Application of Scaled Hydrocarbon Head Potential to Permian, Anadarko Basins and Eagle Ford for Better Resource Assessment and Development*

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Abstract

Insights into the variability of production rates and fluid properties at the pad, township and county scale will help decision makers. Testing mechanisms of the producible hydrocarbons in the Permian, Anadarko and Eagle Ford petroleum system shows encouraging results. The integration of geosciences, engineering, big data and numerical modeling is described and then demonstrated. Many have shown that wells that outperform the average well economics correlate with the degree of overpressure and fluid properties. Several methods have been applied to map these properties at a regional scale. In Varady et al (2017), Scaled Hydrocarbon Head Potential (SHCHP) workflow for resource assessment was presented. We have applied this work to other basins as an adaptable universal tool for tight liquids and hybrid systems. The variability in well performance in Barrels of Oil Equivalent per Day (BOE/D), Hydrocarbon Density (HC API), and Gas-Oil Ratio (GOR) deviate from in-situ maturity trends. Modifying Darcy flow parameters along carrier beds allows empirical calibration. Training sets were used to test the form of the empirical equations. Combining these empirical relationships with standard source rock expulsion and migration maps creates maps of modeled BOE/D, HC API and GOR. Optimized parameters are derived by minimizing the difference between observed and modeled. Over 40,000 wells for the STACK/SCOOP, Wolfcamp/Bone Springs and Eagle Ford formations constrained the formulation. Each basin model is calibrated independently for burial and thermal spatial and temporal to measure a) thermal indicators and b) temperatures. The SHCHP uses a GOR-HC API density function developed by PVT analysis and equations of state (EOS). Pressure gradient at a regional scale is first obtained through a linear inverse solution. Supervised learning uses the structural evolution and geohistory to improve data fitting. SHCHP allows us to integrate

and understand pressure evolution in source rocks and hybrid resources, in different depositional settings, ages, and basins that underwent complex and structural settings. The strong relationship between SHCHP and well performance allows us to 3D map between known productions and diagnose areas exhibiting phase separation in the subsurface. We learn as much or more when the model does not fit the data. Deviations between observed and modeled requires investigators to reach out for a better understanding of the depositional and structural history.

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Application of Scaled Hydrocarbon Head Potential to Permian, Anadarko Basins and Eagle Ford for Better Resource Assessment and Development

By: Carlos Varady, Dr. John Pantano

Petroleum System Analysts, Engineers, and Geoscientists

CoRE
Chevron Center of Research Excellence
BASIN MODELING PROGRAM

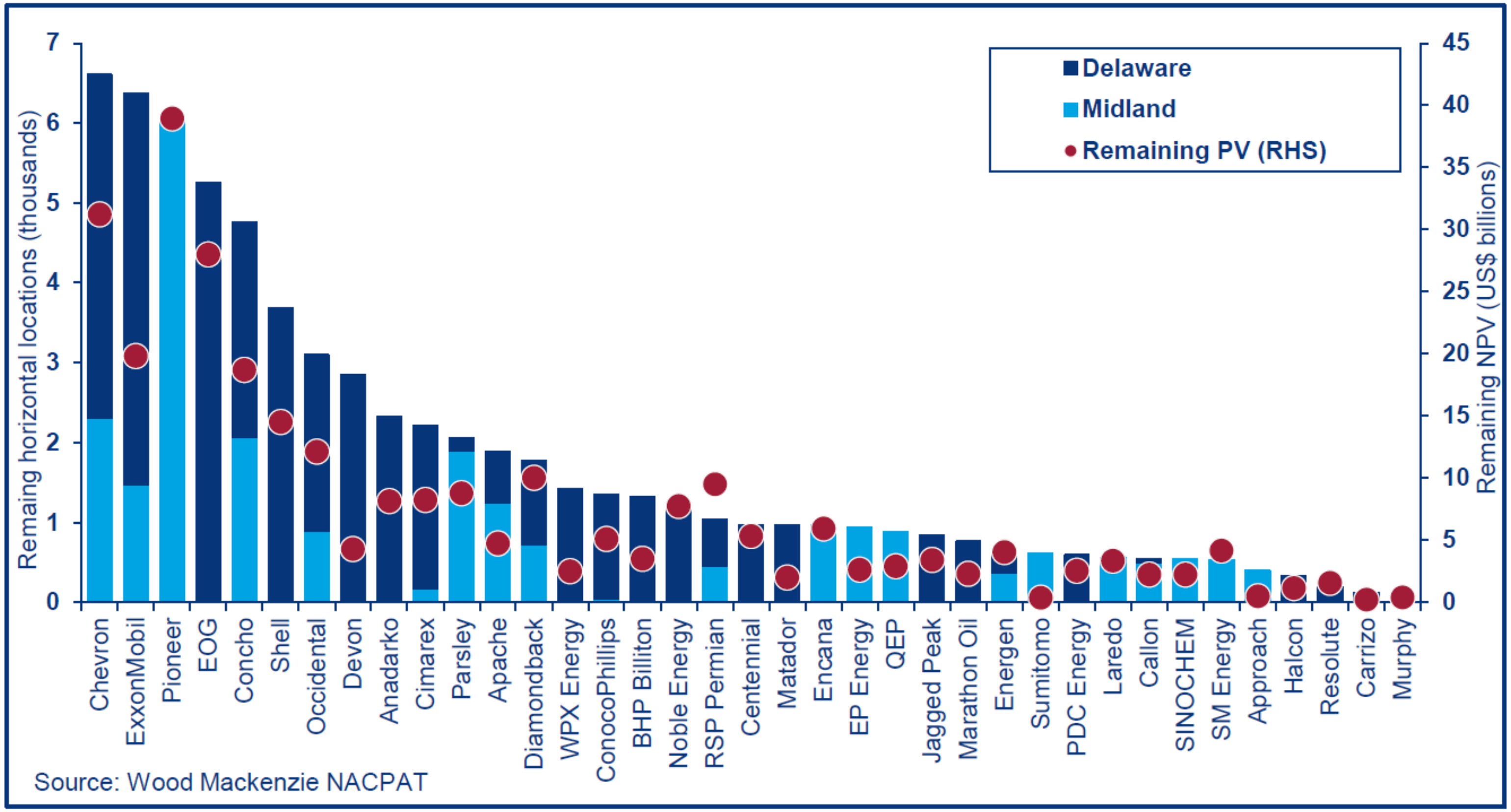
Outline

- Drivers for a New Approach to PSA in Tight Resources
- Characterization of Tight Rocks and Hybrid Systems
- Some Fundamental Principles Behind Well Performance
- Basin Modeling Workflow for Regional Pressure w/ Rates
- Predictions and Diagnostics: Eagle Ford & Permian Basin
- Conclusions

Continuous improvement of PSA Tight Resource Plays

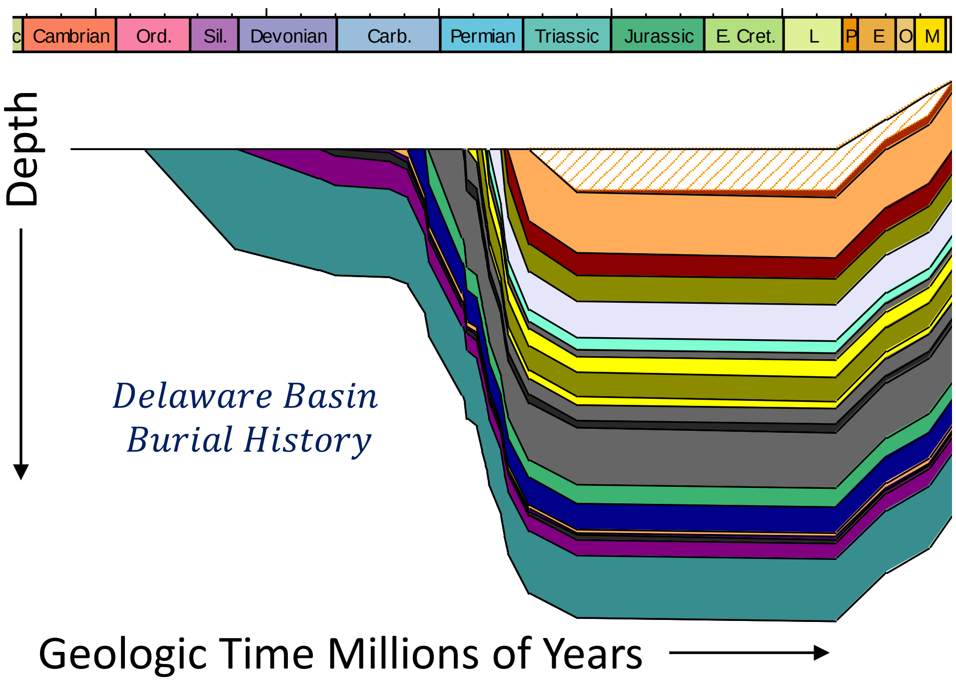
1. Coupled technology with business decisions

