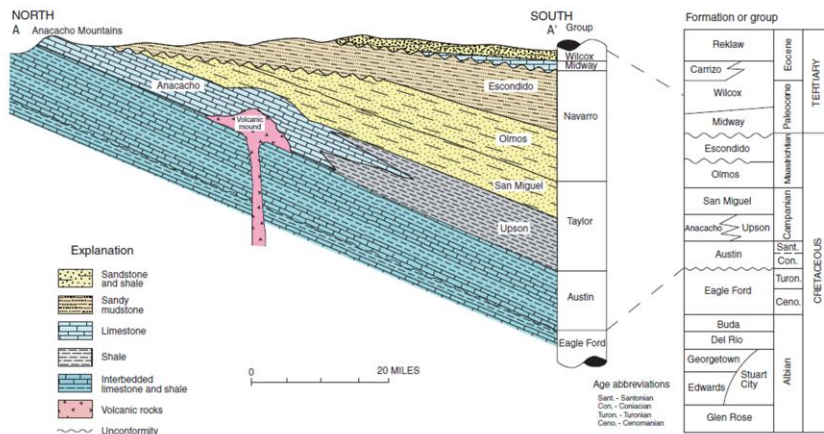
The Maverick Basin in Dimmit County

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Presenter's notes: Study took place in the Eagle Ford in the Maverick Basin in Dimmit County. The study included two wells. Downhole Geochemical Logging (DGL) samples were taken from both wells. Both vertical and lateral cutting samples were collected from the first well and only vertical cutting samples were tested on the second well.

## Cross Section of the Maverick Basin



Diagrammatic northwest-southeast cross section through the Maverick Basin (Condon and Dyman, 2003)

## Downhole Geochemical Logging Analysis



- Cuttings are collected in glass jars, directly from the shaker table during drilling
- Mud blanks are also collected as well
- Analyses normally done in 2 weeks

**1,000 time more sensitive than traditional methods**

### **Focuses on hydrocarbon fluids in various zones**

- Measures from the  $C_2$  to  $C_{20}$  carbon range
- Easily differentiates between multiple phases
- Identifies reservoir compartmentalization
- Identify by-passed pays



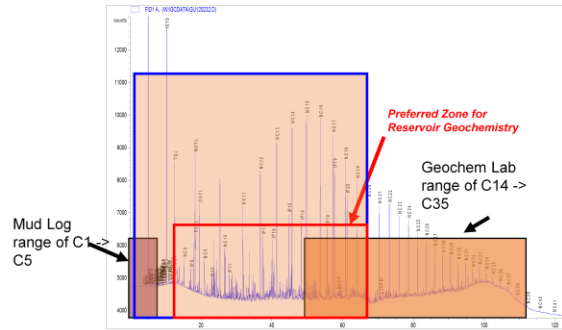
Does this work with all drilling muds?

> **No – Not with ALL Oil-based muds**



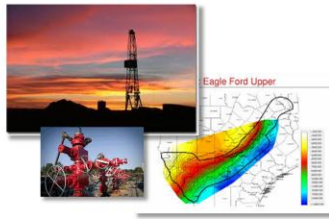
Presenter's notes: One of the most common tools used to understand reservoirs is conventional core analysis. Scientists look at various rock properties like porosity, permeability, variability across a core, grain density, and fluid saturation to better understand how fluids (i.e. oil) will flow through and from a reservoir. This is important in attempting to predict well and field productivity. Additionally, core analysis normally takes many months b/c of the backlog of samples in the various labs. DGL can provide you data in just a few weeks, not a few months. Also, how do you know where to take your cores. The Expl VP at SWM recently said at an AAPG symposium in Vancouver that he prefers to wait a little while into the project to determine where is the most strategic area of the field to take cores, because when little is known they can spent a lot of money taking and analyzing cores from the wrong part of the field. However, while all of these are important properties to measure they do not really focus on hydrocarbons. They focus on rock properties to predict how hydrocarbons will flow from the well bore.

## Conventional Hydrocarbon Analyses



Presenter's notes: This shaded blue box shows the coverage range for DGL. Just looking at the box shows the density of compounds covered by the method. DGL technology measures from C2 -> C20, which enables the data to provide HC fingerprints for gas, condensates, and oils. Notice I did not say that DGL estimates or guesses at the HC phase as other methods do. DGL provides the ability to not only differentiate between gas, condensates, and oils, but it allows you to also differentiate between several different oil signatures, which are not possible with other technologies. Also, DGL measures down to the PPB range which is a 1,000 times lower than other technologies. This allows the method to measure seals down to the molecular level that no other method can do. Finally, and probably most importantly, since the AGI method measures many of the Isoprenoids between C10 and C20. This technology provides the ability to assess compartmentalization in the way reservoir geochemists do. While reservoir geochemists look at the entire HC to understand the HC phase (i.e. gas, condensate, or oil), assess alterations effects, and assess similarity between various HC fingerprints, they primarily work with the C10 to C22 range for evaluating compartmentalization for several reasons.

