PS Diagenetic Controls on Reservoir and Seal Quality at the Field and Basin Scale*

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Abstract

This workflow for integrated subsurface modeling begins with understanding the pore-level depositional and diagenetic properties that account for porosity, permeability, and capillarity. The effects of burial history (pressure, temperature, and time) on these pore-level properties are determined for each depositional facies or its sub-facies. The product of this workflow is characterization of reservoir and seal quality at any location within the field or basin using facies maps and burial history information from basin models to simulate the key burial and diagenetic modification on porosity, permeability and capillarity.

Conventional core is plugged on some specified interval and helium porosity and permeability to air are measured. Crossplots of these porosity and permeability measurements are a standard technique. Potential trends in the crossplots along with core description are the basis for microscopic inspection of a representative subsampling.

The reason that classification of core plugs by depositional environment alone does not always enhance our understanding of reservoir quality is because it is the pore-level structure of the rocks that control porosity and permeability. The pore level structure of the rock is determined by depositional texture (e.g. grain size and sorting) and post-depositional (diagenetic) factors that may vary considerably within the same depositional facies or be the same in different depositional facies.

Therefore, while we argue that understanding the depositional facies is a critical and necessary step in predicting reservoir quality in an exploration play or extrapolating reservoir quality across a field for infill drilling or reservoir simulation, it is not sufficient. Reservoir quality must ultimately be understood at the pore level. The range of pore level attributes of each facies must be determined. In some cases, “sub-facies” or “petrofacies” (e.g. lithic-rich fluvial channel sands Vs. quartz-rich fluvial channel sands or clay coated dune sands Vs. clay-free dune sands) may be required to subdivide the more traditional depositional facies into like rock types. Ultimately, however, the petrofacies or sub-facies need to be related back to something mappable such

as well log responses or more traditional facies maps. In the latter case, statistical relations between sub-facies and the interpreted depositional facies can aid in data sparse projects.

Combining burial and diagenetic calculations of porosity, permeability, and capillarity for both reservoir and seal quality, one can derive saturation versus height for particular hydrocarbon types. Structure maps allow for ranges of calculated hydrocarbons volumes in place. These simulations establish relationships of sensitivity and uncertainty characterization of plausible assumptions. In fields, where pressure and production data are available, the predicted pore-level properties can be used to simulate production that can then be compared with actual production. The production/development phase is where pre-drill simulations are tested and improved rather than forgotten. This comparison fine-tunes the reservoir and seal quality assessment models. In this way, realizations evaluate and grade prospects after the initial and during the subsequent exploration phase. This cycle of prediction, testing, improvement, and prediction improves all phases of hydrocarbon exploration and field development.

Diagenetic Controls on Reservoir and Seal Quality at the Field and Basin Scale

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Context

ABSTRACT

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Combining burial and diagenetic calculations of porosity, permeability, and capillarity for both reservoir and seal quality, one can derive saturation versus height for particular hydrocarbon types. Structure maps allow for ranges of calculated hydrocarbons volumes in place. These simulations establish relationships of sensitivity and uncertainty characterization of plausible assumptions. In fields, where pressure and production data are available, the predicted pore-level properties can be used to simulate production that can then be compared with actual production. The production/development phase is where pre-drill simulations are tested and improved rather than forgotten. This comparison fine-tunes the reservoir and seal quality assessment models. In this way, realizations evaluate and grade prospects after the initial and during the subsequent exploration phase. This cycle of prediction, testing, improvement, and prediction improves all phases of hydrocarbon exploration and field development.

Is there value in including diagenesis into Integrated Reservoir Modeling?
What is the Cost-Benefit of doing diagenesis on field and basin scales?

Why is "why?" important?