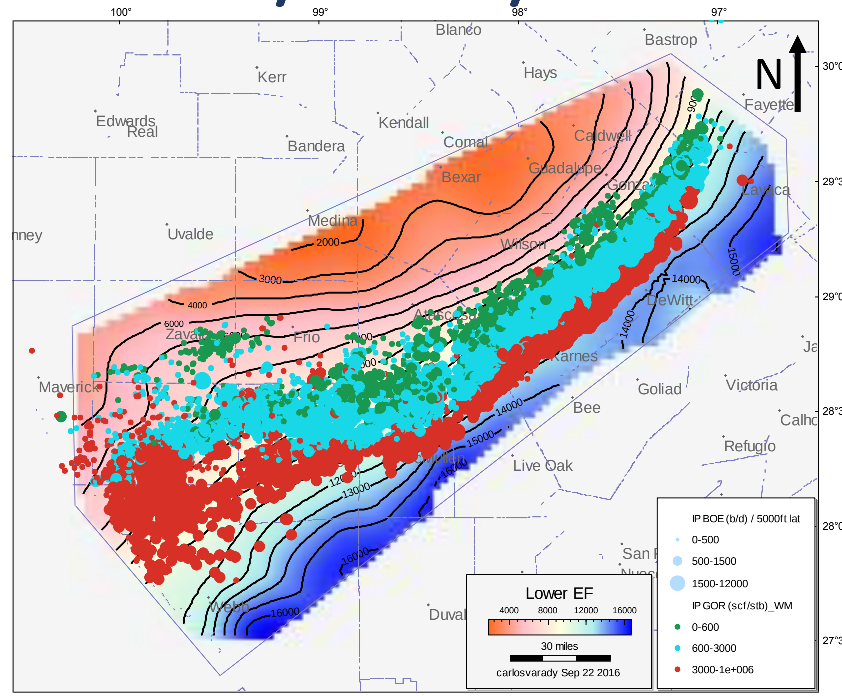
2. Timely diagnostics



Characterizing Tight Rocks and Hybrid Systems

- Hybrid Play, Source-Reservoir
- Multiple Target Intervals
- Fluids: Black Oil to Dry Gas
- Migrated Fluids vs. Self Sourced





- Controls on Well Performance:
  - Pressure vs. Seal vs. Geohistory
  - Gas Oil Ratio (GOR), HC Density
  - Maturity vs. Mixing vs. Retained
- Developed SHCHP to integrate these concepts and estimate pressure <-> performance

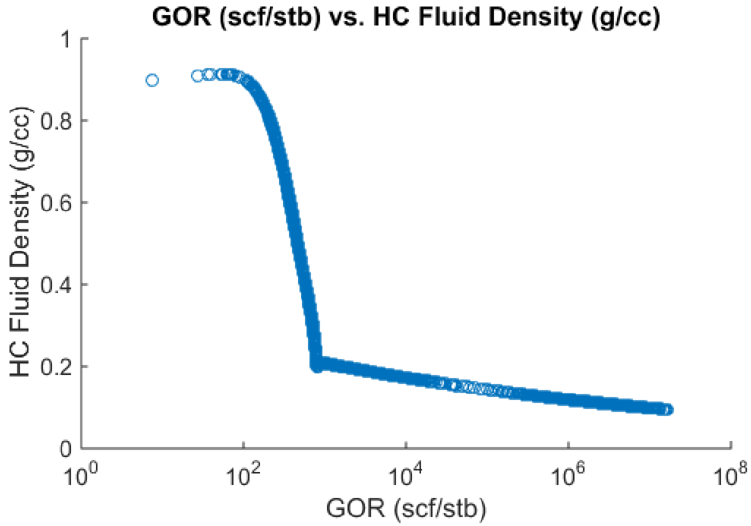
Fundamental Principles Tight Rocks >10^{-9}

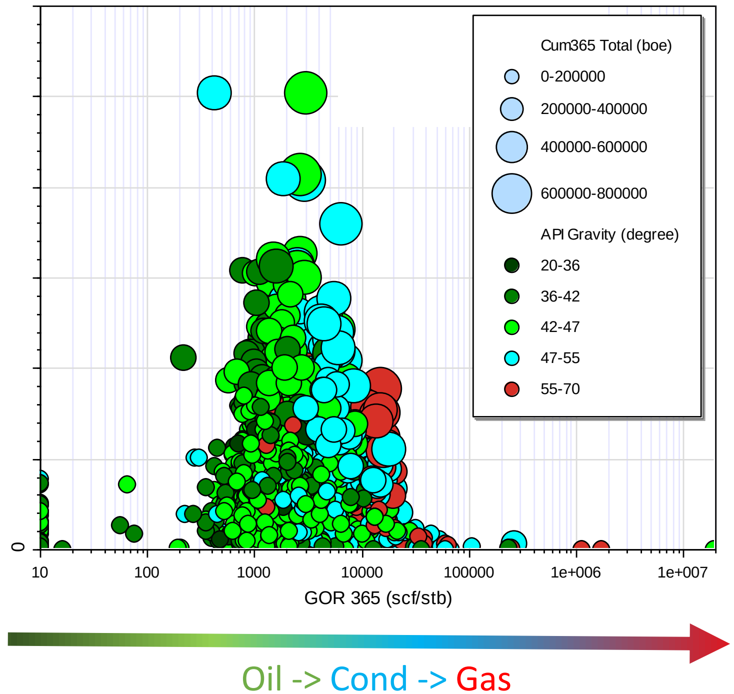
$$\boldsymbol{Pressure + Phase + Permeability = Performance}$$

- Flow through Porous **Matrix**:

$$\cdot \, {}^{i}Q = \frac{kA}{\mu}\frac{\partial P}{\partial x}$$

- HC Density, GOR, Viscosity, and Interfacial Tension



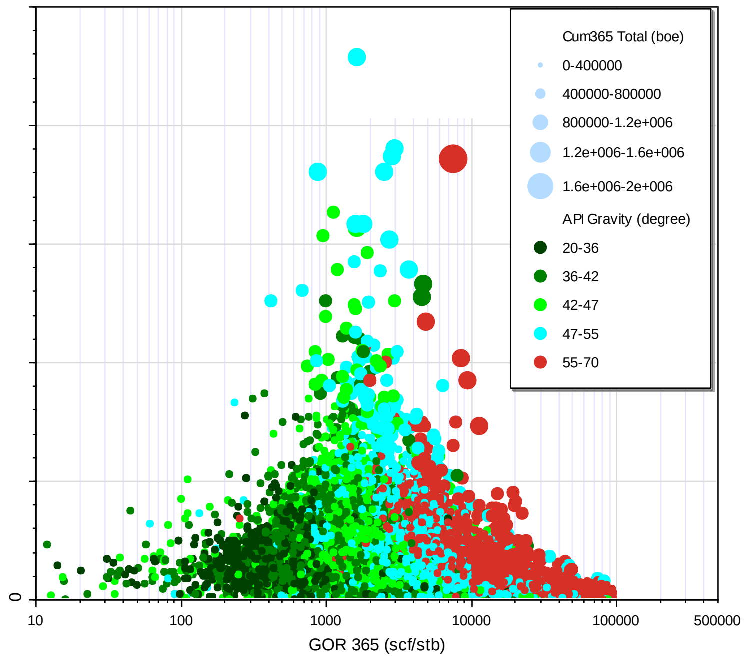


Production Data: Delaware Basin Wolfcamp and Bone Springs

[i]**Black oil to wet gas, not for high pressure dry gas w/ nano scale flow mechanisms, physics, and forces**

