Woodbine Formation Sandstone Reservoir Prediction and Variability, Polk and Tyler Counties, Texas*

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Abstract

The Woodbine Formation in East Texas is continuing to draw attention because of its potential for gas production. Because production to date has largely been limited to deltaic sandstones deposited on the shelf, speculation of downdip play potential, akin to the Tuscaloosa (the age equivalent formation in Louisiana), has been high. An integrated geological and geophysical study of the Woodbine led to the recognition of a younger deltaic sequence, positioned basinward of previous production. A deep well test confirmed the geologic model, finding thick deltaic sandstones. Although the sandstones were tight, they suggest there is a deeper play fairway for the Woodbine.

Abundant geophysical work, including elastic inversion and an amplitude versus offset (AVO) study, was conducted to detect reservoir sands, to no avail. Reservoir prediction, then, relied on the strong integration of data in a sequence stratigraphic framework. Sequences were mapped based on traditional surfaces, and paleogeographic maps were created from top, base, and internal reflection geometries, along with well and core data. Deeper Upper Woodbine exploration potential would not have been realized without changing stratigraphic models away from the Tuscaloosa analogue.

While thick sandstones were discovered, they did not flow despite having wireline log responses characteristic of good reservoir quality, analogous to nearby fields. This prompted an in-depth study of Double A Wells Field, which exhibits Woodbine sandstones of highly variable stratigraphic character, and similar production variability from one well to the next, despite having similar log responses.

The geologically successful test of the Woodbine in Tyler County relied on integrating geology and geophysics in a sequence stratigraphic framework. Despite noncommerciality, reservoir variability displayed at Double A Wells suggests that more than a single well test may be required to prove up commerciality.

Introduction

The Woodbine Formation in East Texas and the Tuscaloosa Formation in Louisiana have been tremendous oil and gas producers since the 1970s (Figure 1). While the Tuscaloosa has had a prolific "downdip" play, producing 1.4 TCFE (trillion cubic feet equivalent) to date basinward of the Lower Cretaceous shelf margin, its age equivalent formation in Texas, the Woodbine, has not enjoyed the same success. Although there have been around three dozen penetrations south of the Sligo shelf margin, commercial production has been limited to one or two wells. This has caused several oil and gas companies to look for a downdip Woodbine play, similar to the Tuscaloosa, in East Texas. Since 2002, over 250 mi of 3D seismic data (Knight Survey) have been acquired in Polk County, downdip of Double A Wells Field.

The Knight Survey (acquired by Seismic Ventures) imaged the Upper Cretaceous Woodbine Formation much better than the previous 2D data in the area. Where seismic stratigraphy was previously tenuous, at best, a new stratigraphic framework for the Woodbine could be interpreted from the new data. It also revealed that the Tuscaloosa and Woodbine, while age equivalent and in a similar geologic setting, are quite different depositionally. This has important ramifications for exploration potential, exploration style, and, most importantly, reserve estimates done by the U.S. Geological Survey (2007).

In the downdip Tuscaloosa Formation, the target is deltaic sandstones deposited in a growth-fault province (Funkhouser et al., 1981; Barrel, 1997). Enormous sediment influx from the paleo-Mississippi River helped create an unstable substrate and allowed growth-faulting to occur. Substantial reservoir quality sands are associated with these growth-faulted, deltaic sequences. The shelf margin also has a distinct shelf-slope break geometry over the Edwards Reef margin (Figure 2). The sediments deposited in the downdip package are thousands of feet thick, and have only been fully penetrated around the Port Hudson salt dome, where salt movement has uplifted and also thinned the sedimentary package (Barrell, 1997).

By contrast, the Woodbine was deposited along a low relief ramp margin, with a much thinner sediment package (Bunge, 2005). The downdip Woodbine package attains a thickness of 2500 feet in the study area (Figure 3). As one might predict, from the ramp margin setting, the Woodbine section is much muddier than its time equivalent in Louisiana. Reef build-ups are present at the Sligo margin, but the shelf-slope break is much less pronounced, and often seems to be exaggerated by minor faults (Figure 4). Also, the Sligo and Edwards margins are not vertically stacked here, as they are elsewhere, resulting in a broad, deep shelf. The transition from a shelf-slope break to a ramp margin occurs around the Beauregard-Allen parish boundary in Louisiana, where a broad regional nose in the Lower Cretaceous is present. The transition has a gradational character, and is somewhat obscured by younger Wilcox faults in Beauregard Parish. It is the opinion of the author that this transition is a more appropriate place to separate the Woodbine and Tuscaloosa plays for national reserve estimates (Figure 1).

Although the ramp style margin and apparent mud-rich nature greatly increase exploration risk for deep targets deposited on the slope, 3D seismic data has helped illuminate the presence of multiple sequences present basinward of the Lower Cretaceous margin (Figure 4). These younger progradational sequences transported sand farther basinward than previously thought. The apparent downstepping sequence stacking of these younger sequences provide a mechanism to consolidate sand into a more sand-rich delta system, despite the mud-rich tendency of a ramp margin (Bertram, 2003). This concept led to drilling the Santos Kincaid 1 well.

The Kincaid well provided proof of the concept, encountering 120 ft of stacked deltaic deposits. While pay was calculated based on analogous Woodbine production, the well displayed poor flow characteristics. This led to an in-depth investigation of Double A Wells Field and nearby production. The Woodbine at Double A Wells is highly stratified, with sands rarely continuing from one well to another over distances of only 2500 ft. Diagenesis is also an important factor that greatly influences individual well performance. Although Kincaid was determined to be non-commercial, production variability in the Woodbine suggests that additional offset wells may be required to fully test the play.

This article shows some of the geophysical work that has proven to be less useful, the stratigraphic model that has proven to be very useful, and will discuss the diagenesis and production variability in the Woodbine.

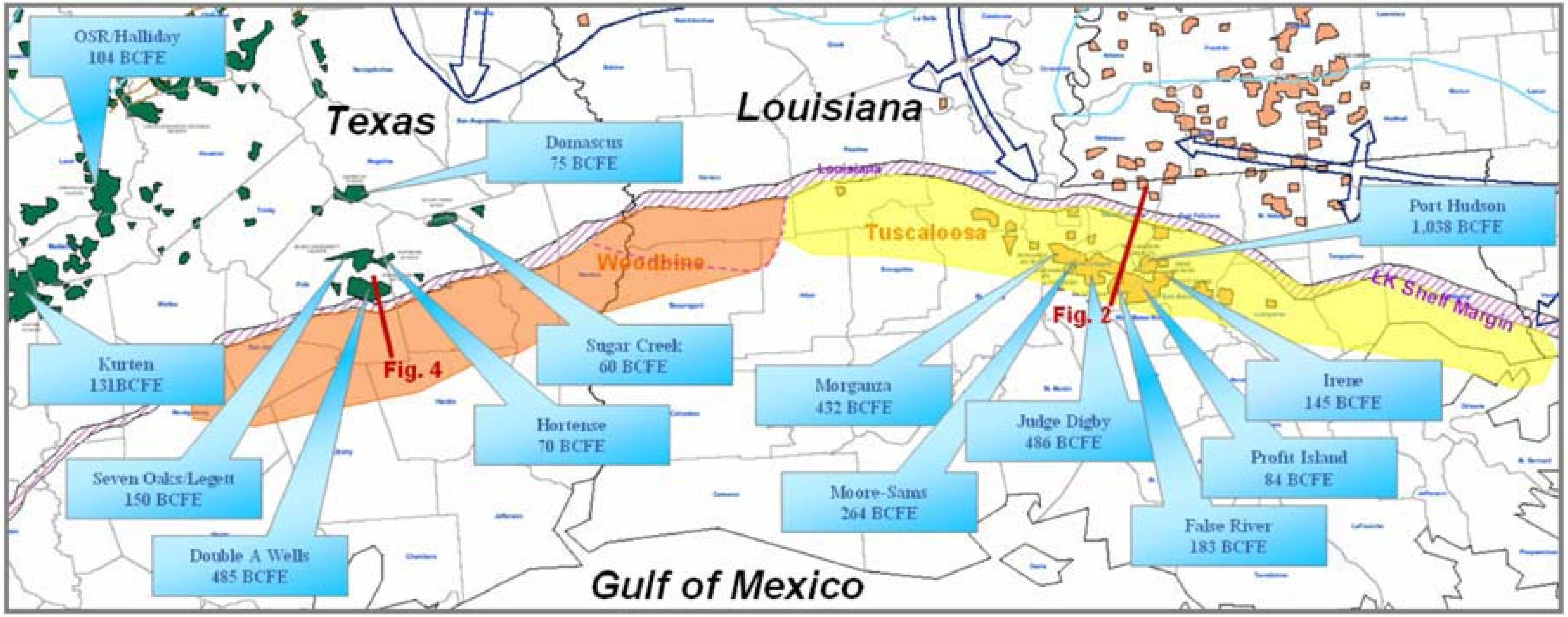


Figure 1. Map of the downdip Woodbine and Tuscaloosa trends with prominent production (modified after Bunge, 2005). Woodbine fields are shown in green, with the downdip trend in orange. Tuscaloosa production is in peach with the downdip trend highlighted in yellow. Barrel equivalents calculated using 5.1 mcf/bbl (thousand cubic feet per barrel). Regional tectonic features are in dark blue (after Martin, 1978), and the Early Cretaceous shelf margin is in purple hachure, with the approximate outboard platform dashed in purple.

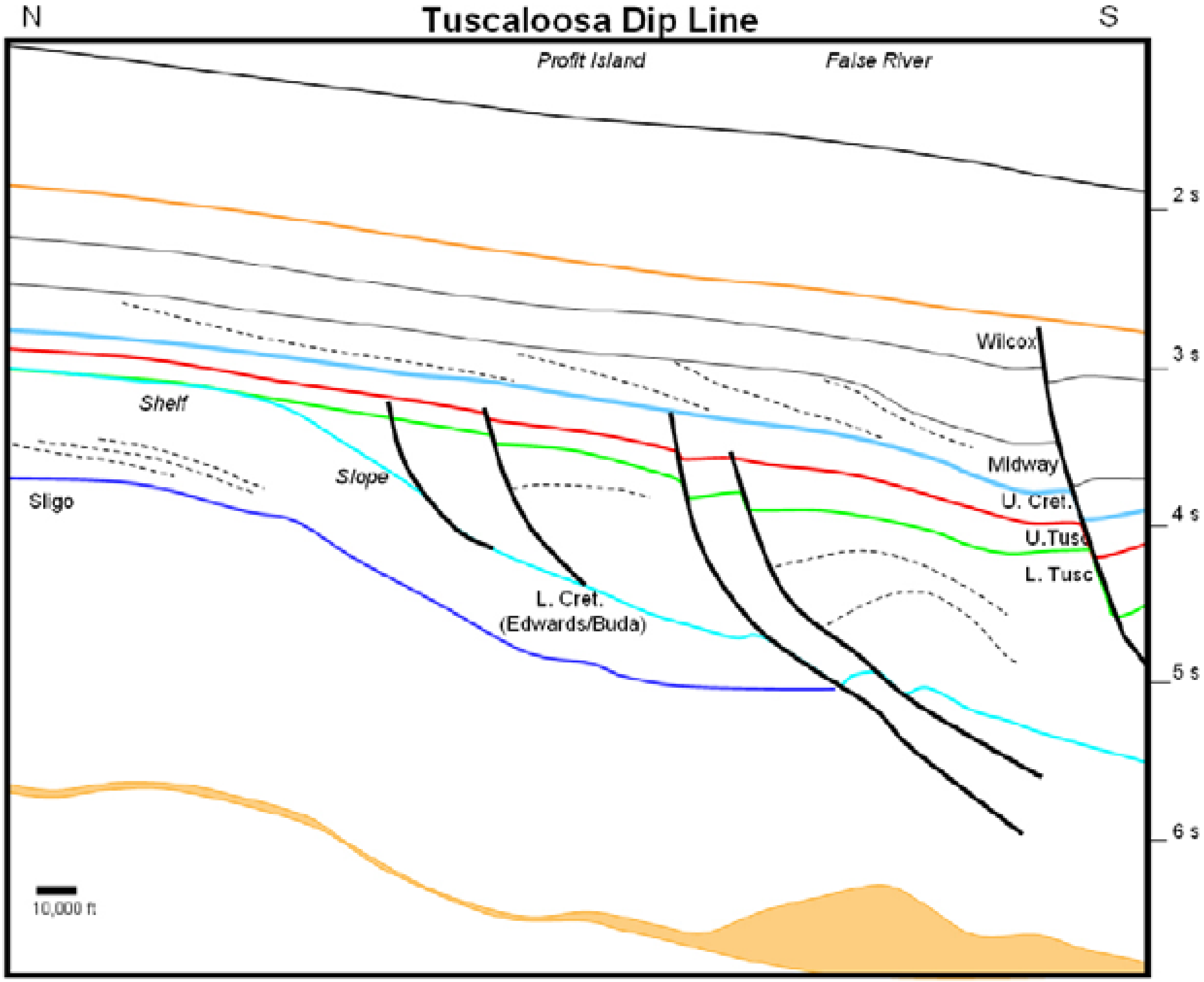


Figure 2. Tuscaloosa dip line. Line drawing based on seismic interpretation. Note the distinct shelfslope break on the light blue Lower Cretaceous (Edwards) horizon. Growth fault structures in the Tuscaloosa (here representing Profit Island and False River fields) are more influenced by intraformation mud than the underlying salt. From top to bottom, colored horizons are top Wilcox (orange), top Upper Cretaceous (Blue), base Austin Chalk (red), top Lower Tuscaloosa (green), top Lower Cretaceous (light blue), and Sligo (purple) (modified after Bunge, 2005).

