Quantifying Bypassed Pay Through 4-D Post-Stack Inversion*

Robert Woock[1], Sean Boerner[2] and James Gamble[1]

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[1]Stone Energy, Lafayette, LA, United States (woockrd@stoneenergy.com)
[2]Formerly CGGVeritas

Abstract

In this study, we performed a 4D inversion study to identify remaining potential within three sands of the Amberjack field, Gulf of Mexico. Petrophysical analysis was critical in determining the changes in reservoir properties due to pressure and fluid changes in each of the sands. This analysis showed that changes in acoustic impedance could be tied to changes in pressure as well as changes in the fluid saturation from oil to brine. Post-stack seismic volumes from a base and monitor survey were processed and calibrated to minimize differences between the two surveys. Post-stack acoustic impedance (P-Impedance) inversion was performed on both surveys and a difference volume was calculated between the post-stack inversion results. Maps were generated of acoustic impedance, acoustic impedance difference, and top reservoir depths for each of the sands. Cutoffs were applied to these maps to match hydrocarbons that had been produced from the reservoir. Once the cutoffs were established, remaining potential maps could be generated.

Reference

Yielding, G., A.M. Roberts, J.S. thatcher, J. Walsh, B. Freeman, M.E. Badley, and J. Watterson, 1991, Fault interpretation during seismic interpretation and reservoir evaluation: 1st AAPG/SPE Archie Conference Proceedings The integration of Geology, Geophysics, Petrophysics, and Petroleum Engineering in reservoir delineation, description, and management, p. 224-241.

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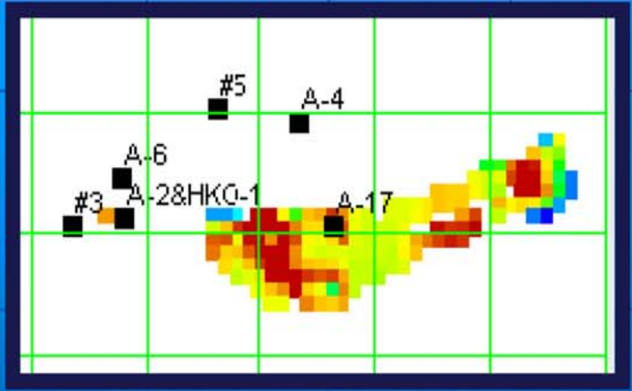
Quantifying bypassed pay through 4D post-stack inversion

Presented to : AAPG 2011 ACE
Tuesday, April 12 , (Theme 9) Seismic Stratigraphic and Source Rock Interpretation (AAPG/SEPM)



Presented by :

Robert Woock	Senior Geophysicist	Stone Energy Company
Sean Boerner	Geophysicist	BHP
James Gamble	Geologist	Stone Energy Company

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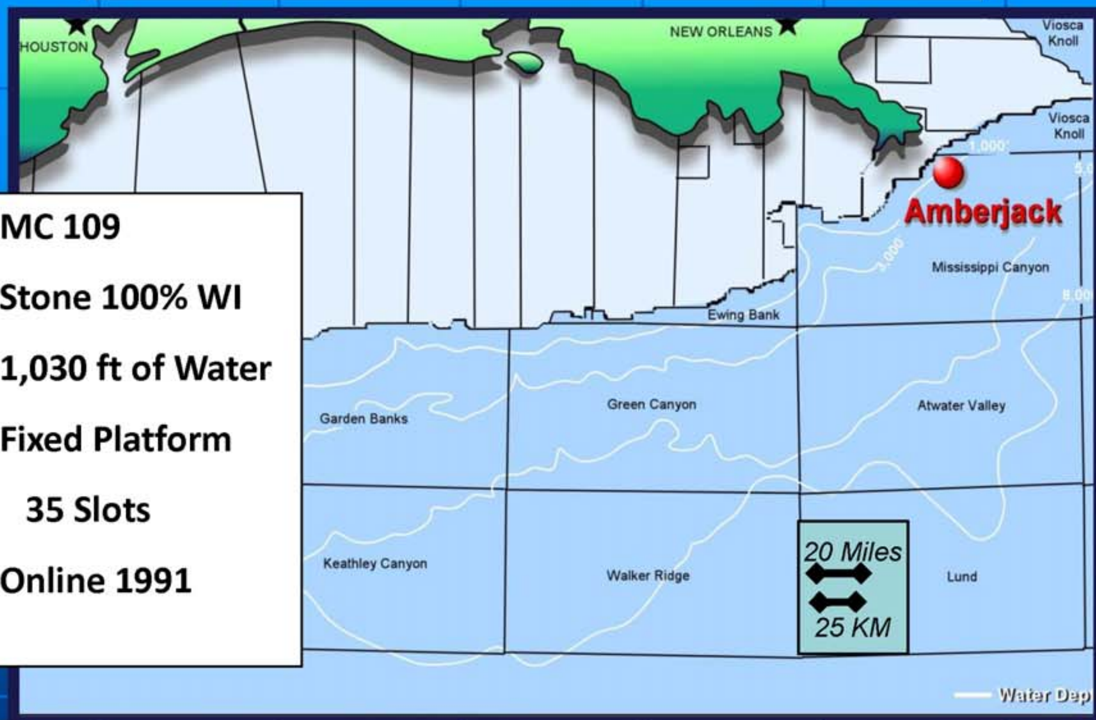
Amberjack Field Location
Gulf of Mexico

Mississippi Canyon Block 109 Amberjack Field



MC 109

Stone 100% WI

1,030 ft of Water

Fixed Platform

35 Slots

Online 1991

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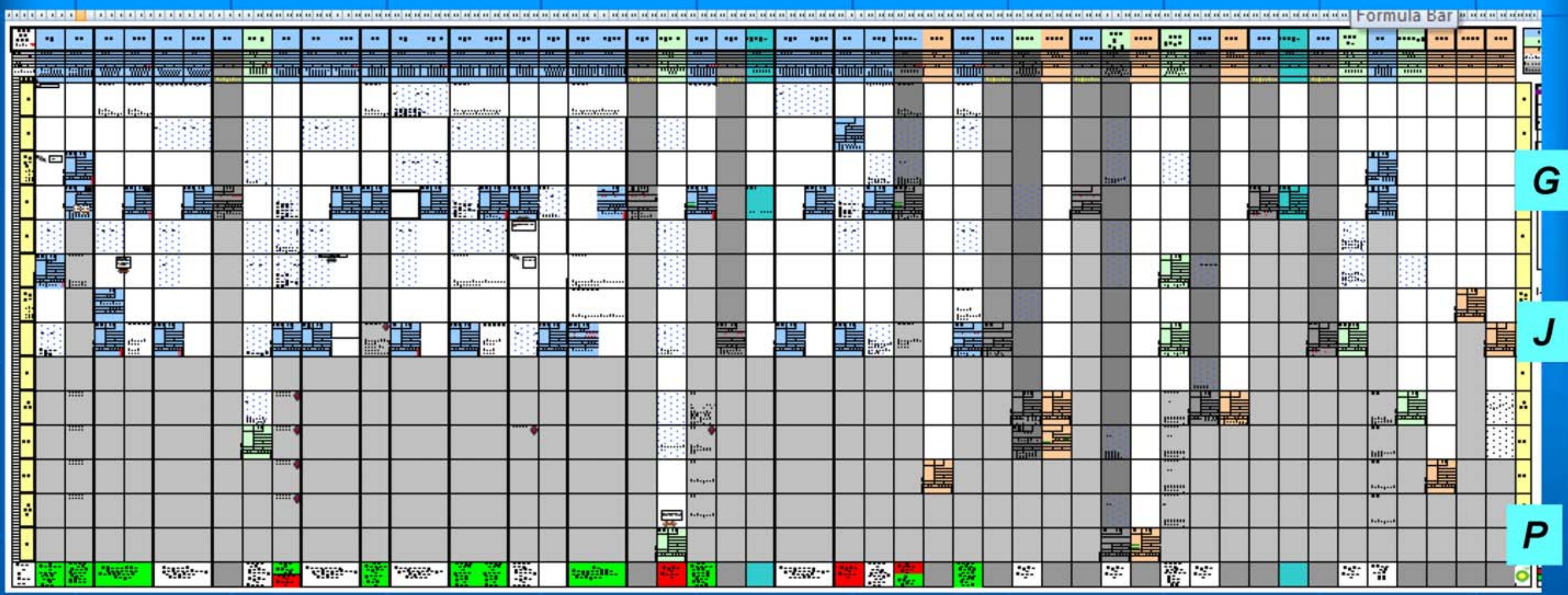
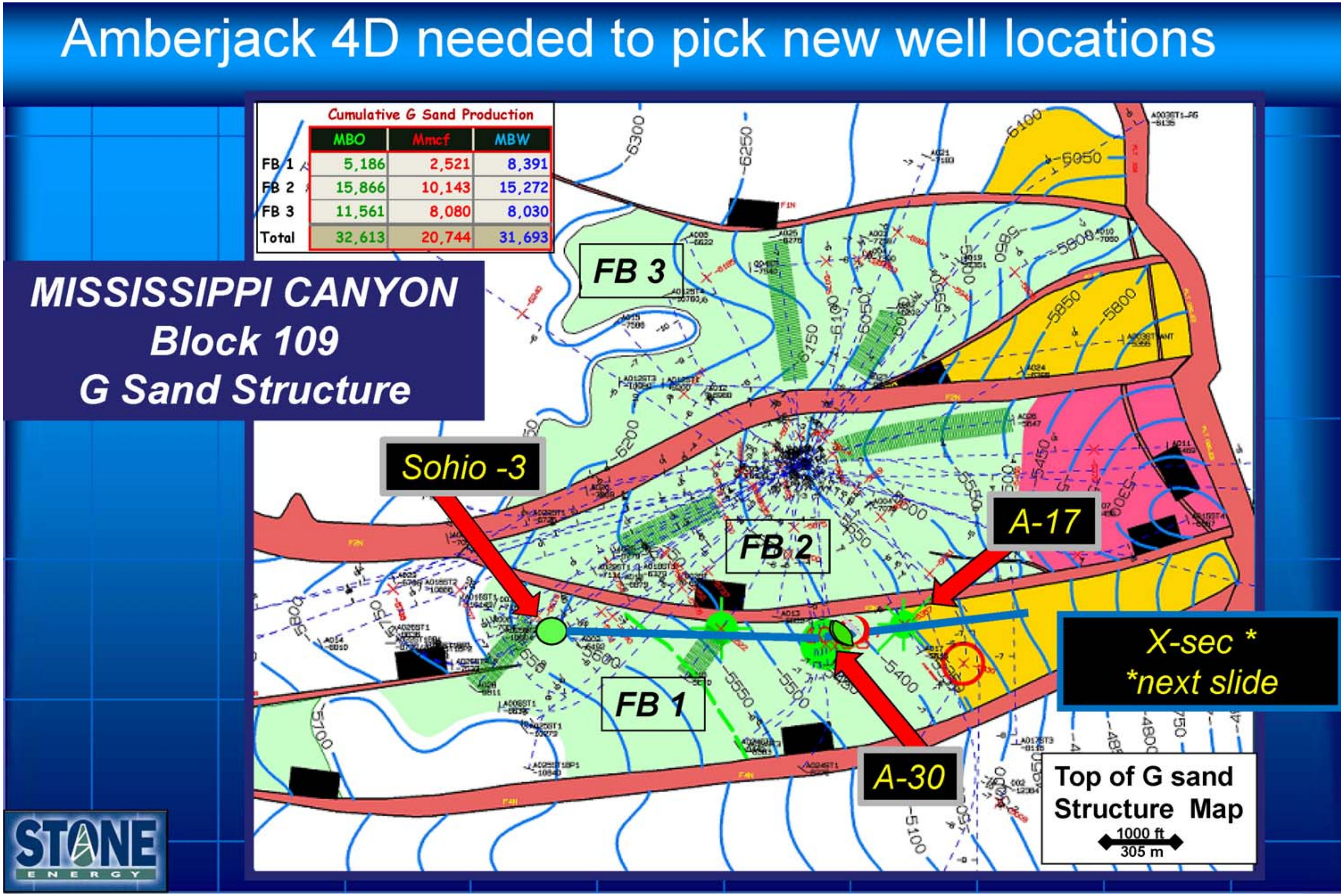
Notes by Presenter: The field is located about 20 miles off the edge of the Louisiana birds foot delta. MC block 109, Stone 100% WI, the Amberjack Fixed Platform has 35 well Slots and sits in 1,030 ft of Water Production came Online in 1991.

