Received Shelton Award for best paper presented in Search and Discovery 2012.

Eagle Ford Reservoir Characterization from Multisource Data Integration*

N. Basu[1], G. Barzola[1], H. Bello[1], P. Clarke[1], and O. Viloria[1]

Search and Discovery Article #80234 (2012)**
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Abstract

The Eagle Ford has emerged as one of the most prolific shale-gas discoveries in North America. Substantial industry activity and technology have been directed towards understanding this resource play to delineate the productive fairway, highlight potential sweet-spots, and unlock its economic potential. Activity rose from 94 well permits in 2009 to over 1000 permits in 2011. Currently in excess of 100 drilling rigs are active across this trend.

Pioneer Natural Resources is using a combination of well logging (pilot and lateral), core, seismic attributes, production logging, micro-seismic, and outcrop observations to provide an integrated analysis of the critical performance drivers and uncertainty within this shale-play. The use of technology is fundamental to our visualization and characterization efforts, including scale, vertical and lateral variability, and an assessment of matrix and natural fracture contribution. Our goal is to accelerate the learning curve and effectively impact development strategies for this resource play.

While the Eagle Ford is a recent discovery (2008), many hundreds of older legacy wells were drilled, and logged this source rock section. The Eagle Ford is a classic example of an unconventional resource play, hidden within a seemingly mature petroleum basin. With advances in drilling and completions technology the industry is unlocking this multi TCFE/BBOE resource potential.

References

Donath, F.A., 1970, Some information squeezed out of rock: American Science, v. 58/1, p. 54-72.

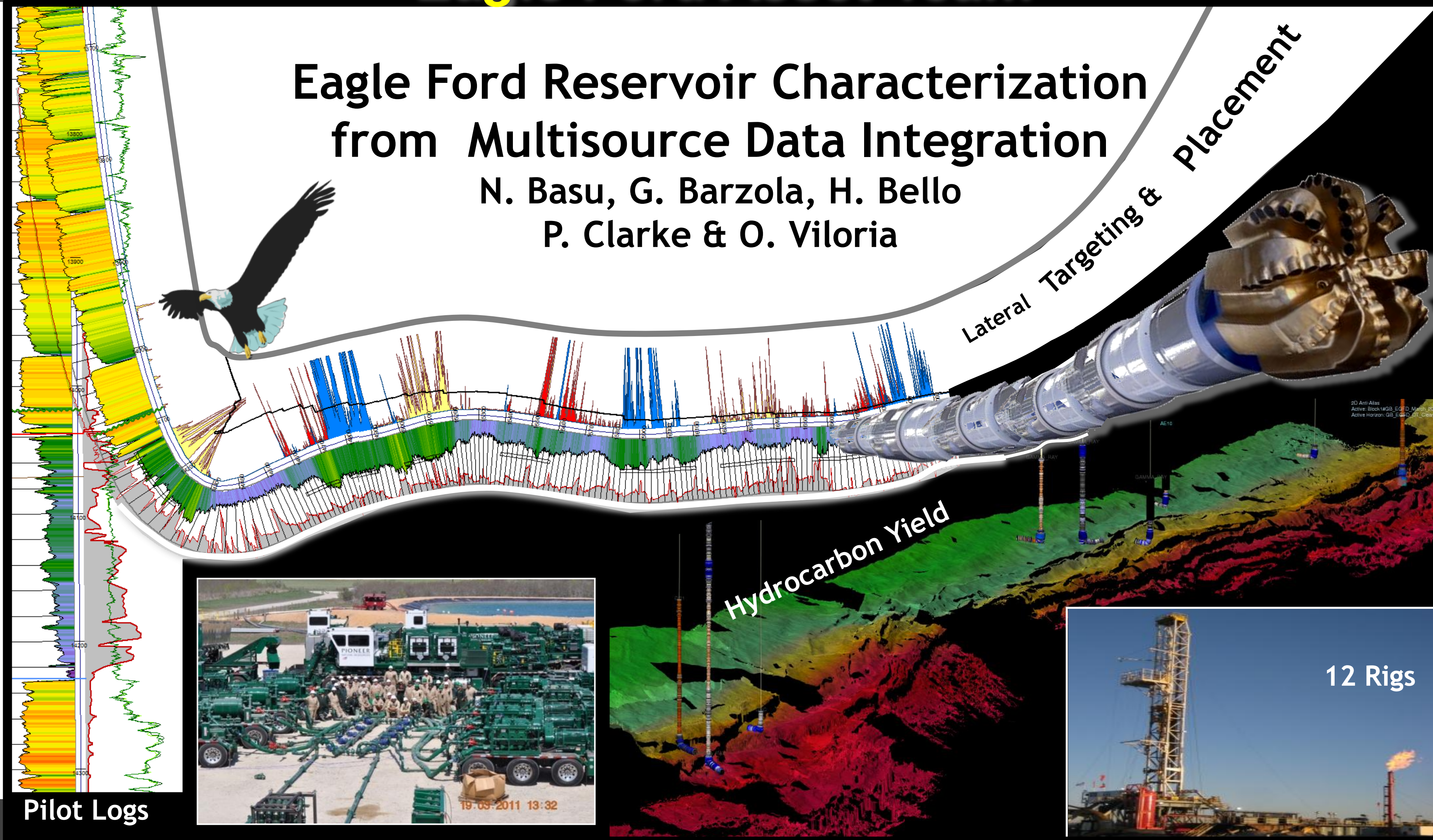
Ferrill, D.A., A.P. Morris, R.N. McGinnis, K.J. Smart, and W.C. Ward, 2011, Fault zone deformation and displacement partitioning in mechanically layered carbonates: The Hidden Valley fault, central Texas: AAPG Bulletin, v. 95/8, p. 1383-1397.

Ferrill, D.A., and A.P. Morris, 2008, Fault zone deformation controlled by carbonate mechanical stratigraphy, Balcones fault system, Texas: AAPG Bulletin, v. 92/3, p. 359-380.

Pioneer Natural Resources
Eagle Ford Asset Team

Eagle Ford Reservoir Characterization from Multisource Data Integration

N. Basu, G. Barzola, H. Bello
P. Clarke & O. Viloria



AAPG ACE
April 23, 2012
Long Beach, CA

Eagle Ford Play - Every Detail Counts…

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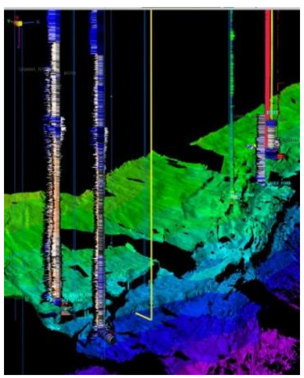
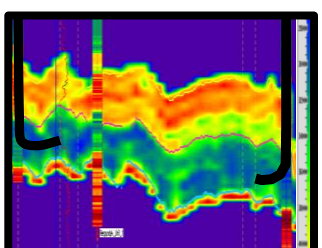
Characterize vertical & lateral variability of Eagle Ford (pilot logs & seismic volumes)

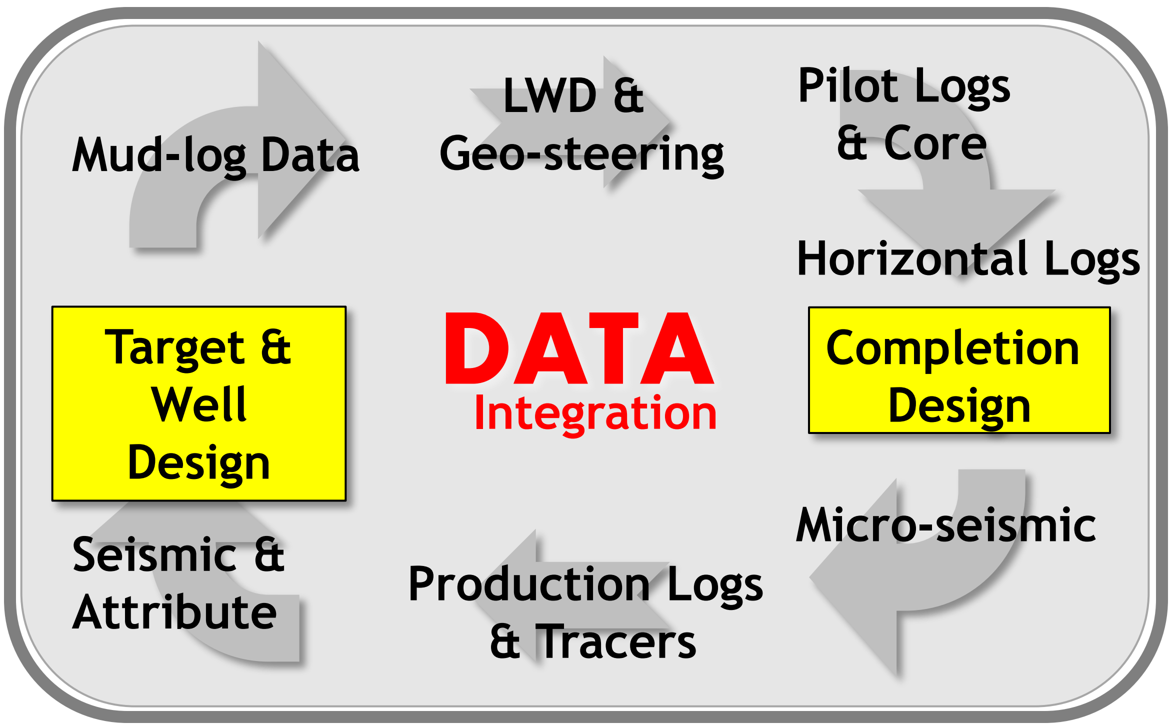
Assess both matrix and natural fracture systems as performance drivers.

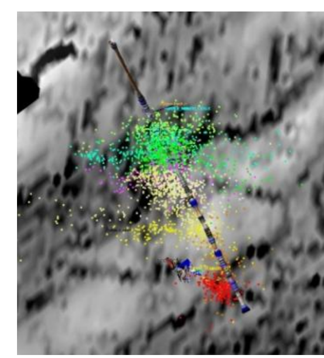
Relationship of above parameters to well performance/production (enhance EUR’s)

Optimize drilling & completion practices (potential cost savings/add value)





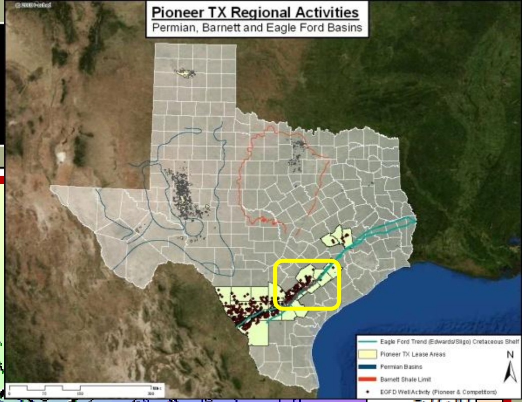


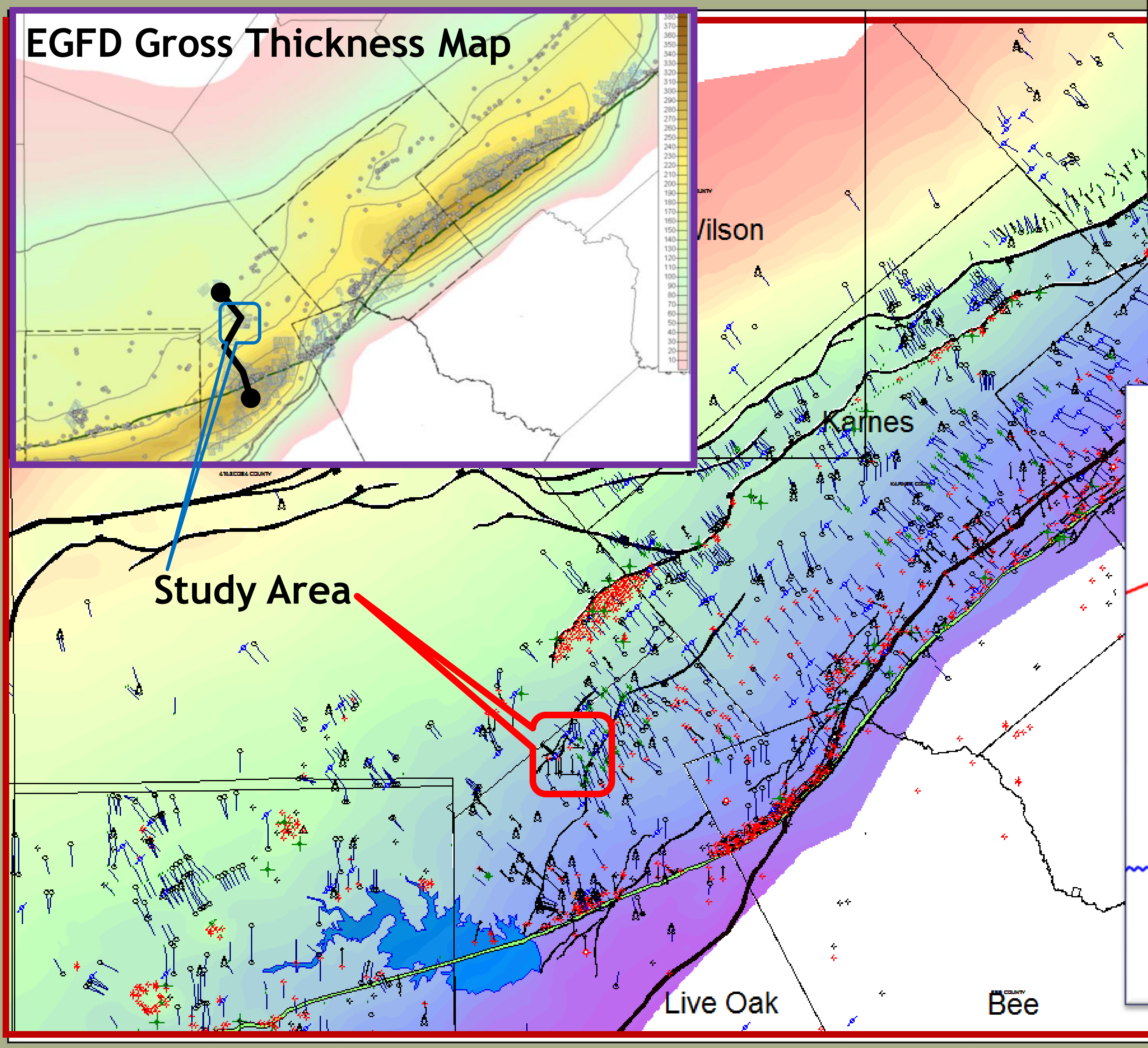


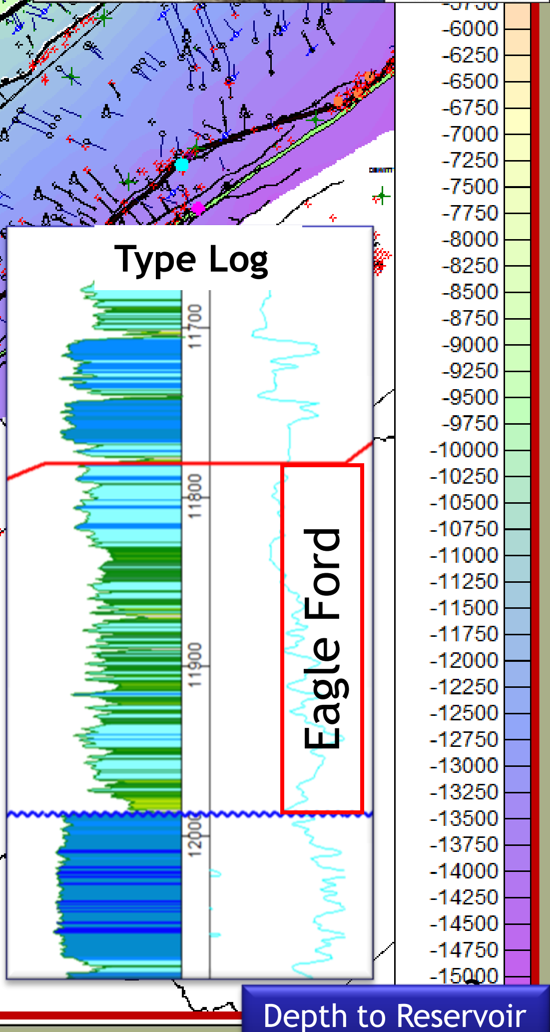
SLIDE 3.