Woodbine “Downdip” Slope Exploration

On poorly imaged 2D data, the stratigraphic complexities of the Woodbine Formation are easily overlooked (Figure 5). Prograding wedges can be vaguely defined on the shelf, and some onlap can be observed farther into the basin, but very little can be consistently defined. Wells like the Blackstone A-249 have drilled very convincingly thick, basal, onlapping wedges, only to find relatively thin sands or sands higher than expected in the section. Indeed, the sands that are present are part of slope or basin-floor fans, but on vintage 2D data they are apparently floating in the middle of the section. On modern 3D data, it can be shown that these sands are indeed sitting on sequence boundaries.

From a petrophysical stand point, an evaluation of reservoir sand shows rock properties of reservoir-quality rock to be of slightly lower impedance and lower velocity. Work was conducted in conjunction with Santos’ joint venture partners and Jason Geophysical on an elastic impedance volume. On amplitude versus offset (AVO) cross-plots, the reservoir-quality sand verses non-reservoir-quality sand “sit on top” of each other in class two space (Figure 6). Translated into the elastic inversion, the reservoir seemed to be highlighted in areas with a lower Pimpedance and lower Vp/Vs (p-wave velocity / s-wave velocity) ratio. While very convincing at first, this crossplot space did not prove to consistently highlight reservoir space, and vox-bodies picked using this criterion proved to be relatively small and scattered (Figure 7). The largest body with possible commerciality was detected around the Arco Carter Fee 1 well. Unfortunately, when a closer look was taken, the Vp/Vs versus impedance anomaly did not actually tie to the sand in the well, but came in hundreds of feet lower! Thus, even if an interpreter chose to have faith in the elastic impedance, only one anomaly appeared to be of commercial size, and the others appeared to be relatively small and scattered. The elastic inversion was only considered to be valid technique for the lower Woodbine stratigraphy. The Upper Woodbine, like that which is productive at Double A Wells Field, is very close to the base of the Austin Chalk where strong reflectivity interferes with the reservoir response.

Due to the inability to distinguish reservoir using AVO and elastic inversion techniques, and the relatively small nature of the above-mentioned geophysical anomalies, Santos chose to exit the downdip, deep Lower Woodbine play. It is noteworthy that a number of wells with logged pay in this portion of the sequence have been unable to establish commercial production. The Arco Carter Fee 1 well was reportedly shut-in after starting a forest fire on a flow test, but efforts were unable to reestablish production thereafter. The Blackstone A-249 well also logged pay, but the well was unable to be completed. The Santos Kincaid 1 well encountered thin sands that were interpreted as tight tests in the deep Woodbine.

Woodbine “Updip” Shelf Exploration

A number of fields produce from the Upper Woodbine shelf deltaic sandstones. The largest of these fields is Double A Wells, which has produced over 450 BCFE (billion cubic ft of gas equivalent). Double A Wells is situated just north of the Lower Cretaceous Sligo shelf margin. Net sand maps of the field suggest the delta was deposited on the shelf margin, with its basinward edge reworked by wave action. The seismic signature at Double A Wells is that of a strongly prograding series of reflections, which are part of the Woodbine B sequence defined below and mapped by onlap and downlap surfaces in 3D seismic data of the Knight Survey.

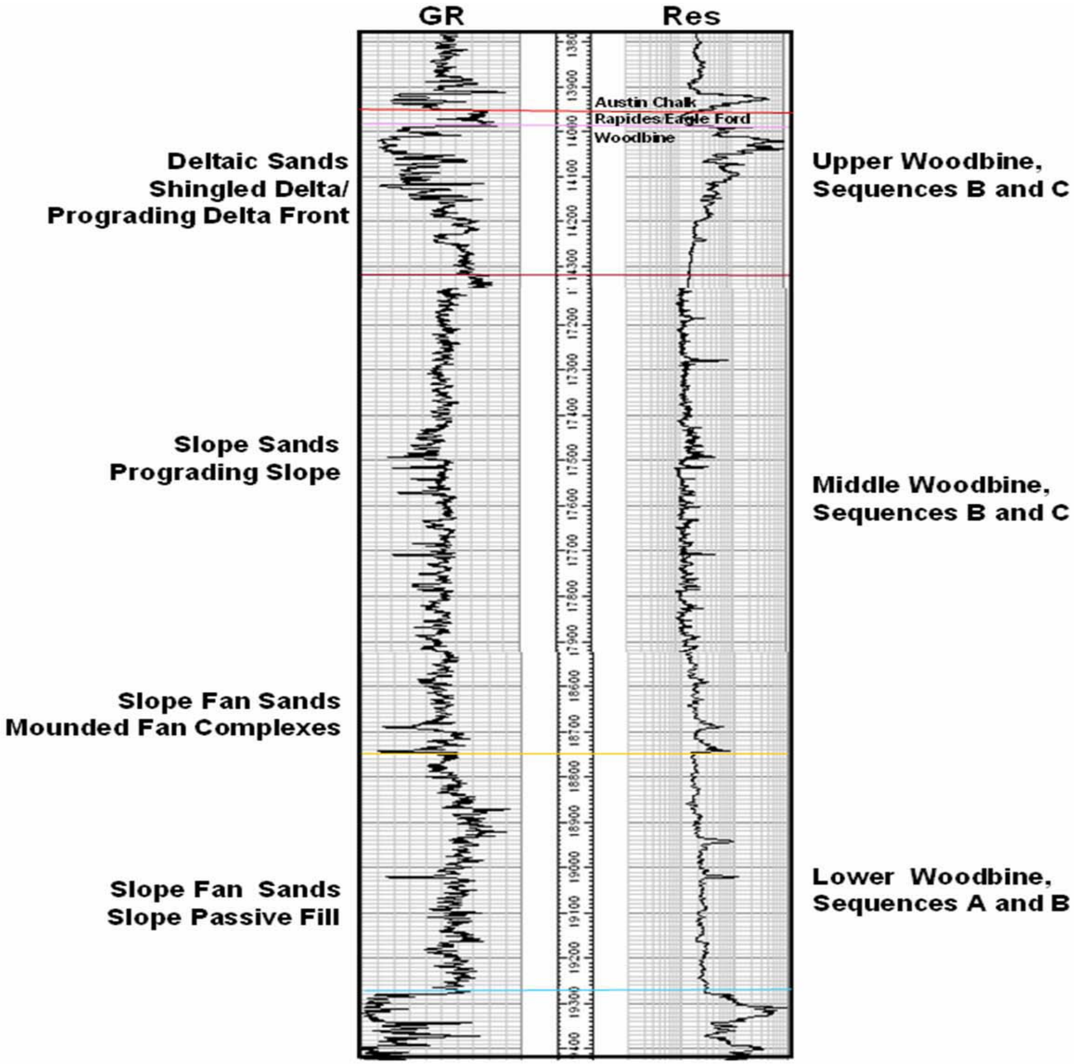


Figure 3. Woodbine type log. Typical log response and occurrence of Woodbine sandstones. The upper Woodbine typically has thick, coarsening-upward gamma. This log response is observed in sequences B and C. The middle Woodbine is typically shaly with spikey stringer sands, interpreted to be slope deposition. Occasionally thicker fan deposits rest at the base of the sequences in the middle Woodbine. These log responses are also observed in sequences B and C. The lower Woodbine is typically shale with rare, blocky sandstones. “Updip” shelf exploration in the Woodbine targets the upper Woodbine, while “downdip” exploration targets the middle and lower Woodbine.

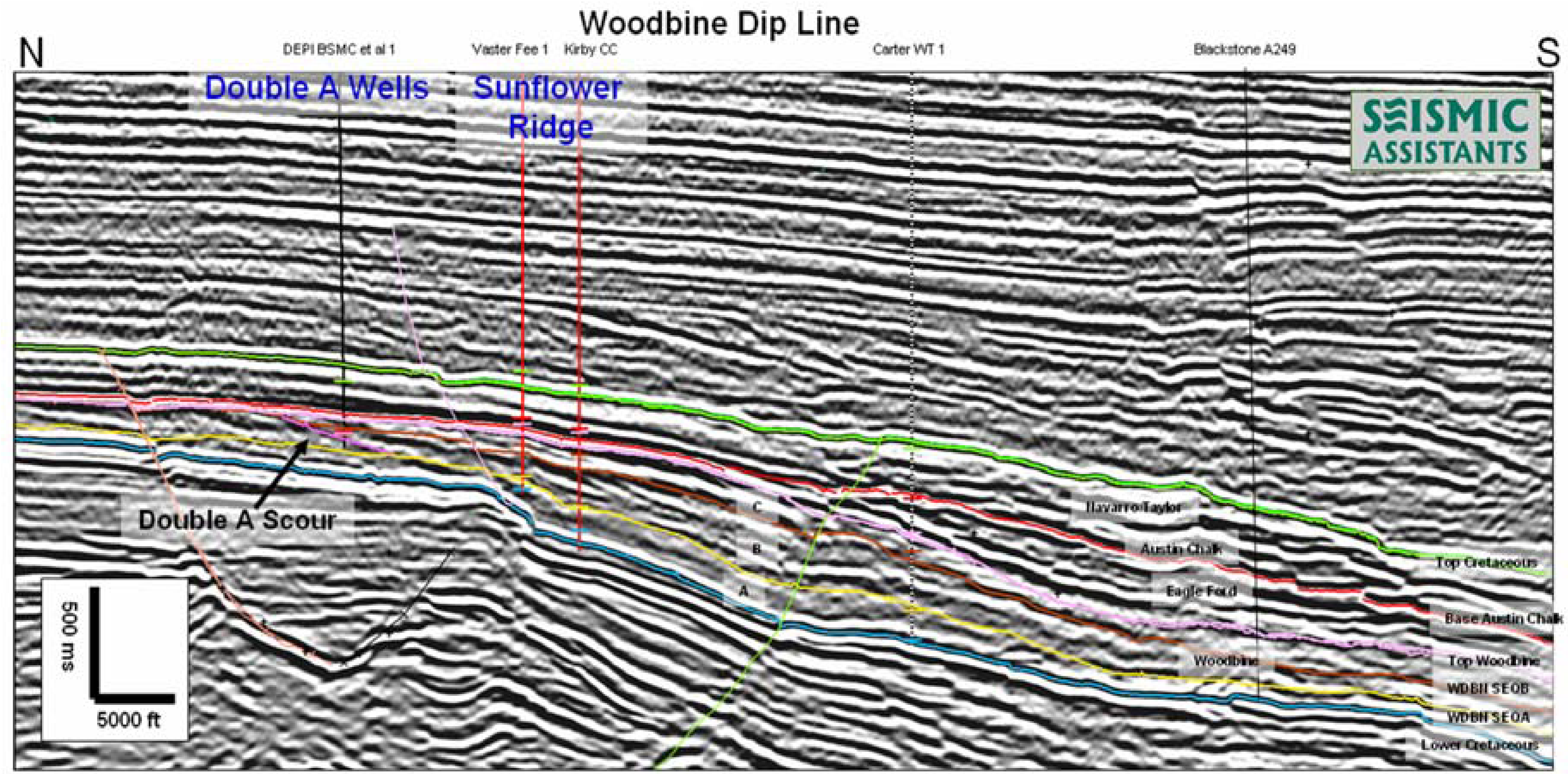


Figure 4. Seismic line from the Knight Survey in Polk County, courtesy of SAI (Seismic Assistants Inc.). The Woodbine was deposited on a broad shelf. Although a shelf-slope break is present, it is accentuated by faulting. The Woodbine was deposited on a more ramp-style margin than the Tuscaloosa. Horizons picks from top to bottom are top Upper Cretaceous (green), base Austin Chalk (red), top Woodbine [top Woodbine sequence C] (pink), top Woodbine sequence B [WDBN SEQB] (brown), top Woodbine sequence A [WDBN SEQA] (yellow), and top Lower Cretaceous (blue). The hot pink horizon highlights the Double A Wells scour, internal to, or a higher order sequence within, B.