Amberjack Well Utilization Chart

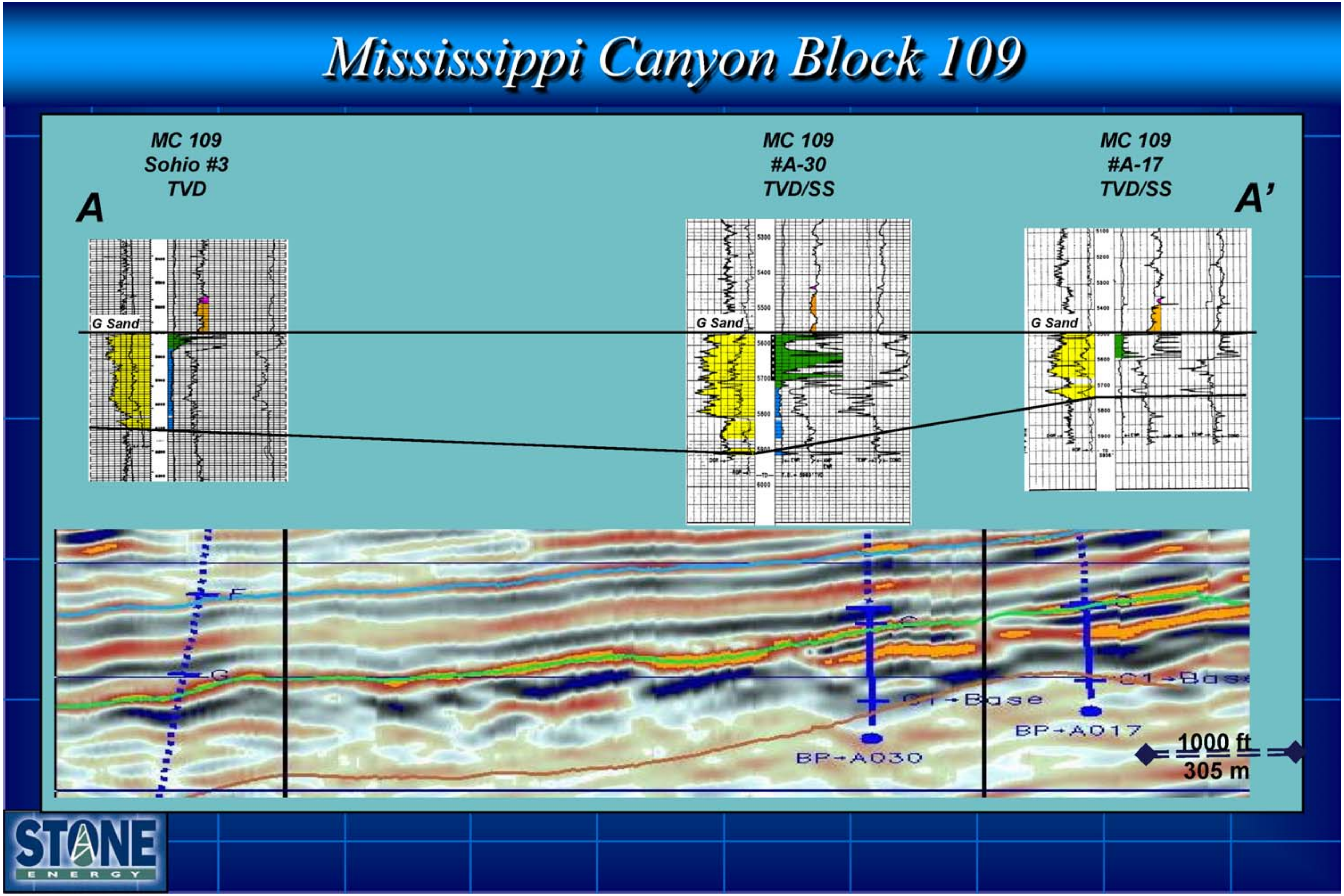


- Heavy dependence on G and J production
- Limited number of reclaimable slots

Notes by Presenter: This is the Amberjack Well Utilization Chart. Note the heavy dependence on G and J production. P sand production was limited to two boreholes, but cummed over 5 million BO. Due to the limited number of reclaimable slots, redevelopment required exacting target selection processes. 4D was seen as necessary to identify and quantify many of the potential targets.

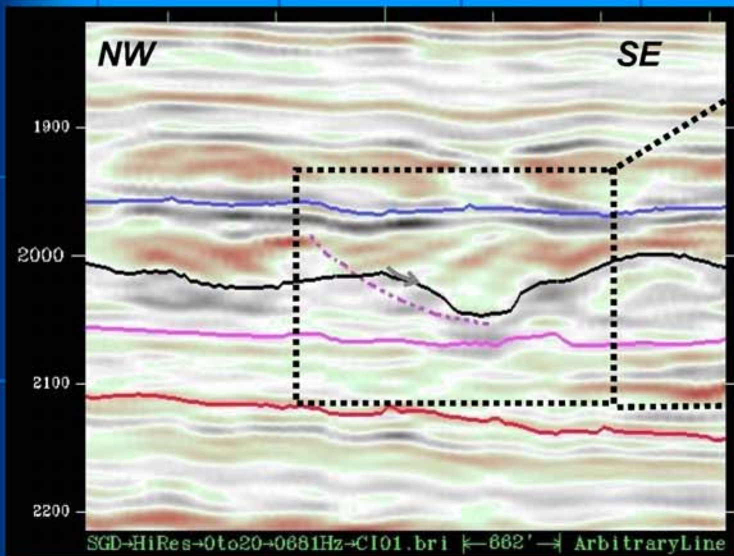


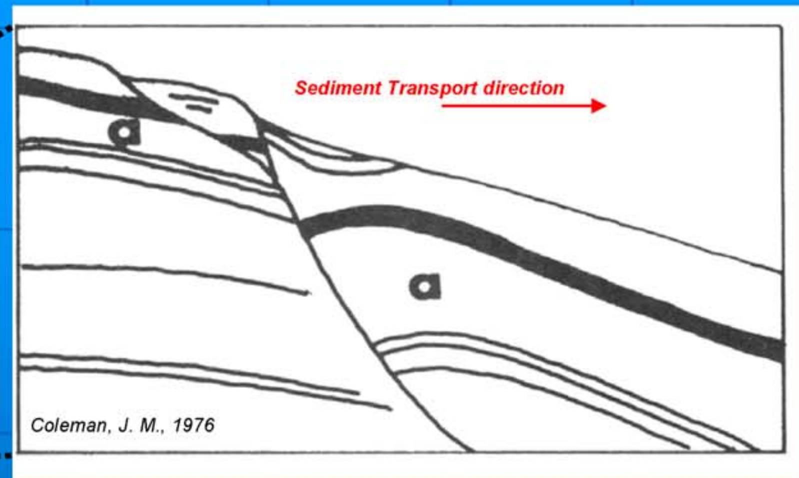
Notes by Presenter: This is the G- sand top structure for the MC109 Amberjack field. This presentation will focus on the southern fault block. We will examine a couple lines running updip from west to east through the Sohio 3, the A-30, and the A-17 wells. At the time of the 4D, there were no penetrations of the updip portion of this fault block (as seen in yellow).

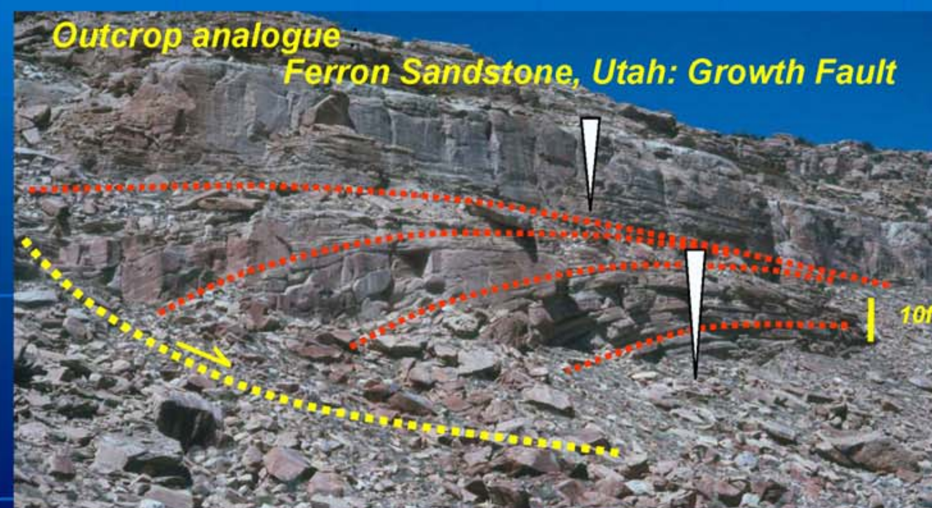


Notes by Presenter: This is the G sand cross-section and seismic expression in reflectivity from the Sohio #3 well to the A-17 well. Clinoforms are clearly delineated along this tract. All three wells have exhibited separate API values and pressure histories confirming compartmentalization.

