Finding Sweet Spots in Shale Liquids and Gas Plays:
(with Lessons from the Eagle Ford Shale)*

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Search and Discovery Article #41093 (2012/2013)**
Posted December 10, 2012, May 13, 2013

*Adapted from oral presentations by the author at AAPG Geoscience Technology Workshop at AAPG Geoscience Technology Workshop, The Eagle Ford and Adjacent Formations: Integrated Technologies, New Potential, March 18-20, 2013, San Antonio, TX, and Tulsa Geological Society luncheon meeting, November 13, 2012, Tulsa, OK.
Editor's note: This article is also an adaptation from an earlier presentation at AAPG ACE, April 22-25, 2012, on the general subject by the author. Adaptation of the earlier presentation, entitled "Sweet Spots in Shale Gas and Liquids Plays: Prediction of Fluid Composition and Reservoir Pressure" is Search and Discovery Article #40936 (2012) (http://www.searchanddiscovery.com/documents/2012/40936cander/ndx_cander.pdf).

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Abstract

This article discusses the importance of understanding petroleum composition (Gas-Oil ratio and viscosity) and reservoir pressure in order to find sweet spots in shale liquids plays. This study also demonstrates the importance of understanding post-burial uplift in shale plays. Although most companies focus on finding the right rock (using TOC, thickness, brittleness, etc.) the properties of reservoir fluids and pressure are at least as important as properties of the rock for defining the most valuable parts of a shale fairway. This study shows that the sweet spot (i.e., the most profitable part) of the Eagle Ford Shale is found where the least viscous liquid phase and the most oil-rich vapor phase occur at highest reservoir pressure.

For this study, in-house source-rock kinetic models were coupled with regional basin modeling in the Eagle Ford Shale fairway to delineate the sweet spot. This work involved the prediction of petroleum compositions and evaluation of the effect of petroleum generation on pore pressure. Maps of thermal stress were converted to maps of gas-oil ratio, viscosity, and BTU content to predict mobility of shale liquids and flow of revenue from wells across the fairway. The results of this study indicate that petroleum compositions in the Eagle Ford Shale are closer to an instantaneous product over a narrow thermal stress range rather than a cumulative product from expulsion and migration over a broad range of thermal stress. The petroleum is in near equilibrium with the thermal stress state of the rock, and most petroleum was generated in situ and retained as the last generated product with limited lateral migration. Fluid viscosities are closely linked to composition (GOR) and are, therefore, predictable. Thus, although the Eagle Ford expelled large volumes of petroleum and this petroleum migrated out of the formation, the petroleum that we produce from the Eagle Ford was generated in situ and is not the result of lateral migration.

Mobility of shale liquids and, thus, revenue flow are also strongly a function of reservoir pressure. The reservoir pressure we see in the Eagle Ford today is the result of how the pressure was created and how it was preserved after burial. Several authors have proposed that most of the over-pressure in shale source rocks was created by petroleum generation. Basin modeling performed in this study suggests that petroleum generation can account for some of the over-pressure within the Eagle Ford Shale gas and liquids fairway (as measured in psi above hydrostatic). However, much of the regional over-pressure was generated from disequilibrium compaction during rapid Late Cretaceous through Paleogene burial. Late exhumation altered shale reservoir pore pressure in the western half of the Eagle Ford fairway. The central part of the Eagle Ford fairway had comparatively less uplift. As a result, the amount of over-pressure in the western part of the fairway is not directly linked to thermal maturity and GOR. Fluids with higher Gas-Oil ratio occur at relatively lower reservoir pressure in the west compared to the central part of the fairway. Therefore, whereas retained petroleum properties can be linked closely to thermal stress, creation and retention of over-pressure is not strictly due to petroleum generation and a broader, basin-scale interpretation is required in order to define regions where revenue generation will be highest. Because it is often the foreland phase of rapid subsidence and burial that catalyzes both disequilibrium compaction and source-rock maturation, the generation of petroleum and over-pressure are often coeval, and their effects on reservoir pressure, effective stress, permeability, and reservoir deliverability can be difficult to differentiate. Lastly, it can be shown that there is a strong inverse link between uplift and over-pressure. North American onshore basins that have experienced large amounts of uplift and erosion are often normally pressured. Basins that have experienced minor amounts of uplift and erosion have retained high over-pressure.

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Finding Sweet Spots in Shale Liquids and Gas Plays

Harris Cander

What is this talk about?

- Identify sweet spots with very little data
- Sweet spot = Highest IRR
- Greatest mobility of most valuable fluid
- *Mobility* of fluids in tight rock
  - Fluid viscosity
  - Reservoir pressure

Petroleum & GOR

- **Petroleum is a mixture of gas and oil**
- **Gas C1 – C5**
- **Oil C6+**
- **Gas-Oil Ratio (GOR)**
  - **Ratio of C1-C5 to C6+ scf/bbl**

GOR: Gas Oil Ratio scf/bbl

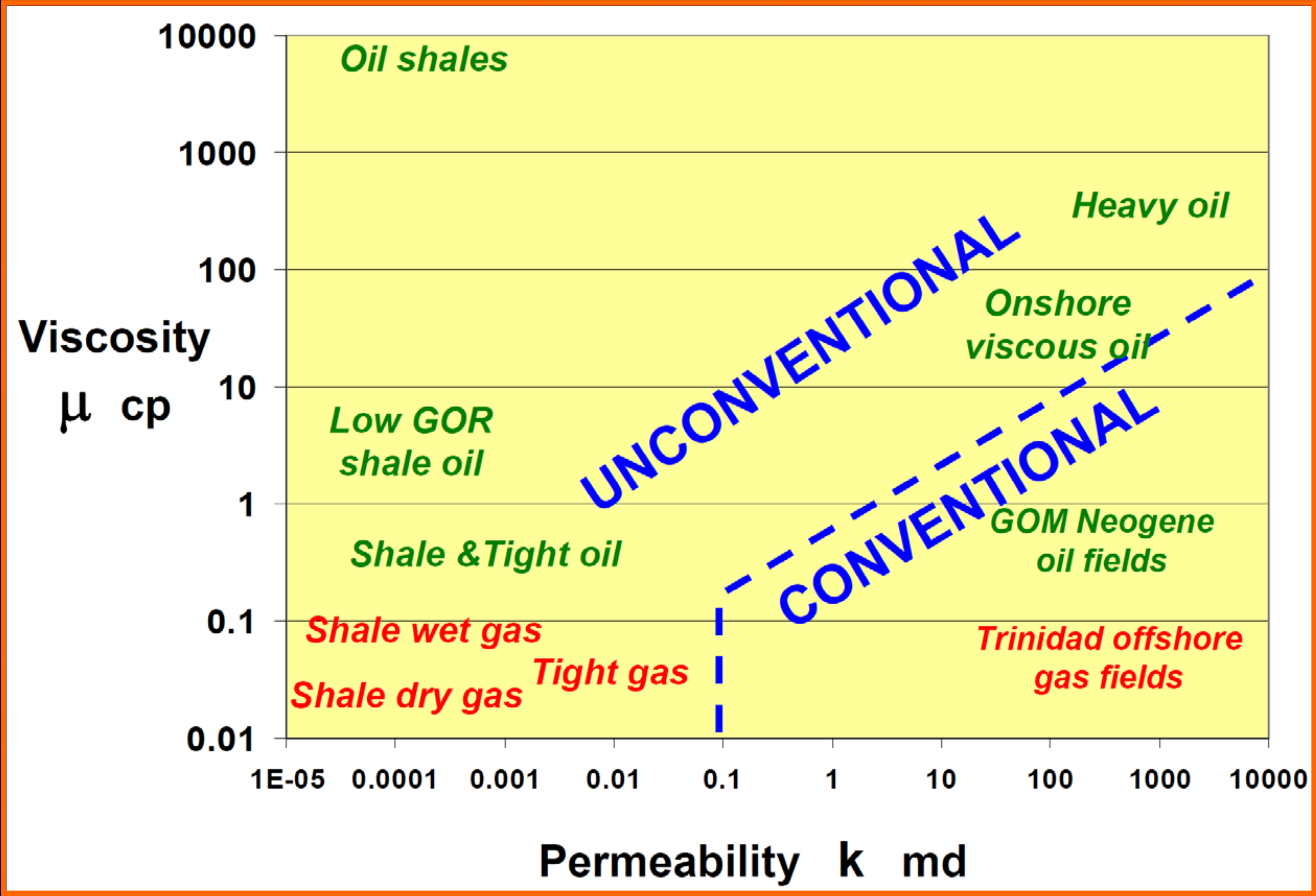
High viscosity Oil	< 200
Black oil	200 - 1000
Volatile oil	1000 - 3200
Wet Gas / Condensate	3200 – 15,000
Wet Gas	15,000 – 70,000
Dry Gas	> 70,000

Phase

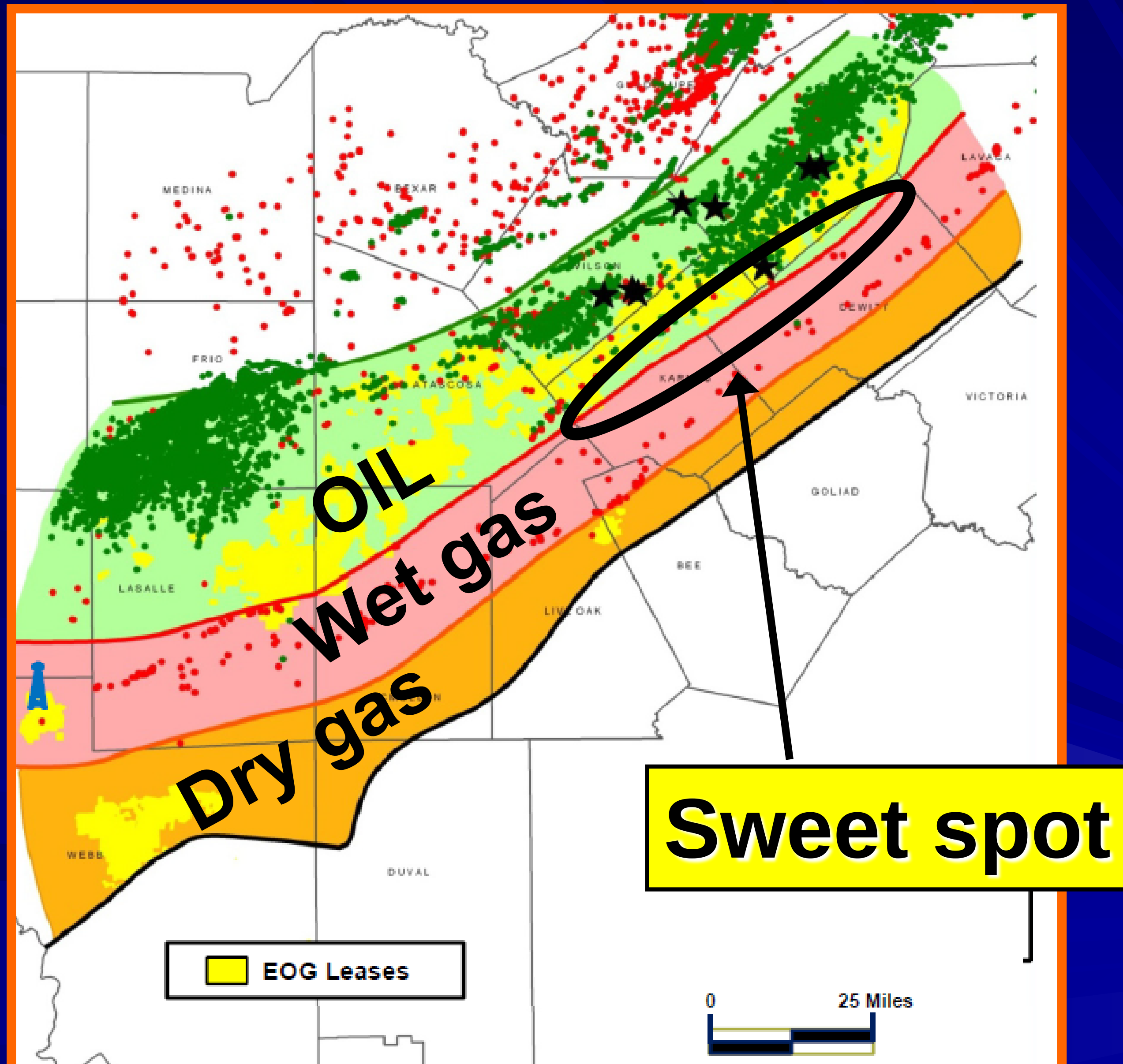
- Liquid < 3200 GOR
- Vapor > 3200 GOR
- Liquid can contain a lot of C1-5
- Vapor can contain a lot of C6+

What are "unconventionals" ?

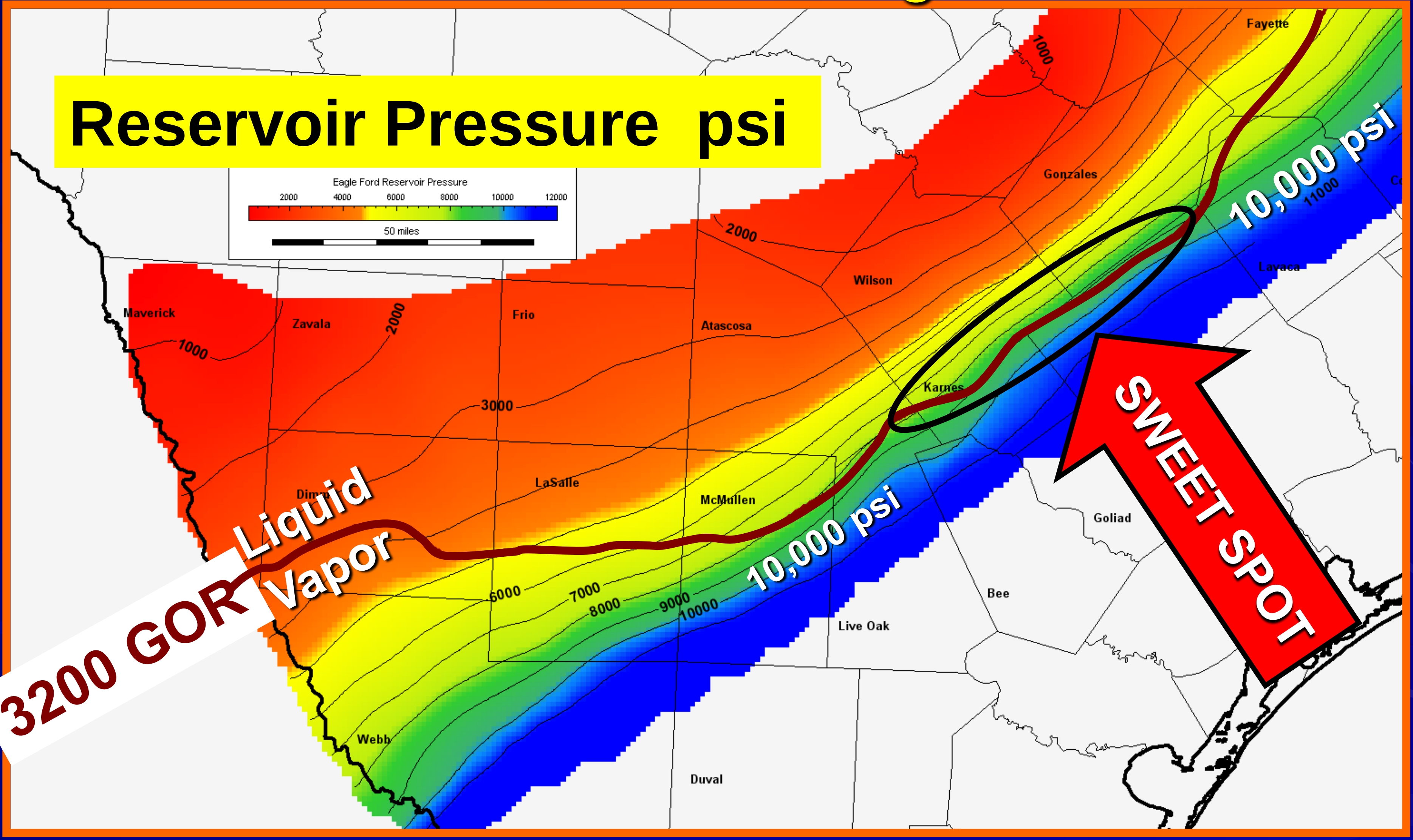
Cander, H., 2012, AAPG Search and Discovery # 80217