Fundamental Principles, Common Theme

Fluid-Rate Relationship in Tight Rocks

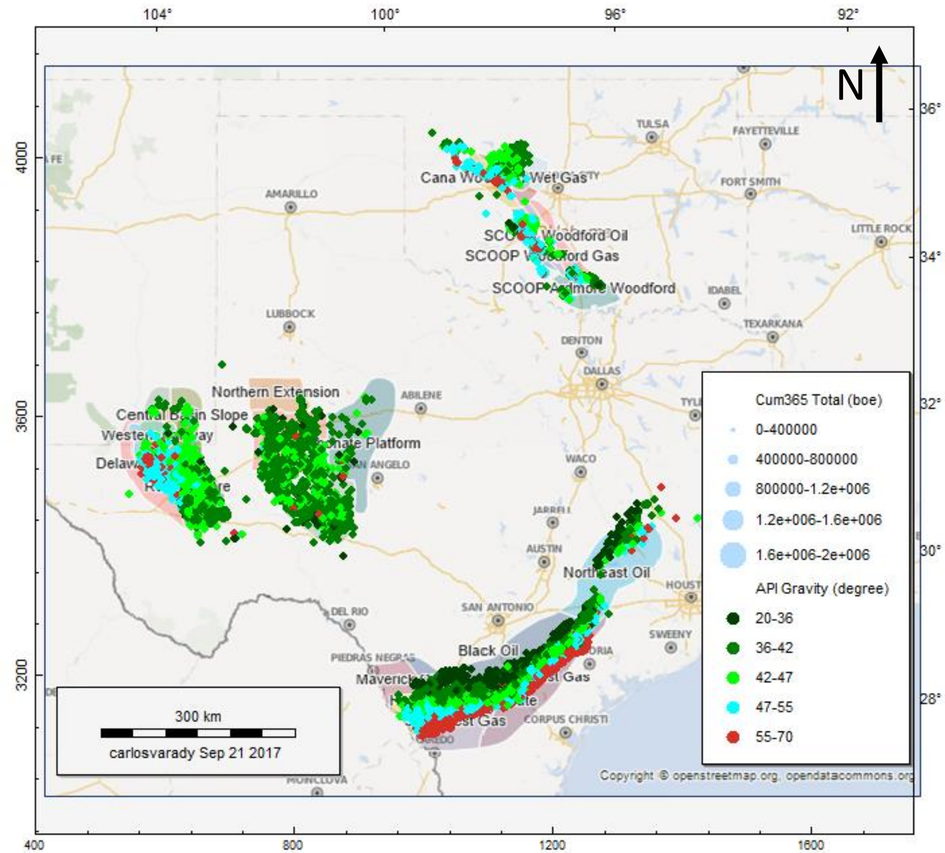


Oil -> Cond -> Gas

Decrease HC Density, Decrease Molecule Size

Increase Mobility Increase Maturity, Increase GOR

Petroleum Systems, Fundamental Physics



A Tool for Tight Rocks and Hybrid Systems

$$SHCHP = \frac{\Delta P_{over}}{\Delta P_{G\,HC} \times 100}$$

- Scaled Hydrocarbon Head Potential: A new tool that relates **maturity**, **pressure** evolution, and **seal** capacity to **fluid** properties and **production** volumes.

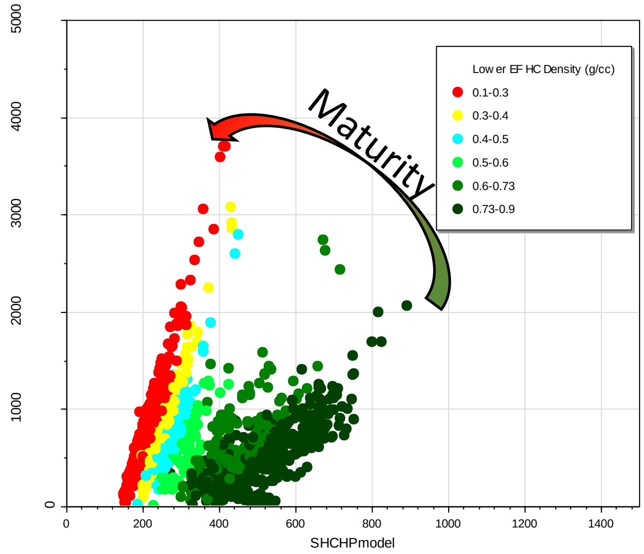
$$\Delta P_{over} = Overpressure$$

$$\Delta P_{G\,HC} = Hydrocarbon\ pressure\ gradient$$

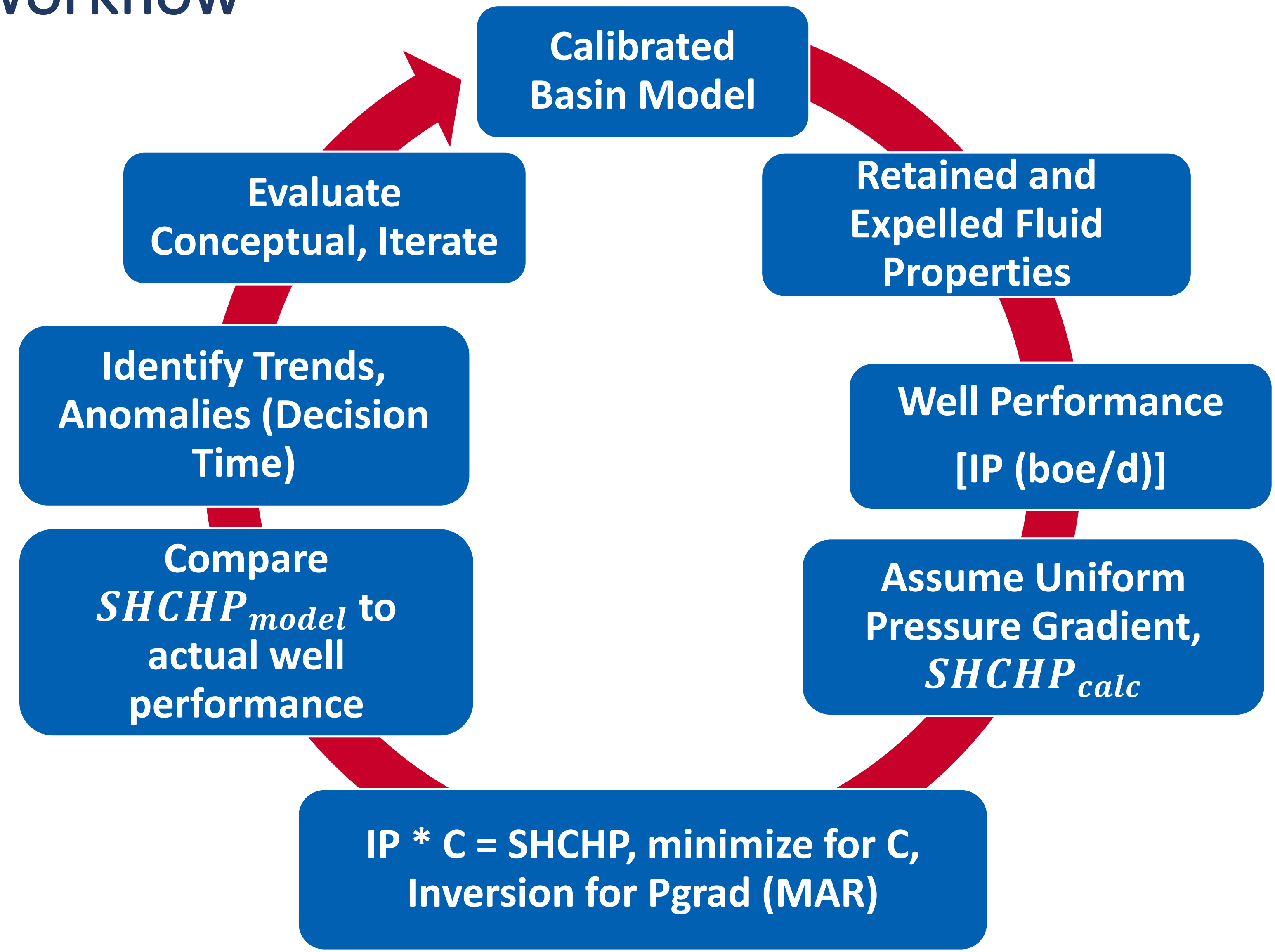
Pressure and Gradient difference taken with respect to hydrostatic

