Reducing Refrac Risk-Key to Generating Bookable Reserves?

Robert Barba

Reducing ReFrac Risk/SEC & ReFracs/Candidate Selection & More

May 26, 2016

Houston, Texas

World Petroleum Council

Guidelines for Application of the Petroleum Resources Management System

November 2011

Sponsored by:

Society of Petroleum Engineers (SPE)
American Association of Petroleum Geologists (AAPG)
World Petroleum Council (WPC)
Society of Petroleum Evaluation Engineers (SPEE)
Society of Exploration Geophysicists (SEG)

PRMS Unconventional Resource Sections

No mention of refracturing in any of the above sections

Objective: Include refracturing booking guidelines into PRMS

Tight Gas Field Example

- 42 well vertical refrac project, recoverable gas in place averages 1.6 BCF per 40 acre proration unit
- All wells currently producing an average of 8 MCFD
  - PV10 for 8 MCFD $28,738 average
- Once commercial success is achieved offset wells with identical zones will still have only the proved developed production reserves bookable
  - PV10 for 500 MCFD $3.2 MM
  - Significant increase in PDP bookable reserves in refrac well
  - No credit for offset well reserves with correlative zones??

Bookable Reserves from Refracs[1]

- Should be a clear indication that the reserves added were incremental and not an acceleration of existing production
- Should establish a reasonable certainty that the refrac operation would be successful
- Should generate a large enough number of successful refracs to establish confidence in the process

1. Holroyd, Samantha "Refrac Integration in the Capital Deployment Plan," December 10-11 2015, Houston Energy Forum.

Primary Refrac Risks

- Are the hydrocarbons there?
  - OIP/GIP vs EUR (recovery factor analysis)
  - Integration of all key disciplines
  - Reservoir pressure
- Can they be consistently mechanically extracted?
  - Acceptable wellbore mechanical condition
  - Control of fracture entry points

Are the Hydrocarbons There?

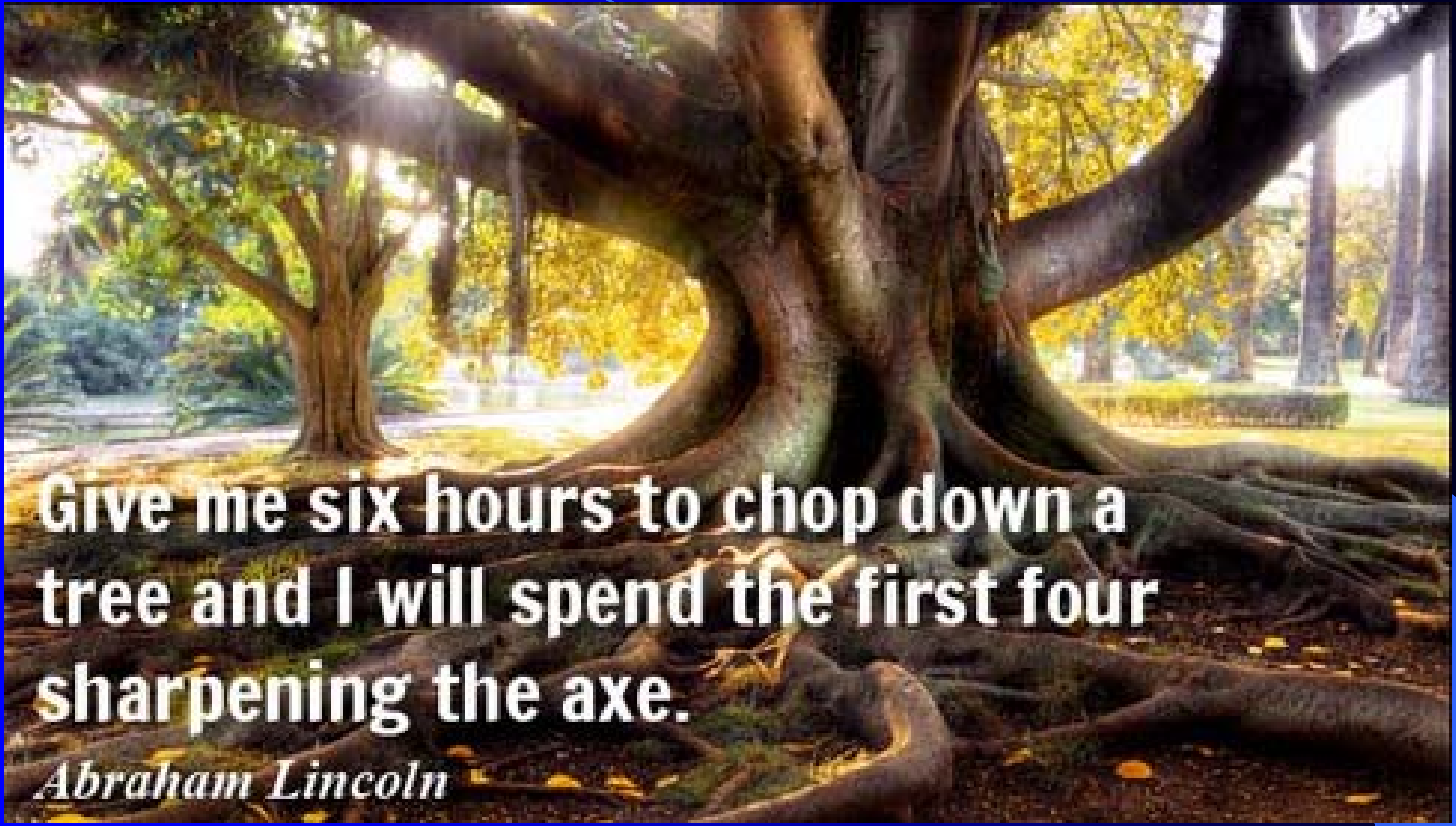
- What are the original hydrocarbons in place?
- How much of this has been produced to date?
- Where are the hydrocarbons located in the vertical column?
- What is the current reservoir pressure in each zone?
- Determination of the above requires an integrated team

Ideal Refrac Optimization Team

- Petrophysicist
  - Net pay, OOIP and OGIP, mechanical properties
- Geologist & Geophysicist
  - Lateral OOIP or OGIP distribution for recovery factor
- Reservoir Engineer
  - Perm, pressure, spacing, EUR estimates
- Completion Engineer
  - Frac design, fluid and proppant schedules
- Production Engineer
  - Flowback practices to minimize drawdown damage
- Frac Service Company Engineer
  - Implement design

Typical Refrac "Optimization" Team

- "Reproduction" Engineer
  - What was done before that "worked"
- Frac Service Company Engineer
  - Same
- "Follow the follower" is the norm
- Xerox designs the rule not the exception
- "Factory mode" = inconsistent results (BP WFD)

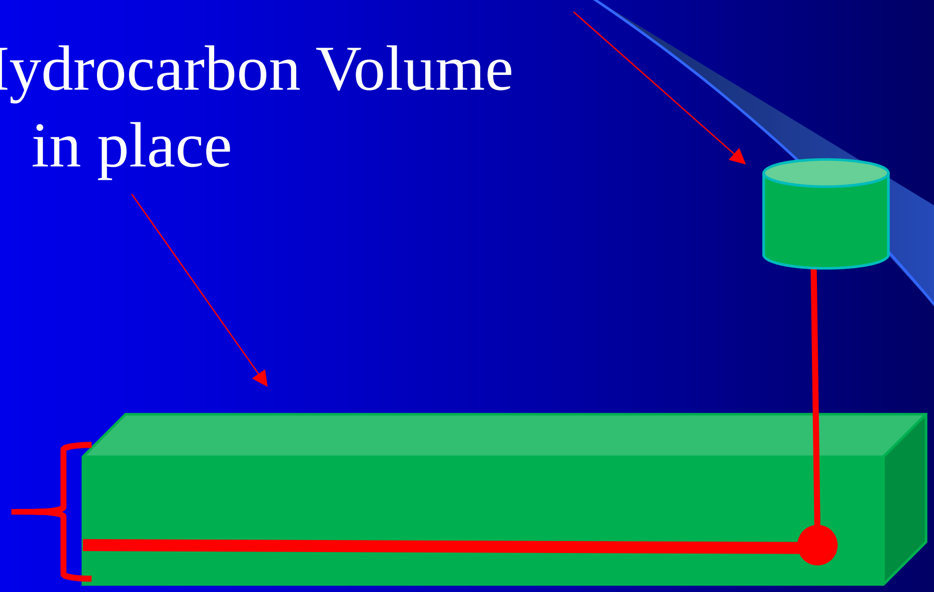

Give me six hours to chop down a tree and I will spend the first four sharpening the axe.
Abraham Lincoln

Recovery Factor Concept

Estimated Ultimate Recovery

Original Hydrocarbon Volume
in place

Conductive
Frac Height
Propped and
Unpropped

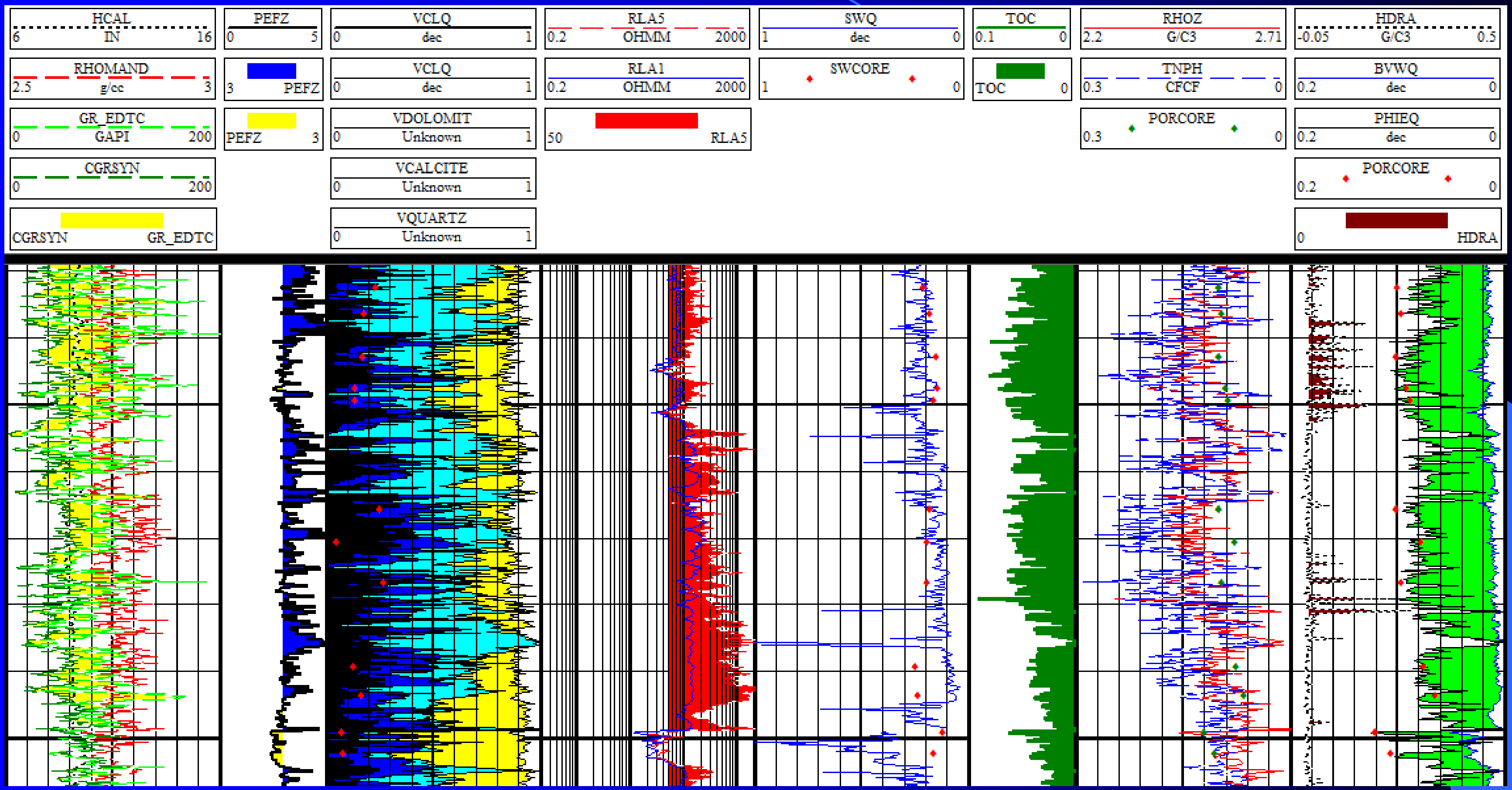


RF = Estimated Ultimate Oil Recovery/Original Oil in Place or
Estimated Ultimate Gas Recovery/Original Gas in Place

Recovery Factor Process

- Hydrocarbon pore volume (porosity, Sw, and net pay)
- FVF (oil) or Bgi (gas) (from reservoir fluid properties)
- Allocated drainage area from lateral length and spacing
- Estimated ultimate hydrocarbon recovery
- Equation (liquids rich reservoirs)(US oilfield units)
  - RF= EUR/OOIP
  - OOIP = (7758*PHIE*(1-Sw)*h*Acres)/FVF
- Equation (gas reservoirs)
  - RF=EUR/OGIP
  - OGIP=(43.56*PHI*(1-Sw)*h*Acres)/Bgi