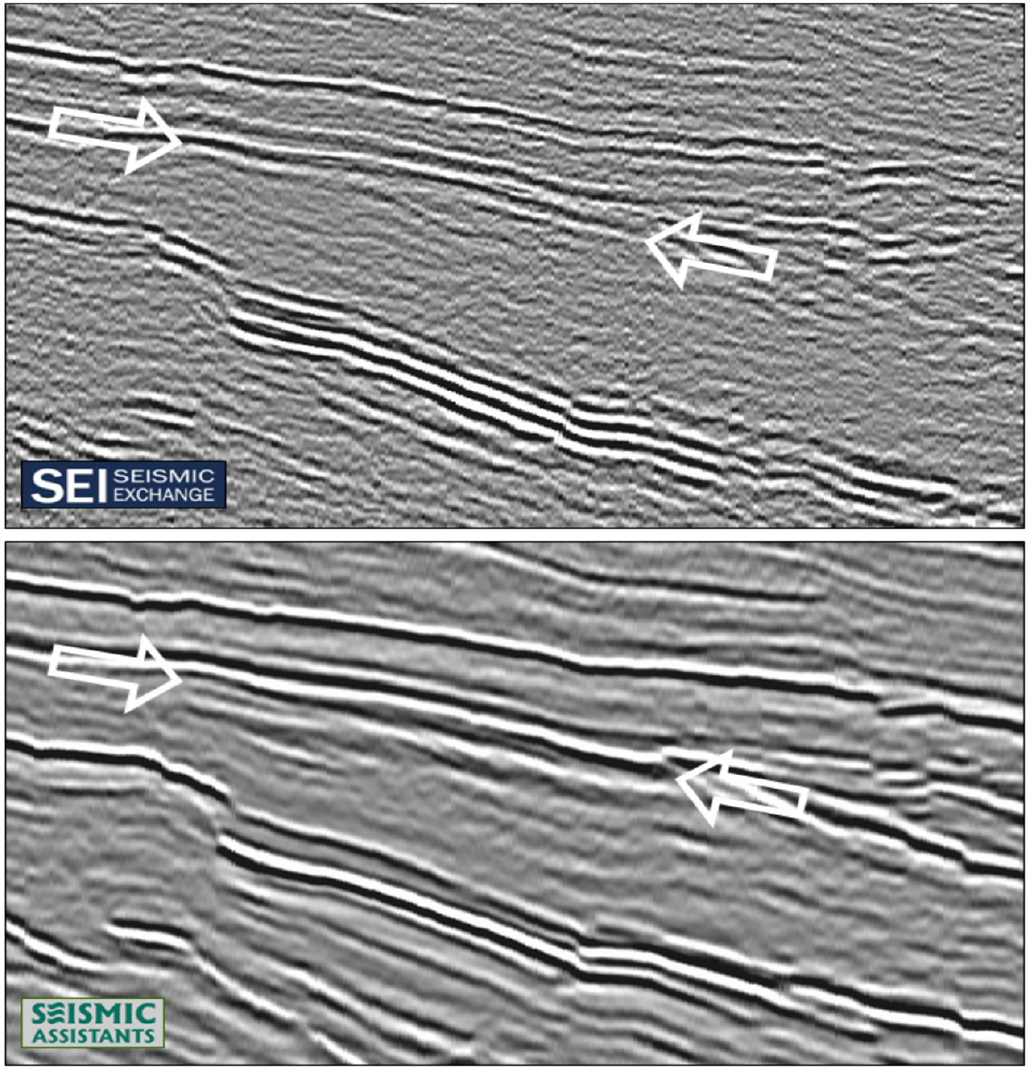
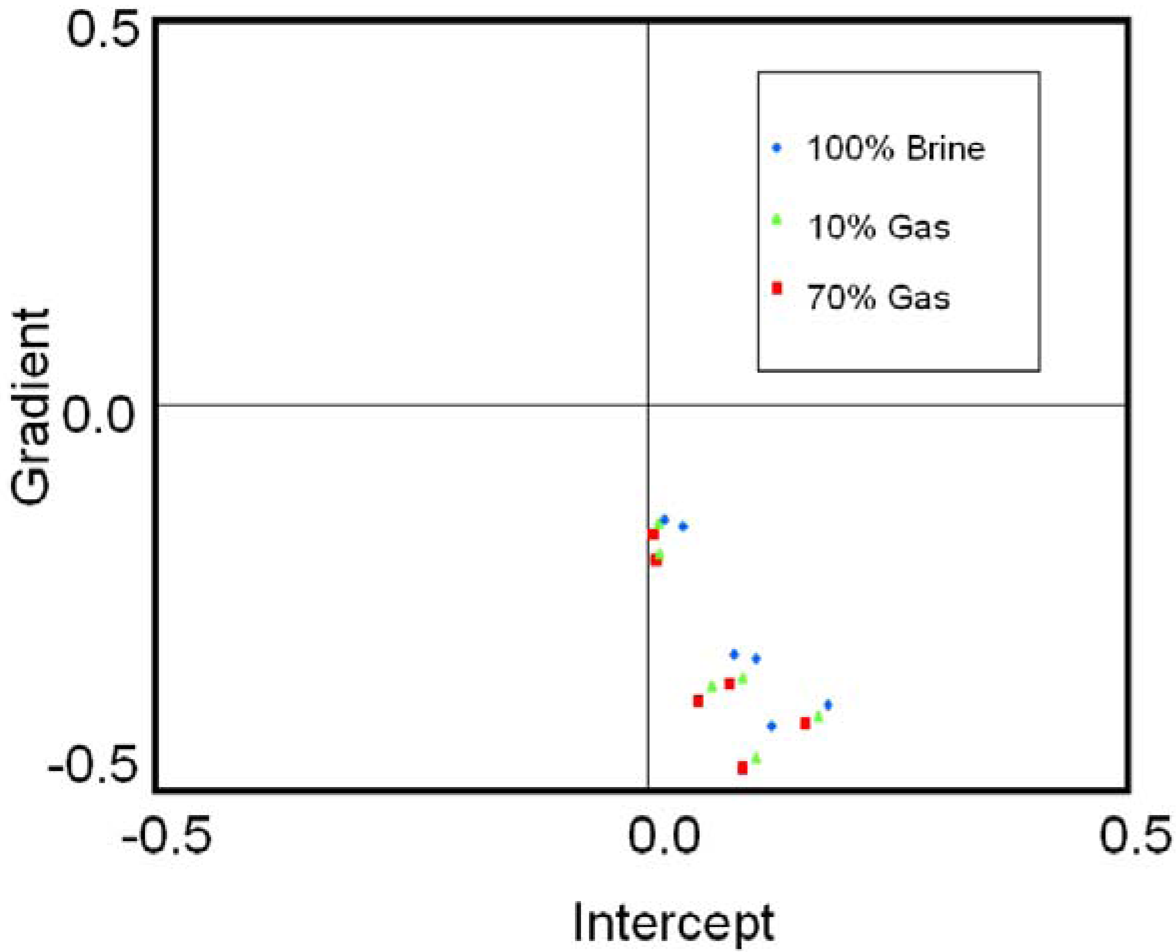


Figure 5. 2D (upper line) vs. 3D (lower line) comparison. Although there is a hint of stratigraphy in the 2D data, the apparent onlap in the middle of the 2D profile between the arrows would be misidentified. 3D data shows the true nature of the downlap surface with shingled reflections. In most 2D data this shingled area is simply a high amplitude, low frequency zone. Data courtesy of SEI (Seismic Exchange Inc.) and SAI.

(A)



(B)

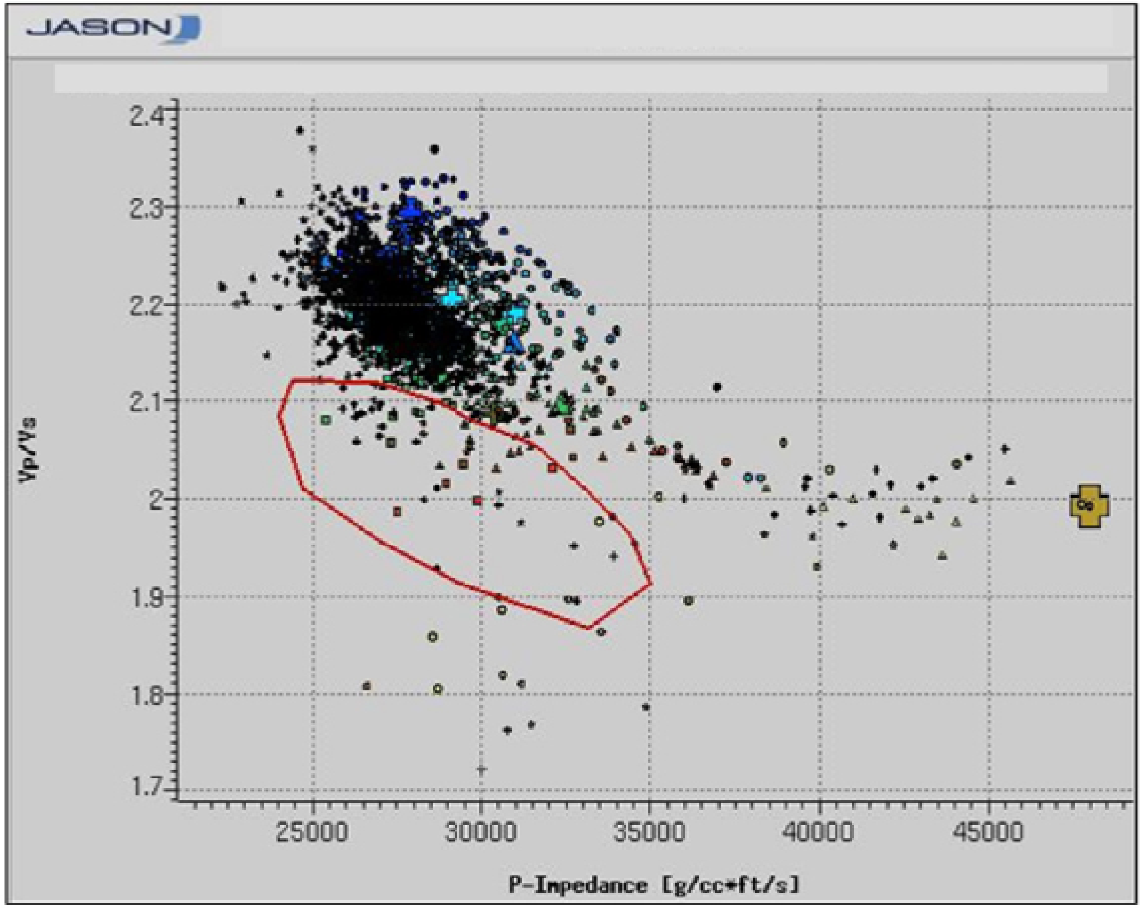


Figure 6. Petrophysical analysis of the Woodbine formation. (A) Fluid substitution effect on seismic response in well logs from Rock Solid Images MOSS analysis. Increasing gas saturation results in a slight decrease in intercept and gradient, but probably not recognizable or unique on seismic. Wells included in the analysis are Willow Creek Champion International 1, Comstock Carter W T & Bro 6, Sonat Carter 1, Comstock Carter WT & Bro E 12, Poko Carter WT-Colabe 1, and Comstock Hamman 1.
(B) Seismic volume cross-plot of the P-Impedance and Vp/Vs from elastic inversion of the Woodbine interval performed by Jason Geophysical. The polygon often highlighted reservoir on well logs, but also highlighted non-reservoir portions.

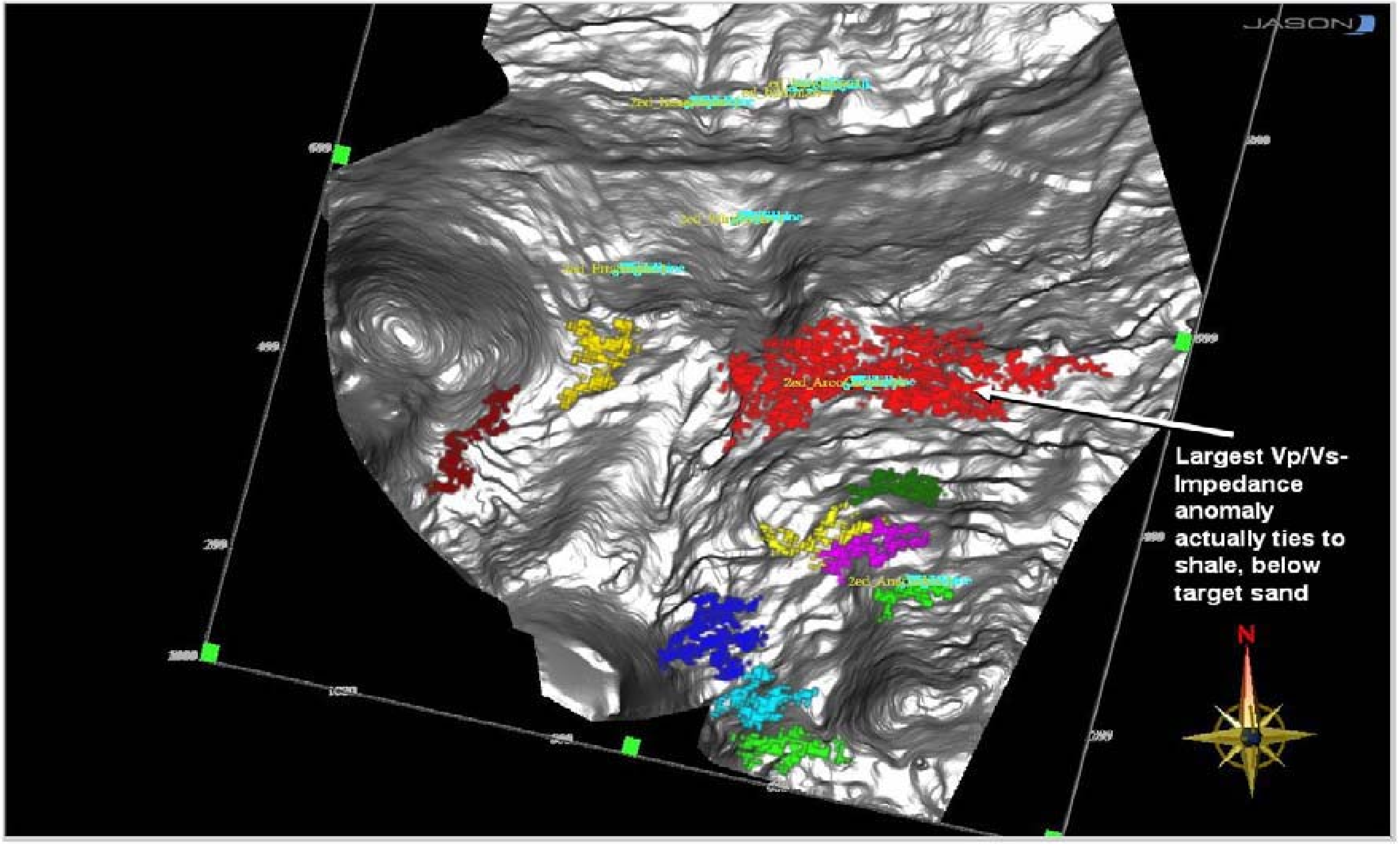


Figure 7. Seismic anomaly bodies identified from elastic inversion by Jason Geophysical. The polygon in Figure 6B highlighted these anomalies, which are relatively small and scattered. Unfortunately the largest anomaly (red) did not tie to reservoir in the nearby well. The surface shown is below the anomalies in the Lower Cretaceous.

