Eagle Ford Reservoir Characterization from Multisource Data Integration*

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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


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
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)
Eagle Ford Structural Framework

Study Area

Thin: Red
Thick: Blue

Eagle Ford Time Isopach
Eagle Ford Structural Framework

Study Area

Thin: Red
Thick: Blue

Eagle Ford Time Isopach
Data Acquisition

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)
Seismic Attribute Extracted (Coherency and Curvature)

OBMI Interpretation:
- Resistive Fractures
- Drilling Induced Fractures
- Bedding
- Faults

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

Production:
- Oil
- Water
- Temperature

Mud Log
- $H_2S$

Frac Stages
- Perf. Clusters

Perm. Effective to Hyd.
- Est. Perm. to Air
Integrating seismic data

Depth Structure Map

Well #2

Gr

Gas

FG

Well #1

Gr

Gas

FG

17%

31%

7%

42%

15%

12:13

9

11

12:13

A

A'

Shallower

Deeper

<Base Eagle Ford>
Mechanical Stratigraphy

- Austin Chalk
- Buda
- Del Rio/Georgetown
- Edwards
- Eagle Ford

Ferrill and Morris (March 2008) AAPG Bulletin
Structural Attributes Mapping

Coherency Attribute (faults)

Curvature Attribute (fracture zones)

Ferrill & Morris 2011
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.
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%)
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.
Data Integration & Interpretation

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.
Well #1 - Data Integration along lateral

Stage 11: 15% (135 bopd)

Stages 7-8: 42% (376 bopd)

- Fractures
- Mudlog
- Radioactive tracers
- Production logging
- Radioactive tracers
- Borehole image
- Microseismic (frac height)
- GR log
- Facies
- Seismic attributes
- Production logging

Stage 12  Stage 6  Stage 1
Map View-Stress Orientation

Surface Microseismic

Dipole Sonic in Pilot well

Size Related to Amp

7-8

$S_{H\text{max}}$

Seismic Attributes
- Coherency
- Curvature

Well # 1
Frac’ed #1 before drilling #2

No fault observed during geo-steering

Regional Dip

Top Lwr Chalk

Top EAGF

0.4 # mud cut & 10 ft Flare

11.2 #

11.6 #

12.4 #

12.8 #

13.0 #

14.0 #

13.8 #

13.8 #

350 ft

550 ft

Mud Gas

Show # 1

Show # 2

Well # 2 offset

LWD Gr

Well # 2

No Data
Stages 9 and 10
UNSTIMULATED

Stage 3 = 22% of total production

Stage 10 flowing 11% of total production

Interpreted fault at which both wells took significant gas kicks

Production Logging (relative contribution)

Frac Stages

Microseismic Events (frac width)

Seismic Attributes
• Coherency
• Curvature

Data Integration Map View

Well # 2
Well # 2 offset

Stage 10 flowing 11% of total production
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.
BACK UPS
• Strong presence in South Texas developing Edwards dry gas play, acreage expansion to > 300,000 Ac.
• Late 2006 re-completed several vertical wells in Eagle Ford zone of interest
  • Acquire & license >2000 sq miles of 3-D seismic
  • Drilling 2\textsuperscript{nd} Eagle Ford Lateral in DeWitt Co. when Hawkville was announced
• 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
• Joint venture with Reliance/Newpek
  • Drilling with 12 rigs
  • 3 dedicated frac fleets (2 PXD).
  • Own midstream facilities
  • Currently producing ~ 400 mmcfed
Horizontal Wells Show True Potential

**Charles Riedesel**

- IP: 15.7 MMCFE/D
- Including 680 bbl condensate
- 6,300 psi FTP (22/64 choke)
- 14 Stages (4 MM # prop)

### Mud-Gas

- Green = over 1,500 u Gas
- Yellow = over 1,000 u Gas
- Purple = over 500 u Gas
- Gray = <500 u Gas

**Menn #1**

- Lateral borehole is ~300 ft from Menn #1 legacy well
- Toe-up Lateral (due to liquids)

- Lateral = 4,500 ft

### Base Eagle Ford From 3D Seismic

- Top Eagle Ford (SS)
- CI = 50 ft

- **Riedesel P & Hz**

- **Menn #1**

- **4,500 ft**

- **Top Eagle Ford (SS)**

- **IP of 15.7 MMCFE/D was ~30x more productive than vertical completion in Menn 1 using ~20x more proppant**
Handy Area - Liquids Rich “Reality”

Handy
19.9 MMCFE/D
(2,030 bbl cond)
14 Stages, 4 MM# prop
7,100 psi FTP

Lateral borehole ~200 ft from legacy well

Legacy Dry Hole A

Lateral 5,000 ft

Scale was compressed x2
wrapped

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

No Neutron log run to determine EF porosity

Mud-Gas
- over 1,500 u Gas
- over 1,000 u Gas
- over 500 u Gas
- over 500 u Gas
- <500 u Gas

Reconnaissance Data (Mature Area)

Raster Mud-log

Full Log Suite

From Seismic

Handy P & Hz

Legacy Dry Hole B

Sligo Test

Sue Handy: 1972

Sue G. Handy 1991

L. Cretaceous
Fractures Interpretation

Stoneley VDL

Fracture Count

Dynamic Image (OBMI-2)

Static Image (OBMI-2)

ELAN Volumes
Relay Ramp View
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

- 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

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EFAT = 12 Geoscientists & 4 Engineers
Ernst Tinaja
Big Bend Nat. Park
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.

**Well # 1 Pilot Logging**

**Fast Shear Azimuth = direction of Fast Shear Wave propagation**

- N17E
- N30E
- N45E
Well # 1 Lateral Logging

OBMI Interpretation:
- Resistive Fractures
- Drilling-Induced Fractures
- Bedding
- Faults

Porosity
- PHIT

GR/SGR
- RHGA
- Uranium
- DRH
Typical Frac Design

- 8 frac tanks for pump
- Proppant Storage
- 20 pump units (45,000 HP)
- Coiled tubing
- Wireline
- Hydration unit
- Control Van
- Water storage

Eagle Ford - Douglas 01 01H
Typical Frac Design

- 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%.
• 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’
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
Frac Height Assessment

- Surface array frac heights are interpreted higher (194’ vs. 116’) than the downhole frac height.
- Downhole 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.

Deep events (fault?) occur 561 ft below the stimulation and are seen only in the downhole data.

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

Event Analysis – Stage 2

Events are sized by energy (compressed dynamic range) and colored by stage.

Stage 2 has a length of 1130° asymmetric to the northeast early, then breaking south and towards stage 3 late.
Well #1, Prod Profile - Stages 1 - 12

Stage 11: major oil @ 15% of total

Stages 7-8: major oil @ 42%
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

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#

Well # 2

Shut-in Pressure
Downhole Gauges
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)
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.
Map-View Completion

Seismic Attributes
- Coherency
- Curvature

Well # 2 offset
## Data Acquisition Summary

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

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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.

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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.

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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).

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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.**

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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.

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

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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. 
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SLIDE 12. Presenter’s notes: Amplitude volume across 2 wells; we can interpret main fault but not highlight any other detailed structural element. 
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SLIDE 13. Presenter’s notes: In this case we have co-rendered the amplitude volume with coherency: 
• Coherency clearly highlights main fault system. 
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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. 
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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. 
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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. 
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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).

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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.

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.

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.

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.
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.

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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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