Core Calibrated Petrophysical Analysis

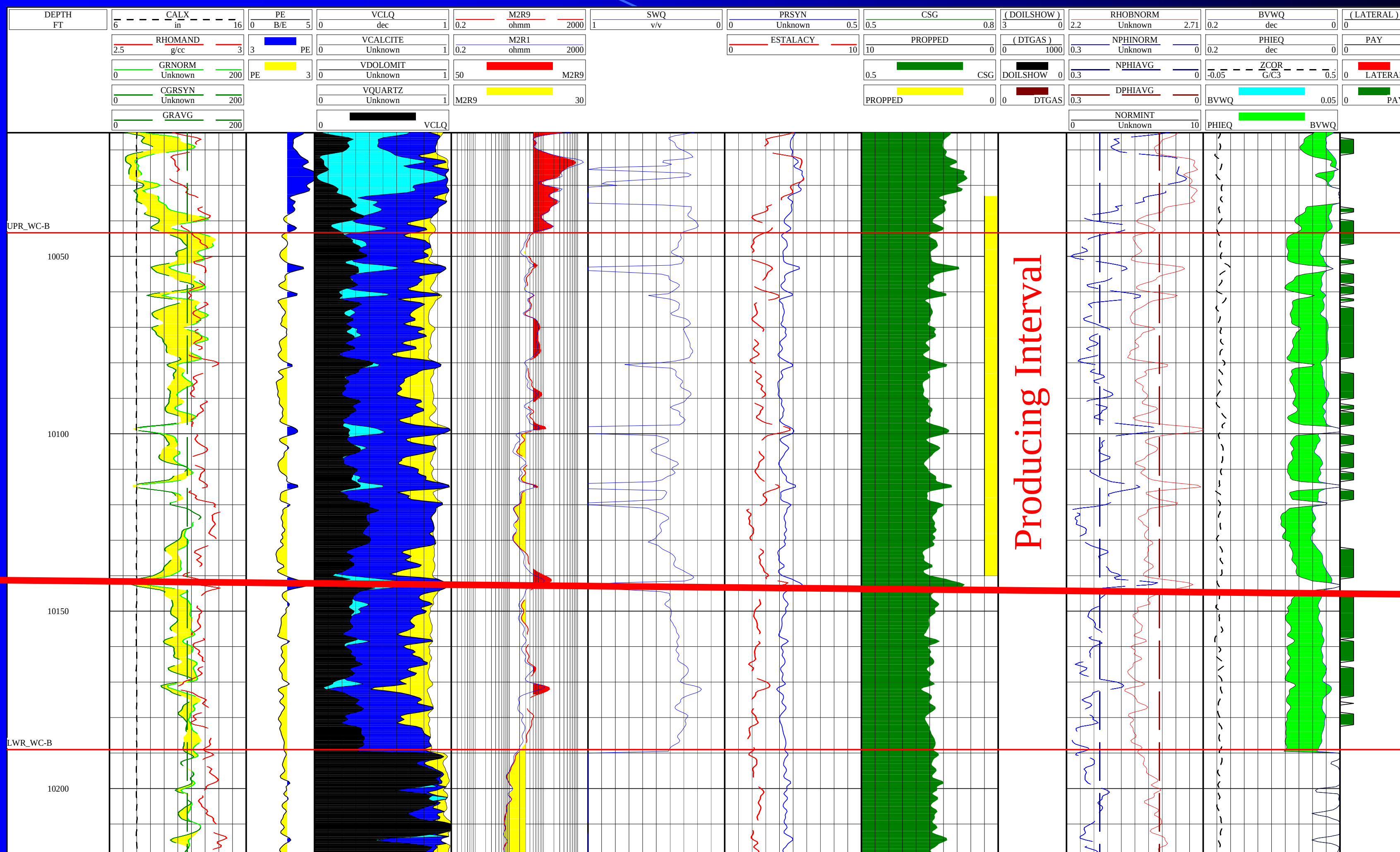


Organic zone flag | Pef | XRD vs Vclay | Rt>50 flag | Sw vs core | TOC | Porosity | Core vs PHIE

What is the Producing Height?

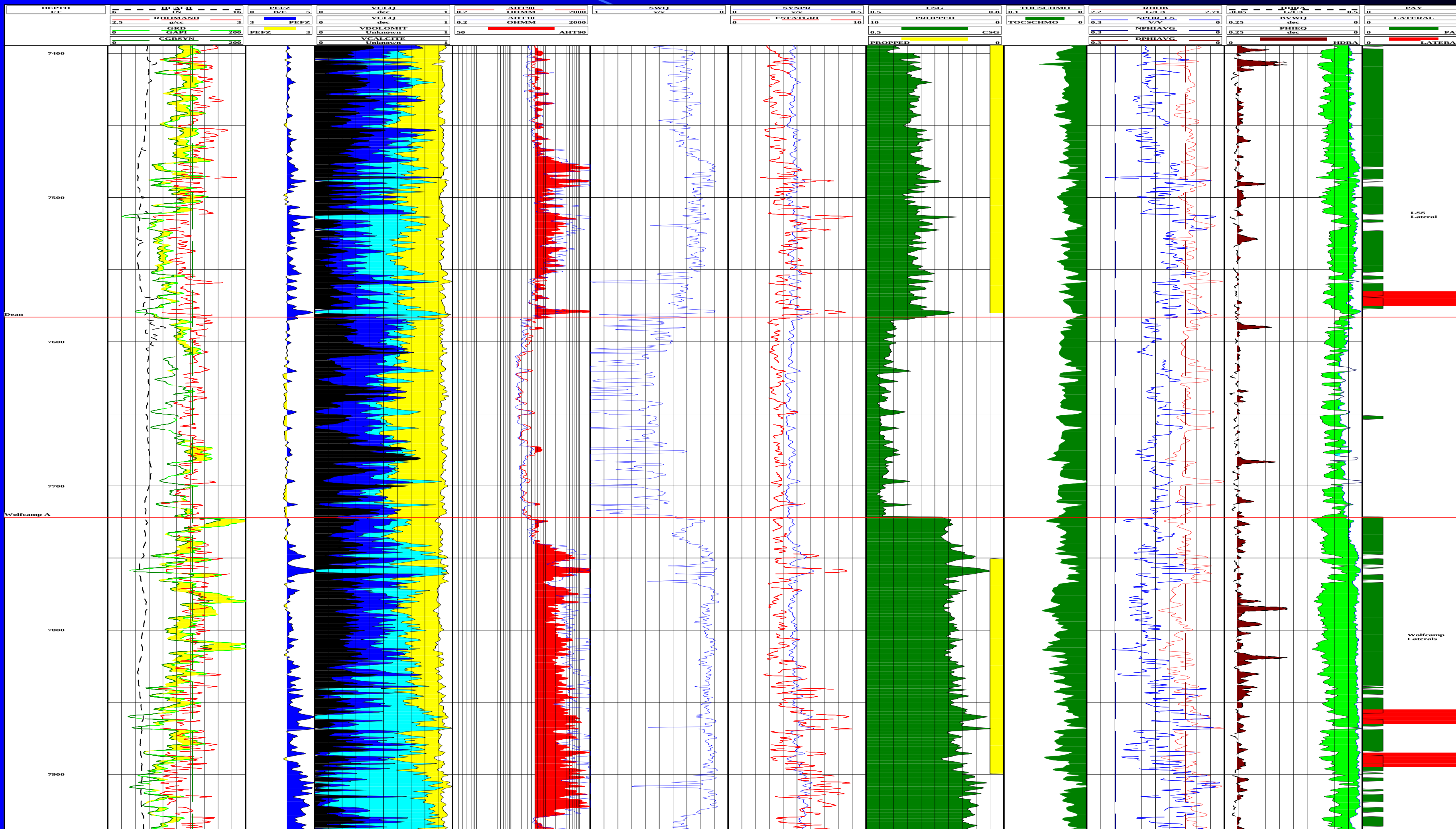
- Critical input to recovery factor process, propped heights are typically less than frac height and can be very limited
- The minimum producing height should be the propped height
- The propped height should be a function of where the in-situ stress “benches” are located relative to the lateral

Wolfcamp Stress "Bench"



Zone	Top	Base	Ft Pay	Porosity	Sw	BOIP/Acre	BOIP 640	BOIP 160	11.3% RF 160
Wolfcamp B All	10037	10182	96.5	0.07	0.334	23,268	14,891,487	3,722,872	420,685
Wolfcamp B Producing	10040	10139.5	63	0.069	0.339	14,861	9,511,075	2,377,769	268,688

Wolfcamp and LSS Example



Zone	Top	Base	Ft Pay	Porosity	Sw	BOIP/Acre	BOIP 640	11.3% RF 160
LSS	7428	7577	128.5	0.063	0.267	35,412	22,663,869	640,254
WC	7750.5	7899.5	129.5	0.068	0.143	39,032	24,980,320	705,694

Refrac Candidate Screening Examples

- Low recovery factors-key factor in candidate selection
  - Primary tool to predict economic potential
- Previous recovery factor study results (gas reservoirs):
  - Canyon Sand Ozona – 800 well study, avg 40 ac recovery factor 16%, 40 acre spacing, 74 ft average producing frac length, first phase 1.6 BCF/well RGIP*
  - S Texas Wilcox & Vicksburg- 130 wells 30% RF
  - S Texas Olmos-6 wells 15% RF
  - E Texas Cotton Valley – 120 well study 31% RF
  - * Anadarko Red Fork – 90 wells, 1 ft Xf w/XLG

*RGIP = OGIP-Cumulative Gas-Residual Gas (20% of OGIP)

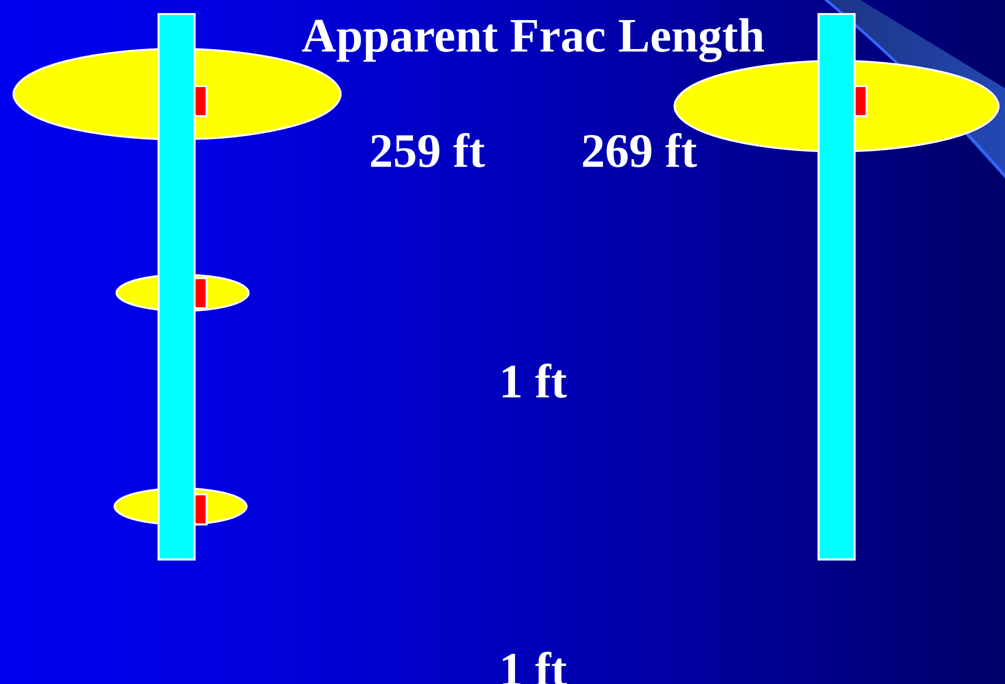
Canyon Gas Well Low RF Causes

- Multiple clusters treated in same frac stage
  - Next refrac well: 5 sands in 1 frac stage over 1500 ft
- Low proppant volumes per foot of pay
  - 412 lb/ft in above well, field average 1400 lb/ft
  - Other tight gas reservoirs 5000 lb/ft minimum*
- Capillary phase trapping (new well fracs)
  - 11% of propped length producing
- Extreme capillary phase trapping (refracs)
  - Extreme rel perm to gas damage if no reorientation
  - S Texas flowback study analog

*SPE 90483 Barba Shook 2004

Multiple vs Single Cluster Apparent Frac Length

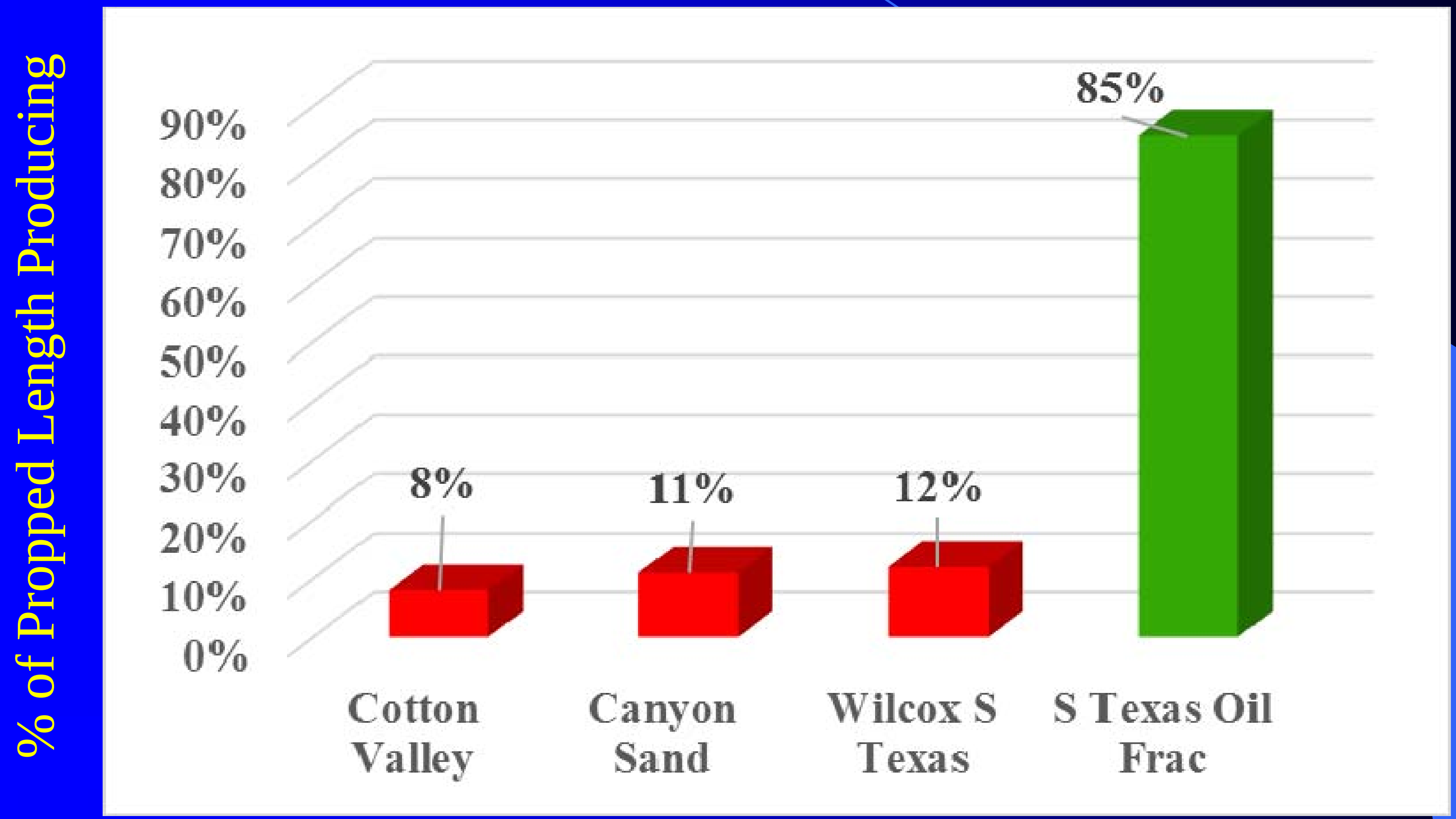
Multiple Cluster Stage | **Single Cluster Stage**