Logs and seismic identify porosity & mineralogy not permeability & capillarity

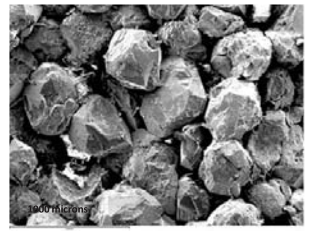
Diagenetic minerals help constrain estimations of pore throat size distribution

Diagenesis and Maturation dominate unconventional resource value

Diagenesis impacts seal quality

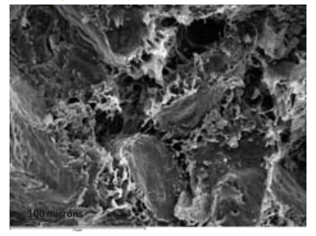
1000X Permeability Delta

Coarse, Quartz Cemented



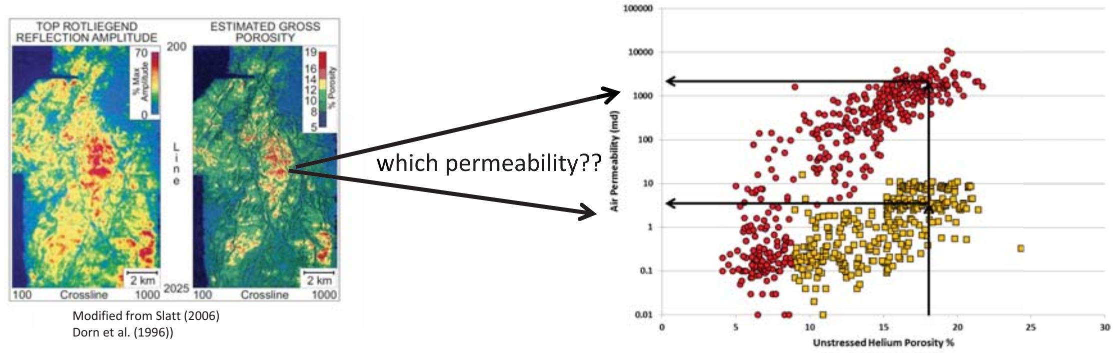
Porosity 19.1% 2200 md

Fine, Illite Cemented



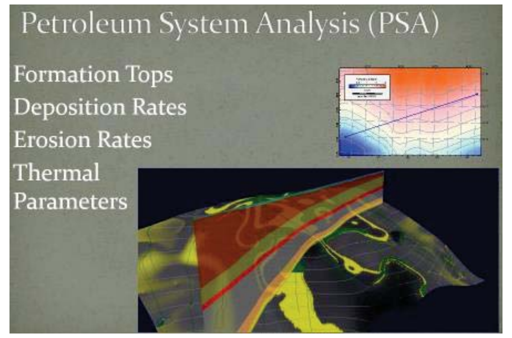
Porosity 20.8% 6.5 md

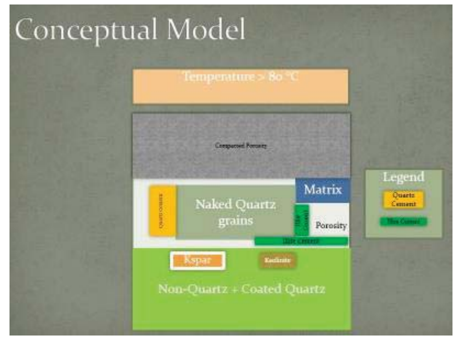
Seismic porosity signatures must be conditioned with permeability relationships
Diagenesis trends have different porosity-permeability relations.



Modified from Slatt (2006)
Dorn et al. (1996))

