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Optimizing Liquid Recoveries from Shales: Through Geologic, Geomechanical, Fluid and Operating Considerations

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Peter and Catherine Meldrum Professor
Chair, Department of Chemical Engineering
University of Utah, Salt Lake City, Utah

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Outline

- Liquids from shales – status and challenges
- Field data and the story of gas oil ratios
- Effect of geologic and operational parameters
- Production of near-critical fluids
- Geomechanical controls
- Field-wide optimization
- Conclusions

Where is the Activity?

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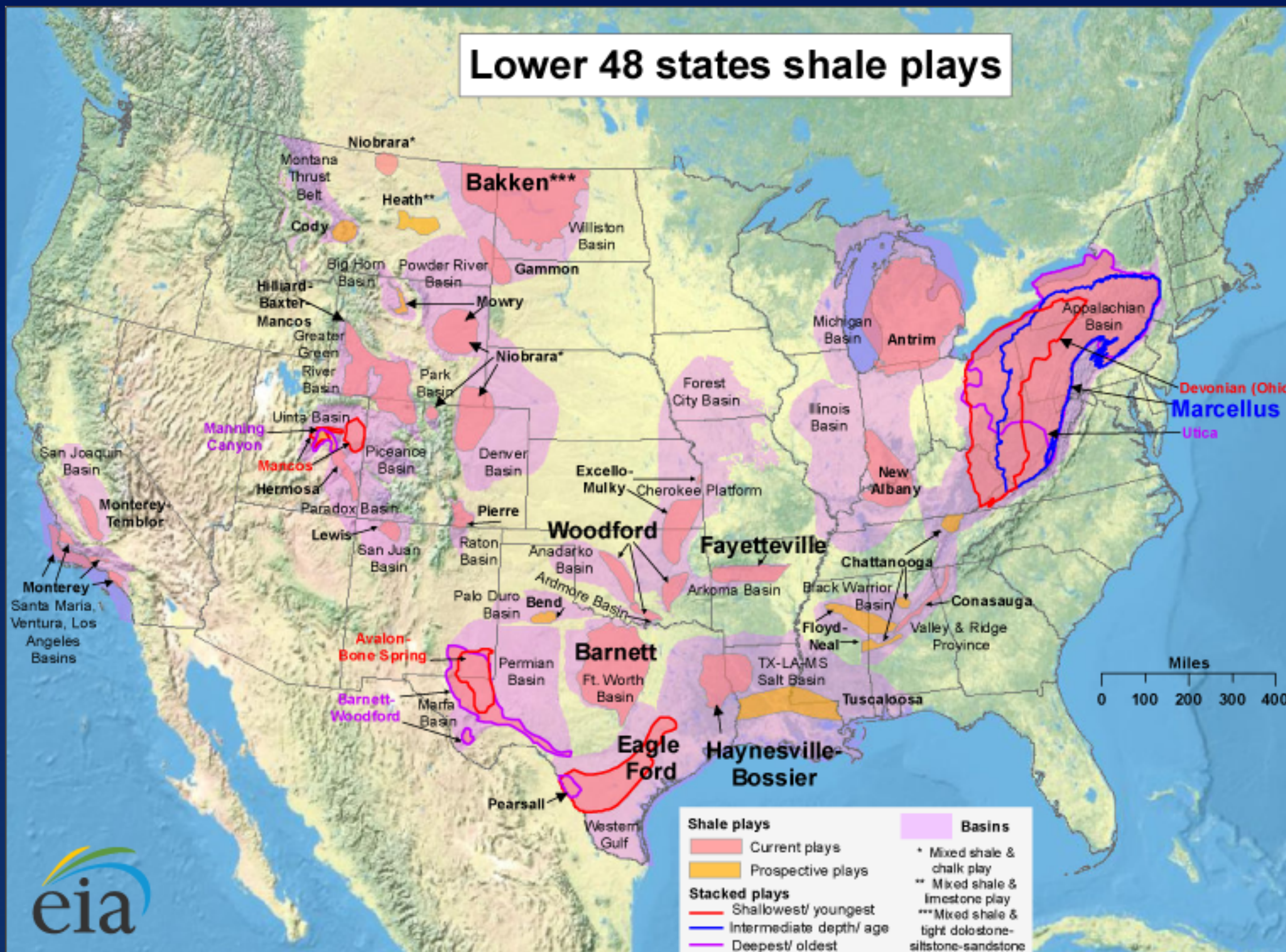
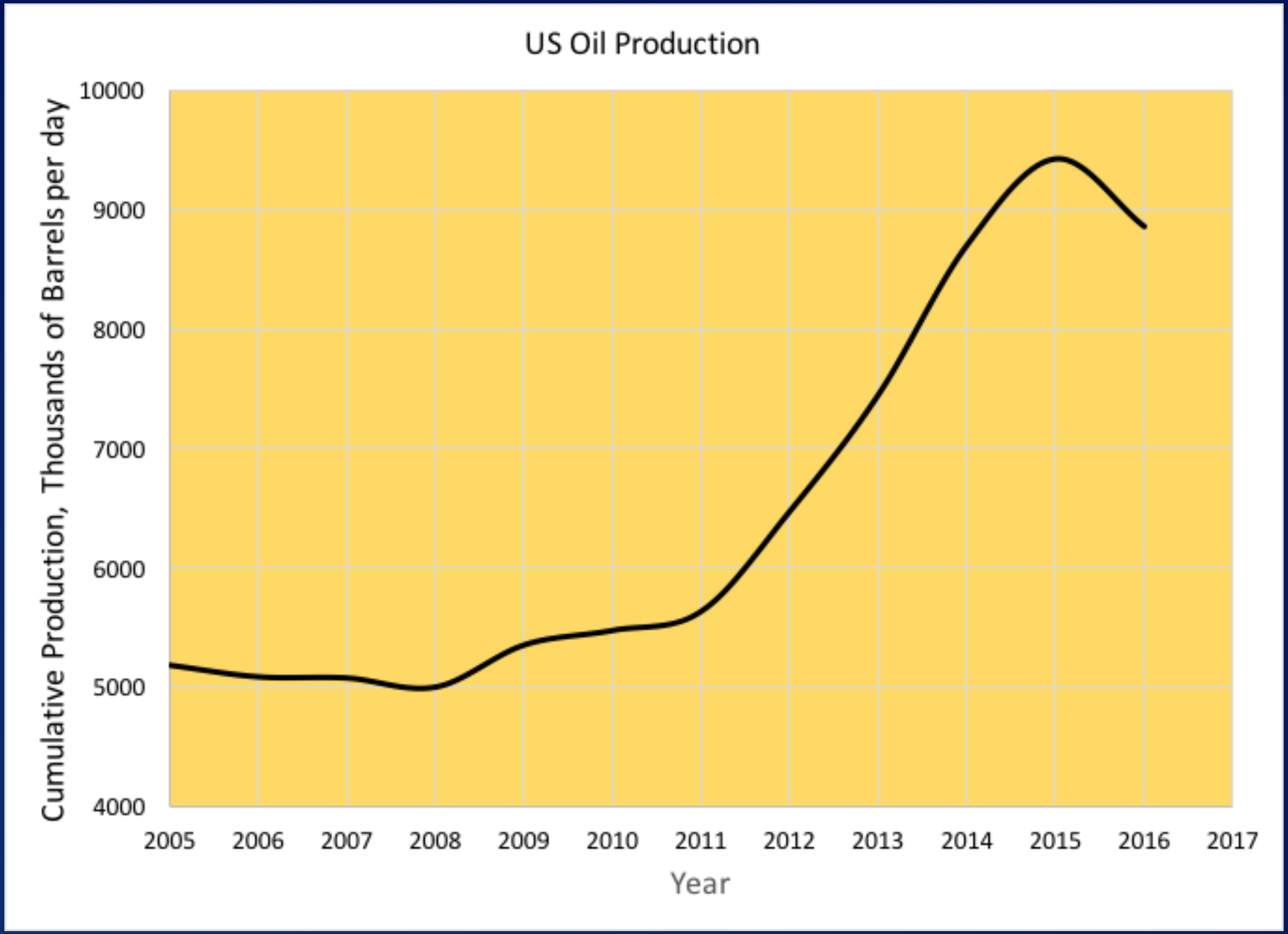


Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

Status and Challenges

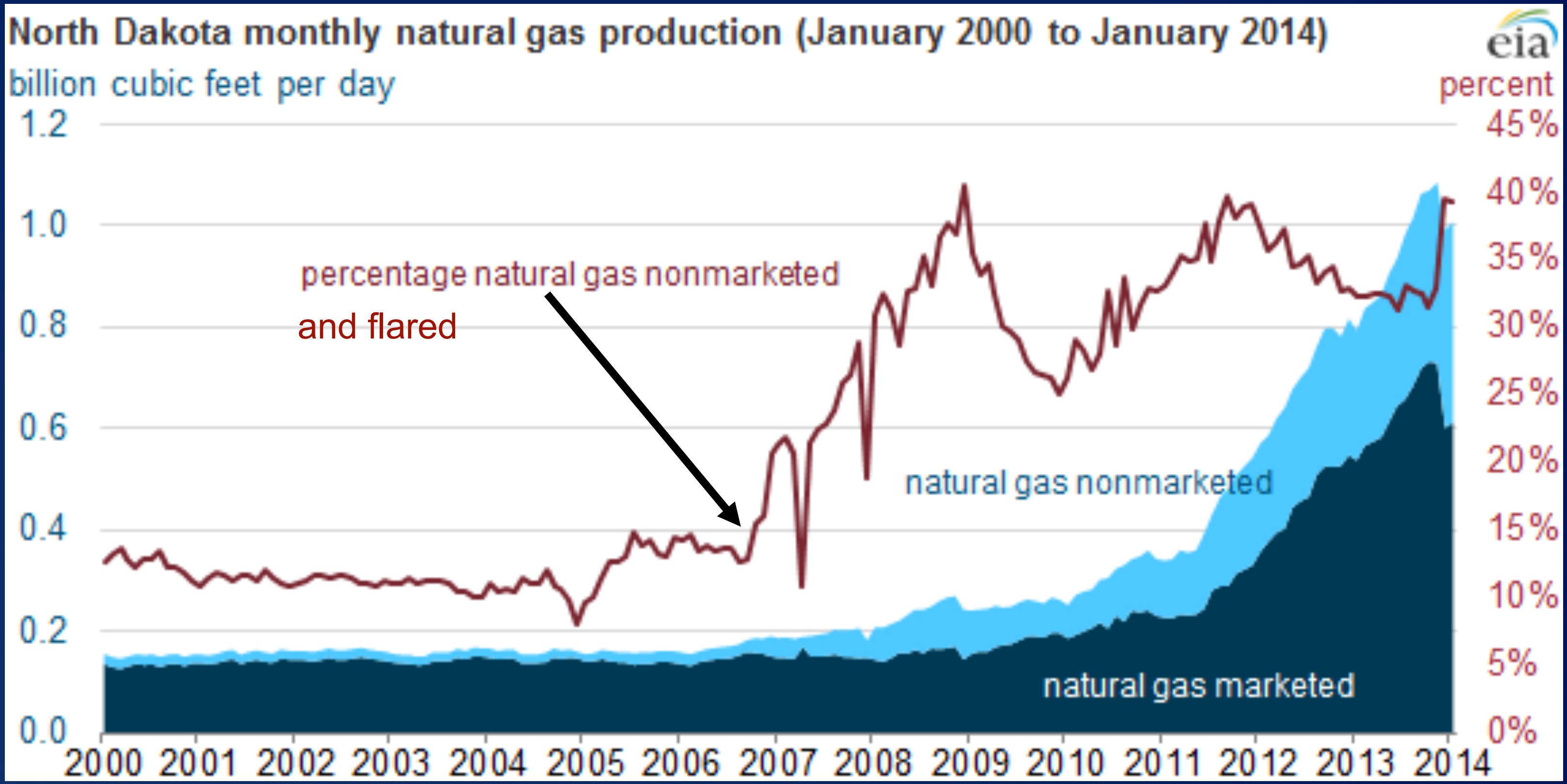


Data from Energy Information Administration

- US oil imports below 30%
- Economic output from Eagle Ford alone $87 billion *(CCBR Eagle Ford Study)*
- Tens of thousands of high-paying jobs

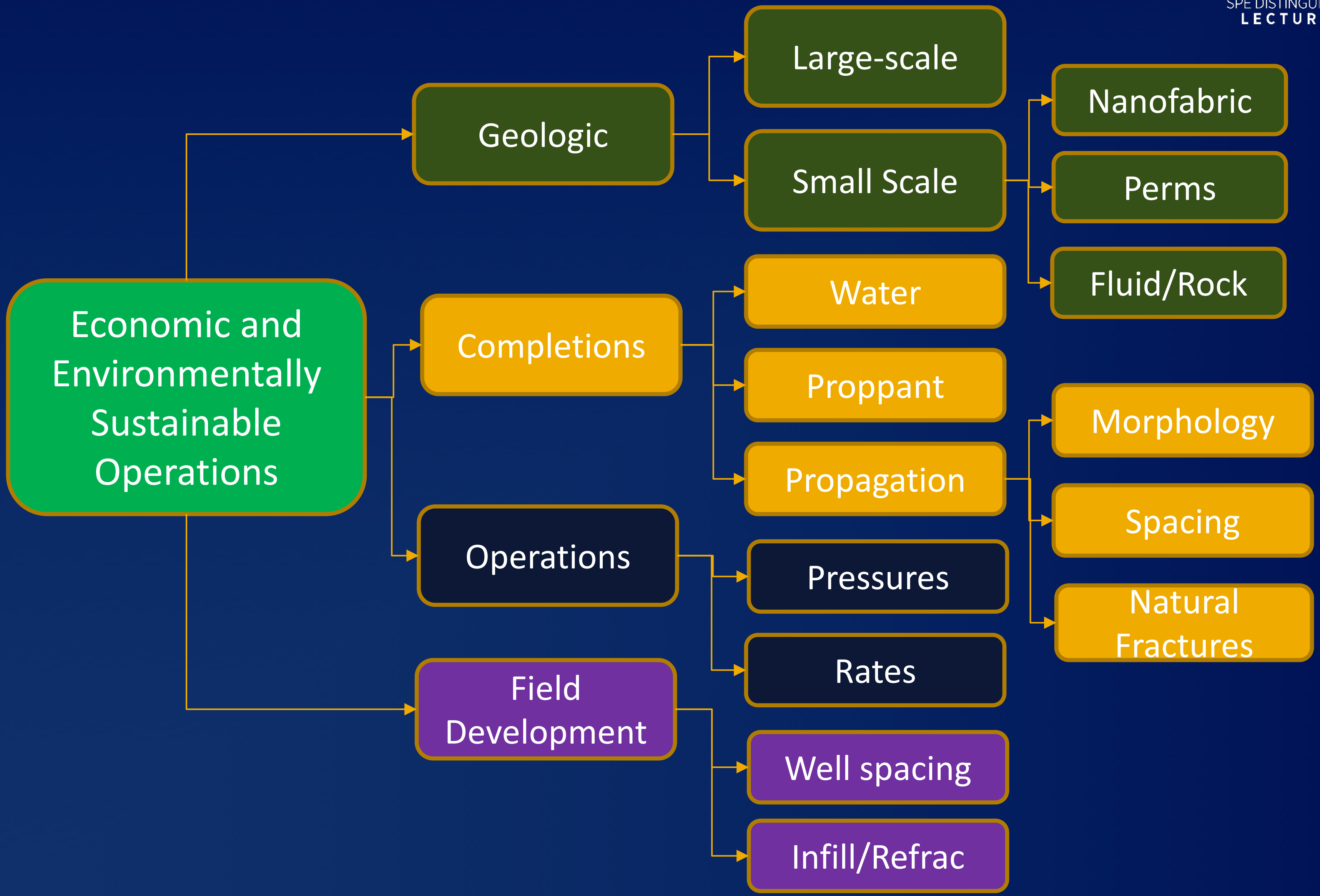
Too good, Too fast?