One of the multiple clusters will have the same frac length as a single cluster

Secondary clusters: Skin removal only (*Xf*=+/- 1 ft)

Producing Length vs Propped Length
Other Tight Reservoirs



Three poorer performing areas all water based gels

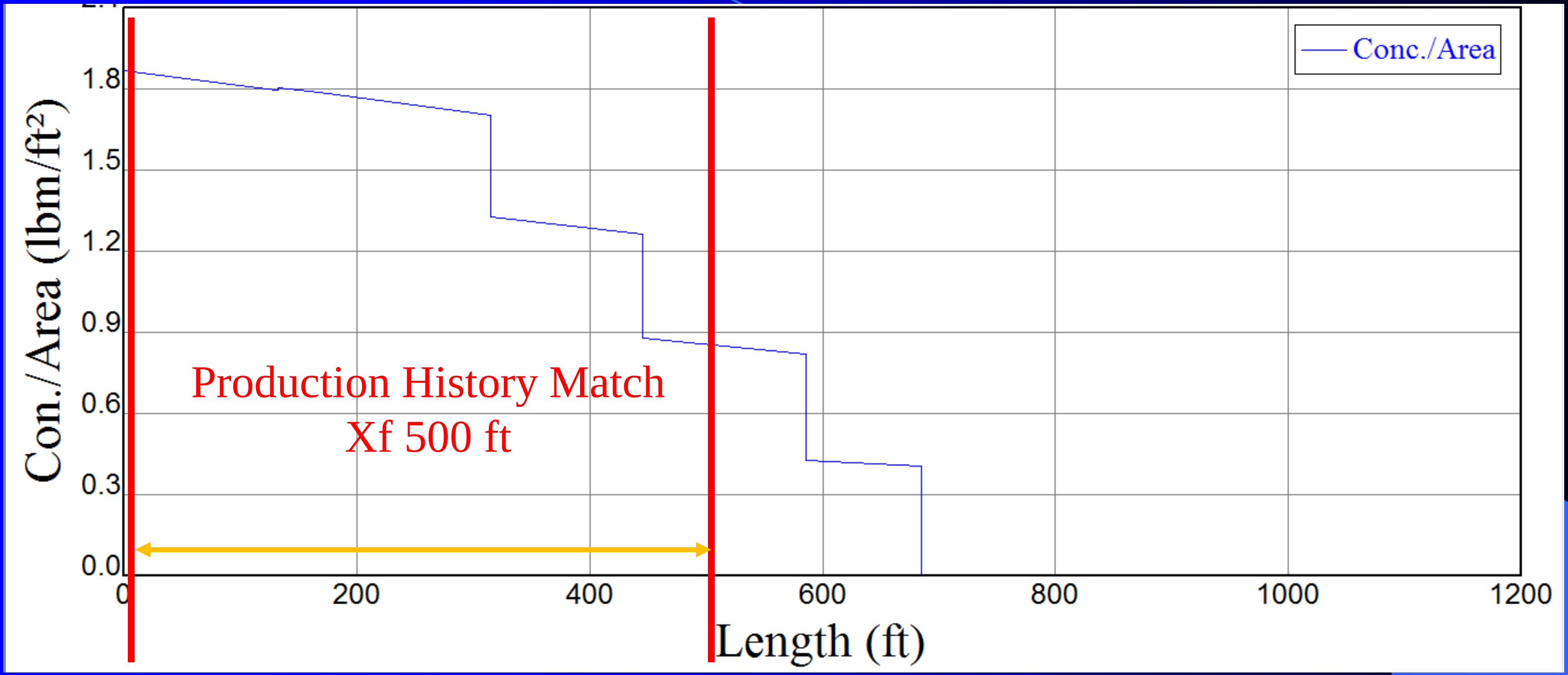
S Texas Rel Perm Damage Example

- SPE 90483 Wilcox and Vicksburg formation performance analysis, similar perm to Canyon (+/-0.02 md)
- Common observation in these formations is that 1+1+1 = 1.5
- If more than one stage is fracced and the individual stages are flowed back and killed prior to the subsequent stage frac the previous stage flow rate on the PLT is always significantly lower than the initial test
- Vicksburg "T" sand was the 2nd of 5 stages, flowed 28 MMCFD for 2 weeks prior to being killed with CaCl water to facilitate the subsequent three stages
  - After drill out all 5 stages flowed 11 MMCFD
  - Production decline normal, damage did not clean up with tim

S Texas Rel Perm Damage Example 2

- Vicksburg well 2 was a 1 mile offset to top producing well in the field, completed shortly after first well thus minimal depletion
  - Offset had nearly identical pay quality
- Top producing well had no flowback of gas between stages
  - Initial rate 80 MMCFD
- Offset well flowed each stage 2 to 3 days prior to killing zone to frac next stage
  - Initial rate 10 MMCFD
- Hypothesis: Once relative permeability to gas was established and fluid was re-introduced into pore throats there was irreversible rel perm to gas damage
  - Refracs-wells have been flowing for years, >> 3 days above
  - Refrac implications: if no reorientation is it all new rock producing?

Oil Based Frac Fluid Example



Post frac history match length
85% of 0.5 lb/ft2 length

South Texas highly water sensitive low perm oil well
Similar results in Vicksburg with same system, rich gas reservoir

Canyon Sand Refrac Workflow

- Identify underperforming wells using a comparison of OGIP to cumulative production
- Verify wellbore integrity with Kinley caliper
- Run multiple gauges for individual zone DFITs (Cramer SPE 152019)
- Identify target zones with economic remaining mobile gas
- Frac each target zone separately down inside of 2 7/8 inch shortened coiled tubing with compatible fluid
  - Next well-Synoil

Multiple Zone DFIT Procedure

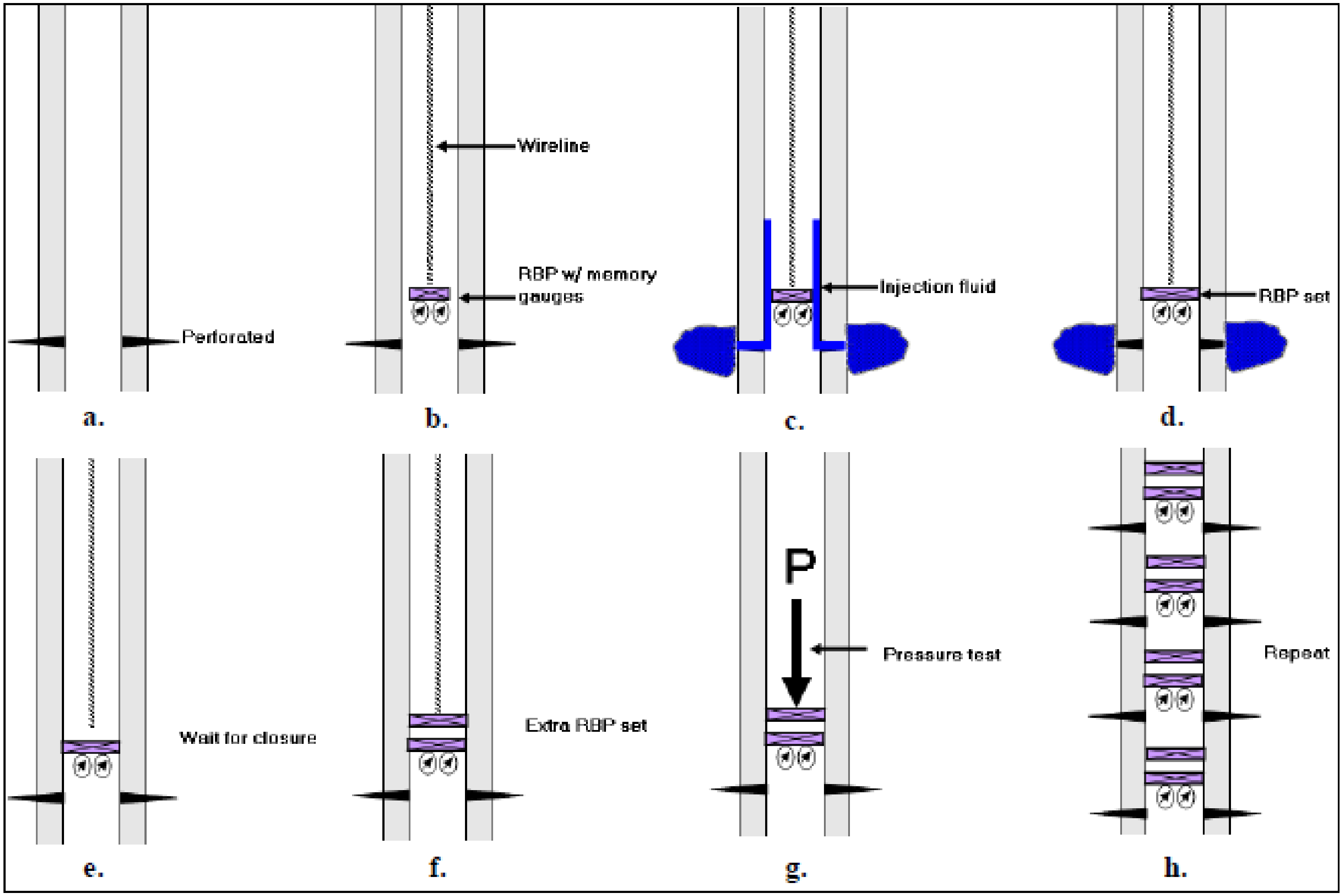
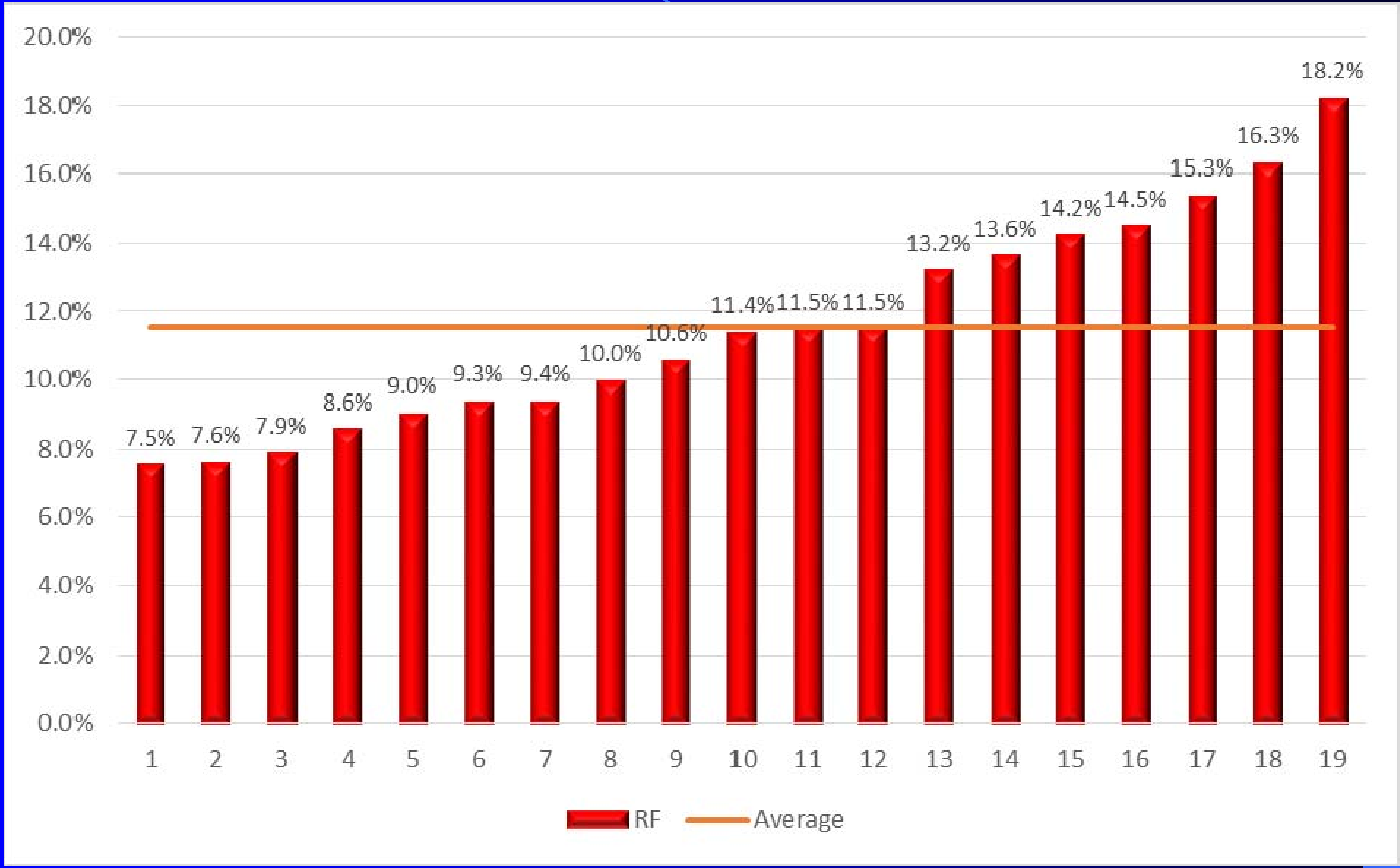