# Downhole Geochemical Logging in the First Vertical Eagle Ford Well

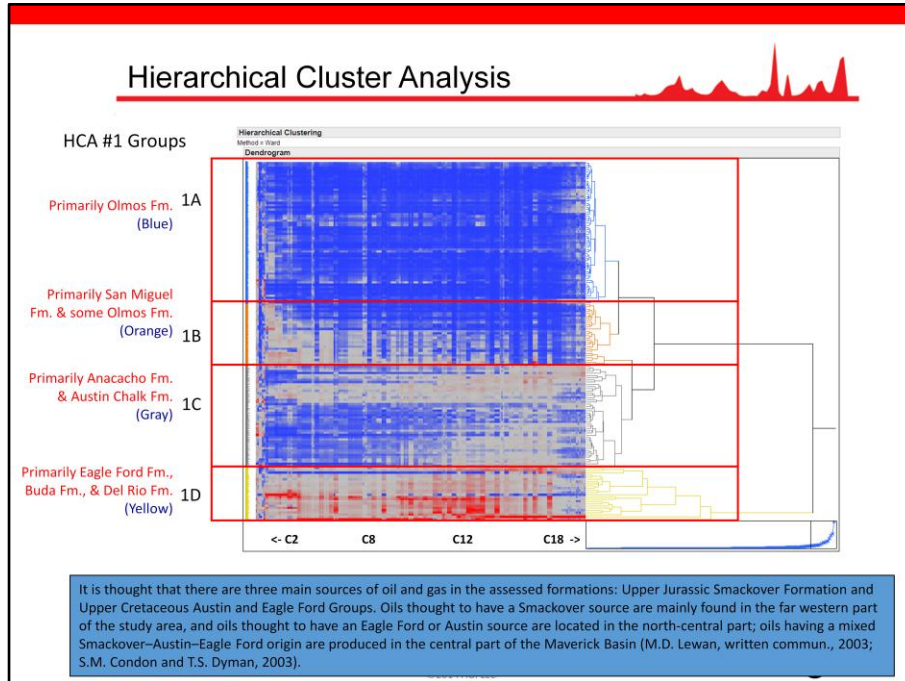


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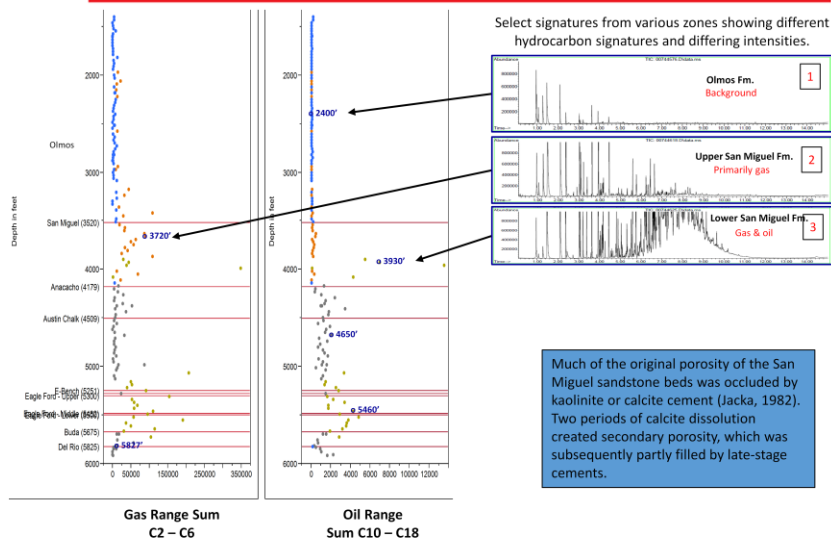
Presenter's notes: 3-D hydrocarbon detection contains a horizontal component and a vertical component. I will start with a brief overview of the Horizontal component.

# Hierarchical Cluster Analysis



Presenter's notes: This chart shows the output from a hierarchical cluster analysis (HCA #1) using all of the samples (shown here in individual rows of data). The Y-axis is simply each individual cutting sample and the x-axis is the carbon range from C2 – C20. Red indicates a positive HC response at that range and blue indicates a negative or no response at that carbon range. Therefore, this process groups the samples together based on their similar geochemical signatures. Therefore, the program does not look at what depth, lithology, or stratigraphy and samples were taken from. It simply clusters samples based on similar signatures. This data set identified four main groups which are shown with the red rectangles and which are numbered 1-4 on the far left. What is interesting about the data is when you begin to look at what samples comprising these four groups you find a very interesting pattern. You find most of the Olmos samples fall in Group 1A. Most of the samples from the San Miguel Fm fall collectively in Group 1B, the Group 1C samples are primarily comprised of samples from the Anacacho & Austin Chalk, while Group 1D is comprised of samples taken from the deeper Eagle Ford, Buda, & Del Rio Fms. What is interesting about this breakdown is that the cluster analysis correlates to published oil & gas sources for the Maverick Basin. Published data ascribes the Eagle Ford as a known HC source, which most likely charges the Eagle Ford, Buda, & Del Rio and the Austin Chalk as a source for the Austin Chalk & the overlying Anacacho. The San Miguel appears to be a third and distinct HC signal while the Olmos is a background signal.

## Depth Profile with Hydrocarbon Fingerprints



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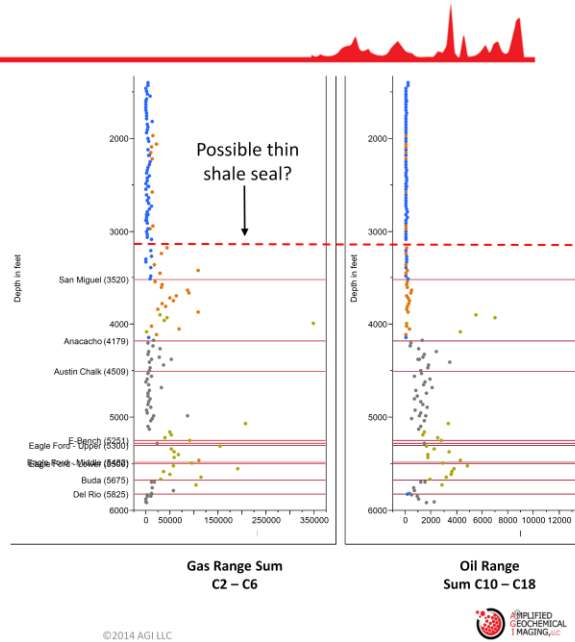
Presenter's notes: This slide includes the same two depth profile charts, with the addition of some select TIC signatures (total ion chromatograms) for various horizons. Of particular note is the change in the TIC patterns as the well was drilled and the apparent increase/decrease in response from the samples. One of the first things that strike you is that in the Lower San Miguel Fm you have a gas/oil signature. As you move from the bottom TIC to the middle TIC, you notice a start similarity. The gas signature in the Upper San Miguel looks just like the HC in the Lower San Miguel without the liquid portion. It is almost as if you have a gas cap over the oil formation. Then as you look into the Olmos Fm the HC signature looks like a reduced version or background version of the Upper San Miguel gas signature. The transition between the three HC zones is intriguing. Beneath this (between 3870' and 4110') is a different signature with more oil-like characteristics appears. These samples are all within the San Miguel Fm. and perhaps a facies change or gradation towards the bottom of this formation may explain the change in the geochemical response. Note the intensity of the oil signature in the Lower San Miguel. This is the highest oil intensity in the entire well, including the Eagle Ford. This prolific liquid rich area could be missed if people were only focused on the Eagle Ford and drilled right through to the Eagle Ford. As we mentioned in the previous slide the cluster analysis separated the San Miguel samples as a unique group or cluster that was noticeably different than the Austin Chalk production and the Eagle Ford generation. However, the San Miguel is not known as a potential source; so, we do not really have an explanation for this unique HC signature in the San Miguel Fm. We also know that, by definition, HCs must have a space to reside. Therefore, the more HCs detected, typically, the greater porosity. Therefore, the greater porosity inferred here by the DGL data is supported by the well logs and the data reported by Jacka in 1982.