Eagle Ford Fluid Fairways

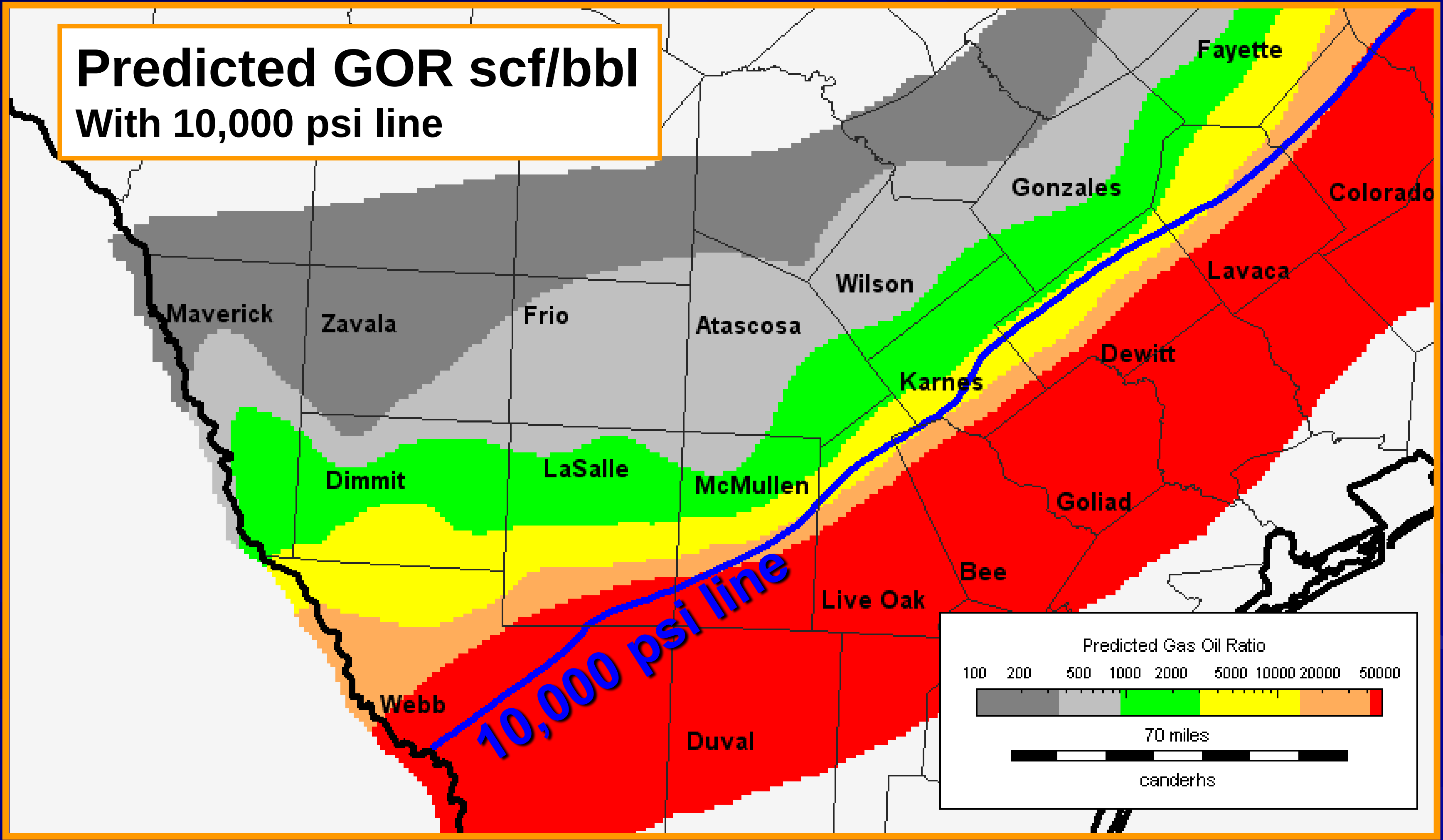


Eagle Ford liquids sweet spot
Intersection of GOR and High Pressure



Liquids Sweet Spot

Least viscous liquid phase at highest pressure
Most liquids-rich vapor phase at highest pressure



“Unconventional” but still obey principles

$$Q = \frac{k * H * DP}{m}$$

Q = well flow rate

k = permeability

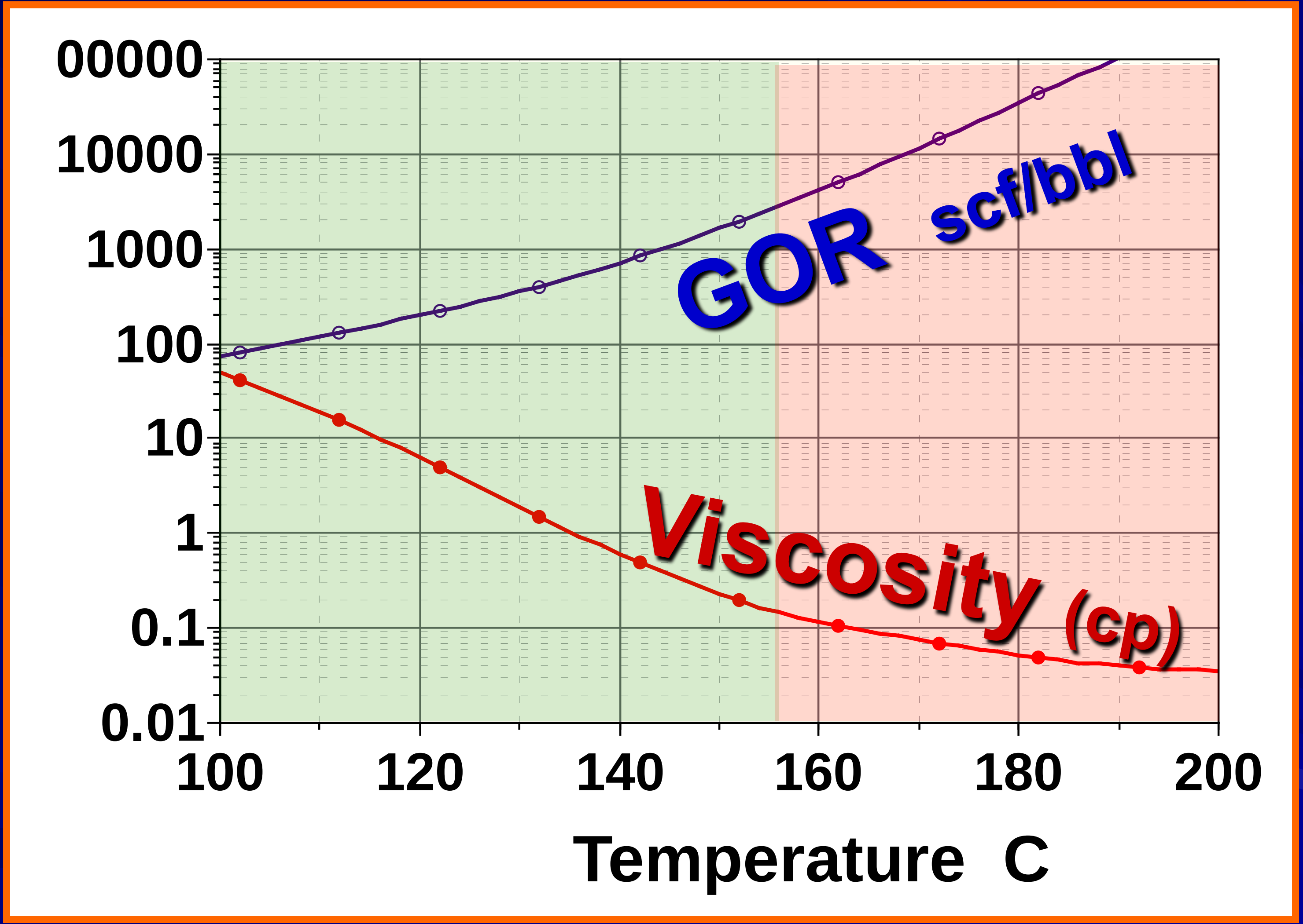
H = thickness

DP = Reservoir Pressure – wellbore pressure

m = viscosity

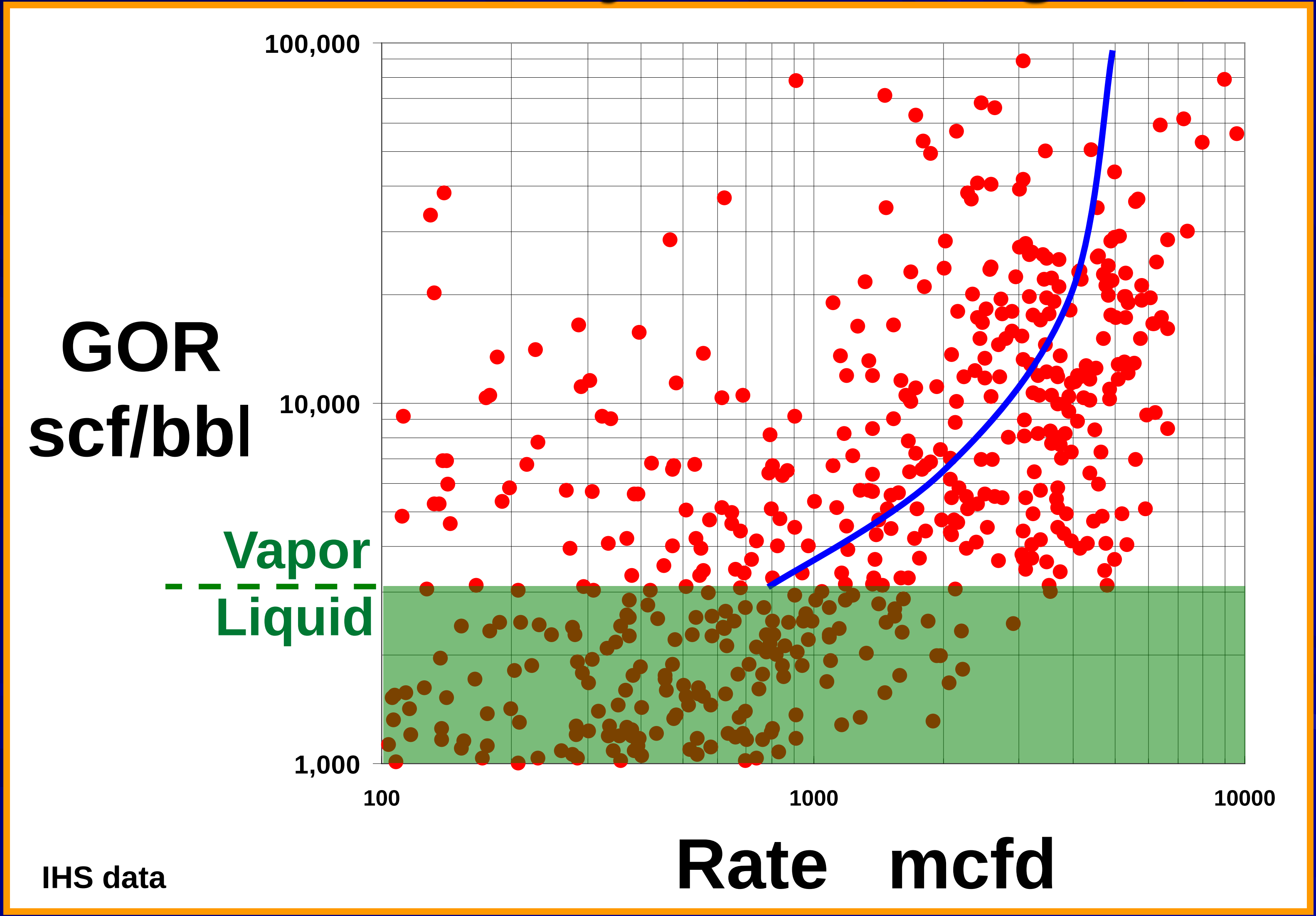
P and m change a lot in a typical shale fairway!