Sequence Definition

Three sequences within the Woodbine were mapped based on seismic reflection termination surfaces and tied to well control. Termination surfaces were defined by toplap or truncation at the top, and by downlap or onlap at the base (Figure 8). On logs, wireline curves exhibit shifts in curve baselines or changes in overall gradient (Figure 9). Systems tracts were not defined due to seismic resolution, and due to the fact that they are often incomplete or truncated. High-resolution biostratigraphy was also conducted on 7 wells in the area, but the lack of preserved fossils rendered the study of limited use.

Sequence A

The lowest sequence, A, is predominantly shale with a high gamma-ray curve. On seismic, it mainly drapes and infills topography. Sand is scarce, with the only example at the Arco Carter well.

Sequence B

Sequence B is strongly progradational in nature. It is the thickest of the three sequences and is a compound sequence set. The Double A Wells canyon and sands are within sequence B (Figure 3). In the updip portion of sequence B, around Double A Wells, logs exhibit a typical shoreface signature, coarsening upward on logs (Figure 9). On seismic, this area has shingled reflections, onlapping at the base and truncated at the top (Figure 8). At the Sligo margin, the section turns more progradational on seismic with complex sigmoid geometries. Logs in this section are predominantly shale with thin sands, very typical of slope deposits. Farther downdip, sequence B thins again and looses the progradational nature. Reflections become parallel or mounded, indicative of slope fans.

Sequence C

The uppermost sequence, C, was only identified through the use of 3D seismic in the Knight Survey. Landward of the Sligo shelf margin, over Double A Wells Field, it is below seismic resolution. Basinward of the Sligo margin, it is a relatively high-amplitude, low-frequency set of reflections with a slightly shingled nature (Figure 8). Farther downdip, it has the most mounding of the three sequences. On logs, in the updip area with the shingled/prograding nature, sequence C has stacked, coarsening-upward sands, such as at Sunflower Field (Figure 9). Downdip, the thickest, most basinward sand, encountered in the Blackstone A-249 well, sits at the base of this sequence. A strong erosional surface, approximately 10 ft below the top of the Woodbine, is reported in nearly every core in Double A Wells Field. The author believes that is the expression of sequence C on the Sligo shelf area, in which case it is well below seismic resolution. Seismic interpretation also supports that this deltaic/shelf system is strongly influenced by current action. When seismic is flattened on the base of the Austin Chalk to restore the stratigraphic section, sequence C is downstepping to sequence B; this should help consolidate sand from muddier sequences.

It is important to note that very few wells have penetrated sequence C. Shingled reflections and downstepping-sequence stacking define the updip seismic character, and are both very strong indicators of a higher energy, sand-prone system. Another positive sand indicator is thicker, mounded reflections downdip, implying that the depositional environment during sequence C moved sands down into the slope and basin area.

Typically, environment of deposition interpretation in the Woodbine has been made, based on an isochron between the base of the Austin Chalk (BAC) reflection and the Lower Cretaceous carbonates (the Buda or Edwards formations) (Figure 10). While this is useful as a look at basin geometry at the beginning of Woodbine deposition, it is too gross of an interval to predict paleo-water depth and depositional systems. Breaking-out sequences in the Woodbine and mapping seismic facies (e.g., Ramsayer, 1979) demonstrates that shelf-margin deltas moved out well basinward of the Sligo margin (Figures 11 and 12).

The Eagle Ford is also separated from the Woodbine, a relation which is important to tectonic history. The Woodbine in the Knight area was deposited during a period of relative quiescence; sequences prograded out into the basin with relatively little influence from tectonics compared to Eagle Ford time. However, at the end of Woodbine deposition, salt in the area began to mobilize and change the basin configuration such that significant accommodation space was created in some areas and subsequently filled by Eagle Ford Group (Figure 13). Sea-level changes were occurring throughout Woodbine time, and have been well documented for Double A Wells and Seven fields (e.g., Harrison, 1980; Young and Barrett, 2003). They are responsible for the stratigraphic traps at these and other Woodbine fields throughout the area.

Outside of the Knight 3D area in Tyler County, the Arco Rice University well has several hundred feet of silty and thin-bedded sands interpreted from logs and core. This represents the distal deltaics associated with sequence C, and provides key evidence for deltaic sands at the Kincaid location. Although the shingled nature of the sequence is not observed in the 2D, the high-amplitude, low-frequency character of the sequence is preserved, allowing it to be mapped. Evidence of sidelap from a delta building out into the Kincaid area is also present on the 2D seismic data (Figure 14).

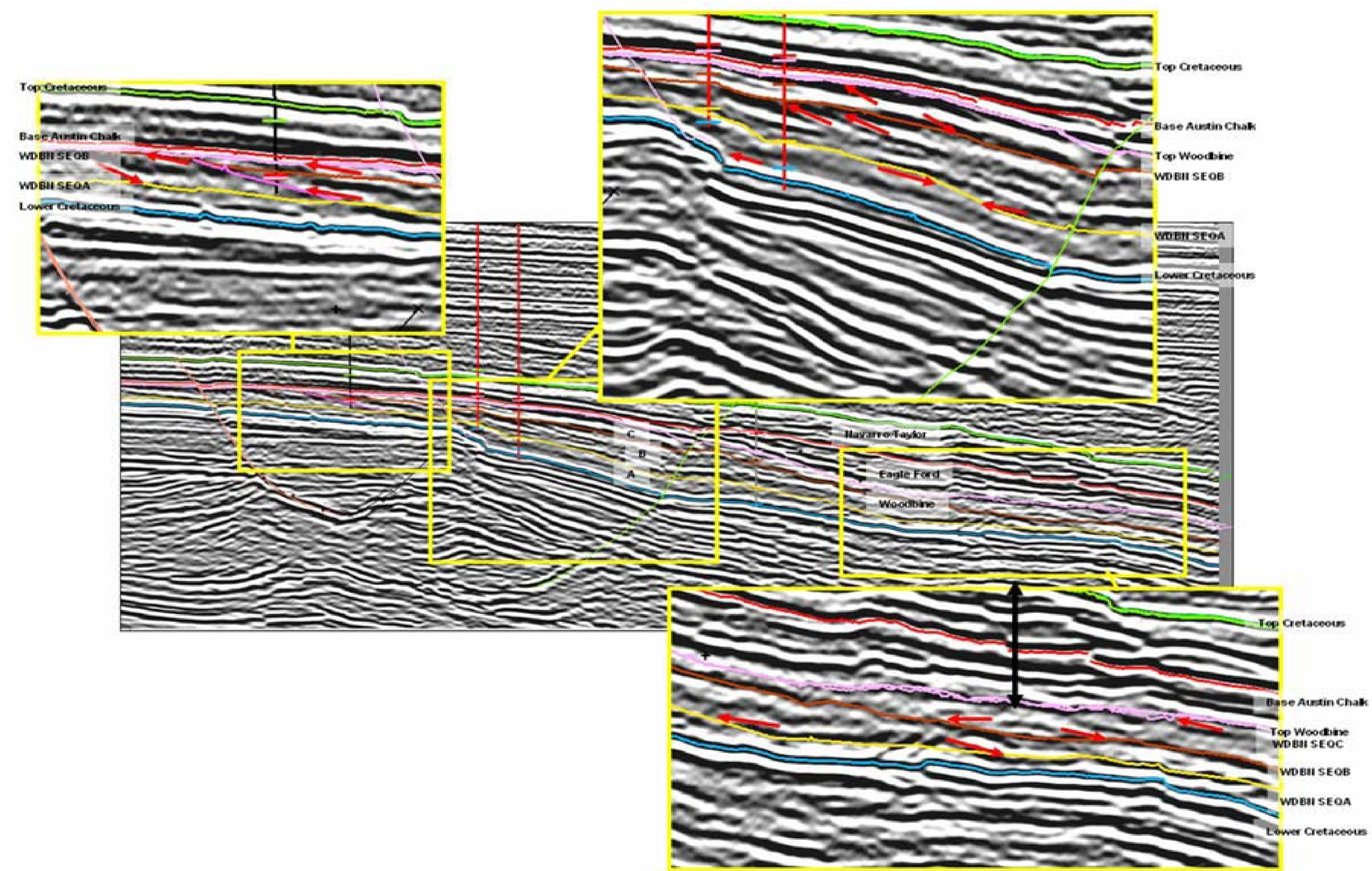


Figure 8. Reflection terminations. Portions of the seismic line in Figure 4 are blown up, highlighting reflection terminations (red arrows) that helped identify and map sequences. The panels also show representative sections from shelf, slope, and basin portions of the Woodbine. Well ties are off due to projection of from out-of-the-plane.

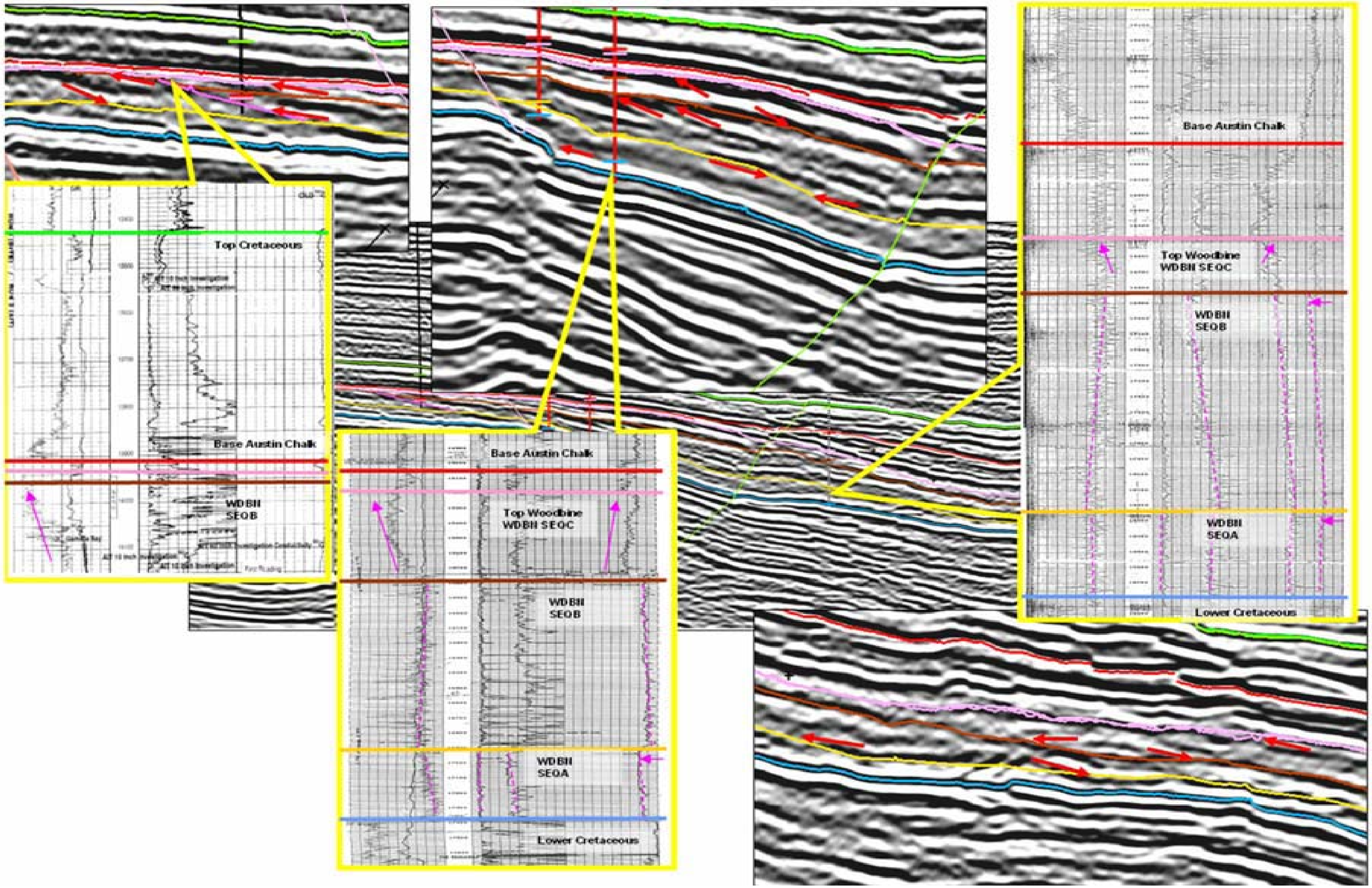


Figure 9. Representative well logs. Shelf, slope and basin deposits have proto-typical log gamma-ray responses. Shelf deltas have coarsening upward response. Slope deposits are mostly shale with thin sands. Basin deposits are thick shale. Sequences are identified by subtle shifts in baseline and baseline gradient of logs (highlighted in pink).