Figure 2: Basic procedure for performing multiple DFITs in a single wellbore

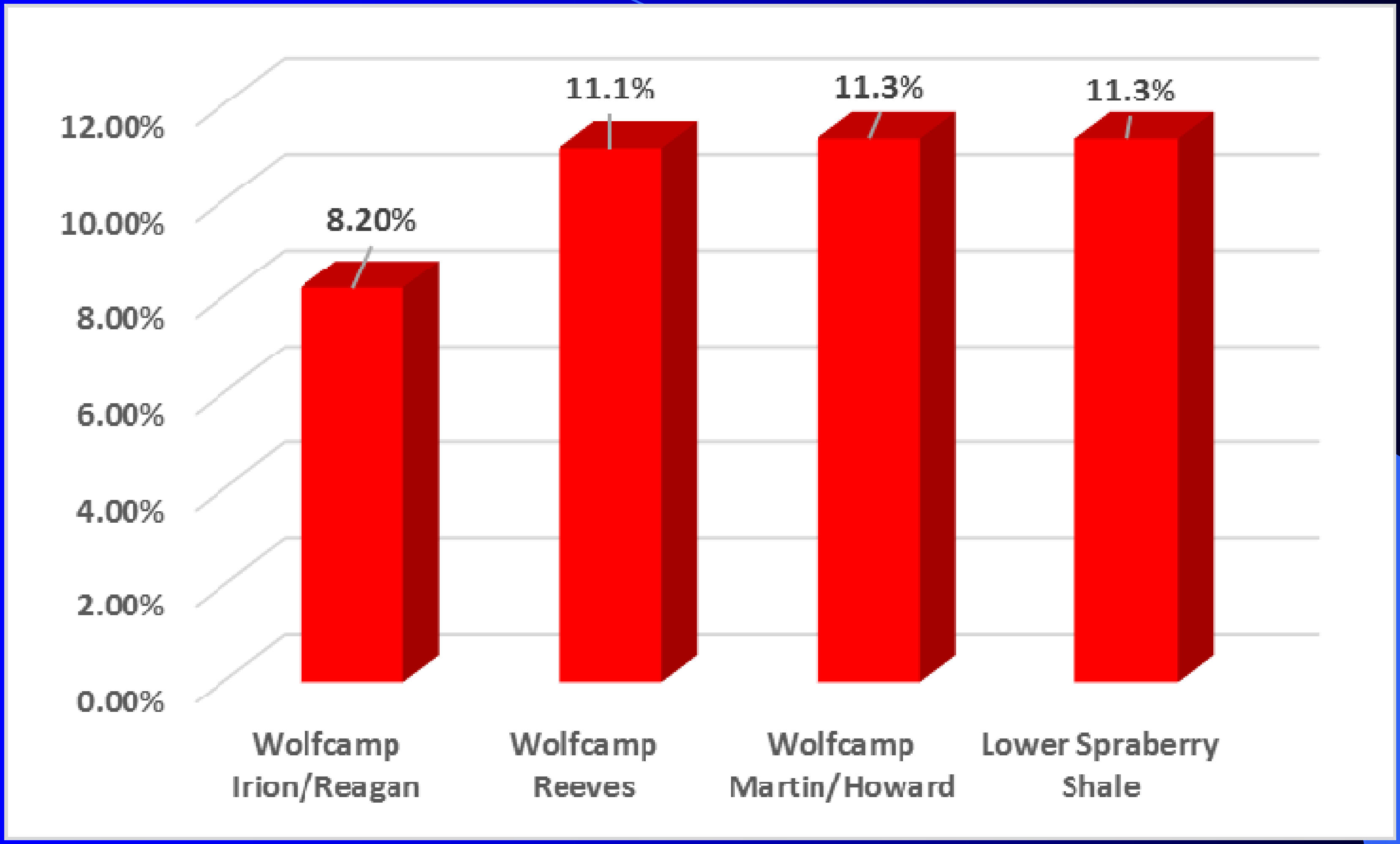
Dave Cramer COP SPE 152019

Bakken Recovery Factor Distribution



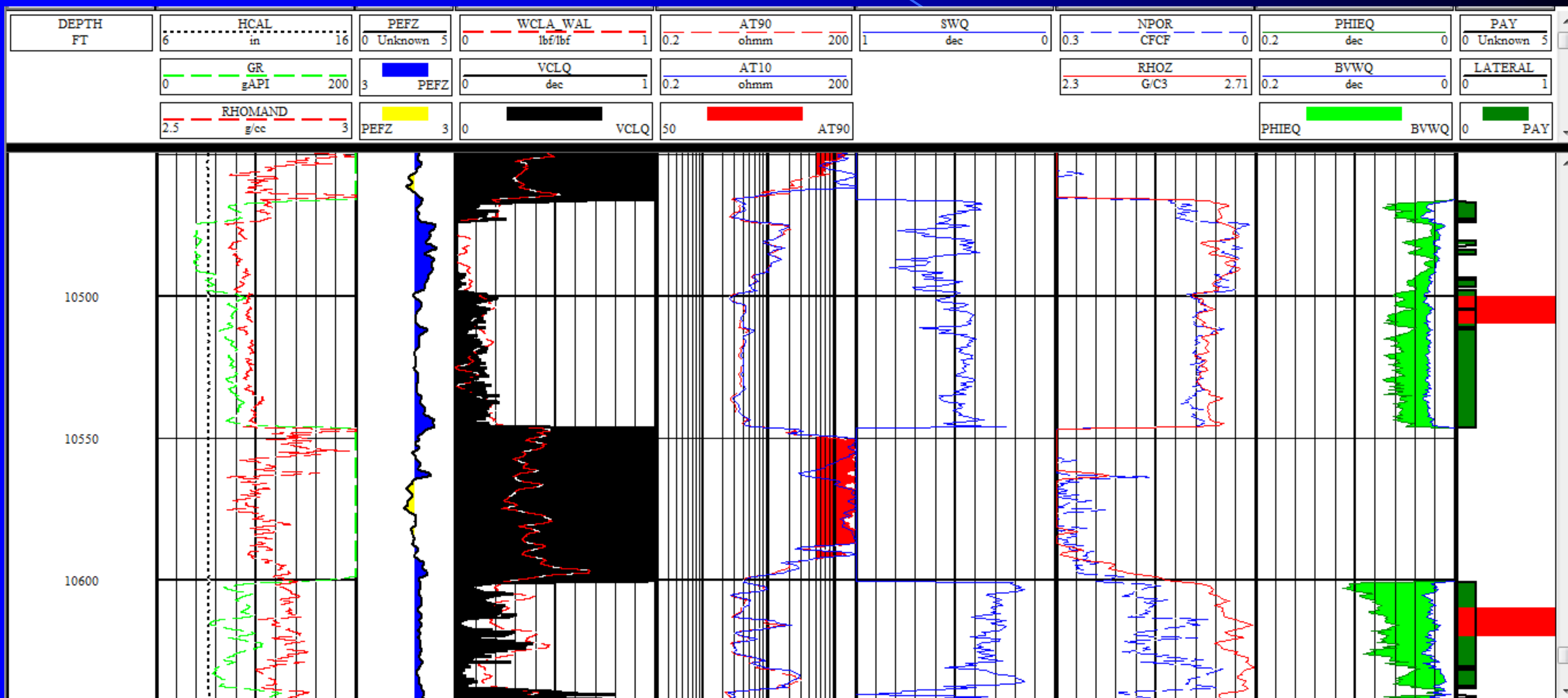
11.5% average holds with other areas included

Comparison with Other RF Studies



150 ft conductive height assumed in Irion/Reagan, 200 ft in others

Bakken Dual Lateral Single Stage Fracs-404,466 BO Stranded Oil



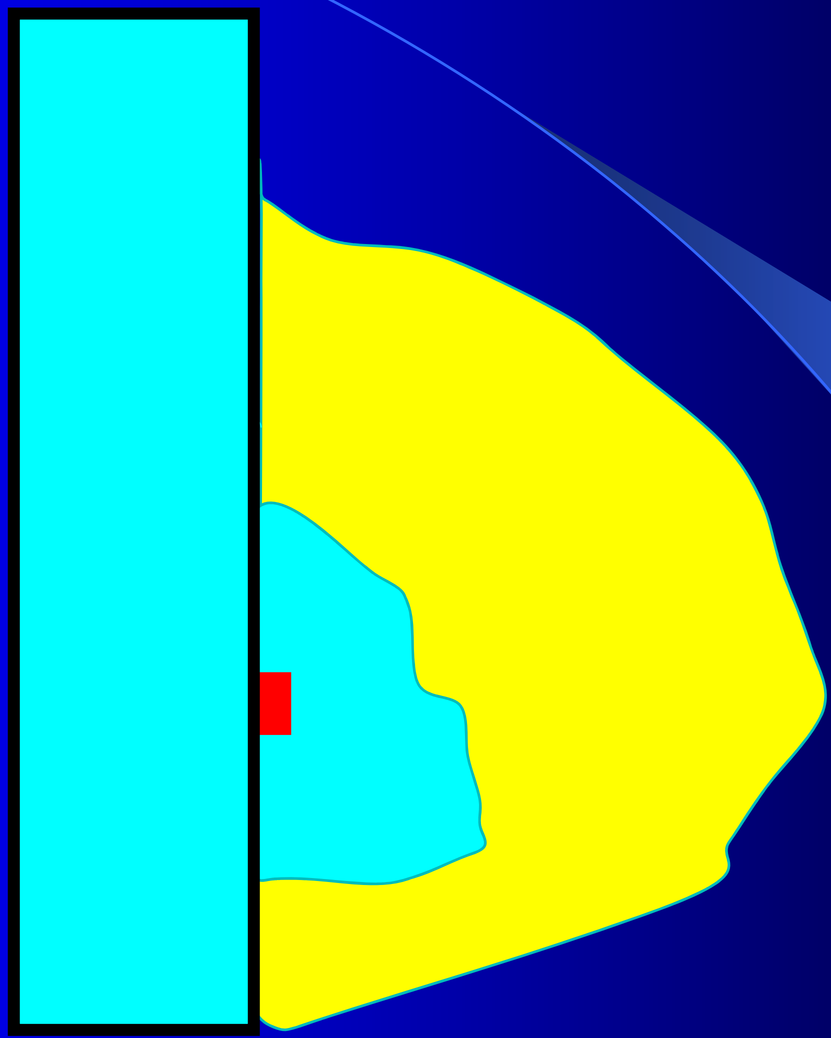
Formation	Top	Base	Ft Pay	Porosity	Sw	BVW	BOIP/Acre	Acres	EUR	EUR/Acre	RF
Bakken	10481	10546	53.5	0.056	0.47	0.026	8,619	288.0			
Three Forks	10601	10638	36	0.07	0.299	0.022	9,789	288.0			
Combined							18,408	576	272,948	474	2.57%

Stranded oil from comparison of 11.5% average RF to 2.57%

Mechanical Considerations

- Horizontal shale wells-in many cases diverters are appropriate
  - “Protection fracs” work best with diverters
  - Consol study (SPE 177295)-diverted entire wellbore first
  - Engineered completions (Drill2Frac) possible applications
- Bakken case previous slide (404 MBO incremental oil) -diverters not recommended due to large OIP, can easily justify re-lining with expandable casing and fraccing each stage separately with plug and perf
- Vertical wells: diverters can be problematic:
  - Rocks sensitive to overflushing:diverters=flush to top perf
  - Phased perforations may not have same in-situ stresses in the same perforation clusters