Click to view notes

Location Map



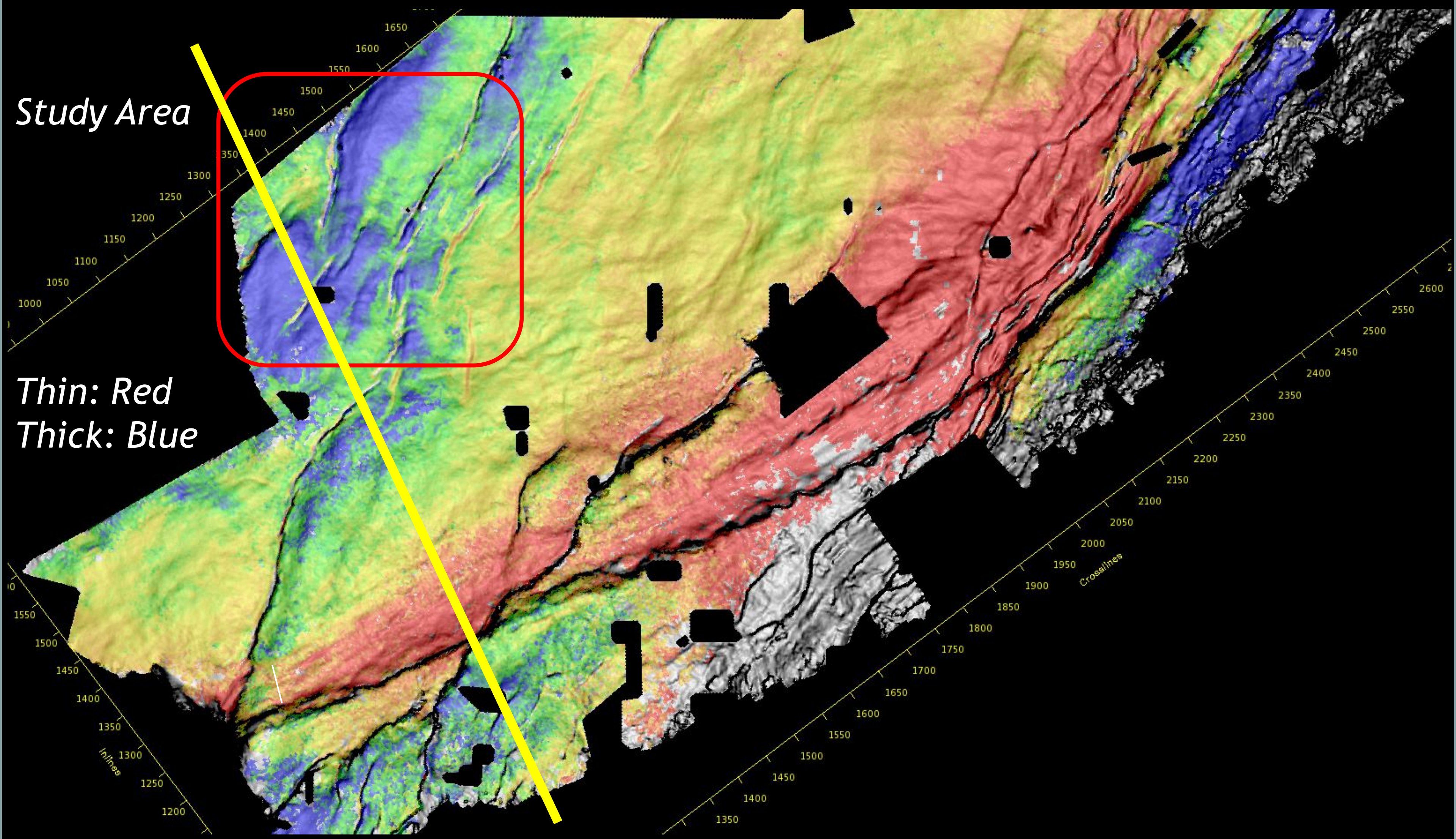




SLIDE 4.
Click to view notes

Eagle Ford Structural Framework

PIONEER NATURAL RESOURCES

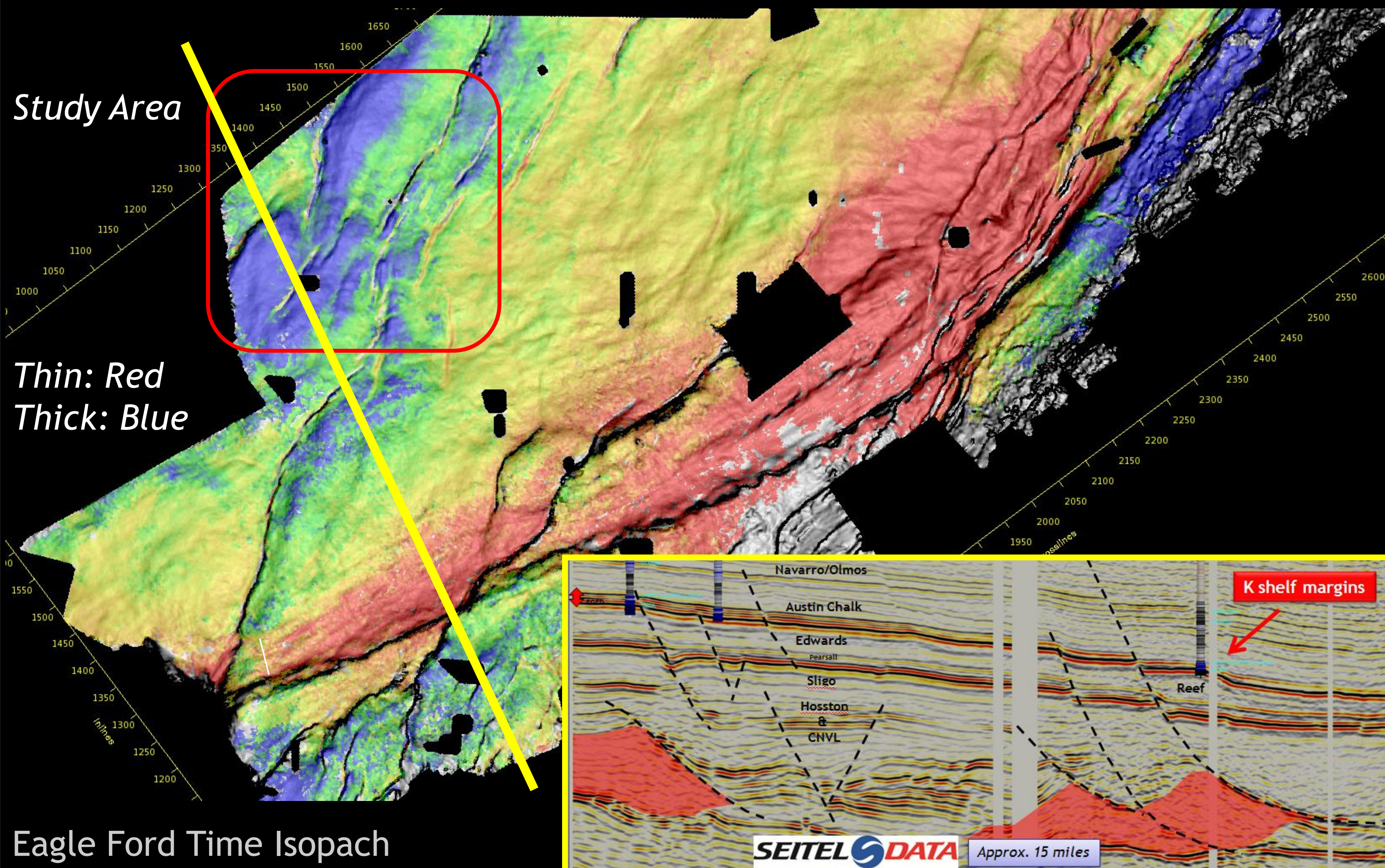


Eagle Ford Time Isopach

SLIDE 5.
Click to view notes

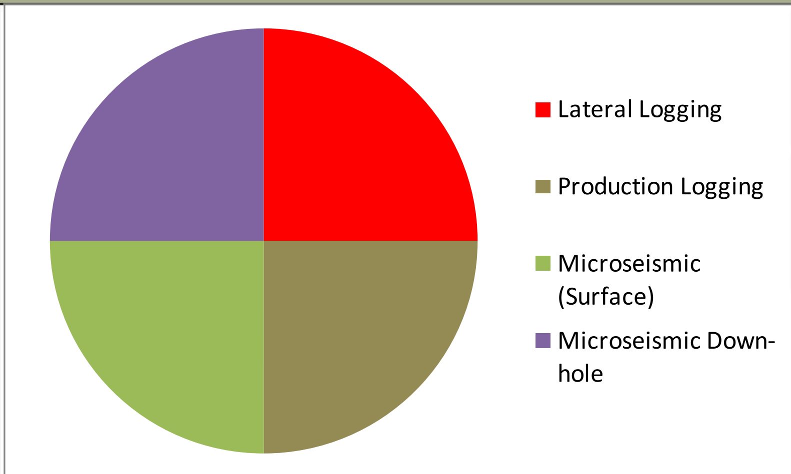
Eagle Ford Structural Framework

PIONEER
NATURAL RESOURCES



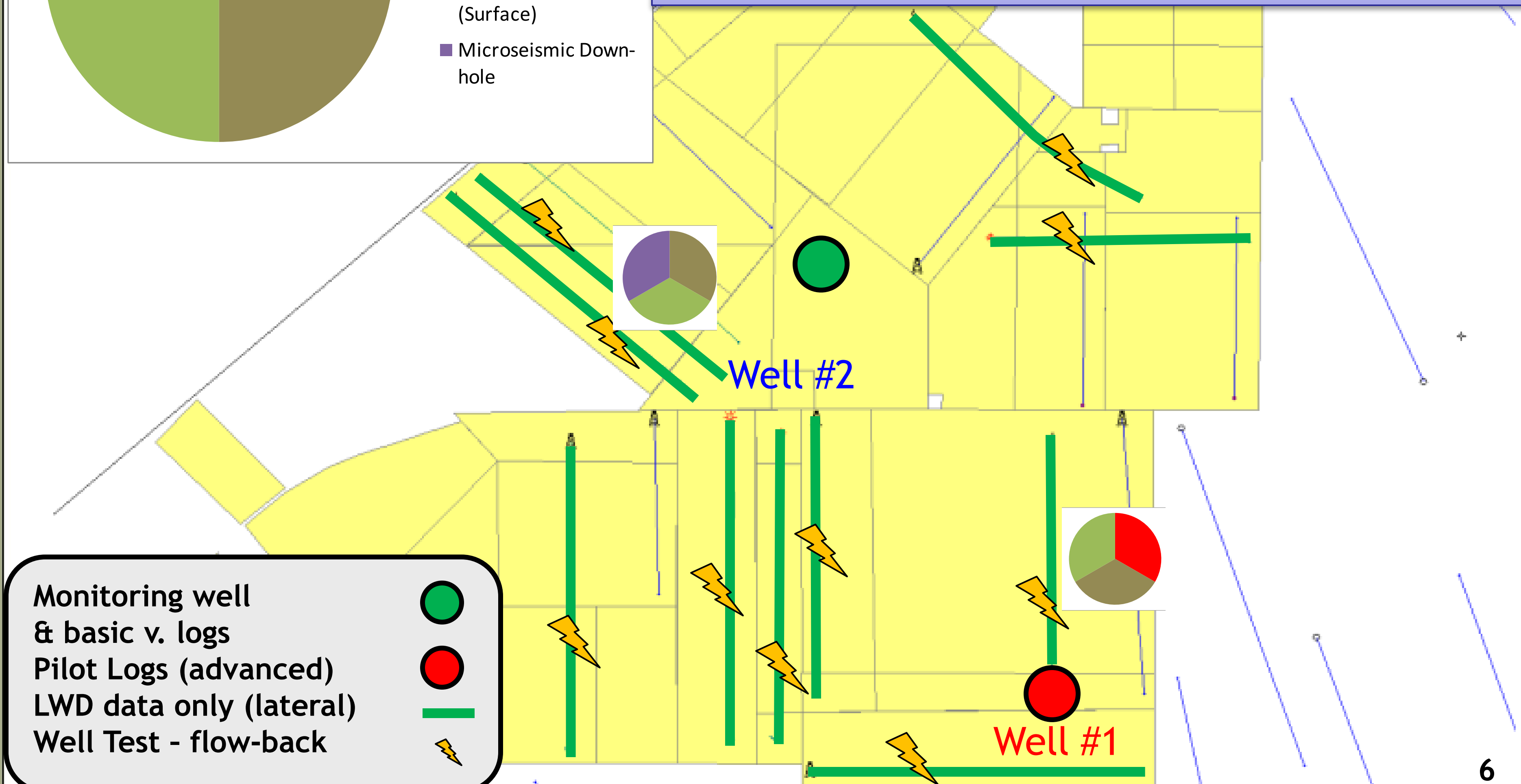
Data Acquisition

PIONEER
NATURAL RESOURCES



Pilot
- Run2a: QAIT-HLDS-APS-ECS-HNGS-DTC
- Run2b: OBMI-PPC1-SonicScanner (MSIP)-PPC2-EDTC(GR)

Lateral
- Run2b: Dual OBMI-PPC1-SonicScanner-PPC2-EDTC(GR)- DWCH(TLC)
- Run2a: QAIT-HLDS-APS-ECS-HNGS-EDTC-DWCH(TLC)



Monitoring well & basic v. logs
Pilot Logs (advanced)
LWD data only (lateral)
Well Test – flow-back

Seismic Attribute Extracted (Coherency and Curvature)

SLIDE 7. Click to view notes

Well # 1 (Lateral)

RA Tracers:
Iridium - 192
Scandium - 46
Antimony -124

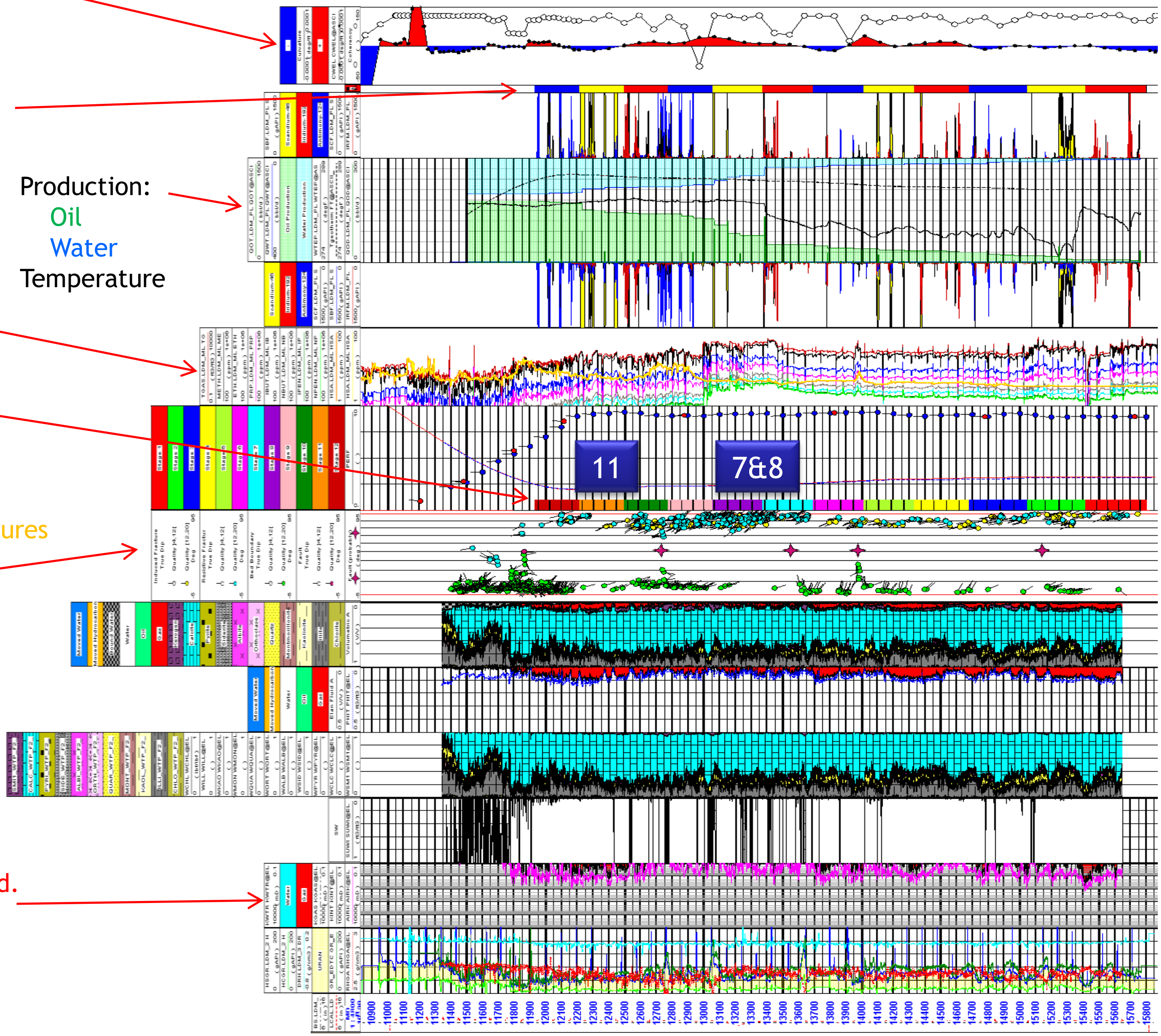
Production:
Oil
Water
Temperature

Mud Log
H_2S

Frac Stages
Perf. Clusters

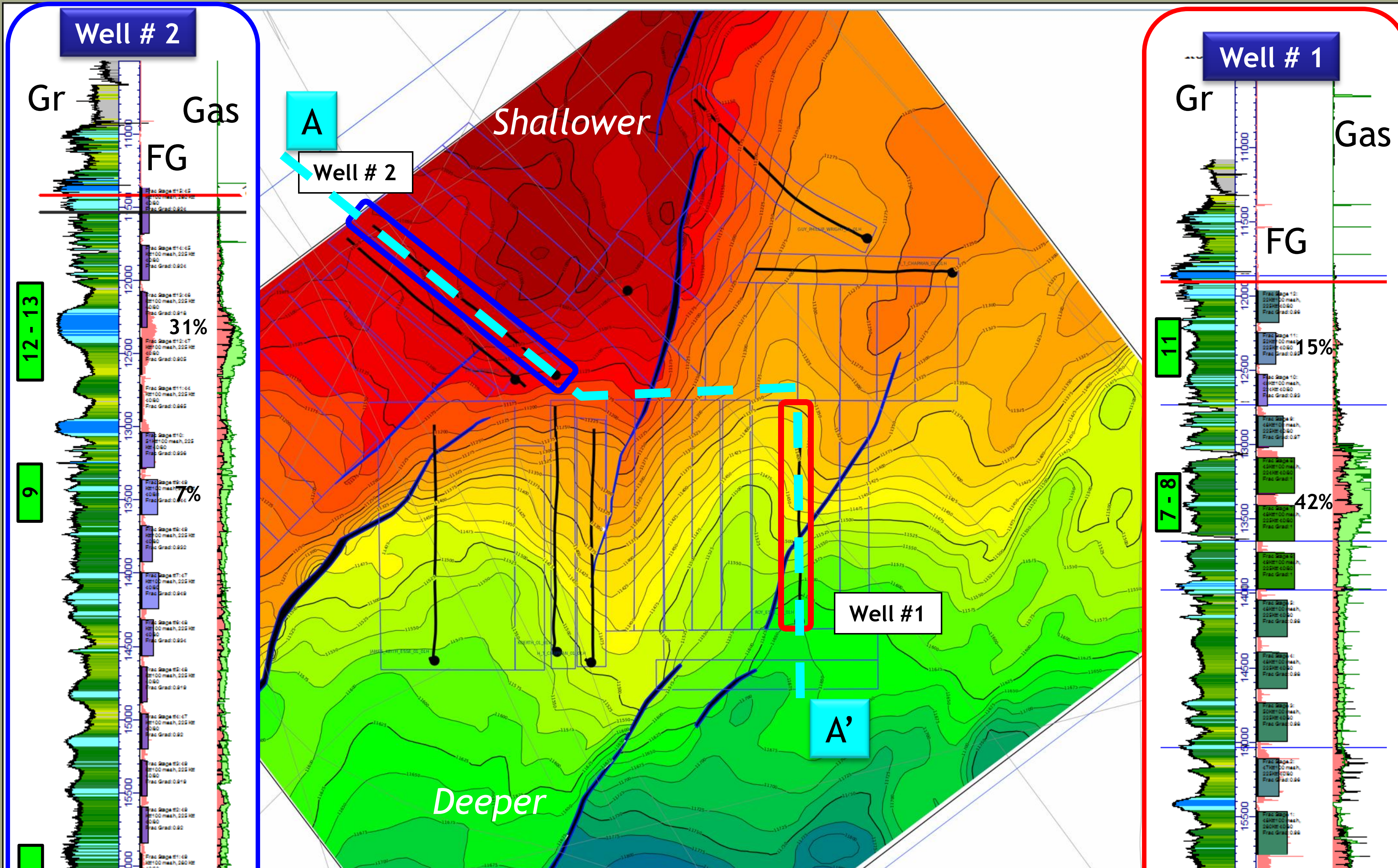
OBMI Interpretation:
Resistive Fractures
Drilling Induced Fractures
Bedding
Faults

Perm. Effective to Hyd.
Est. Perm. to Air



SLIDE 8.
Click to view notes

Integrating seismic data



Depth Structure Map
<Base Eagle Ford>

SLIDE 9.
Click to view notes

Amplitude Volume

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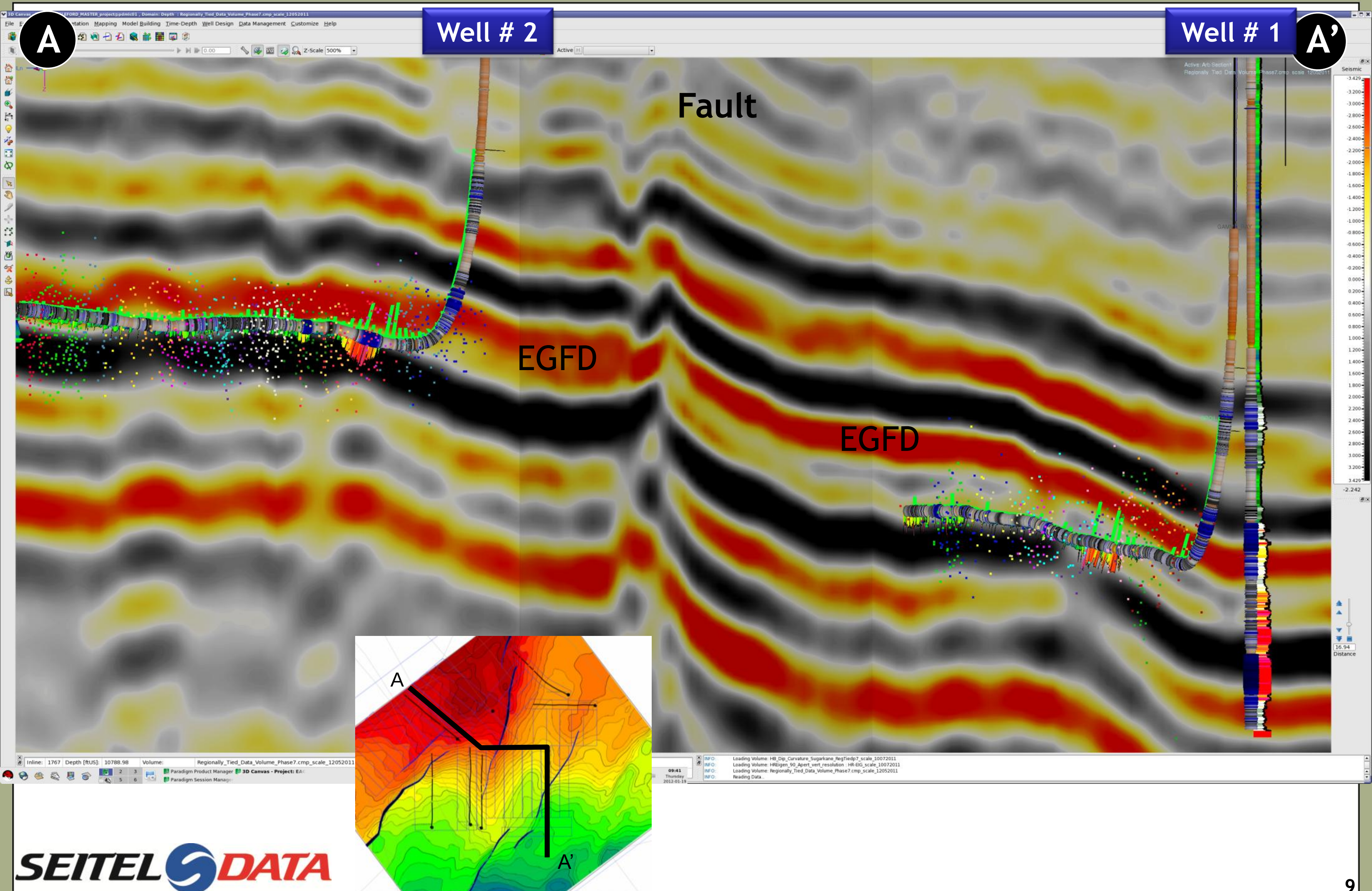
NATURAL RESOURCES



SEITEL DATA

Mechanical Stratigraphy

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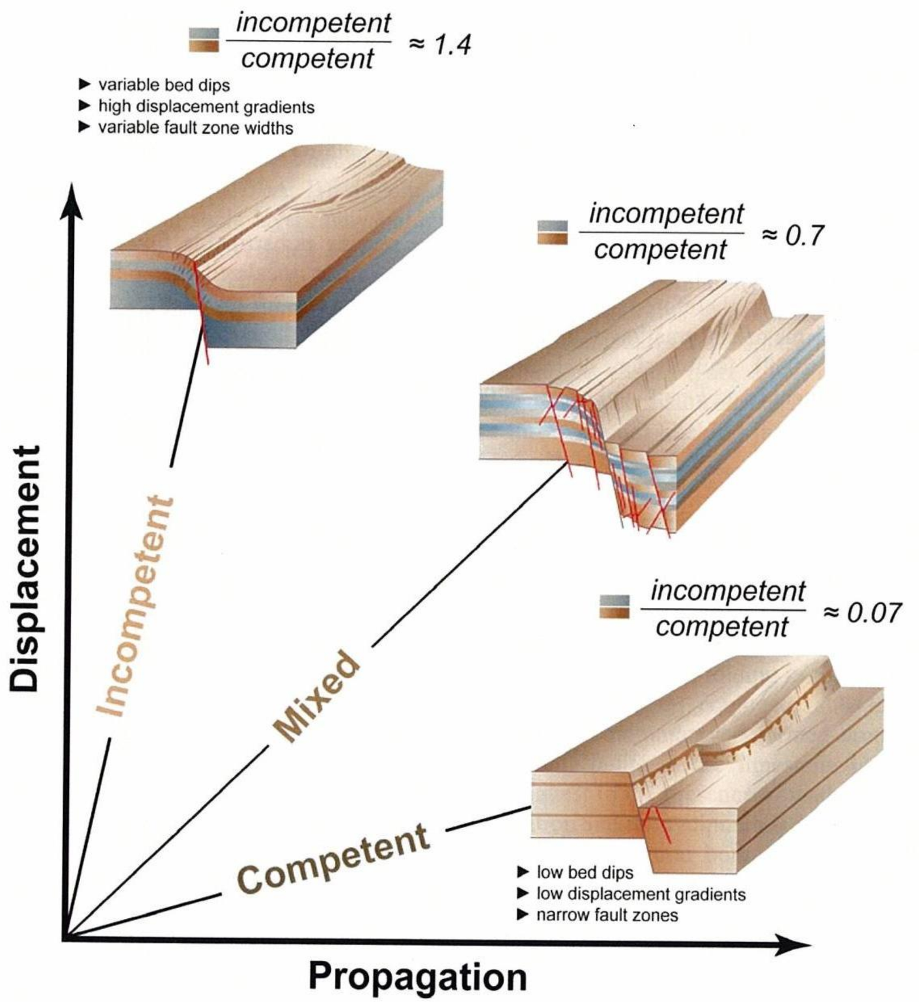
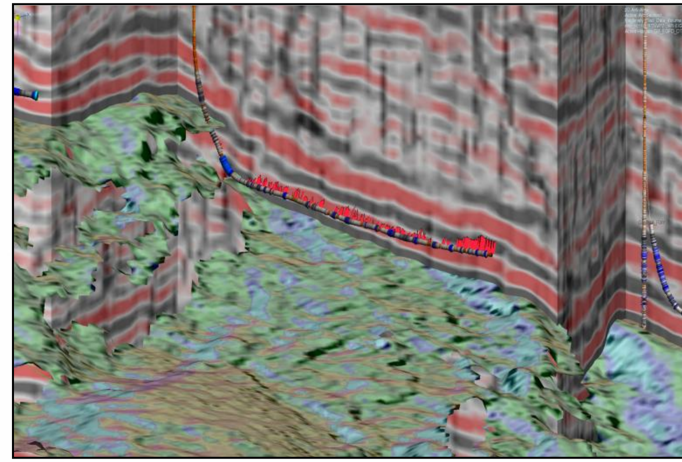
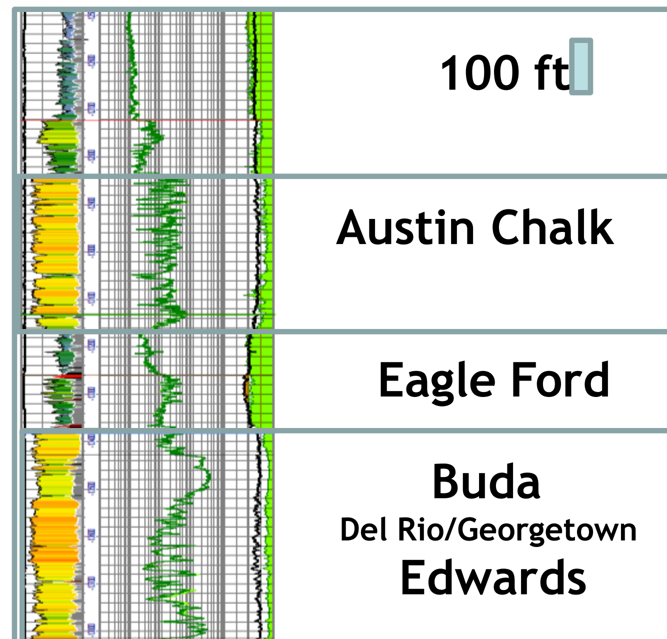