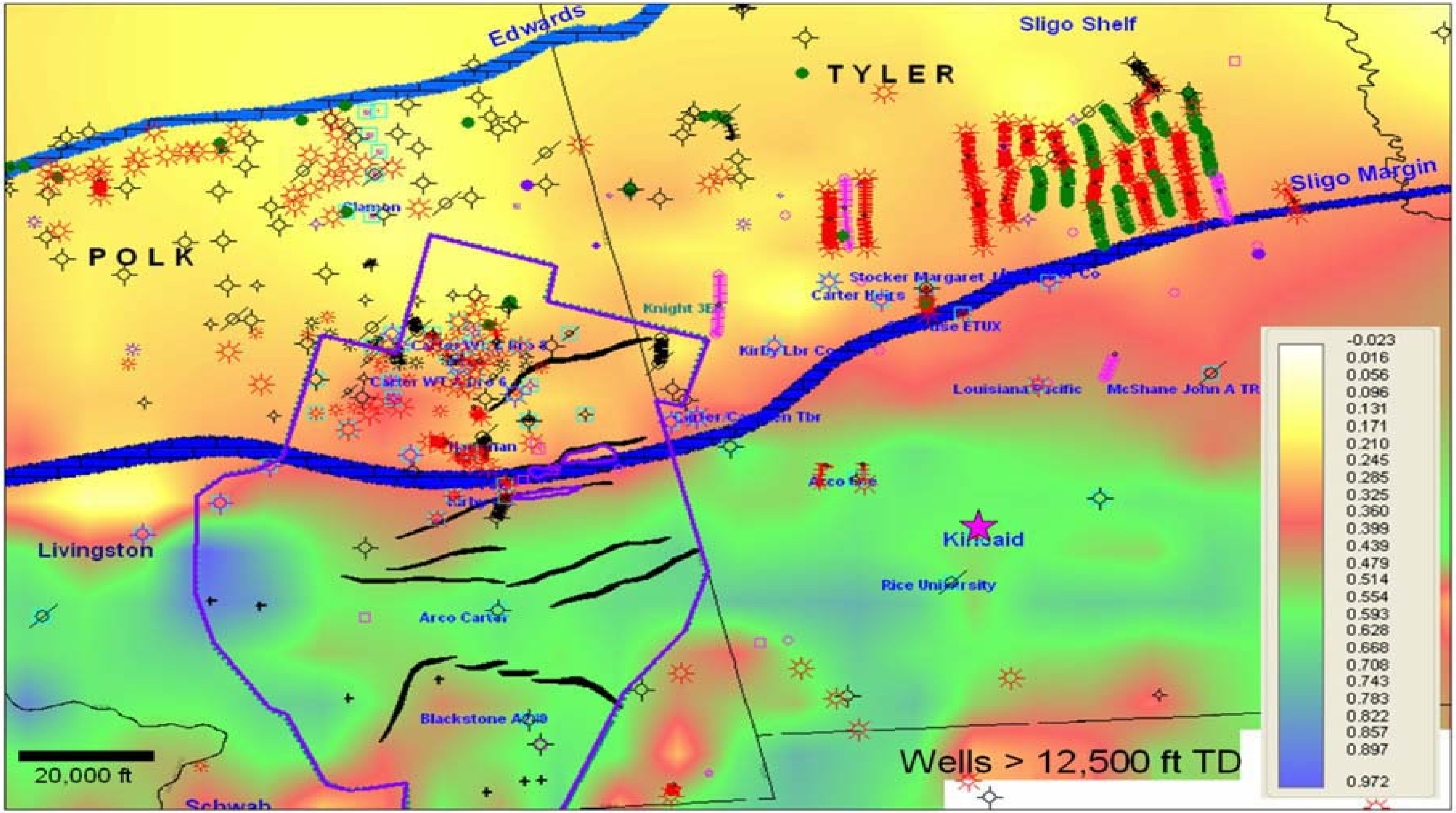


Figure 10. Upper Cretaceous clastic wedge isochron map. This isochron interval is bounded by the base of the Austin Chalk and top of Lower Cretaceous, encompassing the Woodbine, Eagle Ford, and Rapides formations. The Lower Cretaceous reef margins are shown (Edwards to the north, and Sligo to the south). Despite the apparent deep basin position suggested by the isochron, sequence work shows that younger delta systems prograded basinward of the Sligo margin, the Santos Kincaid well location (pink star). The outline of Knight Phase I&II merge with the Double A Wells 3D surveys licensed by Santos is shown in purple. The scale is in seconds. Only wells with depths greater than 12,500 ft are shown.

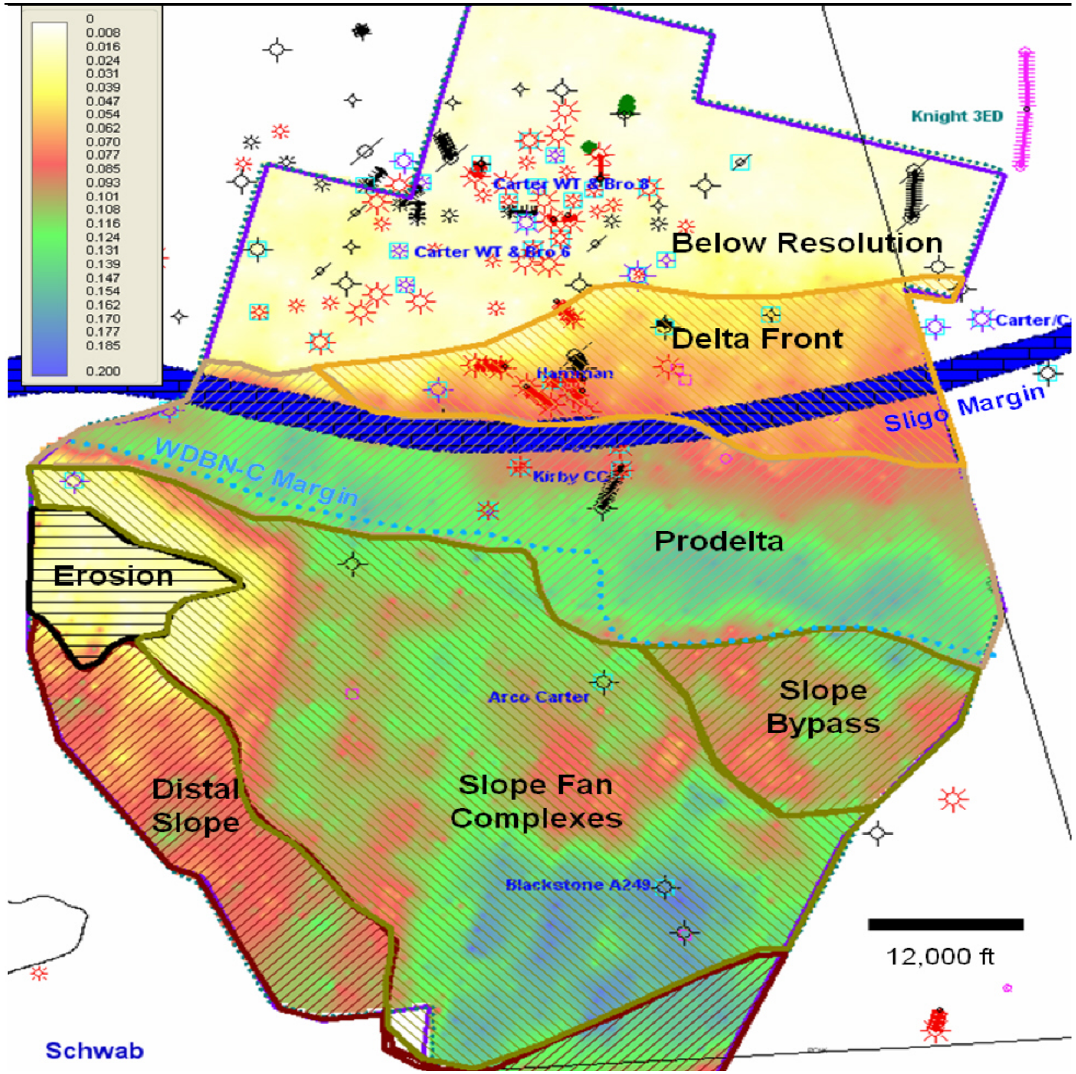


Figure 11. Woodbine Sequence C isochron map with seismic facies interpretation. Seismic facies key is in Figure 12. Log control shows that the delta front prograded as far as the Sligo margin, but that the prodelta zone prograded beyond the Sligo margin, forming thick deposits before thinning onto the slope (basinward of the noted Woodbine C margin). Note the divergent trends of the Sligo and Woodbine margins; into Tyler County to the east, this divergence is much greater.

Environment of Deposition Table – Woodbine Sequence 'C'

Symbol	Interpretation	Example Seismic Facies	Lithologic Prediction	Reservoir Potential	Comment
	Delta	Top-Dwn Sh, low; C-C Psub, mod	Sandy	high	Coarsening upward on logs, sandy facies at top. Main reservoir risk is diagenesis.
	Prodelta	Top-Dwn Sh, high or mod	Mixed clastics	moderate	Coarsening upward, but often not clean sandstone.
	Slope Bypass	C-C C, low	Shale	Low	Shale with stringer silts/sands
	Slope Fan Complexes	C-Dwn m, low; Te-On Sh, mod	Predominantly Shale, Thin Sands	Low	Thins sands present, but often cemented. Geophysical anomalies suggest porous areas relatively small
	Distal Slope	C-C C, low	Shale	Low	Distal slope sediments
	Erosion	(section absent)	(none)	(none)	Section removed by erosion

Figure 12. Tabulation of environment of deposition for the seismic facies map in Figure 11.

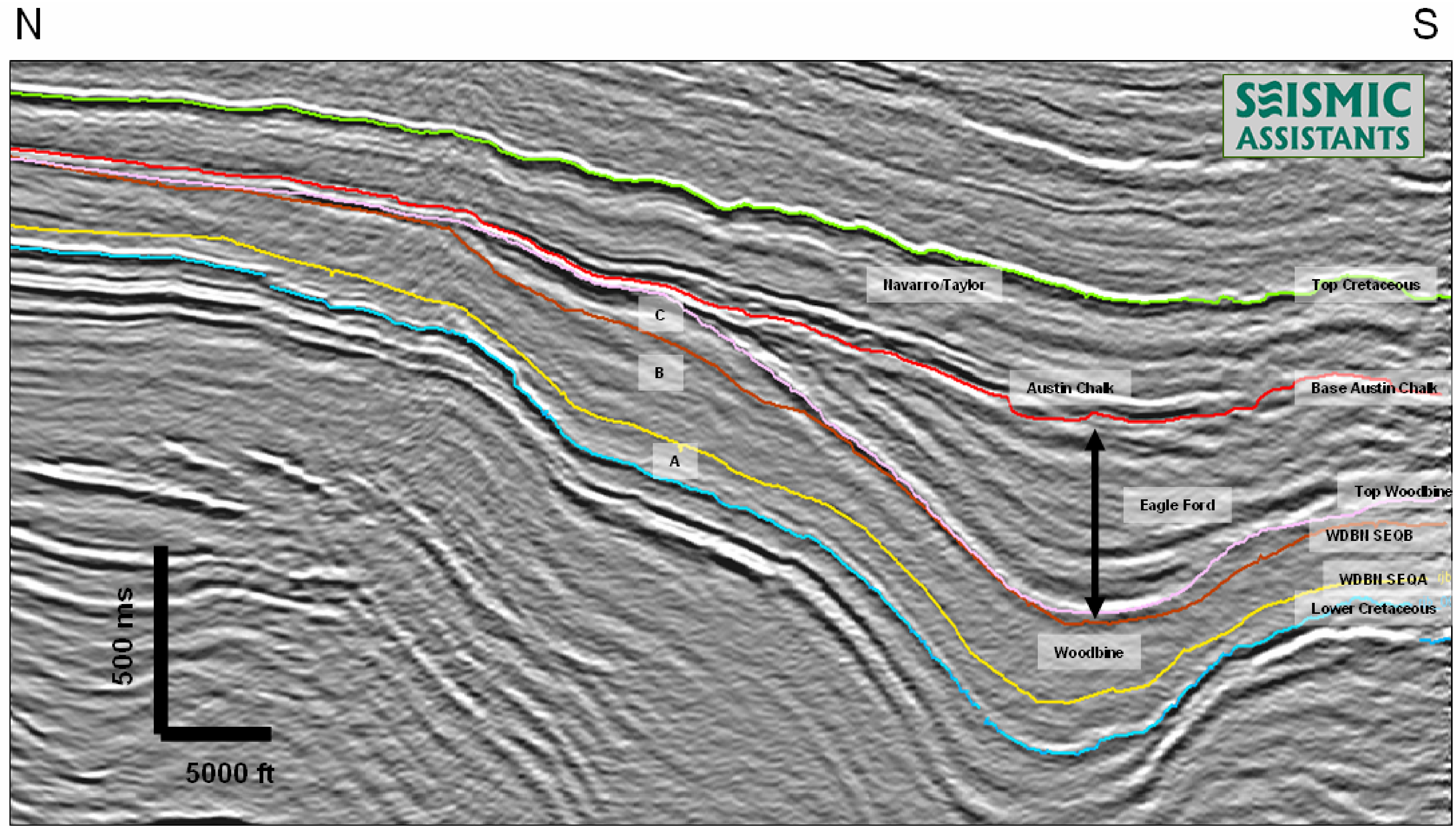


Figure 13. Salt movement immediately after Woodbine deposition changed the landscape, deforming the Woodbine and creating accommodation space for the Eagle Ford.