Ball Sealer Diversion



Frac does not stop moving forward after ball hits, perfs overflushed

Ball Sealer Diverson-Exxon JIT

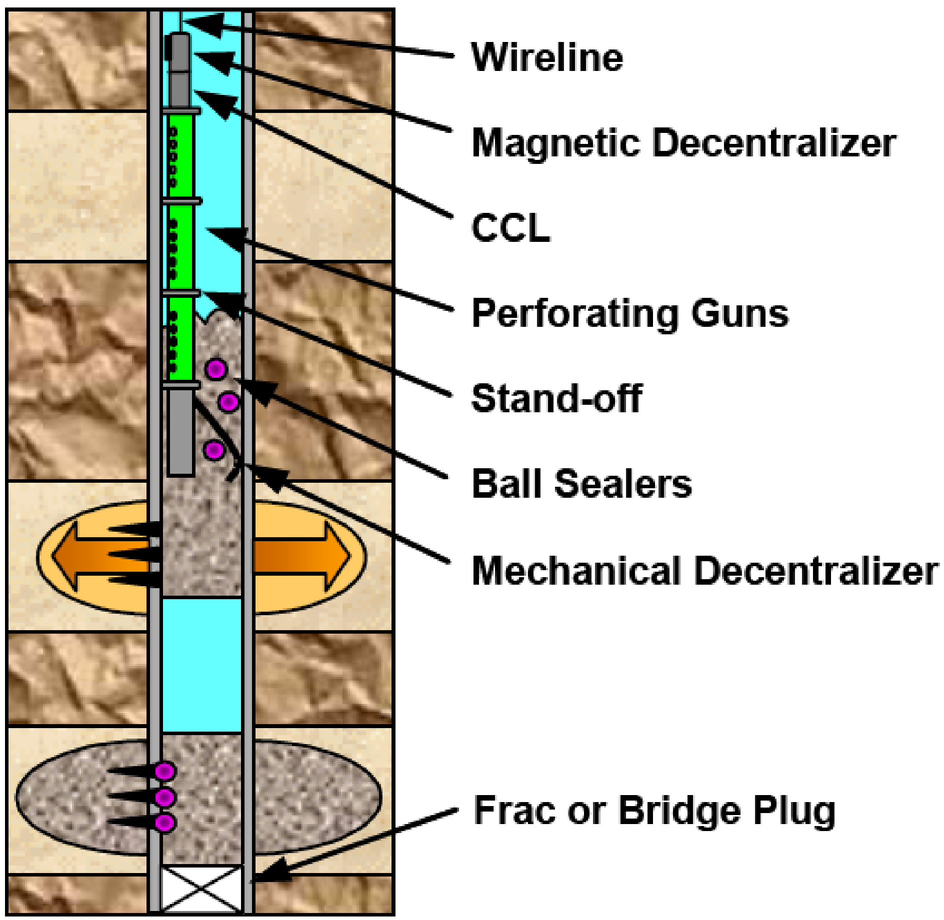
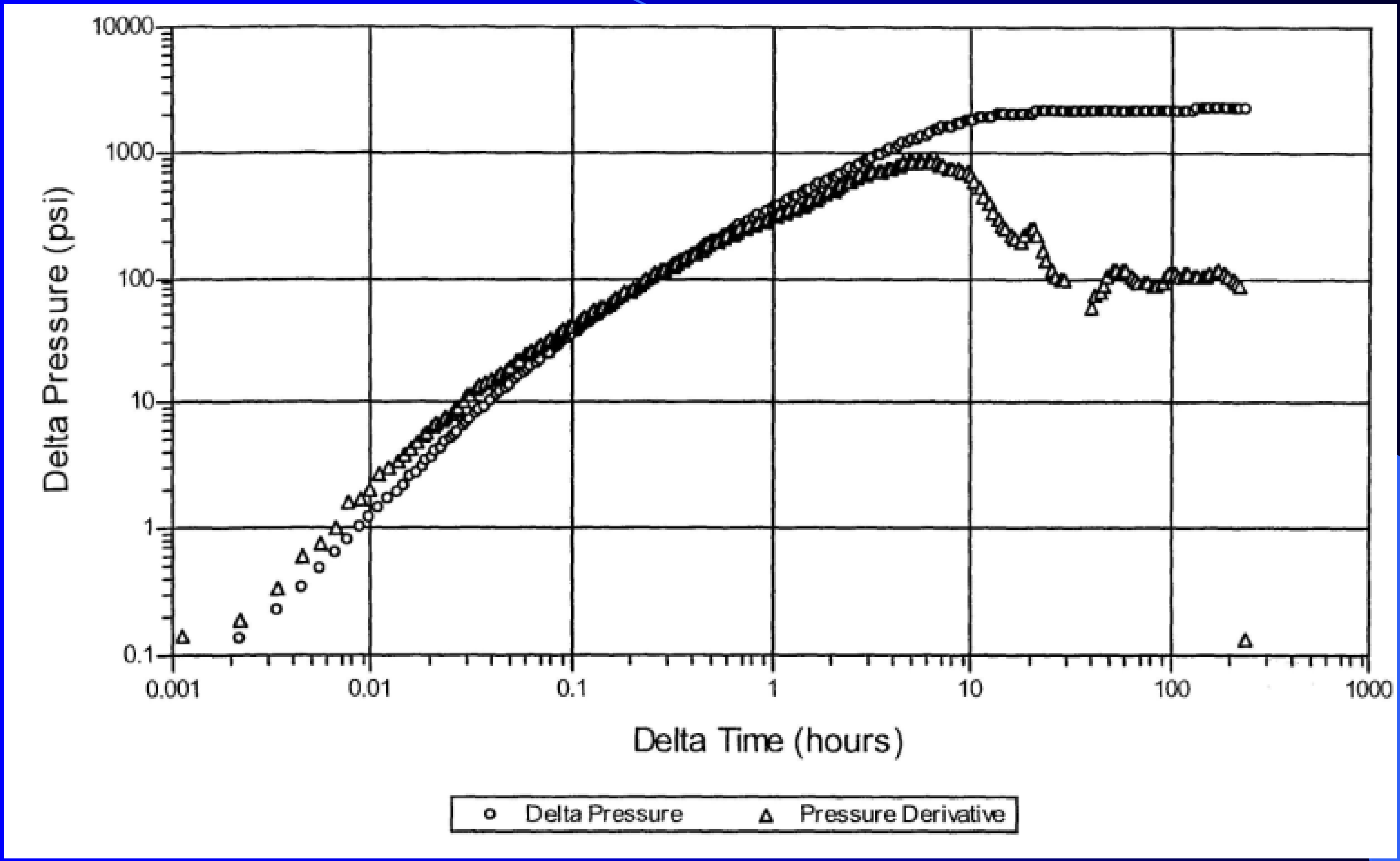


Figure 1. JITP Bottom-Hole Assembly

JIT Stage Post Frac PTA



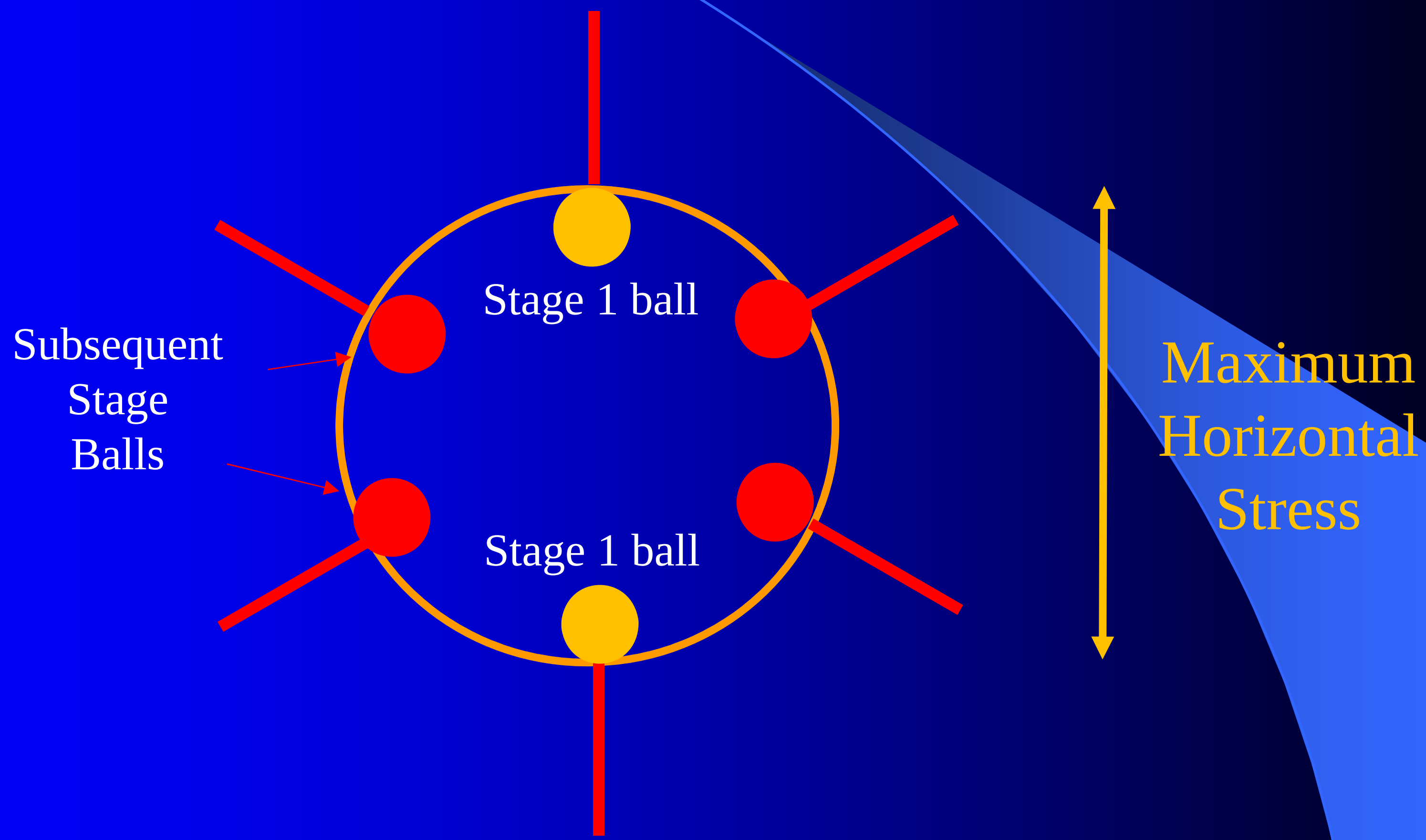
1100 MCFD expected rate, 66 MCFD actual rate

No linear or bilinear flow indicated, frac not connected to wellbore

Diverter Case Study-2 clusters

- Operator had 2 zones present in a vertical well 20m apart, desired to frac both zones in the same frac stage
  - DFIT of both zones, 1 of 2 zones 400 psi below virgin psi
  - DFIT only sees lowest pressure zone
- Microseismic was run to determine the effectiveness of the diversion
  - Biovert run at the end of stage 1
- Both the upper and lower clusters had microseismic events prior to and following diversion
  - Stage 1 frac flushed with stage 2 pad
  - 4% recovery factor assuming 20 acre drainage
  - 10% observed in “best practices” stages

Possible Diverter Scenario



Multiple isotopes observed in same clusters when diverter used
Flush following first stage could open secondary perforations
Horizontal wells-larger stress difference vertical vs horizontal

Implications for Reserve Booking

- Existing recovery factor critical, must have adequate recoverable hydrocarbons
- Mechanical diversion may be required to offset random results from diverters
- Recovery factor analysis key there to determine economics of the more expensive mechanical diversion
- Fluid sensitivity issues expected with dry gas reservoirs, may need hydrocarbon based fluids if fracs do not re-orient

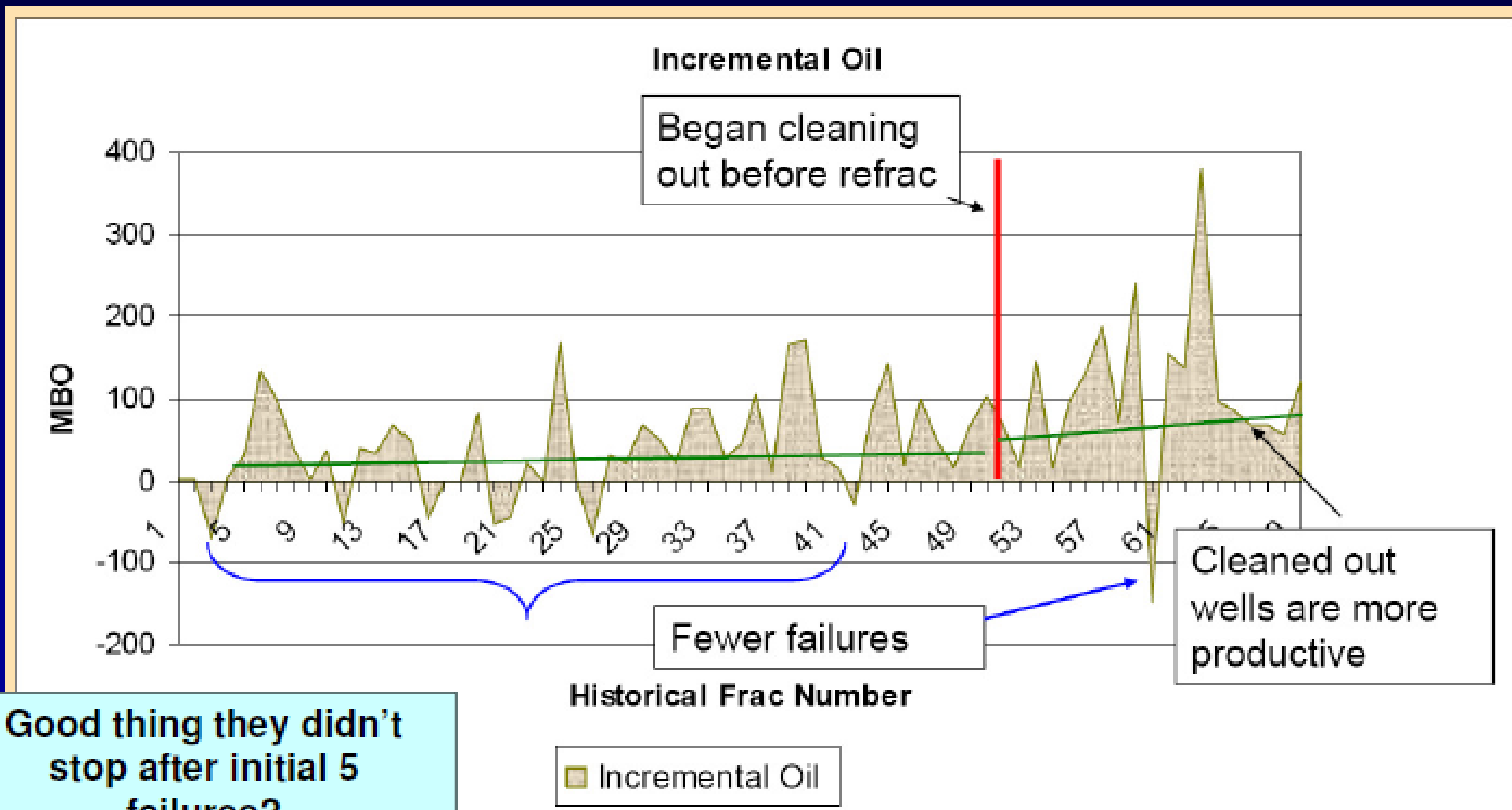
Reducing Primary Refrac Risks

- Are the hydrocarbons there?
  - OIP/GIP vs EUR (recovery factor analysis)
  - Integration of all key disciplines
  - Reservoir pressures measure
- Can they be consistently mechanically extracted?
  - Acceptable wellbore mechanical condition
  - Control of fracture entry points
  - Diverters in horizontals-consider Consol technique unless treatment is a parent well protection frac
  - Diverters in vertical wells-only if OIP/GIP low and cannot justify mechanical diversion

How Many Refracs Are Needed to Derisk Process?

- SPE 30745 (Beliveau Shell Canada 1995)
  - Six horizontal wells needed to generate consistent results
  - Statistically shown to be relevant to other technology introductions
- Fracknowledge Canadian refrac study
  - Several projects-5 wells typically needed to refine process
- XTO/Exxon Bakken 70 well refrac program
  - First five wells failed (see next slide)

Headington/XTO/XOM implemented >70 refracs in similar candidates between 2006 and 2011.



Good thing they didn't stop after initial 5 failures?