Maturity vs. GOR & Viscosity

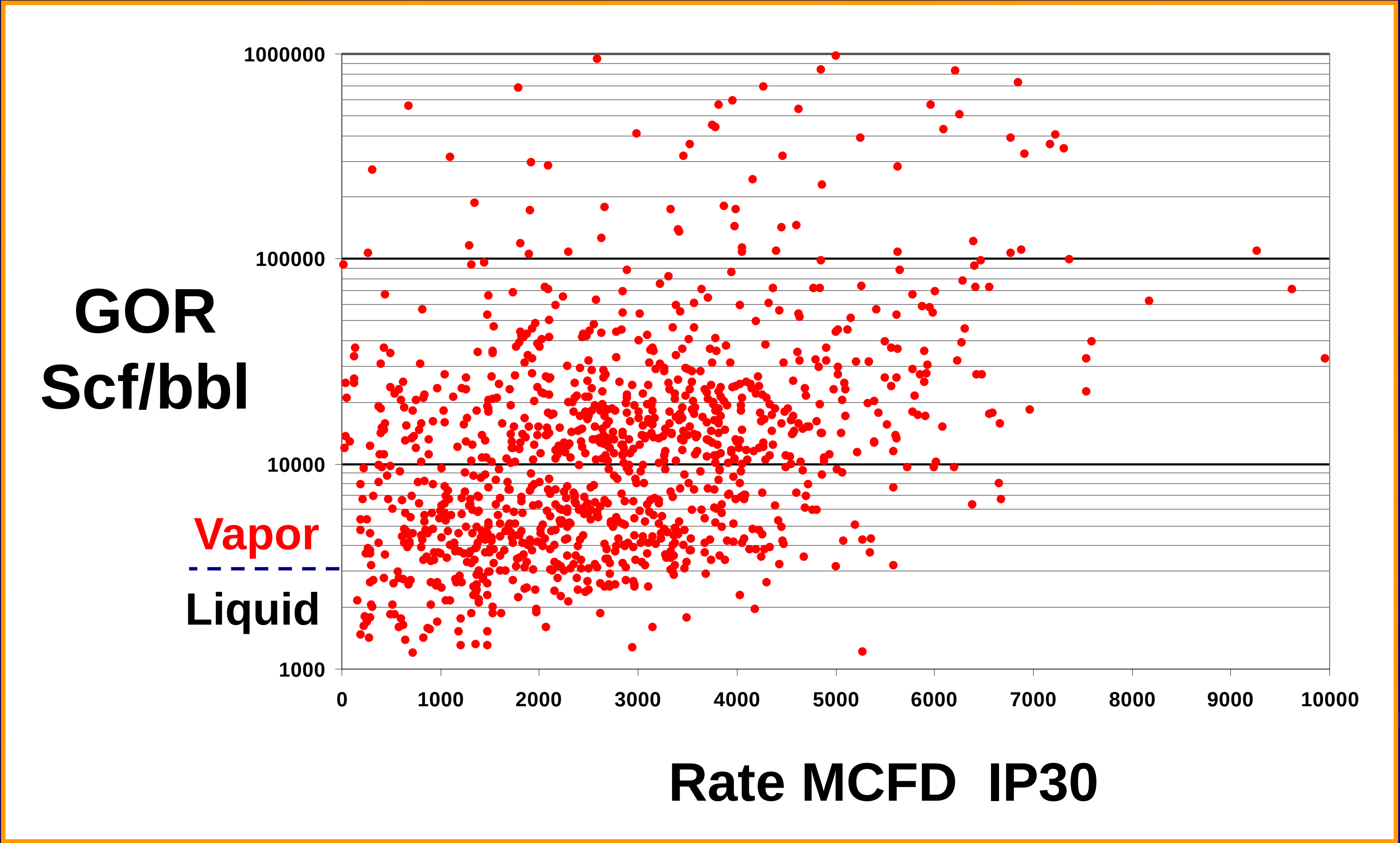


Eagle Ford Gas Rate

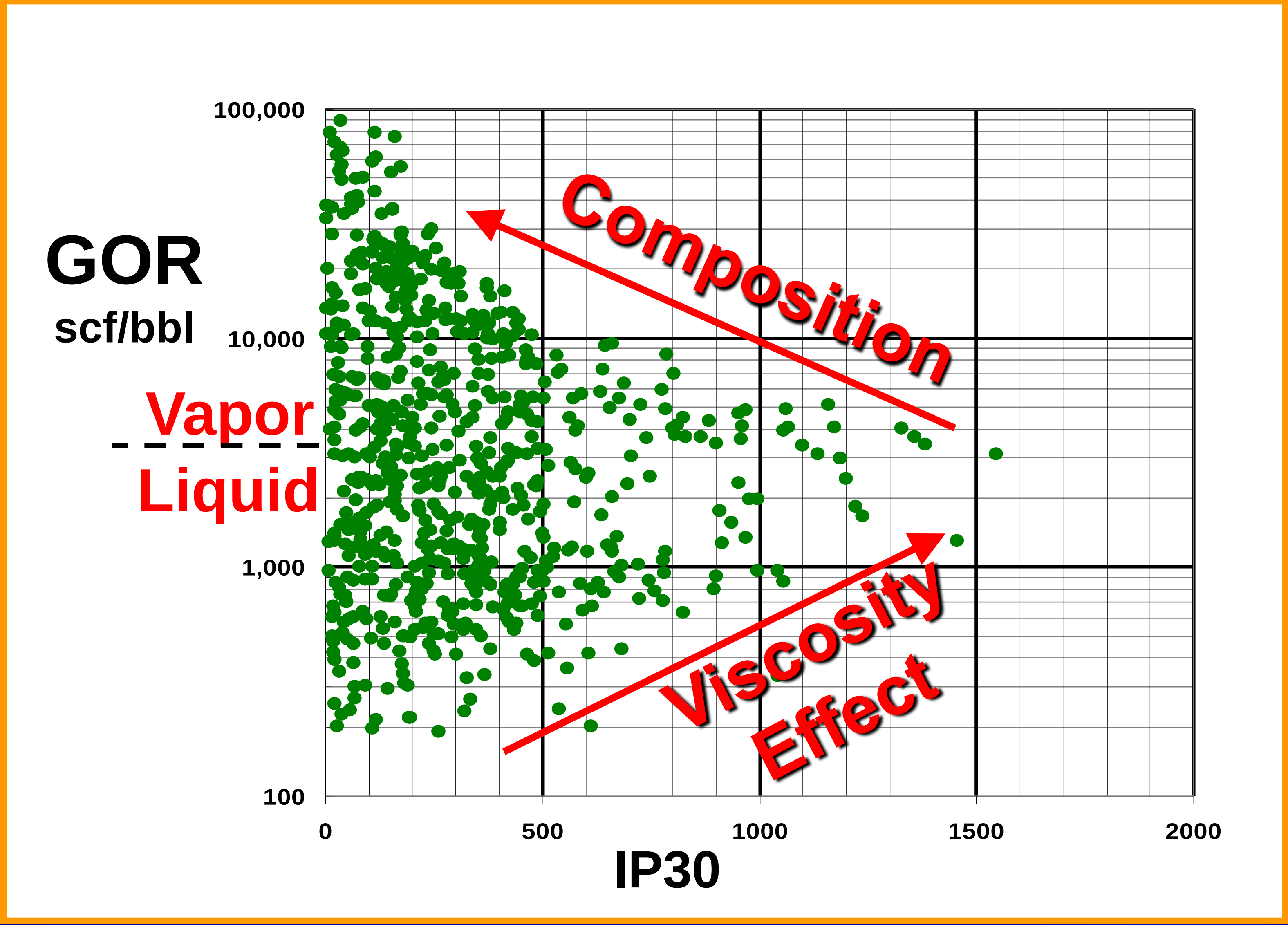
Influence of viscosity – even in "gas"