## Depth Profile

### Key Zones of Interest

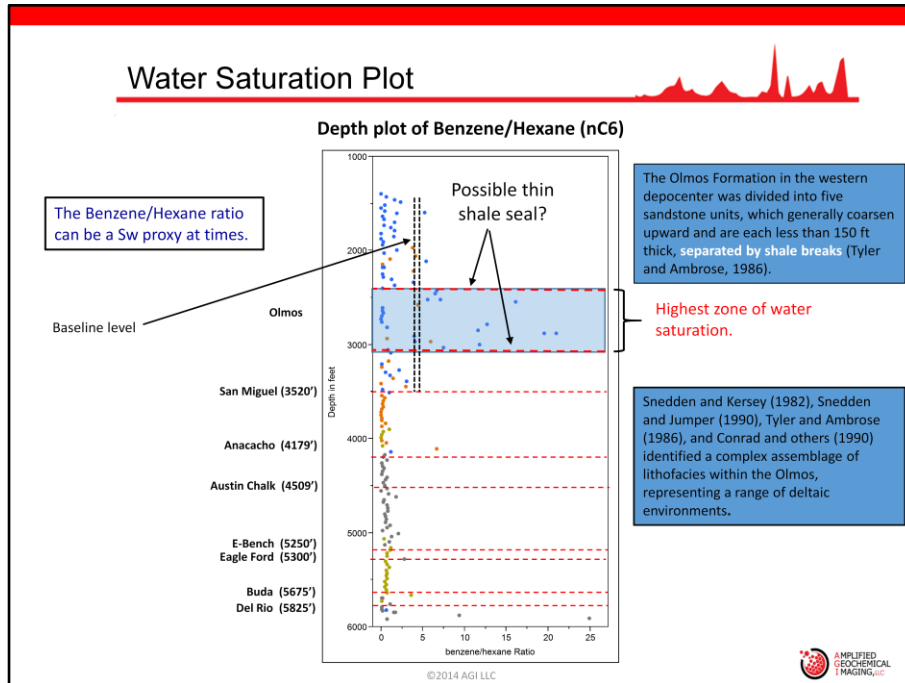
There appears to be a strong gas-like section in the San Miguel Fm. with a more oil like composition between 3870' and 4110'. These data also suggest the bottom of the Olmos is not an effective seal as several samples above the San Miguel contain an increased gas response.

The Olmos Formation in the western depocenter was divided into five sandstone units, which generally coarsen upward and are each less than 150 ft thick, separated by shale breaks (Tyler and Ambrose, 1986).



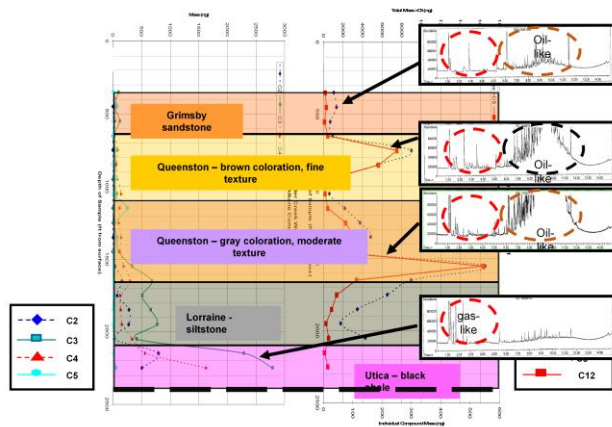
Presenter's notes: As we drill a little deeper into the data, notice the gas increase starts just above the San Miguel Fm. around 3100'. Therefore, this would imply that the gas in the San Miguel is also in the Olmos and there is no seal between the two. Yet why does the gas in the San Miguel begin to substantially increase at 3100'? One explanation may be due to a thin seal in the Olmos. Tyler & Ambrose reports that the Olmos is divided into multiple sections and whether that number is 3 or 5 depends in what portion of the field you are in. However, the point is, there are thin shale seals interlaced within the Olmos. So, the question can be raised to we have a small undetectable seal at about 3100'?

# Water Saturation Plot



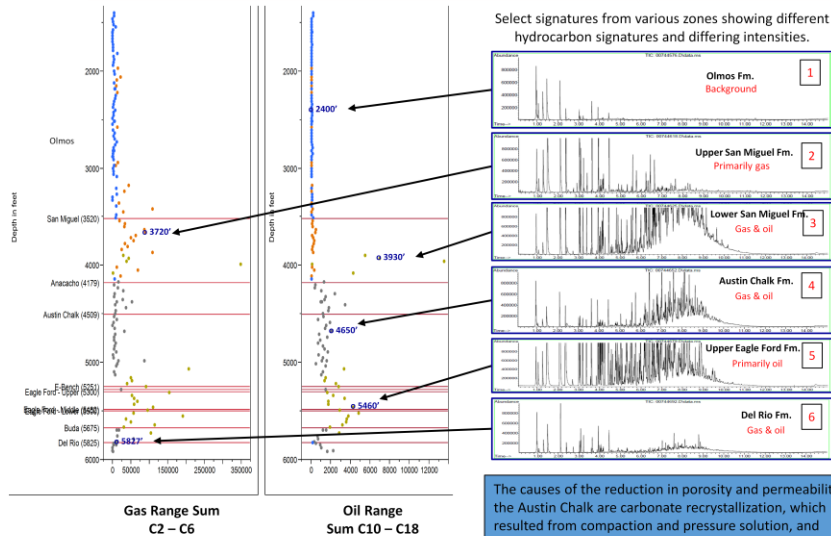
Presenter's notes: This graph plots the ratio of Benzene over Hexane (nC6) versus depth. The premise is that in a hydrocarbon zone the ratio of Benzene to hexane is roughly 1.0. However, in water-saturated zones, benzene preferentially dissolves in the water because benzene is very water-soluble because it is a polar compound while hexane, a nonpolar compound, does not readily dissolve in water. Thus, the benzene concentration increases substantially over the hexane concentration. We can see from the plot that Benzene/Hexane ratio is consistently low throughout the hydrocarbon bearing zones. However, we see in the Olmos a dramatic increase in the ratio. There appears to be a background ratio between 2 – 4 which then dramatically increases between 2400' – 3100'. So, why is this? From literature, we know that the Olmos in this area is deltaic sandy shale as reported by Snedden others. So, we would expect higher water saturation in this zone, which we see between 2400'-3100'. Therefore, this begs the question does the geochemical data indicate small thin sealing shale sections at 2400' and 3100'. The gas plot and the Sw proxy might indicate that.

## Butler Creek #1 – Utica Well



Presenter's notes: As a brief aside I want to take a minute and talk about this Utica well example b/c it shows a different form of compartmentalization or seal. The section between 350 – 550 ft is the Lower Silurian. You see a HC fingerprint at 400 ft shows a definite oil fingerprint. The fact that the HC fingerprint comes back down to baseline at about 600 ft is interesting as that is the transition to another stratigraphic section. This may be indicative of a possible seal, but it is impossible to tell since samples were only collected every 100 ft. If we had it to do all over again, we would have had much closer spacing. Given the extreme sensitivity of our method, it is unlikely that this HC show would show up on a well log. Therefore, you have to ask if this is indicative of a missed pay or a possible migration pathway. The next section is the Queenston and is a very huge section of about a 1,000 ft. The various Strat columns talk about the Queenston as both a sand and a shale indicating the lithology probably varies from clays to sands. The cutting descriptions tend to support that and actually divide this section into an upper and lower section as seen in the next slide. When you combine the G&G data and the DGI (Downhole Geochemical Imaging) data, you begin to get a clearer picture of what might be occurring. From the stratigraphy & lithology, you appear to have three distinct zones. The DGI data corroborates that. First of all the DGI data shows you have oil in all three zones, which is important. Additionally, even though the later eluting HC are off scale you can see differences in the early eluting HCs when you compare all three oils. That is information you probably would not get in a well log. Well logs would probably miss the oil in the L. Silurian section and it would definitely not tell you that you have three different oils. The fact that these 3 oils are different may indicate potential seals between these section. We cannot tell that for sure because of the wide 100 ft sampling intervals used for this project. Additionally, remember it was noted in the surface survey that on the compound plots of the heavier (i.e. oil) components we saw a distribution at the surface for the delineation of liquids. This downhole section indicates those oil expressions at the surface were most likely coming from either the upper or the lower Queenston formations. Keep in mind not all hydrocarbons are created equal. For example, in the Bakken, oil is produced from both the Bakken formation and the Three Forks formation, but the Bakken has better economics, and is the preferred zone for completion, because it has better oil quality and better pressure. Therefore, downhole testing could be used in situations like the Bakken where you may wish to complete a specific zone, but you might have questions about which formation you are in. The AGI downhole could tell you which formation you are in because of the differences in the oil chemistries. Additionally, the oil chemistry can be used to aid in the identification of stratigraphic intervals in areas where you may not have good well control or where the stratigraphy is uncertain. The chemistry of the hydrocarbon found in the cuttings could identify the stratigraphic interval if you have tested similar intervals in other wells in the field.