$$\boldsymbol{IP\ BOE\left(\frac{boe}{d}\right) \times C = SHCHP} = \frac{\Delta P_{over}}{\Delta P_{G\,HC} \times 100}$$

C= Inversion (constant) through Minimum Absolute Residual



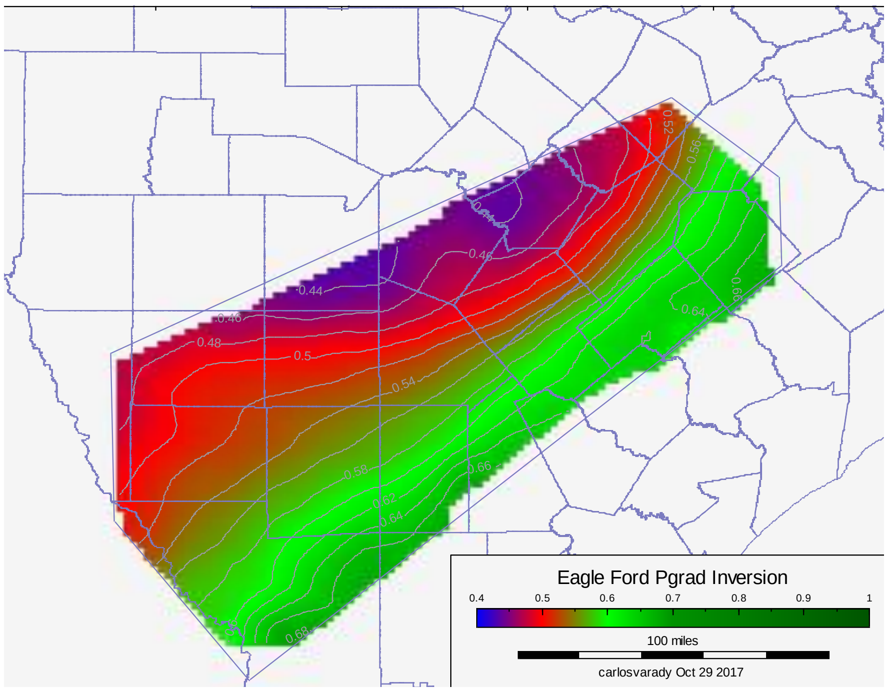
Workflow



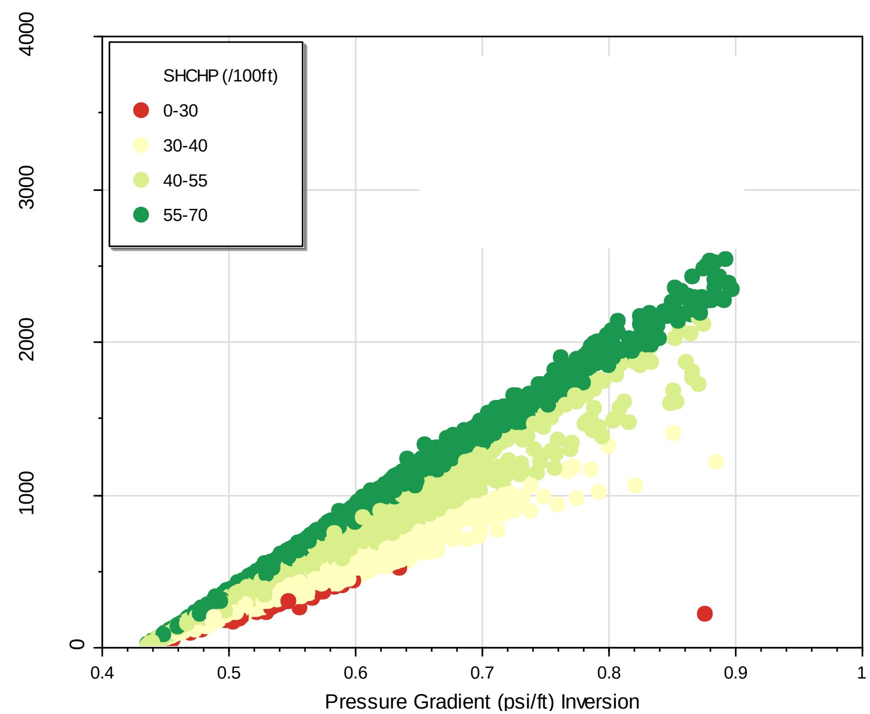
Calibrated Basin Model
Retained and Expelled Fluid Properties
Well Performance [IP (boe/d)]
Assume Uniform Pressure Gradient, $SHCHP_{calc}$
IP * C = SHCHP, minimize for C, Inversion for Pgrad (MAR)
Compare $SHCHP_{model}$ to actual well performance
Identify Trends, Anomalies (Decision Time)
Evaluate Conceptual, Iterate

Eagle Ford Pressure and SHCHP Calibration

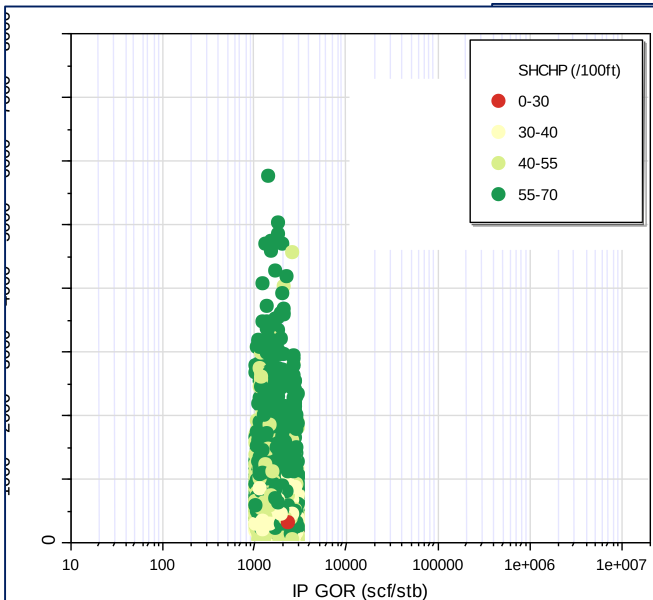
Pressure Gradient Regional Map Basin Modeling + Inversion