- Low oil recoveries – inadequate understanding
- Gas flaring – inadequate infrastructure
- Water use and reuse
- *Important to get the most out of each well*



From Energy Information Administration

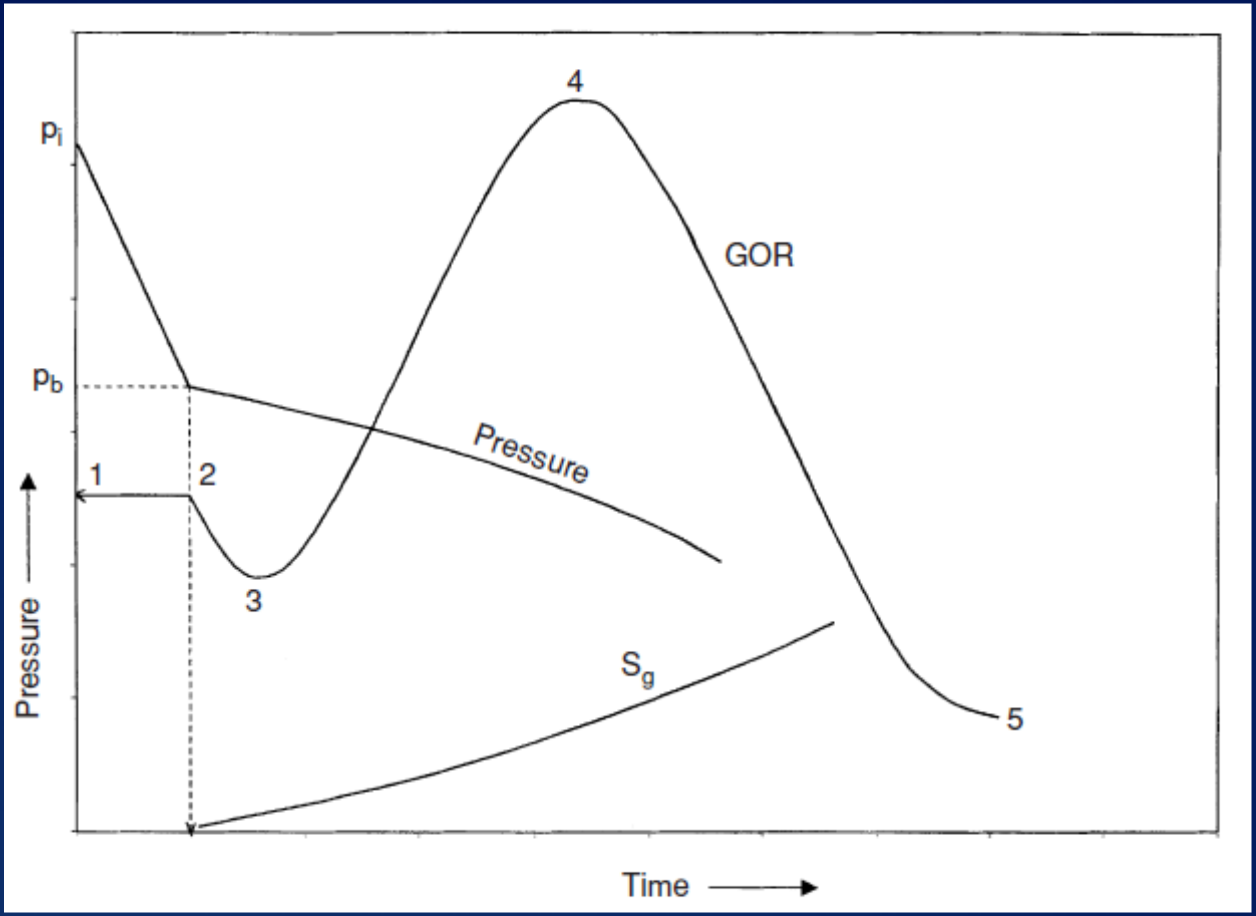
Outcomes and Related Aspects



Primary Production from Shales

- Slow overall pressure decline because of low permeability
- Transition to free gas and management of gas oil ratios over time
- Importance of fluid type and phase behavior
- Reservoir access and surface area creation

GOR Story: Conventional GOR Behavior



GOR: Gas oil ratio

The Unconventional System

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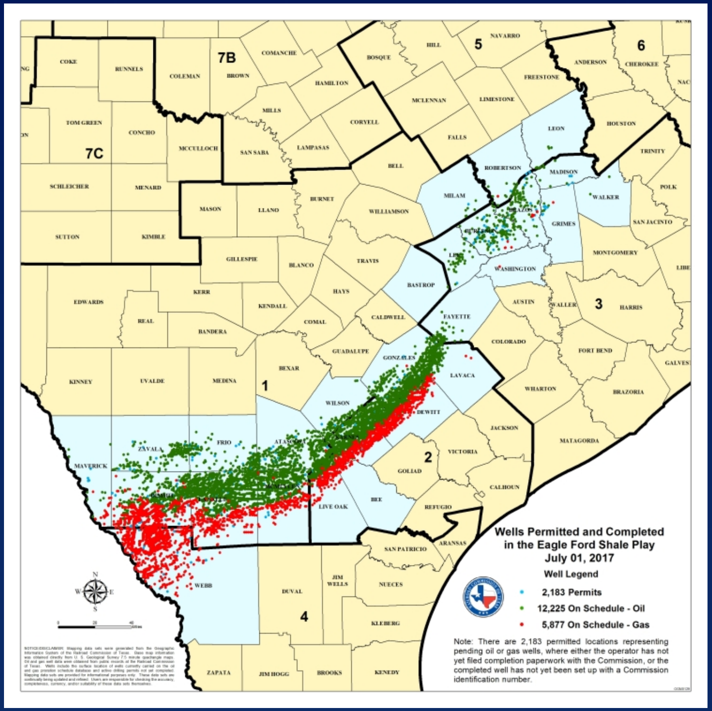
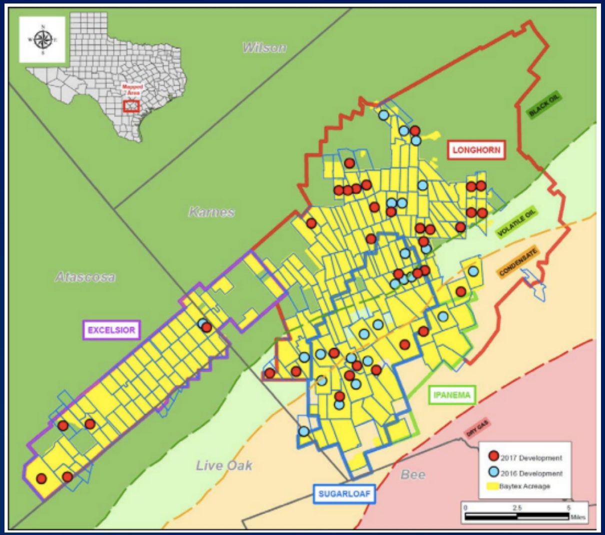
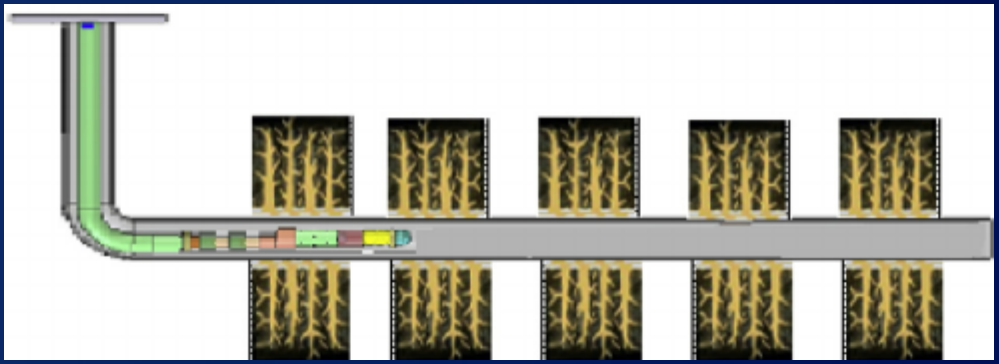
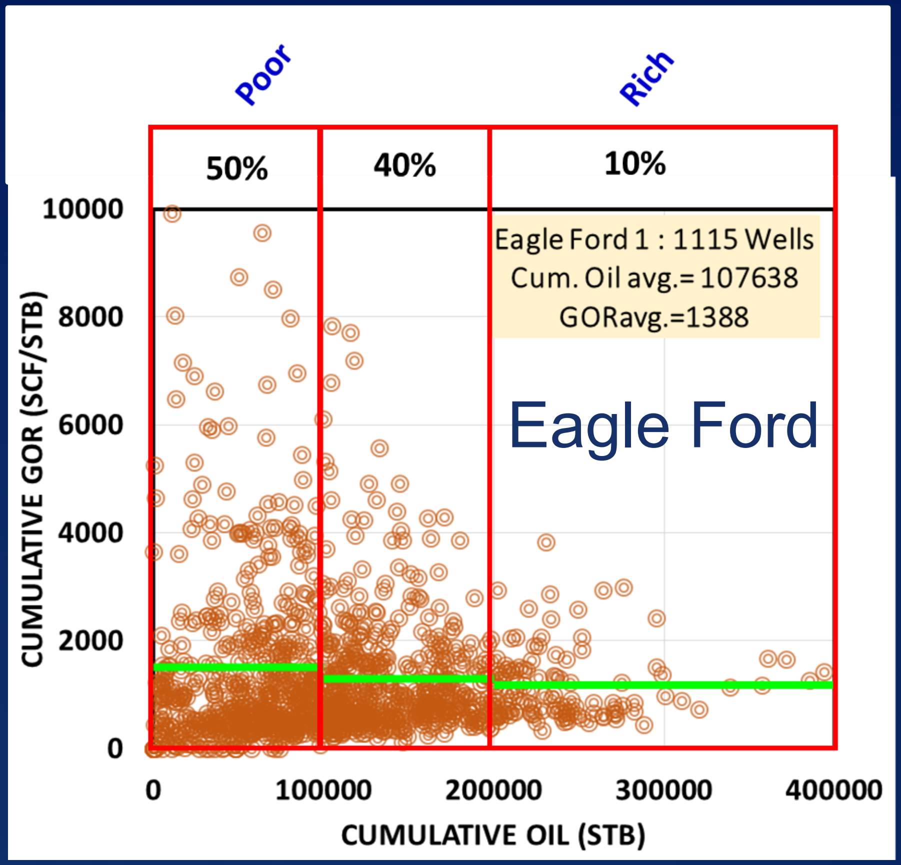
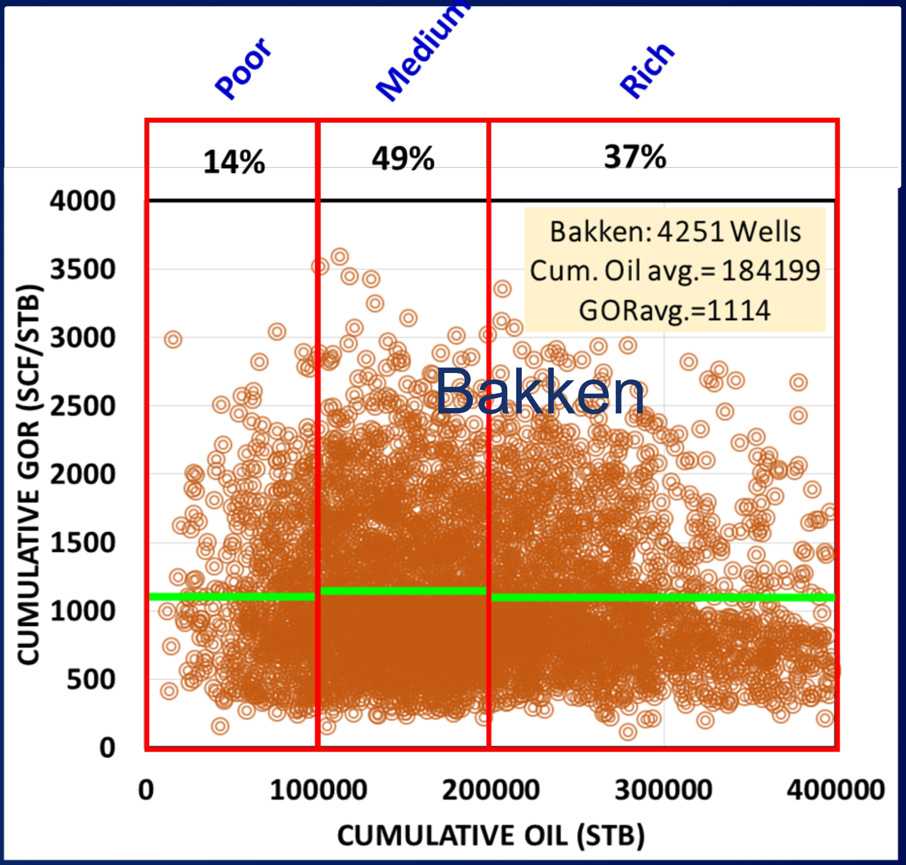