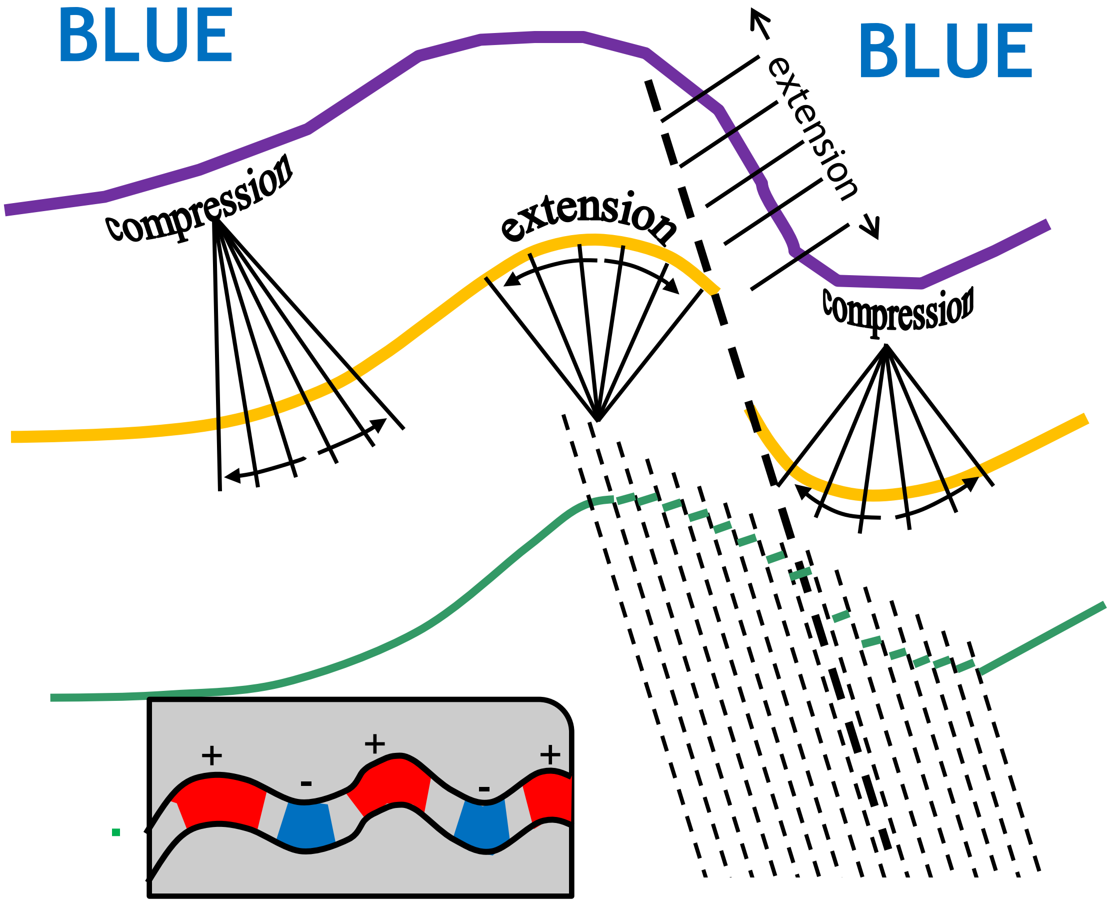




Ferrill and Morris (March 2008) AAPG Bulletin

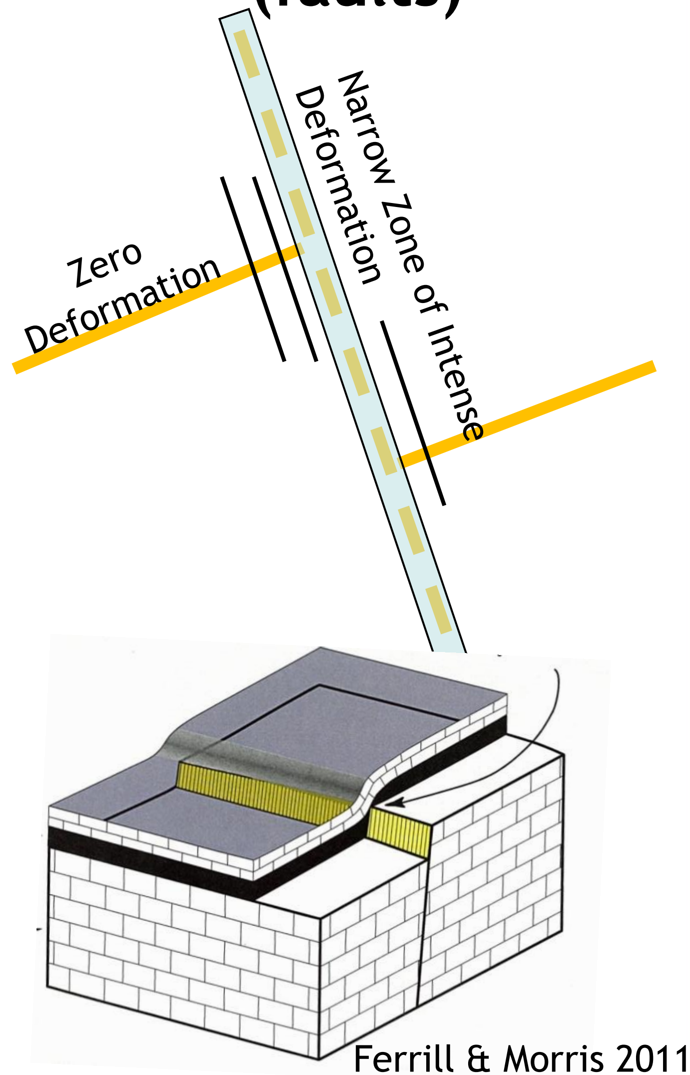
Structural Attributes Mapping

PIONEER
NATURAL RESOURCES



Curvature Attribute
(fracture zones)

Coherency Attribute
(faults)



Ferrill & Morris 2011

SLIDE 12.
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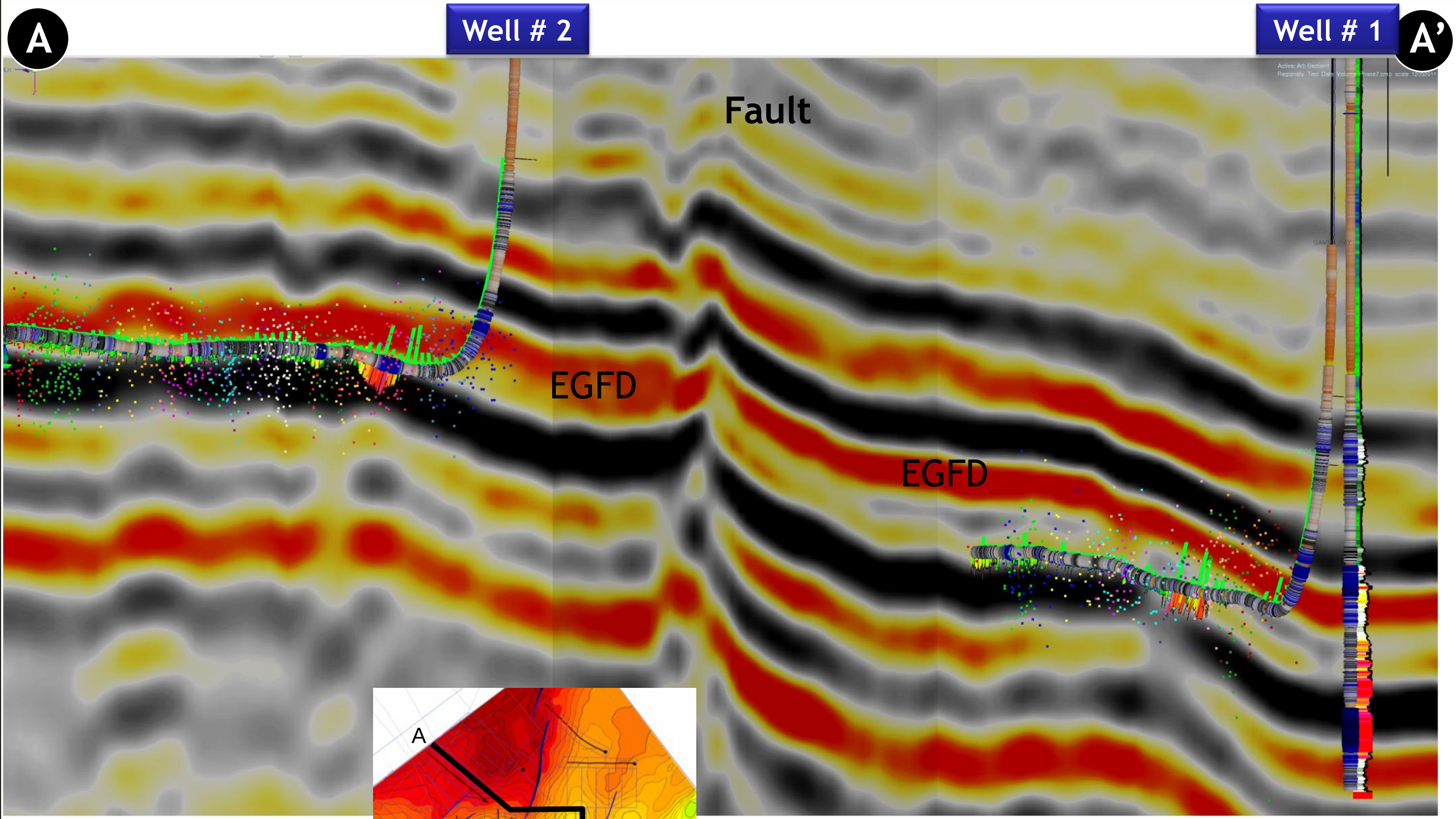
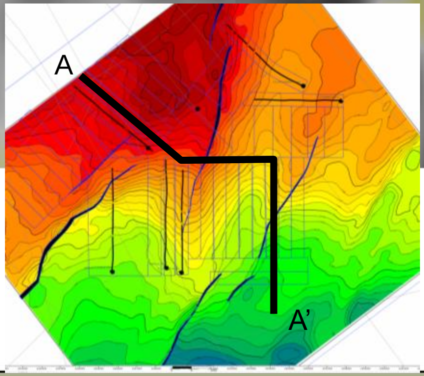
Amplitude Volume

PIONEER
NATURAL RESOURCES

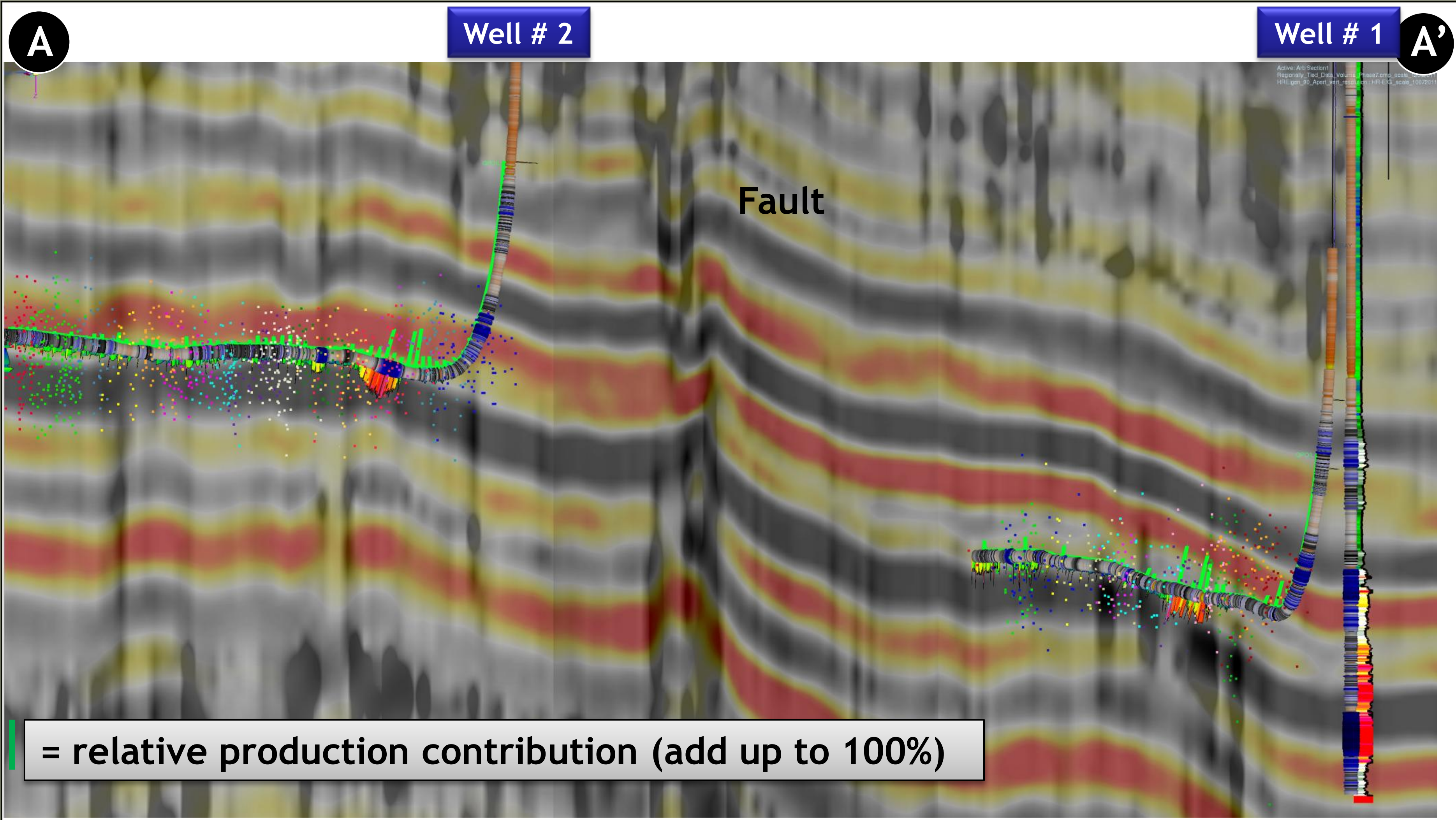




SEITEL DATA

Amplitude & Coherency

PIONEER
NATURAL RESOURCES



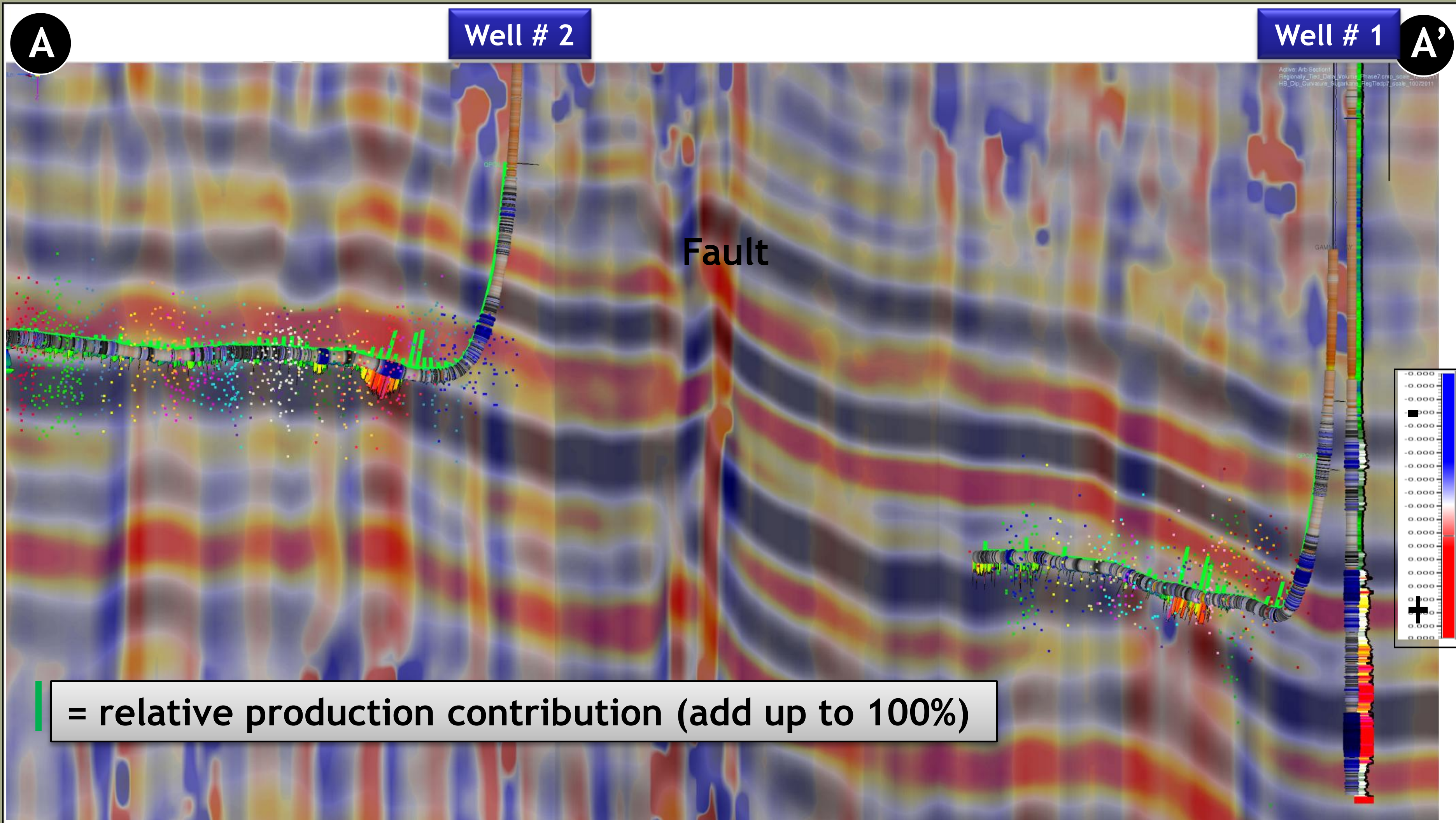
Max Tgas from mudlogs and initial oil production is related mainly to presence of faults and associated fractures (high-order geometries); high-resolution coherency is detecting mainly high-angle faults.

SLIDE 14.

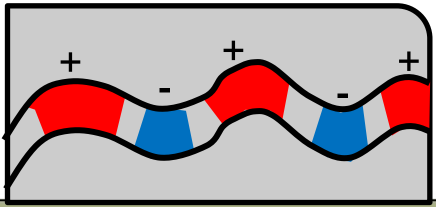
Click to view notes

Amplitude & Curvature

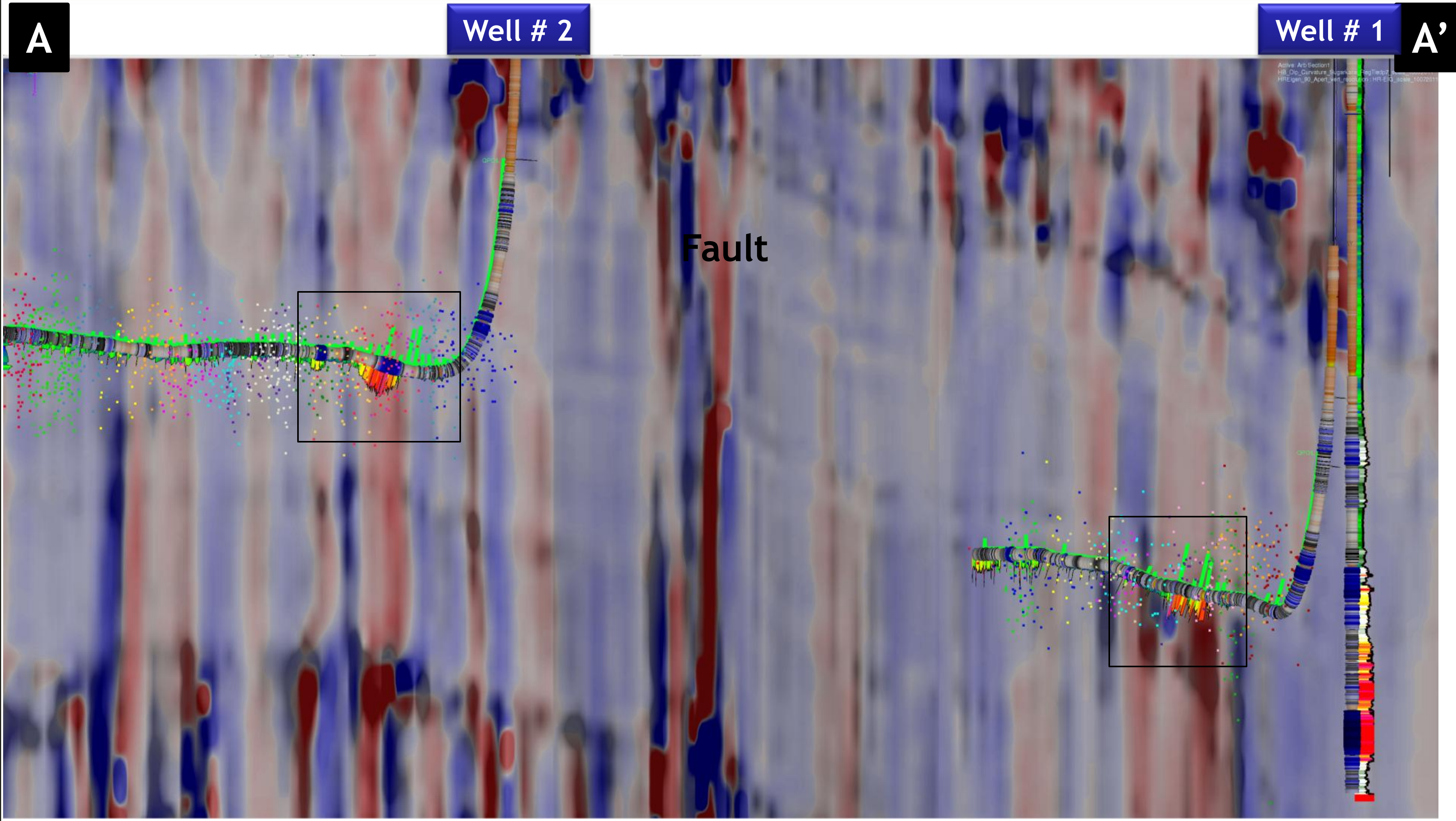
PIONEER NATURAL RESOURCES



Positive curvature (red) has a good correlation with zones of strong gas shows from mud logs, which also show higher initial contribution from production logs.