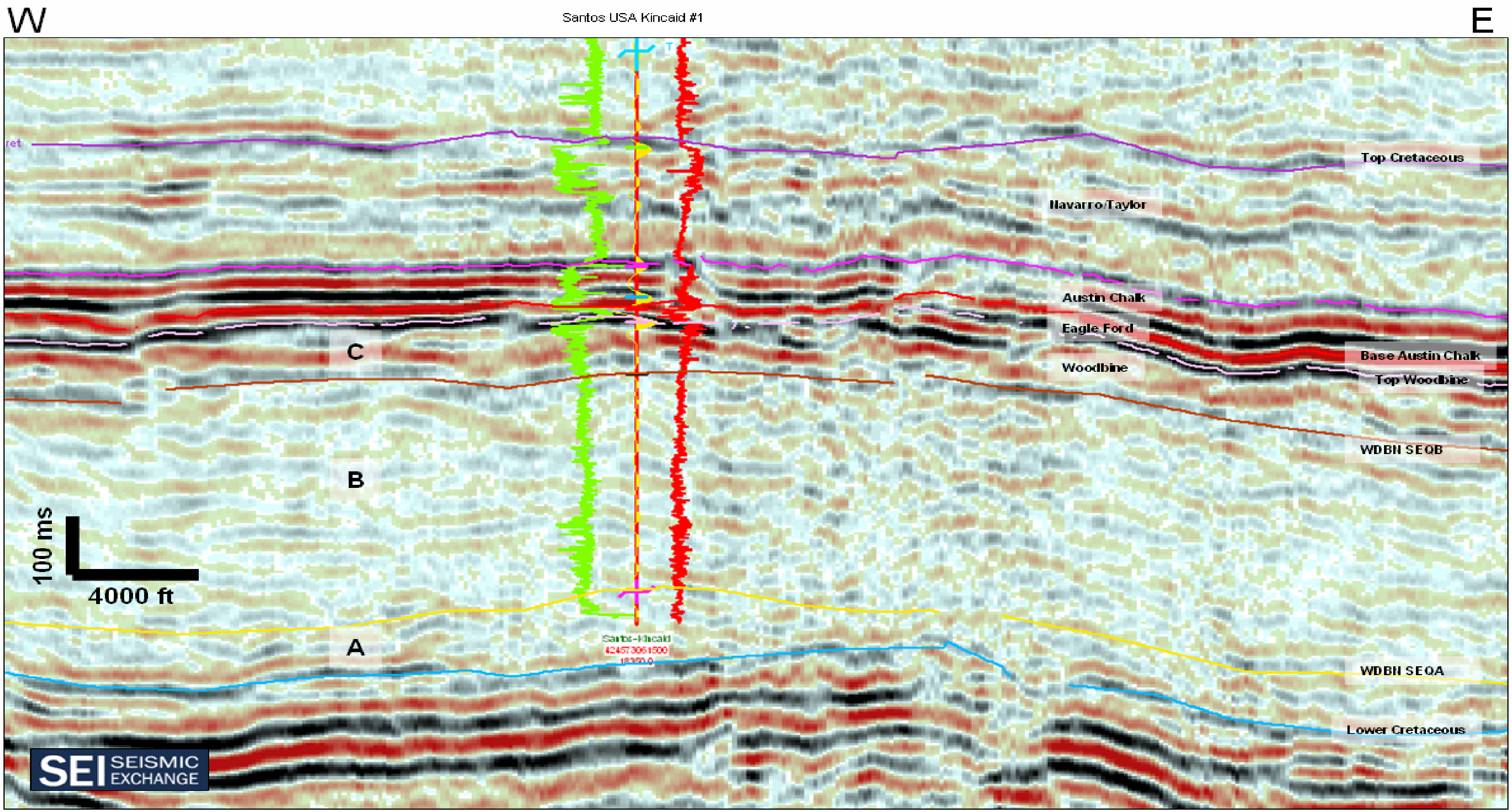


Figure 14. Strike seismic line across the Santos USA Kincaid 1 well. The well was drilled on a broad anticline with gentle structure. Sidelap of the interpreted delta may be observed near the label "C" of the uppermost Woodbine sequence. The C sequence tends to be of slightly higher amplitude and lower frequency compared to the rest of the Woodbine.

Well Results

Drilled to test the concept of sequence C being present as a high-energy unit that moved sand basinward of the Sligo margin and was subsequently folded into a gentle four-way closure, Santos USA spudded the Kincaid 1 well in late 2005. The Kincaid well did provide proof of concept, but, unfortunately, proved to be a noncommercial discovery.

The Kincaid well drilled a broad four-way structure mapped on 2D seismic (Figure 14). The low-frequency, higher amplitude nature of sequence C was used to map a sediment package basinward of the Sligo margin. The strike line in Figure 14 displays sidelapping reflections on the lateral edge of the delta system penetrated by the Kincaid. Important well control consisted of the Vision Louisiana Pacific discovery to the north, with a poorly developed coarsening-upward sand at the top of the Woodbine, and the Arco Rice University downdip, which has nearly 400 ft of silty, dirty sands interpreted in logs and core (Figure 15).

The initial logs on the Kincaid caused great excitement, showing 100 ft of net sand and 18 ft of net pay using a porosity cutoff of 9%. The thickness and log character of the sandstones is very similar to Double A Wells Field: coarsening upward, with multiple blocky sands at the top (Figure 16). Porosity was as high as 14%, well over the 9% cutoff derived from production analogues across the region.

Two unexpected results occurred when testing the well. Of the three blocky sands in the Upper Woodbine, the lower two never established flow despite having porosity above regionally established cutoffs and log-calculated pay. The uppermost sand displayed a classic resistivity invasion profile as well as crossover in the density and neutron curves. Testing yielded gas-cut water, another unexpected result for the Woodbine. Regionally, only one other Woodbine well (Sonate Carter 1) is known to be wet with a similar log response.

The Lower Woodbine sands also fit the geologic model, being thin-bedded, fining-upward slope deposits or thin-bedded, slope overbank deposits. Although tested, they were tight, as expected due to their thin-bedded nature and lack of lateral continuity.

Double A Wells Field Study

Facies and Production

The unexpected results at the Kincaid prompted an in-depth study of the Woodbine reservoir at Double A Wells Field. Fifteen wells were chosen to cover a range of production that represented wells with no flow, low, and high rates. In addition to detailed petrophysical analysis, a geologic characterization was carried-out. Nine parasequences were interpreted, based on discrete flooding surfaces, which allowed the identification of four log facies, all within sequence B, as discussed above (Figures 16 and 17). Cumulative production and gas/oil ratio maps were also made for five fields: Seven Oaks, Leggett, Hortense, Double A Wells, and Sunflower (Figure 18).

The cumulative production maps show that production within Woodbine reservoirs is highly variable. The best example is at Seven Oaks / Leggett, where every second well can be noted to have good production. One to two BCFE wells and dry holes typically can be observed to offset 10-16 BCFE wells. Most fields have one or two stellar producers, a handful of moderate producers, and marginal production from the rest of the wells. At Sunflower, the Comstock Hamman 1 produced nearly half of the field production, almost 13 BCFE, and it is offset by a dry hole. Double A Wells has a core area of very high cumulative producers (> 15 BCFE); despite this the eastern side of the core producing area contains a trend of low production.

Three cross sections were made across Double A Wells Field, and four facies were interpreted based on log character (Figures 16 and 17). Blocky gamma-ray signature is interpreted to be a delta channel. Less blocky, thinner, and stratified sands are interpreted to be delta overbank and splay deposits. These two are the productive, sandy facies in the field. Less clean, silty zones are interpreted to be delta-front deposits. Dirty, high gamma zones are interpreted as prodelta deposits. The last two facies are non-productive.

After picking the parasequences and making facies interpretation, it was observed that the sandstones are highly stratified and rarely continue from one well to the next. They are slightly more continuous in the dip direction compared to the strike direction. Cross section A in Figure 16 shows the extreme nature of the stratification. Thick channel sands are not continuous over the distance between the Carter WT 6 well and Carter Bro BA 1 well, a half mile away. Both wells were drilled and completed in the same way six months apart, and both wells have thick, blocky, resistive sandstones. From a wireline log standpoint, they are virtually identical; however, in the parasequences, the sands do not appear to be connected. Indeed, the Carter WT 6 well has produced almost 40 BCFE while the Carter Bro BA 1 well has produced less than one BCFE! As with the Kincaid well, the reservoir problem at the Carter Bro BA 1 well appears to be below log resolution.

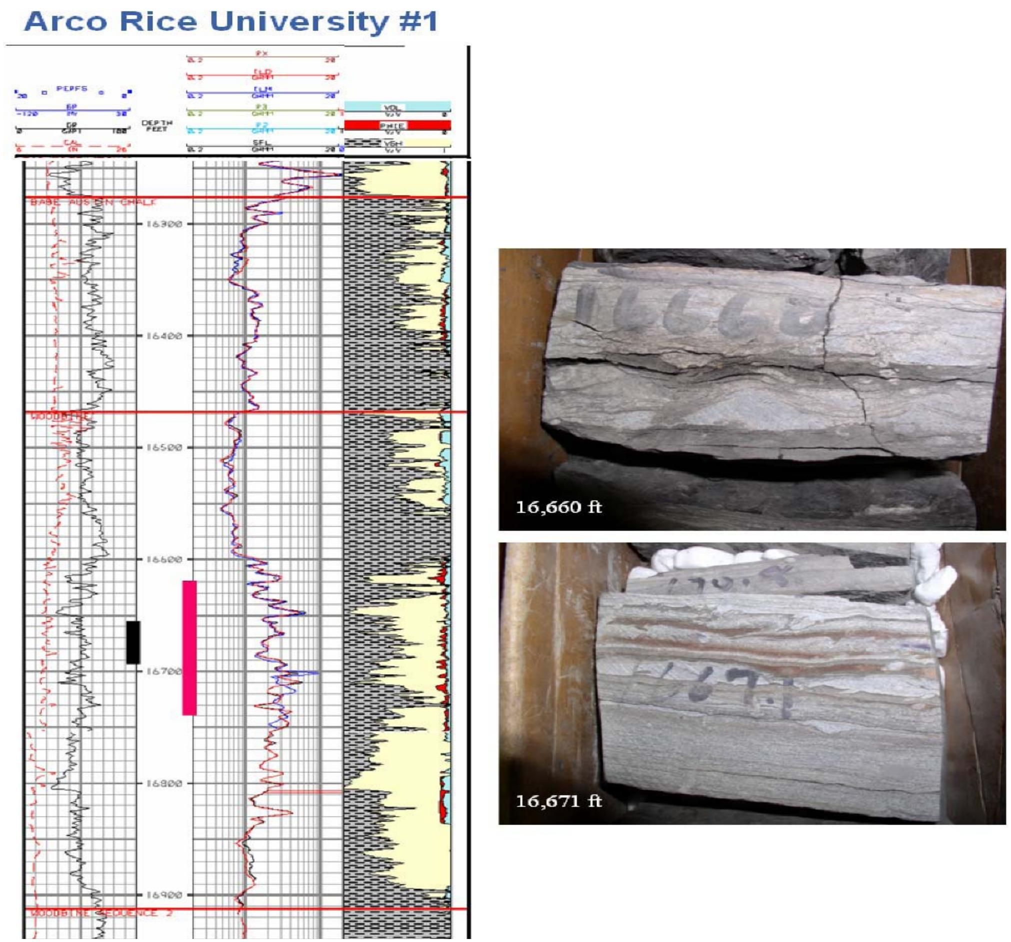


Figure 15. Arco Rice University 1 well. This well played a key roll in setting-up the Kincaid prospect by exhibiting thick sandstones and siltstones downdip of the Kincaid 1 location. The cored section is represented by the black bar and perforated interval is represented by the red bar on the well log. Log tracks from left to right are CALI-GR, Resistivity, and Rock Volume. While drilling, the mudlogger recorded gas 1950 units over the background through the upper Woodbine sandstones. Although the zone was perforated, there is no record of flow testing or stimulation attempts. Some key observations from core include bioturbation, syneresis cracks, flame structures, current and wave ripples. The depositional environment interpreted from core is prodelta with relatively shallow, calm water and high sediment influx. Core is three inches wide. (Core photos and interpretation courtesy of Ray Young.)