Example Production





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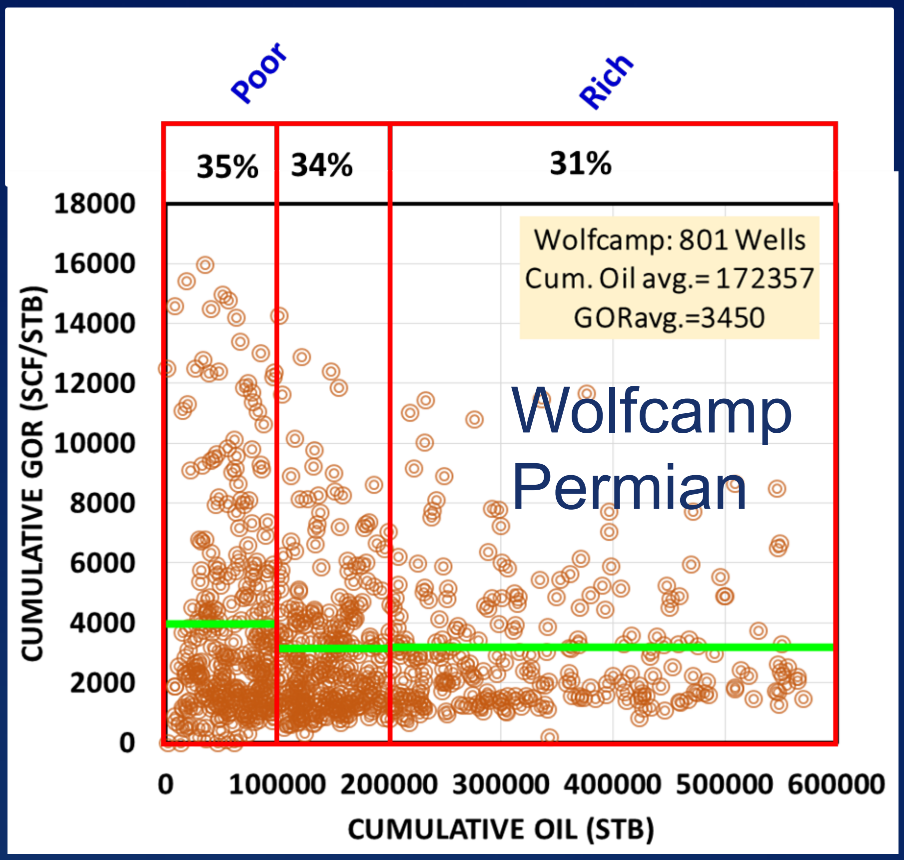
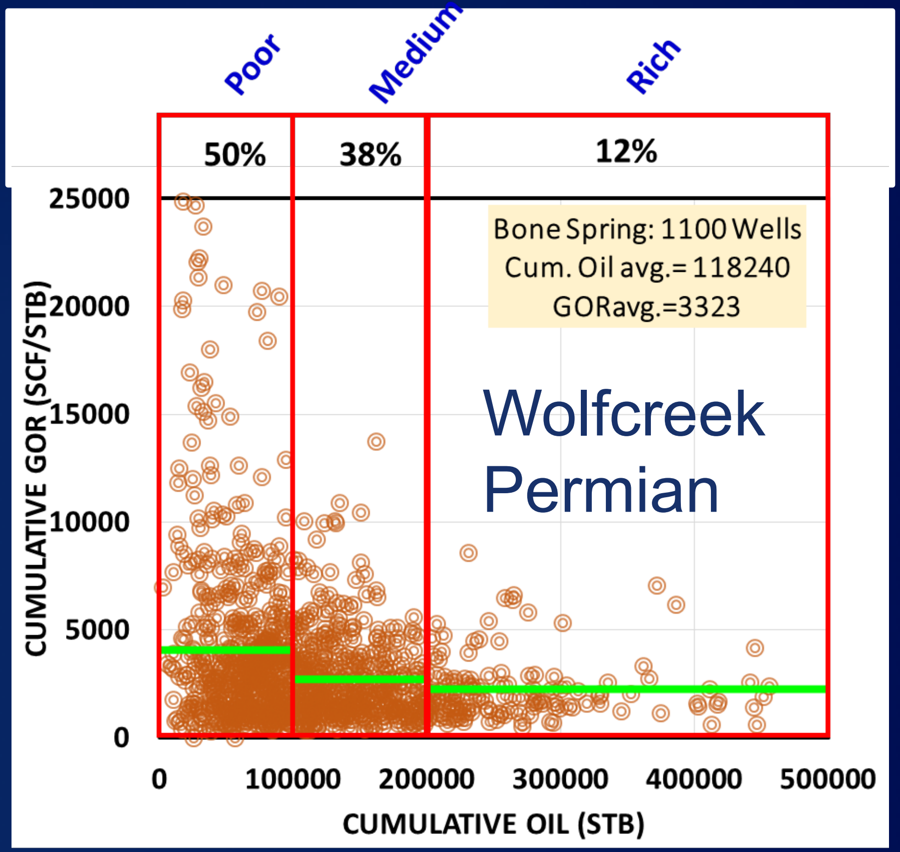
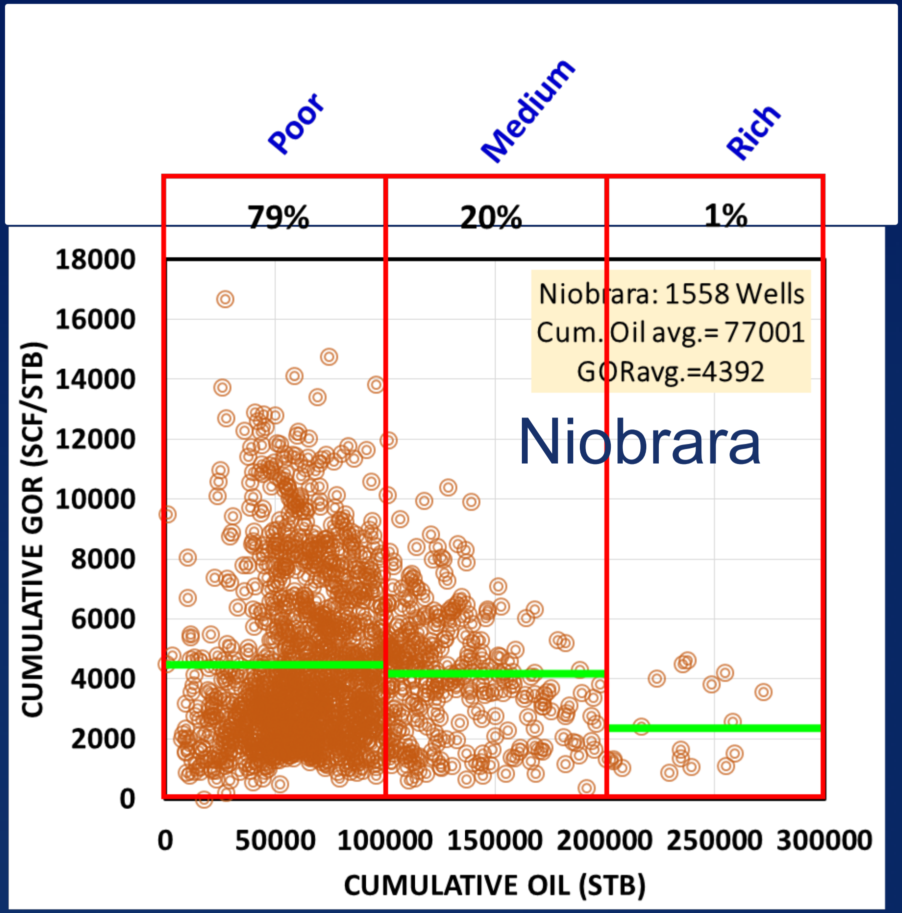
Example Production

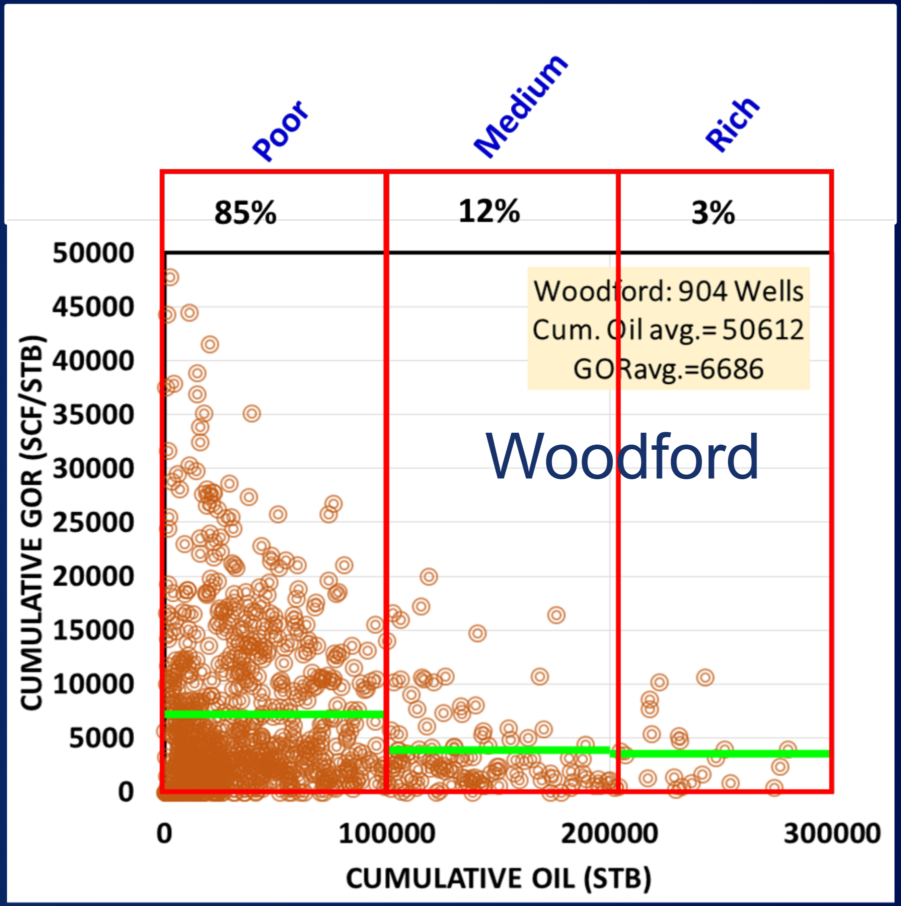




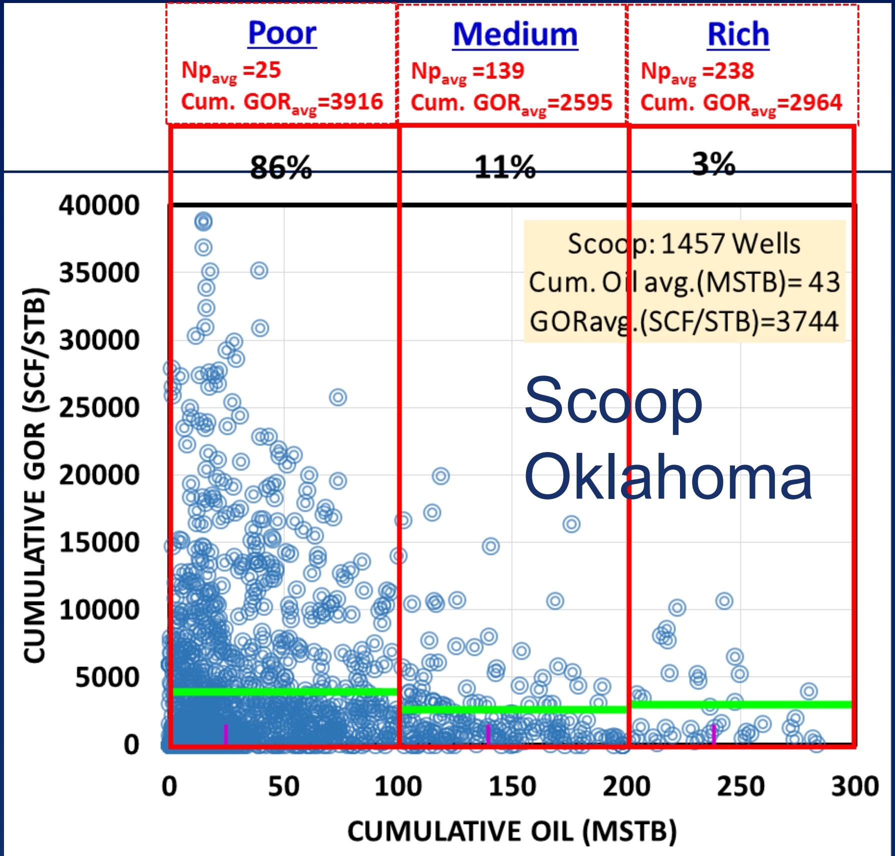
- In general, higher gas oil ratio equates to lower cumulative oil