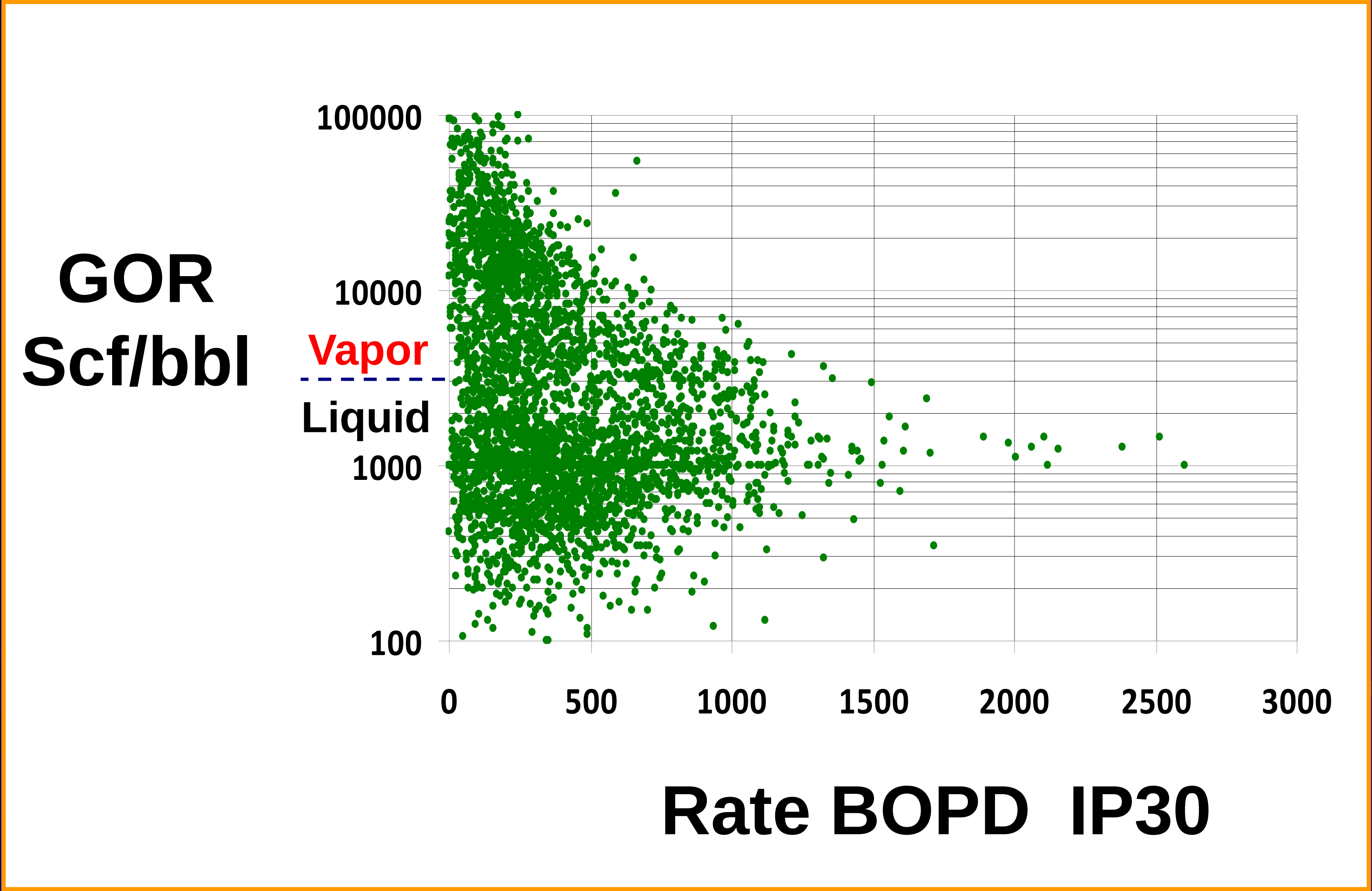
IP30 MCFD vs. GOR



Liquids Rate (IP30 BOPD) vs. GOR Data from mid-2011

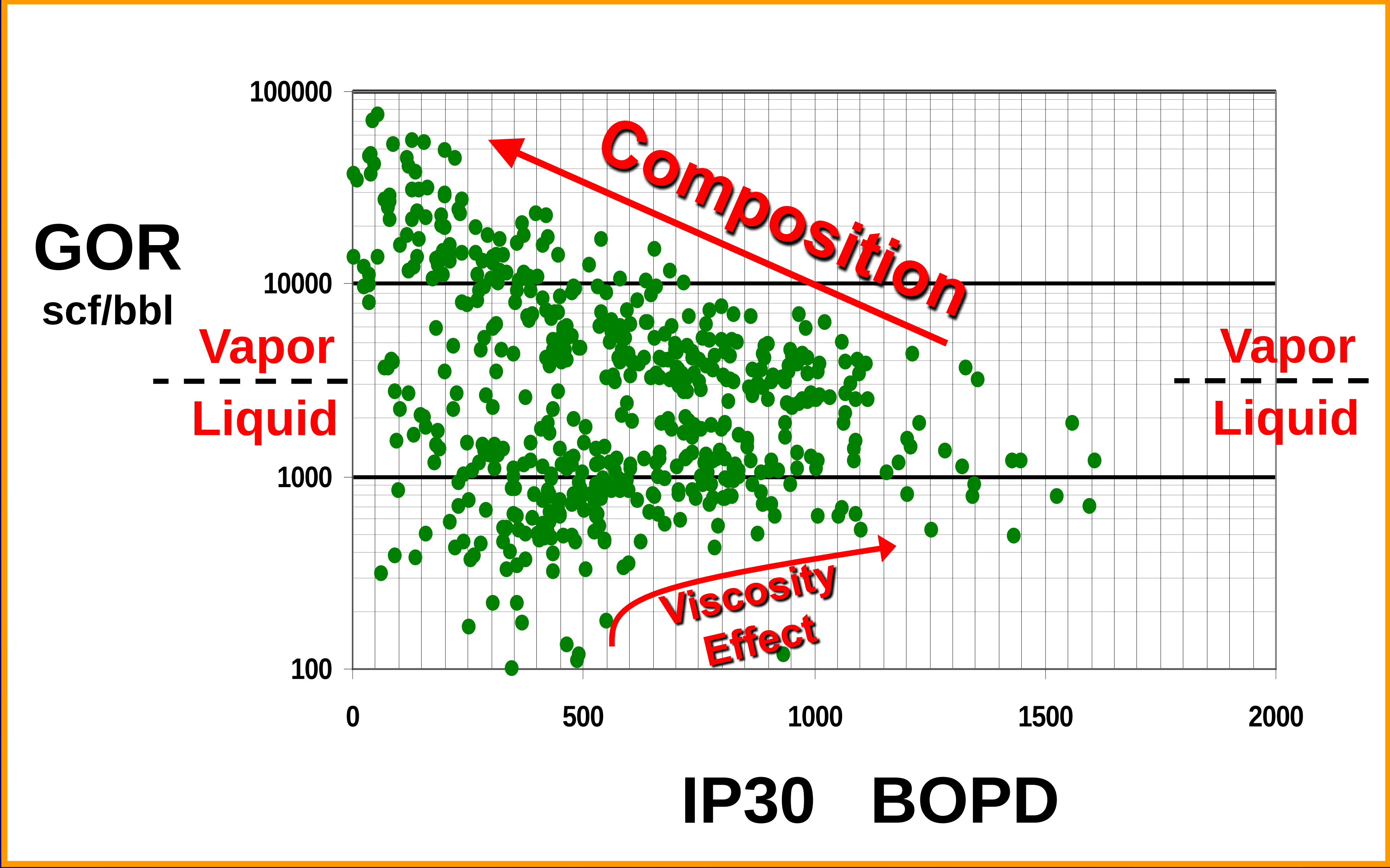


IP30 BOPD vs. GOR



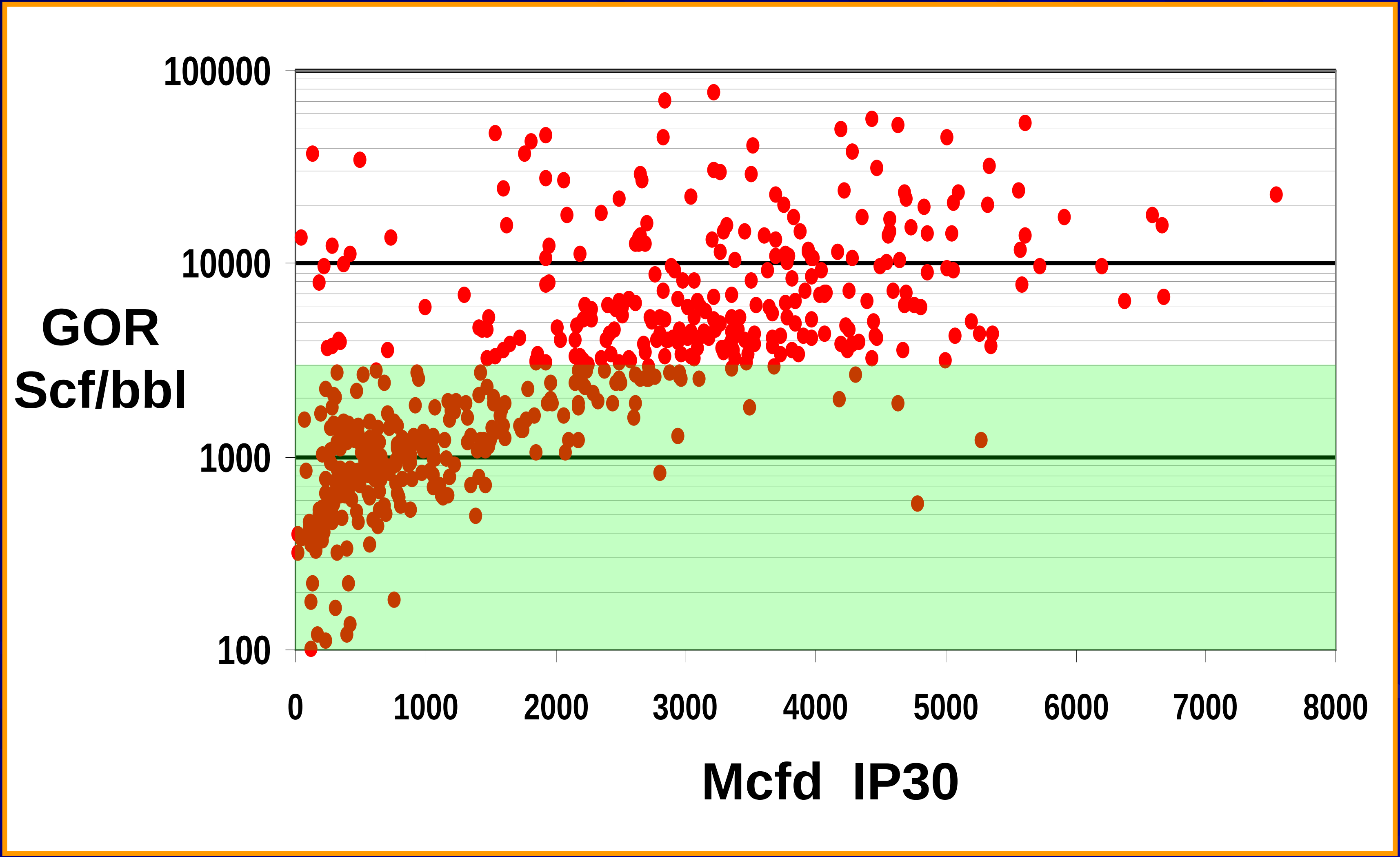
Oil Rate (IP30 BOPD) vs. GOR

Karnes, DeWitt, Wilson, Gonzales Counties in 2012



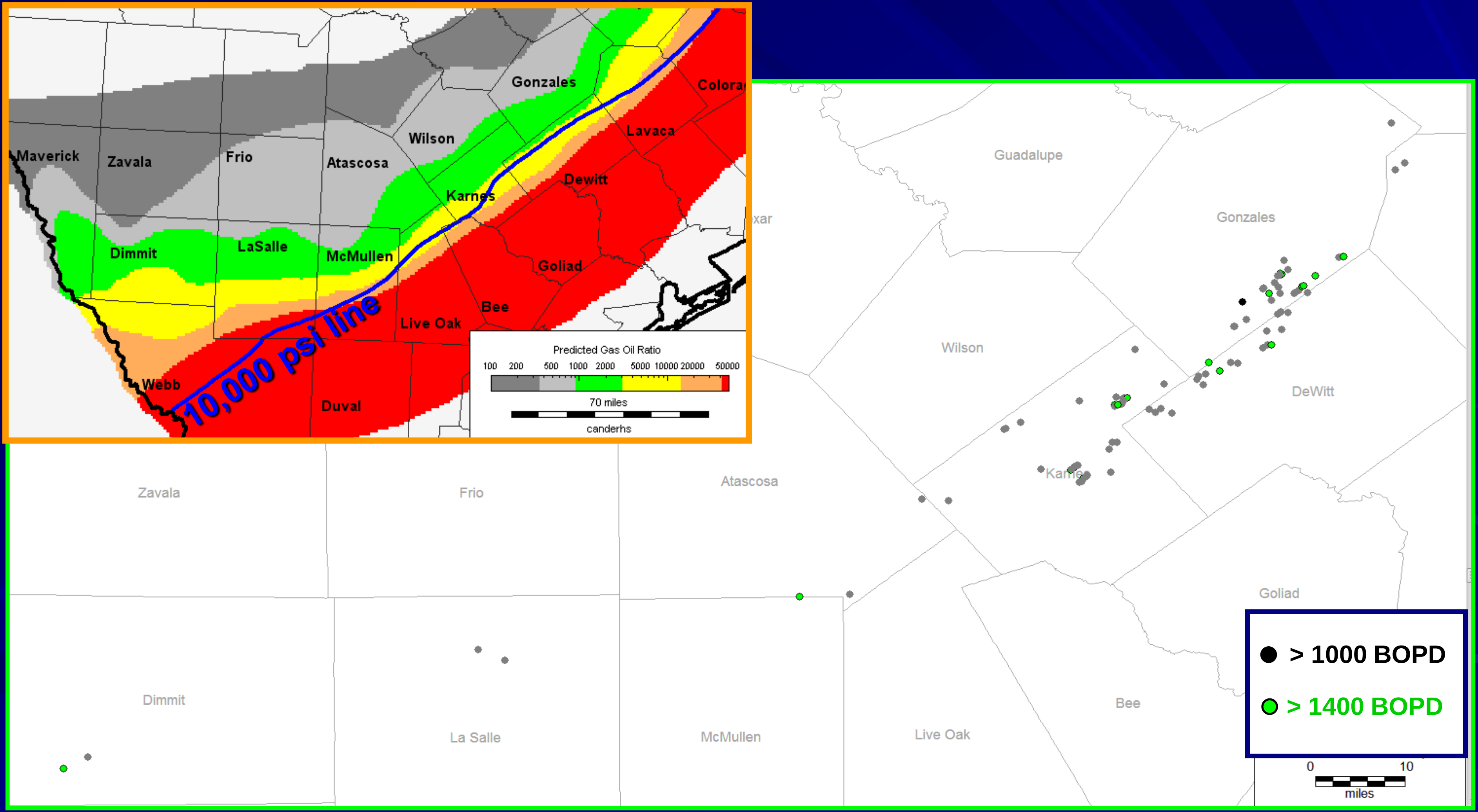
IP30 max Gas vs. GOR

Karnes, DeWitt, Gonzales, Wilson (about 1400 wells)

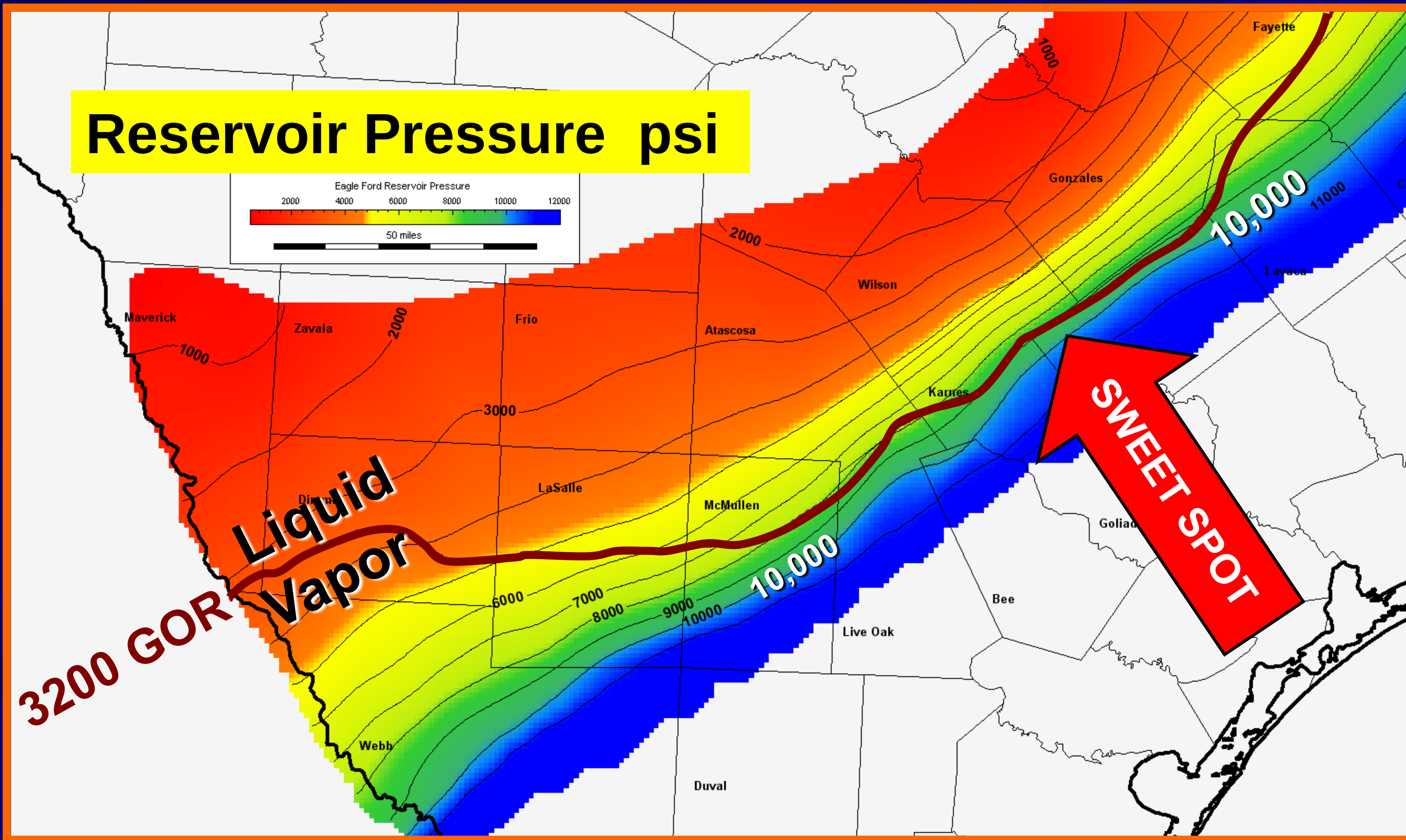


"Oil" Wells with > 1000 BOPD IP30

Area where 1000 – 3000 GOR occurs at highest pressure

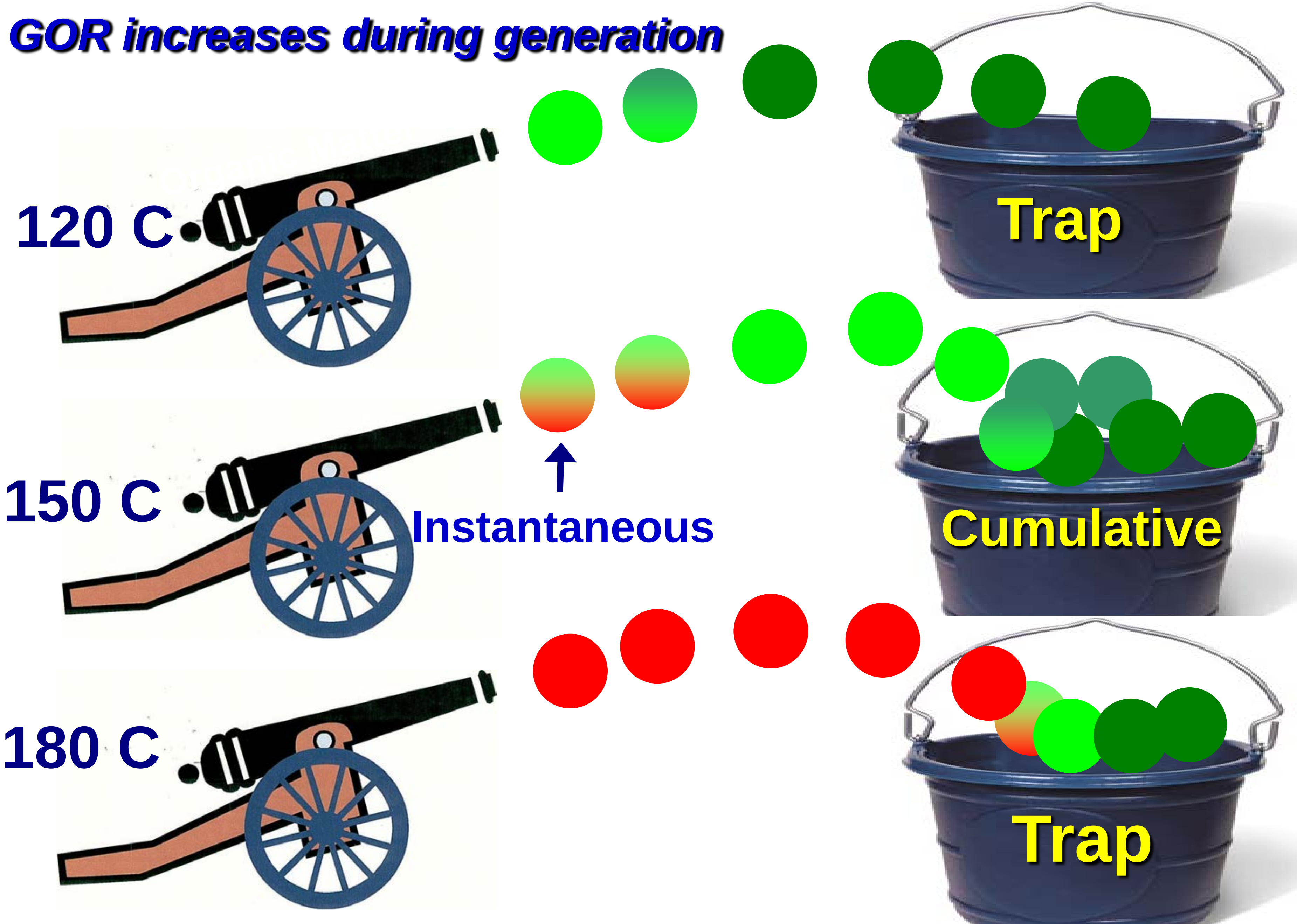


Eagle Ford liquids sweet spot
How to predict composition and pressure?



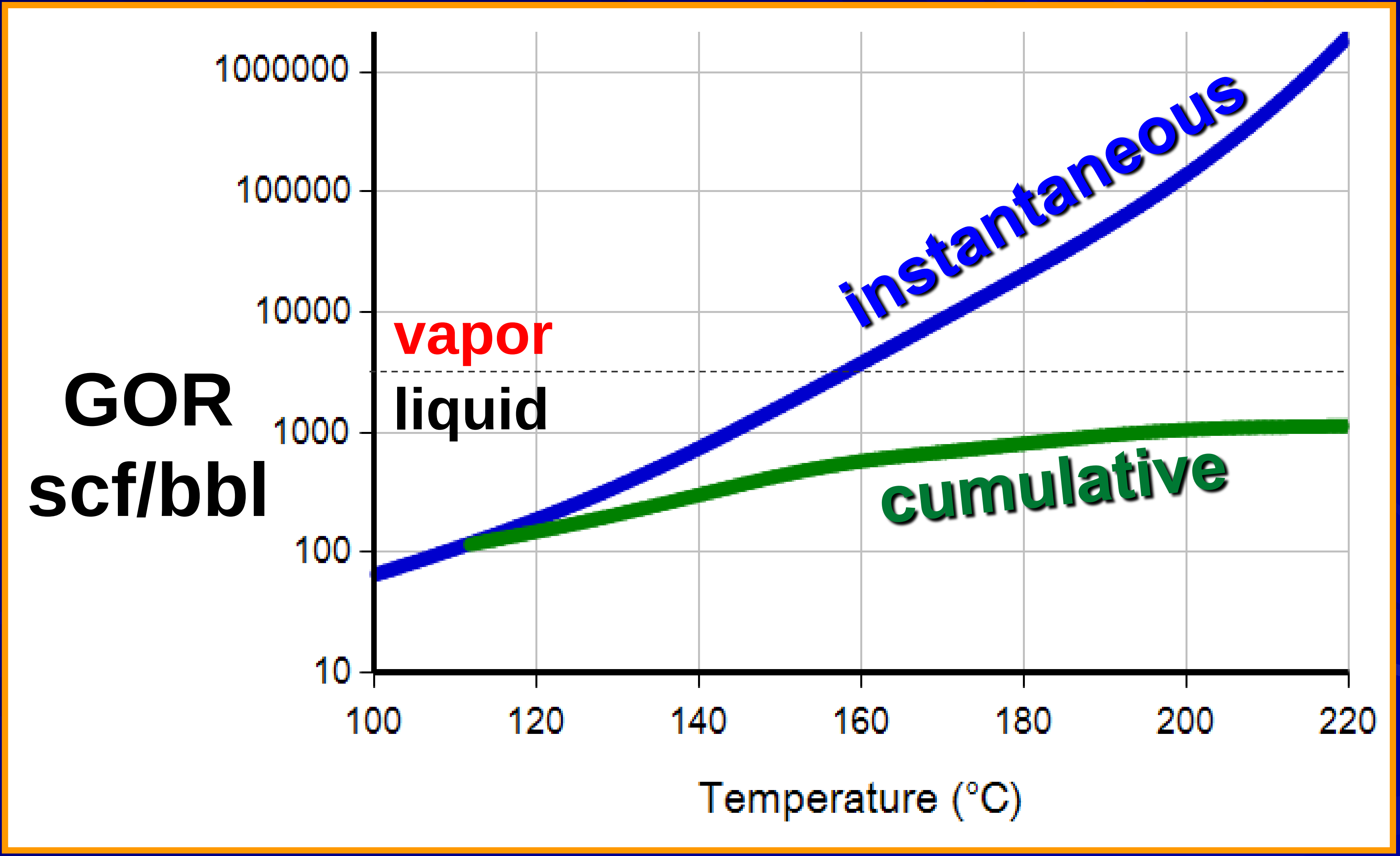
Instantaneous vs. Cumulative

GOR increases during generation



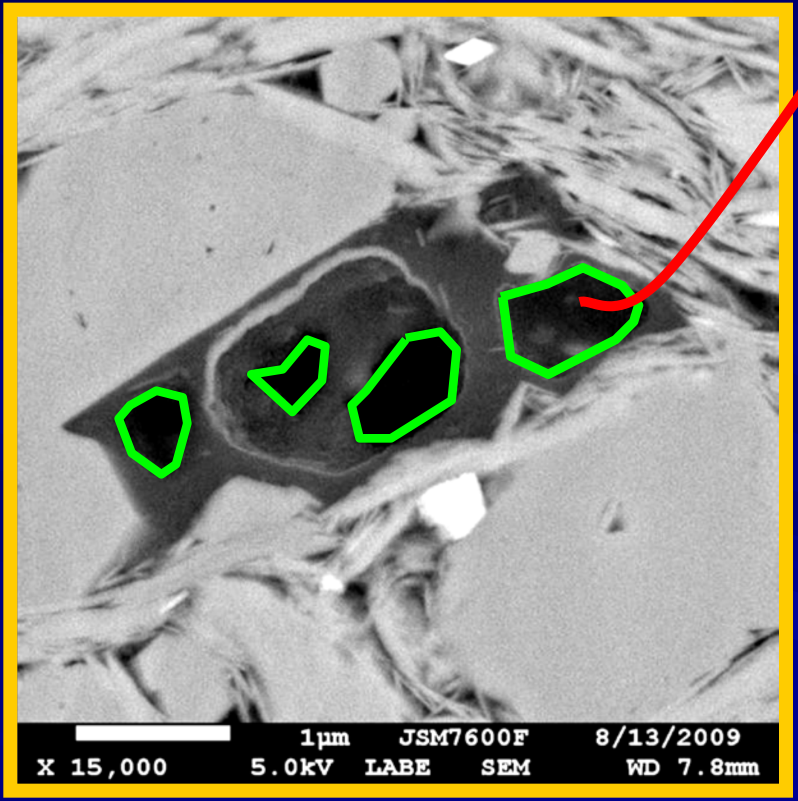
Instantaneous vs. Cumulative GOR

"Western" Eagle Ford organofacies



Previous kinetic model

Reach "sorption" threshold of kerogen and then "expulsion"