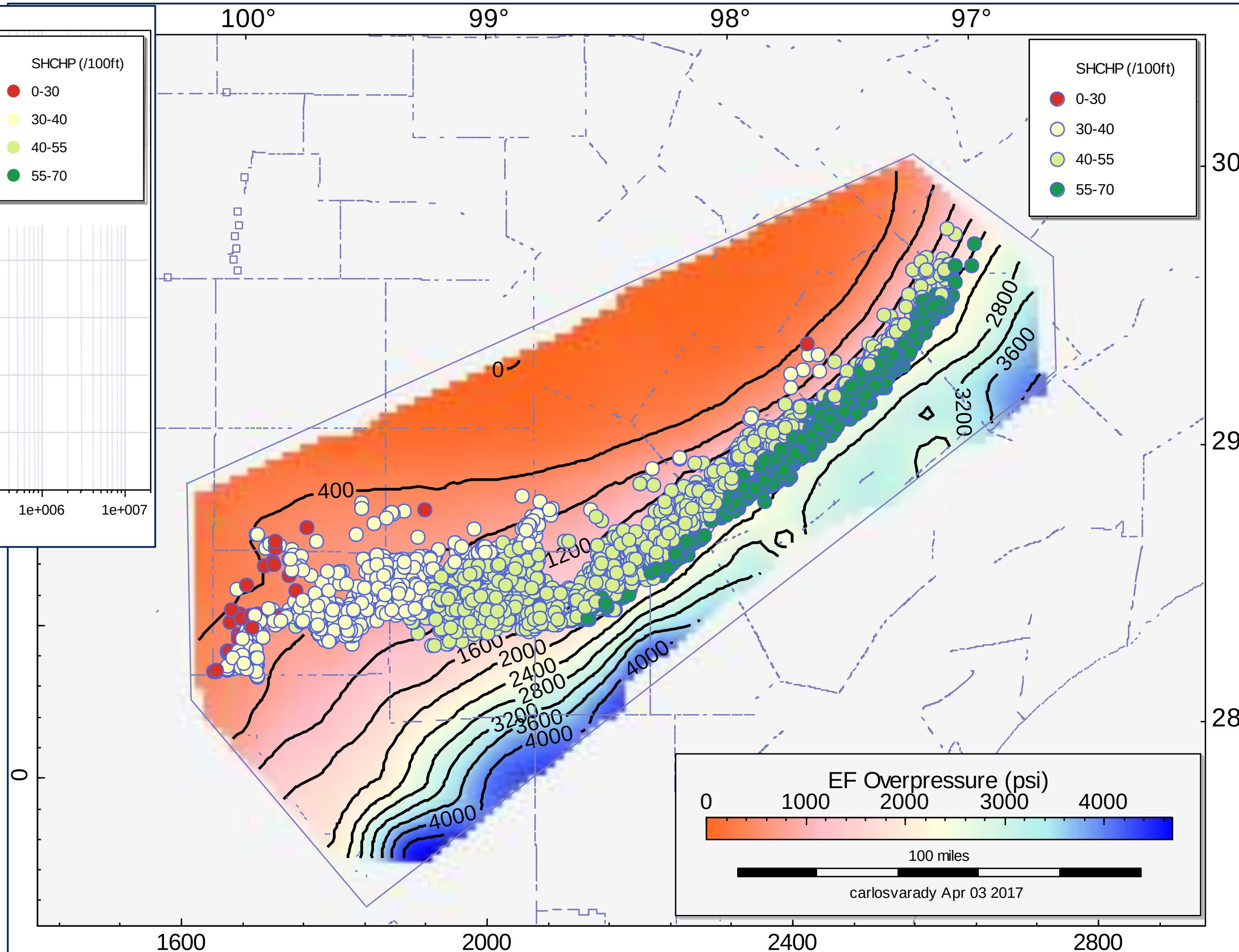


Strong Relationship Between SHCHP, Pressure and Rates



Recap Analysis from SHCHP Development



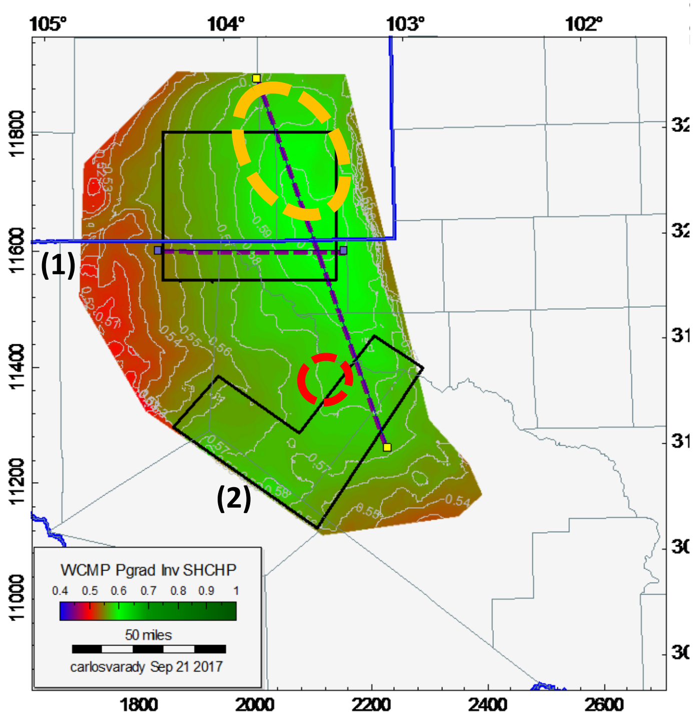


- HC **Density** trends correlate to retained fluid **maturity**. It can also be observed from **Gas-Oil ratio** and API of **produced fluid**.
- **Overpressure** from **generation** & **burial**, related to formation **seal** capacity, structural evolution and stresses that led to punctuated **expulsion** events in **exhumed** basins.

Wolfcamp Pressure and Well Rate Trends

Delaware Basin Pressure Map:

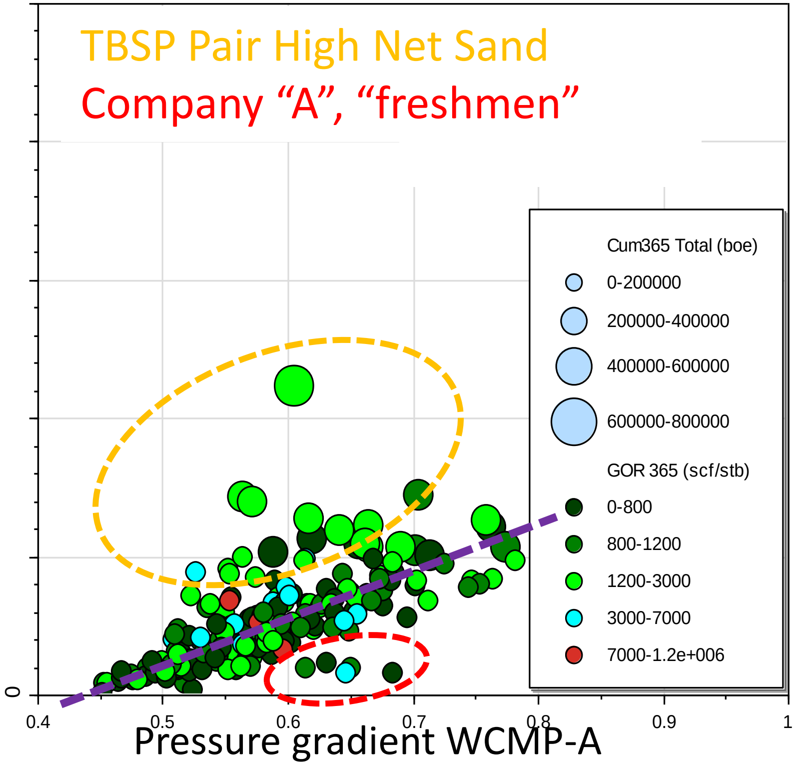
Exhumation may lead to pressure loss



(1) Burial and Uplift E-W and (2) Alpine High AOI

Overpressure (estimated):