## Depth Profile with Hydrocarbon Fingerprints



The causes of the reduction in porosity and permeability in the Austin Chalk are carbonate recrystallization, which resulted from compaction and pressure solution, and crystallization of secondary ferroan calcite as cement (Davis, 1981).

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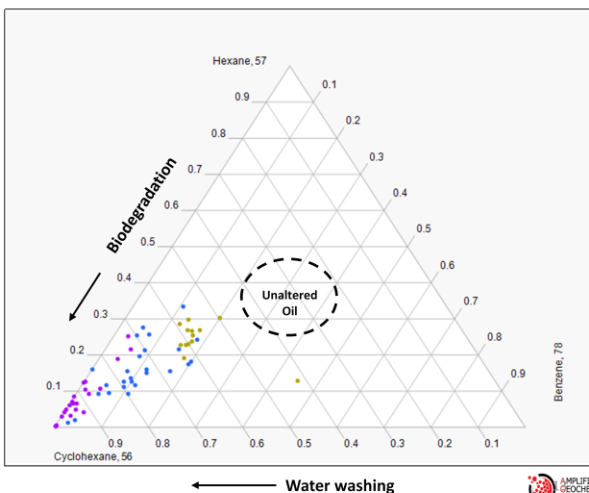
Presenter's notes: As you move into the Anacacho & the Austin Chalk the HC fingerprint changes into a gas/oil signature, which is lower in intensity than both the Lower San Miguel & the Eagle Ford. You can see by the gray dots that this is a distinct HC signature from other formations and is consistent with literature that implies the Austin Chalk is self-sourcing and sources the Anacacho. The cluster analysis indicates that as you enter the Eagle Ford you switch to a different HC signature, which is predominately oil, and the intensity increases dramatically. Then in the Del Rio Fm., you see dramatic decrease in HC intensity and once again switch to a gas/oil signature. So, several HC signatures are observed as you move vertically along the well and the highest accumulations of oil are found in the Lower San Miguel Fm. and the Eagle Ford Fm. respectively.

## Oil Alteration Plot

The geochemistry data seems to indicate a separate source for the San Miguel Fm.

This C6 ternary plot shows that the Eagle Ford samples are more typical of an unaltered oil signature, and there appears to be increased oil alterations (i.e. water washing and/or biodegradation) as you move through the Austin Chalk & San Miguel.

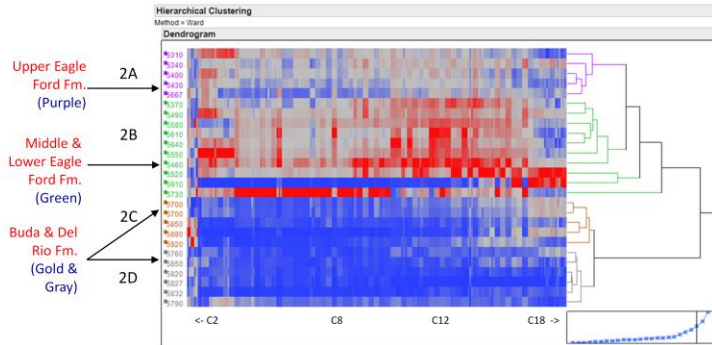
- San Miguel
- Austin Chalk
- Eagle Ford



Presenter's notes: This ternary plot also lends some credence to that assumption. Here we have plotted Benzene, Cyclohexane, & Hexane in an attempt to differentiate the degree of alteration between oil sets. As seen here there is a distinct difference between the geochemical make-up of Eagle Ford Fm. samples and the San Miguel Fm. Oil samples. Therefore, the Star plots and the ternary plot seem to indicate that the San Miguel oil is different from the Eagle Ford and may well be sourced from the Austin Chalk.

## Hierarchical Cluster Analysis for the EF-1

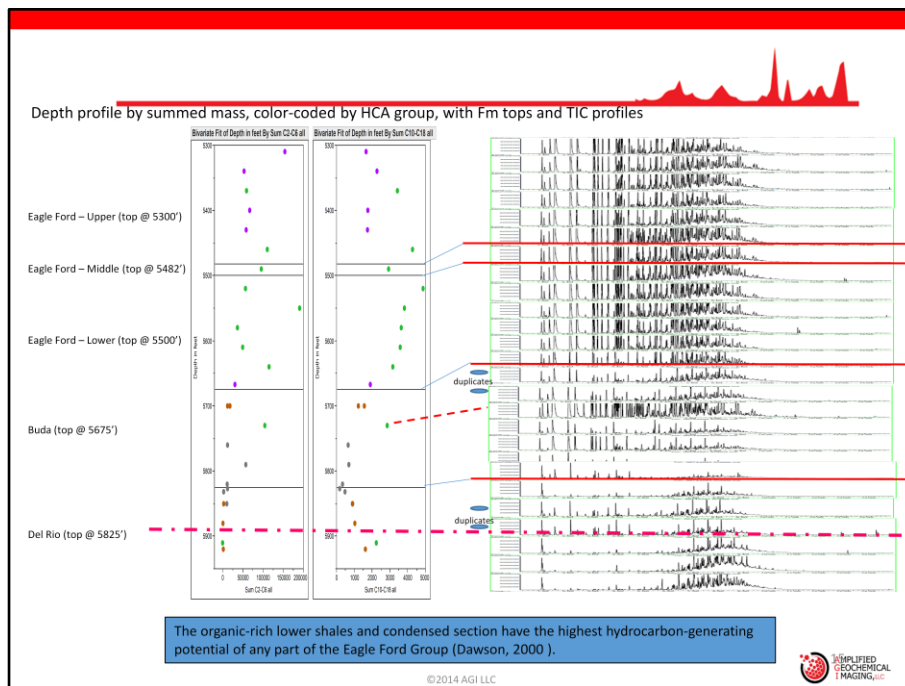
Cluster analysis for the Eagle Ford,  
Buda, & Del Rio formations



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Presenter's notes: This is the output from another HCA processing (HCA 2), which only included the samples from the Eagle Ford, Buda, and Del Rio Fms. In this process, we have identified four groups as shown. The top two groups clearly have a greater mass response.