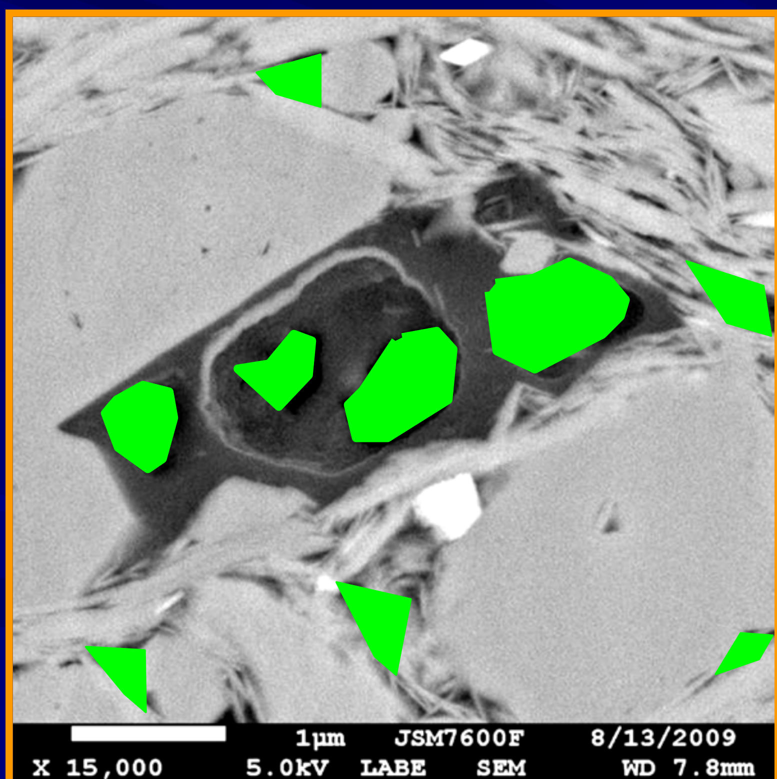
<u>Problem</u>

Source rocks <u>retain more</u> petroleum than previously thought

<u>Expel less</u> than previously thought

Updated BP Kinetic Model

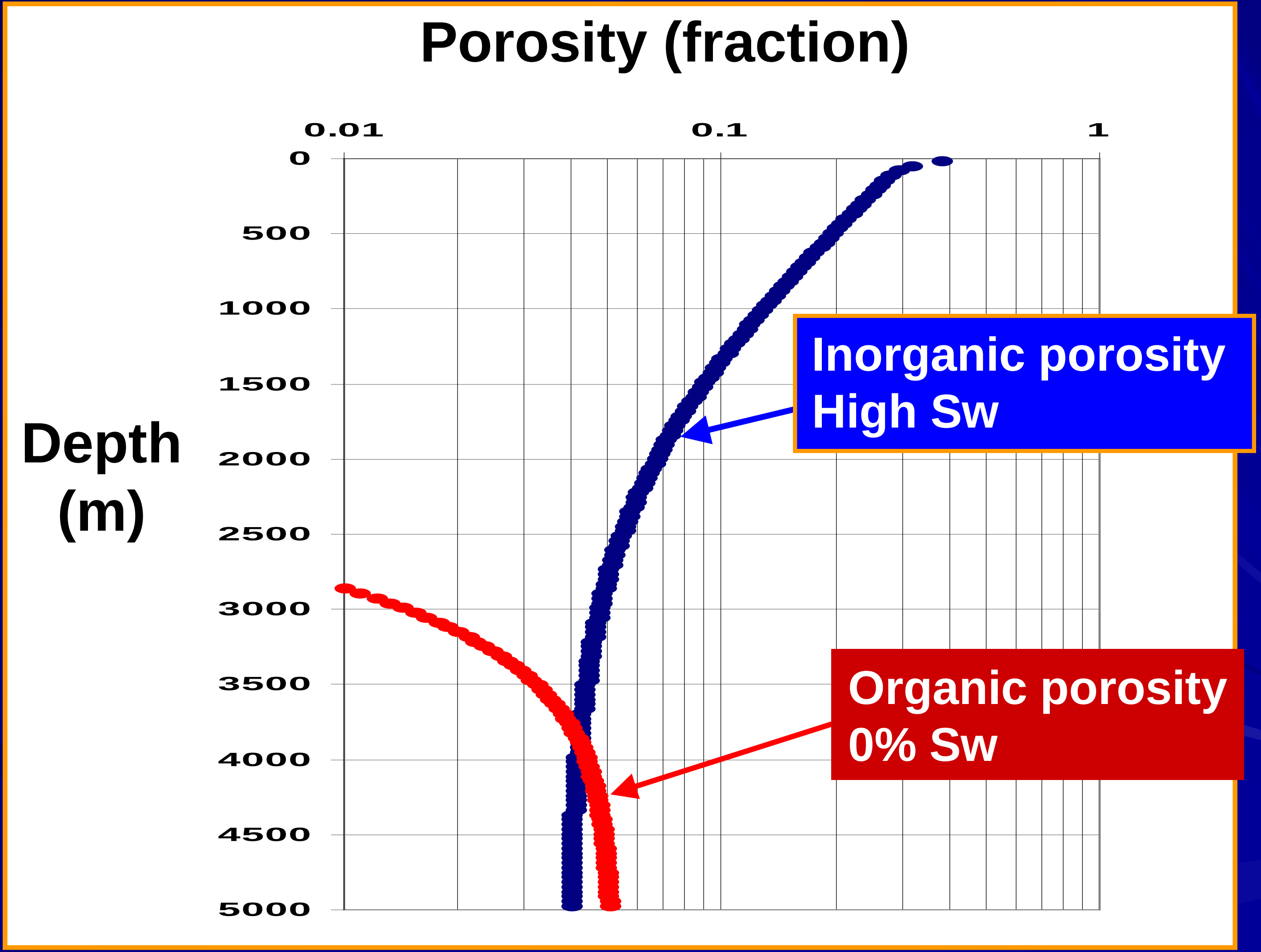
- **Storage in *organic* and *inorganic* porosity**
- **Calculate volume of retained petroleum in source rock**
- **“Instantaneous” composition (GOR) is a “source rock” calculation**



Source interval

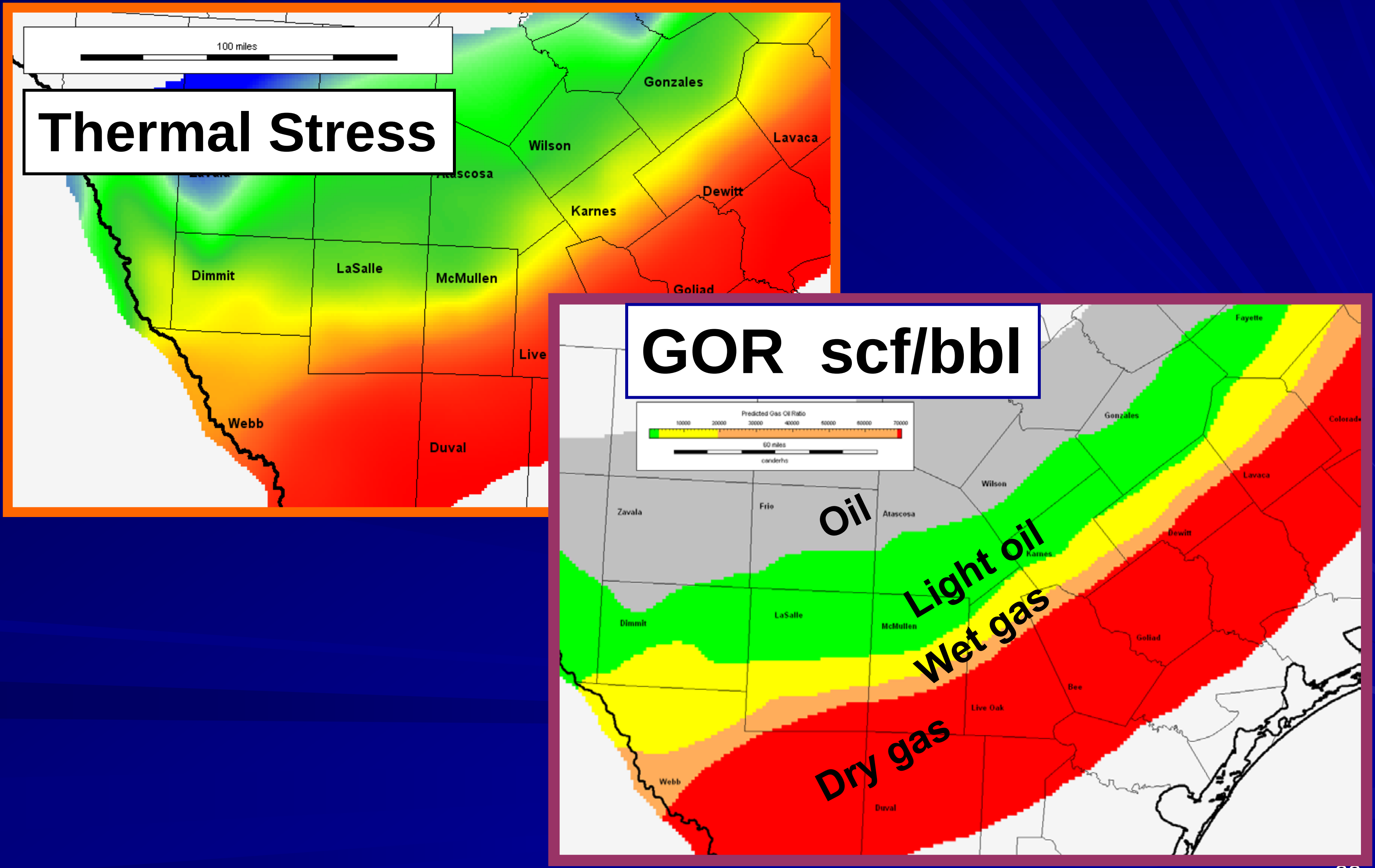
Model the petroleum generation, plus…
Changes in inorganic and organic porosity

8% TOC
Carbonate-rich
Over-pressured

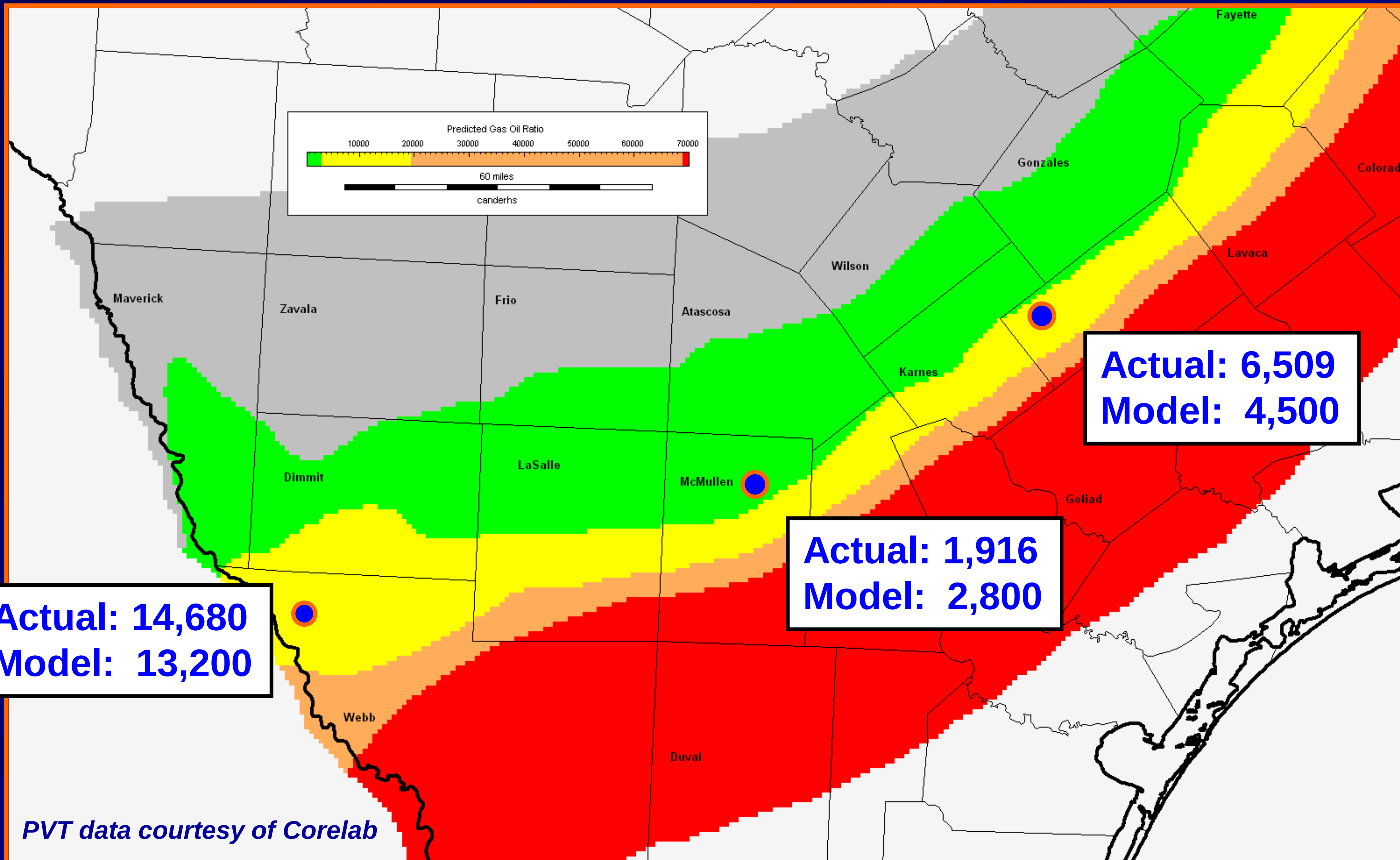


GOR predicted from Thermal Stress

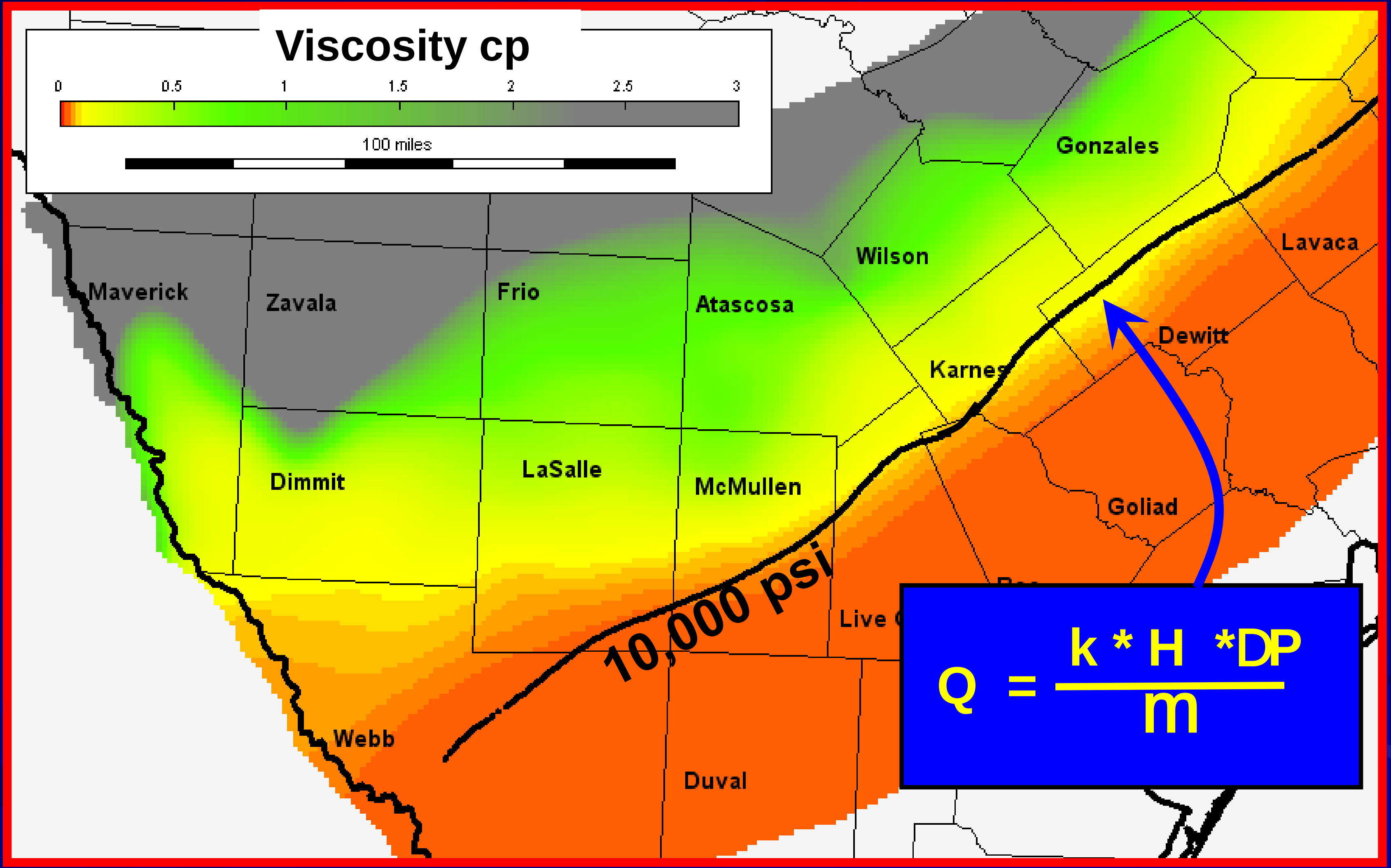
GOR is close to an Instantaneous Composition



