High Resistivity, High Porosity (Apparently) Monterey Formation: What Is Its Lithology and How Do We Analyze the Logs?

Presented by:
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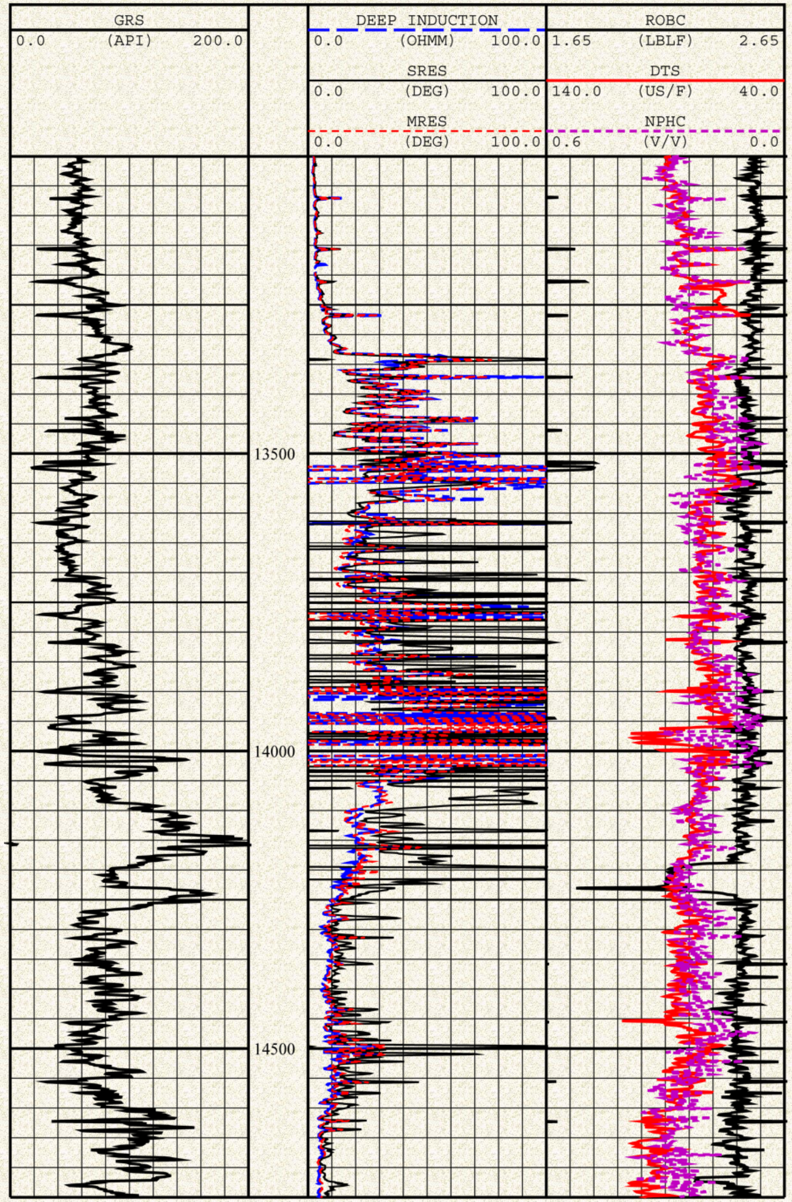
Disclaimer

- This should go without saying, BUT....
  - All the log examples in this talk are public data, and all analyses were performed as examples for this presentation
  - No client data are shown in any log example
  - We conducted our own research into the rock properties and physical processes responsible for these anomalies.
  - We have not used any client proprietary research or documentation in deriving the models or work approach.