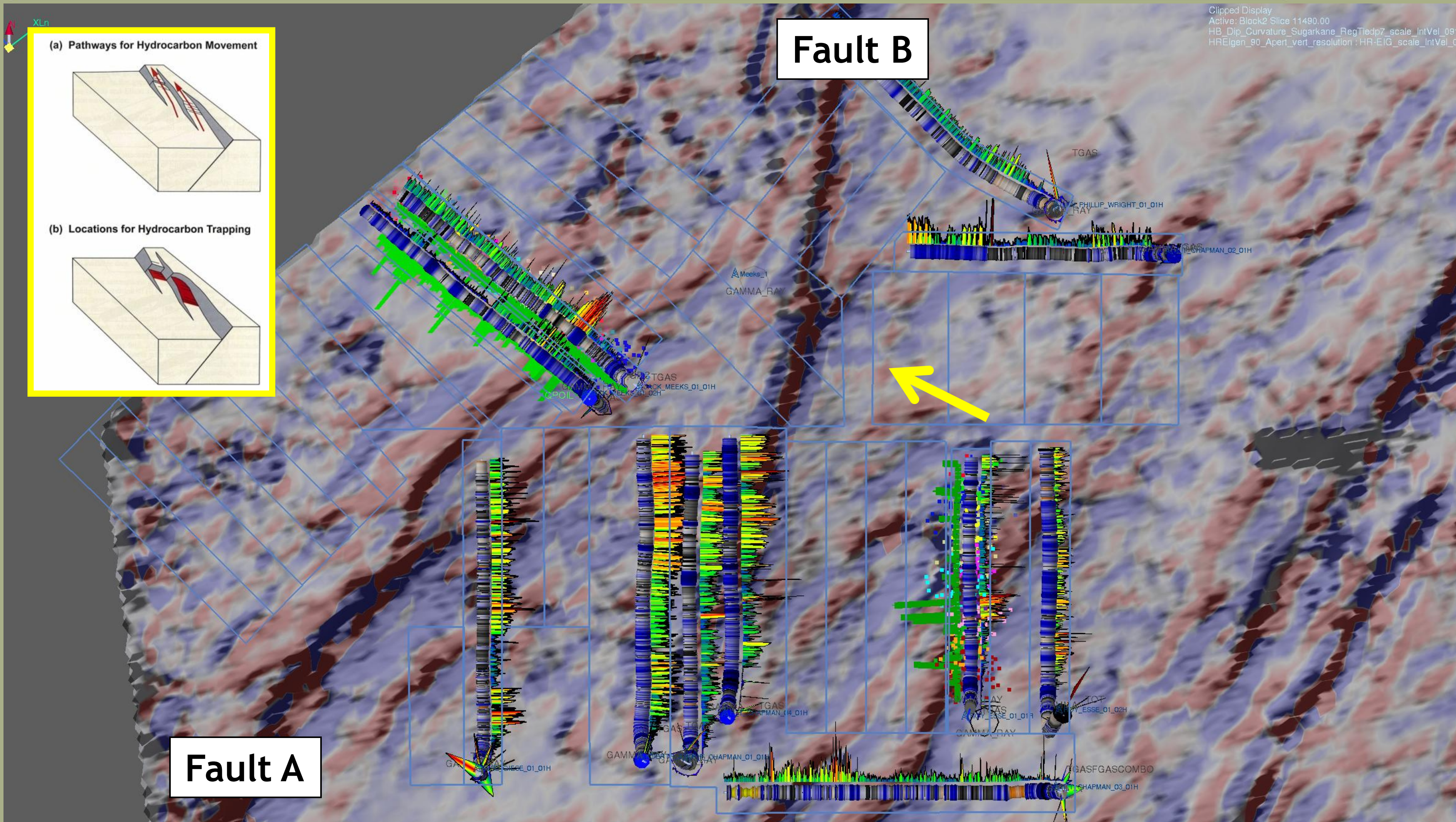
Coherency & Curvature



= relative production contribution (add up to 100%)

Data Integration & Interpretation

PIONEER NATURAL RESOURCES

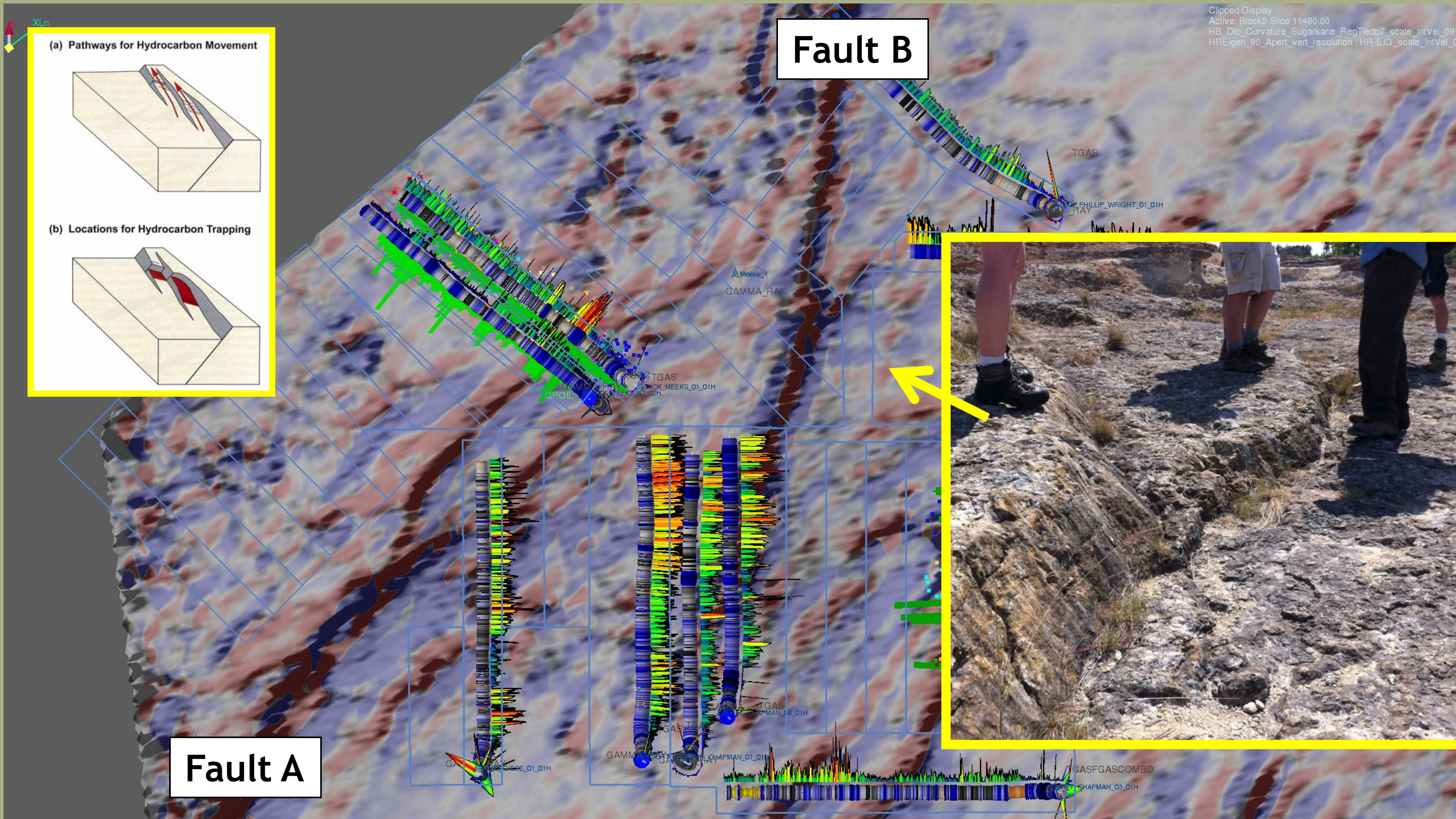


Geologic Model (also observed during field trip) shows enhanced fracture permeability in damage zone associated with Relay Ramp – where displacement is accommodated by smaller-scale faults/fractures.

SLIDE 17.
Click to view notes

Data Integration & Interpretation

PIONEER
NATURAL RESOURCES

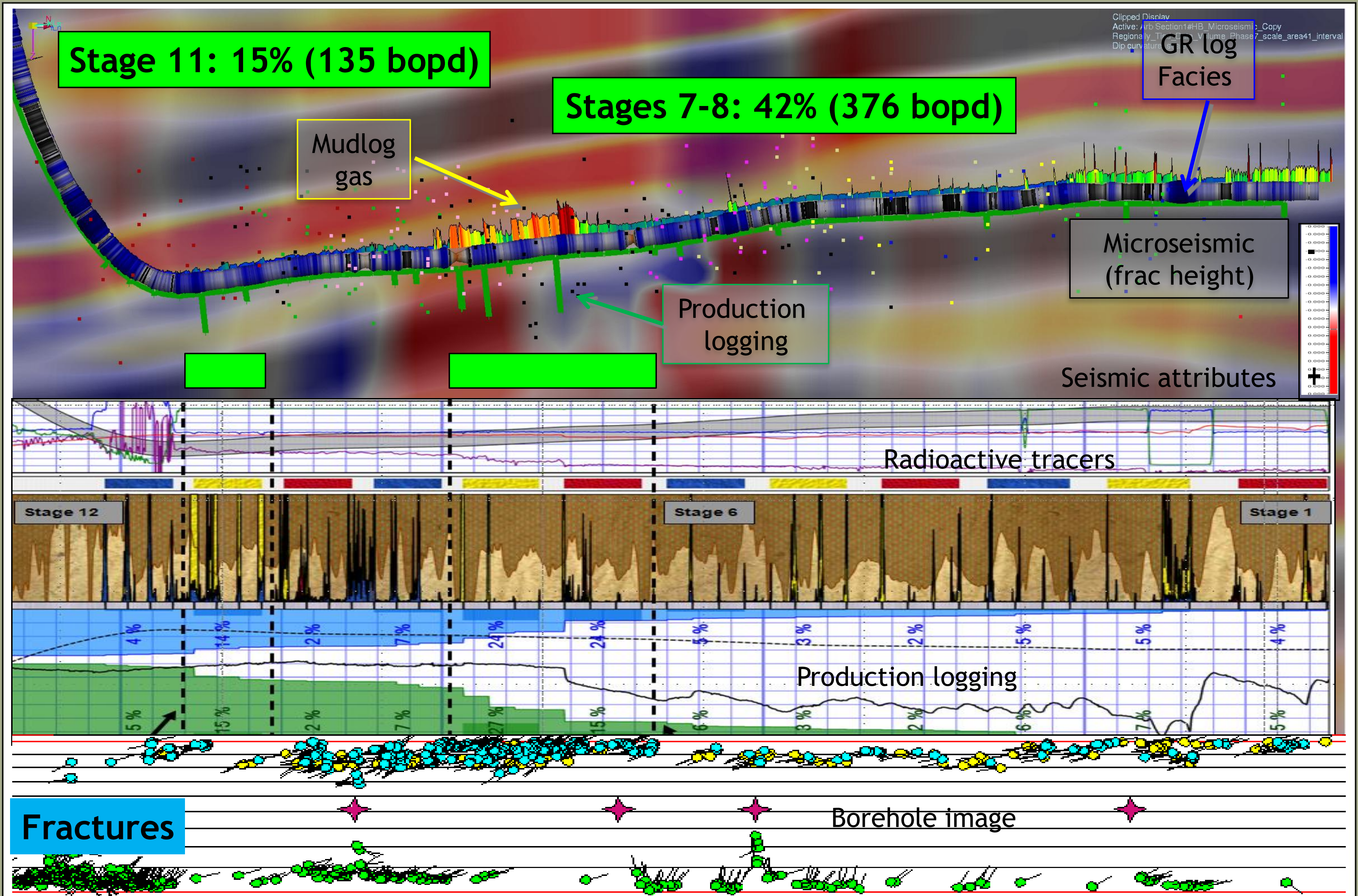


Geologic Model (also observed during field trip) shows enhanced fracture permeability in damage zone associated with Relay Ramp – where displacement is accommodated by smaller-scale faults/fractures.

SLIDE 18.
Click to view notes

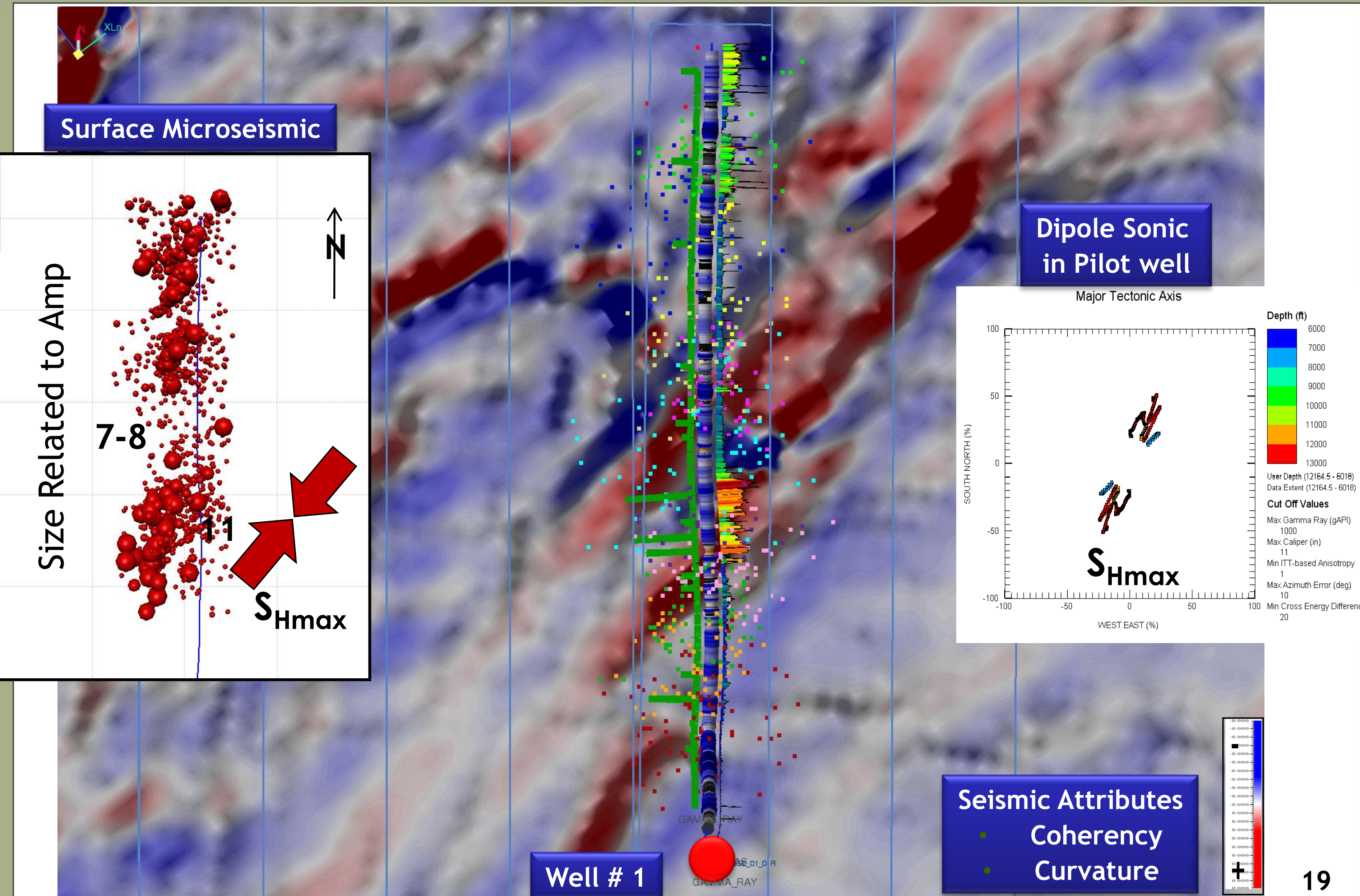
Well #1- Data Integration along lateral

PIONEER NATURAL RESOURCES



Map View-Stress Orientation

PIONEER
NATURAL RESOURCES



SLIDE 20.
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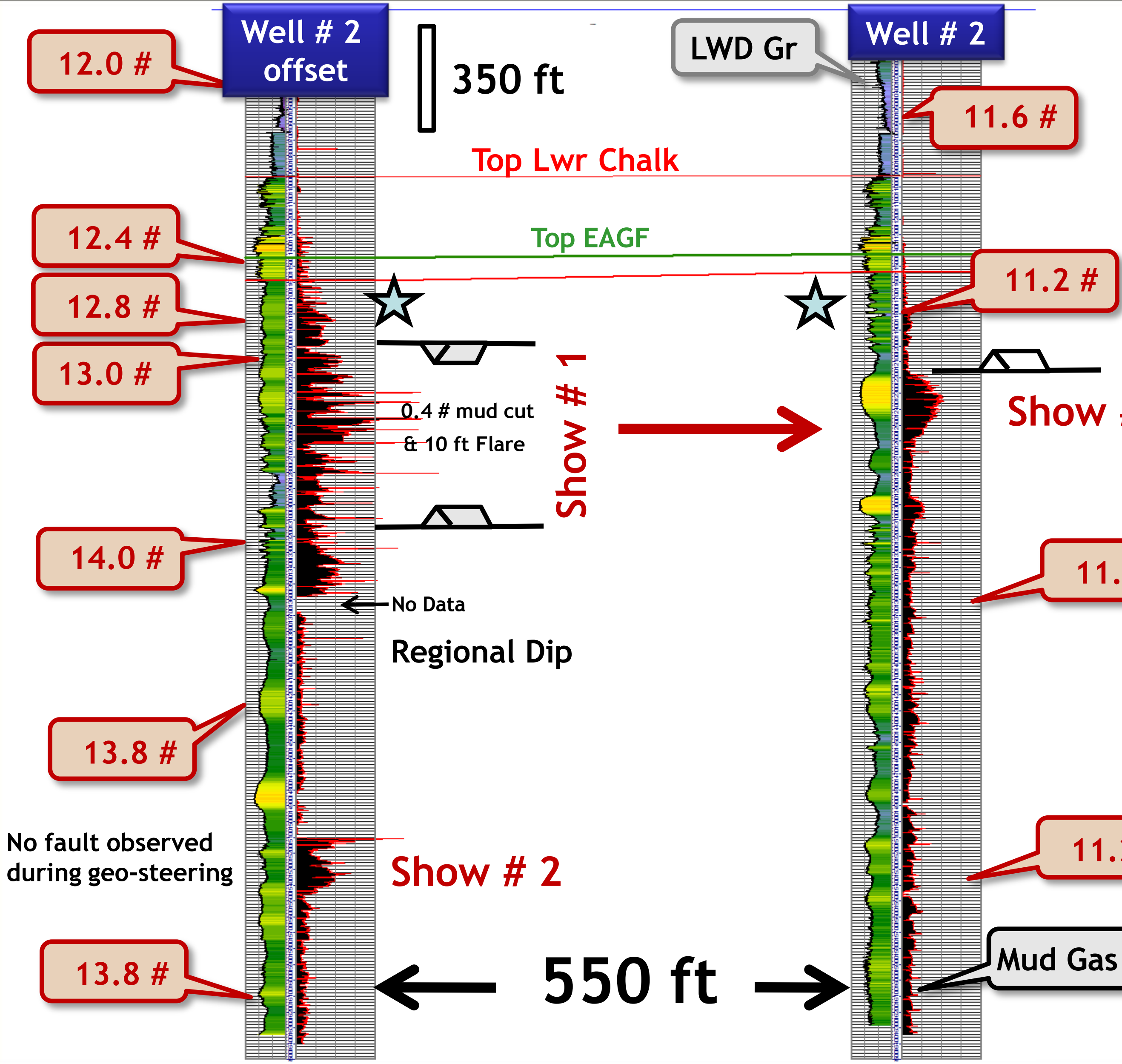
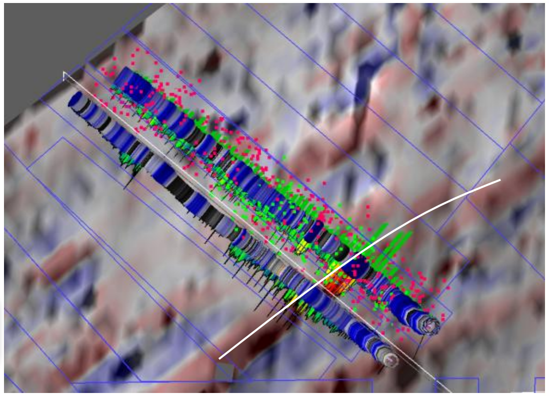
Natural Fractures-Impact on offset wells

PIONEER NATURAL RESOURCES





Frac'ed #1 before drilling #2

SLIDE 21.
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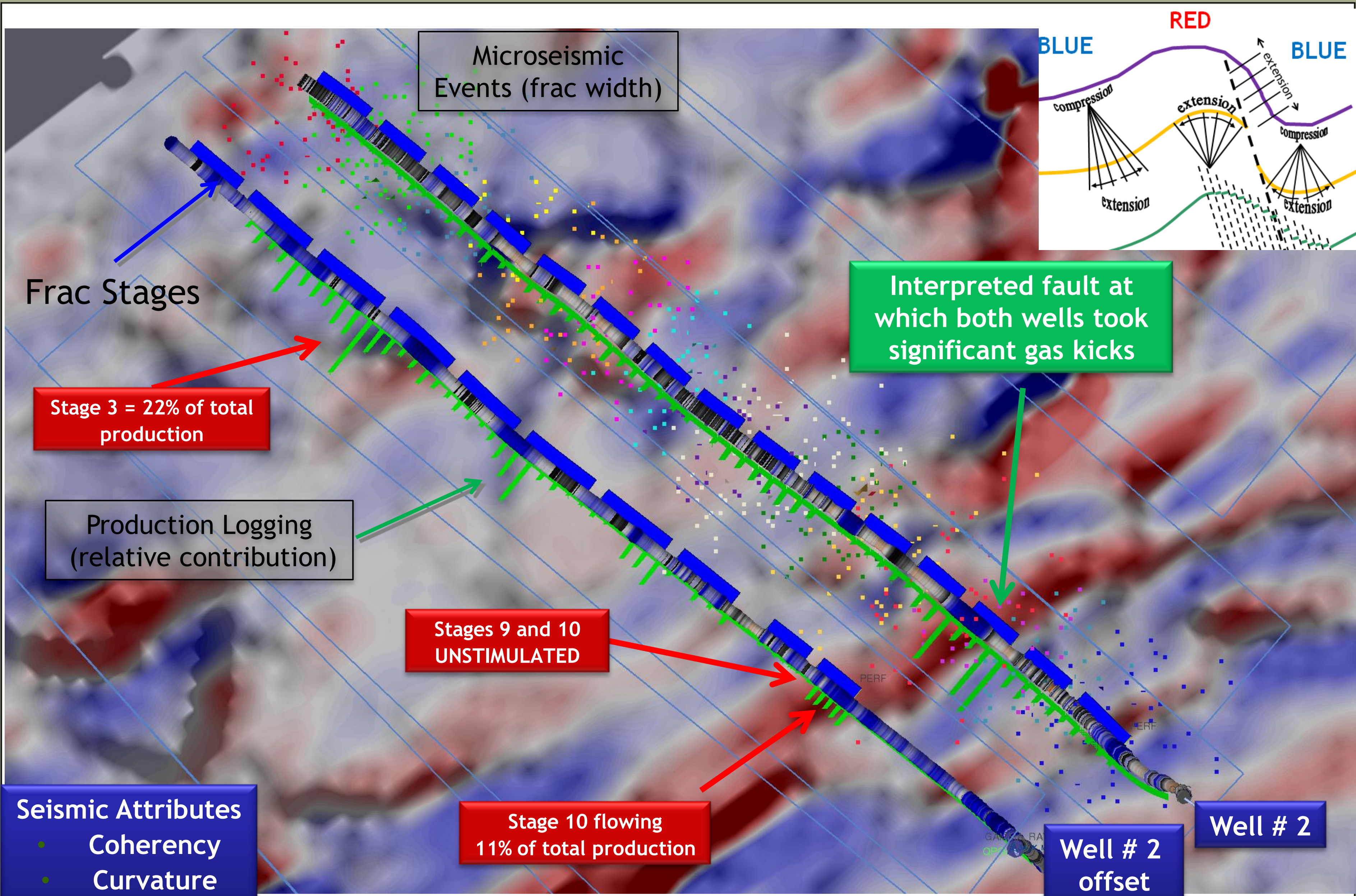
Data Integration Map View

PIONEER
NATURAL RESOURCES



Summary

- Horizontal logs confirmed presence of natural fractures (open and healed) and production logs showed early fluid-flow dominated by those fracture zones.

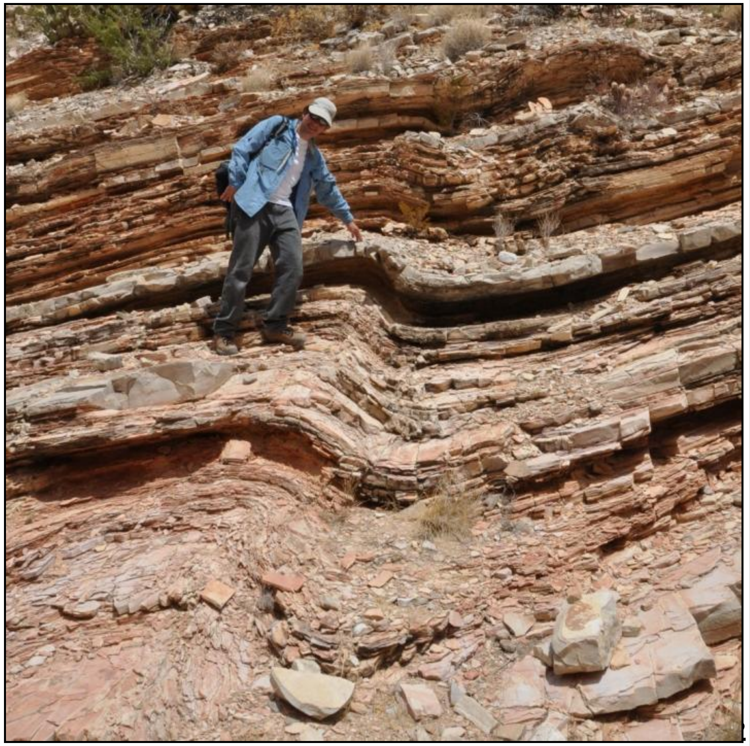
- Mud log data in lateral highlight these “more” productive zones.

- These zones can be predicted and tie directly to structural fabric/attributes observed from seismic and outcrops.

- Confirm present-day stress field direction is predictable from seismic attributes and that it is not same along the trend.

- Surface and down-hole microseismic showed comparable results.

- Production logging and chemical tracers show similar relative contribution along lateral.