PVT GOR vs. Predicted GOR



Eagle Ford Viscosity (modeled)



$$Q = \frac{k * H \ *DP}{m}$$

High pressure helps <u>mobility</u> of more viscous liquid phase fluids

What about Pressure?

$$Q = \frac{k * H \; * DP}{m}$$

Over-pressure in source rocks

- **Due to Petroleum generation?**

- **Due to Rapid burial?**
  - **Compaction disequilibrium**

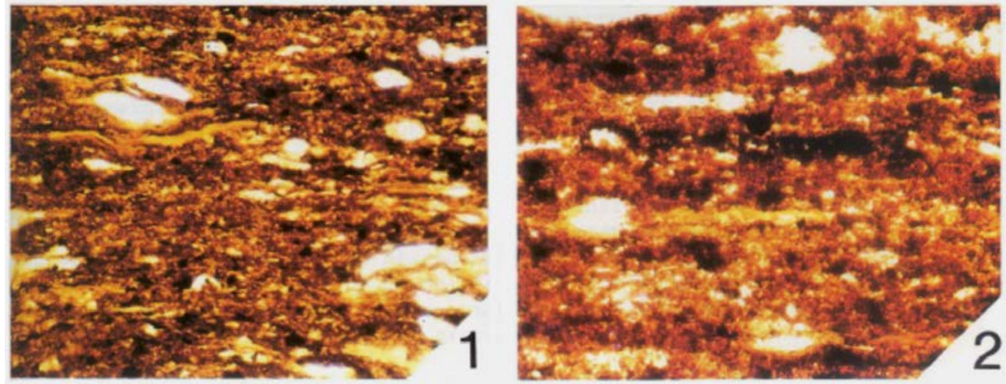
- **How is over-pressure preserved?**

Petroleum generation & over-pressure

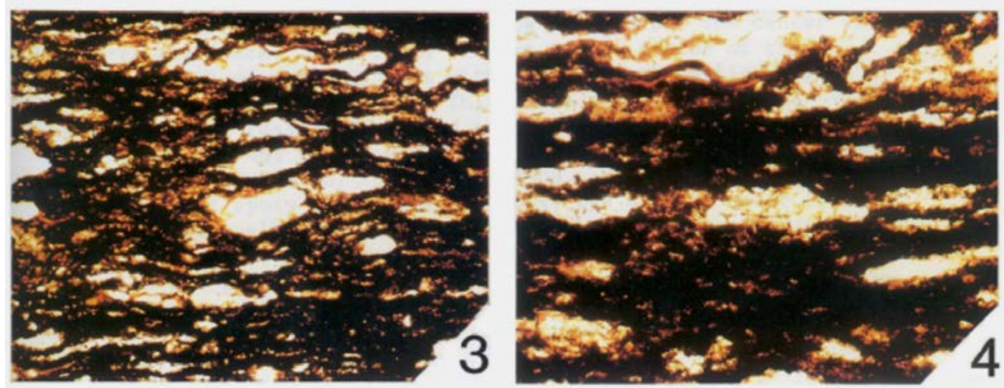
Momper, 1979
- Volumetric expansion

Lewan, 1985
- Hydrocarbon generation
- Bitumen network
- Microfractures
- Expulsion

Lewan: Pyrolysis of Woodford Shale

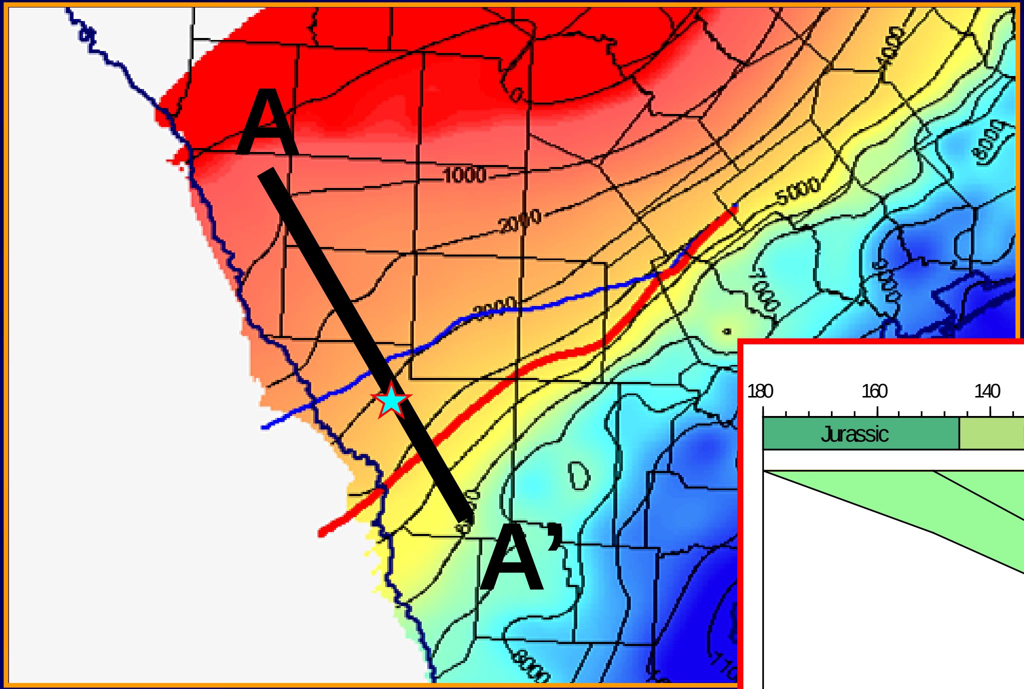


Immature – dispersed organic matter

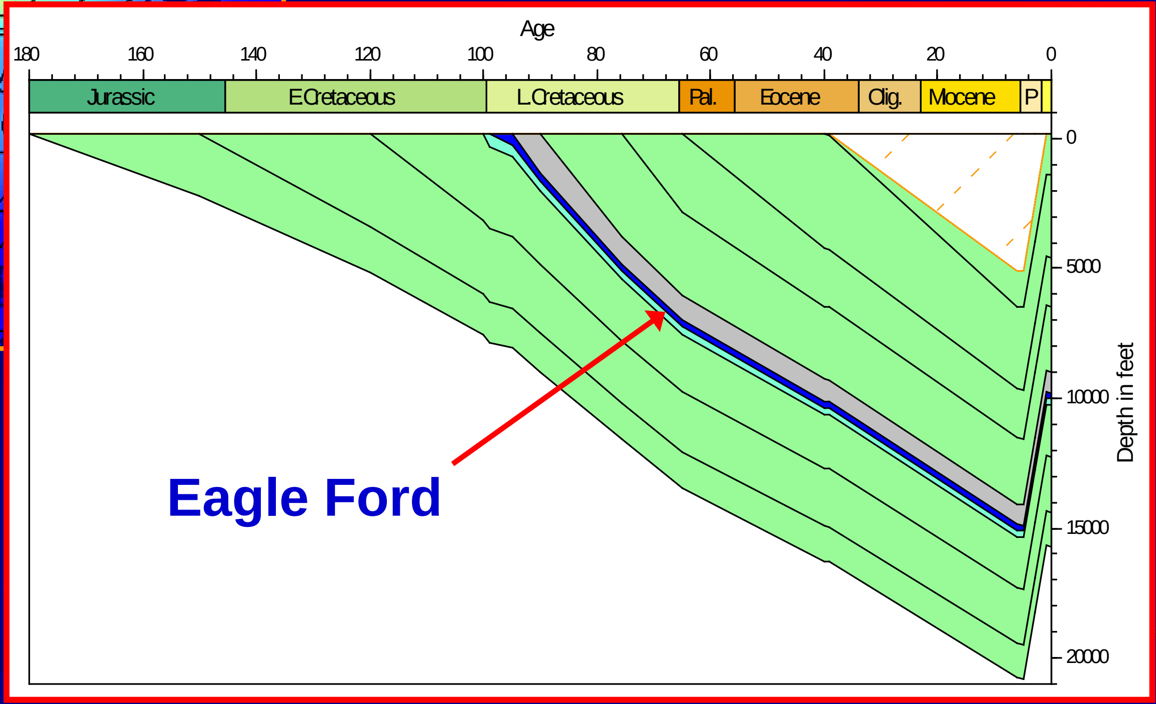


Mature – bitumen network develops

Eagle Ford Shale Basin Model

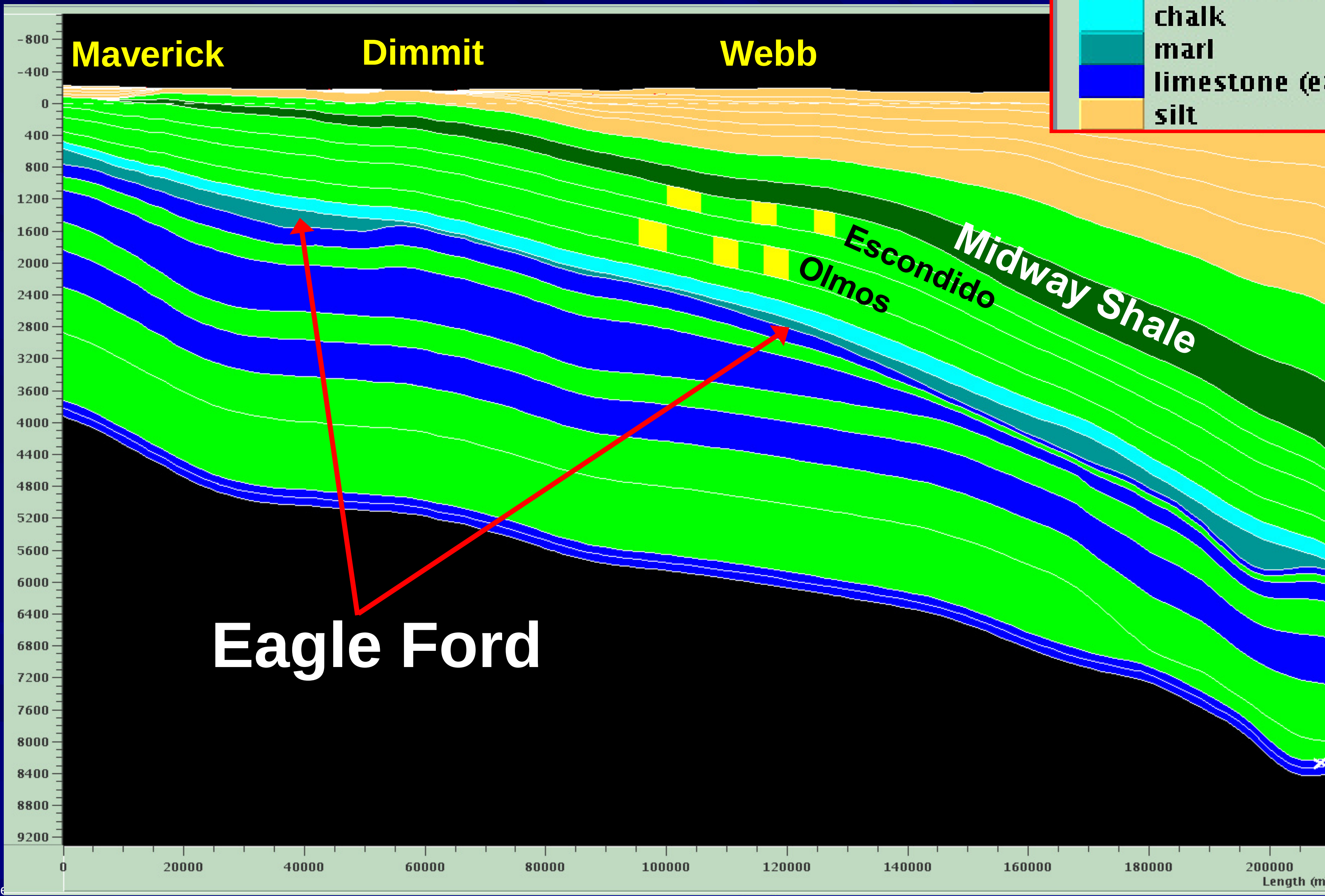


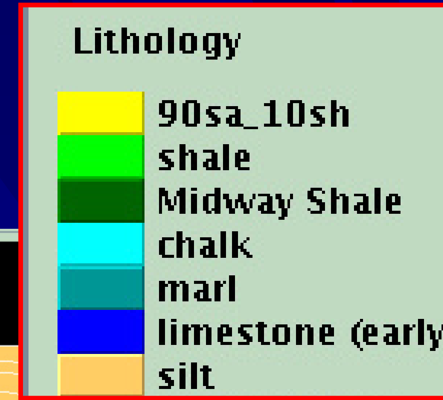
Eagle Ford Structure (m)



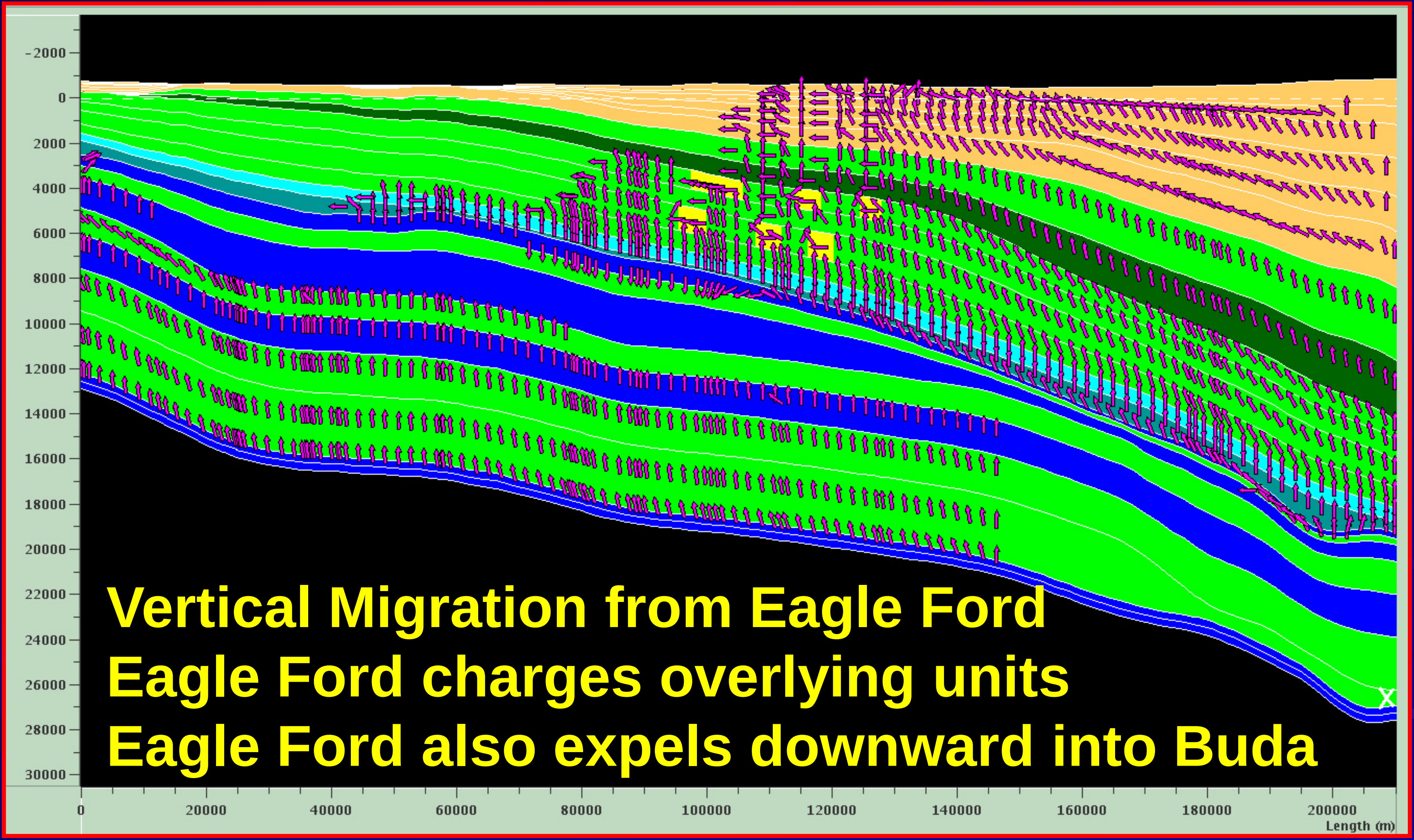
3000 – 7000 feet of exhumation in west; Less in east part of fairway