McCrady et al 2011 Tight Reservoir Completions ATW Banff 2011 from Mike Vincent 2015 Refrac AW keynote

Bookable Reserves from Refracs[1]

- Should be a clear indication that the reserves added were incremental and not an acceleration of existing production
  - Frac only new rock in laterals?
- Should establish a reasonable certainty that the refrac operation would be successful
  - Integrated approach critical
- Should generate a large enough number of successful refracs to establish confidence in the process
  - 5 to 6 wells may be needed to "debug" new procedures
  - Stay with the program keep long term view

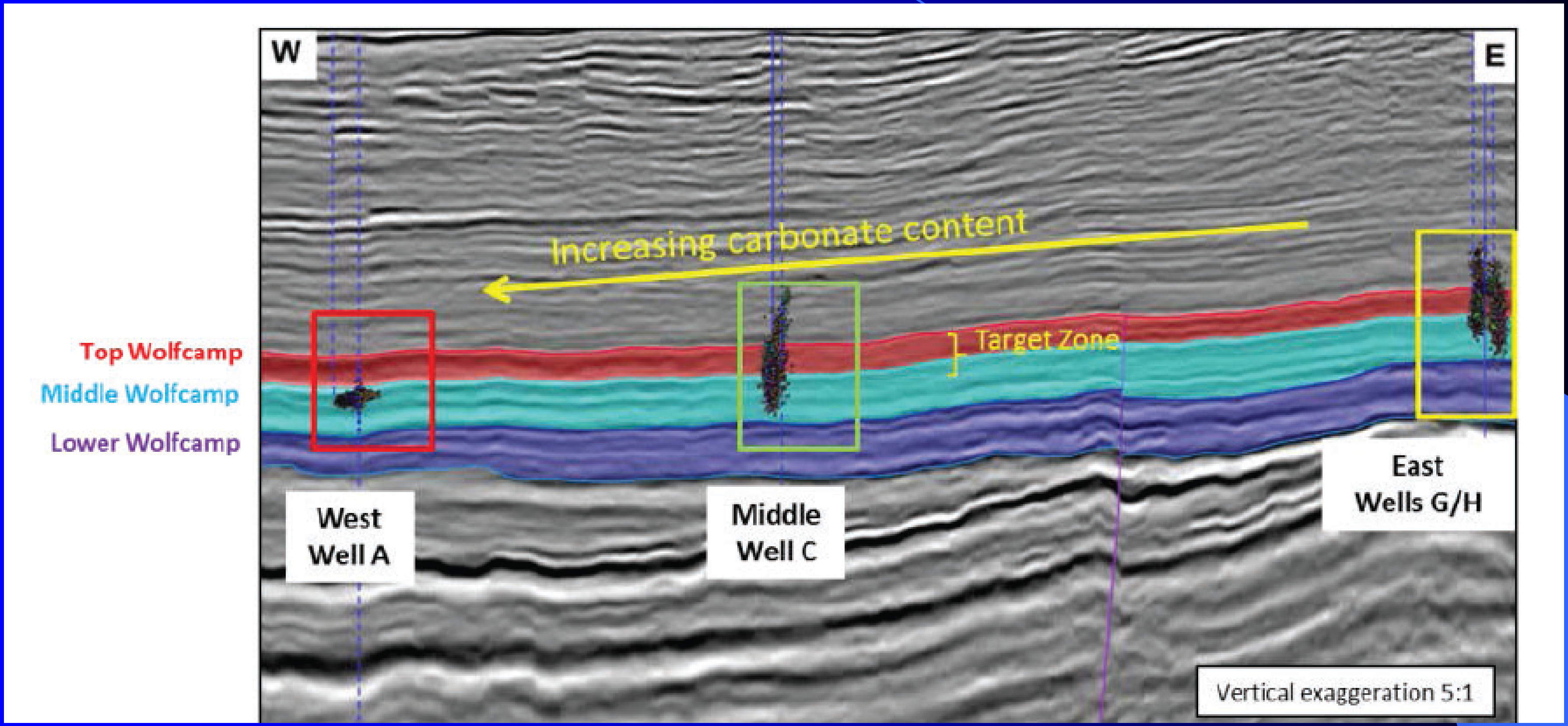
1. Holroyd, Samantha "Refrac Integration in the Capital Deployment Plan," December 10-11 2015, Houston Energy Forum.

Backup Slides

Recovery Factor Summary

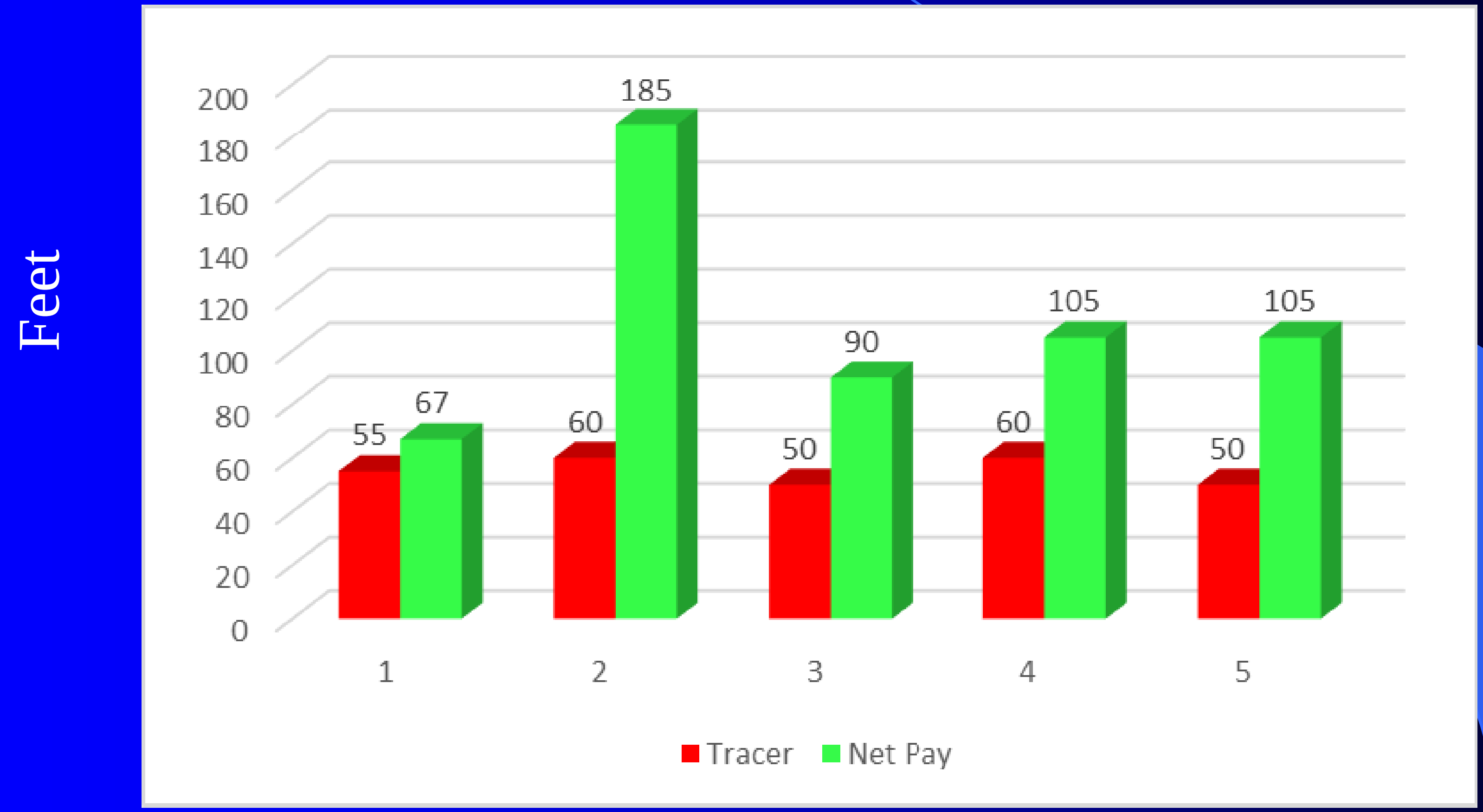
- Identification of refrac candidates and refrac candidate performance predictions
- Production performance estimates for various landing zone options prior to drilling the lateral
- Normalization of performance among wellbores with varying oil in place volumes for “best practices” exercises
- Provides an indication of how much of the vertical pay column is connected to the wellbore via propped and unpropped conductivity

Lateral Below Stress Bench



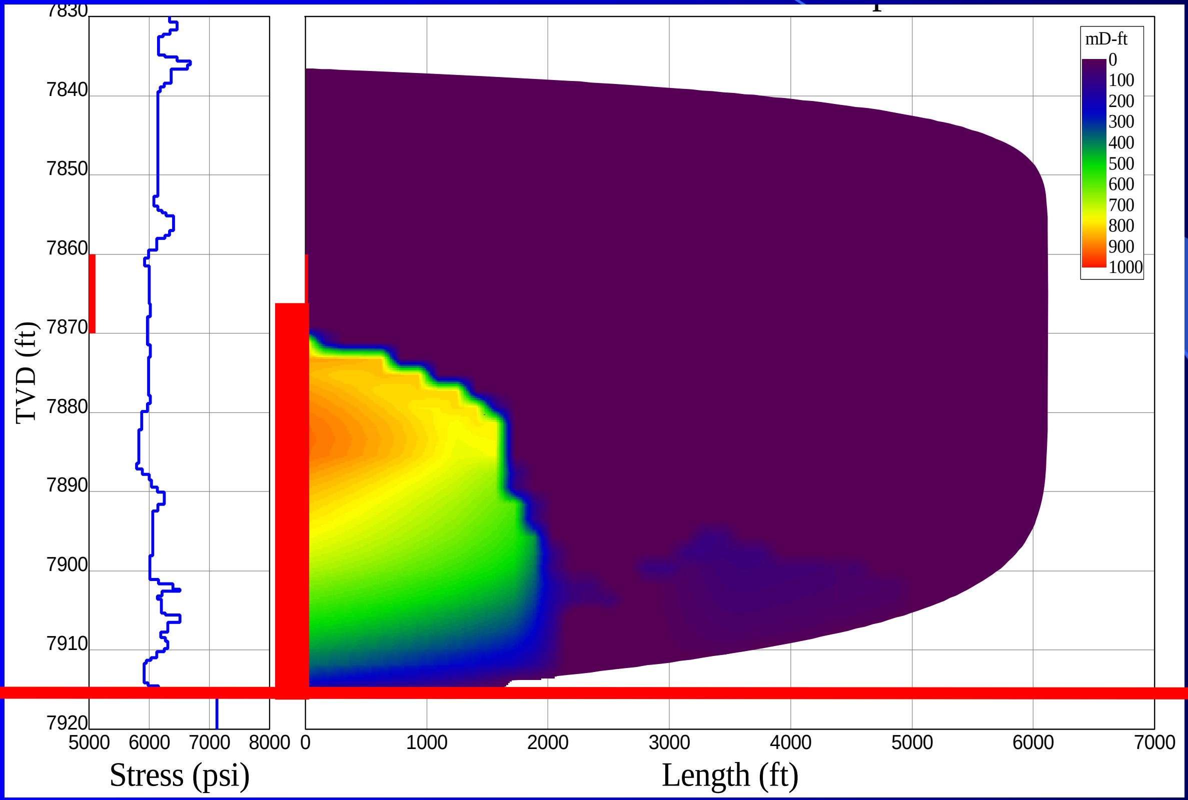
Urtec 2015 2154046 COP

Slickwater Propped Height Tracer Comparison



All vertical pilot wells, low deviation
Marcellus with Onandaga lime below

Slickwater Propped Height 3D Model vs Tracer

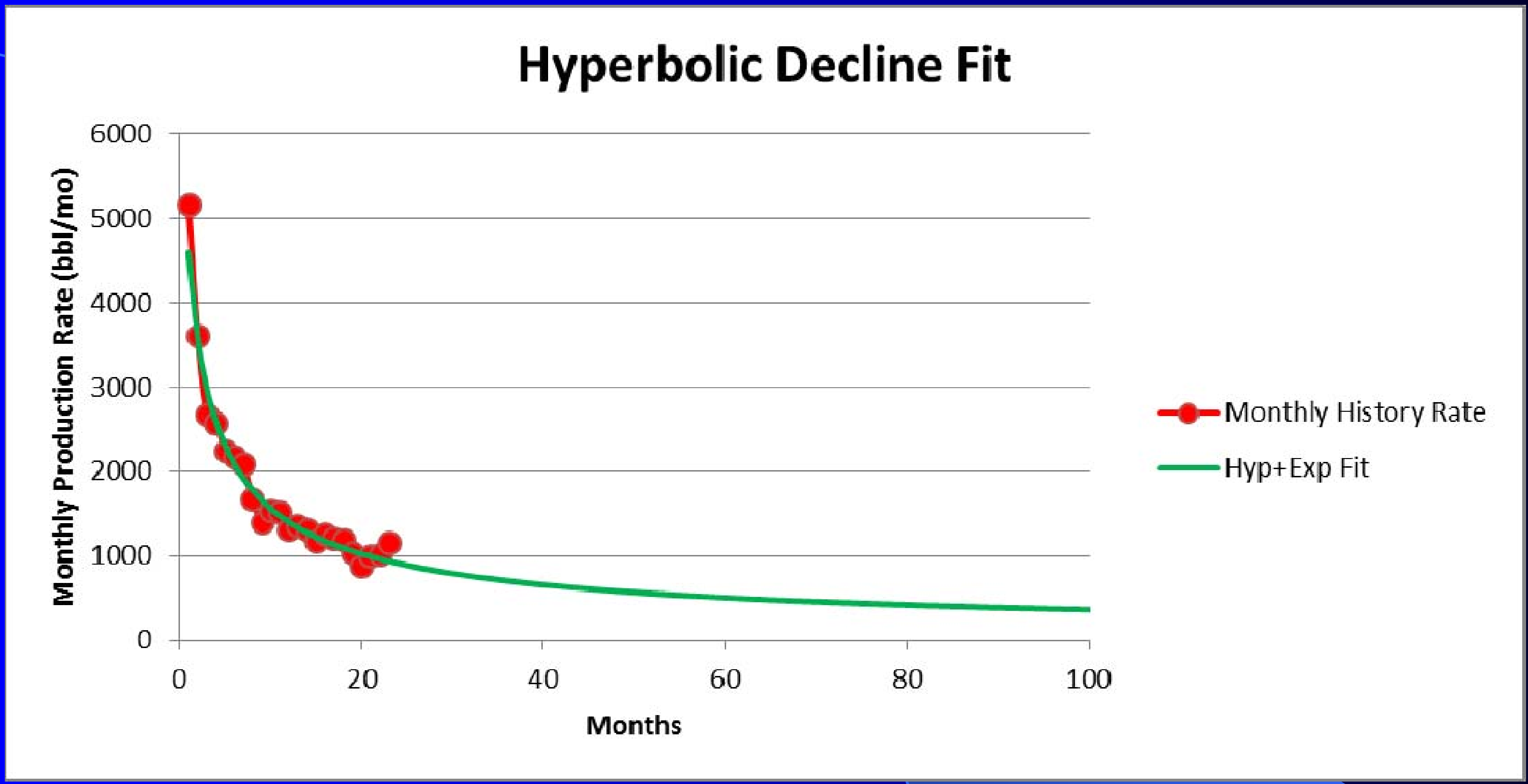


Stress "Bench"