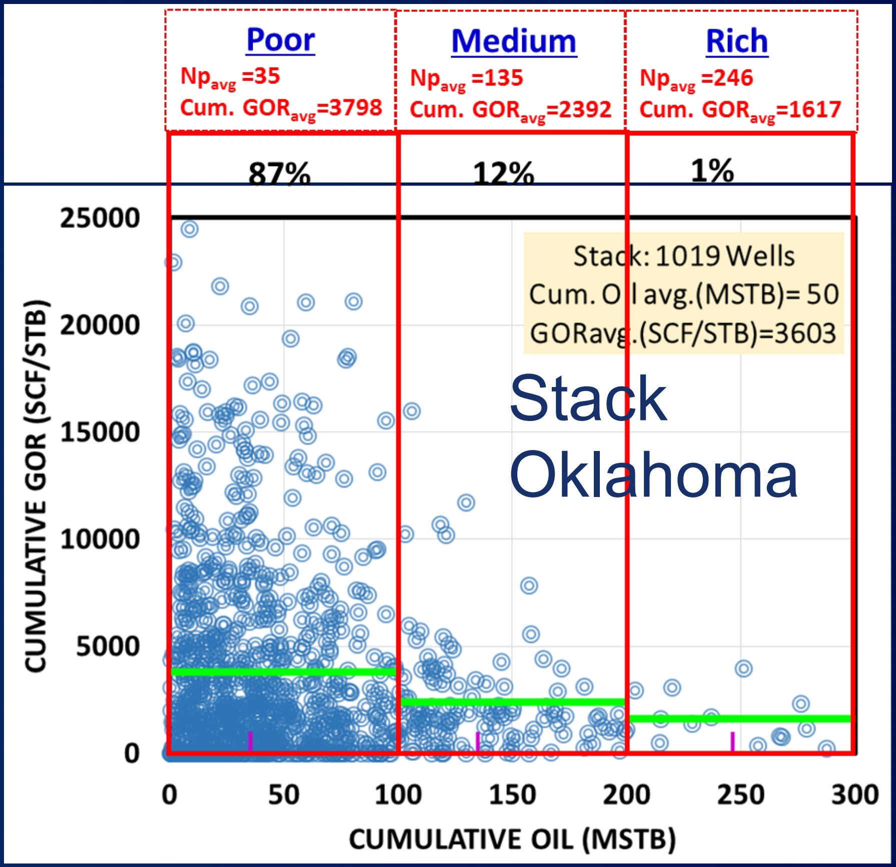
Example Production





Example Production





- The new Oklahoma plays

Methods

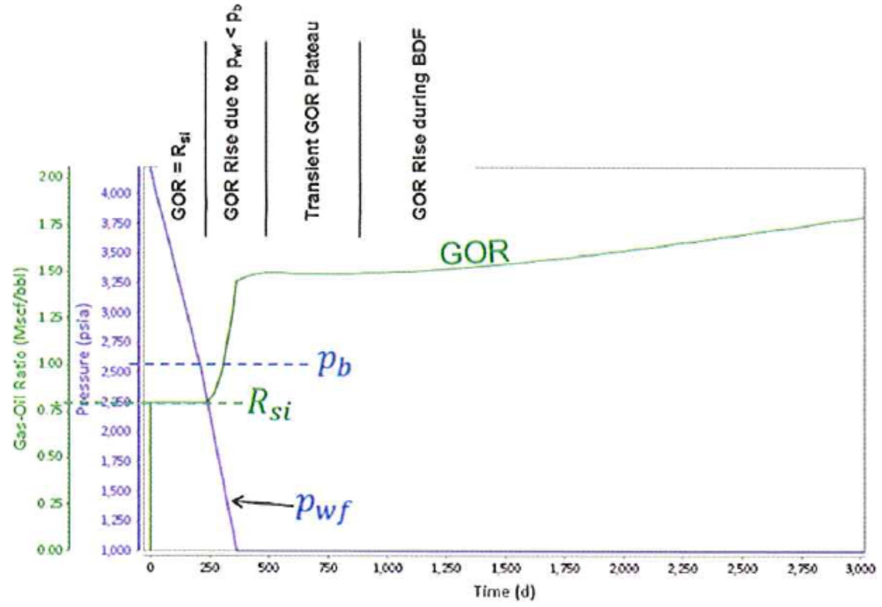
$$\nabla \cdot \left(\frac{\mathrm{k} k_{ro}}{B_o \mu_o} \nabla \varphi_o \right) = \frac{\partial}{\partial t} \left(\phi \frac{S_o}{B_o} \right) + q_o,$$

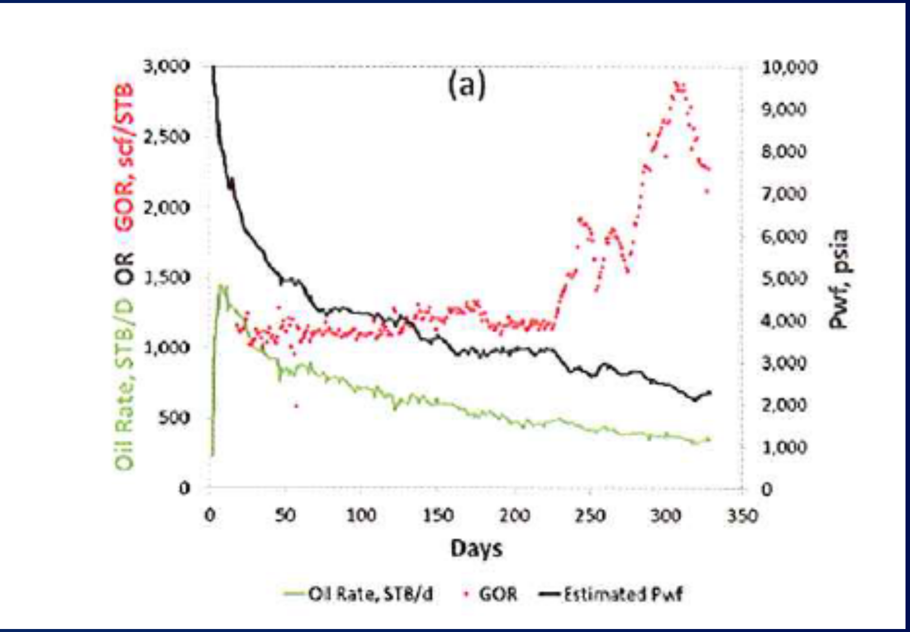
$$\nabla \cdot \left(\frac{\mathrm{k} k_{rw}}{B_w \mu_w} \nabla \varphi_w \right) = \frac{\partial}{\partial t} \left(\phi \frac{S_w}{B_w} \right) + q_w,$$

$$\nabla \cdot \left(R_s \frac{\mathrm{k} k_{ro}}{B_o \mu_o} \nabla \varphi_o + \frac{\mathrm{k} k_{rg}}{B_g \mu_g} \nabla \varphi_g \right) = \frac{\partial}{\partial t} \left(\phi R_s \frac{S_o}{B_o} + \phi \frac{S_g}{B_g} \right) + R_s q_o + q_{fg}.$$

- Three-phase, three-dimensional reservoir simulation
- Commercial codes, in-house simulators

Field Unconventional

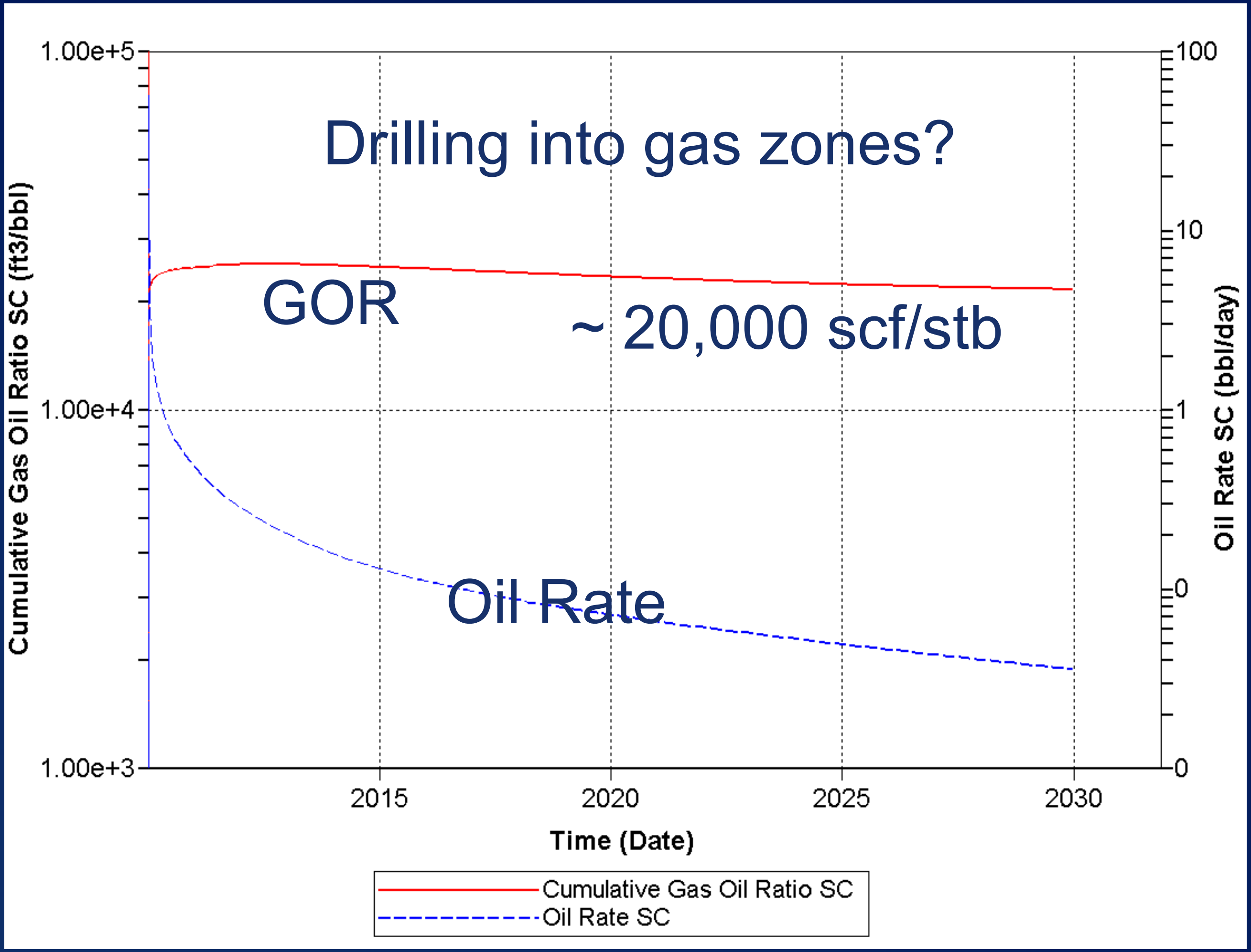




Jones, *URTec 2460396*

- GOR does not rise to very high values
- This is fundamentally different from conventionals

Why So Many Poor Wells?