Shelf edge Delta depositional faults: Seismic, Schematic, & Outcrop







Modified from; Compartmentalization interpreted as shelf edge clinoforms (Yielding et al, 1991)

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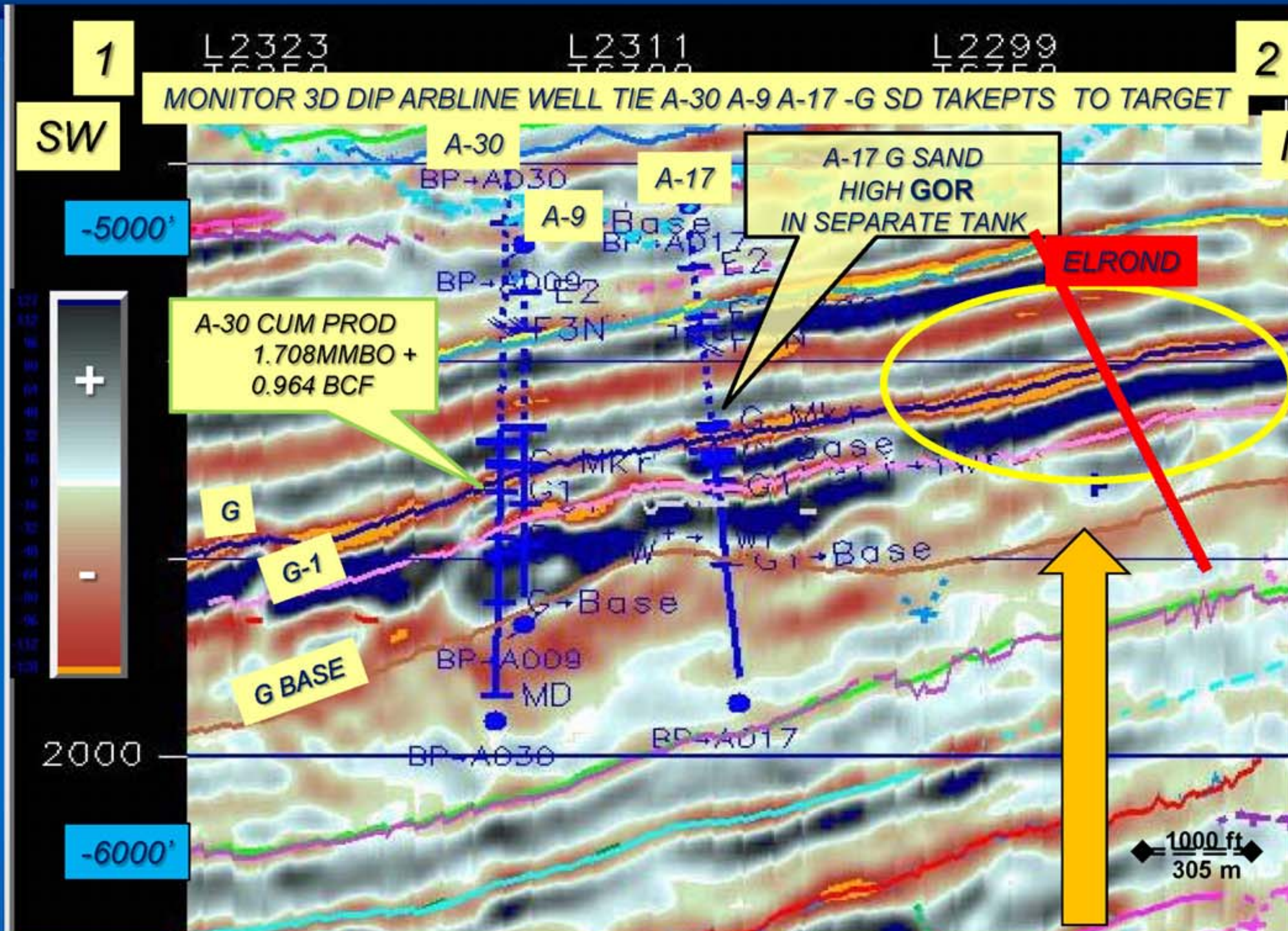
Notes by Presenter: Syndepositional growth faults are common in shelf edge delta complexes, with associated rotation of bedding planes in the hanging wall. Note the growth structure in this field seismic line. As noted by prior authors, the interpretation of intra-reservoir growth faults were derived from a combination of seismic mapping, literature research and the use of outcrop analogues such as the Ferron Sandstone in Utah.

MISSISSIPPI CANYON 109: *ELROND* Prospect



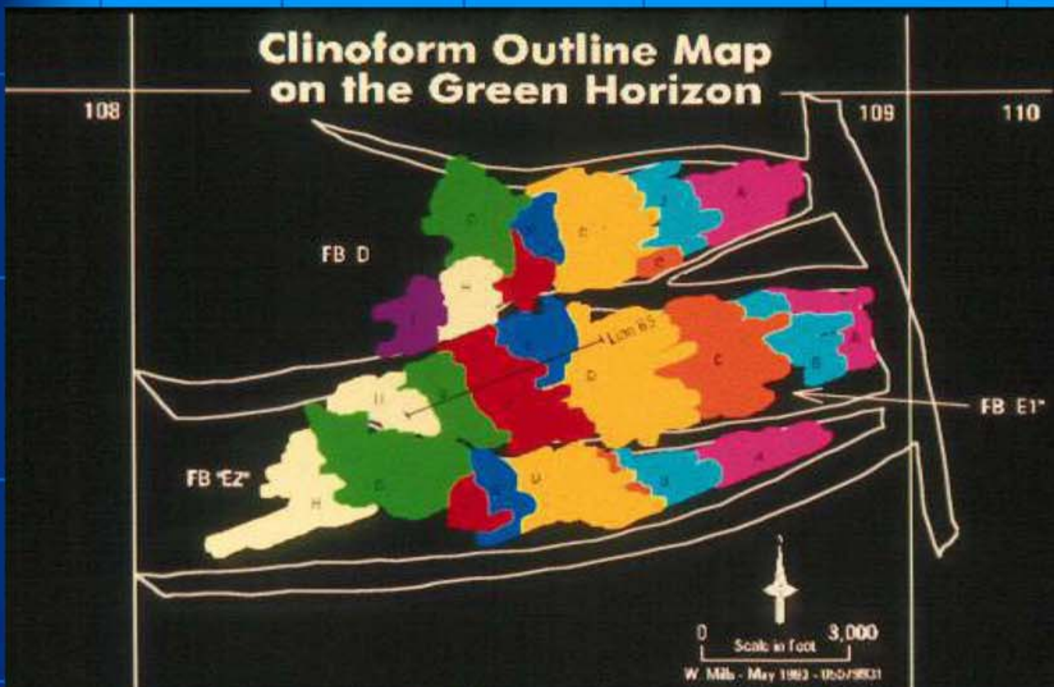
This updip pay objective requires input from Geology, Engineering, and Geophysics. But how do you support the story beyond a snapshot?

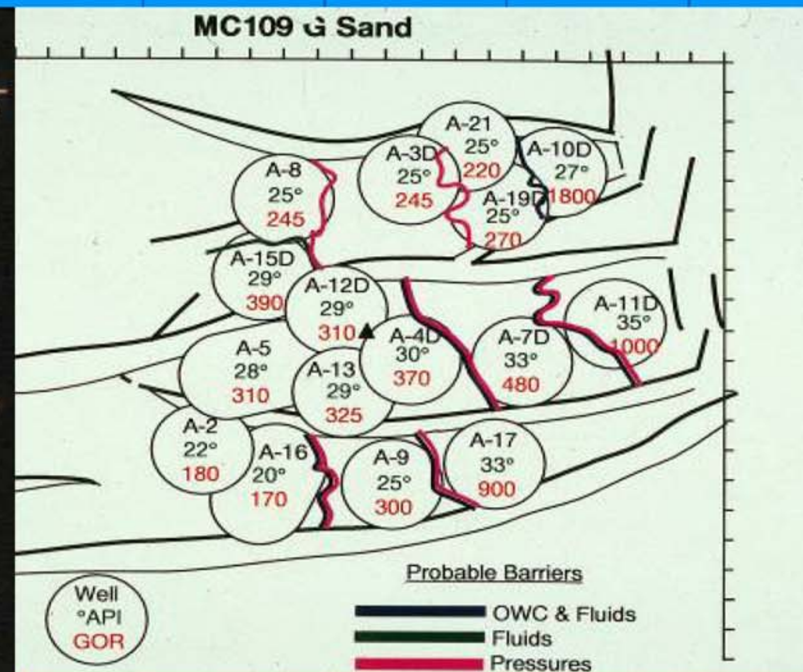
Management wants 4D verification for new objectives

Notes by Presenter: This line moves further updip in the same fault block, from a potential bypassed clinoform, through the A-030 and A-017 wells, and into the Elrond prospect (now drilling). Several well have already proven the accuracy and value of the 4D. We will see some results at the end of this presentation.

Historic View of Amberjack Compartments

Production, GOR and API data indicated reservoir compartmentalization in the G reservoir.





Compartmentalization interpreted as shelf edge clinoforms (Yielding et al, 1991)

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Notes by Presenter: These pictures are taken from an earlier publication. The project team remapped these overlapping shapes as voxel clinoform bodies. The colors represent coeval depositional events. API and GOR climbs in updip isolated clinoforms. The empty areas may be potential target areas for redevelopment.

Amberjack 4D field study

Our **4D inversion** on three sands, **G, J,** and **P** included these steps;

1. **Petrophysical analysis** conducted to determining the **acoustic impedance** of **pressure** and **fluid saturation**
2. Post-stack seismic volumes from a **base** and **monitor** survey were **calibrated** to minimize differences
3. **Post-stack** acoustic impedance (**P-Impedance**) inversion on both surveys
4. A **difference** volume was calculated between the post-stack inversion results.
5. Maps were generated of **acoustic impedance, acoustic impedance difference**, and **top reservoir depths**.
6. **Cutoffs** were applied to match hydrocarbons that had been produced from the reservoir.
7. Remaining **potential** maps were generated from calibrated difference maps.

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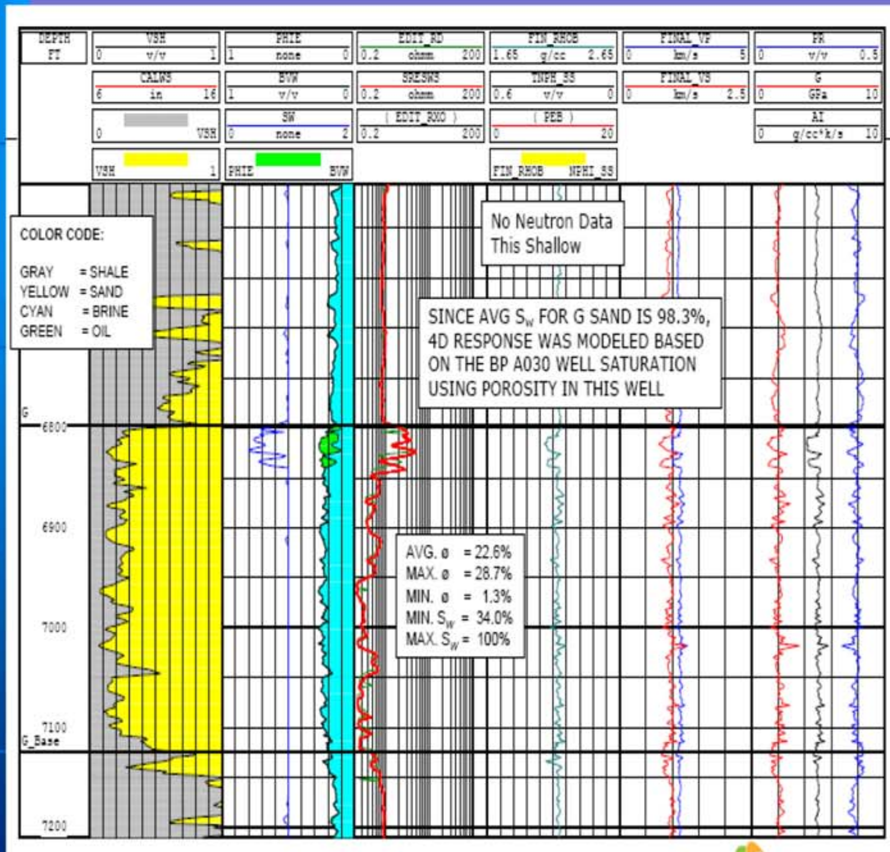
Notes by Presenter: Our 4D inversion on three sands, G, J, and P included these steps:

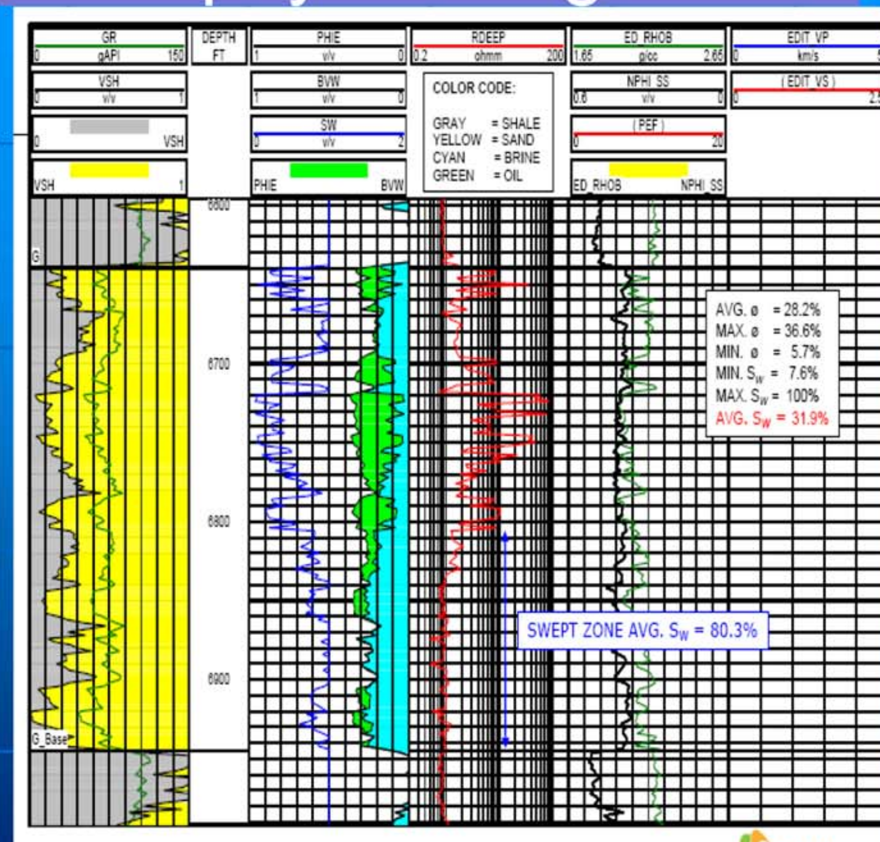
1. Petrophysical analysis conducted to determining the acoustic impedance of pressure and fluid saturation
2. Post-stack seismic volumes from a base 3D (WG 1994) and monitor 3D (Proprietary 2002) survey were calibrated to minimize differences
3. Post-stack acoustic impedance (P-Impedance) inversion was processed on both surveys
4. A difference volume was calculated between the post-stack inversion results.
5. Maps were generated of acoustic impedance, acoustic impedance difference, and top reservoir depths.
6. Cutoffs were applied to match initial saturations and hydrocarbons that had been produced from the reservoir.
7. Remaining potential maps were generated from calibrated difference maps.

G sand Logs

- A-25ST1 & A-30 wells Petrophysical logs



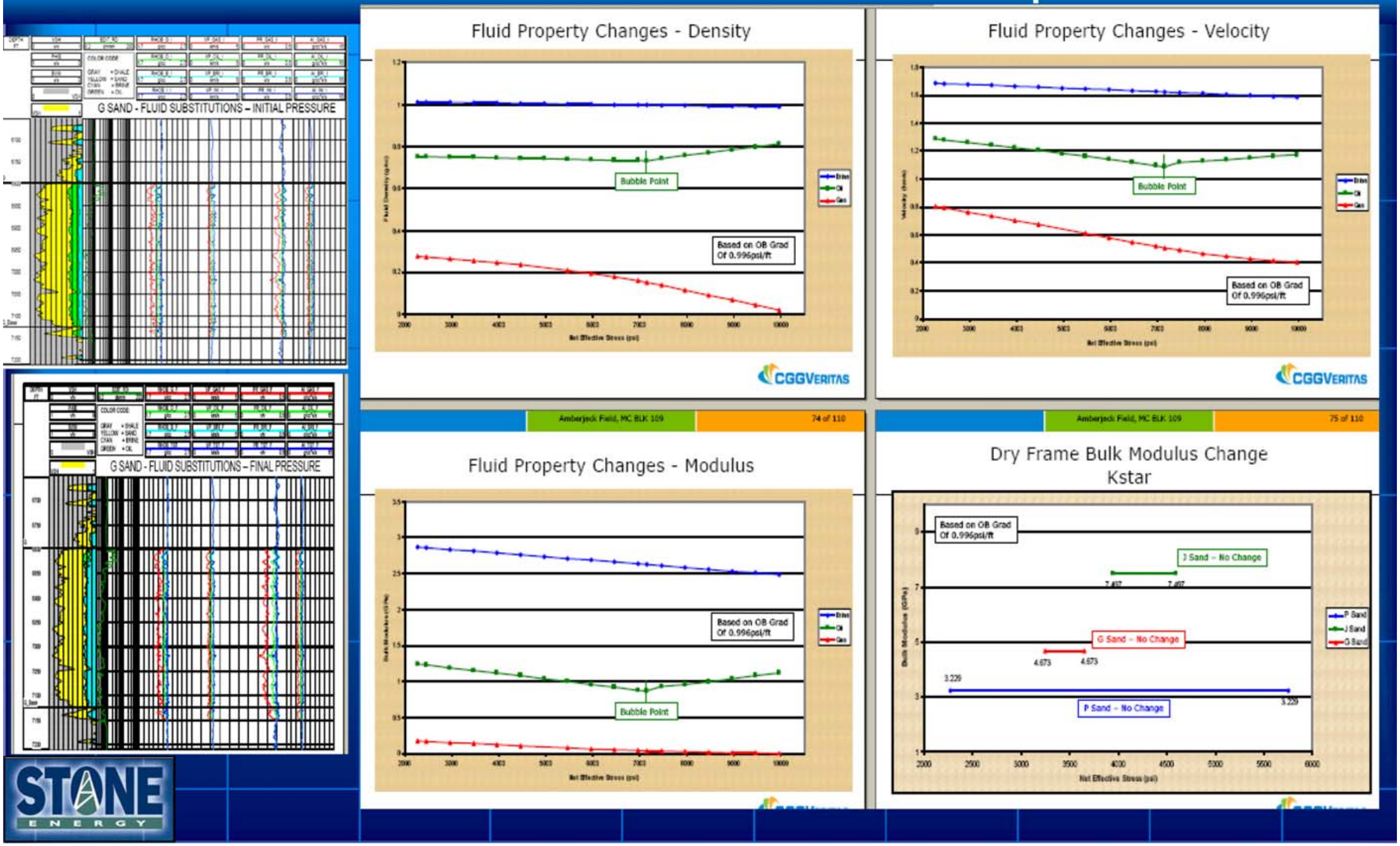
BASIC INTERPRETATION - BP A025ST1 - G Sand



BASIC INTERPRETATION - BP A030 - G Sand - Swept Zone

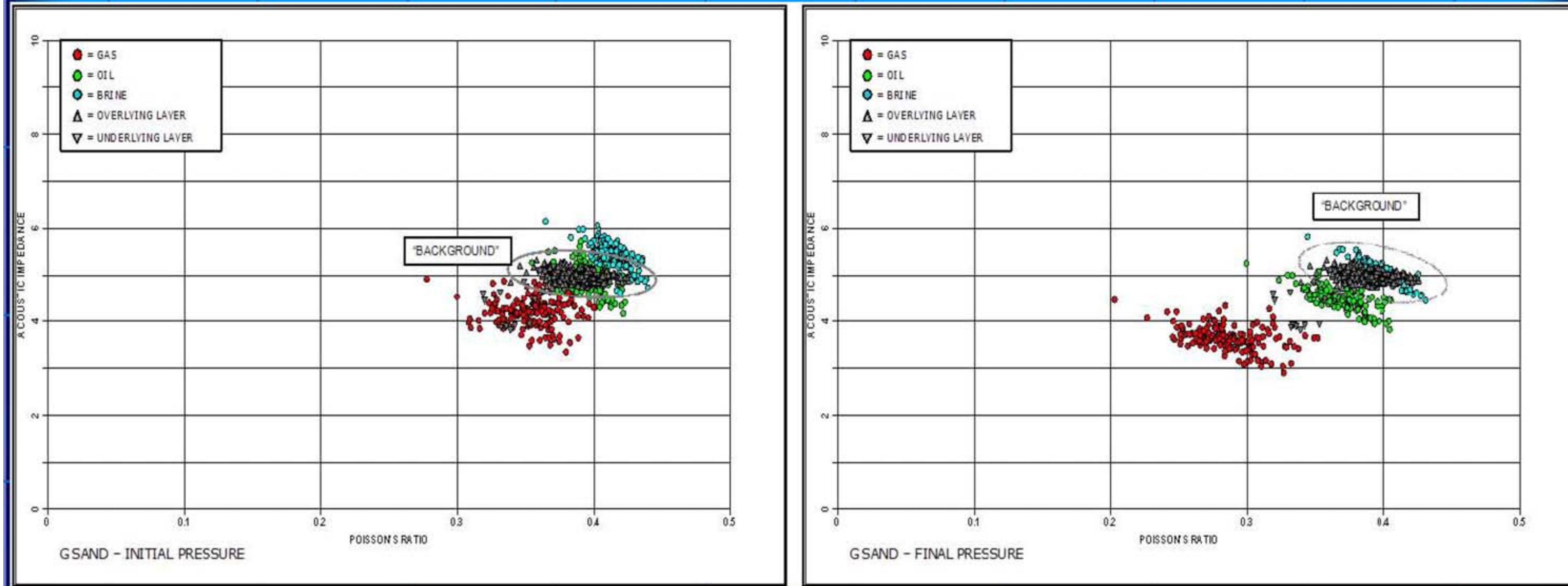
Notes by Presenter: Petrophysical analysis was critical in determining the changes in reservoir properties due to pressure and fluid changes associated with production activities. We quantified the acoustic impedance values tied to pressure and fluid saturation (oil and brine) in initial and at time 2. Here are shown the edited insitu G sand logs from two of the key wells used in our petrophysical analysis.

G sand Modeled Production Response



Notes by Presenter: Petrophysical modeling plots show the measurable changes from typical G-sand production histories on Density, P-Velocity, Bulk Modulus, and Dry frame modulus. Deviations from the horizontal lines are the measurable signals that can be searched for in the 4D difference volumes. The two G sand logs show modeled pressure and fluid changes from initial to monitor time conditions. The horizontal axis for the x-plots is net effective stress. Virtually all the Petrophysical signal comes from the reservoir fluids. The lower right box confirms the dry frame bulk modulus of each reservoir is fairly stiff in this stress range.