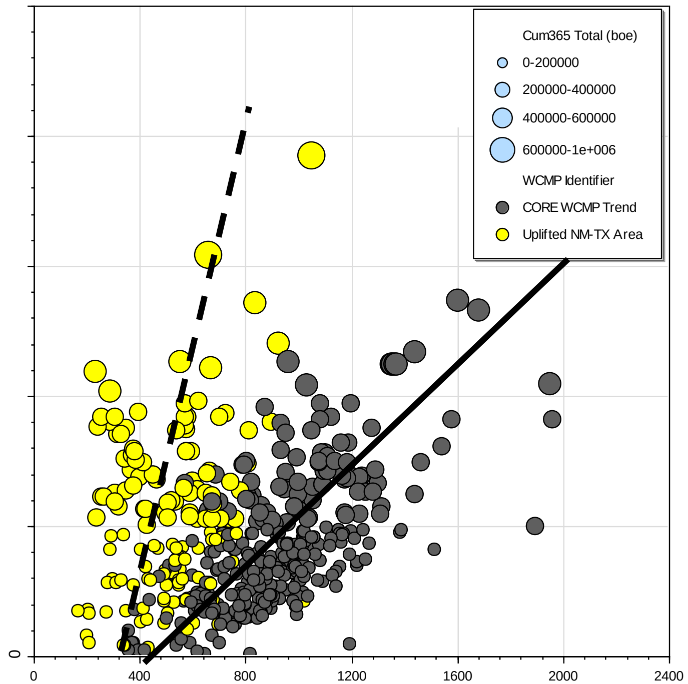
Controls on cumulative 12 month BOE

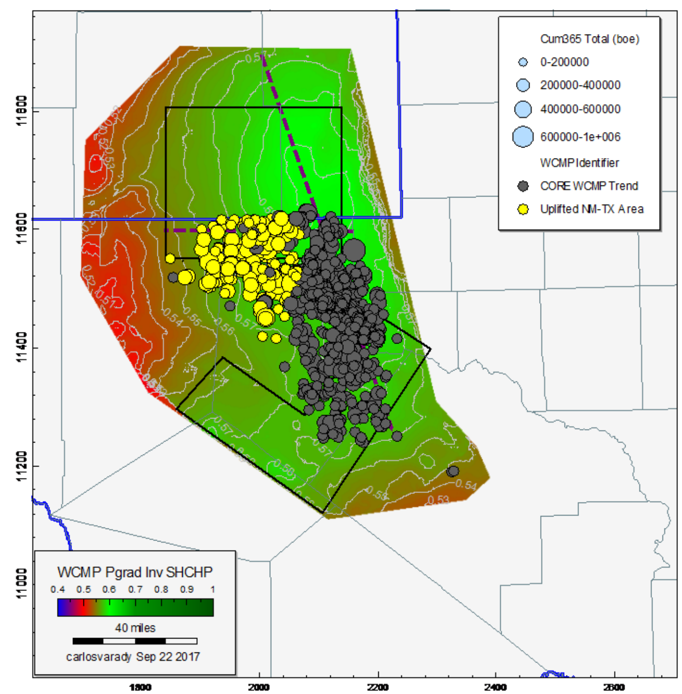


Diagnosing HC Mixing and Phase Separation

SHCHP identifies once the "self-sourced", uniform uplift-tectonics assumptions breaks

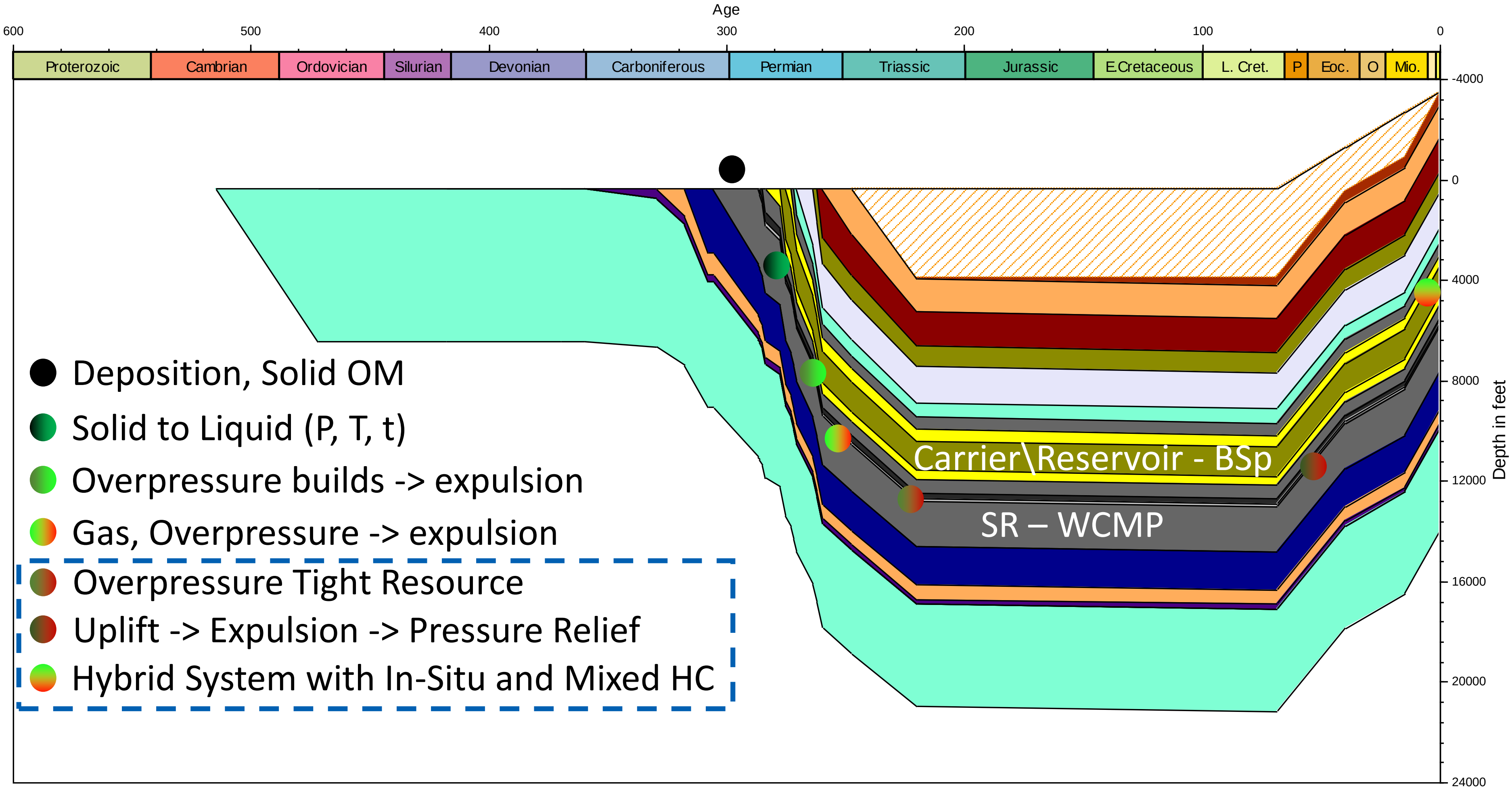
Deviation from SHCHP- 12 mo cum boe Trend coincides with uplift & Pgd loss