- Perhaps, gas accumulation due to migration or interference

Effect of Bubble Point on Recovery

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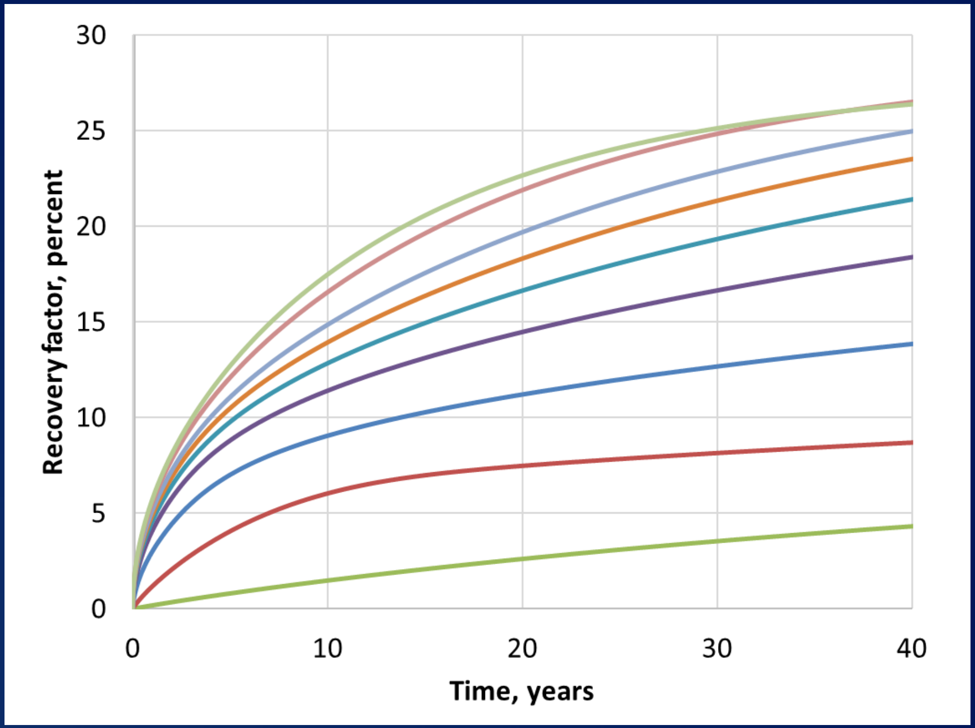
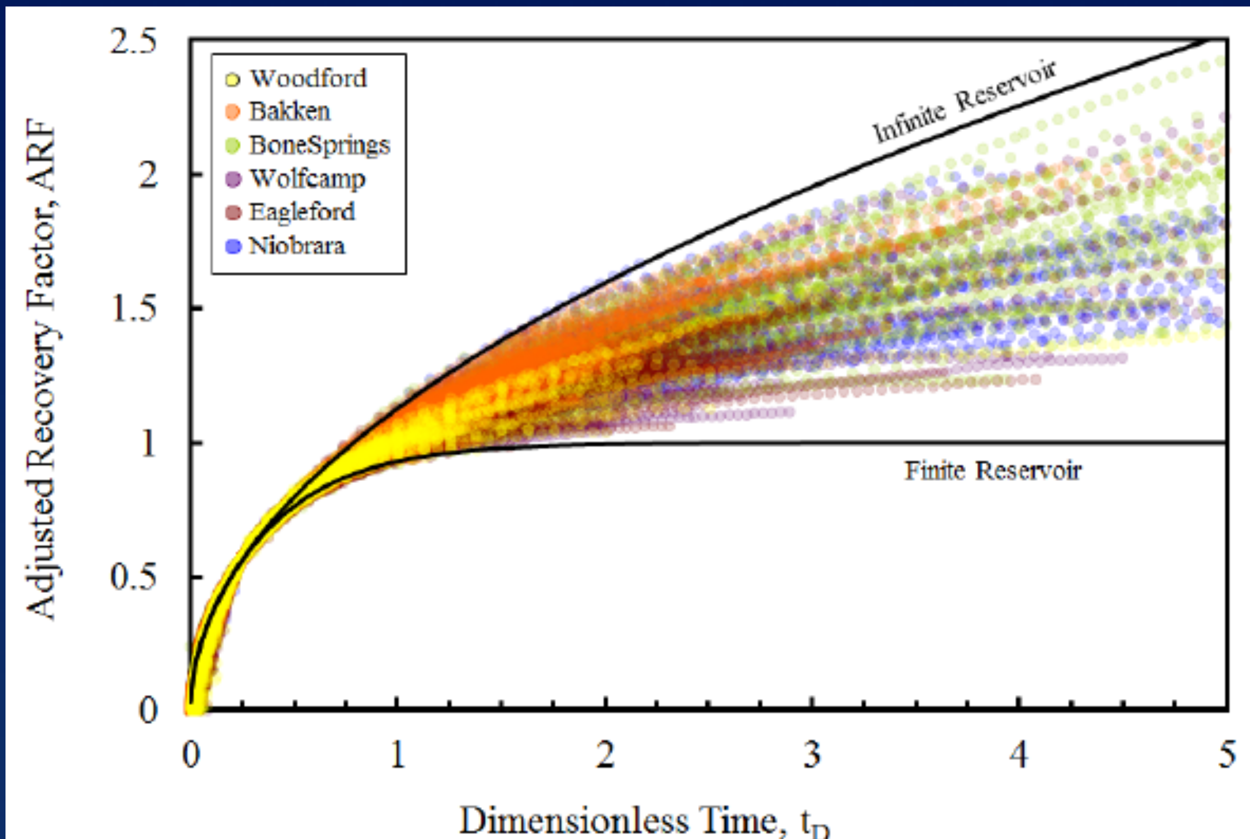
	Pb	RF @ 40 years
(Pb = BHP)	1000	4%
	1225	9%
	1450	14%
	1900	18%
	2350	21%
	2800	24%
	3250	25%
	4375	27%
(Pb = Pi)	5500	26%



Higher amount of dissolved gas provides more energy

Higher recovery factors with higher bubble point pressure, Pb

Field Data



$$RF = \frac{1.404 N_P Bo}{\varphi X_f h L}$$

$$t_D = \frac{0.0063 Kt}{\varphi \mu C_t L^2}$$

$$\text{ARF} = \frac{RF}{c_t \Delta P}$$

Lessons from the Field

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Operational parameters

Reservoir and fluid parameters

Impact on Recovery

TRANSIENT FLOW (Early production)		
Larger is better		Smaller is better
Pressure Drawdown	Number of Fractures	Fracture Spacing
Matrix perm	Total compressibility	Oil viscosity

BOUNDARY FLOW (Late production)	
Larger is better	Smaller is better
Pressure Drawdown	
Number of Fractures	Fracture Spacing
Total compressibility	
Matrix perm	Oil viscosity

Geologic Factors
Identification of Important Parameters

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- Experimental design
- Reservoir simulations
- Generate response surfaces
- Perform Monte-Carlo simulations
- Ranking of parameters
- Identify and quantify uncertainty

Parameters of Importance in Shale Production

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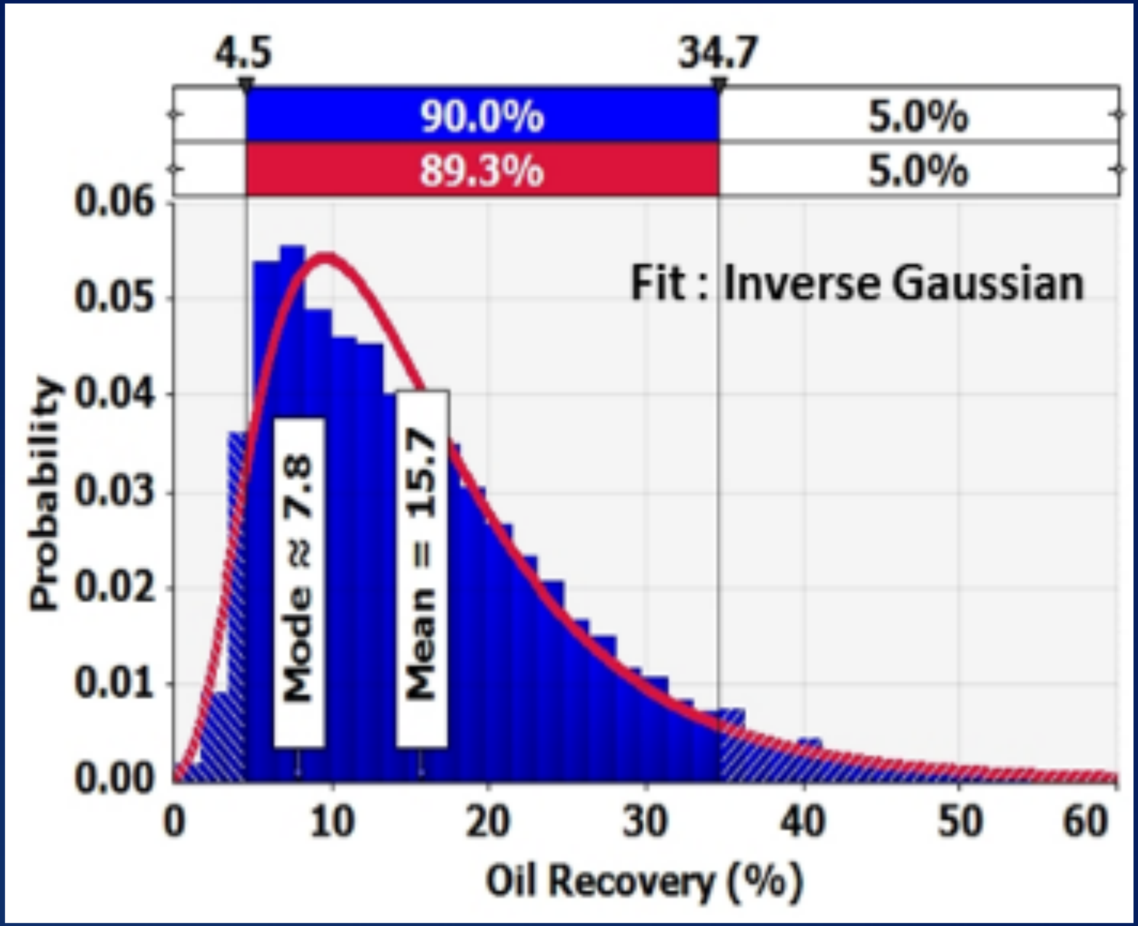
Oil Recovery from Shales			
1 yr	**10 yrs**	**20 yrs**	**Economic Rate 5 bbl/d/fracture**
Hydraulic Fracture spacing	Matrix permeability	Matrix permeability	Matrix permeability
Matrix permeability	Hydraulic Fracture spacing	Hydraulic Fracture spacing	Initial dissolved gas oil ratio
Initial dissolved gas oil ratio	Initial dissolved gas oil ratio	Initial dissolved gas oil ratio	Hydraulic Fracture spacing
Initial Reservoir pressure	Slope of dissolved GOR	Slope of dissolved GOR	Initial Reservoir pressure
Slope of dissolved GOR	Initial Reservoir pressure	Initial Reservoir pressure	Formation Compressibility
Producing BHP	Gas rel. perm exponent	Formation Compressibility	Slope of dissolved GOR
Gas rel. perm exponent	Formation Compressibility	Producing BHP	Producing BHP
Formation Compressibility	Producing BHP	Gas rel. perm exponent	Gas rel. perm exponent

- *Six of the top 8 Parameters are Geologic*
- *Only 2 of the variables are operationally controllable parameters*

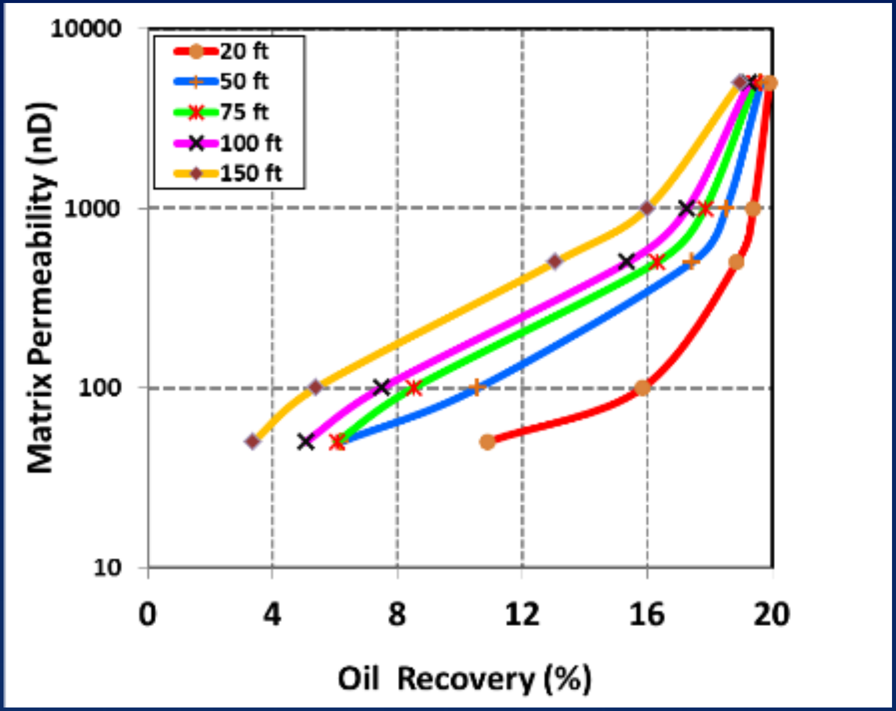
Quantify Uncertainty

Input: Variability in reservoir properties → Output: Probability distributions and variability



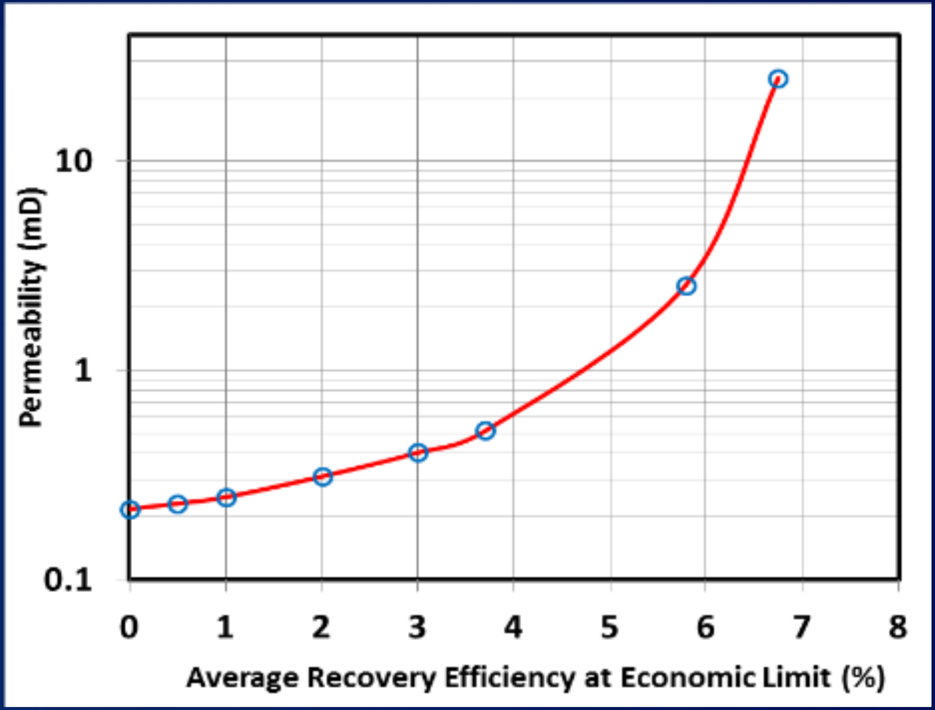
Probability density functions and P10, P50 and P90 can be generated