‘G’ sand fluid properties

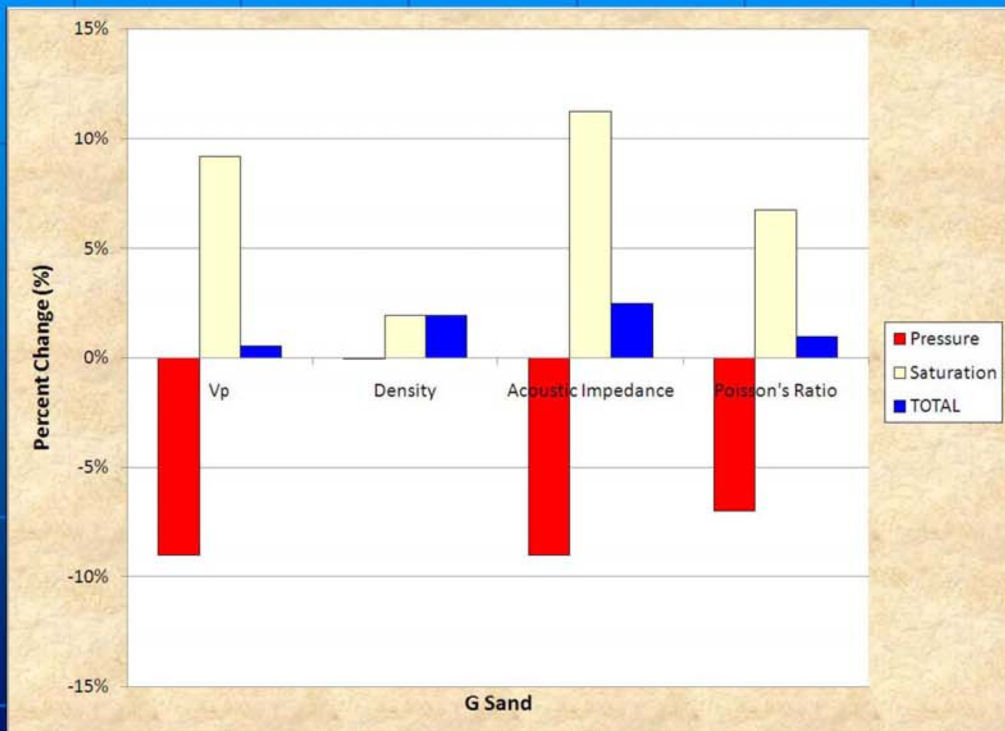


‘G’ sand fluid properties at initial pressure conditions (left) and final pressure conditions (right).

Notes by Presenter: Cross-plots were used to quantify the modeled and observed petrophysical changes. Here we see G-sand fluid properties at initial pressure conditions (left) and final pressure conditions (right). Note the change in reservoir rocks relative to the background (shale) from a decrease in pressure.

Quantifying bypassed pay through 4D

Changes in the 'G' sand fluid properties with changes in pressure and oil saturation from initial to final conditions. Reducing pressure decreases P-impedance . Replacing oil with brine increases P-impedance. Replacing oil with brine with the observed pressure drop tends to slightly increase the total P-impedance



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Notes by Presenter: This handy bar chart illustrates the scale and sign of the 'G' sand properties differentials relative to the maximum impedance signal. These deltas are the results of changes in pressure and oil saturation from initial to final conditions. Reducing pressure decreases P-impedance. Replacing oil with brine increases P-impedance. Replacing oil with brine with the maximum observed pressure drop tends to slightly increase the total P-impedance. From the lack of a density response to pressure we see the utility of the prestack density volume from the monitor survey in helping distinguish which reservoirs had clean pressure signals and which had some combination of pressure and brine signals.

Amberjack pressure changes

FLUID PROPERTIES – G SAND

Initial Pressure

APPROXIMATE TEMP.	115	degF
APPROXIMATE PRESS.	2476	psi
SALINITY	66,700	ppm (NaCl equivalents)
API	28	deg
GOR	310	scf/b*
GAS GRAVITY	0.65	

	BRINE	OIL	GAS
BULK MODULUS (GPa)	2.790	1.395	0.033
DENSITY (g/cc)	1.043	0.817	0.145

*Maximum GOR under these conditions is approximately 310 scf/boe

Final Pressure

APPROXIMATE TEMP.	115	degF
APPROXIMATE PRESS.	2076	psi
SALINITY	66,700	ppm (NaCl equivalents)
API	28	deg
GOR	310	scf/b*
GAS GRAVITY	0.65	

	BRINE	OIL	GAS
BULK MODULUS (GPa)	2.771	1.359	0.024
DENSITY (g/cc)	1.042	0.815	0.120

Pressures correspond to the end of Western 3D Seismic Survey, October 1995 and BP Seismic Survey which ended January 2003.

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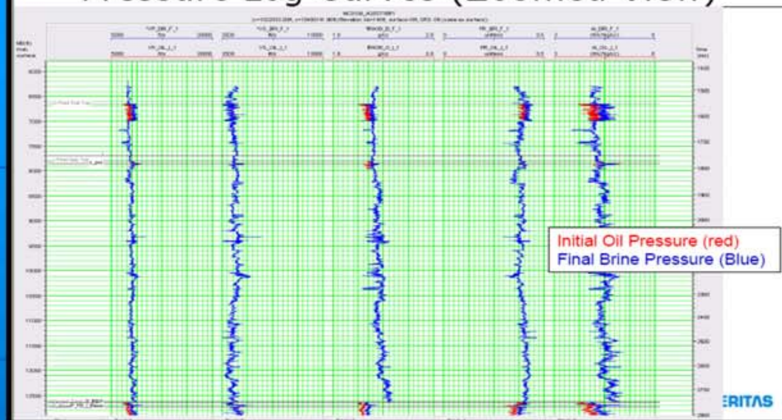
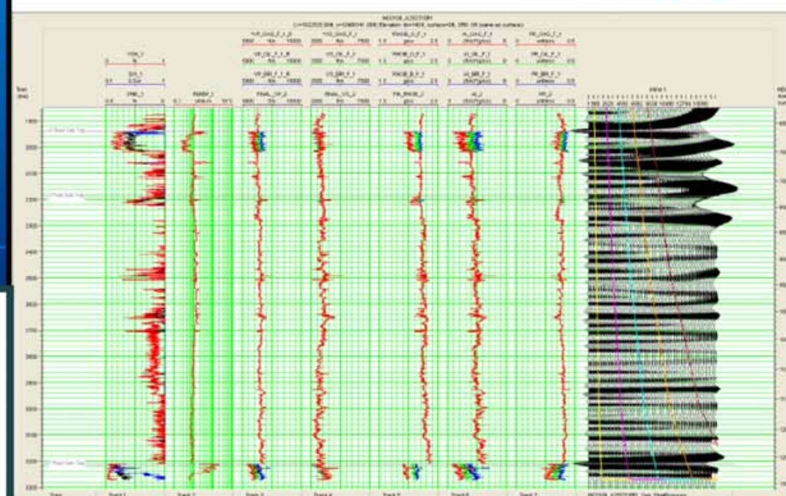
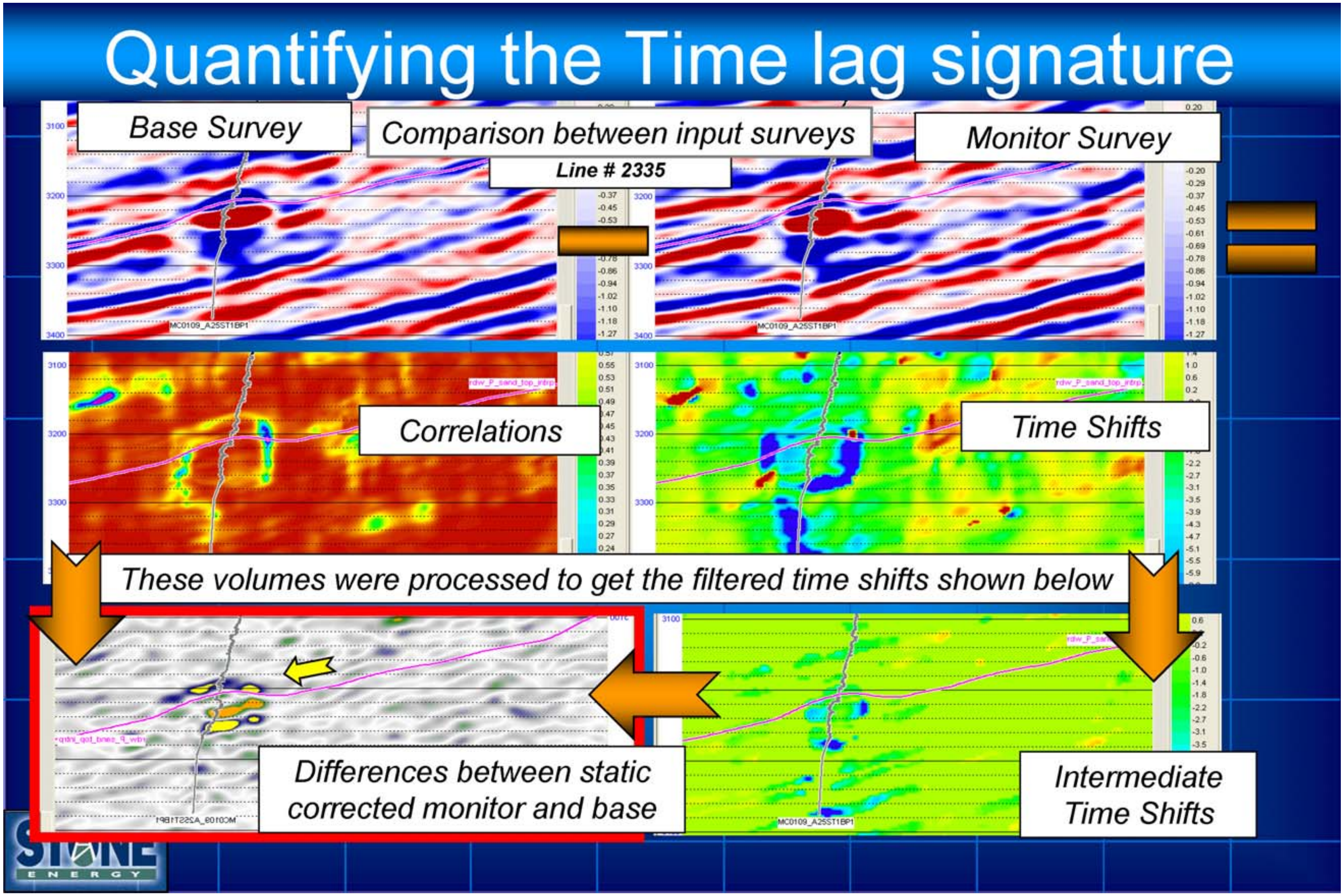
Initial Oil Pressure vs Final Brine Pressure Log Curves (Zoomed View)