NW-SE Dip section

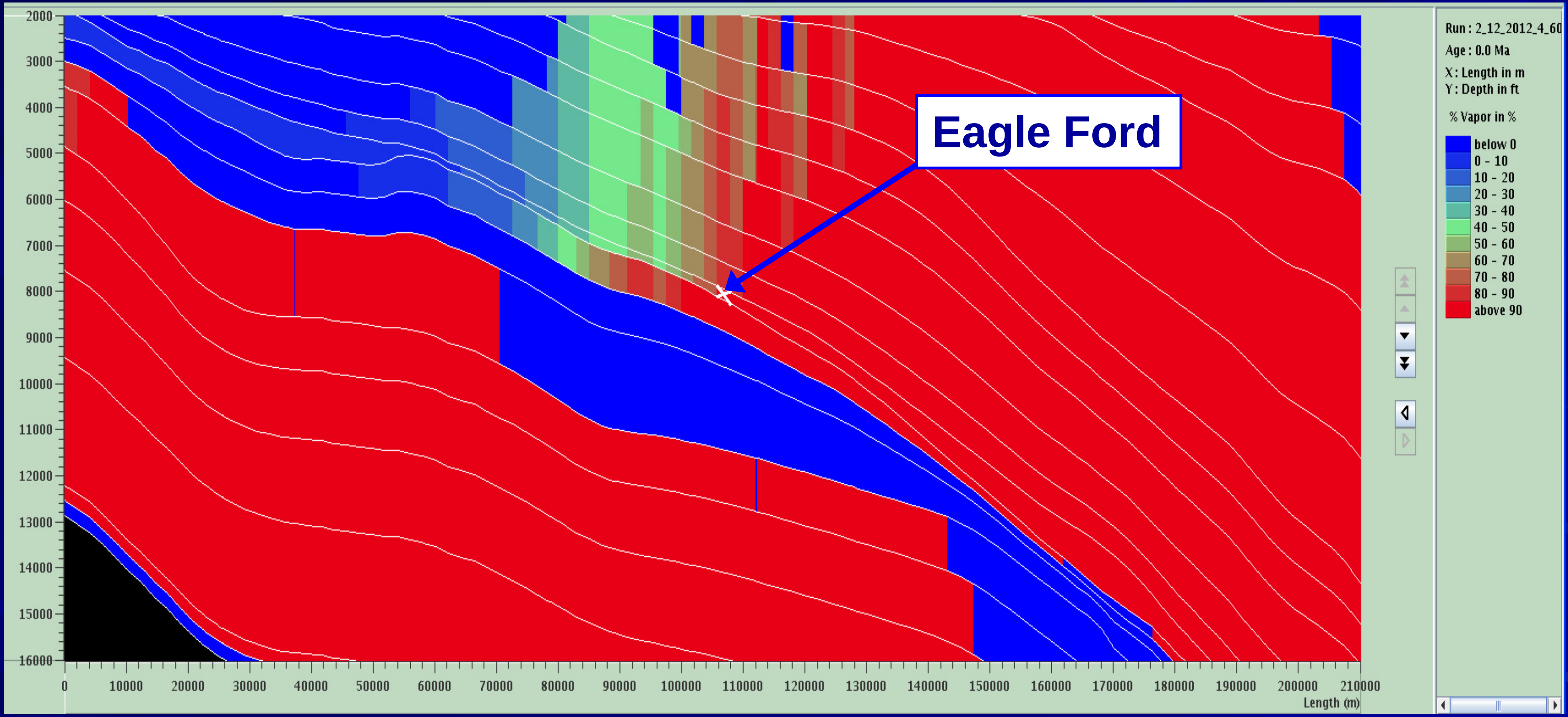




Eagle Ford Petroleum Charge

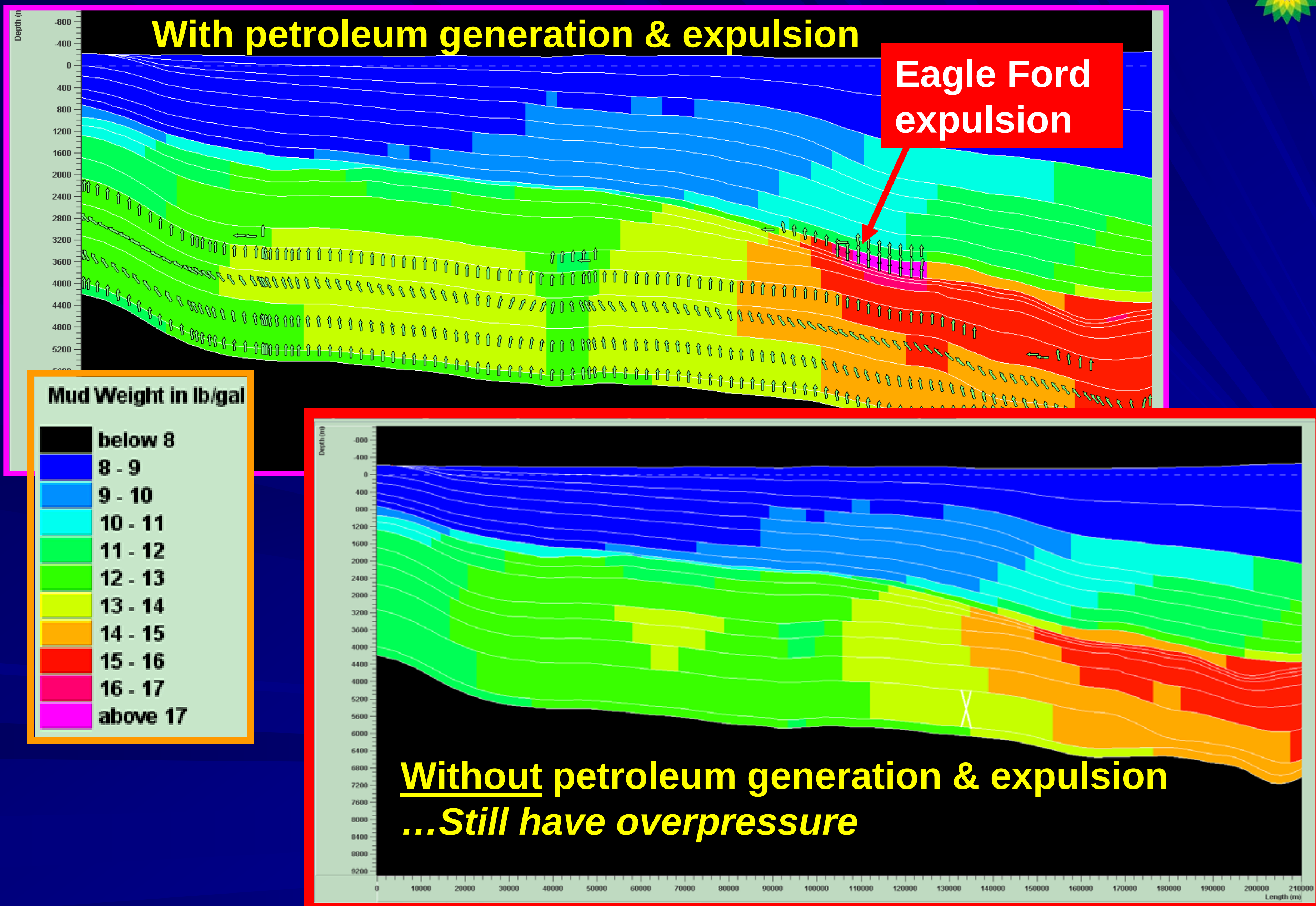


Phase
Liquid updip & above vapor

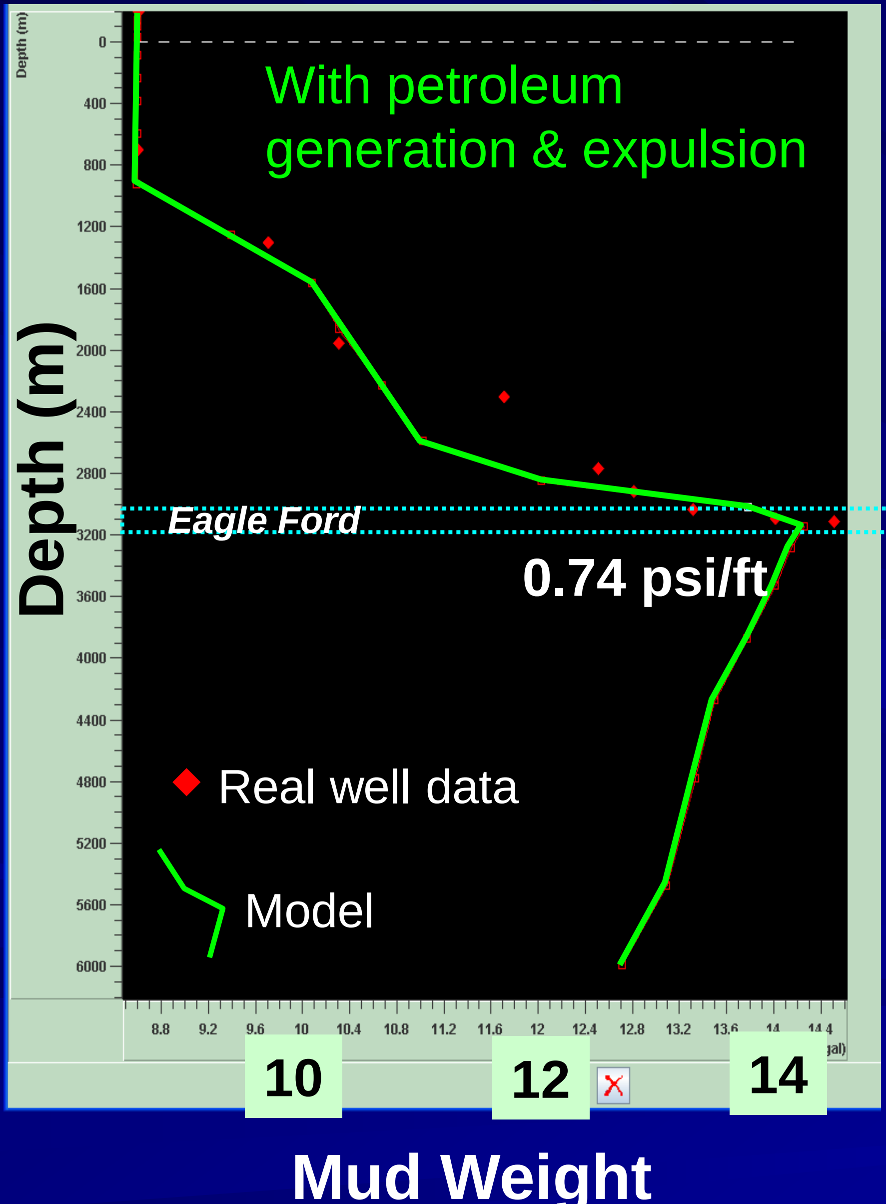


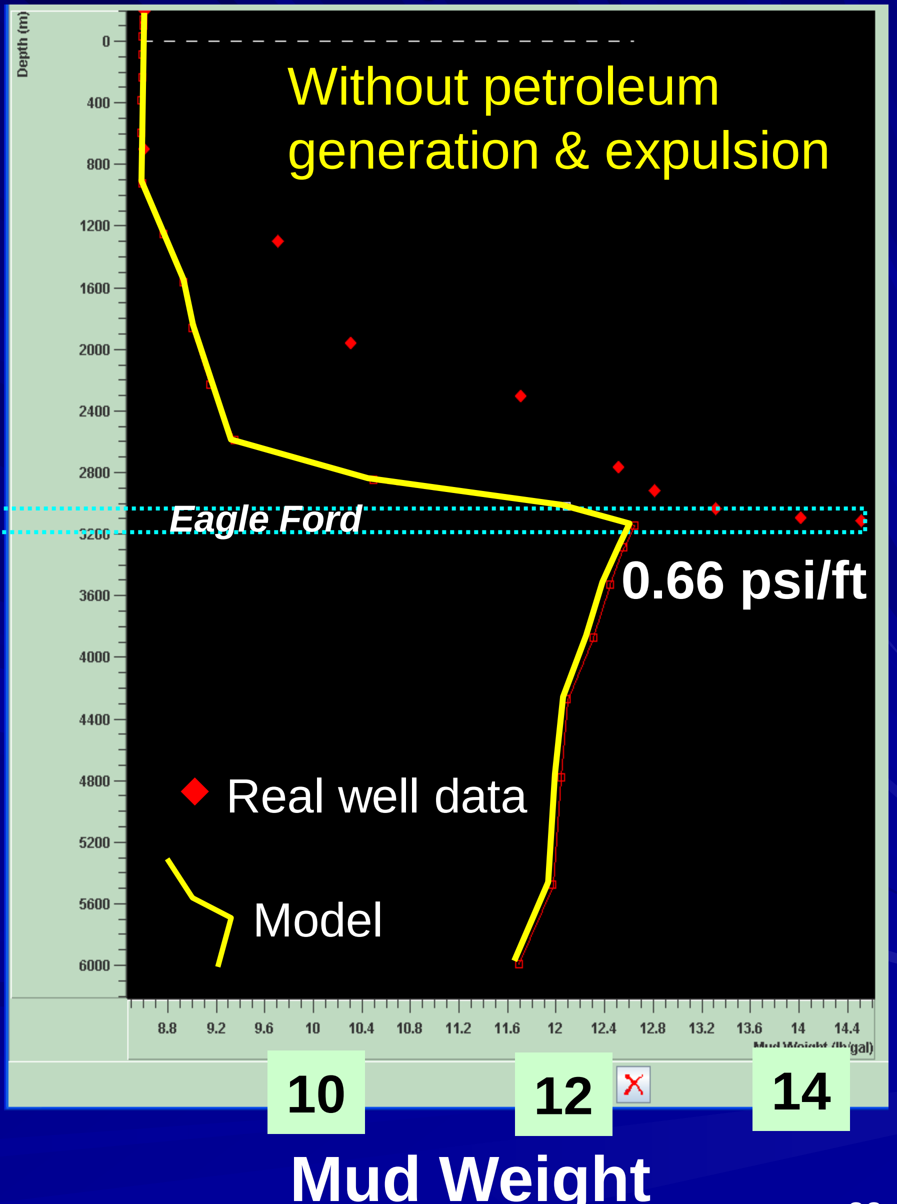
Note vertical maturity trend in overlying Upper Cretaceous strata