Eagle Ford Asset Team-Geosciences

- **BACK UPS**

SLIDE 25.
Click to view notes

Exploration

- Strong presence in South Texas developing Edwards dry gas play, acreage expansion to > 300,000 Ac.
  - Late <u>2006 re-completed</u> several vertical wells in Eagle Ford zone of interest
    - Acquire & license >2000 sq miles of 3-D seismic
    - Drilling 2nd Eagle Ford Lateral in DeWitt Co. when Hawkville was announced

Appraisal

- Drilled 4 appraisal wells that extended play >100 miles to the NE from original HK discovery area.
  - PXD drilled over 150 wells (~35 have pilots & full logs). And cut over 2000 ft of core (six wells)
    - Remarkable change in liquids yield (NGL/Condensate) across play

Development

- Joint venture with Reliance/Newpek
  - Drilling with 12 rigs
    - 3 dedicated frac fleets (2 PXD).
      - Own midstream facilities
        - Currently producing ~ 400 mmcfed

[redacted]

SLIDE 26.

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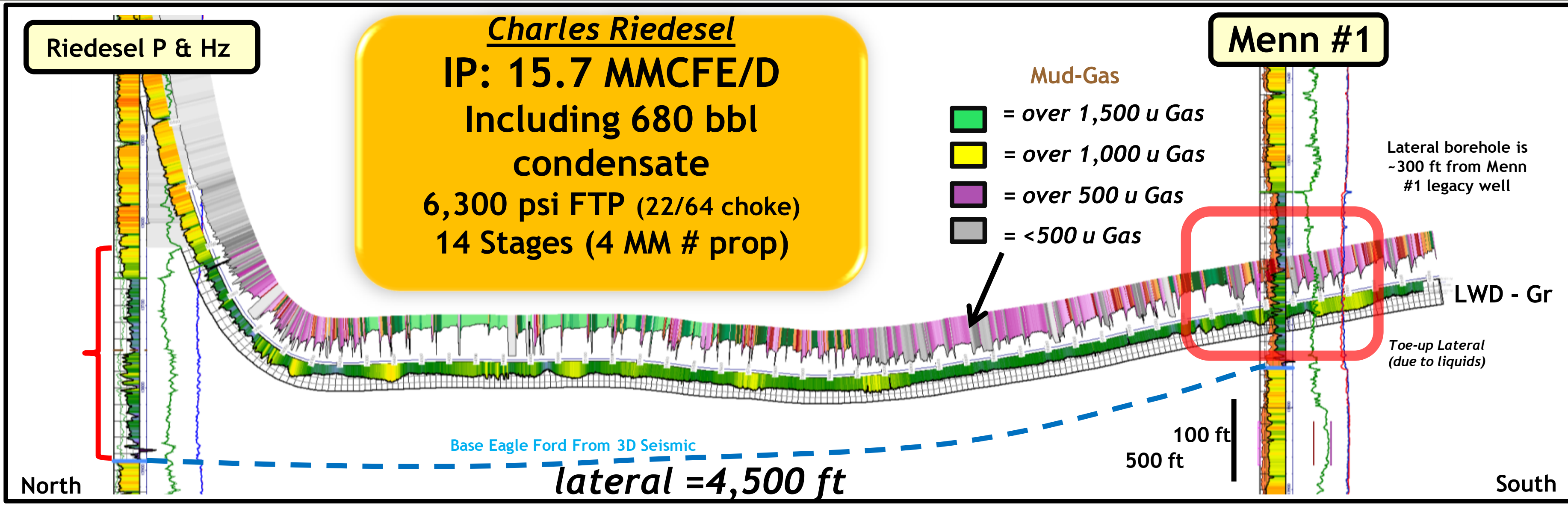
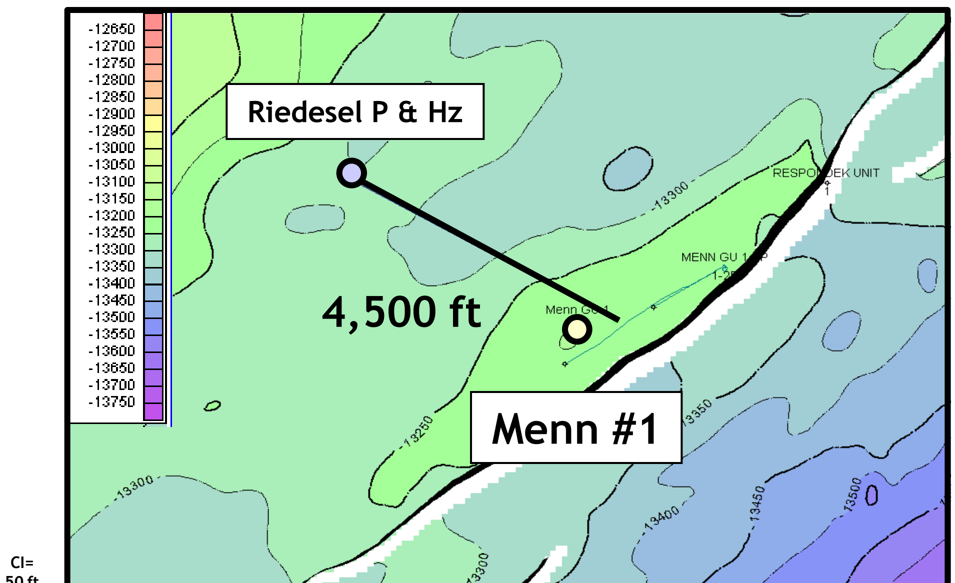
Horizontal Wells Show True Potential





Top Eagle Ford (SS)

- IP of 15.7 MMCFEPD was ~30x more productive than vertical completion in Menn 1 using ~20x more proppant

Handy Area - Liquids Rich "Reality"

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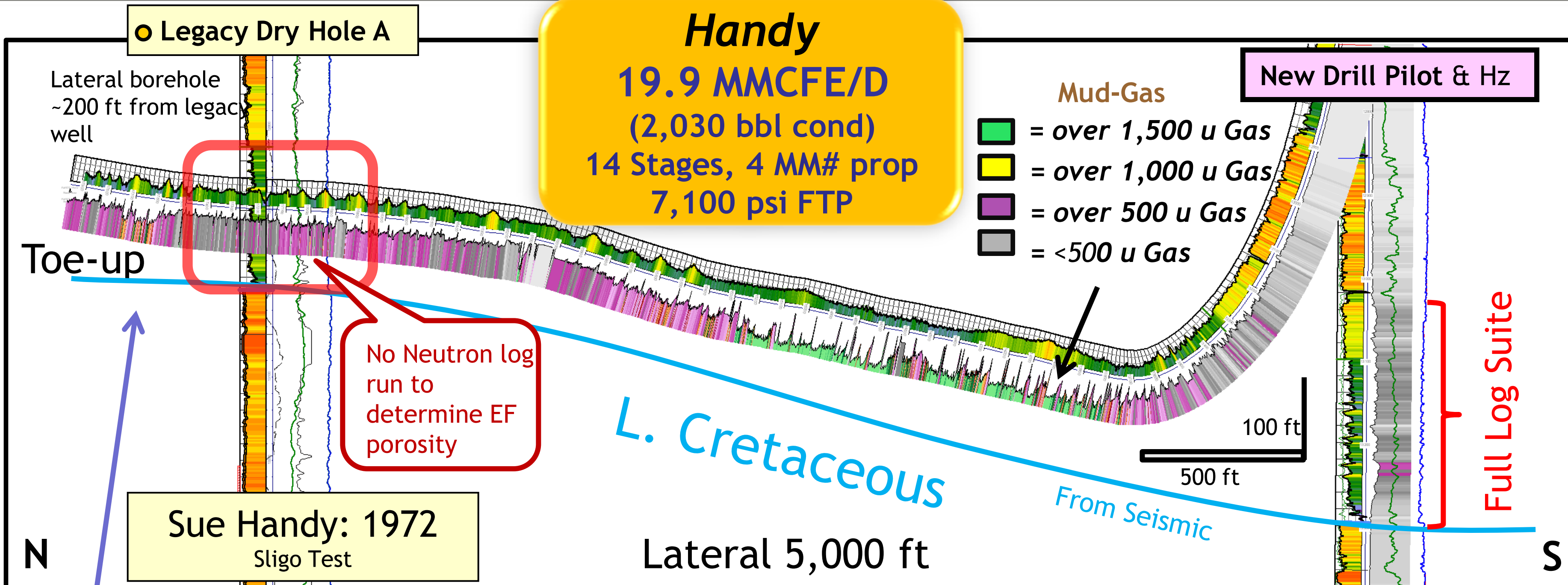
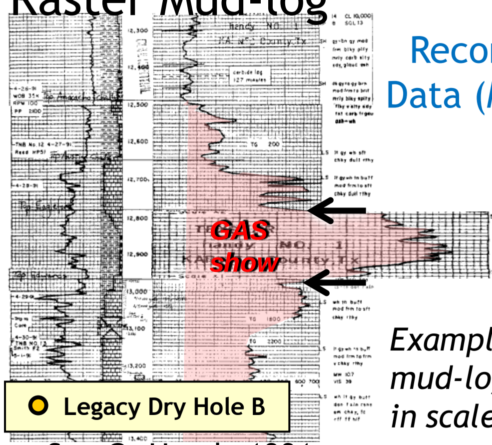


Raster Mud-log

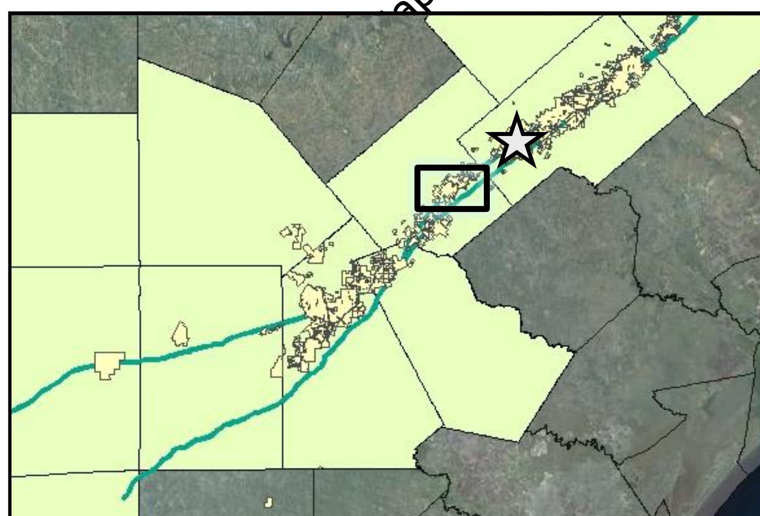


Sue G. Handy 1991

Reconnaissance Data (Mature Area)

Scale was compressed x2 wrapped

*Example of legacy mud-log (note change in scale). Colored gas curve red **(n=653)***



SLIDE 28.

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Fractures Interpretation

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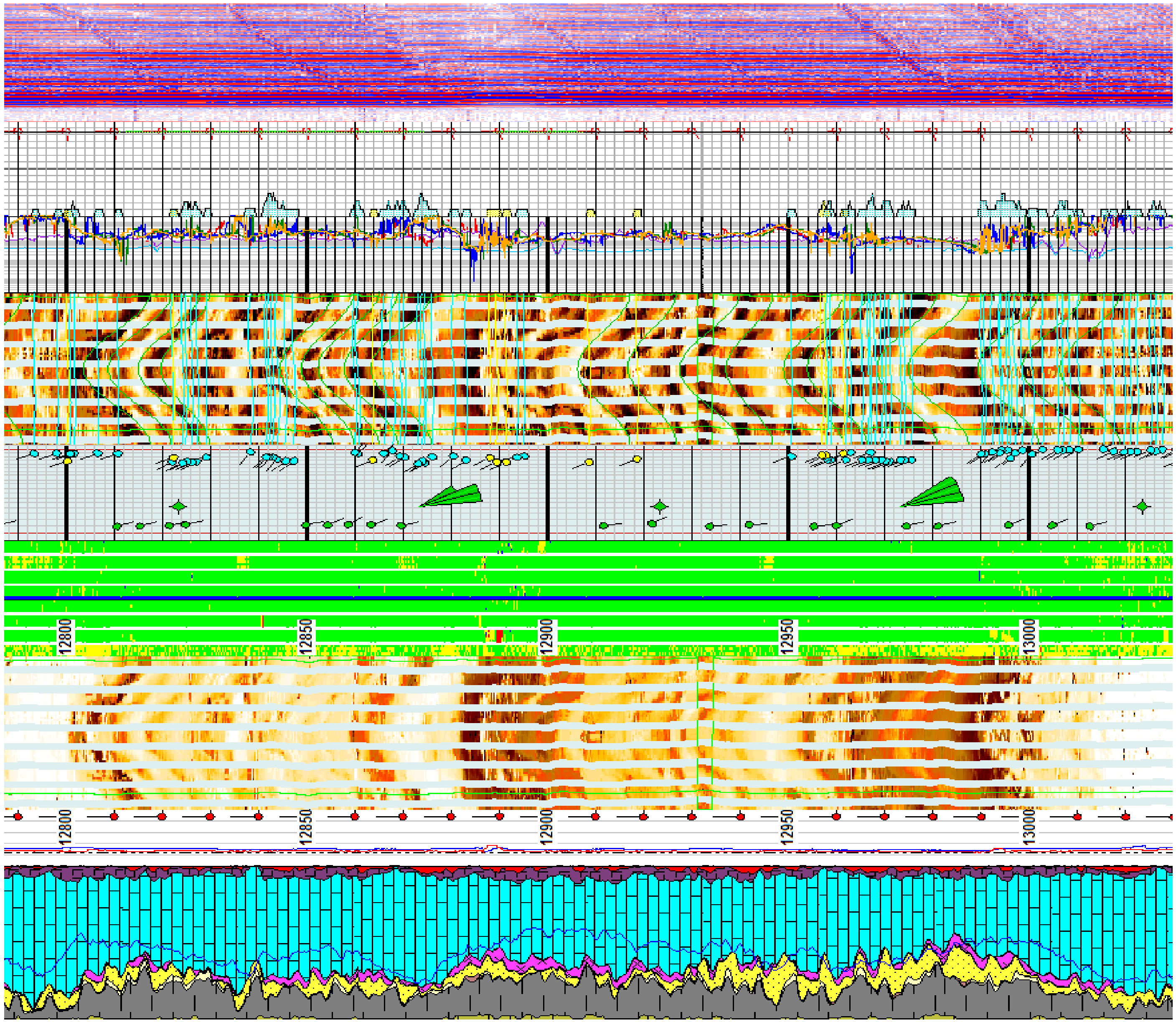
Stoneley VDL

Fracture Count

Dynamic Image (OBMI-2)

Static Image (OBMI-2)

ELAN Volumes



Relay Ramp View

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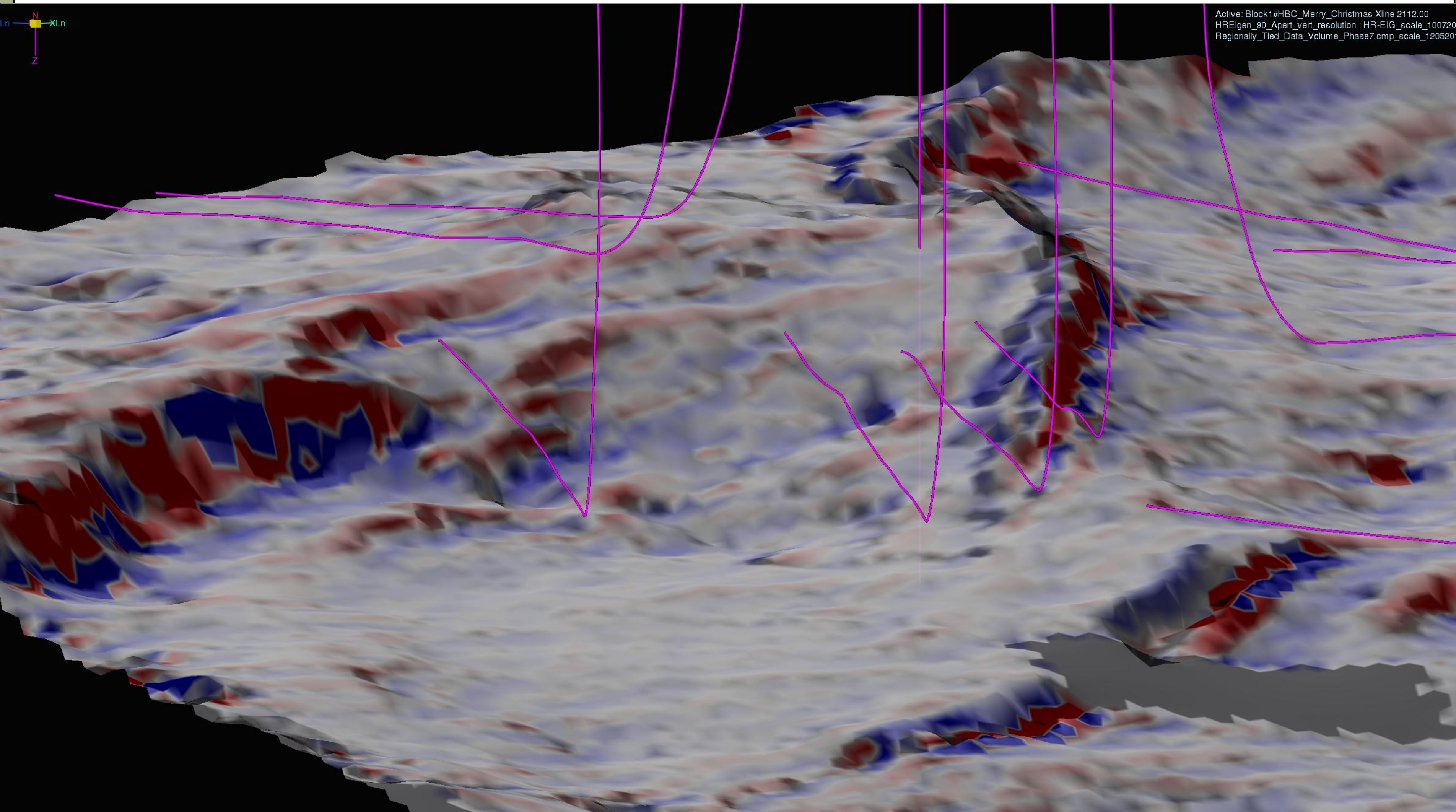
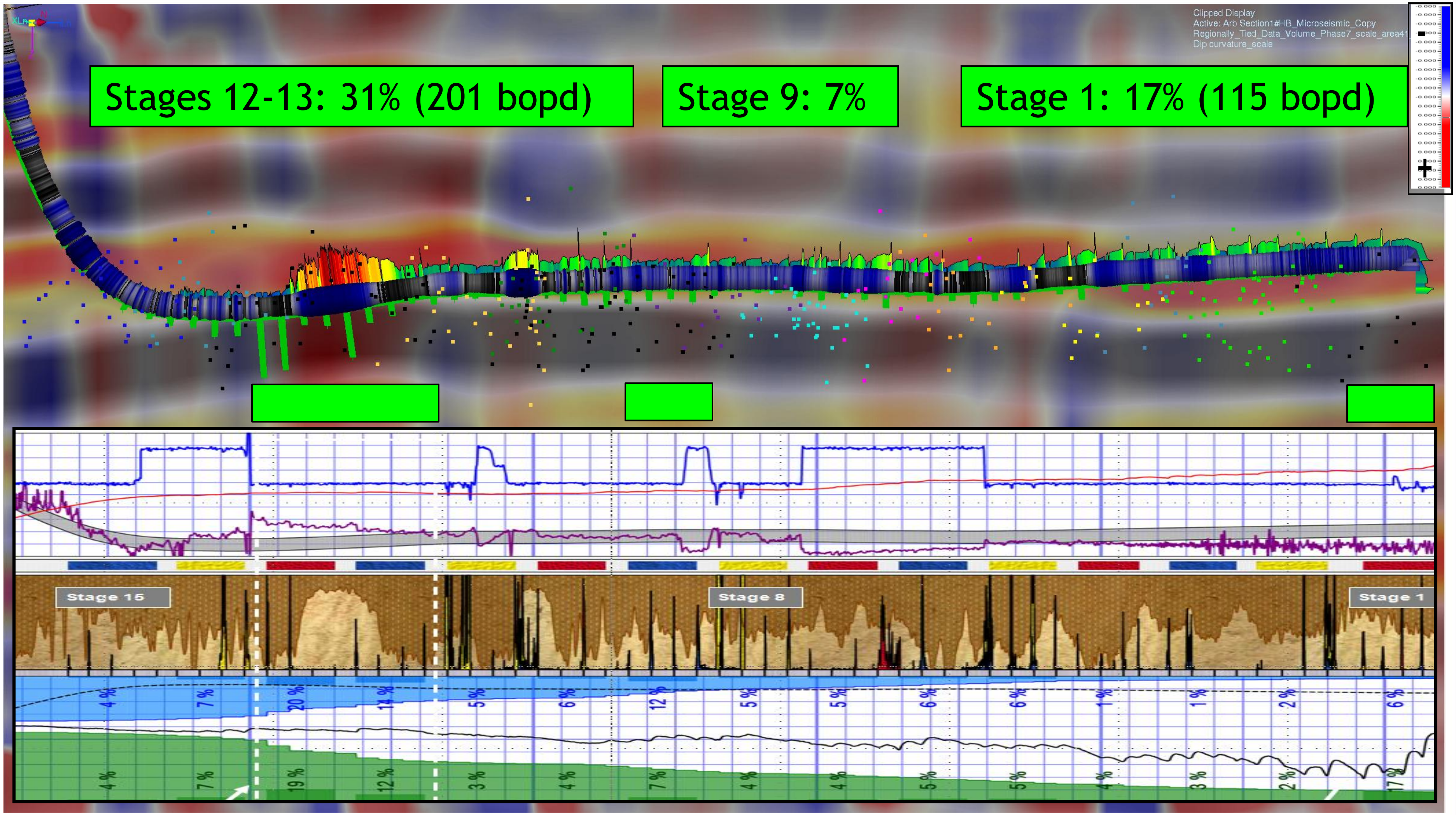


Well # 2- Data Integration along lateral

PIONEER NATURAL RESOURCES



Positive curvature shows a good correlation with highest oil contribution.
Positive curvature can be detecting natural fractures systems, strongest gas show while drilling.