Presenter's notes: This is a similar depth profile through the Eagle Ford, Buda and Del Rio sections. The TICs to the right indicate a very consistent and high mass response for all of the samples throughout the Eagle Ford (Upper, Middle and Lower). The TICs throughout the Eagle Ford support what was seen in the star plots in that there is a similar hydrocarbon signature throughout the Eagle Ford. Additionally, the data shows the highest HC intensity is found in the Lower Eagle Ford section, which is consistent with literature that says the Lower Eagle Ford has the highest HC generating capacity due to its higher organic content. The TICs in the Buda seem visually different from the Eagle Ford. However, the radar plots in the previous slide indicate the HC's in the Eagle Ford and the Buda are very similar. So, the variance in the HC signatures between the Eagle Ford & the Buda is most likely due to a decrease in intensity. That is confirmed in the depth plot. The Eagle Ford samples have an intensity range from about 2500 ng – 5000 ng while the intensity for the Buda is roughly less than 2500. So, the fact that the star plots indicate a similar HC between the two Fms and that the intensity decreases from the upper Buda to the lower Buda seems to support the concept that the Eagle Ford is charging the Buda. One of the powerful messages from this slide is the fact that the decrease in HC intensity correlates to a decrease in porosity as well. We know from the well logs that the Buda generally has a lower porosity than the Eagle Ford. So the decrease in HC intensity trends with the porosity data. This porosity assertion is supported by the fact that there is one sample in the Buda at 5730' that clusters with the Eagle Ford samples, shows an increase in intensity, and the TIC pattern is similar to the Eagle Ford section and the well logs indicate this sample point has a higher porosity than the rest of the Buda. Based on this you see the Lower Eagle Ford seems to have the highest porosity of the various Eagle Ford sections. The Upper Del Rio Fm. also has an oil-like signature and is very similar to the Buda. This may indicate that the top of the Del Rio is also being charged by the Eagle Ford. Notice half way through the Del Rio Fm. the HC signature begins to change and the intensity increases. This may indicate that the bottom of the Del Rio may be charged from the underlying Georgetown Fm. What this also indicates is that there does not appear to be any seals between the Upper Eagle Ford down through the Georgetown Fm.

# Downhole Geochemical Logging in the Lateral Eagle Ford Well

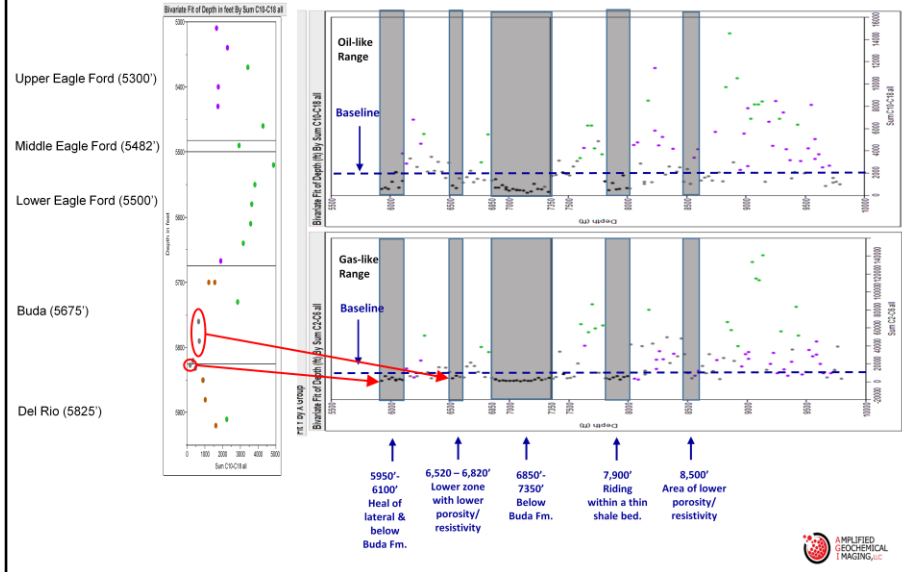


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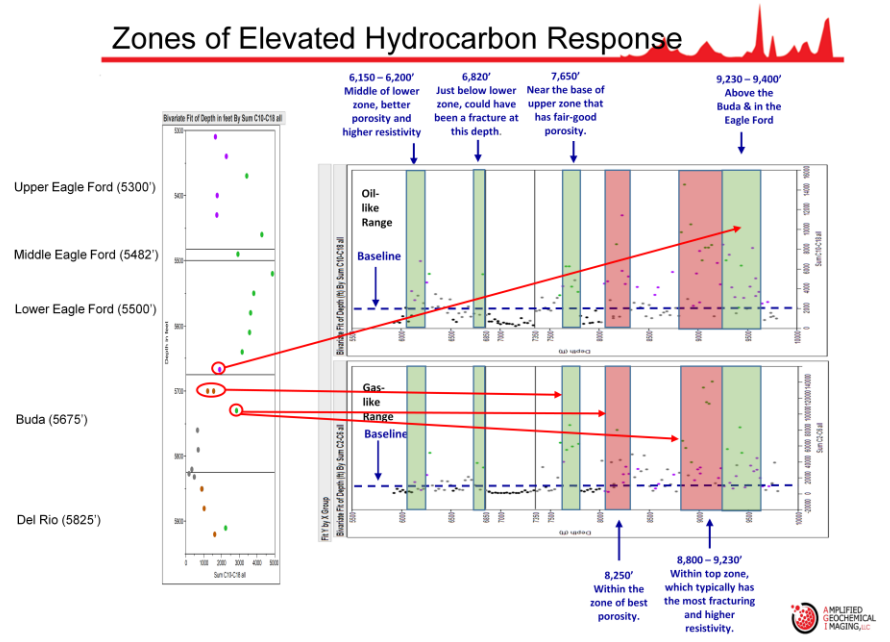
Presenter's notes: 3-D hydrocarbon detection contains a horizontal component and a vertical component. I will start with a brief overview of the Horizontal component.