Operational Parameter Effects Fracture Spacing



Hydraulically Fractured Unconventionals

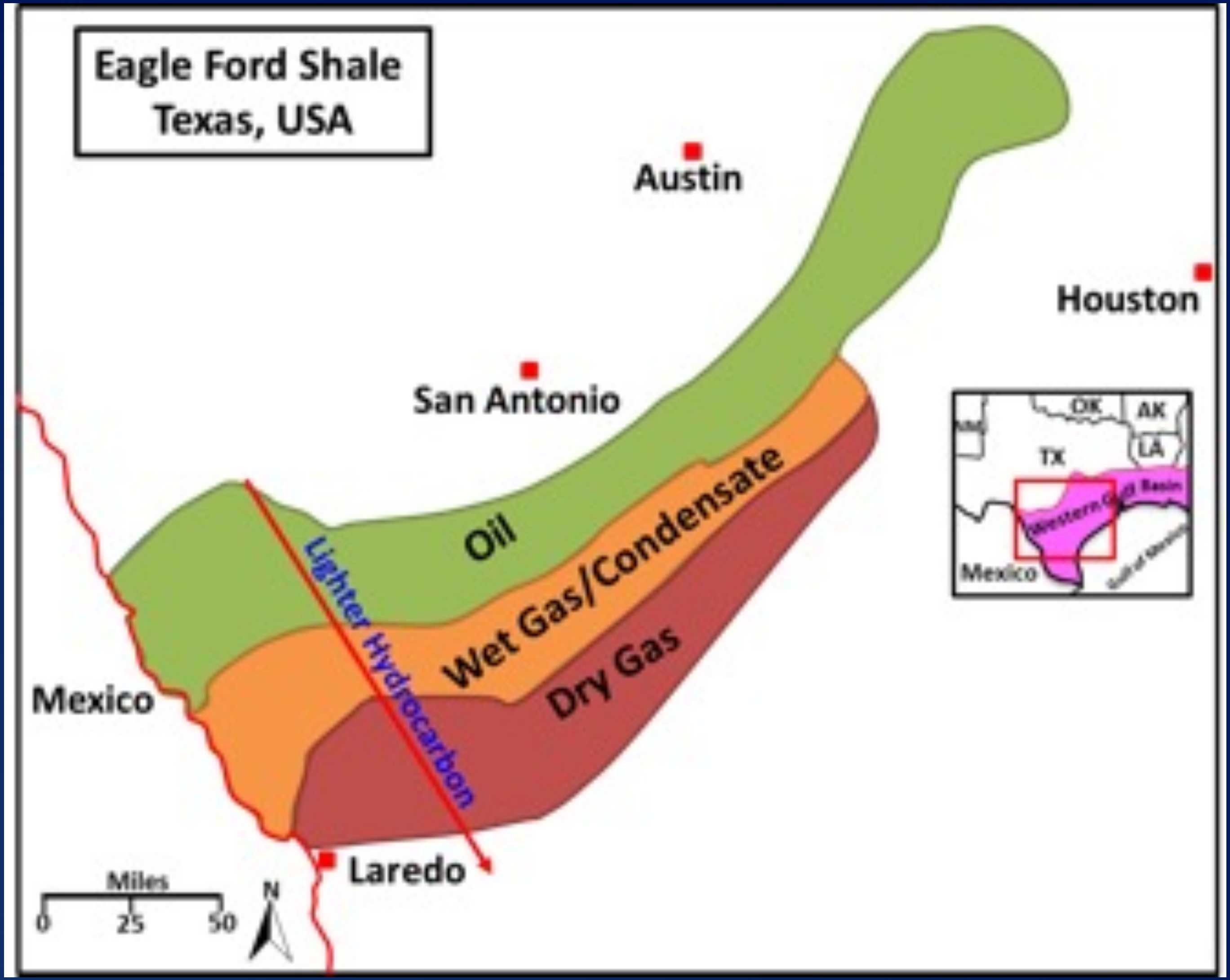
Panja, Conner and Deo (2015) International Journal of Oil, Gas and Coal technology.



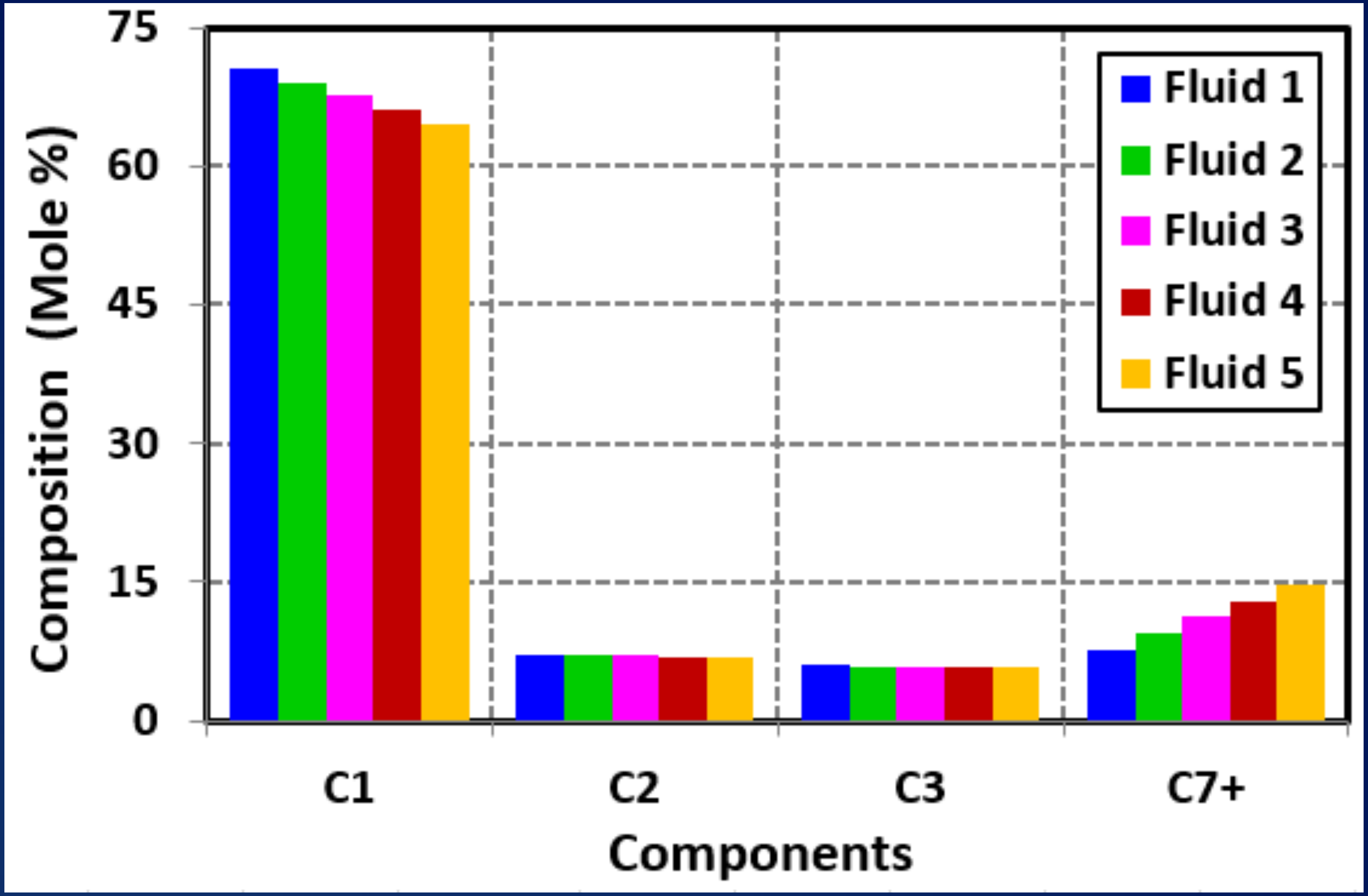
Conventional Reservoirs Under Primary Depletion

Levine and Prats (1961)

Production of Near-Critical Fluids

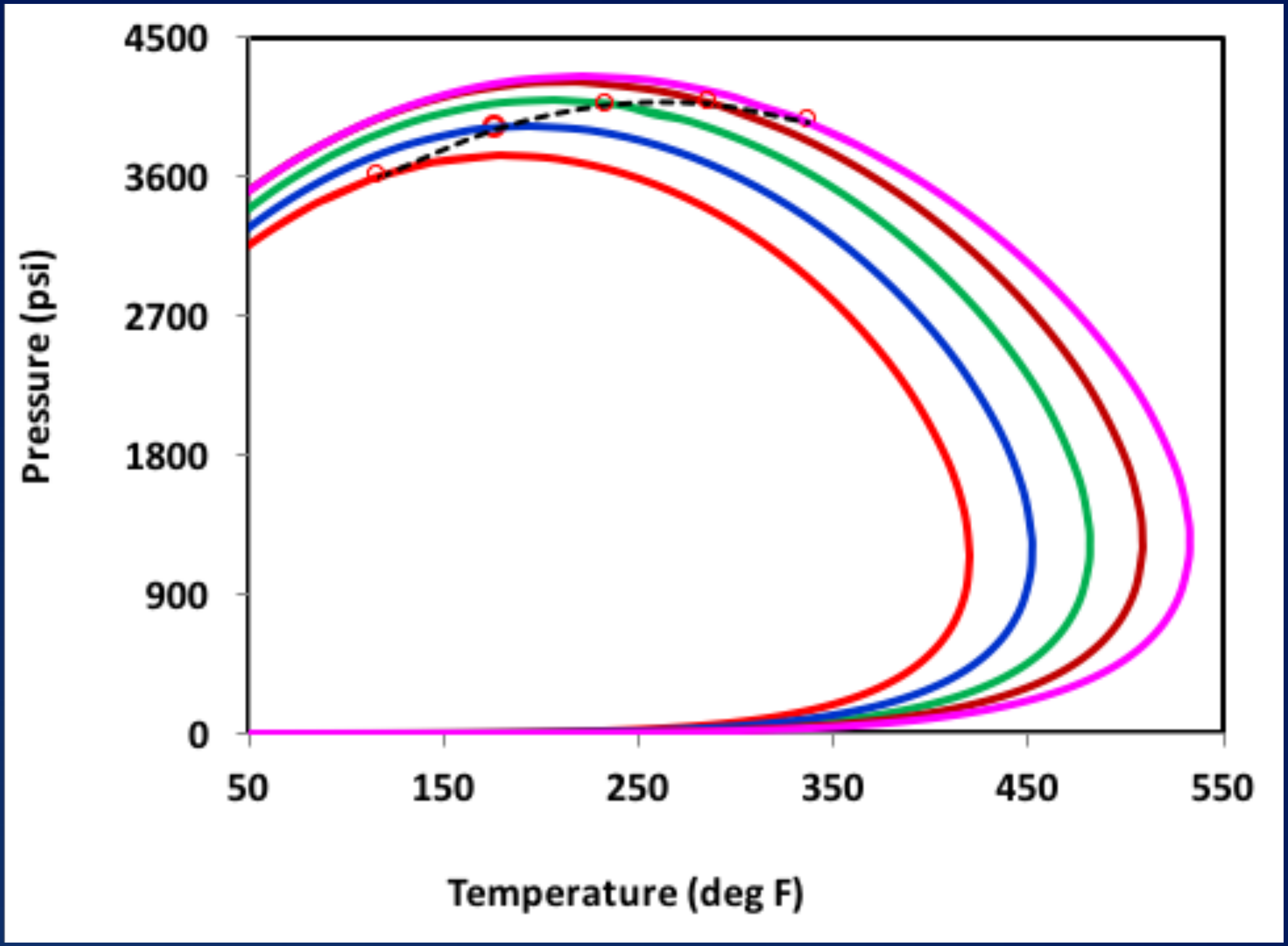


Fluid Compositions



- Lean (Fluid 1) to Rich (Fluid 5)

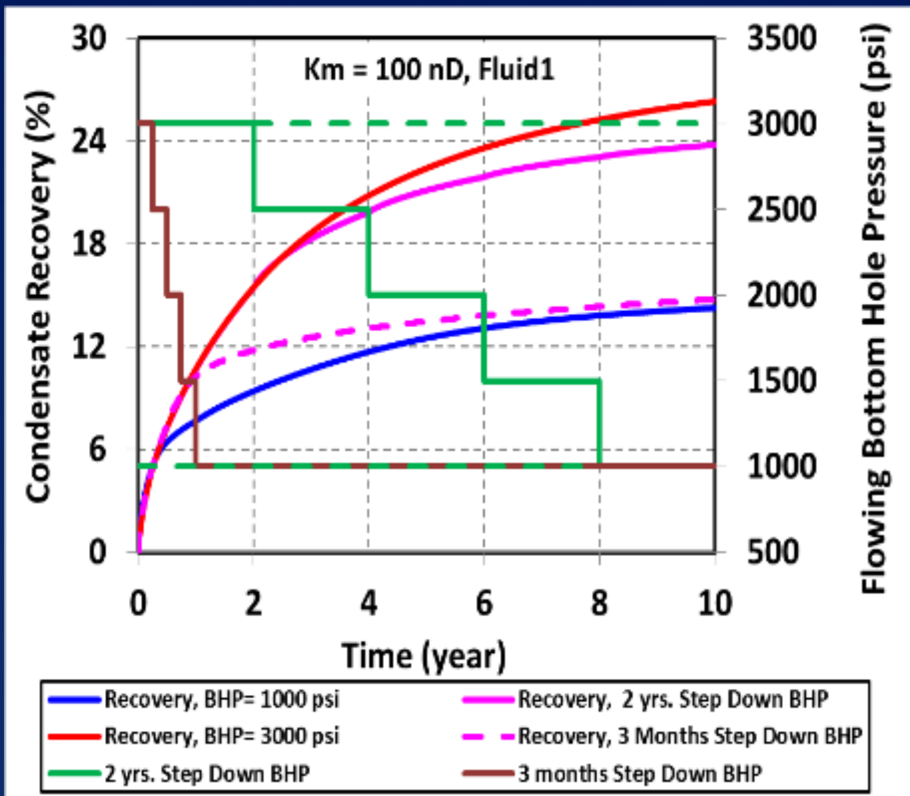
Phase Diagrams

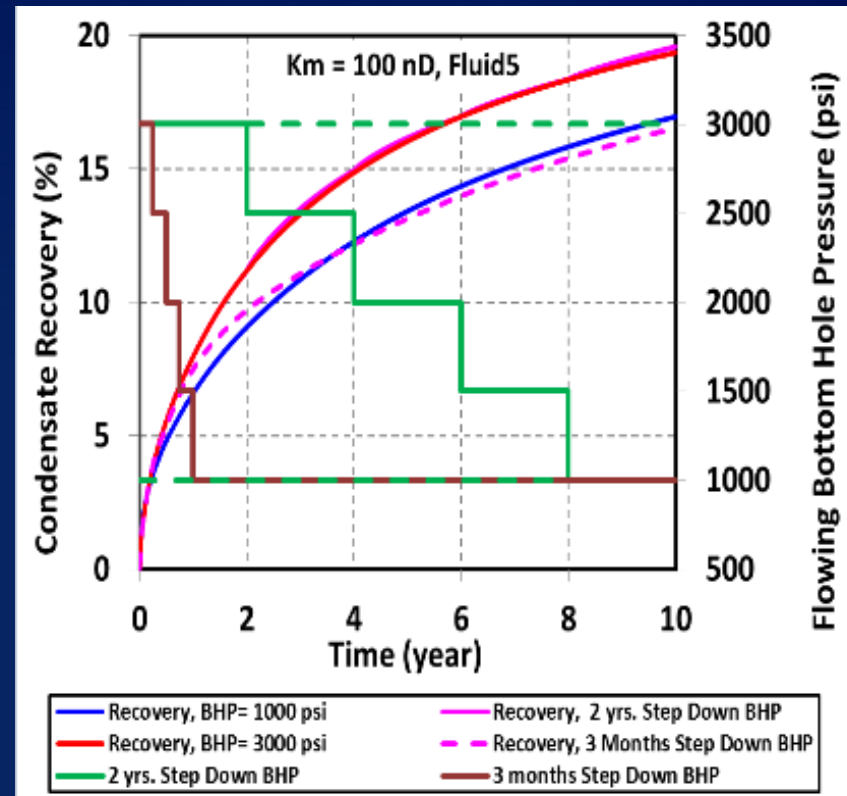


- Right of the critical point: Condensate
- Left of the critical point: volatile oil or oil