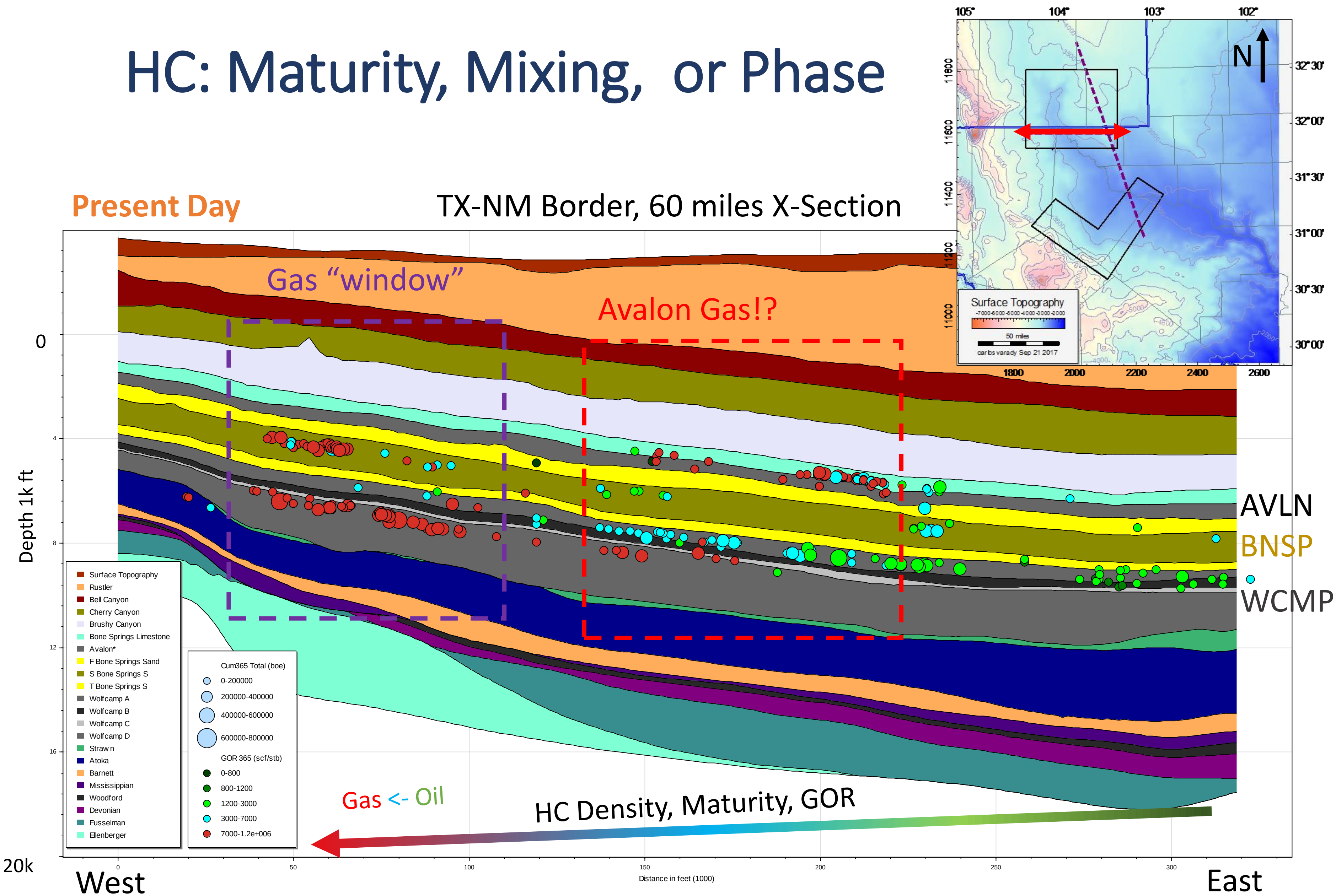
SHCHP is an integrated variable for energy, fluid, seal, and our basin model interpretation

Exhumation Can Lead to UnderPressuring, Expulsion, and Mixing of HC

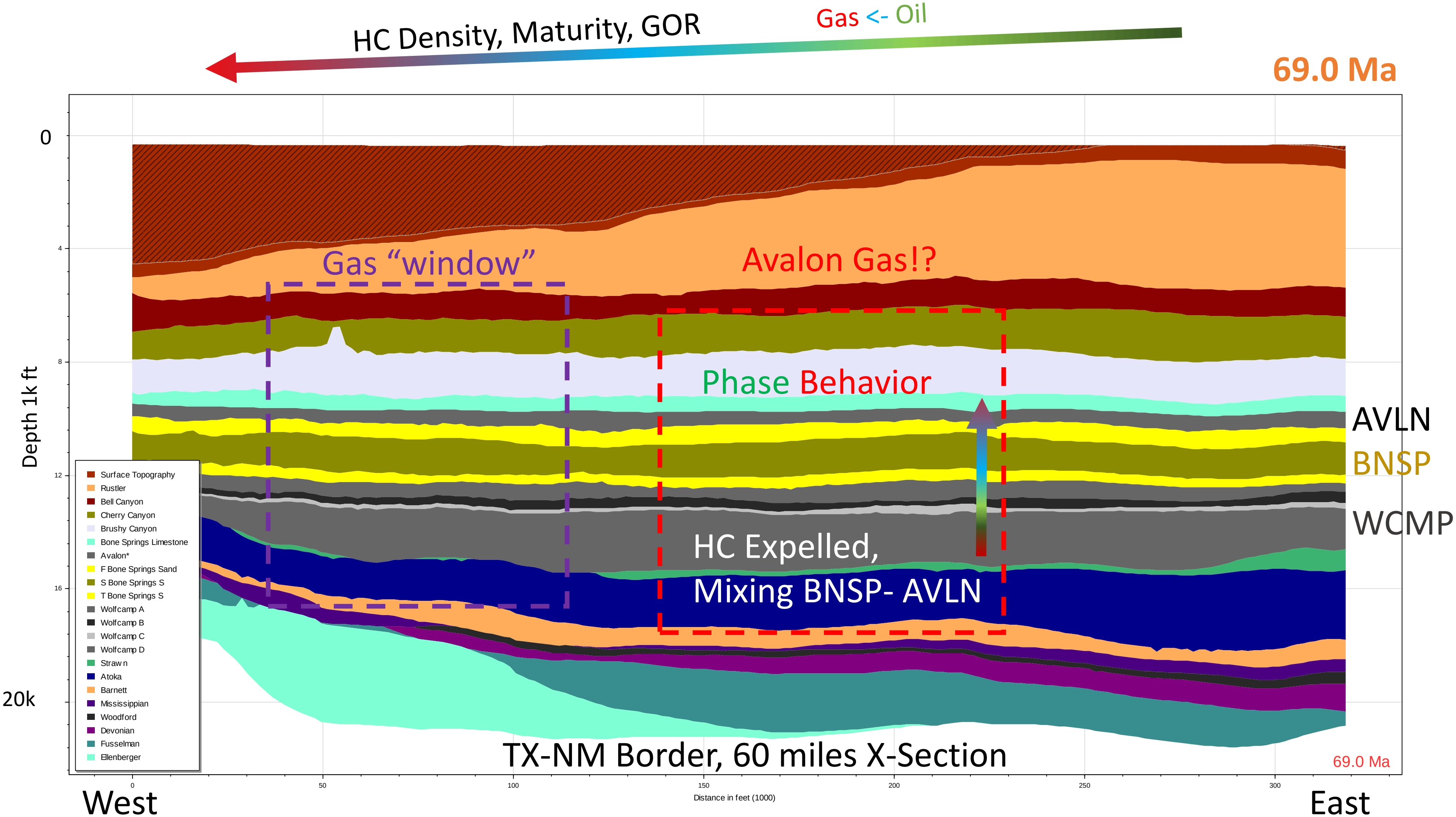


Exhumation may lead to mixing, high-grading HC, and shifts closer to a phase boundary.