Slickwater 3D frac simulations generally agree with tracer heights

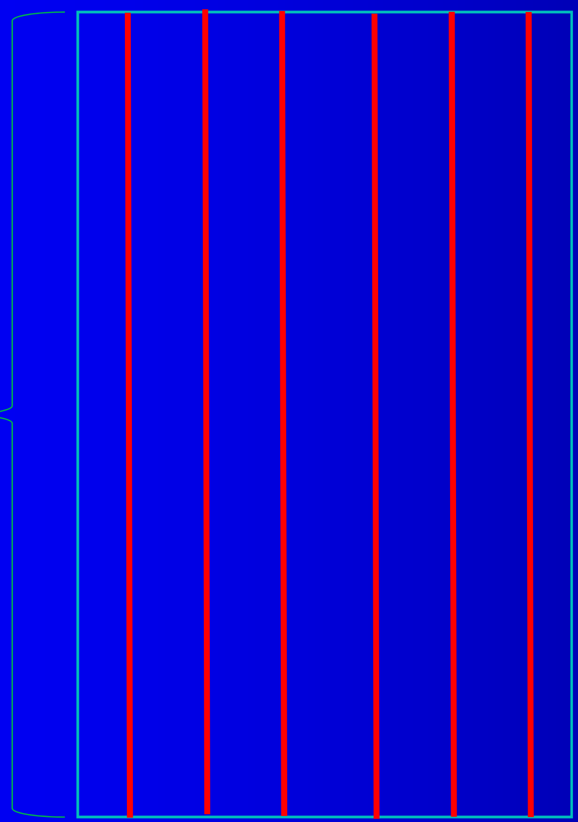
Similar results in Fracpro, Stim-Plan, Fraccade, and Gohfer

EUR from Hyperbolic Decline Analysis



Di = 75%, B = 1.5, Switch to exponential =5%, 30 BOPM economic limit
EUR = 155,430 BO

Drainage Area Normalization



6 wells per 1.5 sections

160 acres per wellbore

7920 ft length

Drainage area=(GPI/7920)*160

GPI = Gross perforated interval

Reduce GPI for failed stages

Example:

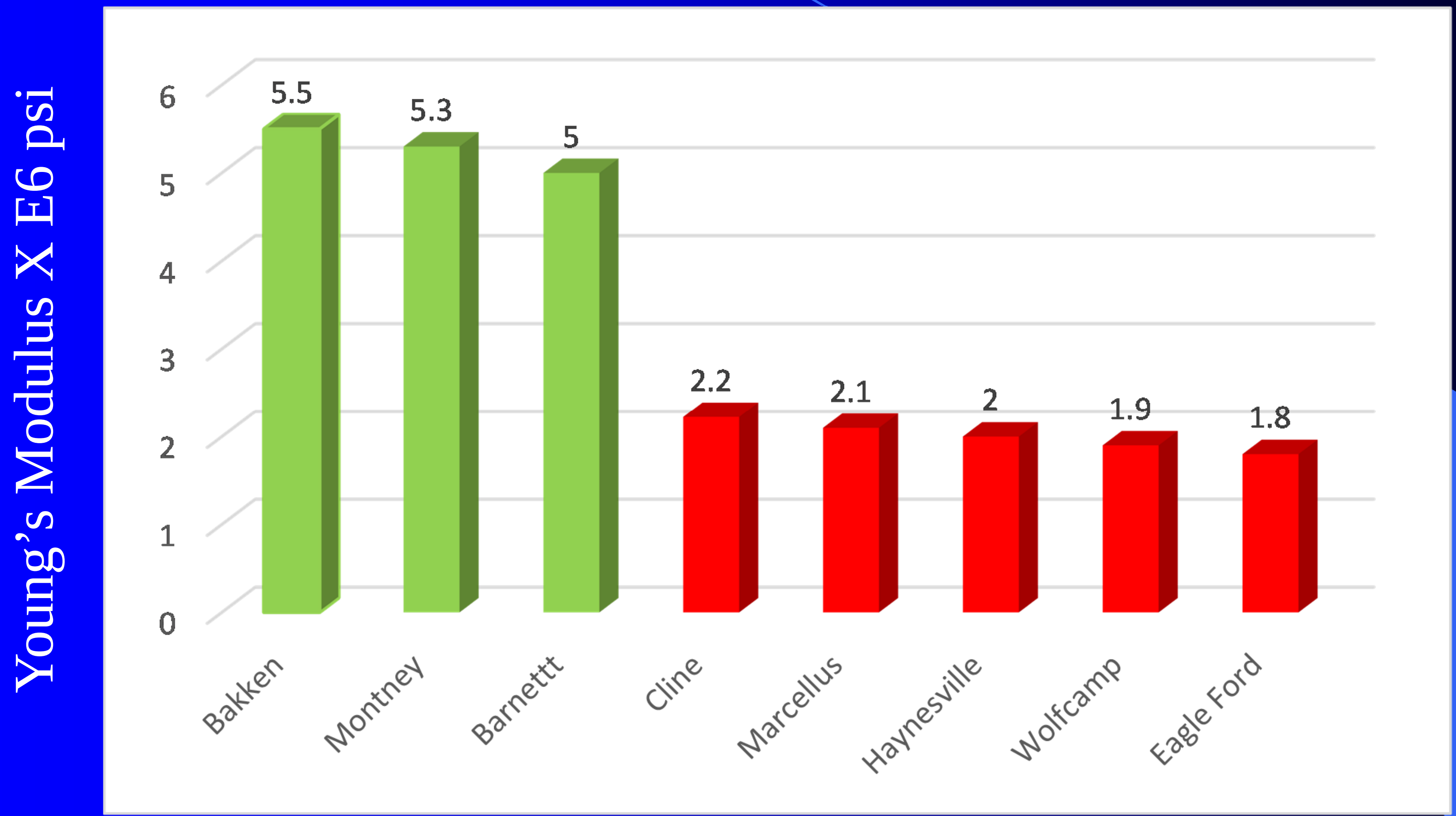
3960 ft GPI
All stages successful
Drainage area = 80 acres

Bakken model=10,000 ft lateral = 320 acres

Recovery Factor and Conductive Height

- To test the hypothesis that only the conductive height is producing a recovery factor analysis can be done that assumes only the expected propped height is producing
- In most cases to date this estimate is very high and probably not reasonable (15% or higher)
- This suggests that some unpropped height is being generated above and possibly below the proppant bank
- While it has not been proven with absolute certainty, a hypothesis is proposed that relates unpropped height to Young's modulus

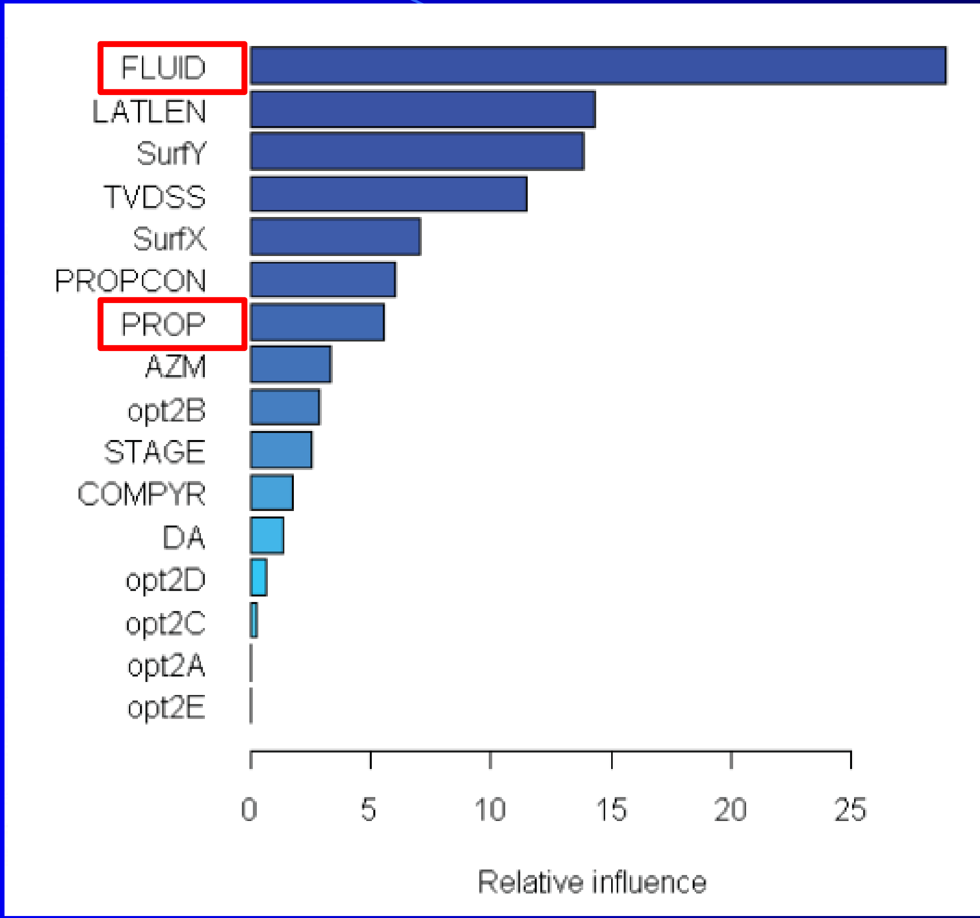
Static Young's Modulus Distribution



Anecdotal Support for Young's Modulus Impact

- Barnett Shale- laterals historically landed high to avoid Ellenberger water, production not adversely affected
- Bakken – higher trajectory clusters performed better than lower trajectory clusters (SPE 160160)
- Marcellus – higher trajectory wells perform poorly (Atlas Energy 2010 DUG presentation)
- Data suggests more unpropped height can be obtained in higher modulus formations

Is It More Proppant or More Fluid?



Commonly discussed "best practice" is increasing lb of proppant per ft of lateral
Ignores fact that more fluid is required to transport higher proppant volumes
Fluid volumes five times more important than proppant volumes

SPE 173334 LaFollete et al Delaware Wolfcamp

Recovery Factor Applications

- Identification of refrac candidate wells and zones
- Refrac candidate well and zone performance predictions
- Production performance estimates for various landing zone options prior to drilling the lateral
- Provides an indication of how much of the vertical pay column is connected to the wellbore via propped and unpropped conductivity
- Normalization of well performance for "best practices"
  - Critical for comparisons in different areas of a play
  - Work in progress-compare RF's for different diversion options

Canyon Tight Gas Sand Microseismic

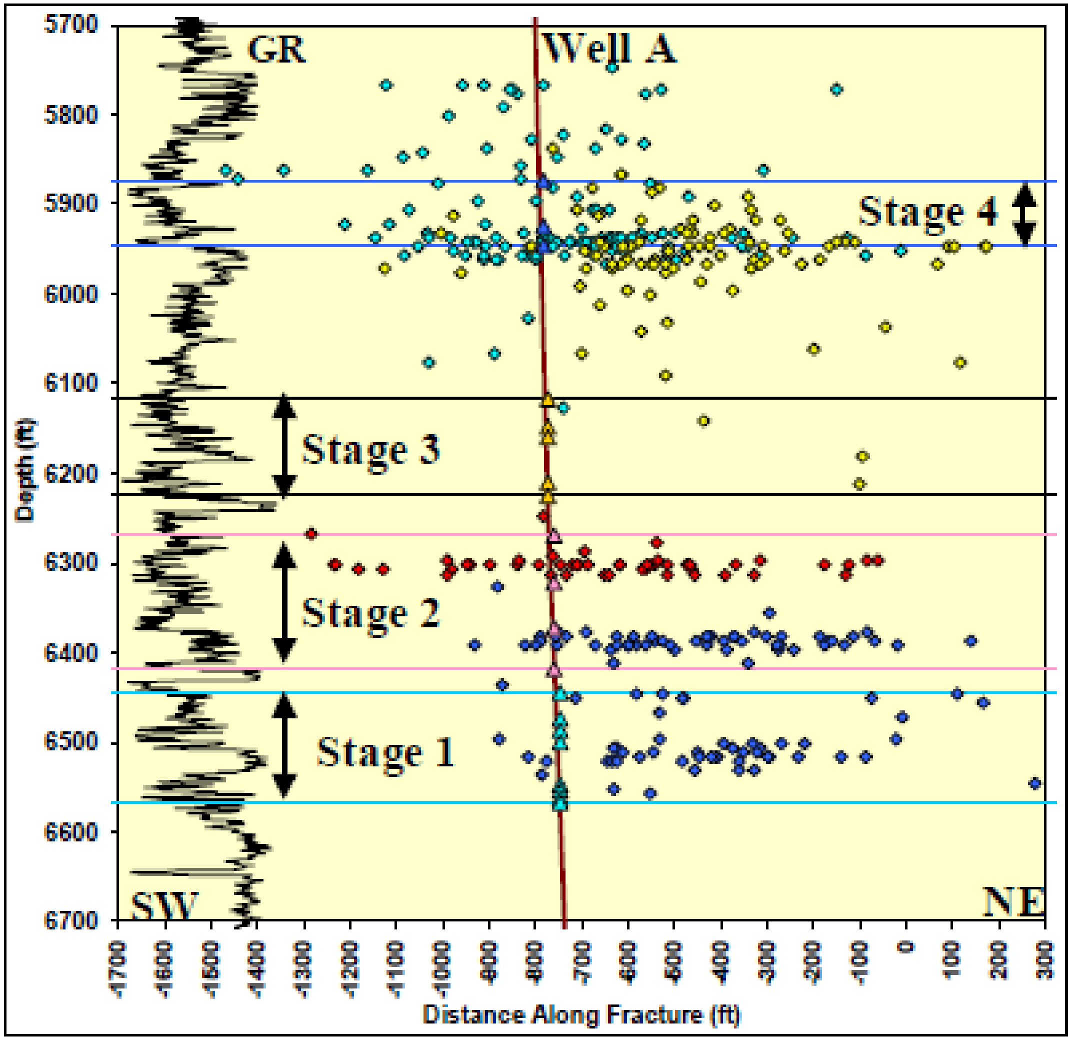
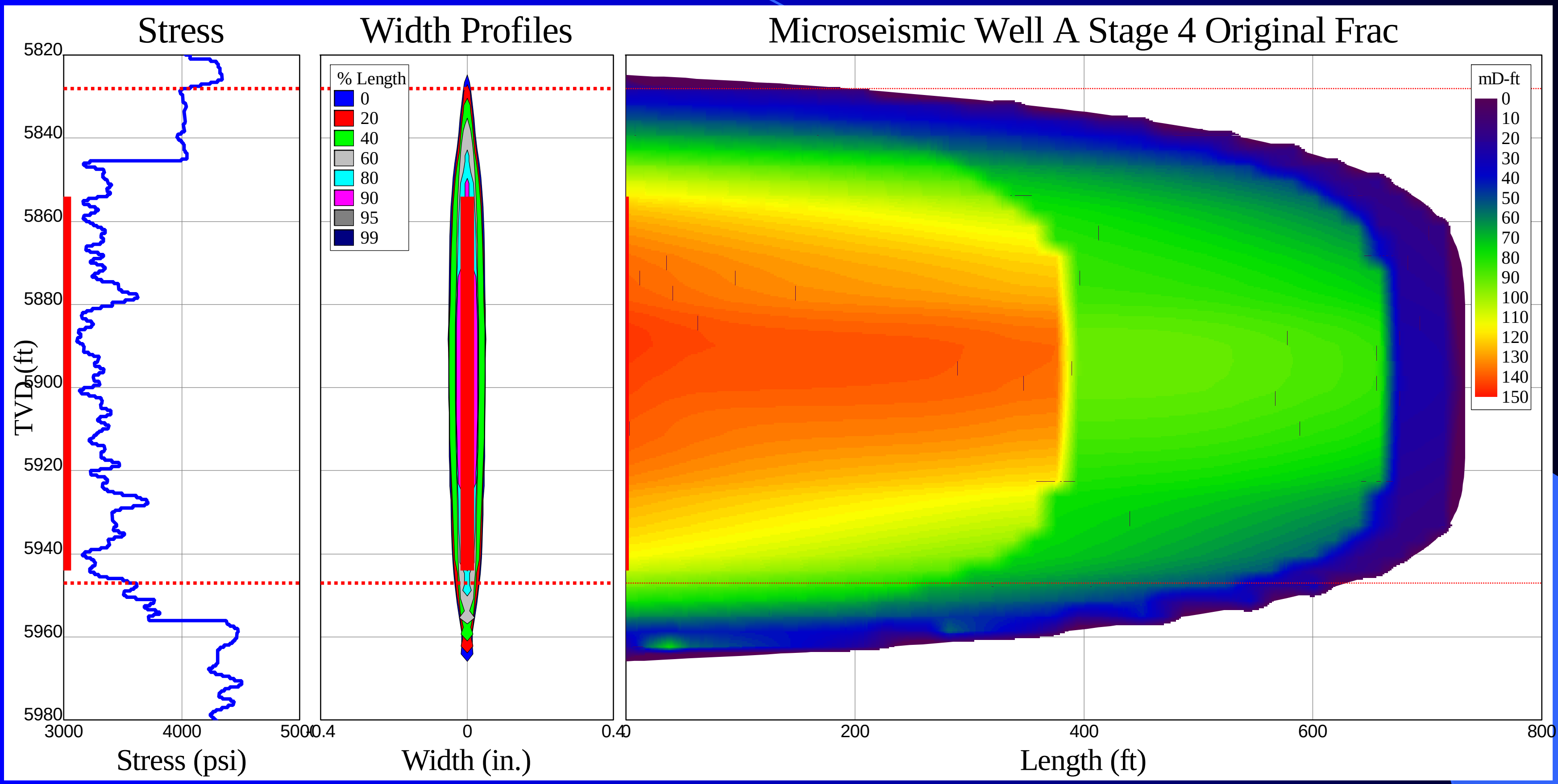