Final Pressure Curves – Gas Case VI



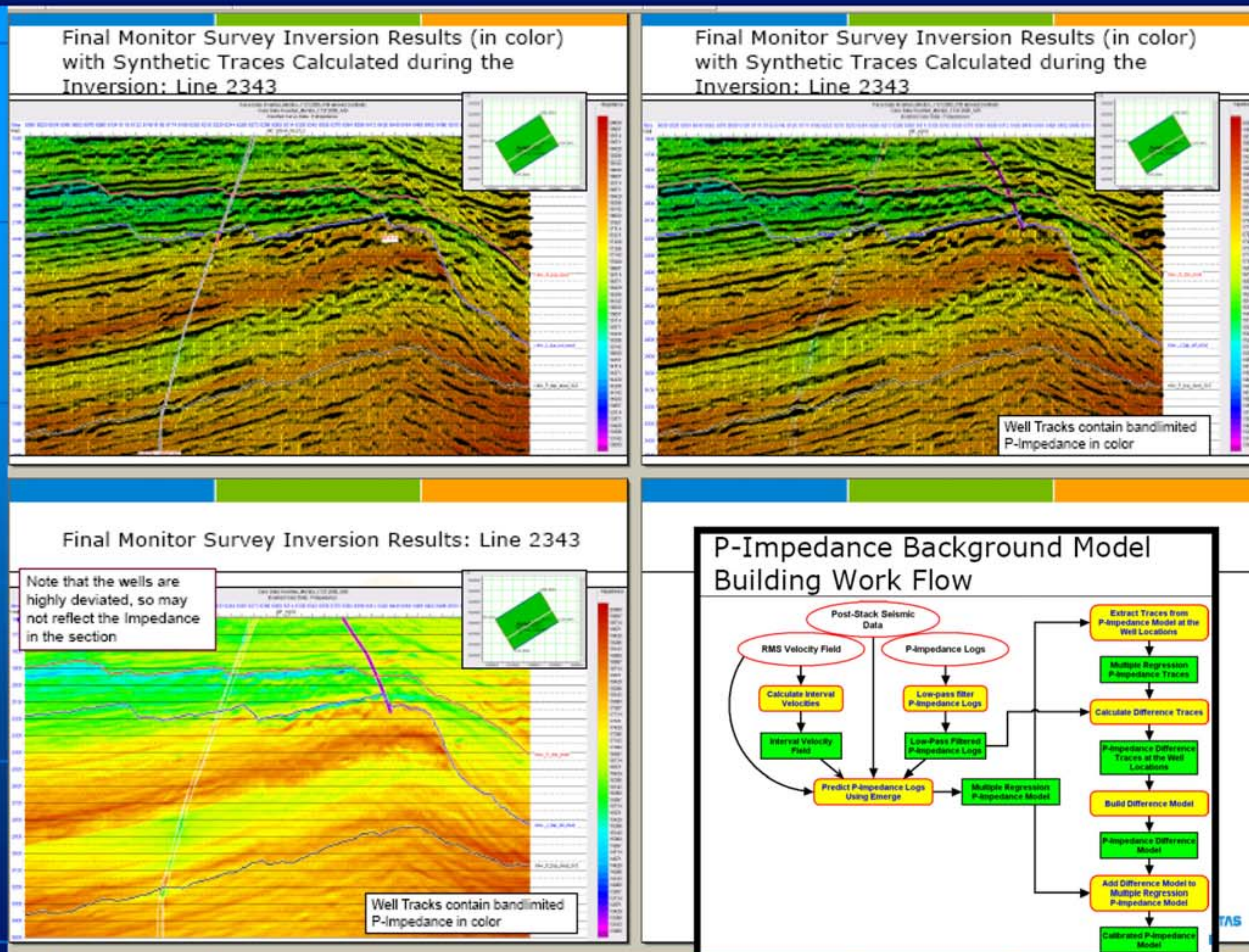
Notes by Presenter: Geophysical modeling analyses on selected wells were computed. This excerpt shows some of the input and offset modeling to determining the AVO response of pressure and fluid saturation. This work included time matching of the production history to the seismic acquisitions. The modeling was used to calibrate the 3D Monitor prestack time density volume as well as the post stack volumes used for the 4D difference studies. The pressures correspond to the end of the Western Geco 3D acquisition in October 1995, and the BP monitor 3D acquisition ending in January 2003.



Notes by Presenter: The base reflectivity is differenced with the monitor reflectivity. “Roman” columns and arch structures are resolved. A filtering scheme was developed to collapse the columns to the edges of the arch which developed above the producing sand. Lag Shadowing appears to occur over a 150ms window. Efforts to incorporate the time lag signature into the petrophysical analysis were only successful to the extent we achieved excellent registration. The distribution of lag affects appears to indicate they include mechanical changes to the encapsulating lithologies. Lag effects were compensated by filtered time shifts which preserved the petrophysical properties in the target intervals. As a conjecture we suggest the remaining arch might be described as mechanical alterations due to reservoir volume change resulting from production. We have no other explanation at this time.

Using Inversion to quantify interval changes

- Excerpt from inversion study

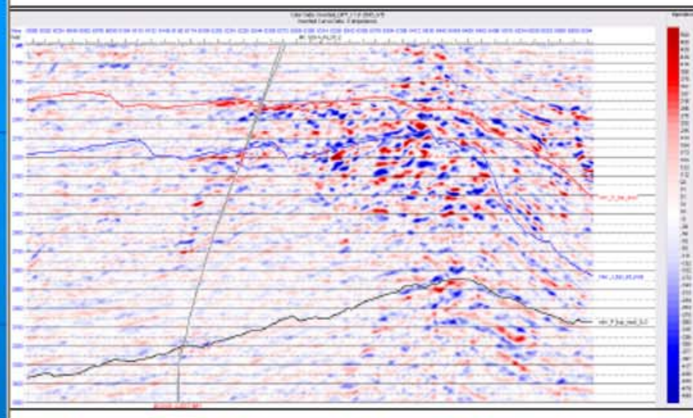


Notes by Presenter: Post-stack seismic volumes from a base and monitor survey were calibrated to minimize differences. Post-stack acoustic impedance (P-Impedance) inversion was performed on both surveys. To check the calibration we start in the upper left image. Here the well tract is visible but it is replaced in the upper right image by a band limited P-impedance tract that blends into this monitor inversion. The bottom left box shows the P-impedance post stack inversion results without the overlay of the synthetic traces. Those synthetic traces were produced in the inversion process. The work flow shown is one of many which map out the processing steps involved in the inversion.

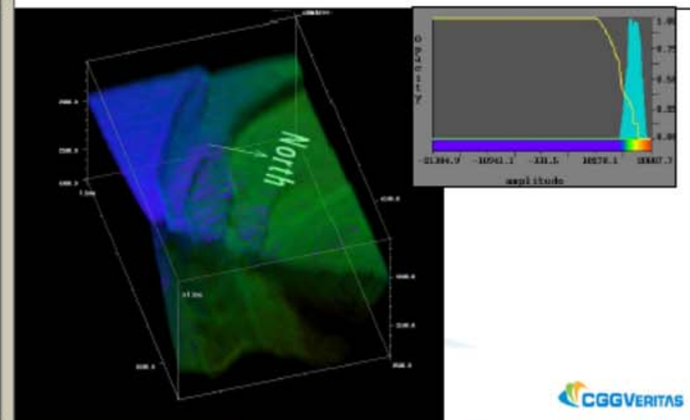
T2-T1 Inversion Difference

- Excerpt from Difference mapping

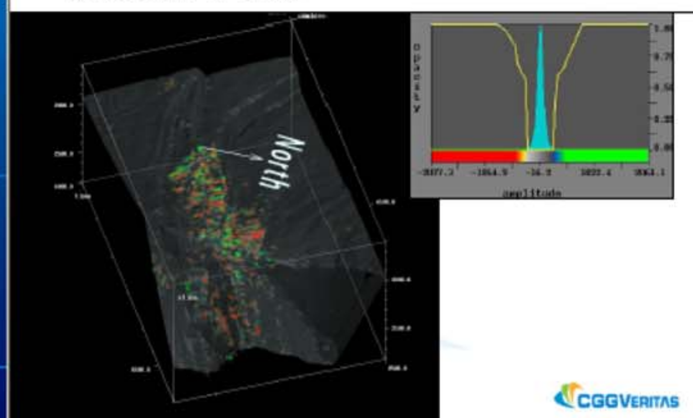
Difference Volume: Line 2343



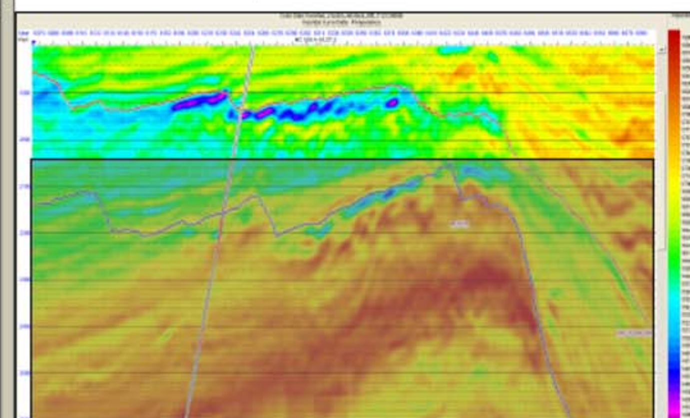
Extraction from the Base Survey Impedance Volume around the 'G' Sand