Production Optimization for Near-Critical Fluids

Lean → Rich





- Lean Condensate
    - Higher recoveries at higher BHP
    - Two-year step down produces similar behavior
- Rich condensate – choking the well does not make a big difference

Recent Industry Trends

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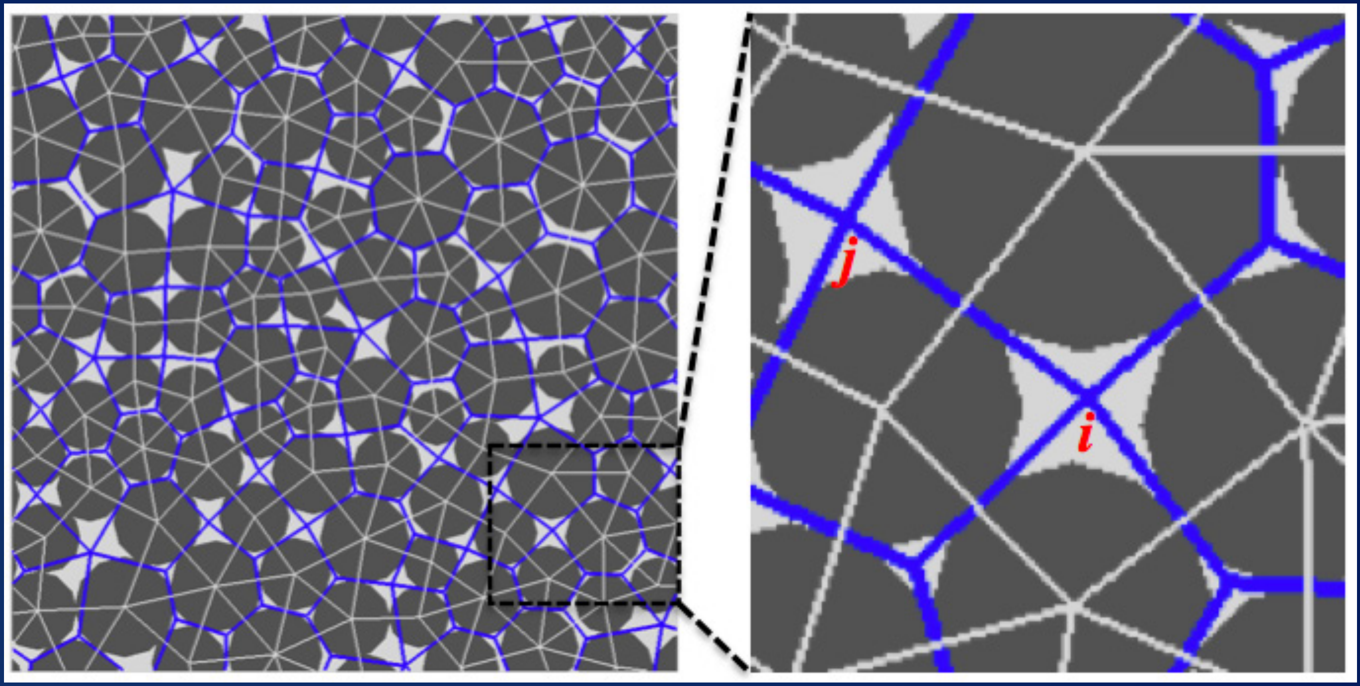
Oil Drillers Bet Choking Wells Will Keep Shale From Going Bust

by Bloomberg | Dan Murtaugh & Rebecca Penty | Friday, October 02, 2015

- Some producers are choking back on wells to improve liquid rates and arrest sharper declines

Geomechanical Considerations

- Analytical and numerical models available
- Discrete Element Model (DEM)
- Guidelines for attaining desired fracture outcomes, given formation characteristics
- Challenges: Field validation through micro-seismic or other means



Dual-grid system

Effect of Stress

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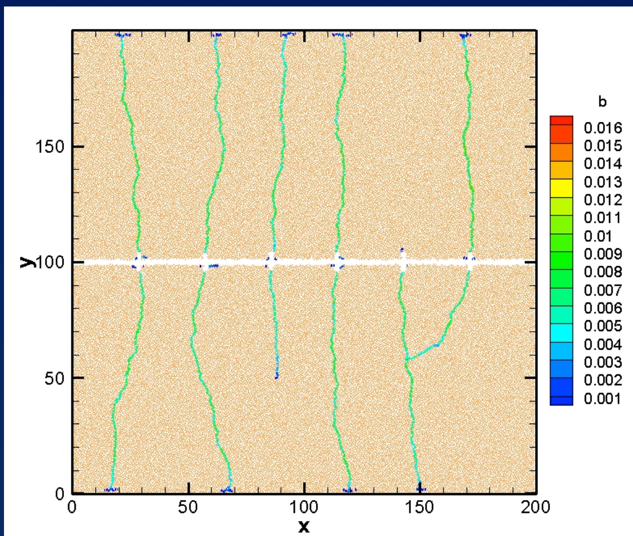
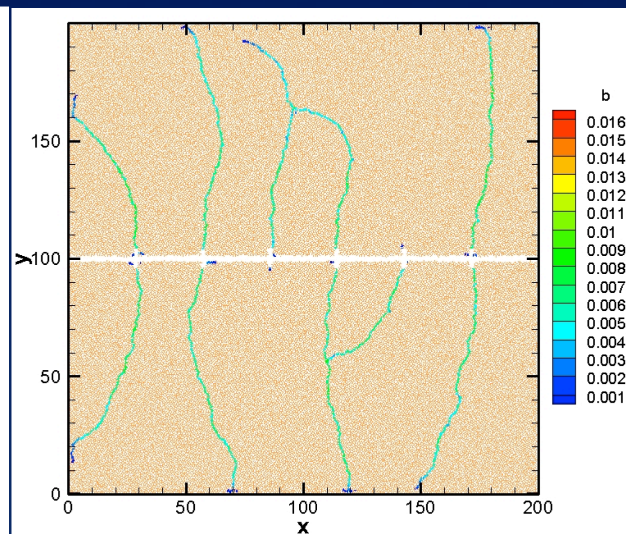


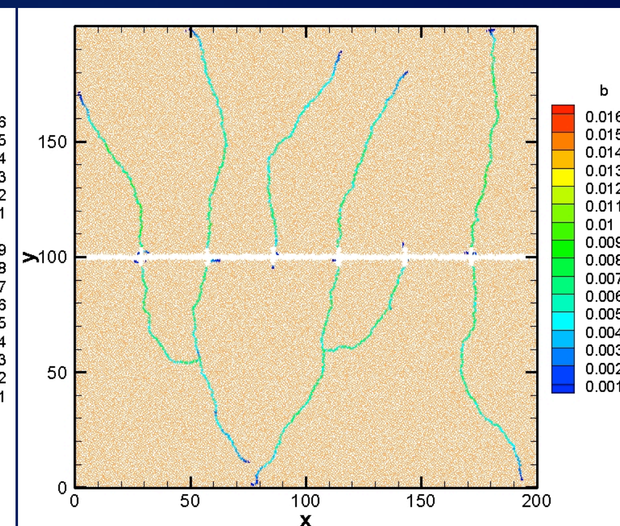
$\sigma_{H,MIN} / \sigma_{H,MAX} = 0.5$

Fractures nominally propagate in one direction – parallel to the maximum stress direction



$\sigma_{H,MIN} / \sigma_{H,MAX} = 0.9$

Due to stress shadowing, some perforations do not initiate fracture.



$\sigma_{H,MIN} / \sigma_{H,MAX} = 0.98$

Fracture propagation impacted by the overprint of additional mechanically induced stress associated with neighboring fractures

Eagle Ford Example

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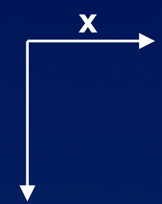
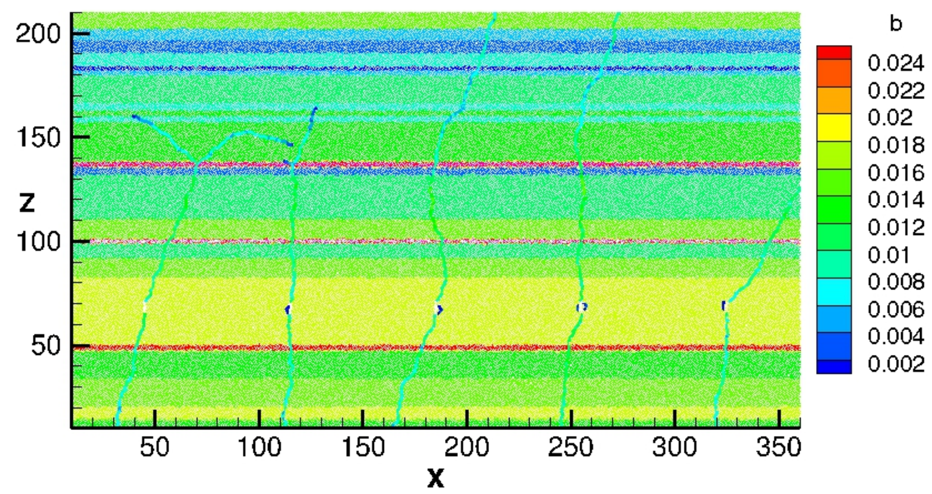
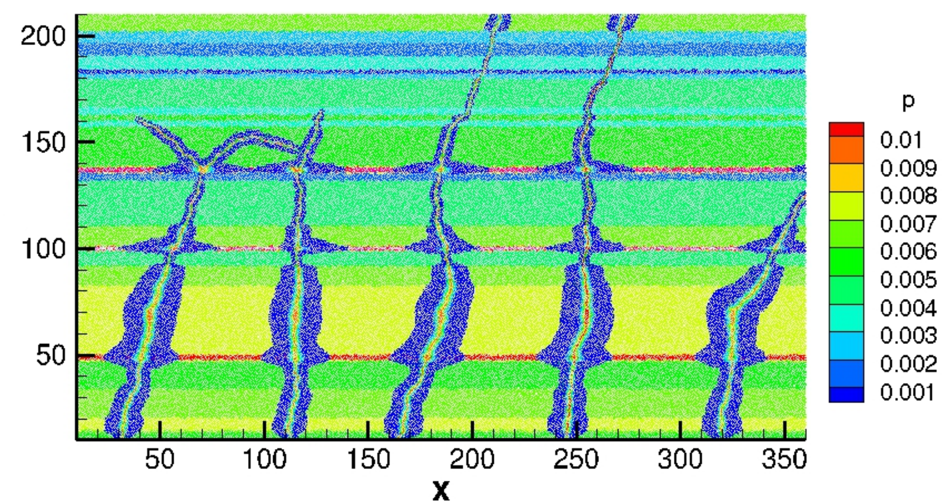


Aperture



Net Pressure



- Incorporation of layering and full heterogeneity
- Decision on where to place the well

Effect of Natural Fractures

Jing Zhou, Hai Huang, John McLennan and Milind Deo, *Hydraulic Fracturing Journal*, Volume 4, Number 2, pp 66-82.