## Zones of Low Hydrocarbon Response



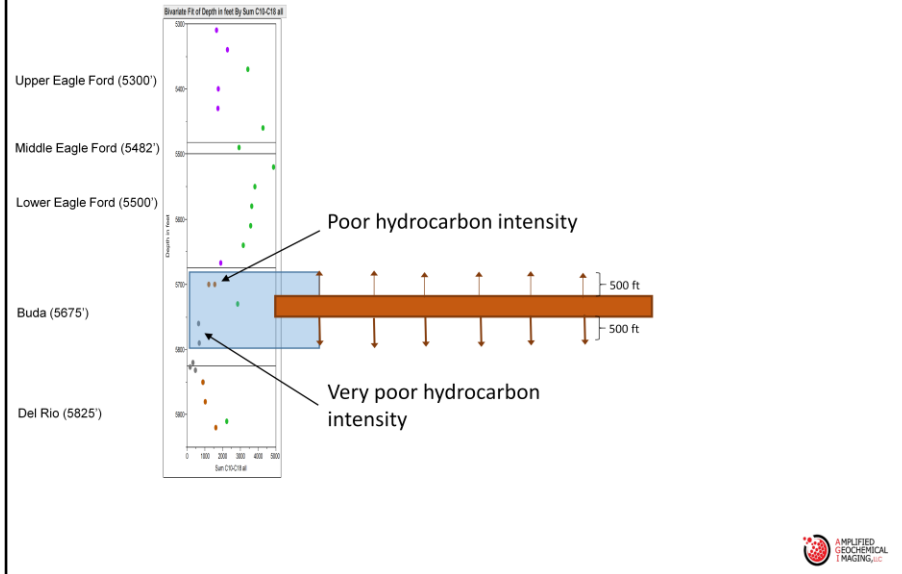
Presenter's notes: The Buda was subdivided into eight different zones based on porosity and resistivity. Three zones appeared to have higher porosity, resistivity, and perhaps more fractures. Oil-like components are plotted on the top scale while gas-like components on the lower scale. The X-axis on each plot is the depth and the Y-axis is the HC intensity. The depth chart has been turned on its side to more easily represent a lateral view of the data. The color of the dots or data points relates to cluster analysis, which will we will not go into except to say the green cluster appears to have the highest degree of intensity and the black has the lowest degree of intensity. We have also added dashed blue line to indicate the approximate HC baseline. The gray shaded areas indicate areas of low HC response according to the DGL data. Conversations with the client indicate correlations between these low DGL readings and well notes. For example, the low DGL concentration from 5950'-6100' related to the heel of the lateral drilling where the drill bit was below the intended Buda fm. The downturn in HC concentration from 6520'-6820' corresponded to a zone of lower porosity/resistivity. Well logs indicate the decrease in HC concentration from 6850'-7350' was due to drilling out of zone beneath the Buda fm. The decrease in HCs at 7900' was likely due to riding in a thin shale bed. Around 8500' the lateral drilling was above the upper target zone within the Buda, which was identified as an area with lower porosity/resistivity, which would explain the decrease in there. Therefore, in each case where there is a significant decrease in HC concentration in the lateral drilling event, the DGL detects that decrease and it relates to geologic anomalies on the formation.

## Zones of Elevated Hydrocarbon Response



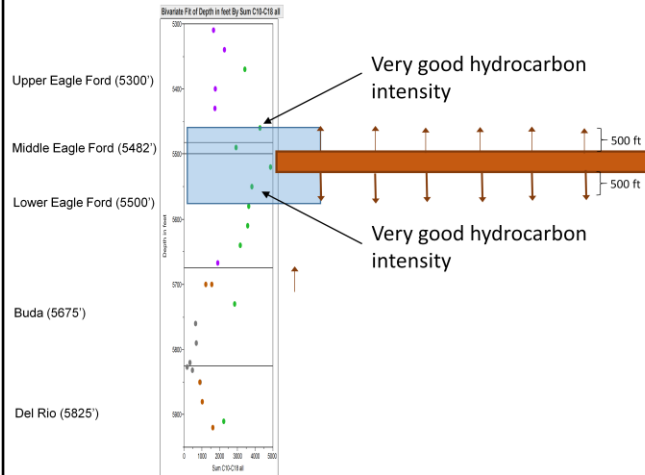
Presenter's notes: As mentioned previously there were three subdivisions within the Buda that had been identified as zones of higher porosity, resistivity, and perhaps more fractures. These three zones were middle of the lower zone, the base of the upper zone, and the top zone. As seen in the plot above, the increases in HC concentrations from the DGL plot tracked well with these known zones of enhancement. For example, a kick in the oil components is seen between 6150'-6200' in the middle of the lower zone. It was believed the HC kick at 6820' coincided with a small naturally occurring fracture. At 7650' & 8250' the drill in the upper zone which was known to have better porosity & resistivity. At 8800'-9230' they reach the top zone which typically has the most fracturing and highest resistivity. The red shading shows that these two sections, 8250' & 8800' are by far the most prolific HC bearing zones in the lateral well and stand-out in terms of HC concentration. In addition, the final section between 9230'-9400' the lateral went out of the Buda and into the Lower Eagle Ford, which we know from the vertical data, was the second most HC prolific section of the well. It is also very interesting to note that besides the 50' section at 6150' there are no strong HC responses in the lateral until you get to 7650'. So, this may indicate, at least in this well that fractured before 7650' may not be economically advantageous.

## Poor Lateral Placement



Presenter's notes: This slide shows the approximate location of the lateral well in the Buda formation. The wide brown section represents the lateral and the brown arrows indicate possible fracture stages at 500 ft intervals. You can see the hydrocarbon (HC) profile on the left. You can also see that the client attempted to locate the lateral in the sweet spot (i.e. highest porosity and highest HC potential) of the Buda. The blue shaded area represents the possible drainage area (i.e. 500 ft above and below the lateral) of the lateral. You can see that the drainage area encompasses a very poor HC intensity zone, both above and below the lateral. The result is reduced production from this well.

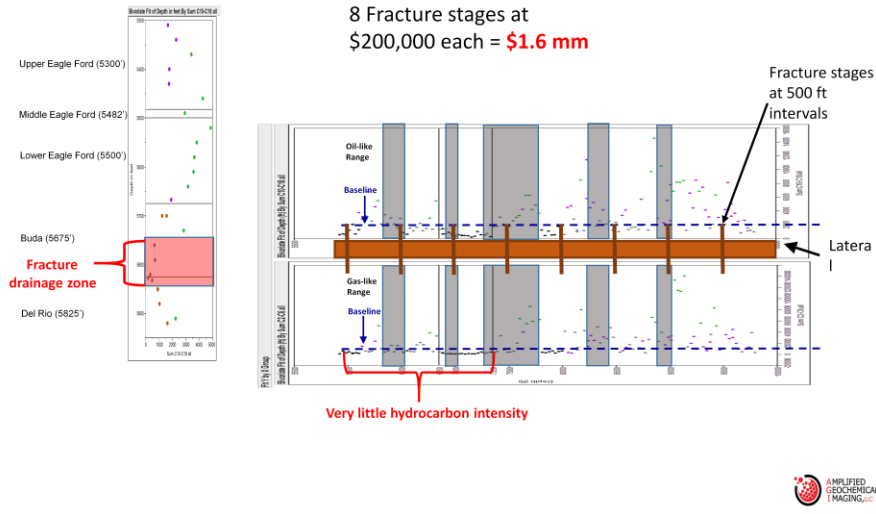
## Excellent Lateral Placement



Presenter's notes: This diagram illustrates if the lateral had been placed higher in the well in the Lower Eagle Ford Fm. You can quickly see the drainage area indicated by the blue shaded area incorporates a much more HC rich zone and an area of much higher porosity. Thus, for the same amount of completion investment, the well should gain a substantial increase in production if the DGL vertical data is used to aid in the selection of the lateral placement.