Extraction from the Inversion Difference Volume around the 'G' Sand



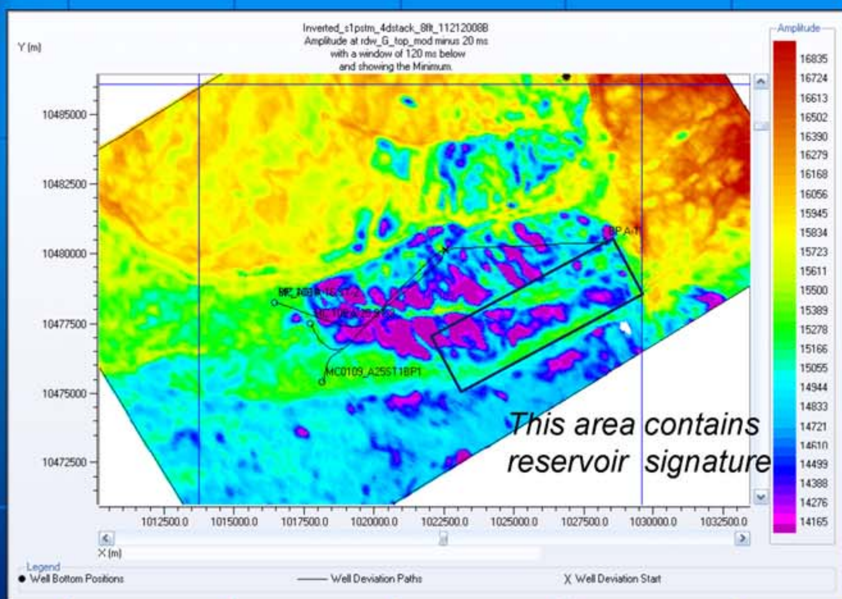
'G' Sand Impedance: Line 2343

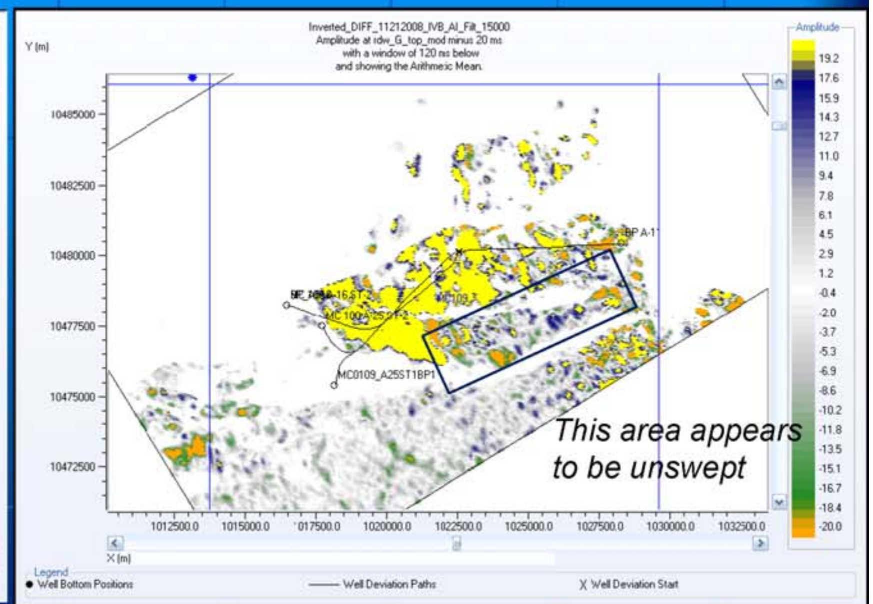


Notes by Presenter: A difference volume, seen in the upper left image of a volume slice, was calculated between the post-stack inversion results. It's the delta acoustic-impedance which we can compare with our petrophysical models to see what has happened within our reservoirs. We're not done yet, but we can almost see the end of this stage of our project. The top right image is the 3D rendered G sand top, on the lower left image the horizon is shown with the impedance differences extracted from the volume. The lower right image shows a slice through one of the impedance time volumes where the G sand stands out. Maps of acoustic impedance and acoustic impedance difference were then generated for each of the sands.

Quantifying bypassed pay through 4D

Map of the inverted acoustic impedance for the ‘G’ sand. Low acoustic impedance values would indicate the presence of reservoir (left map). Compare to the difference map (right map).





Notes by Presenter: Here are those maps for our G-sand. The map of the inverted acoustic impedance is shown on the left. Low acoustic impedance values would indicate the presence of reservoir. Compare to the Acoustic impedance difference map on the right. Prior to the next step, Top reservoir depth maps were derived, and along with the geologist’s pay sand isopachs, we sampled the impedance and difference volume to produce reservoir volumes. These were matched to the hydrocarbon volumes that had been produced from the reservoir. Note the boxed area where it appears we have an unswept area. This is the updip area in the southern fault block we talked about earlier. In our next step we estimated the unswept volumes for screening purposes.

Quantifying bypassed pay

- Original (T1) volumes are attributed to the original inversion volume
- Impedance difference volumes are calibrated to produced volumes.
- The remainder is possible bypassed pay
- **Inspection is required to determine the distribution and connectivity of bypassed volumes.**

Quantifying bypassed pay through 4D inversion

G Sand Fault Block #1 Production

Well Name	Gas Production (MCF)	Oil Production (Barrels)	Water Production (Barrels)	Gas/Oil Ratio (GOR)	Total Oil & Gas (Stb)	Formation Volume Factor from Client	Total Oil & Gas Produced (Reservoir Barrels)	Total Fluids Produced (Reservoir Barrels)
A002	363,720	1,085,639	2,083,419	373	2,060,700	1.20	1,717,300	3,800,719
A030	781,981	1,474,750	1,482,488	373	3,571,214	1.20	2,976,012	4,458,500
A017	475,118	84,285	48,217	373	1,358,060	1.20	1,131,716	1,179,933
Total =	1,620,819	2,644,674	3,614,124		6,990,033		5,825,028	9,439,152

Sum of the "Total Oil & Gas (stb)" divided by the formation volume factor. This will be in reservoir barrels

Sum of the "Total Oil & Gas Produced (Reservoir Barrels)" and the "Water Production (Barrels)". This will be in reservoir barrels

Figure 4: Hydrocarbon and brine production from three wells in the 'G' sand and fault block #1; one of three fault blocks. The fluids produced were converted back to reservoir barrels.

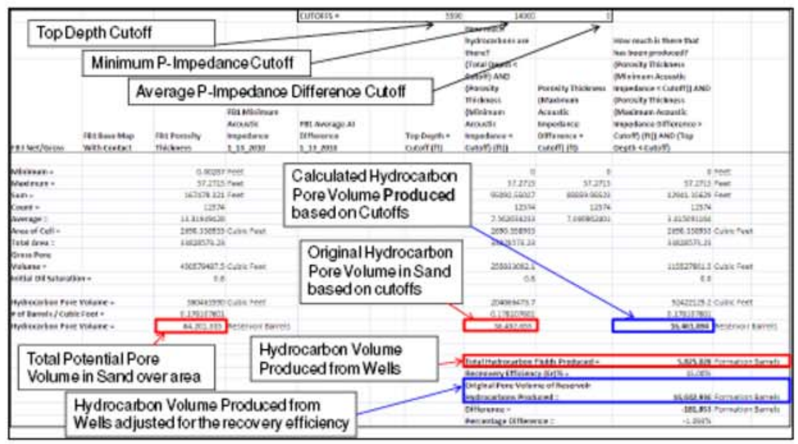


Figure 5: Applying cutoffs to the top depth map, the minimum acoustic impedance, and the acoustic impedance difference maps, we can calculate the hydrocarbons produced. We can match the production from the wells (Fig. 4) by iterating on these cutoffs.

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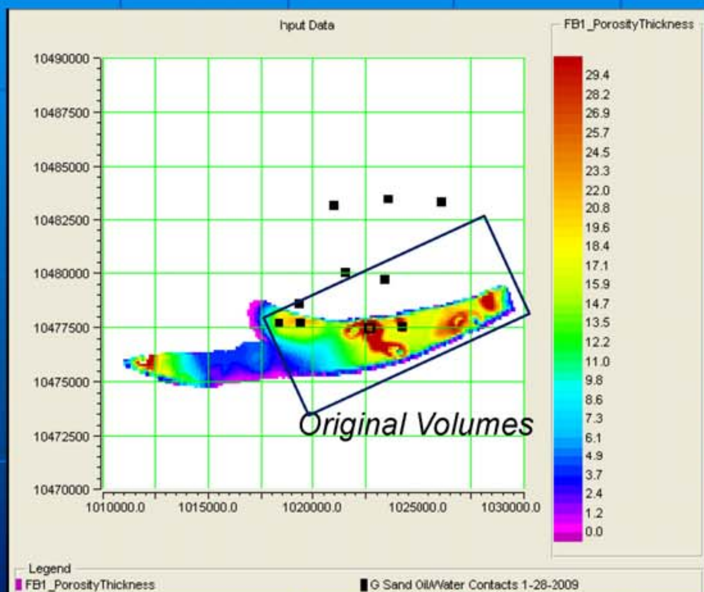
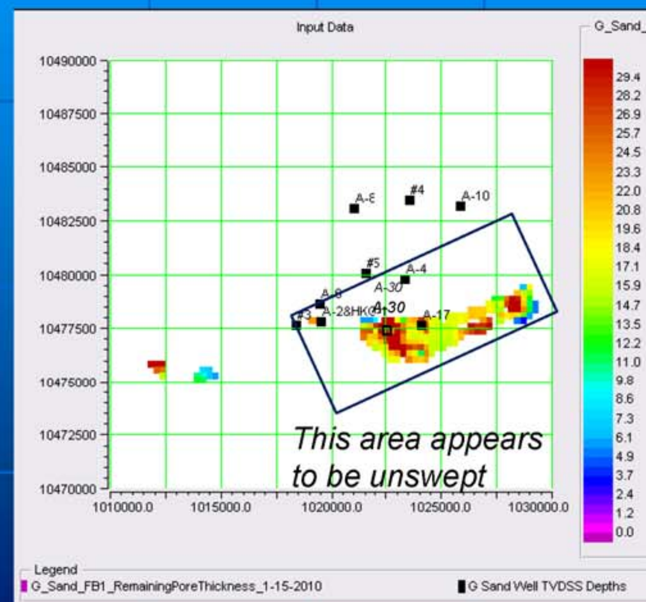
Notes by Presenter: Cutoffs were calculated through a speadsheet program. These cutoffs were applied to our inversion derived maps to match hydrocarbons that had been produced from the reservoir:

- Original (T1) volumes are attributed to the original inversion volume.
- Impedance difference volumes are calibrated to produced volumes.
- The remainder is possible bypassed pay
- Inspection is required to determine the distribution and connectivity of bypassed volumes.

Quantifying bypassed pay through 4D

Fig. 6: Original hydrocarbon thickness in feet of the 'G' sand for fault block #1 (left map) and the remaining potential in fault block #1 (right map).