Talk Outline

PIONEER
NATURAL RESOURCES

- **Project's Regional Setting**
  - Location
  - Stratigraphy
  - Local Structural Control
- **Data Acquisition**
  - Summary
- **Data Integration & Application to Subsurface**
  - Lateral Logging Interpretation
  - Seismic Attributes
  - Data Integration Examples

Talk Outline

PIONEER NATURAL RESOURCES

Ernst Tinaja
Big Bend Nat. Park

- Project's Regional Setting
  - Location
  - Stratigraphy
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Talk Outline

PIONEER NATURAL RESOURCES

Ernst Tinaja
Big Bend Nat. Park

- Project's Regional Setting
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  - Seismic Attributes
  - Data Integration Examples

Well # 1 Pilot Logging

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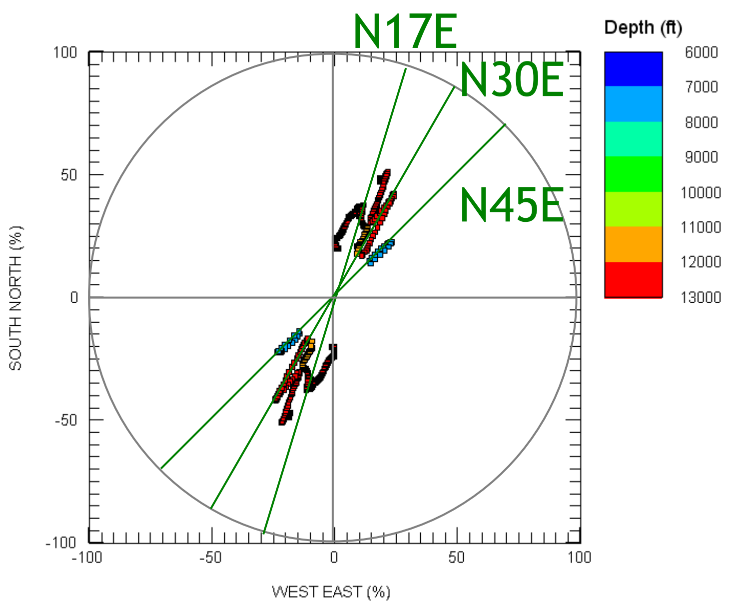
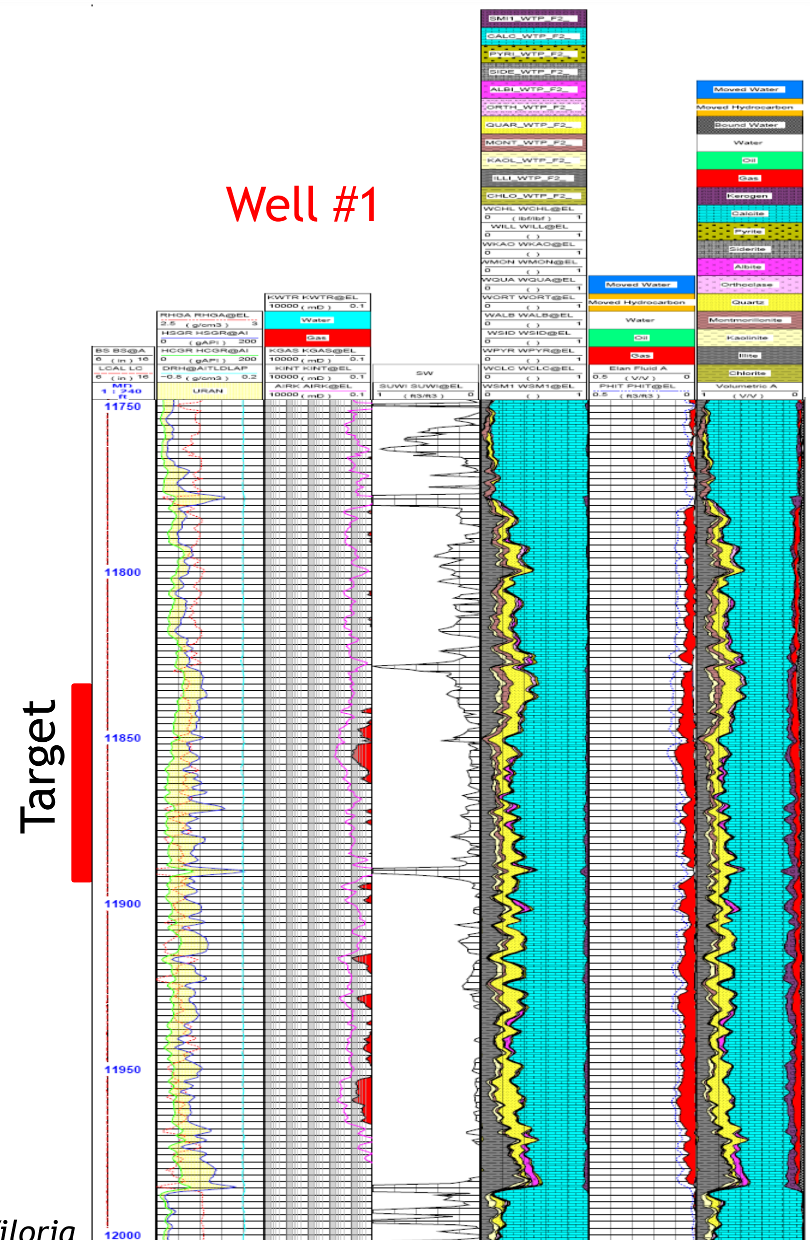
Fast Shear Azimuth = direction of Fast Shear Wave propagation



Drilling-induced fractures in Buda indicate max horizontal stress ~N30E, corroborated by azimuthal shear anisotropy (above).

No natural fractures were detected in Eagle Ford from the OBMI



Interpreter - Viloria

SLIDE 35.

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Well # 1 Lateral Logging

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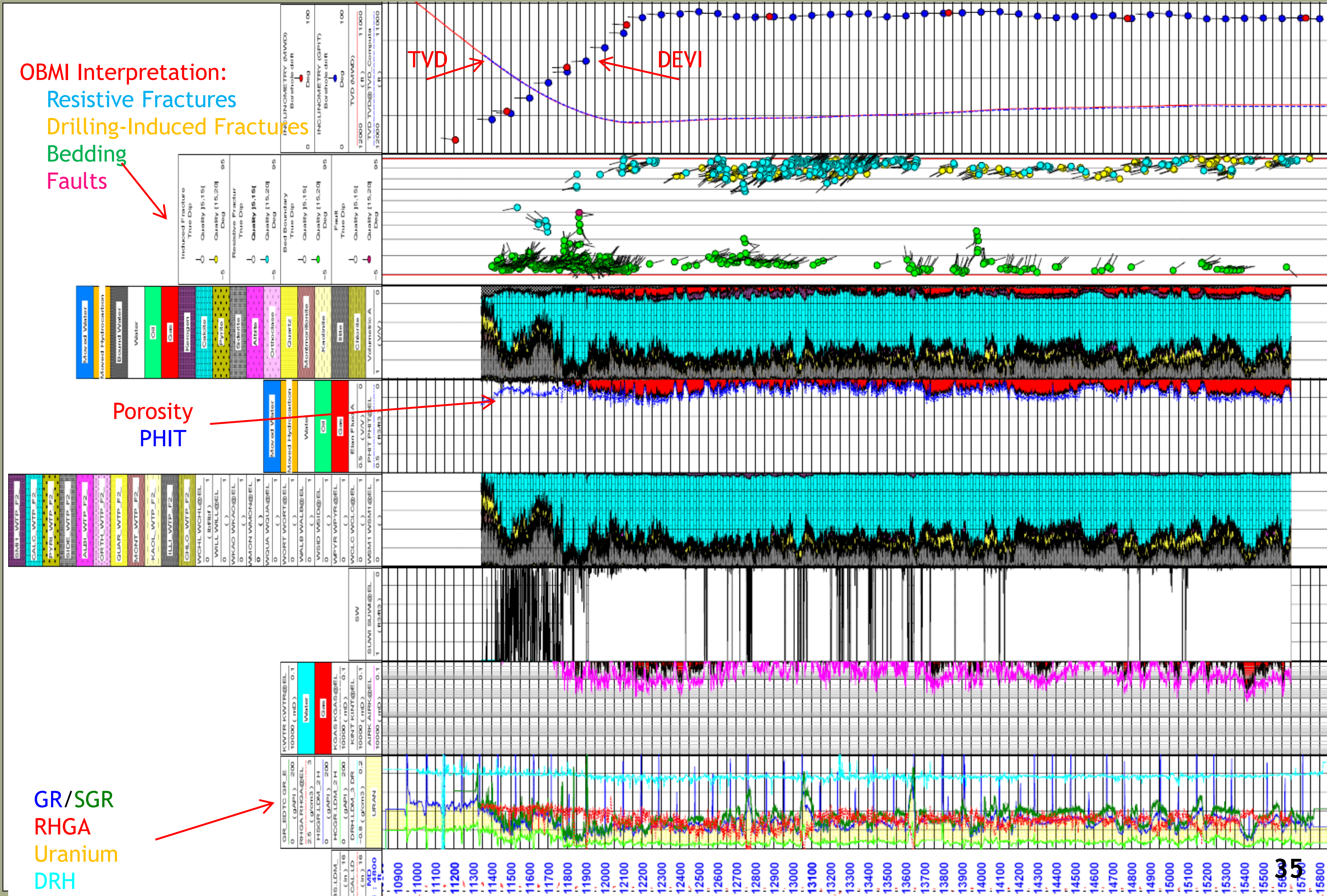
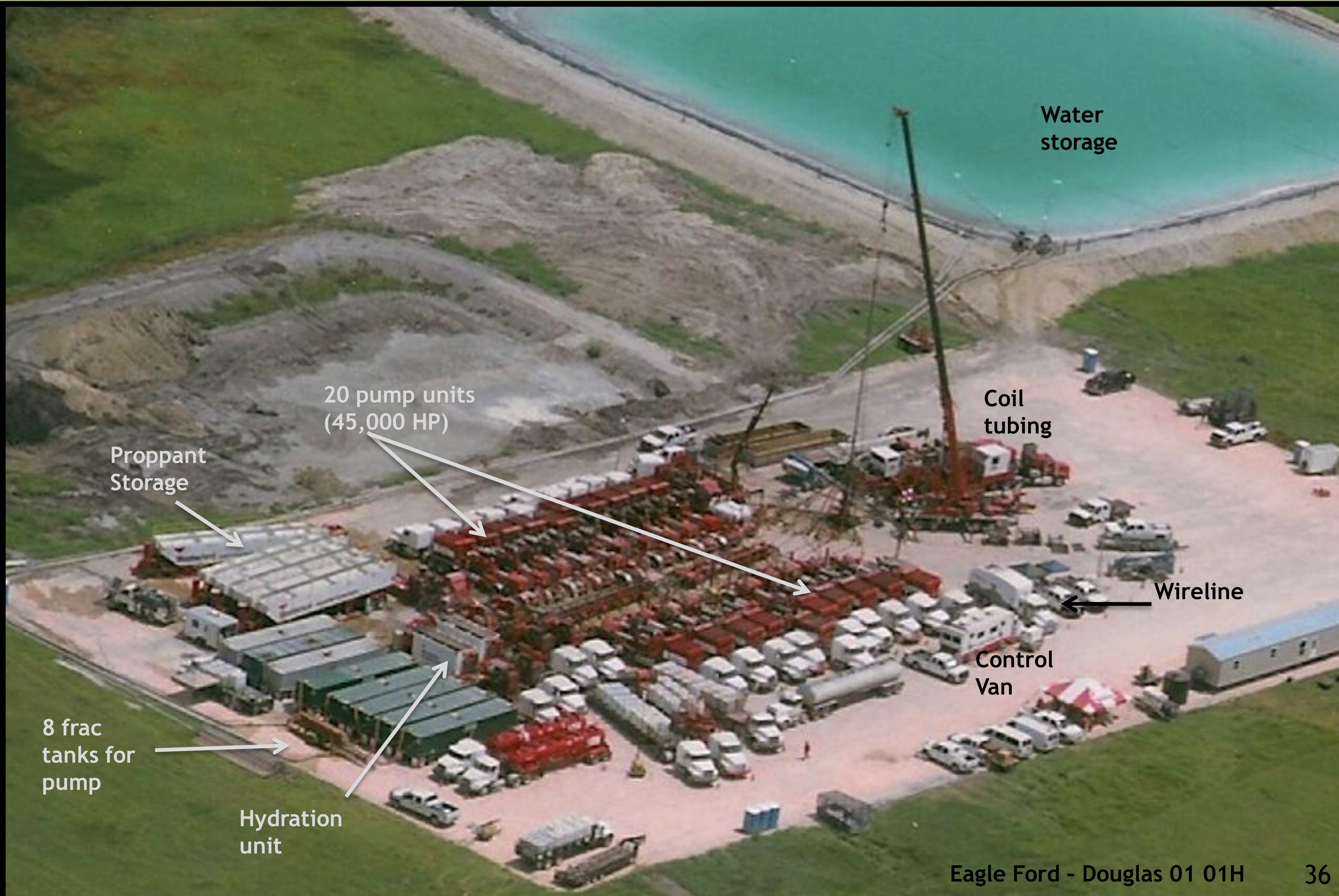
NATURAL RESOURCES



Typical Frac Design

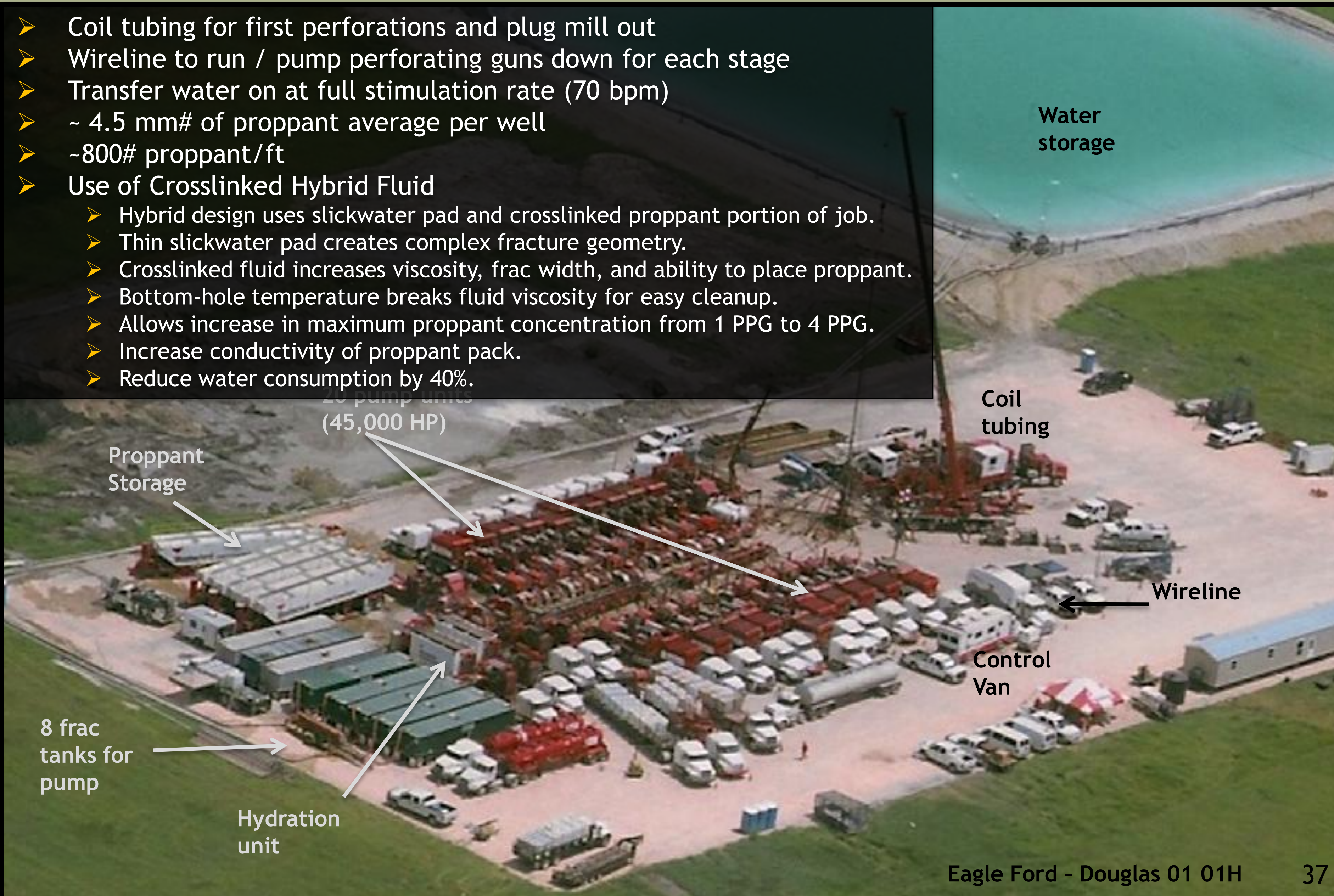
PIONEER NATURAL RESOURCES



Typical Frac Design

PIONEER NATURAL RESOURCES

- Coil tubing for first perforations and plug mill out
- Wireline to run / pump perforating guns down for each stage
- Transfer water on at full stimulation rate (70 bpm)
- ~ 4.5 mm# of proppant average per well
- ~800# proppant/ft
- Use of Crosslinked Hybrid Fluid
  - Hybrid design uses slickwater pad and crosslinked proppant portion of job.
  - Thin slickwater pad creates complex fracture geometry.
  - Crosslinked fluid increases viscosity, frac width, and ability to place proppant.
  - Bottom-hole temperature breaks fluid viscosity for easy cleanup.
  - Allows increase in maximum proppant concentration from 1 PPG to 4 PPG.
  - Increase conductivity of proppant pack.
  - Reduce water consumption by 40%.



SLIDE 38.

Click to view notes

Microseismic Acquisition-Array lay-out

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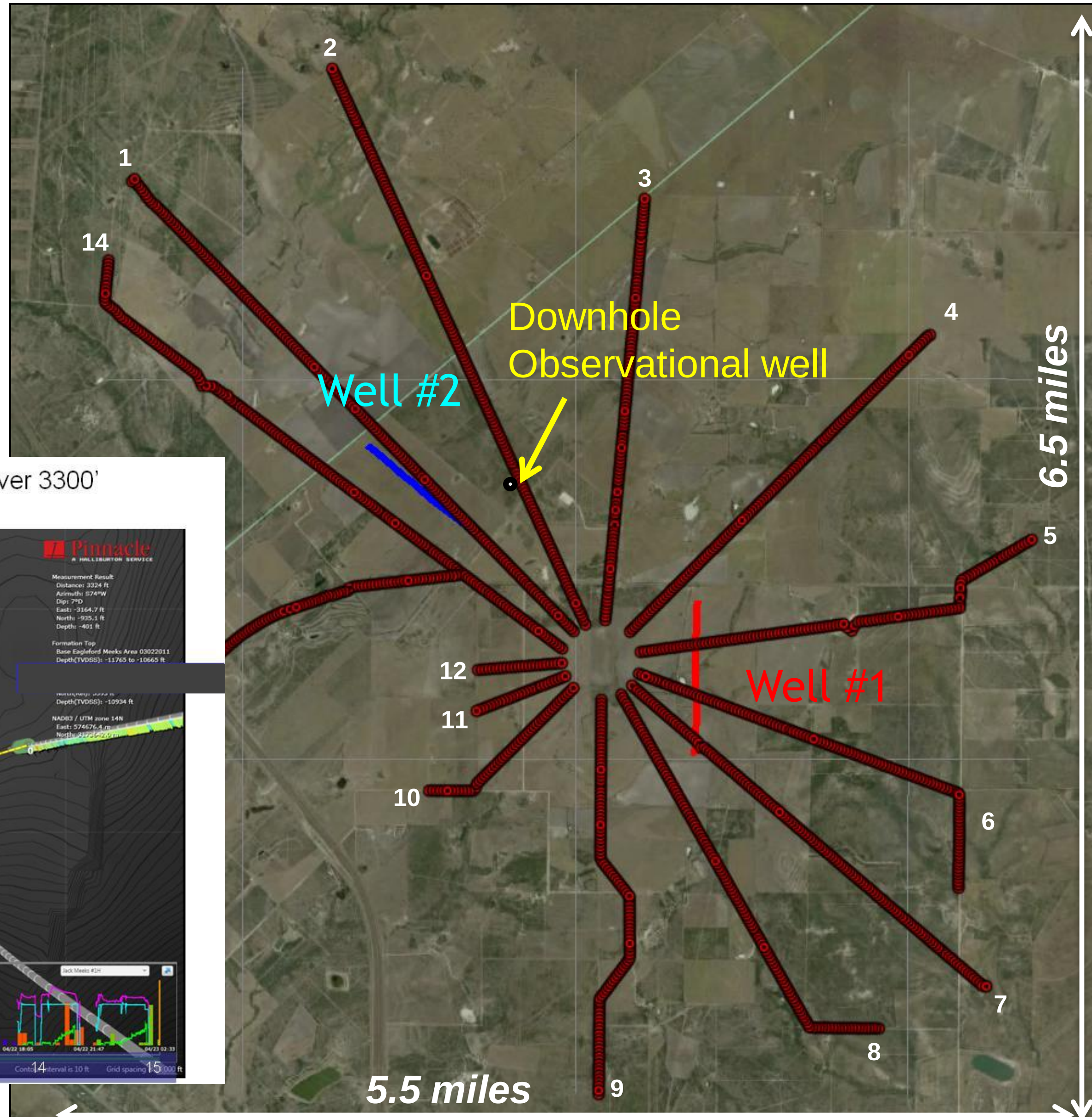
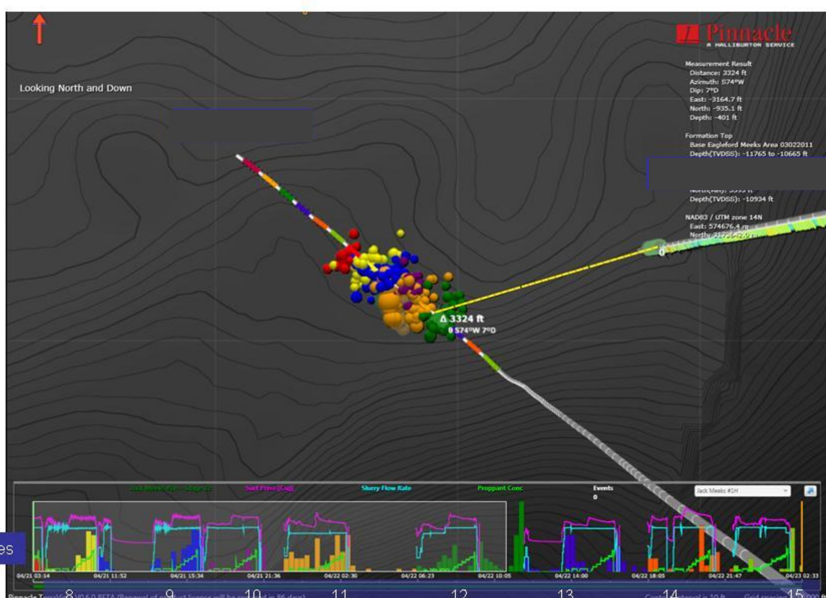
- 1531 stations in the surface array. They are represented as red spheres.

- The array consists of 14 lines centered in-between the two wellheads.

- The well #2, in blue, and well #1 path is shown in red.



Distance to Downhole observation well 2900 to over 3300’



SLIDE 39.

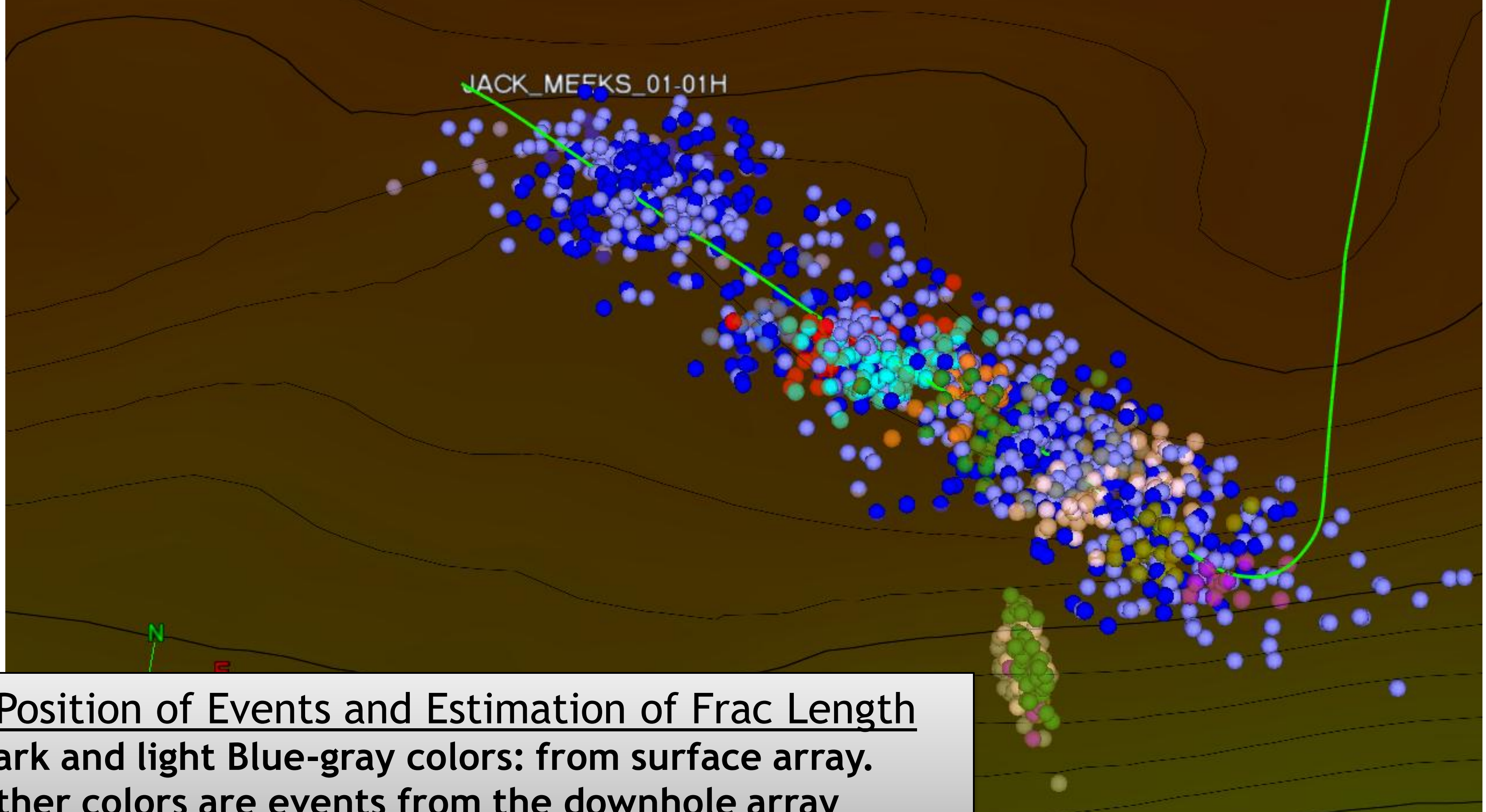
Click to view notes

Well #2, Surface and Downhole Array

PIONEER NATURAL RESOURCES

Frac Length Assessment

- Surface acquisition: longer Avg length of 1,035’ vs. 816’ for the downhole.
- Similar overall position of events from the two methods
- “Area extent” within ~80-100 Ac



Position of Events and Estimation of Frac Length

•Dark and light Blue-gray colors: from surface array.