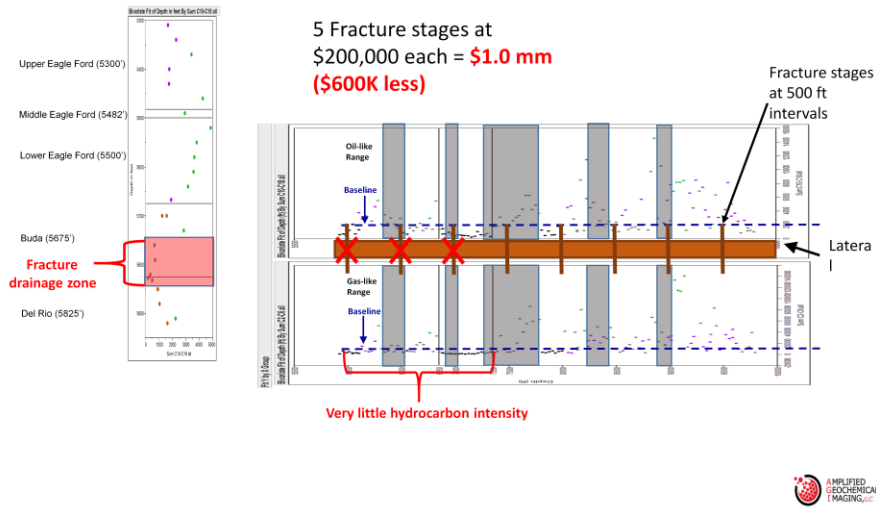
## Optimizing Fracturing Stages

8 Fracture stages at  
\$200,000 each = **\$1.6 mm**



Presenter's notes: Once again, this slide shows the HC intensities in the lateral section. The vertical brown lines represent the possible location of fracture stages spaced every 500 ft. At a cost of \$200,000 per fracture stag, the cost to fracture eight stages in this well would be \$1.6 mm. This slide shows what many companies have done over the last few years or continue to do, and that is place their fractures equidistance along the well fracture with the same number of fractures and the same spacing from well to well.

## Optimizing Fracturing Stages



Presenter's notes: Once again, this slide shows the hydrocarbon intensities in the lateral section. The vertical brown lines represent the possible location of fracture stages spaced every 500 ft. However, the previous data showed that there was little or no hydrocarbon richness and porosity in the first 1500 ft of this lateral section. Therefore, there is little production benefit in placing fractures from 6000 ft – 7500 ft. Eliminating those first three fractures would result in a \$600,000 saving with probable little impact on production.



## Downhole Geochemical Logging in the **Second Vertical** Eagle Ford Well



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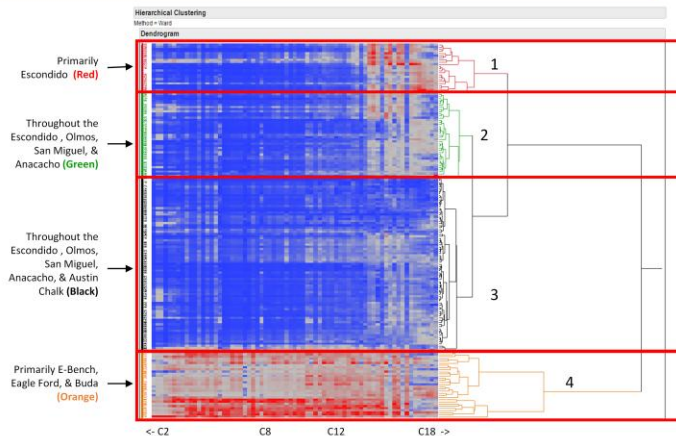


Presenter's notes: 3-D hydrocarbon detection contains a horizontal component and a vertical component. I will start with a brief overview of the Horizontal component.

# Hierarchical Cluster Analysis

## Hierarchical Cluster Analysis #1

Four primary groups have been identified through HCA processing (1, 2, 3 and 4), and they've been color coded as red, green, black and orange, respectively.



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Presenter's notes: This chart shows the output from a hierarchical cluster analysis (HCA #1) using all of the samples (shown here in individual rows of data). This process groups the samples together based on their geochemical similarities, and from this process, we have identified four main groups which are shown with the red rectangles and which are numbered 1-4 on the far left. The dendrogram structure on the far right of this chart shows how the samples are related to each other, and from this structure, it is clear that Group #4 is distinct from the other three groups. The blue-grey-red section of this chart shows the mass response for each compound that has passed signal to noise processing; the compounds are in elution-time order, which means the most volatile compounds are on the left of this chart and the higher molecular weight compounds are to the right. The colors are scaled according to the mass response for that compound and for that sample in terms of standard deviation, either below the mean for all samples (blue), at the mean (grey), or above the mean (red). As seen by the red color indication the Escondido Fm. displayed a liquid hydrocarbon with little light or gas contribution and primarily a back-end liquid portion (C14 - C20), while the hydrocarbons in group 4 (the Eagle Ford) a gas/oil hydrocarbon signature ranging from C2 C20. Groups 2 & 3 were primarily void of hydrocarbons or had low concentrations of hydrocarbons.

## Depth Profile with Hydrocarbon Fingerprints

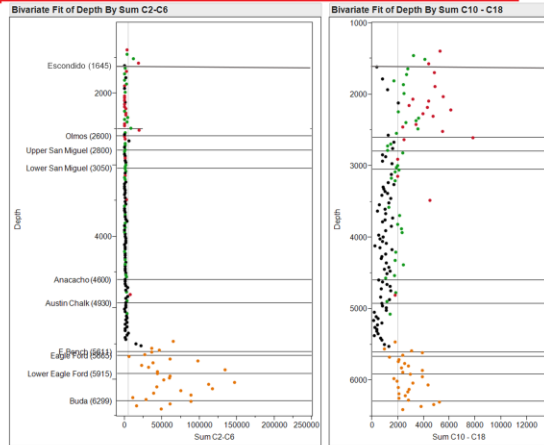
### Key Zones of Interest

Depth profile of samples collected (Y axis) showing their mass response (X axis) for the light compounds (C2-C6) and the high molecular weight compounds (C10-C18), left and right respectively.

There appears to be a strong oil-like section above the Olmos, but with little or no gas component.

The Eagle Ford section contains both light, mid-range and high MW compounds suggesting a high API oil. More focus is warranted on this section.

It is thought that there are three main sources of oil and gas in the assessed formations: Upper Jurassic Smackover Formation and Upper Cretaceous Austin and Eagle Ford Groups. Oils thought to have a Smackover source are mainly found in the far western part of the study area, and oils thought to have an Eagle Ford or Austin source are located in the north-central part; oils having a mixed Smackover-Austin-Eagle Ford origin are produced in the central part of the Maverick Basin (M.D. Lewan, written commun., 2003; S.M. Condon and T.S. Dyman, 2003).