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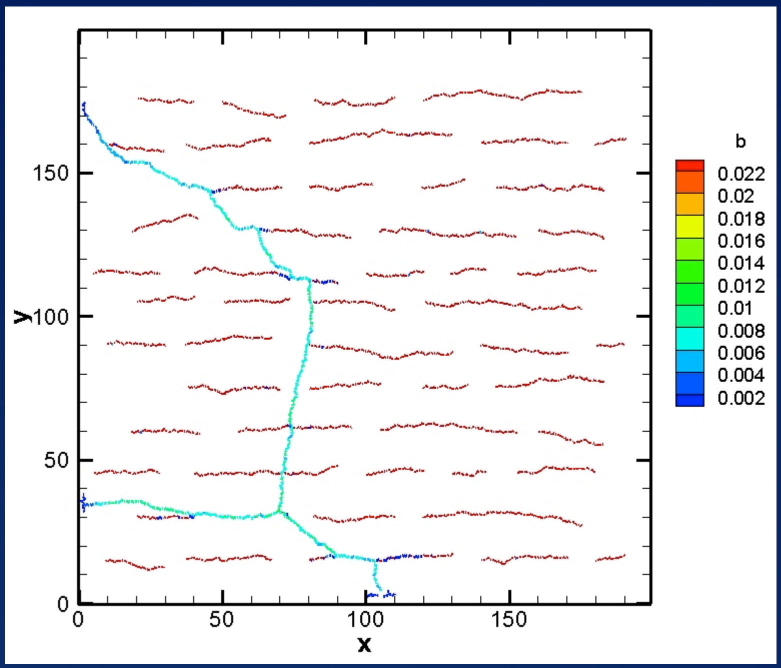
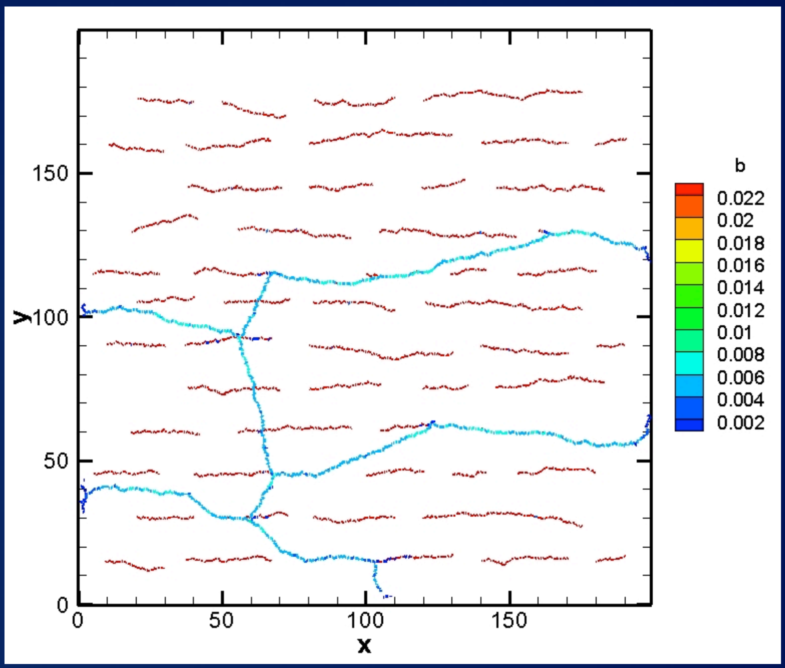
$\sigma_{H,MAX}$

$\sigma_{h,MIN}$

High Viscosity



Low Viscosity



- Through-going fractures with higher viscosity fluids
- Reactivating natural fractures with lower viscosity fluids

Some Geomechanical Guidelines

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Features	Completion Guidelines
Shorter fractures with large apertures	Higher viscosity fluids, high injection rates
Bi-wing fractures in higher permeability formations – clear stress contrast	Higher viscosity, higher rate
Overcome stress shadowing and fracture merging	Use perforation cluster spacing greater than 50 feet
Reactivate fractures in naturally fractured formations	Use lower rate or viscosity – more fluid into the fractures

- Treatment depends on outcomes desired for the fracture morphology

Field-wide Optimization
Workflow to Run Large Multiple Well Models

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1 IDENTIFICATION OF MODEL COMPONENTS

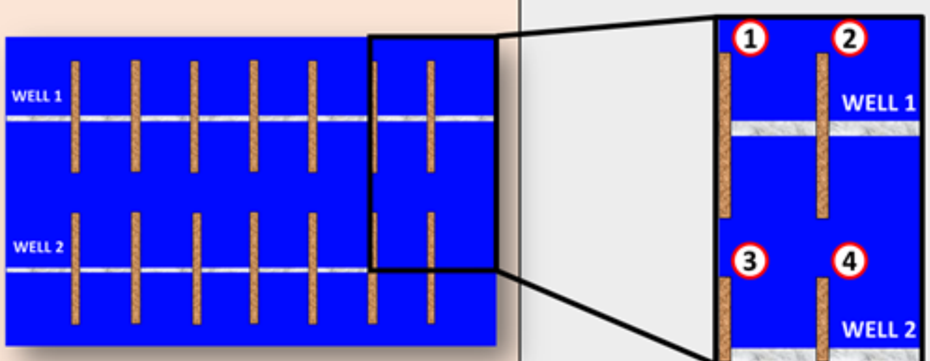
- Boundary conditions
- Interference effects
- Gravity segregation
- Heterogeneity
- Well completions
- Etc.

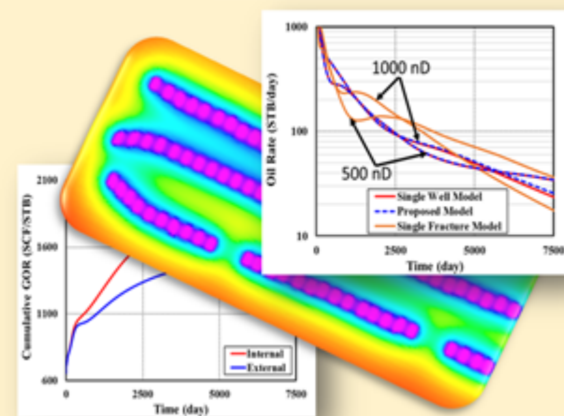
2 SIMPLIFICATION

- Negligible driving forces
- Symmetry
- Representative elements
- Representative medium

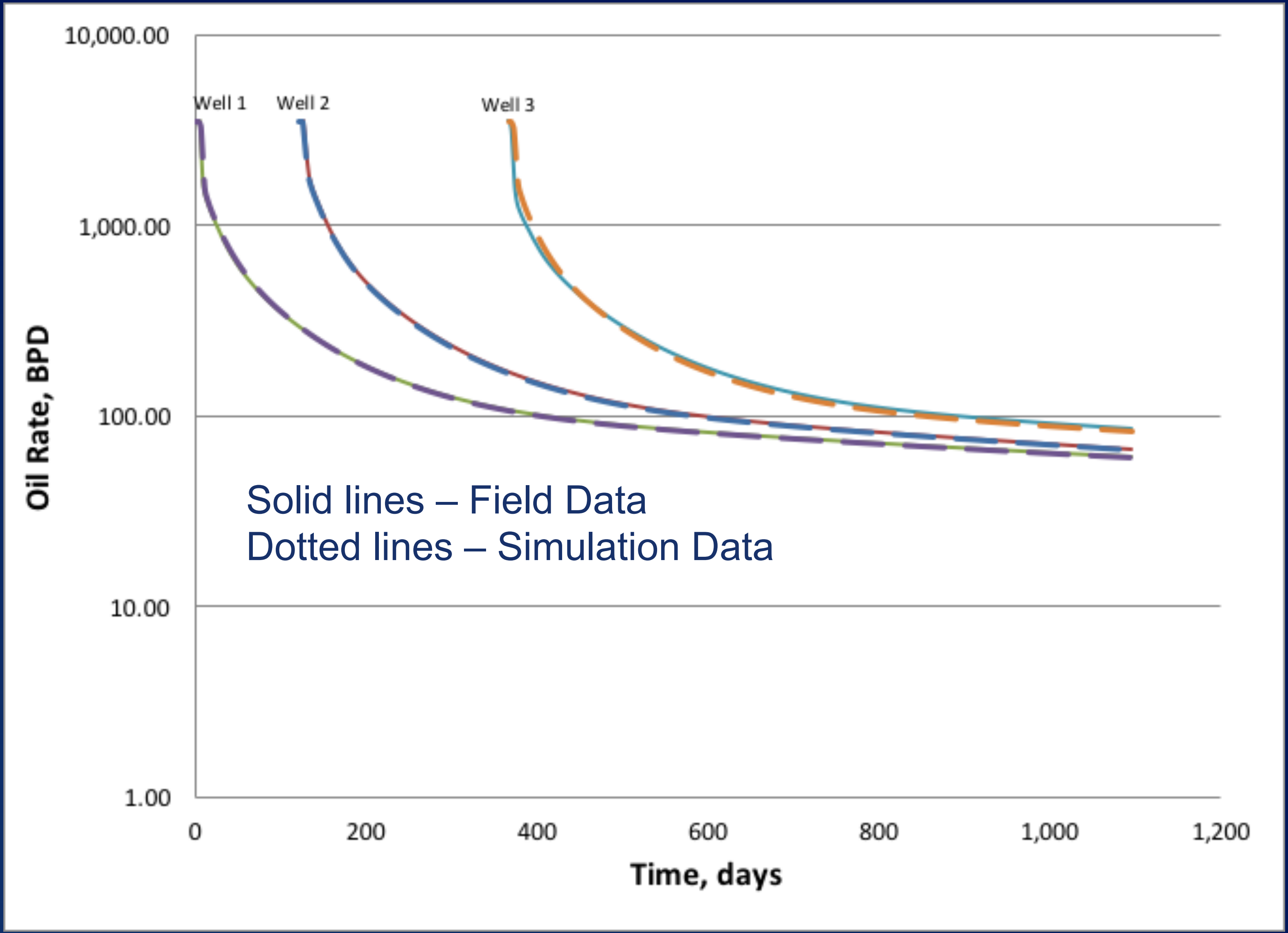
3 POST-PROCESSING

- Symmetric factors
- Multiplier factors
- Number of representative elements
- Conversions
- Average properties





Bakken – Multiwell, Multilayer Model



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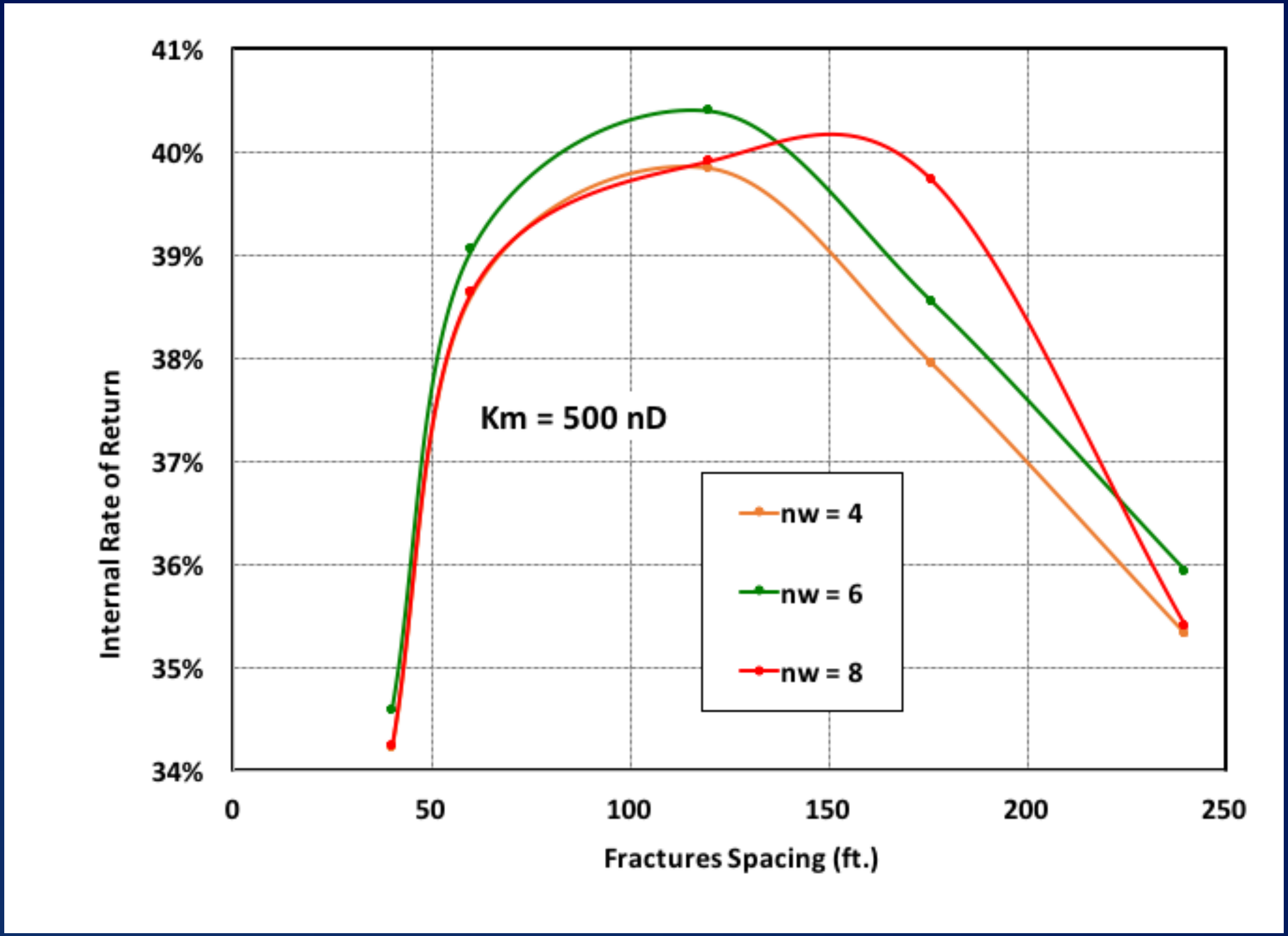
Fracture and Well Spacing Optimization



- Fracture and well spacing (nw) for given geologic conditions

Conclusions

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- Improving liquid recoveries critical for sustaining liquids production from shales: Integrated understanding of reservoir and operational parameters necessary
- Gas-oil ratio signatures for low-permeability, hydraulically fractured reservoirs are different from conventionals and provide understanding of production
- Matrix permeability and fracture spacing emerge as the two top factors that determine fluid recoveries
- Importance of certain parameters – like matrix permeability shift as the flow transitions to boundary dominated

Conclusions

- Holding higher producing bottom hole pressures leads to higher recoveries and often to higher liquid rates for near-critical fluids
- Possible to represent most liquids data in North America on a single curve
- Geomechanical models may be used to guide creation of desired fracture morphology given reservoir properties
- It is possible to use a simplified simulation workflow to accurately represent multi-fracture, multi-well cases and perform fracture and well spacing optimization

Acknowledgements

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- Dr. Palash Panja, EGI, University of Utah
- Dr. Raul Velasco, Chemical Eng., Univ. of Utah
- Dr. Jing Zhou, Idaho National Laboratory
- Dr. Hai Huang, Idaho National Laboratory
- Dr. John McLennan, University of Utah
- Dr. Raymond Levey, EGI, University of Utah

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