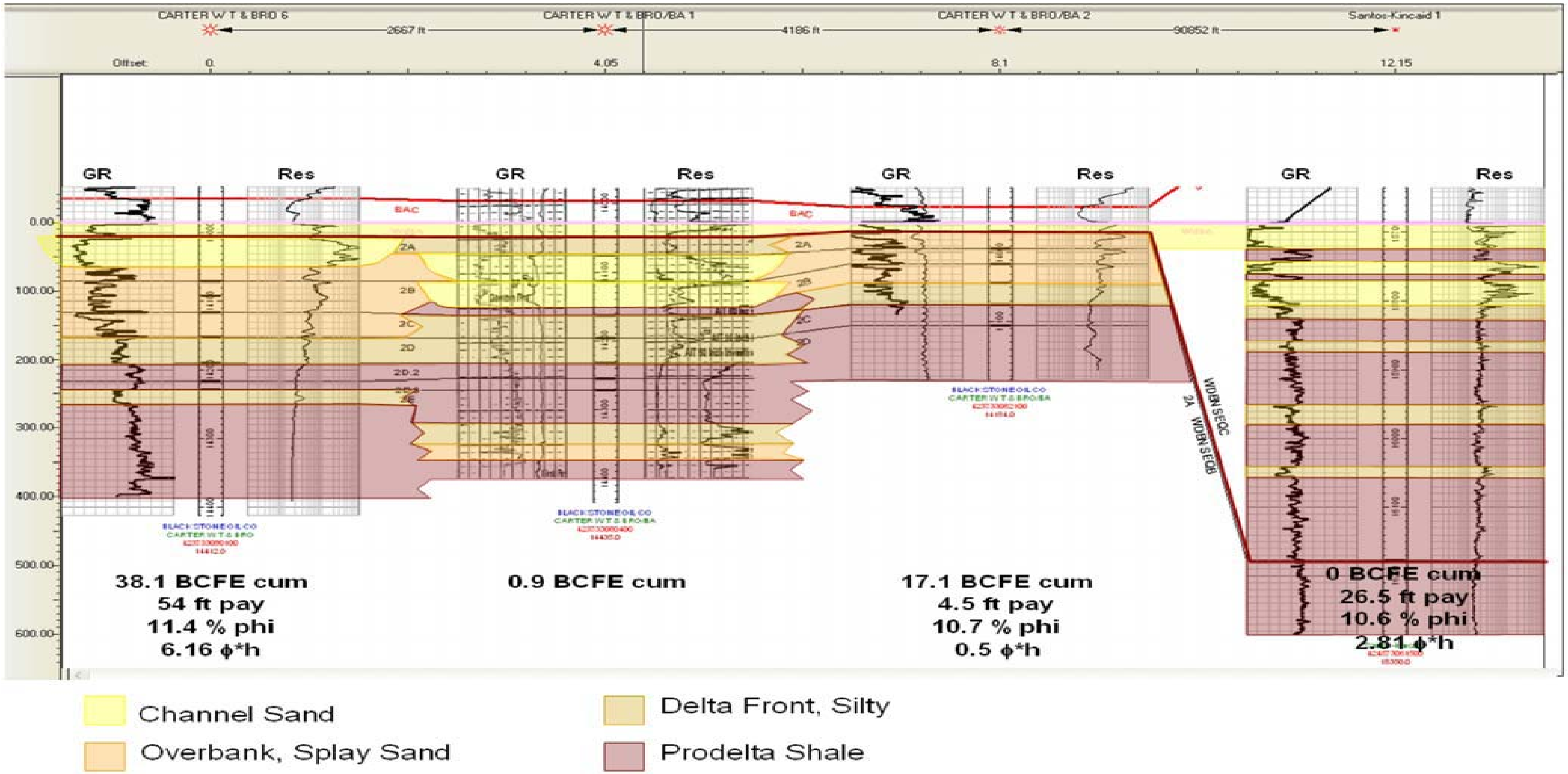


Figure 16. Cross section through Double A Wells Field with the Santos USA Kincaid 1 well included. Nine parasequences and four facies are identified. Reservoir sands may be highly variable over short distances. The Carter WT & Bros 6 and the Carter WT & Bros/BA 1 wells were drilled within months of each other with the same completion techniques. Both have similar log character with thick sandstones and high resistivity, but very different production. Parasequence interpretation suggests that these sandstones are not connected. Sandstone thickness, average porosity (phi), and porosity thickness (phi*h) do not directly correlate to production, nor does log facies. The Carter WT & Bro/BA 2 well has thin sands and low phi*h, but produced very well. The Kincaid well has similar log character to Carter WT & Bros 6 well but was tight in the lower two sands and wet in upper sand. Log tracks are GR on the left and resistivity on the right.

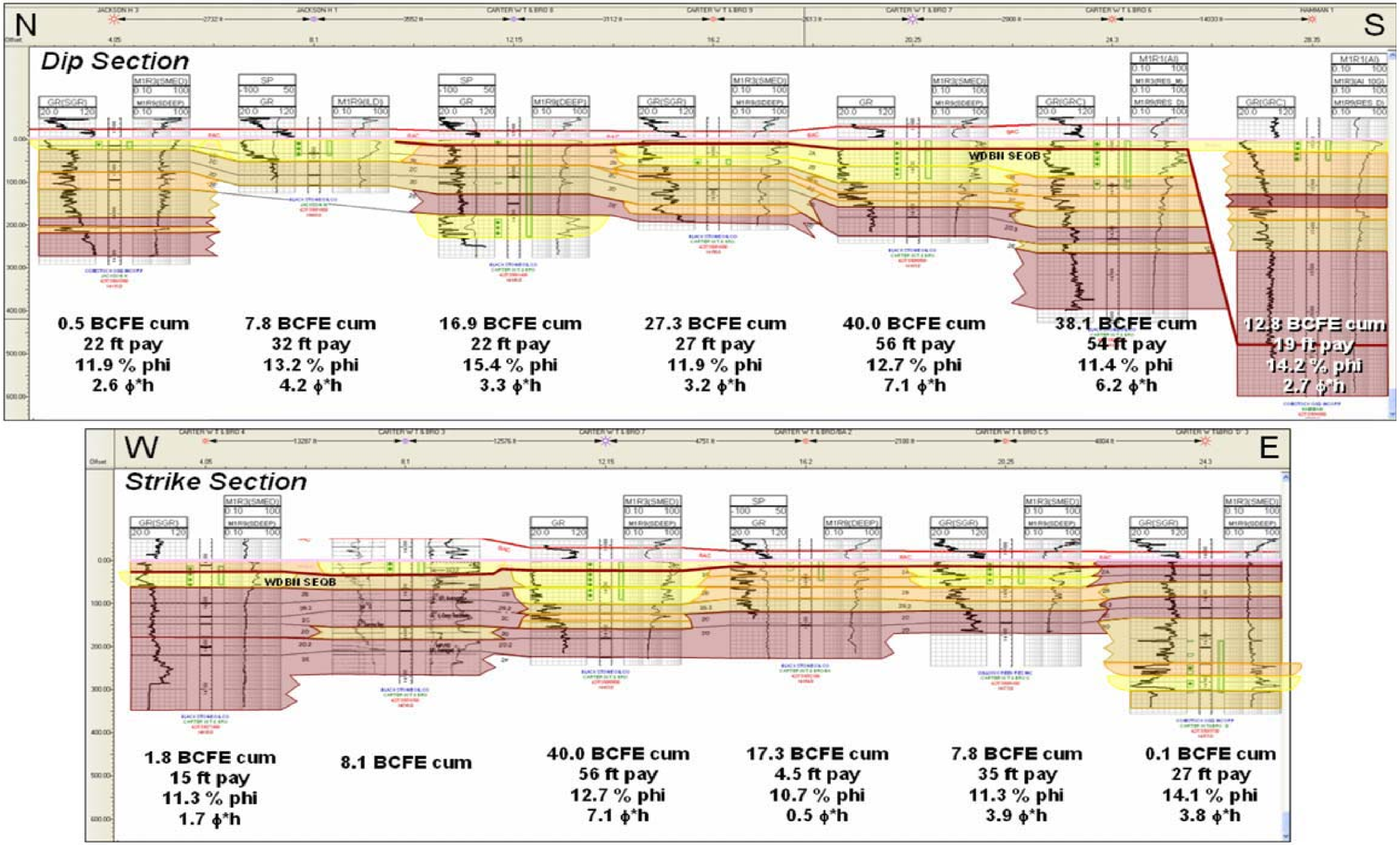


Figure 17. Double A Wells cross sections. The top section is a N-S dip section; the bottom section is a W-E strike section. See Figure 18 for location. When subdivided to a parasequence level, the Woodbine displays a high degree of heterogeneity. Sandstones are slightly more continuous in the dip direction. Production does not correlate to pay thickness, porosity (phi), or porosity-thickness (phi*h). See Figure 15 for log and facies explanation.

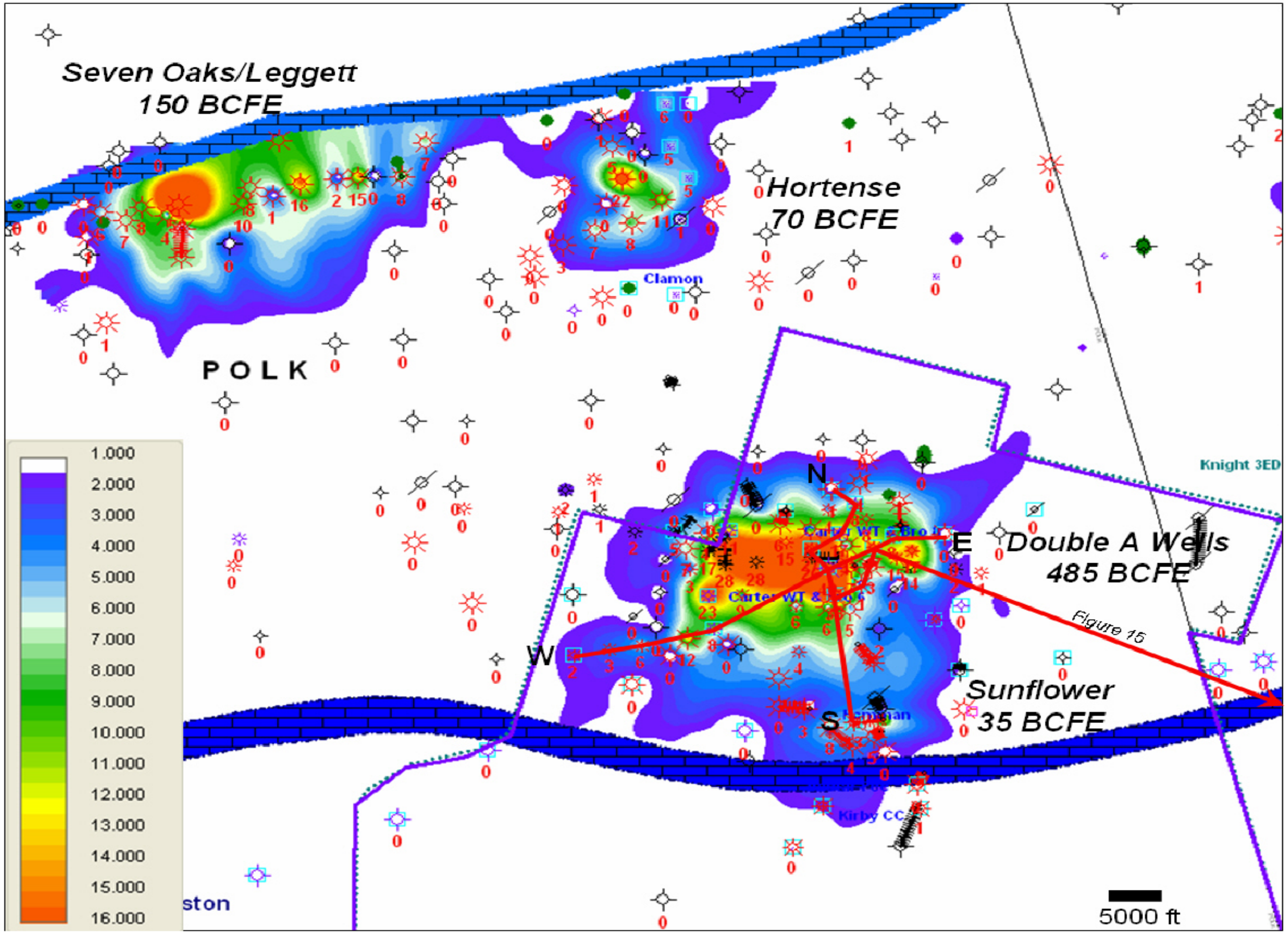


Figure 18. Cumulative Woodbine production by well. Outside of Double A Wells, fields generally have a few outstanding producers, and productivity can vary greatly from well to well. The best example of production variability is at Seven Oaks / Leggett. Only wells with a total depth greater than 12,000 ft are shown. Red numbers are well production cumulatives from the Woodbine in BCFE.