Basin overpressure during Eocene



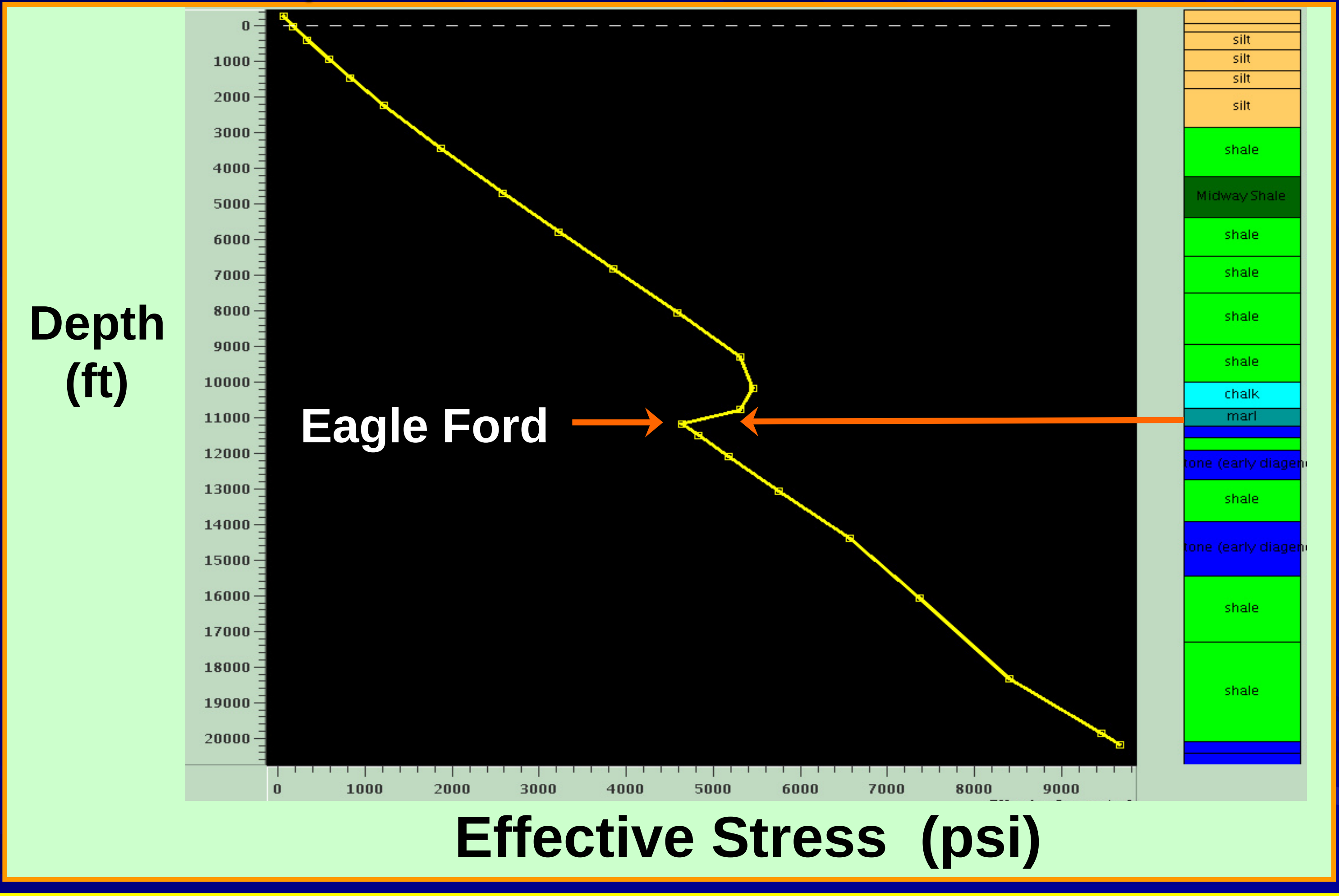
Difference in over-pressure
With and without petroleum generation & expulsion





Drop in Effective Stress in Eagle Ford

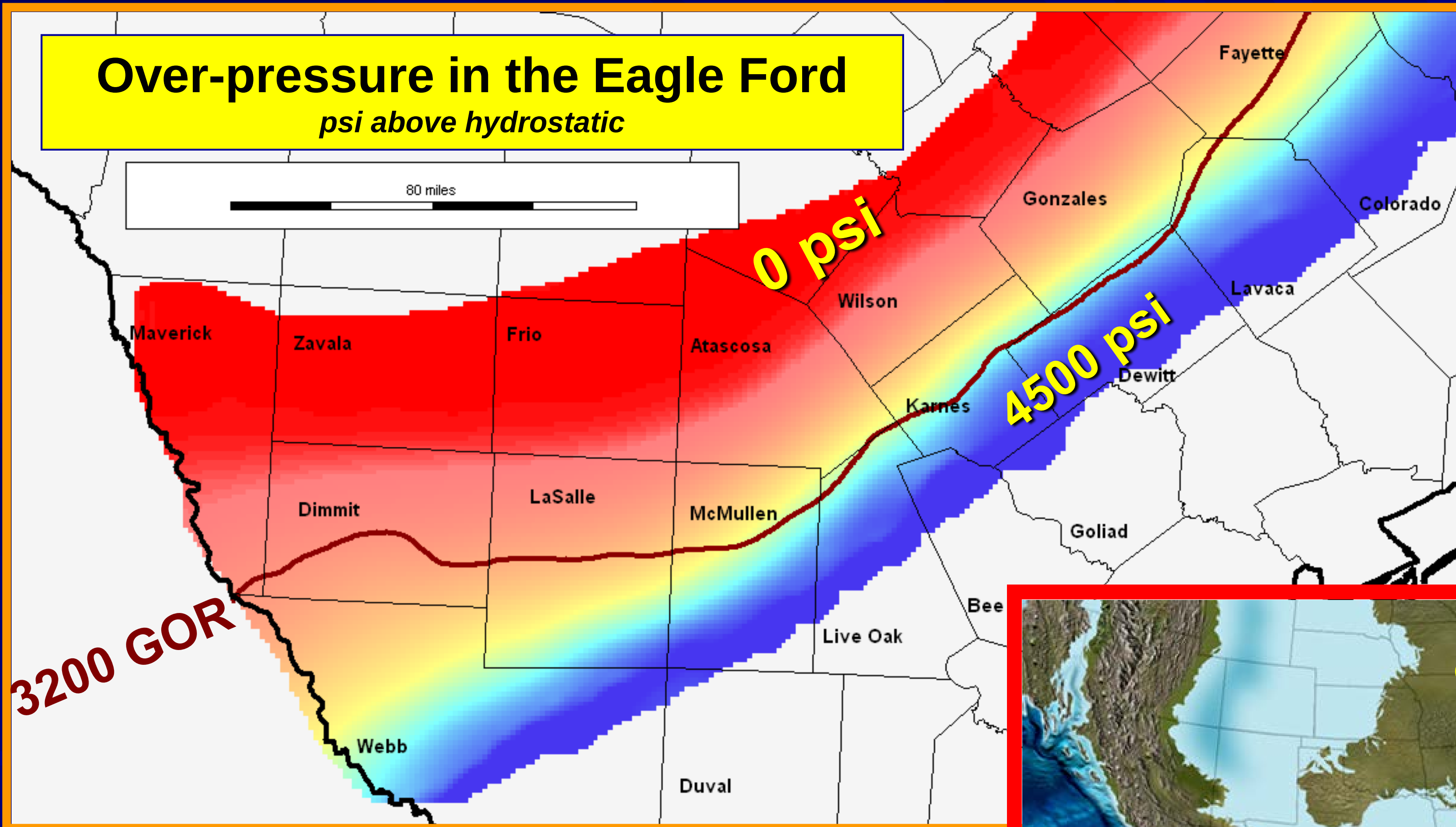
Preservation of pore throats



Permeability is not just a function of facies or the rock
Permeability is also a function of pore pressure

Gas window and Over-pressure

Not completely linked… Why not?

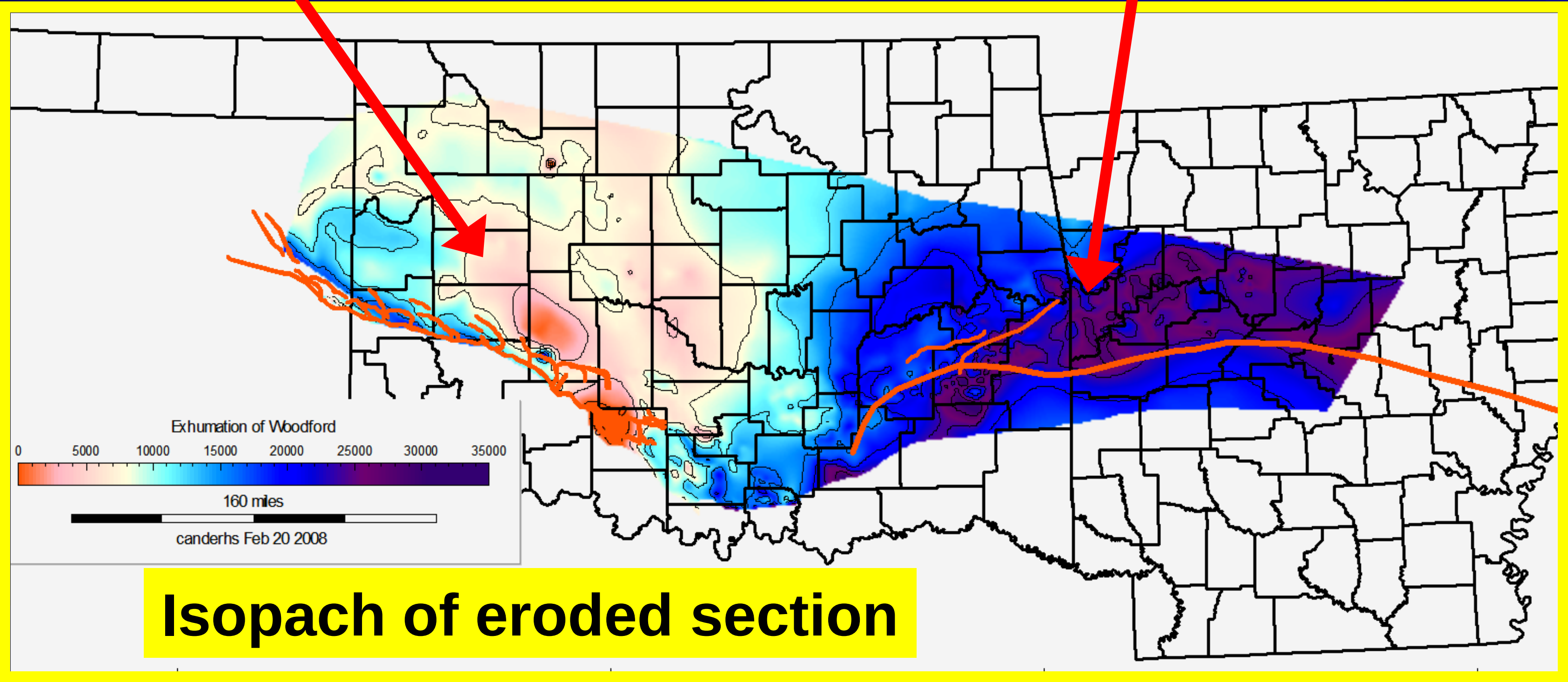


Post-Laramide exhumation in west causes loss of over-pressure and decoupling of GOR and pressure contours

Exhumation: loss of pressure

Anadarko
Minor exhumation
Over-pressure preserved

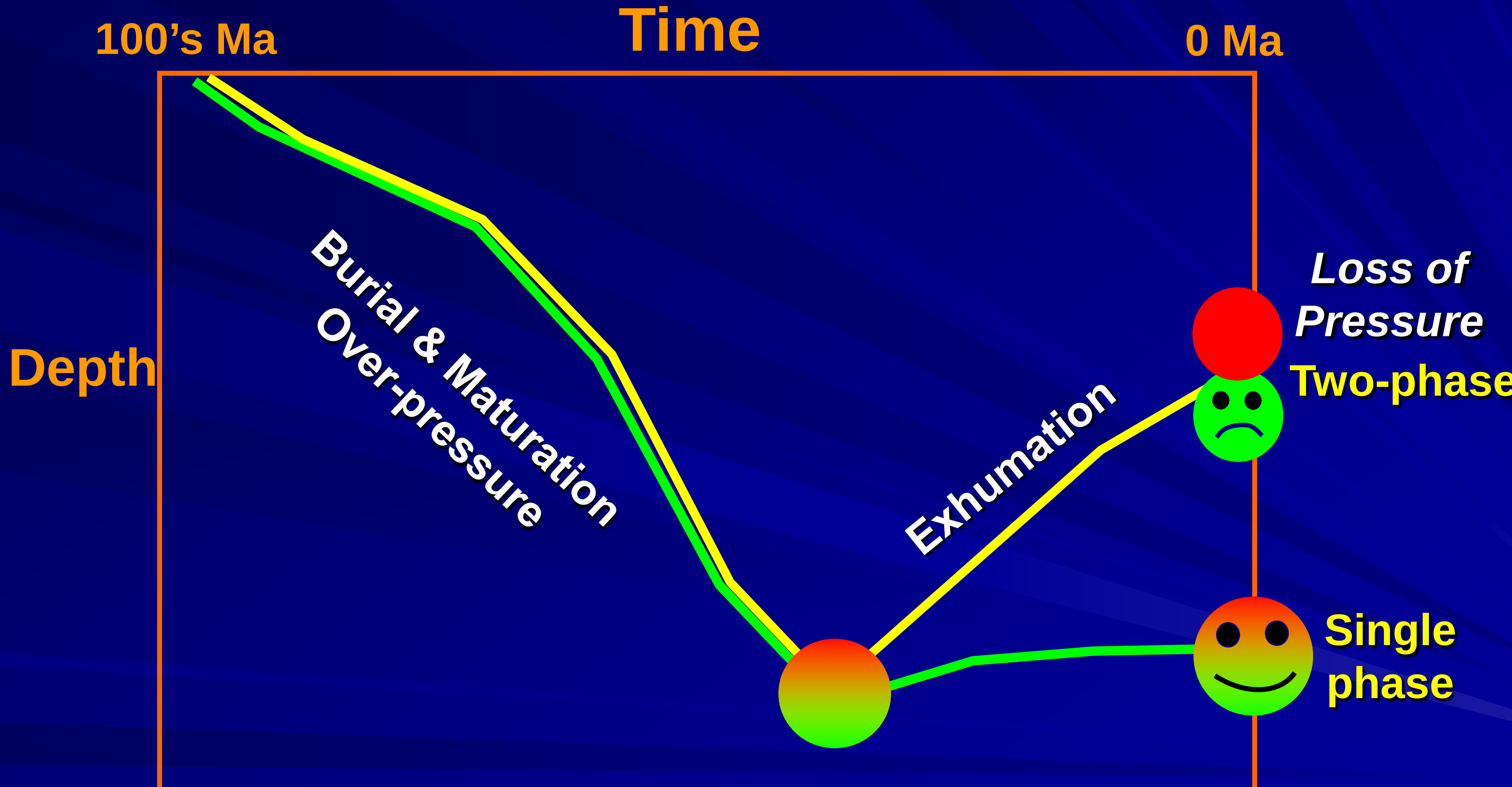
Arkoma
High exhumation
Over-pressure lost



Exhumation and Over-pressure

Fairway	Exhumation	Over-pressure
Arkoma Woodford Foreland	> 10,000 ft	Mild to none
Fayetteville Foreland	> 10,000 ft	Mild to none
Anadarko Woodford Failed rift	< 6,000 ft	High
Haynesville Passive margin	< 6,000 ft	High
Eagle Ford Central Passive margin	< 5,000 ft	High
Eagle Ford West Distal foreland	> 6,000 ft	Moderate

Exhumation can move fluid near two-phase point (bubble or dew point)



GOR
reflects burial

Same maturity
Different phase
Different mobility

When might GOR prediction fail?

- Substantial uplift
  - – Fluid goes two-phase during uplift
  - – Produced GOR is higher than predicted
- Wrong kinetic model
  - – Kinetics change as Organofacies change
- Frack into depleted area
- Frack into underlying reservoir
  - – Petroleum migrated into underlying reservoir
  - – Cumulative composition

Summary: Sweet Spots

$$Q = \frac{k * H * DP}{m}$$

- Fluid viscosity and reservoir pressure
  - First order controls on sweet spots in shale
- Retained petroleum predicted by right kinetic model
  - Viscosity and GOR are directly linked to maturity
  - Caution: Prediction can fail
- Over-pressure
  - Petroleum generation *and* compaction disequilibrium
  - Lost by substantial exhumation
- GOR and Pressure prediction require understanding of burial *and* uplift history!

Thanks!

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BP

Slides available at AAPG Search & Discovery
Cander, H., 2012