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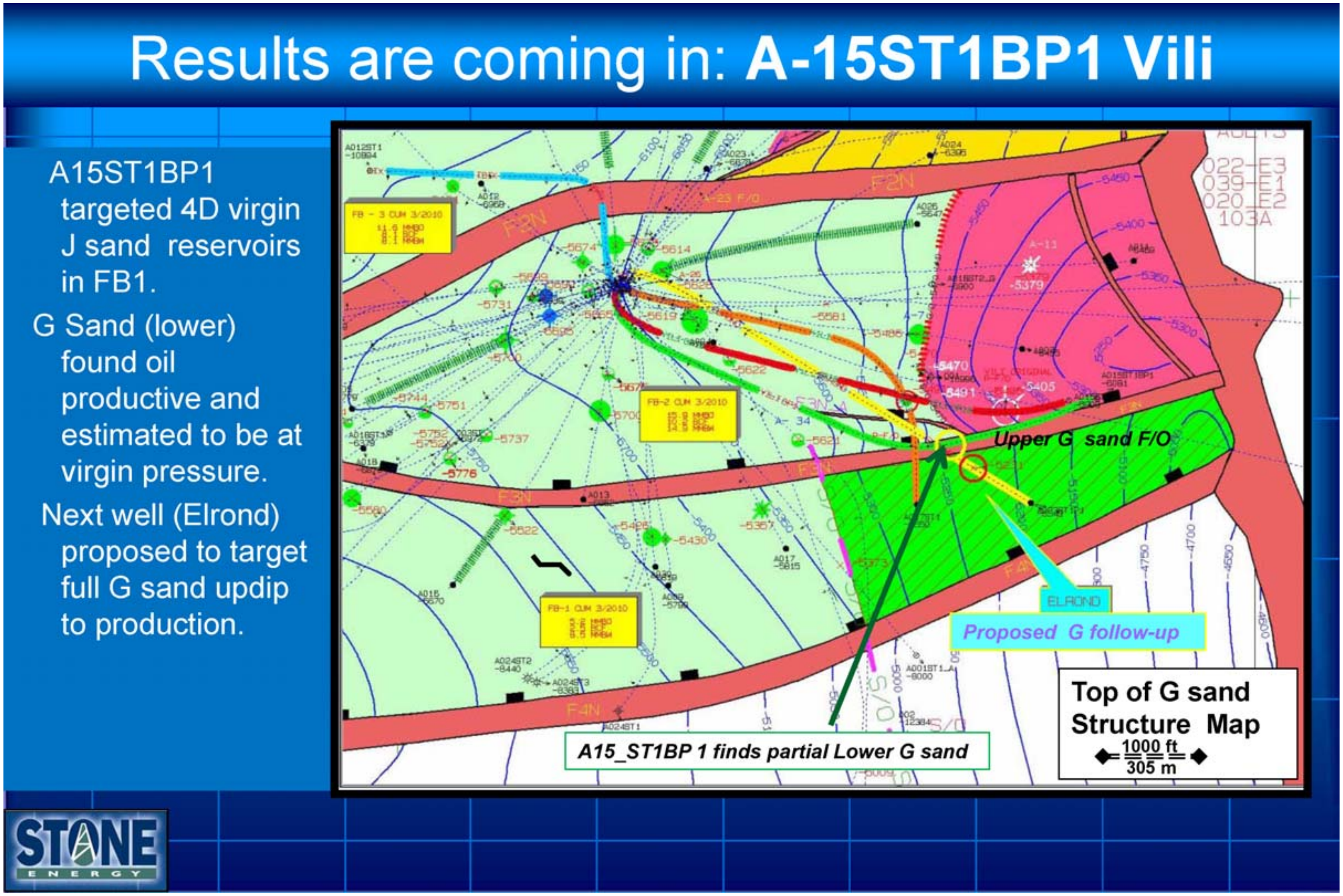
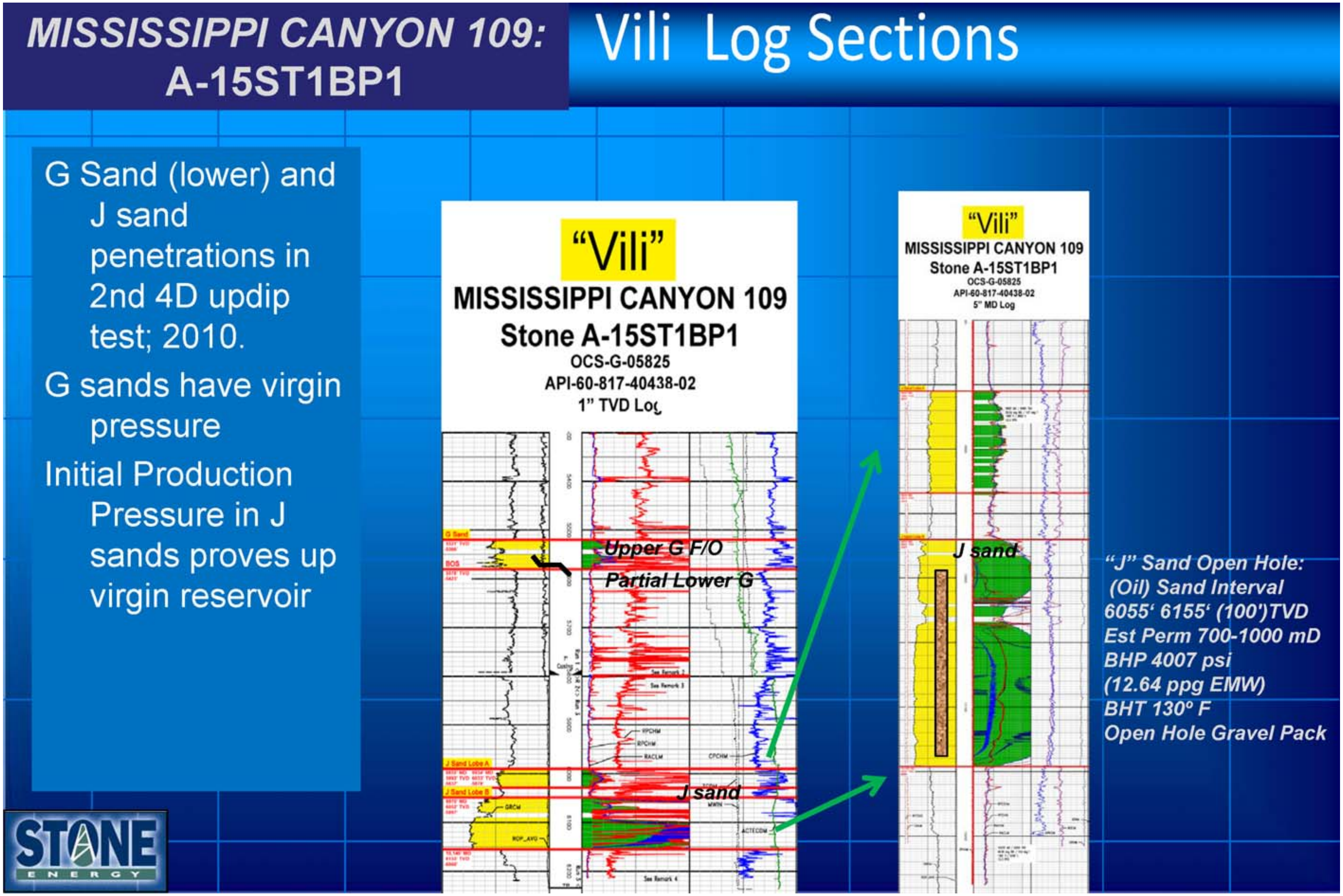
Notes by Presenter: Finally we see the distribution of original volumes in the map on the left. The color bar is expressed as porosity feet, with the hot colors being thicker. Once the cutoffs were established for the inversion difference volume to match hydrocarbons that had been produced from the reservoir, remaining potential maps could be generated. This map, seen on the right is used to prospect for bypassed and virgin pay reservoirs. The derived volumes are useful as Gross recoverable estimates, but do not necessarily break down the individual isolated compartments. There's much work still to be done by the whole integrated team to mature prospects from this point. Let's look at some drilling results, just coming in with our ongoing drilling program at the Amberjack platform.



Notes by Presenter:

1. A recent well targeted J-sands with suspected virgin pressures. But it did clip our G sand target near the northern bounding fault.
2. A15ST1BP1 targeted 4D virgin J sand reservoirs in FB1.
3. G Sand (lower) found oil productive and estimated to be at virgin pressure.
4. Next well (Elrond) proposed to target full G sand updip to production.
5. It’s important to note that economics will drive drilling programs to favor virgin reservoirs because of their high initial flow rates.
6. But there are Drilling, producing, and regulatory issues related to updip undrained reserves.
   - Oil vs. gas; economic impact of equivalent volumes
   - Regulatory hurdle to complete gas updip of existing oil production
7. 4D helps by providing evidence to build a better geologic reservoir model which demonstrated the isolation of these target clinoforms.



Notes by Presenter:

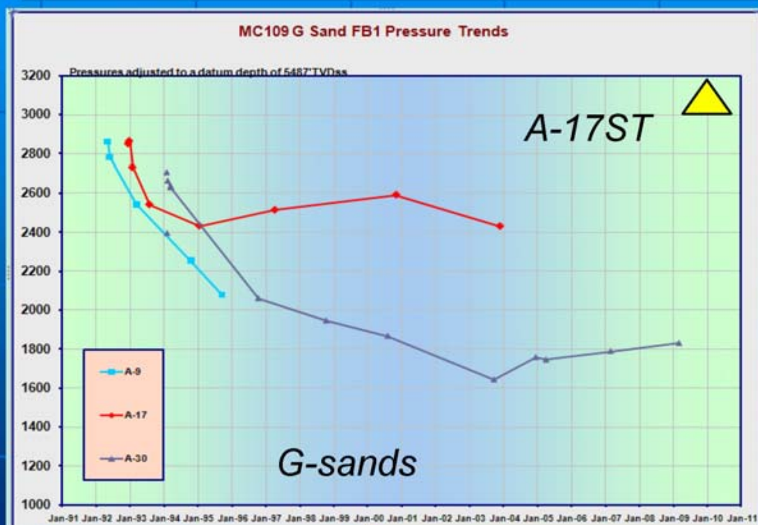
1. This is the Vili well as seen with G Sand (lower) and J sand penetrations in the 2nd 4D updip test; drilled and completed in late 2010.
2. G sands were found with virgin pressure.
3. The Initial Production Pressure in this J sand also proves up a virgin reservoir updip of earlier penetrations.
4. Let's now check out the production pressure plots for this fault block.

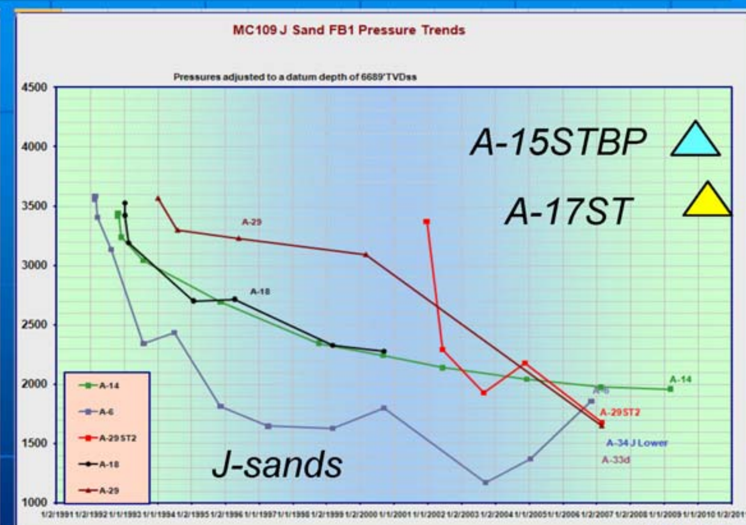
Testing the Concept: A-15STBP

A15STBP (Vili) targeted "4D" virgin J sand reservoirs.

- **G Sand (lower) found oil productive and estimated to be at virgin pressure based on drilling parameters and log response**

Next well (Elrond) proposed to target Top G sand updip to production.





Field: MC109			Well Name: OCSG 05825 A015 STBP							Reservoir: J		
Completion Num: 608174043802S01			Compl. Date: 10/17/2010			First Prod Date Oil: 10/19/2010				First Prod Date Gas: 10/19/2010		
Prod Month	Prod Year	Prod Days	BOPM	MCFPM	BSWPM	GOR scf/bbl	H2O Cut %	Cumul. Oil Bbls	Cumul. Gas MCF	Cumul. Wtr Bbls	Average BOPD	Daily MCFGPD
ubtotal			73,186	62,806	12			242,961	165,867	47		

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Notes by Presenter: Here we have the pressure history plots for Fault Block 1. The G sand is on the left and J sand on the right. The lower member of the G Sand was found oil productive and estimated to be at virgin pressure based on drilling parameters and log response. Although no MDT pressures for the G sand were obtain in the Vili well, a more recent well, the A-17 ST (yellow triangles) has confirmed this as virgin pressure. There are several factors to consider in explaining why the initial pressures plot higher than the older wells downdip but we are not yet certain of our answer. The blue triangle shows the A15ST1BP1 (Vili) initial pressure. Note the J sand plot on the right where the well targeted virgin J sand reservoirs updip to the other FB1 wells. Again the new J–sand reservoirs are plotting at or above older wells downdip. Though we have found some downdip bypassed pay targets, it's easy to favor updip virgin reservoirs in this initial 4D drilling program. The table at the bottom shows why this is important. In its first three months of production the Vili well had produced over 240 thousand Barrels of Oil and 165 thousand MCF gas.

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