Diagenesis

Diagenesis at Double A Wells Field was well documented by Barrett et al. (2004) using core. Four diagenetic overprints were identified: calcite, quartz, quartz and calcite, and matrix. Calcite diagenesis is early and extensive, completely occluding porosity. Quartz overgrowths also occurred early, but vary from light to heavy cementation. In the quartz and calcite overprint, calcite is present with quartz and clays. It is not extensive and does not completely occlude porosity, and cementation varies from light to heavy. The last overprint is matrix-related. Here high percentage of depositional matrix occurs, and highly compacted sandstones are present. Clays impede quartz and calcite overgrowths, and secondary porosity from grain dissolution is more common.

These same diagenetic overprints were observed in nineteen rotary sidewall cores at Kincaid (Figure 19). Calcite cementation alone was not observed, and only three samples have the quartz diagenetic overprint. The quartz and calcite diagenetic overprint was observed in eight samples, and the matrix diagenetic overprint was observed in eight samples. Within the same sand lobe, multiple overprints with varying degrees of diagenesis are present. This is also true in the Carter 7 well, one of the best producers in Double A Wells (Figure 20). The Carter 7 well was exposed to minimal cementation, and clay coatings on the framework grains helped preserve primary porosity. In contrast, the Santos Kincaid well contains extensive overgrowths and is devoid of clay coatings in the few samples recovered. Porosity is interpreted to be secondary from grain leaching rather than primary porosity.

Barrett et al. (2004) also compared the digenetic overprint to lithofacies and showed that the best reservoirs of Woodbine, with the highest porosity and permeability, tend to be in massive and thick-bedded sandstones with quartz or quartz-carbonate diagenetic overprints. While these lithofacies and overprints tend to be the best reservoir, reservoirs with the same lithofacies and diagenetic overprint can be tight and fully cemented. Unfortunately for the Kincaid well, despite having thick-bedded sandstones and quartz-carbonate diagenetic overgrowth, it is very tight. Secondary porosity due to grain leaching, as observed in the Kincaid well, has less permeability than primary porosity preserved by clay coatings, as observed in the Carter 7 well. Thus even if explorationists find the more prospective lithofacies in the Woodbine, diagenesis is still the key to a successful well.

The thick sand at 15,700 ft did flow at commercial rates when it was tested, but it was wet, which is an anomaly in the Woodbine. The commercial failure is believed to be the result of a possible seal breech, as noncommercial gas was present in the reservoir. Structural movement associated with subtle anticlinal folding could have fractured the top seal. Perhaps future 3D seismic will better image the structure and improve the understanding of why seal integrity is compromised

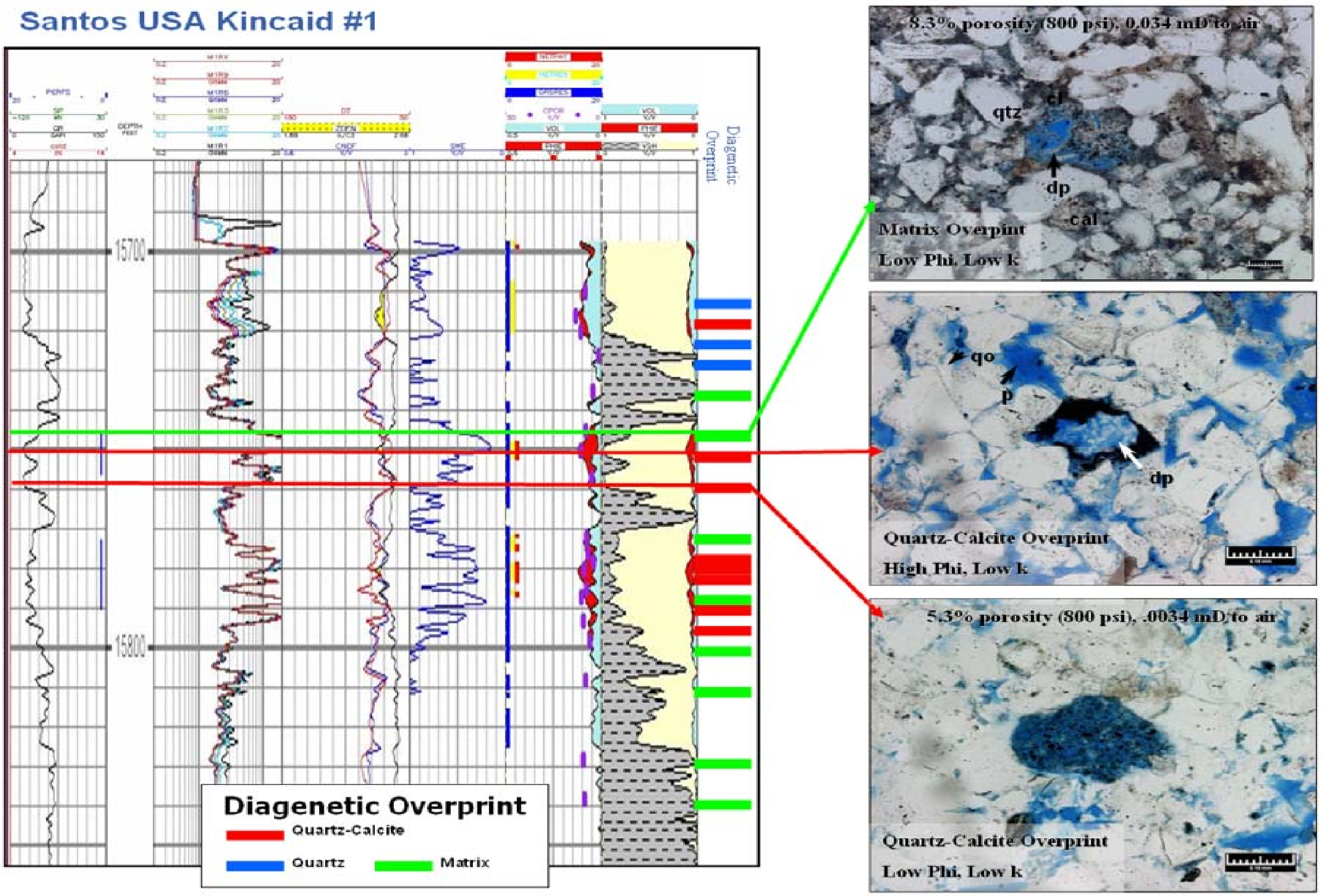


Figure 19. Santos USA Kincaid 1 diagenesis. Diagenetic overprint as described in Barrett et al. (2004) was applied to rotary sidewall cores taken at the Kincaid well. Diagenetic overprints vary within the same sandstone on logs. Porosity appears to be moldic from grain dissolution, with little primary porosity. Log tracks from left to right are: GR, Resistivity, Sonic and Density, Swe, Gross (Blue)-Net (Yellow)-Pay (Red), and Rock Volume. Core Points are indicated by the purple dots and diagenetic overprint locations.

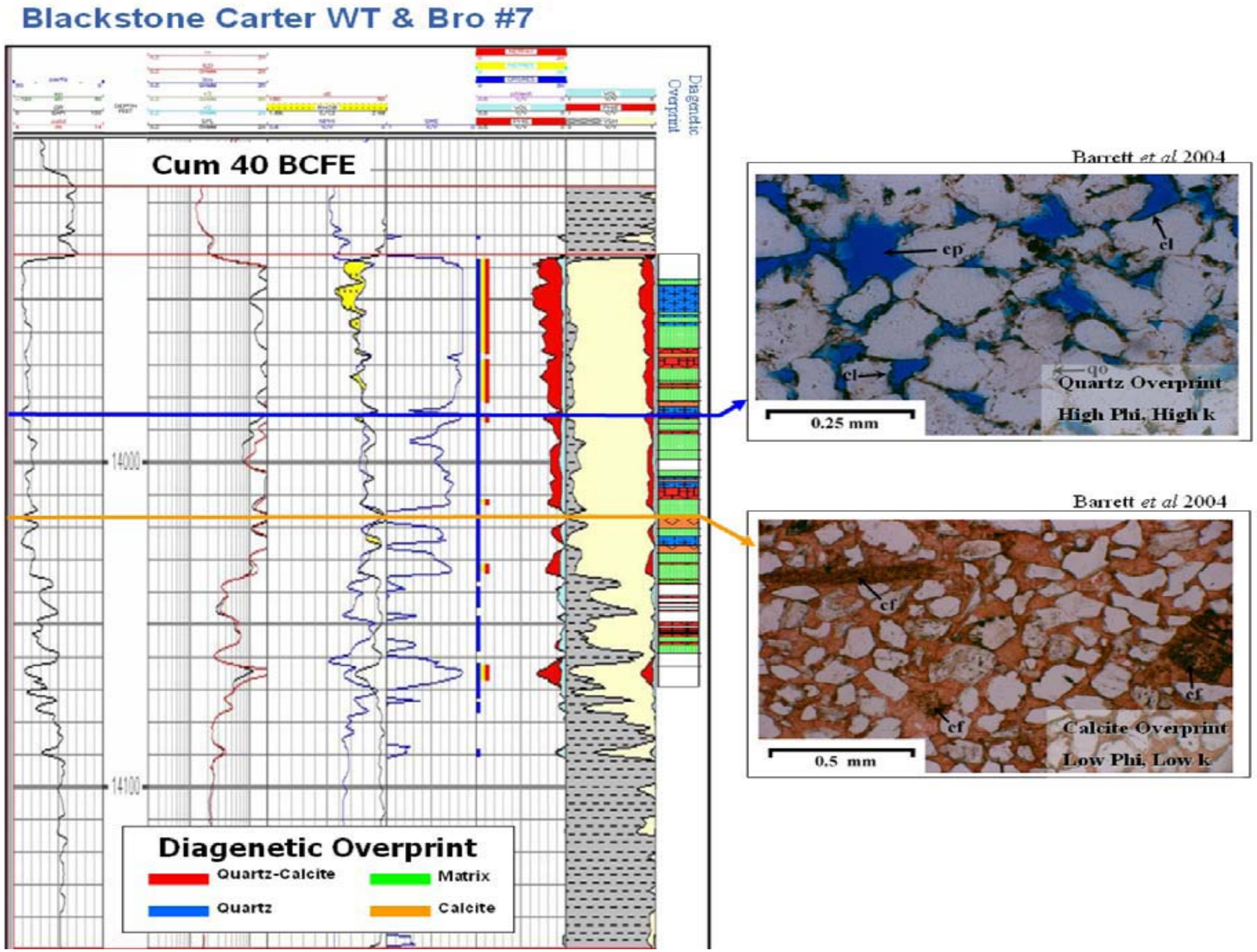


Figure 20. Blackstone Carter WT & Bro #7 well with diagenetic overprint from Barrett et al. (2004, reproduced with permission of the Gulf Coast Association of Geological Societies). Diagenetic overprint varies greatly within the same sandstone package. The upper photomicrograph has quartz overgrowths, but cement is light and clay coatings are present on the grains. The lower micrograph has the calcite overprint. It is highly cemented with few point to point contacts, indicating early cementation, before compaction. Although it has a clean gamma and high resistivity, porosity is completely occluded, as observed on the log. See Figure 19 for log explanation.

Conclusion

Seismic, log, and core information were integrated to create a new depositional model for the Woodbine Formation in East Texas. Seismic stratigraphy and seismic facies analysis led to the recognition of younger sequences depositing deltaic sediments farther basinward than previously recognized. New seismic stratigraphy interpretation improved well log correlations, helping to distinguish a sequence stratigraphic framework and eliminating the pitfalls of lithostratigraphic correlations. Despite intense efforts with geophysical attributes, the techniques employed were unable to distinguish reservoir from non-reservoir, making it more necessary to rely on sound geologic models.

The Kincaid 1 well was drilled based on this stratigraphic framework and discovered a new delta complex east of previous drilling and farther basinward from the Sligo margin. Despite this proof of concept and apparent reservoir-quality sandstone from logs, the Kincaid reservoirs were tested as a non-commercial accumulation.

A detailed analysis of Double A Wells and other surrounding fields showed the Woodbine is highly stratified and diagenetically complex. It is believed that failure at Kincaid was due to an unfavorable diagenetic history. From a pessimistic standpoint, this raises the assessment of reservoir risk. Finding sandstone is one challenge, but finding reservoir-quality sandstone is an even greater challenge. From an optimistic standpoint, this creates opportunity. In all of the Woodbine fields studied, fantastic production was offset by very poor performing wells or dry holes. Is it possible to have an offset to the Kincaid well in a separate stratigraphic compartment with a more favorable diagenetic history? Did the Kincaid test the fringe of the next Double A Wells Field analogue?

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