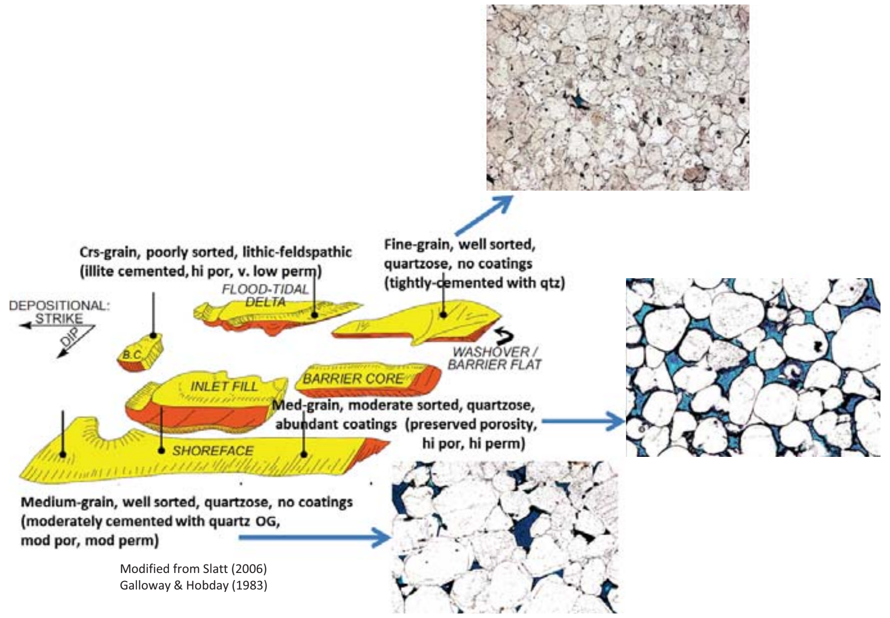
Basin Modeling with Petrographic Analysis





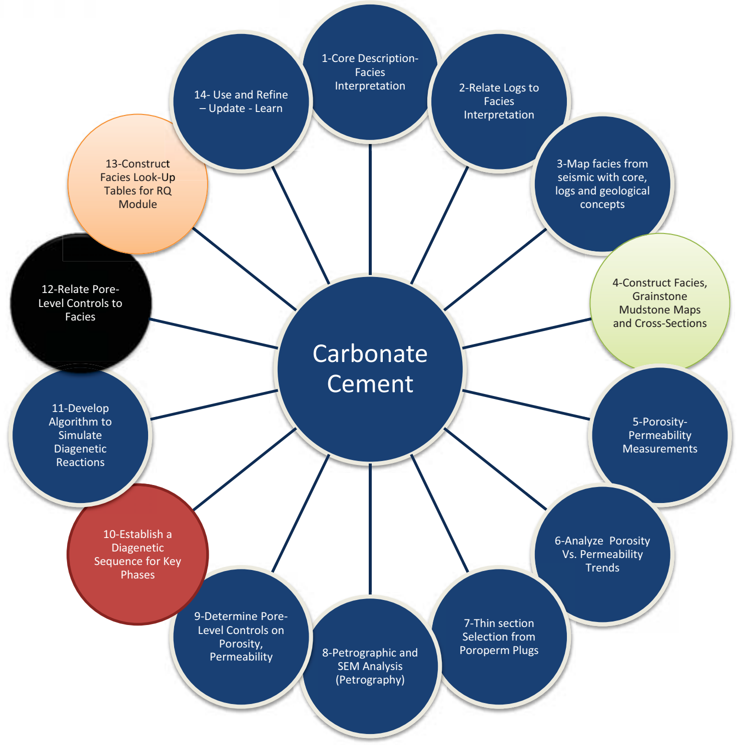
Reduce time/effort by:

1. Understand diagenetic processes that dictate porosity, permeability and capillarity
2. Derive process based empirical relationships using petrographic, petrophysics, seismic, log and sedimentology.
3. Focused data collection to semi-quantify relationships
4. Simplify chemical reactions (Road Block in Past?)
5. Test depositional, burial and thermal history variations across fields in a basin and learn
6. Iterate



Modified from Slatt (2006)
Galloway & Hobday (1983)

Improvements via Deployment



Benefits - Challenges - Opportunities

Benefits

1. Vehicle to integrate petrographic, petrophysics, sedimentology, reservoir simulations, basin models and seismic interpretations via systematic hypothesis testing
2. Tighter looping with exploration process
3. Lessons learned from one field assist in developing others
4. Distribution and ranges of reasonable parameters
5. Field geometries in basin establish better understanding of depositional and cementation histories internal to fields

Challenges and Opportunities

Challenge	Opportunities
• Limited Technical Expertise	• Fascinating
• Historical Silos	• Evolving Environment
• Minimal Success	• Minimal Success

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