•Other colors are events from the downhole array

SLIDE 40.

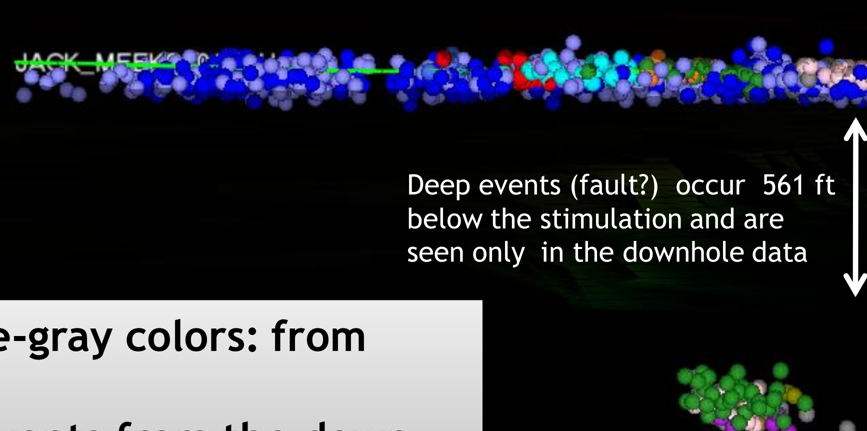
Click to view notes

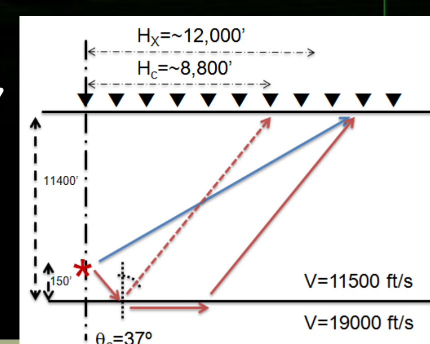
Well #2 Surface and Downhole

PIONEER
NATURAL RESOURCES

Frac Height Assessment

- Surface array frac heights are interpreted higher (194' vs. 116') than the downhole frac height
- Down-hole array also noted very deep events that are related to a deep fault or a refraction of shallower data
- Good Frac containment within Eagle Ford Reservoir





- Dark and light Blue-gray colors: from surface array.
- Other colors are events from the down-hole array

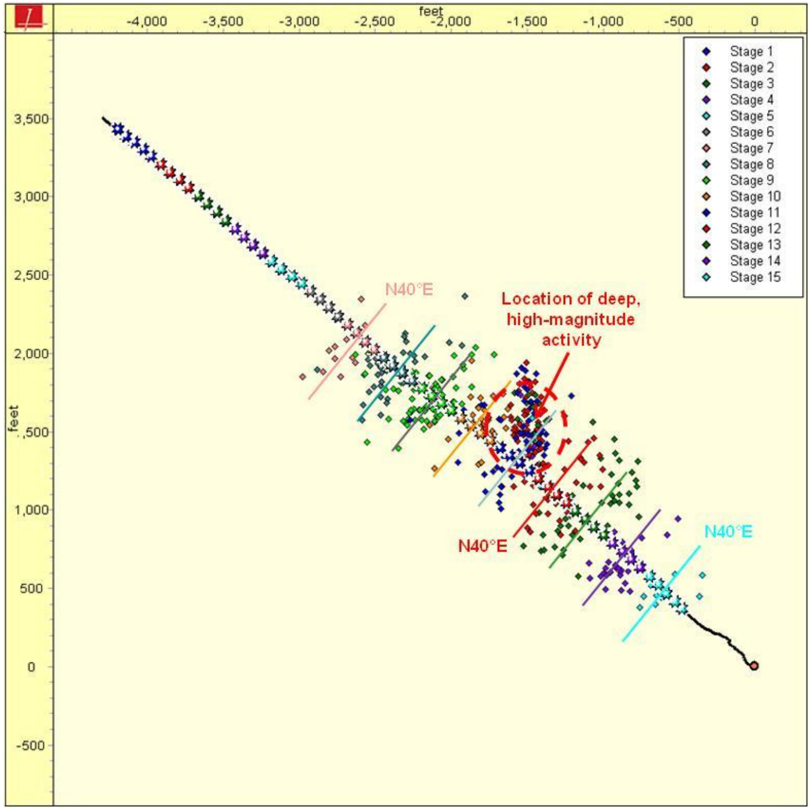
Pioneer Well #2, Azimuth variation

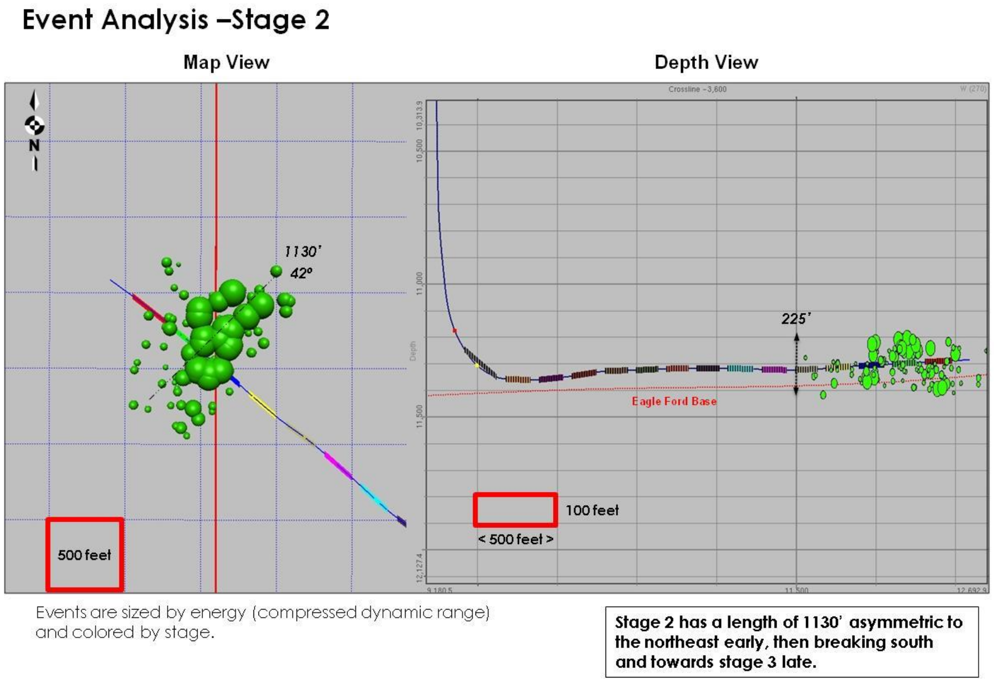
PIONEER NATURAL RESOURCES

Frac Azimuth Assessment

From Downhole the fracture azimuths are all interpreted as approx. N40°E

The MSI Surface Array detected the average azimuth trend as 45° for all 15 stages



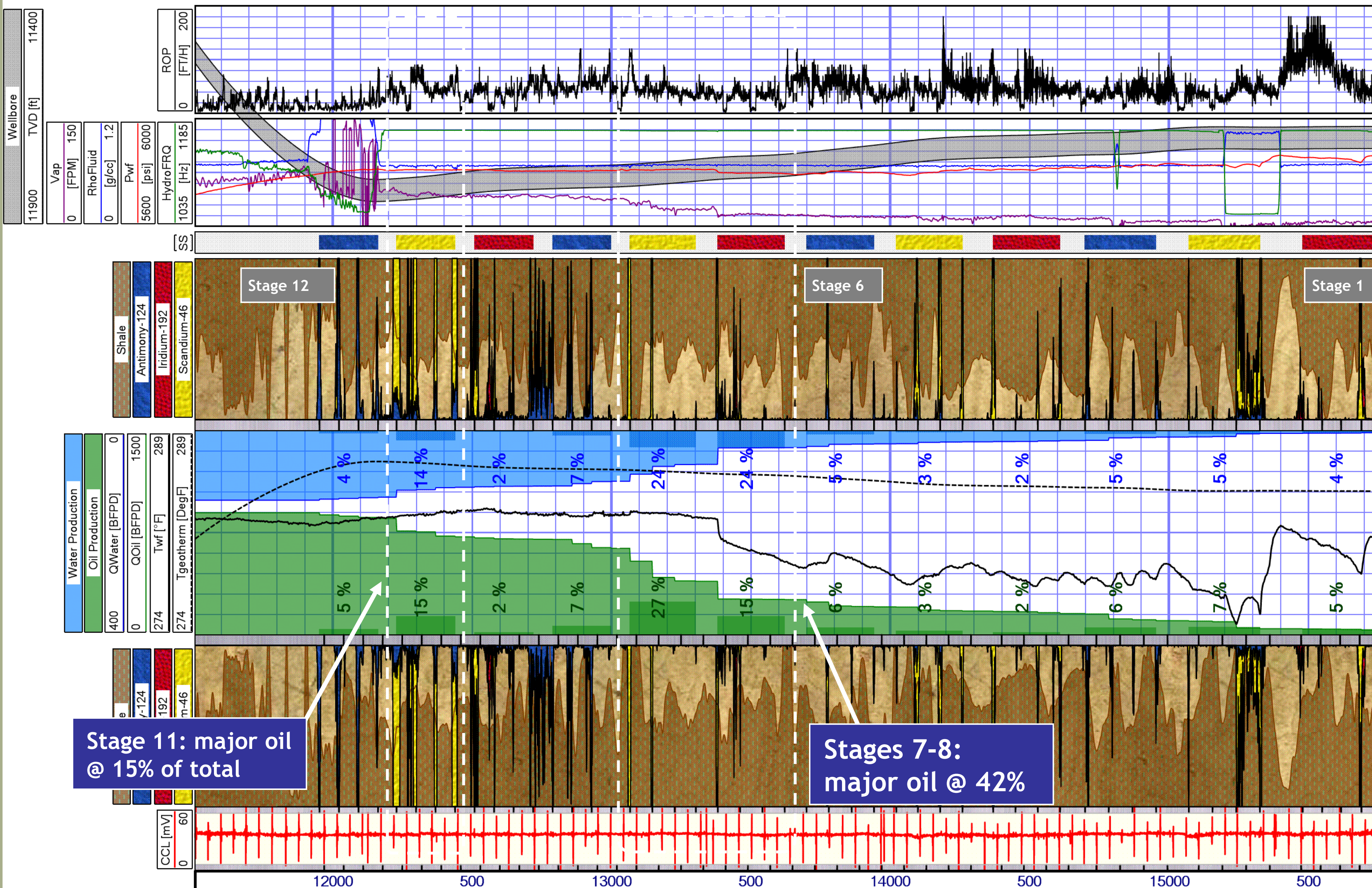


SLIDE 42.

Click to view notes

Well #1, Prod Profile - Stages 1 - 12

PIONEER
NATURAL RESOURCES



SLIDE 43.
Click to view notes

Well #2, Chemical Tracer Results

PIONEER NATURAL RESOURCES

Key
>200
150 to 200
100 to 150
70 to 100
50 to 70
35 to 50
25 to 35
17 to 25
12 to 17
8 to 12
5 to 8
3 to 5
2 to 3
1 to 2
0.05 to 1

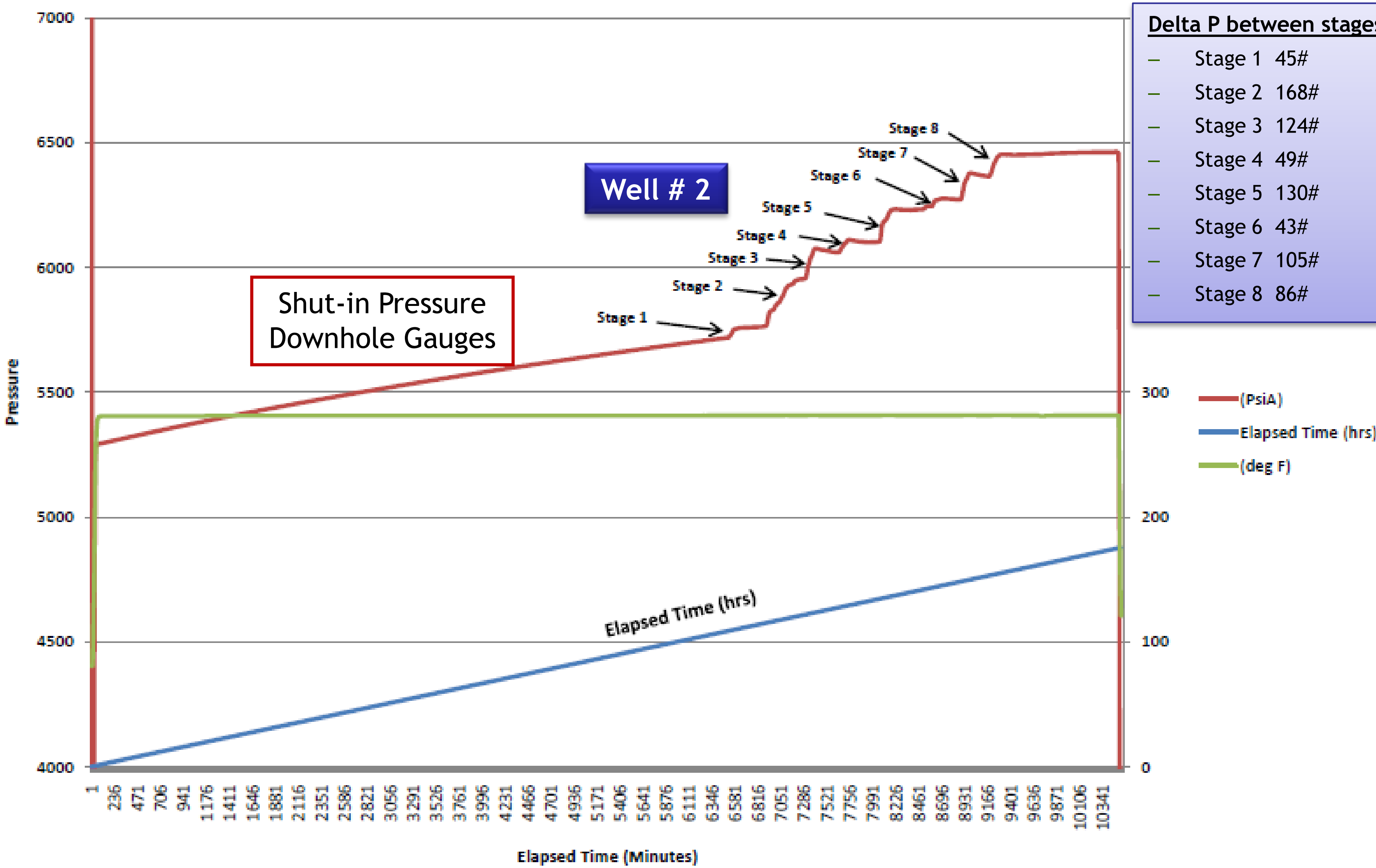
				Chemical Frac Tracer Concentration, ppb													
				Stages 1&2	Stage 3	Stage 4	Stage 5	Stage 6	Stage 7	Stage 8	Stage 9	Stage 10	Stage 11	Stage 12	Stage 13	Stage 14	Stage 15
	Flowback, bbl *	Sample Date	Sample Type	CFT 1200	CFT 1000	CFT 1100	CFT 1300	CFT 1700	CFT 2000	CFT 2200	CFT 1900	CFT 2100	CFT 1600	CFT 1500	CFT 2500	CFT 2400	CFT 1400
1		04/19/11 23:00	Water (Pre-Frac)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2		04/22/11 14:30	Water (Pre-Frac)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	5440	04/28/11 12:00	Water (Produced)	8.8	9.2	14.6	8.5	18.1	15.5	15.3	8.9	67.9	52.3	67.2	61.5	63.4	99.8
4	5929	04/28/11 22:00	Water (Produced)	9.3	10.7	15.4	7.6	19.1	14.7	15.1	9.1	62.1	54.2	62.2	58.7	56.4	86.8
5	6645	04/29/11 14:00	Water (Produced)	10.2	11.9	16.5	9.6	19.0	13.1	13.3	8.3	59.6	55.8	70.3	59.4	59.4	76.1
6	7133	04/30/11 02:00	Water (Produced)	11.2	10.3	15.6	10.7	17.7	12.7	14.1	8.5	51.4	58.1	70.5	56.1	59.9	61.8
7	7962	05/01/11 02:00	Water (Produced)	15.1	8.7	17.0	10.1	15.1	12.0	14.9	8.9	44.0	47.8	65.7	52.5	59.5	59.8
8	8648	05/02/11 02:00	Water (Produced)	15.1	9.5	18.6	13.1	15.9	12.7	12.6	7.9	43.9	48.7	62.3	57.4	63.6	55.6
9	9254	05/03/11 02:00	Water (Produced)	17.5	8.9	23.1	15.2	15.4	12.9	11.7	6.9	40.8	49.7	66.8	53.6	65.4	59.5
10	10281	05/05/11 02:00	Water (Produced)	32.6	10.7	26.3	17.6	21.9	11.9	9.9	6.6	44.9	60.3	65.3	37.0	62.7	48.4
11	10702	05/06/11 02:00	Water (Produced)	33.6	13.1	27.4	16.8	21.7	11.3	10.1	6.9	44.0	51.7	63.4	39.3	62.3	53.5
12	11066	05/07/11 02:00	Water (Produced)	34.7	11.2	29.0	19.6	22.4	10.2	8.6	5.3	43.5	54.3	56.4	36.5	57.8	45.4
13	11401	05/08/11 02:00	Water (Produced)	34.0	11.6	28.9	19.4	21.1	10.4	10.5	5.4	44.4	53.4	60.3	36.1	54.5	39.0
14	11844	05/09/11 14:00	Water (Produced)	32.3	11.1	22.4	16.0	15.4	12.4	9.2	5.6	38.2	50.6	56.5	32.9	48.0	44.5
15	12517	05/10/11 02:00	Water (Produced)	22.8	12.4	19.5	17.0	25.3	11.4	24.5	16.9	57.2	56.4	47.1	26.1	27.8	21.9
16	13573	05/11/11 14:00	Water (Produced)	15.7	5.1	13.4	9.5	9.0	6.8	8.2	3.9	28.0	31.9	38.5	33.2	36.8	38.7
17	13825	05/12/11 14:30	Logging Sample	34.8	11.5	25.3	15.8	16.1	11.2	7.5	3.1	44.9	46.4	52.8	35.3	44.8	28.2
18	14120	05/13/11 13:45	Logging Sample	53.2	21.5	40.1	28.5	19.6	13.1	4.1	1.6	16.7	15.3	23.1	12.1	17.1	51.4
19	14123	05/13/11 14:00	Water (Produced)	55.5	17.2	53.8	35.4	26.3	13.8	4.6	1.6	15.1	20.0	23.8	17.6	18.4	47.9
			Avg ppb	25.7	11.4	23.9	15.9	18.8	12.1	11.4	6.8	43.9	47.5	56.0	41.5	50.5	54.0
			% total ppb from Stage	6.1%	2.7%	5.7%	3.8%	4.5%	2.9%	2.7%	1.6%	10.5%	11.3%	13.4%	9.9%	12.0%	12.9%
			% total ppb @ last sample	15.8%	4.9%	15.3%	10.1%	7.5%	3.9%	1.3%	0.5%	4.3%	5.7%	6.8%	5.0%	5.3%	13.6%

Stages 1 - 6 are increasing concentration with flow time. Stage 1 with 17% of the oil production has the highest concentration during the CP log run on 05/13/11.

Stages 8 - 15 are decreasing concentration with flow time. Stage 1 with 17% of the oil production has the highest concentration during the CP log run on 05/13/11. Stages 12 - 13 were major oil producers during the CP log run.

Pressure Interference, Well#2 and Offset

PIONEER NATURAL RESOURCES



Delta P between stages

- Stage 1 45#
- Stage 2 168#
- Stage 3 124#
- Stage 4 49#
- Stage 5 130#
- Stage 6 43#
- Stage 7 105#
- Stage 8 86#

SLIDE 45.