HC: Maturity, Mixing, or Phase

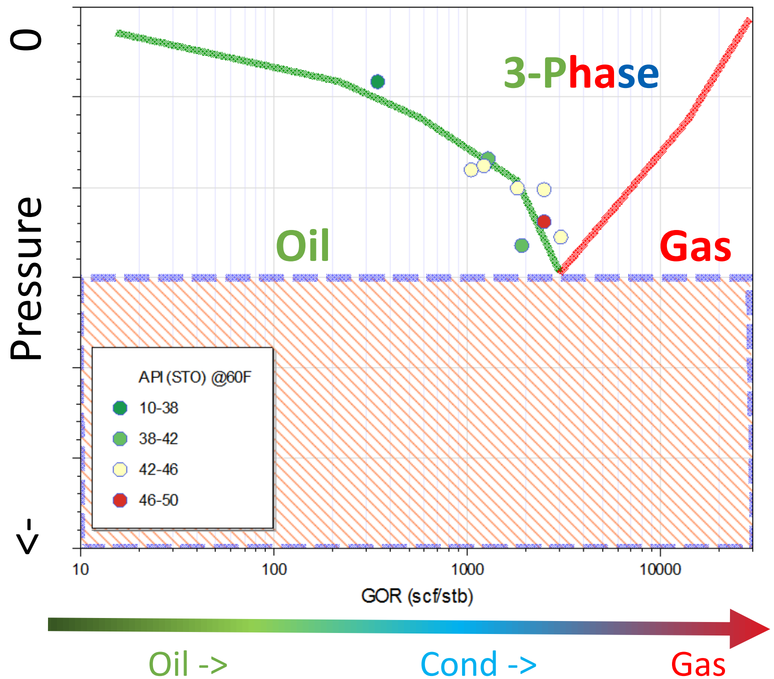


Key: Burial, Generation, Seal, and Exhumation

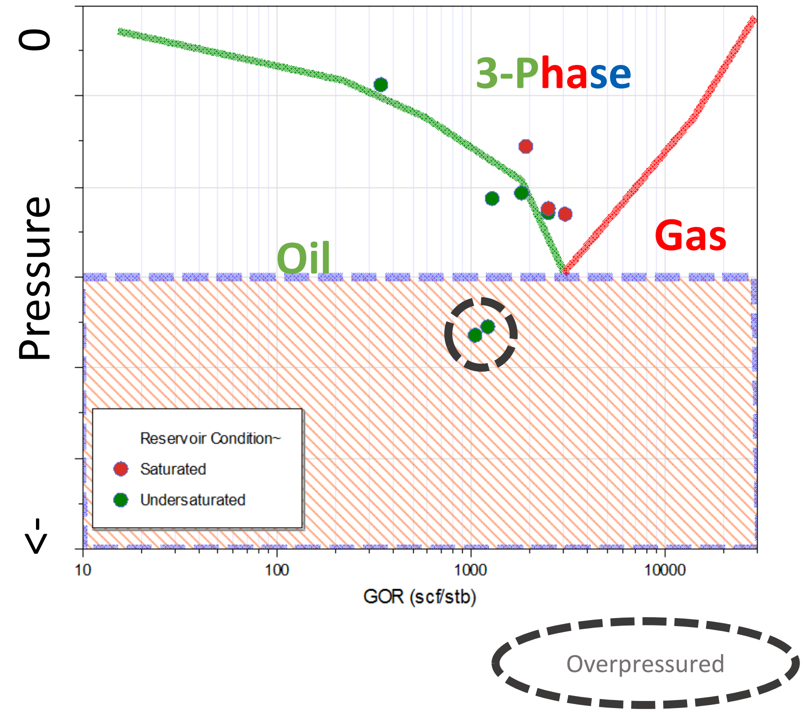


Exhumation May Lead to Phase Separation

Saturation Pressures



Reservoir Conditions



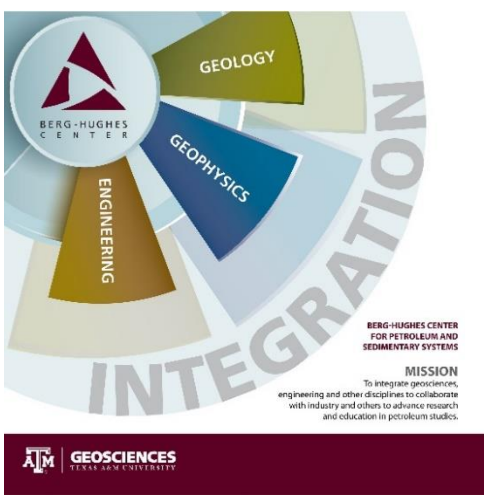
Analysis and Action Feedback is Critical

- **Integration** of spatial and geohistorical variations with engineering operations reveal trends
- *Multiple working hypothesis via multiple lines of evidence implies*:
  - More variability in subsurface than our simplistic relationships
  - Engineering factors impact production (lost opportunities)
- Diagnostic capabilities are as important as estimations or predictive outputs.
  - A feedback between action and diagnostics is only way to improve our analysis process

$$\boldsymbol{Pressure + Phase + Permeability = Performance}$$

Conceptual Model + Integration + Diagnostics = Production

Special Considerations



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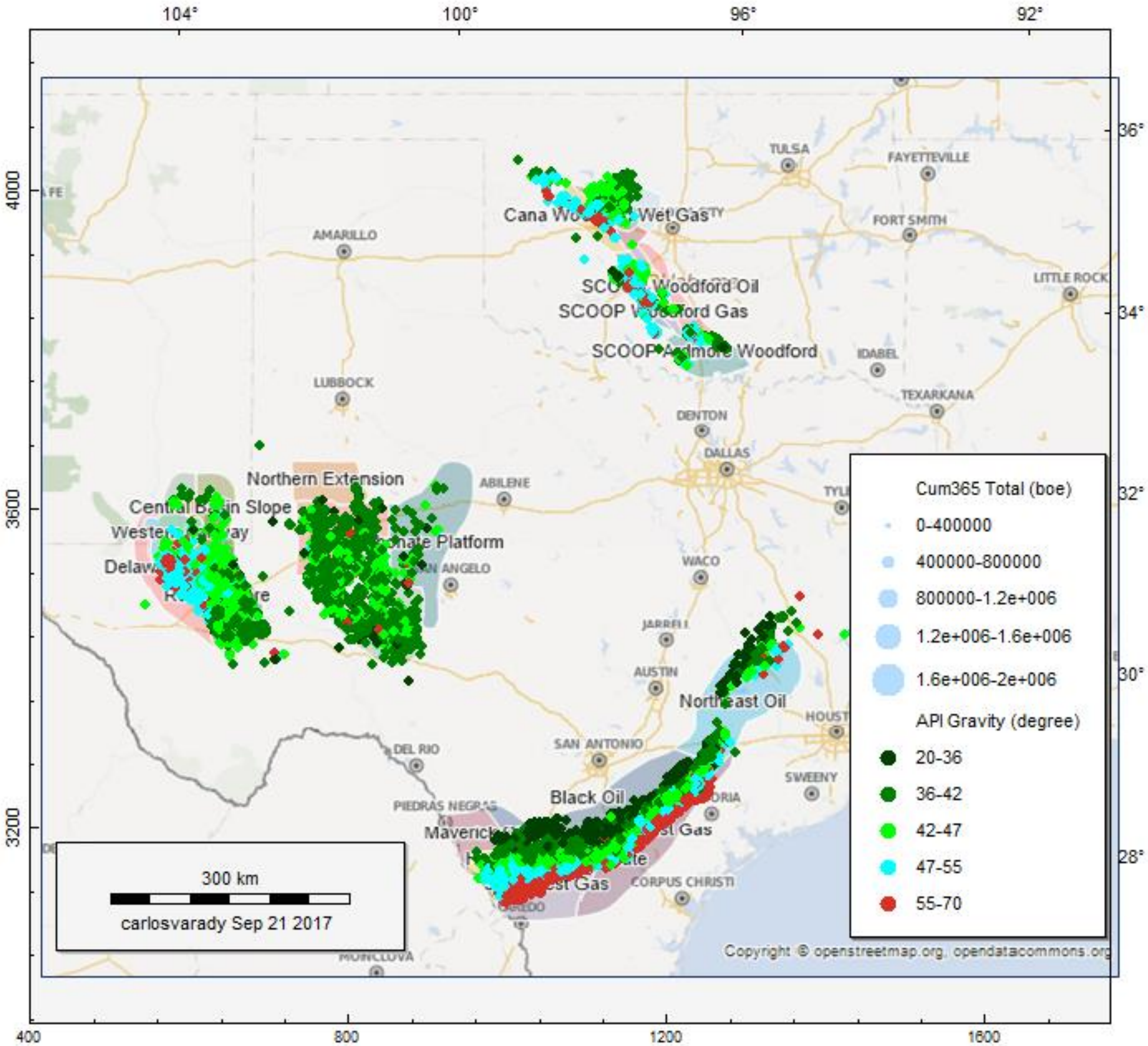
Q & A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