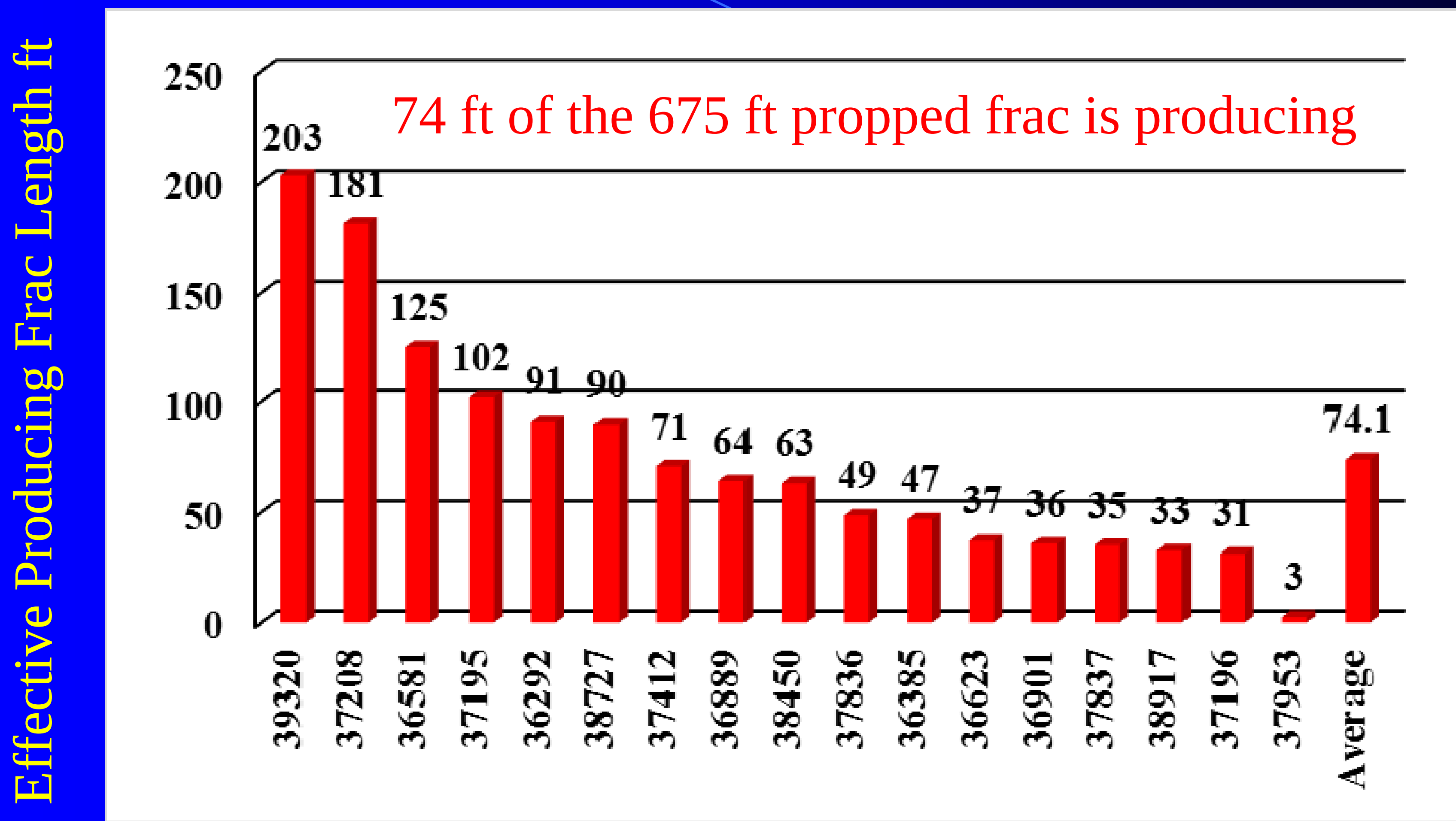
Figure 5 - Well A Microseismic Mapping: Side View

Canyon Tight Gas Sand 3D Geometry



Frac length and height agree with microseismic-675 ft Xf propped

Canyon Sand RTA Xf Apparent

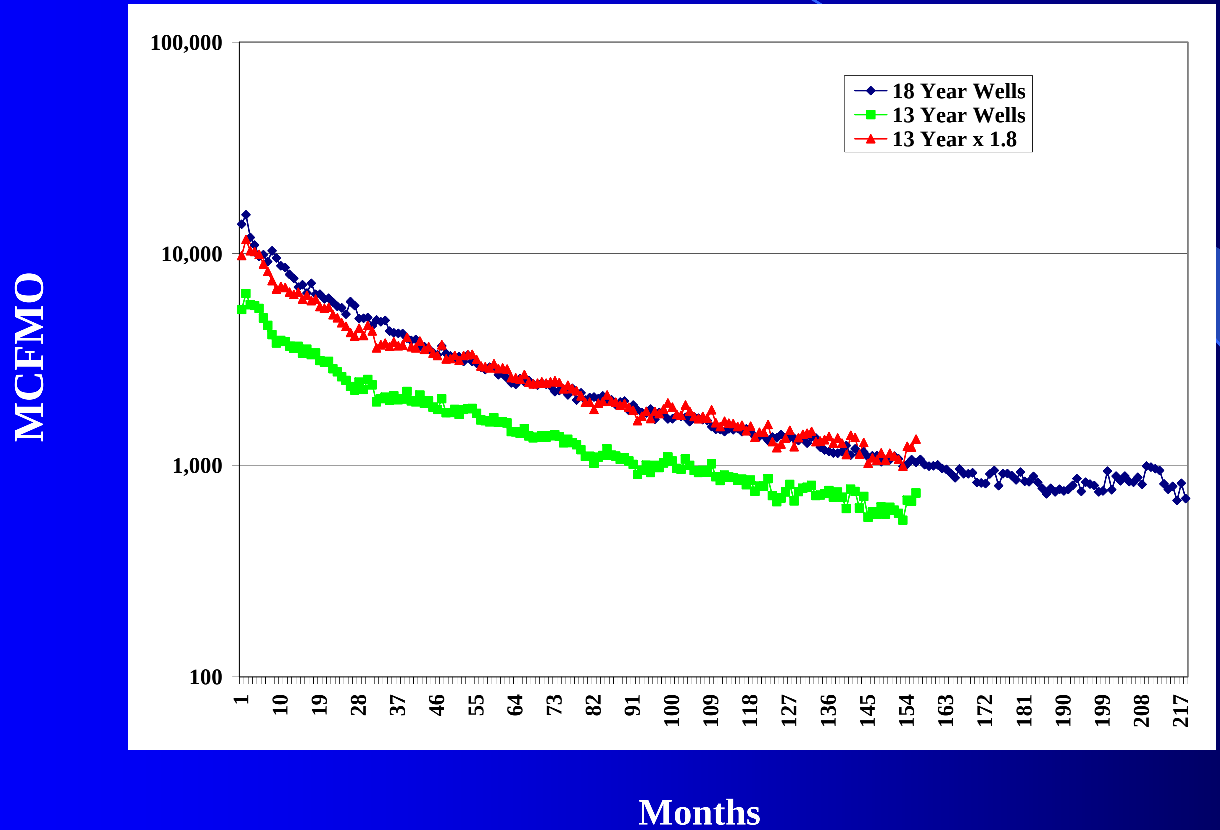


11% of propped length producing with water based gels
Low Sw formation, no formation water production

Refrac Candidate Economic Evaluation

- Determine the volume of stranded hydrocarbons for the refrac candidate using OIP and the expected RF with type of refrac completion
- Wells do not have to be in the same area
  - Recovery factor process normalizes the analysis
- Apply a type decline to the volume of stranded hydrocarbons to perform economic analysis, vary IP to match expected volumetric recovery over time
- The cash flow analysis can determine if the well can economically be re-lined and fracced conventionally or if a lower cost diverter program will be appropriate

Composite Canyon 120 Well Historical Decline



13 year average production green, 18 year average production blue

ultiplier on 13 year in red - matches 18 year production decline rate

Decline rate independent of well age

Apply decline profile (% by month) to IP, change IP to match 25 year cum gas to RGIP

Run economics off production decline

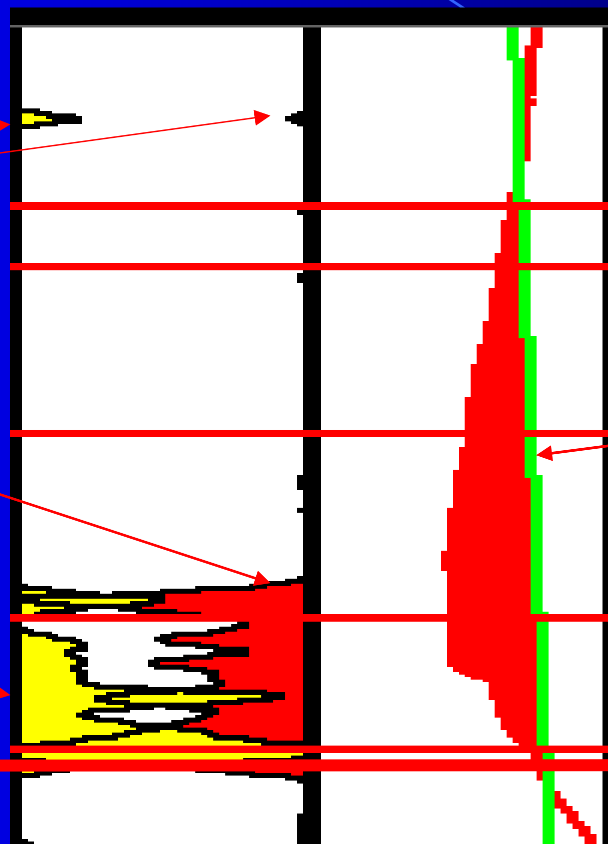
Stress "Benches" and Propped Height

- The dipole sonic data can be used to see the most likely base will be for the proppant below the laterals
- This is useful in determining how the conductive height and the net pay profiles intersect
- The basic Eaton equation using Poisson's ratio (ν), pore pressure (PPG), overburden (OBG), and calibration factor (Pext) can be used to develop the stress profile:
  - NUFN = (ν/1-ν)
  - CSG= (OBG*NUFN)+ PPG*(1-NUFN)+Pext
- Tracers can be used in vertical pilots to validate the location of the "benches" and verify propped height

Slickwater vs Borate Tracer

Proppant “wedges”?
200 ft from bench

Borate Height



Temperature

Slickwater Height

Stress bench

1-2 hour break time max vs 60 hours for closure in above well
Gelled fluids do not improve propped height

Improving Conductive Height

- With gelled fluids not an option, other means are proposed for field testing in vertical pilot holes
- Lightweight proppants
  - Current version $2/lb wholesale, needs to come down
  - Mixing with conventional proppant possible benefits
- Self suspending proppants (SPE 163818)
- Fiber (“Hiway” and similar systems)
  - “Pillars” unlikely, results probably from improved proppant transport
- Refracs-can access “new rock” above previous proppant pack with improved prop transport