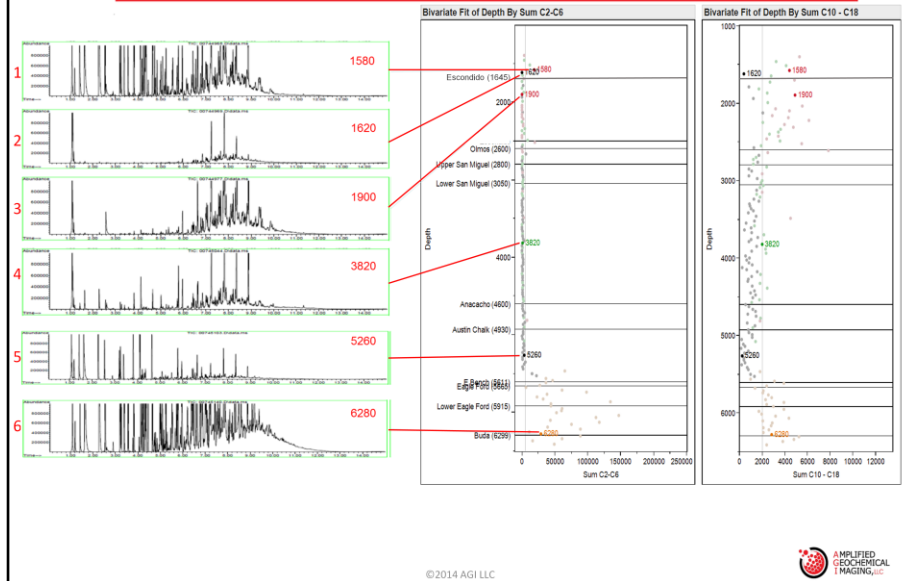


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Presenter's notes: Forget about the coloration of the dots for a minute and just look at the gas and liquid HC profiles for this Well 2. Obviously, we are looking at the summed light compounds (C2-C6) to the left, and the heavy compounds (C10-C18) to the right once again. First, notice the HC pattern in this well is dramatically different from the first well. In well 1, you had a very light gas tinge in the Olmos Fm while here there is no gas, just a liquid signature. In Well 1, we had a strong gas-only response in the Upper San Miguel and a prolific oil-like signature on the Lower San Miguel. Here in Well 2, there is no gas signature at all and only a low concentration oil signature throughout the section. In Well 1 there was a gas/oil signature throughout the Anacacho & the Austin Chalk Fms, while in Well 2 there was no gas and the same oil-only signature seen in the San Miguel. These charts show the same color scheme as was used in the HCA 1, and it shows the mass response. The cluster diagram indicates that the hydrocarbons in the E-Bench, Upper Eagle Ford, Lower Eagle Ford, and Buda Fm. appear to be similar or the same. Literature indicates that the Lower Eagle Ford is the primary hydrocarbon source in the Maverick Basin. If true, it appears that there may be no seal between the Lower Eagle Ford and the adjacent formations (i.e. Upper Eagle Ford, E-Bench, and Buda) and the Lower Eagle Ford may be charging these formations. It is interesting to note, just like in Well 1, the Eagle Ford cluster of hydrocarbons essentially stops at the base of the Austin Chalk. Literature also indicates that the Austin Chalk is a hydrocarbon source as well. If that is true, it appears this Austin Chalk signature is pervasive upward (i.e. cluster group 3) through the Anacacho, San Miguel, and Olmos with no compartmentalized seals between these various formation.

## Depth Profile with Hydrocarbon Fingerprints



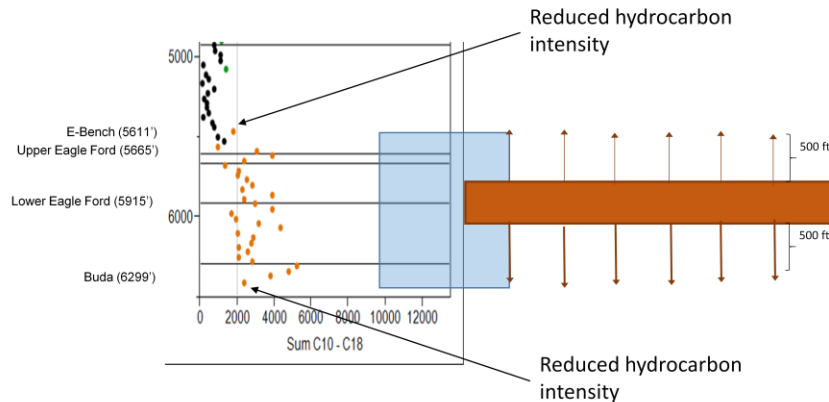
Presenter's notes: This slide includes the two depth profile charts, with the addition of some select TIC signatures (total ion chromatograms) for various horizons. Of particular note is the change in the TIC patterns as the well was drilled and the apparent increase/decrease in response from the samples. The pattern that is evident in TICs 2 and 5 represent a background-like signature, and although the signatures from 1 and 6 appear visually similar, the statistical processing is able to discriminate between these patterns. You can see in this well there is an increase in both light end and heavy end components as you reach the bottom of the Austin Chalk Fm. This is visually apparent from the TIC signature from the sample selected at 6,280'. The HC signature seen at 6,280' is similar in fingerprint and intensity (roughly 4,000 -4,500 ng) to the HC seen in the Eagle Ford Fm in Well 1.

Well 2 was only 2.5 miles away from Well 1, but was 200' structurally lower and closer to the sourcing restricted mini-basin in Dimmit Co.



Presenter's notes: Had you drilled Well 2 first, you would have been lead to believe there was strong oil content in the Escondido and not much else until you got to the Eagle Ford. You may well have by-passed the most prolific zone in the well in the San Miguel Fm. If you looked at Well 1 first, you may have completely missed the liquid portion of HCs in the Escondido. It is dramatic how different the HC profiles can be in two wells in the same field only 2.5 miles apart. This is the perfect example of why you need to develop HC profiles in unconventional shale plays because no two wells are normally the same. You might say all we are interested in is drilling laterals in the Eagle Ford and we do not need new or additional information to do that. In addition, there is some truth to that. But then let's also be honest in saying you may be grossly under-estimating or over-estimating your reserves b/c you don't have an accurate picture of your hydrocarbons in place and there could be some significant by-passed pays, such as the Lower San Miguel in Well 1, that you are leaving in the ground. Additionally, the production from the Eagle Ford may not be the same for both wells. Let us look at that.

## All Lower Eagle Ford Sections Are Not the Same



**The top of the Lower Eagle Ford Fm. is 415 ft deeper in this well.**



Presenter's notes: This slide shows the approximate location of the lateral well in the Lower Eagle Ford formation. The wide brown section represents the lateral and the brown arrows indicate possible fracture stages at 500 ft intervals. You can see the hydrocarbon (HC) profile on the left. The blue shaded area represents the possible drainage area (i.e. 500 ft above and below the lateral) of the lateral. In the first Eagle Ford well, the liquid hydrocarbon intensity ranged 3,000 – 5,000. Here it primarily ranges from 2,000 – 4,000. That's a 20% decrease in hydrocarbon intensity. Additionally, at the ends of the 500 ft drainage zone your have drop-off in hydrocarbon intensity to 2,000 ft. Based on this information I would expect lower porosity and less production from this lateral as compared to the previous well. Therefore, this data infers that not all wells are equal even when they are all producing from the Eagle Ford.

## Downhole Geochemical Logging

- is 1,000 times more sensitive than other methods
- Is the only method that measures from C2 – C20
- can be a powerful proxy for porosity
- can guide the placement of laterals
- can guide your fracture stages
- can help to explain production variations

Thank You!