Click to view notes

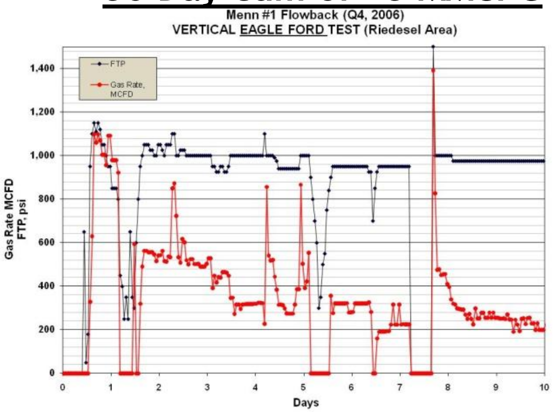
Early Vertical Recompletions Encouraging

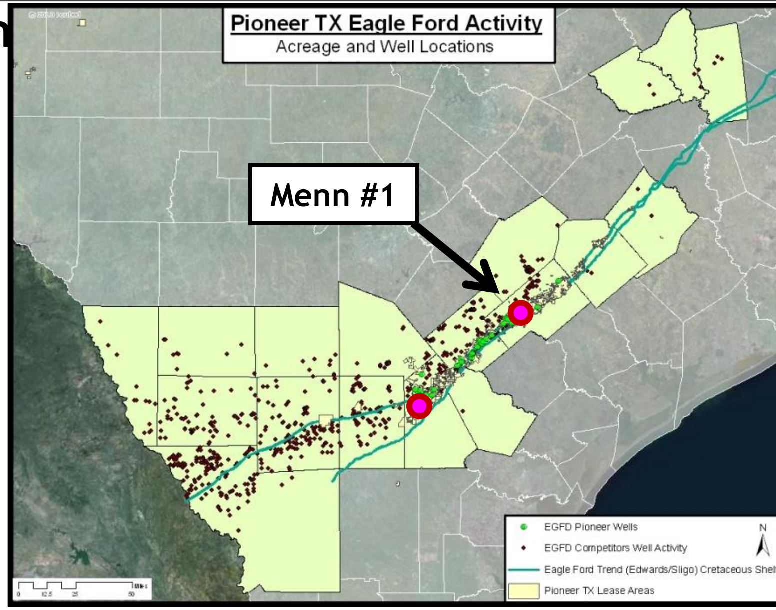
Menn #1 Recompletion

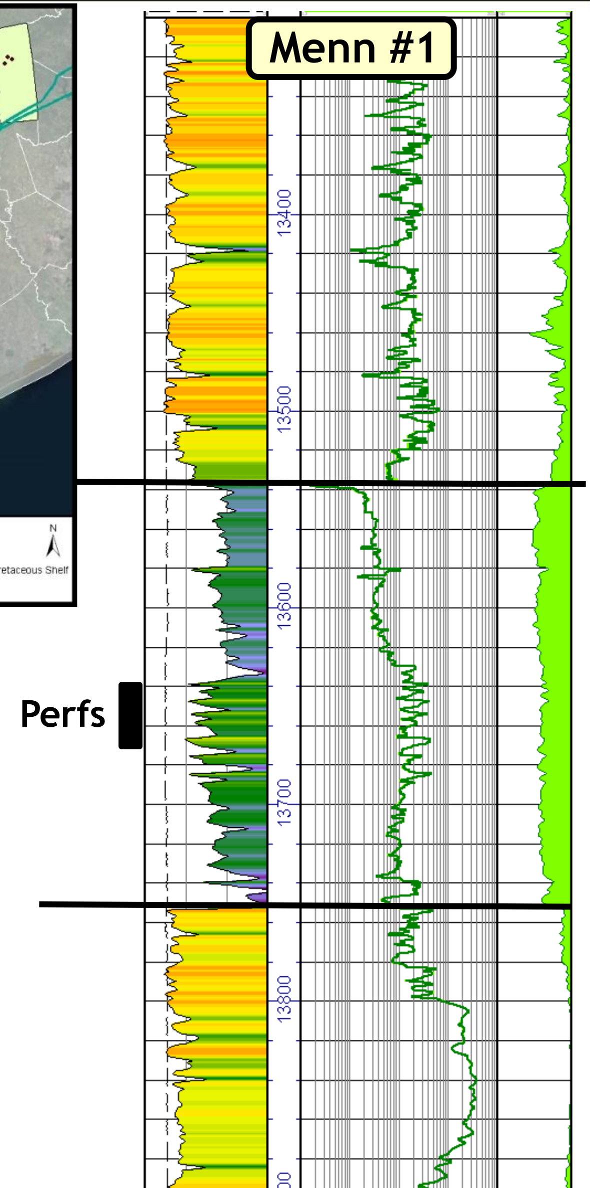
Vertical Well (Q4, 2006)

Tested: IP 550 MCF/D

30 Day cum of ~3 MMCFG





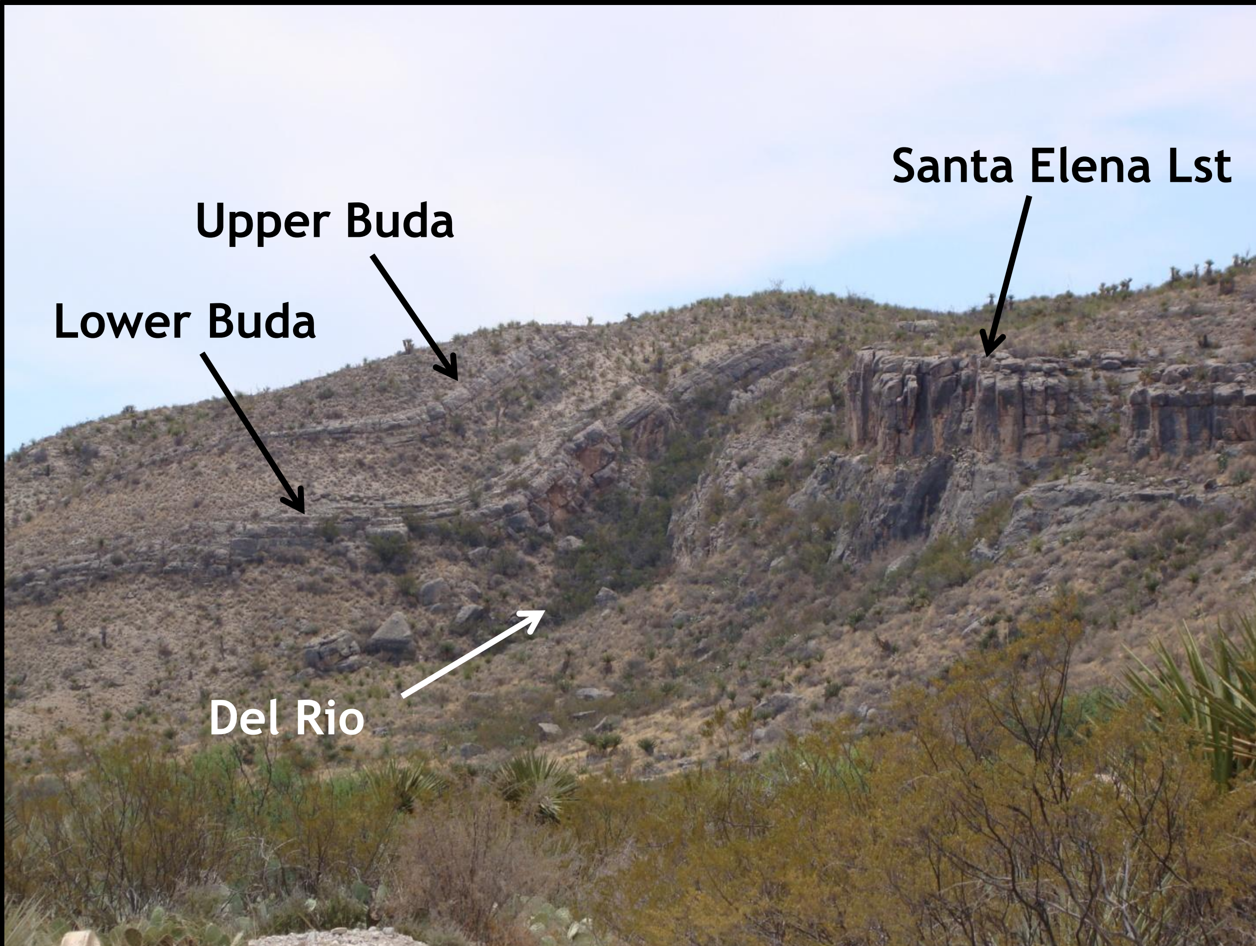


2006 Re-completion program = three (3) wells

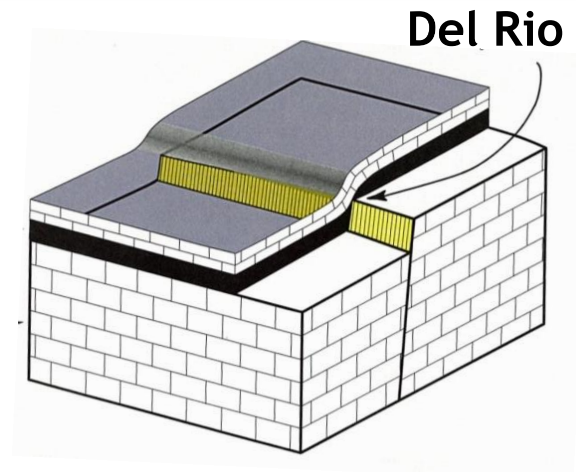
1) Menn #1: IP 550 MCF/D (190,000# prop.) WET GAS
2) Wernli 1-4: IP 200 MCF/D (45,000# prop.) DRY
3) Rolf #2-6: IP 50 MCF/D (2,500# prop.) DRY

Single Stage Frac (in vertical Edward Dry Hole)
Small stimulations (larger frac. = more productive?)
Frac. Gradient >0.9 psi/ft (much higher than est.)
Abnormal (high) Pore Pressure (over 0.7 psi/ft)

Big Brushy Canyon



Note contrasting structural style. Massive thick Lst has single large-displacement fault. Deformation in overlying thin Buda accommodated by folding and fracturing. Del Rio shows dramatic thickness variation.



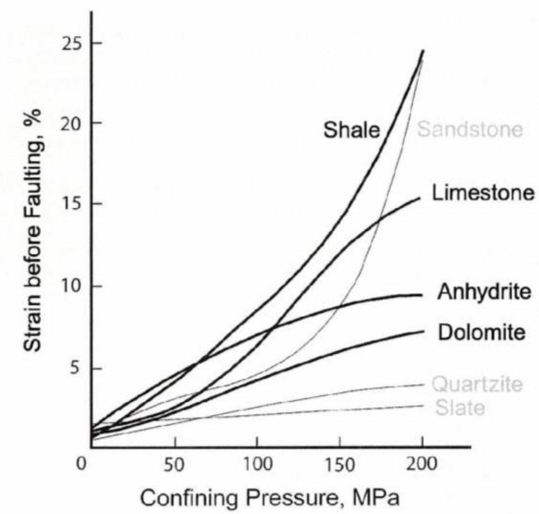
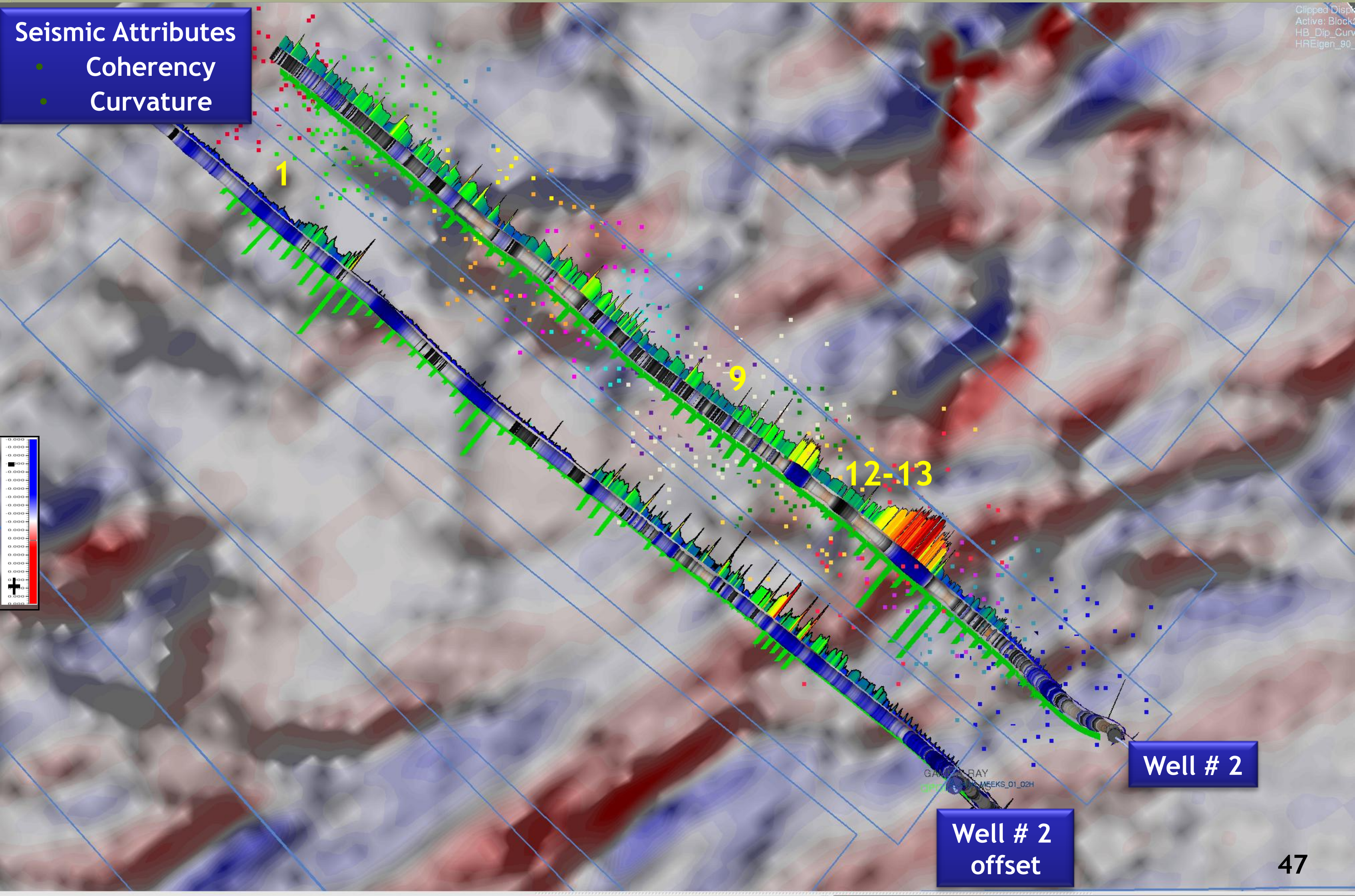


Figure 2. Graph of percent strain before faulting (ductility) versus confining pressure for a range of common rock types, including lithologies common in carbonate rock sequences (from Donath, 1970, adapted from the *American Scientist*).

Map-View Completion

PIONEER
NATURAL RESOURCES



Data Acquisition Summary

PIONEER NATURAL RESOURCES

Source		Use
1. Quad Combo (Pilot & Lateral)	→	Full Petrophysical Evaluation
2. Dipole Sonic	→	Stress Field, Fracture recognition
3. OBMI	→	Fracture ID, Stress Field
4. Microseismic	→	Frac length/width, Stress Field
5. Microseismic Surface & downhole	→	Compare accuracy of both methods
6. Production Logging	→	Relative contribution along lateral
7. Chemical tracers	→	Relative contribution along lateral

SLIDE 2. Presenter's notes: We believe that in plays like Eagle Ford every detail counts, and the sooner you understand the key variables that drive your economics the better.
For that reason we are integrating as much data as possible from multiple sources in order to be able to drill and complete these wells as efficiently as possible.

Go Back to Slide 2.

SLIDE 3. Presenter's notes: Here we zoom in to locate Live Oak/Atascosa county boundary.

- Base EGFD regional depth structure map shows regional dip to the SE, shallower to NW.
- In study area EGFD around 12,000' TVD.
- Couple of major structural trends are observed, the NE-SW trending Edwards and Sligo margins, and the Karnes trough to the north. Also some major Jurassic growth faults in the Rio Grande salt basin to the west, some of which go across our study area.
- On the inset is the EGFD isopach map, showing that its section thickens along these Cretaceous margins and regionally thins to the NW.
- The type log shows that our target section in this area in in the order of ~200'

Highlights of Study Area

- Below average thickness (210 ft), at least for PXD position.
- Thickness changes controlled by presence of Jurassic faults.
- Potential for natural fractures
- Good facies (low clay)
- Good matrix porosity
- Oil window & lower pressure

Go Back to Slide 3.

SLIDE 4. Presenter's notes: This is a further zoom-in into Live Oak County; here the base Eagle Ford surface (in color), with time isopach values, allows us to observe the following:

- The Edwards and Sligo margins extend NE-SW; Pawnee Edwards field is located where these 2 margins stack on top of each other.
- EGFD section thins over these margins and thickens in between.
- A **relative thick** related to NNE-SSW Jurassic growth faults some of which detach in salt as observed in the regional seismic line that follows.
- Our study area is highly faulted.

Go Back to Slide 4.

SLIDE 5. Presenter's notes: Inset shows a **relative thick** related to NNE-SSW Jurassic growth faults some of which detach in salt as observed in the regional seismic line.

Go Back to Slide 5.

SLIDE 6. Presenter's notes: Study Area

- Fully covered with new generation 3D.
- Drill a pilot in well #1, describe logs.
- Log the lateral in well #1 with basically same log suite of pilot.
- Acquire microseismic during completion from surface and downhole array.
- Run production logging in both wells, T, Spinner, Density, ICL & Gamma (3 companies for comparison).

Go Back to Slide 6.

SLIDE 7. Presenter's notes: Start by integrating log data. Radioactive tracers
Here is a display that integrates all petrophysical interpretation along lateral:

- with mudlog data (note gas shows in sections with high concentration of interpreted open fractures)
- Results of production logging, also showing main contribution from those fractured zones.

Let's now integrate data with seismic.

Go Back to Slide 7.

SLIDE 8. Presenter's notes: For integration we first review our seismic data and evaluate a couple of techniques we can use to enhance faults and fracture prediction.

- We have an arbitrary line extending from Well #2 to NW, through a fault and then well #1 to SE.
- Here is displayed both wells, GR along the lateral, color-coded (light blue carbonate facies, lower GR and green higher GR shalier facies)

Also given are frac gradients and gas shows.

Go Back to Slide 8.

SLIDE 9. Presenter's notes: Amplitude volume across 2 wells; we can interpret main fault but not highlight any other detailed structural element.

Go Back to Slide 9.

SLIDE 11. Presenter's notes: Coherency detecting zones of narrow deformation.
Curvature can be more accurate to predict fractures based on shape of seismic events.
Deformation: single faults vs. relay ramp.
Go Back to Slide 11.

SLIDE 12. Presenter's notes: Amplitude volume across 2 wells; we can interpret main fault but not highlight any other detailed structural element.
Go Back to Slide 12.

SLIDE 13. Presenter's notes: In this case we have co-rendered the amplitude volume with coherency:

- Coherency clearly highlights main fault system.

Go Back to Slide 13.

SLIDE 14. Presenter's notes: Here we have co-rendered the amplitude volume with curvature:

- Curvature also highlights presence of main fault but also shows distinct character along the lateral, enhancing areas of positive curvature that correlate well. Other parameters are shown in detail in following slides.

Go Back to Slide 14.

SLIDE 16. Presenter's notes: If we plot this information in a map view:

- We have our curvature volume co-rendered with coherency to highlight areas of faults and fractures.
- Display wellbores with all acquired data from logging and completion operations.
- 2 main faults are tipping-off while smaller faults are accommodating displacement in between (relay ramps).
- Majority of main gas shows correlate to those areas of smaller faults and fractures.

Conclusion: Stay away from single fault zone, narrow deformation; relay ramp can have faults and frac enhancement, accommodating more displacement in several fractures.
Go Back to Slide 16.

SLIDE 17. Presenter's notes: Inset shows that same structural style was observed in the field trip.
Following is review in close detail of integration along the lateral.
Go Back to Slide 17.

SLIDE 18. Presenter's notes: In seismic display here, we have:

- the GR along the lateral (dark blue low GR, grey High GR)
- Display Tgas curve in color
- The green histogram spikes indicate proportion of oil production from each stage from production logs.
- Microseismic events
- Radioactive tracers

Integration with fractures interpreted in OBMI and Production Logging results
Main contribution (from Prod log and chemical tracers) comes from areas where we have identified presence of open natural fractures from log data (OBMI-Sonic) and from geological model (curvature).

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SLIDE 19. Presenter's notes:

- In this display we are present all "stress" data gathered through different sources.
- Dipole Sonic in pilot, information from microseismic along lateral and correlation to seismic attributes showing a strong correlation in-between all sources.
- This provides us confidence that seismic is capturing variation of stress field across the trend accurately.
- Also we can clearly observe how largest gas show and production contribution from production log correlate with a highly fracture zone from seismic attributes.

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SLIDE 20. Presenter's notes: Here is a display showing these 2 wells: on the right--well #2 showing that the entire target section was drilled with ~11.2# mud.
In the offset well at predicted MD we encountered high pressure and had to mud up to ~14# to drill rest of the well, obviously proving communication along that fractured trend.

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SLIDE 21. Presenter's notes: Let's analyze impact of #2 well completion on #2 offset well.

- We can observe that microseismic events barely make it to the offset well.
- No proppant placed in well #2 was observed in offset well.

- Also, no chemical tracers used in well #2 were detected in offset well.
- To further prove presence of open fractures, we decided to perforate but not frac stages 9&10 along offset well.

11% of well production comes from stage #10 which coincides with positive curvature and coherency event.

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SLIDE 25. Presenter's notes: Summary of what Pioneer did in the last 5 years.

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SLIDE 26. Presenter's notes: 2010 offset of Menn, vertical test, by a 4500' lateral (Riedelsel).

Go Back to Slide 26.

SLIDE 28. Presenter's notes: For interpretation of fractures along the lateral we used:
OBMI data coupled with Stoneley VDL to highlight open fractures.

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SLIDE 30. Presenter's notes: Another example where highest contribution correlates with biggest show and positive curvature.

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SLIDE 34. Presenter's notes: From pilot log we generated:

- A petrophysical evaluation of the EGFD section, calculated key reservoir parameters, e.g., porosity, TOC, dry weight fraction of carbonate, clay, Sw, etc.

Interpretation of horizontal stress from the OBMI and Dipole Sonic.

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SLIDE 35. Presenter's notes: From lateral log we generated:

- Also, petrophysical evaluation of the EGFD section--calculated key reservoir parameters, e.g., porosity, TOC, dry weight fraction of carbonate, clay, Sw, etc.
- From OBMI we are mostly interested in obtaining information about faults and fractures along the wellbore.
- From dipole sonic we can also understand vertical stress variations.

Note that light blue resistive fractures which could be healed or open and their concentration in upper 3rd of the wellbore, towards the heal.

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SLIDE 38. Presenter's notes: While we are completing these wells, we are acquiring microseismic, data.
We want to know how comparable are results from surface to downhole in order to be able to build confidence in surface techniques for interpretation at these depths.
Note scale of the area.
On our microseismic are:

- Surface array (MicroSeismic) consisting of 14 lines centered in-between the 2 wellheads
- 1531 stations on the surface
- Coverage of 2 wells.
- A downhole array (pinnacle) using an existing Edwards wells and covered ~60% of the lateral length.

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SLIDE 39. Presenter's notes: Comparison of some of the key parameters in-between 2 methods

- Light blue and Blue colors are surface array data.
- Disclosure, downhole data was able to record only ~2/3 of the lateral due to distance to observation well.
- Both arrays record approximately the same stimulation occurring in the same area around the well, but the interpreted frac length from the surface acquisition method determined a longer average length of 1,035' vs. 816' for the downhole.

Overall position of events from the two methods overlap with the exception of some very deep events related to a fault or refraction of shallower events that the deep array may have detected.

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SLIDE 40. Presenter's notes:

- Both arrays record events with some scatter about the well, but the surface array frac heights are interpreted as higher (194' vs. 116') than the downhole-determined average frac height.

Downhole array also noted the very deep events that are related to a deep fault or a refraction of shallower data.

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SLIDE 41. Presenter's notes: Last, comparison of the azimuth of the fracture network created, and in both cases they show a consistent orientation.
Summarizing, we established that at this depths (~12,000') results from the surface and downhole array are consistent.

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SLIDE 42. Presenter's notes: We completed these wells with 12-15 stages, placed from 2.7MM to 3.5MM# proppant (40/80Hydroprop); 500M to 700M 100 mesh; ~250' fracs, 4 clusters, ~12 hole/clusters; avg rate~50 gallons.

- We run production logging with 3 different companies to compare results.
- We run: Temperature, Density, Spinners and GR.
- We also have 3 different types of radioactive tracers to evaluate frac placement, and we can see from the log data that we have a fairly good containment.
- From 2nd track we have Oil-water production as well as T data.
- We can observe that all stages contribute to flow; however, most contribution comes from Stage 11 and 7/8.

Data Quality

Temperature: down-pass data is repeatable.

Spinner:

Proper RPS response vs. line speed changes.

Spinner data in oil phase yields the most accurate velocity for oil rate.

Density:

Responds to high-oil and high-water holdup intervals.

Minimal gas detected.

ICL & Gamma:

Good data, good depth correlation.

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SLIDE 43. Presenter's notes: We also run chemical tracers to understand fluid contribution along the lateral and how it compares with results from production logging. In this case, well #2 data, the idea is that, after we build a statistical DB that shows that chemical tracers are good proxy for identifying contribution along the lateral, we can phase out production logging and save $$.

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SLIDE 45. Presenter's notes:

- Exploration phase characterized by early vertical completions:
- Menn #1, Wernli and Rolf., tested EGFD vertical section, as type log shows, we learned:
    - Bigger frac, higher IP.
    - Changes in liquids yield.
    - High frac gradients.
    - Formation overpressured.

Go Back to Slide 45.

SLIDE 47. Presenter's notes:

- In this view we also capture how data from production logging and microseismic correlates to seismic attributes.
- After we completed well #2, we drilled an offset; based on this information we warned our drilling department that we could be crossing an area pressurized by the #2 well completion.

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