Background

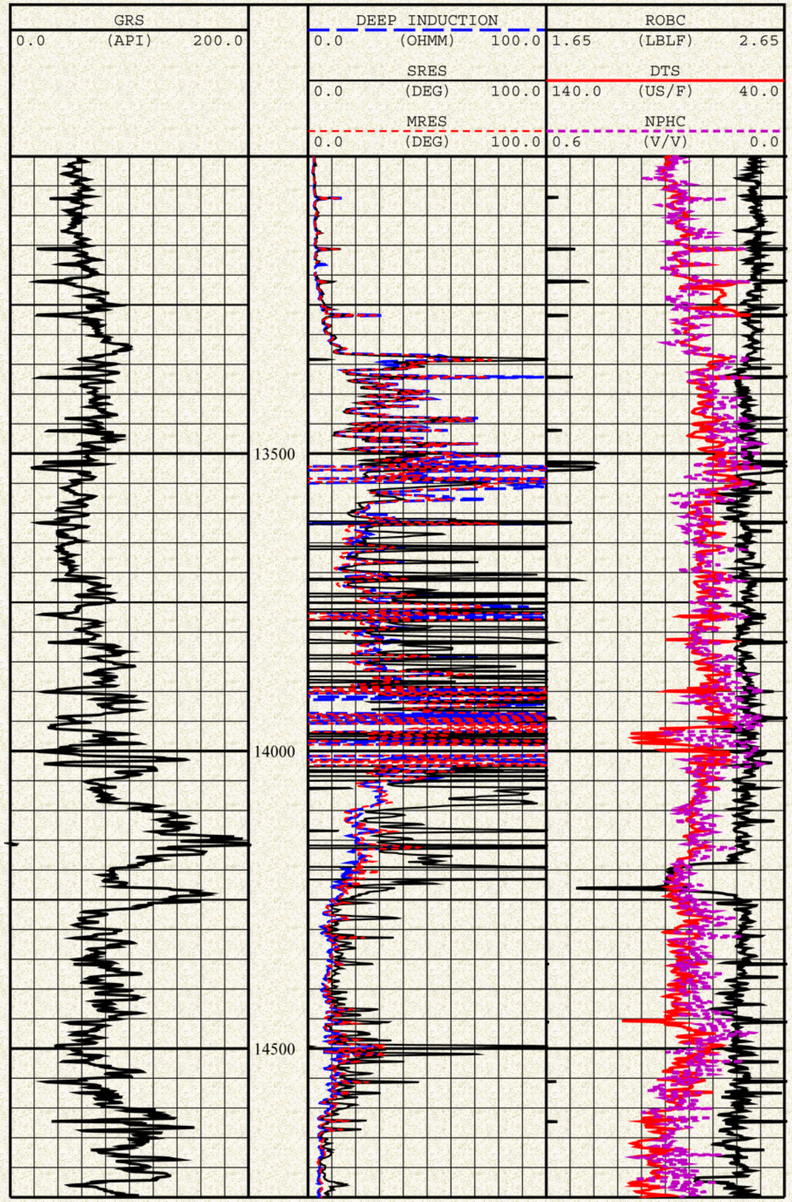
- We first encountered the log sections and rocks I am going to show you today through client work, when we were presented with logs and well performance data that did not agree
- Our goal was to adapt our models to provide our clients with accurate quantitative results
- On the basis of our research, we have refined our Monterey petrophysical model to handle these unique rocks



The Problem

Below the Ct/Quartz transition in the San Joaquin Valley, there is a facies of the Monterey Formation characterized by:

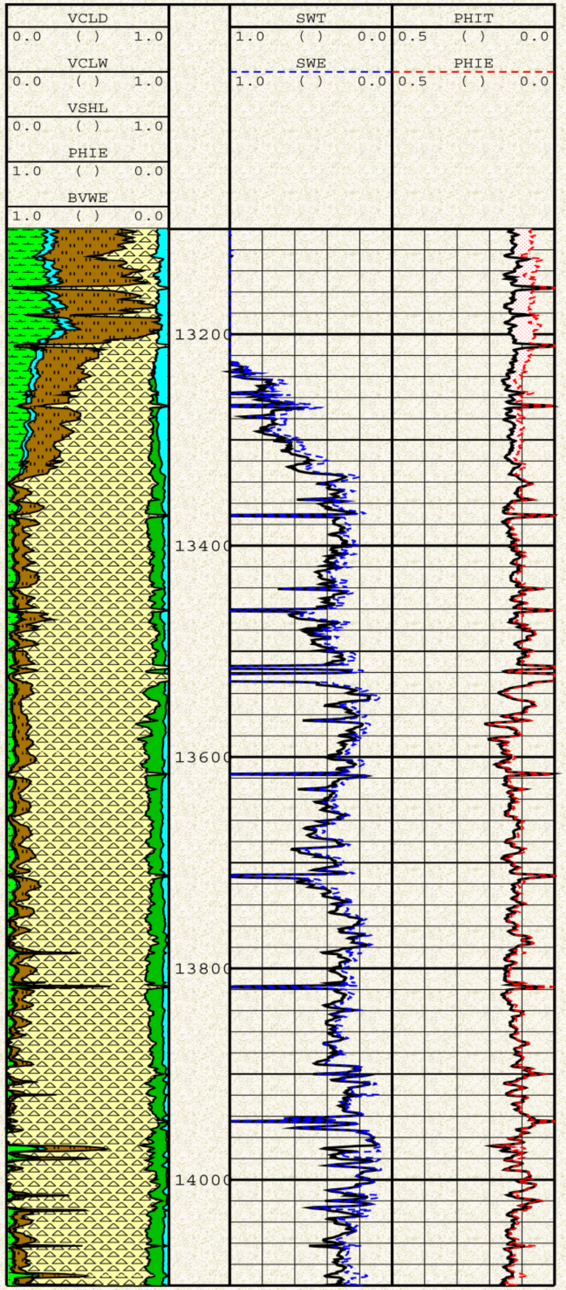
- **High resistivity (can be >100 ohm-m), usually spiky**
- **Moderate to high apparent porosity for the depth (>20% at 8000’-9000’, can be >10% below 13000’)**
- **Gamma logs are variable but not necessarily high; GR is moderate in this example**



The Problem contd…

Mudlog descriptions show chert and porcelanite: generally hard, brittle rock with low clay/clastic content

- **Colors are dark brown to black, sometimes mudlogs mention organic matter**
- **In many (most?) wells with this log signature, mudlog shows of oil are minimal to none, though they may have moderate total gas and some or all of C1-C5 spectrum**
- **LVT muds complicate the evaluation of mudlog hydrocarbon shows in these rocks**

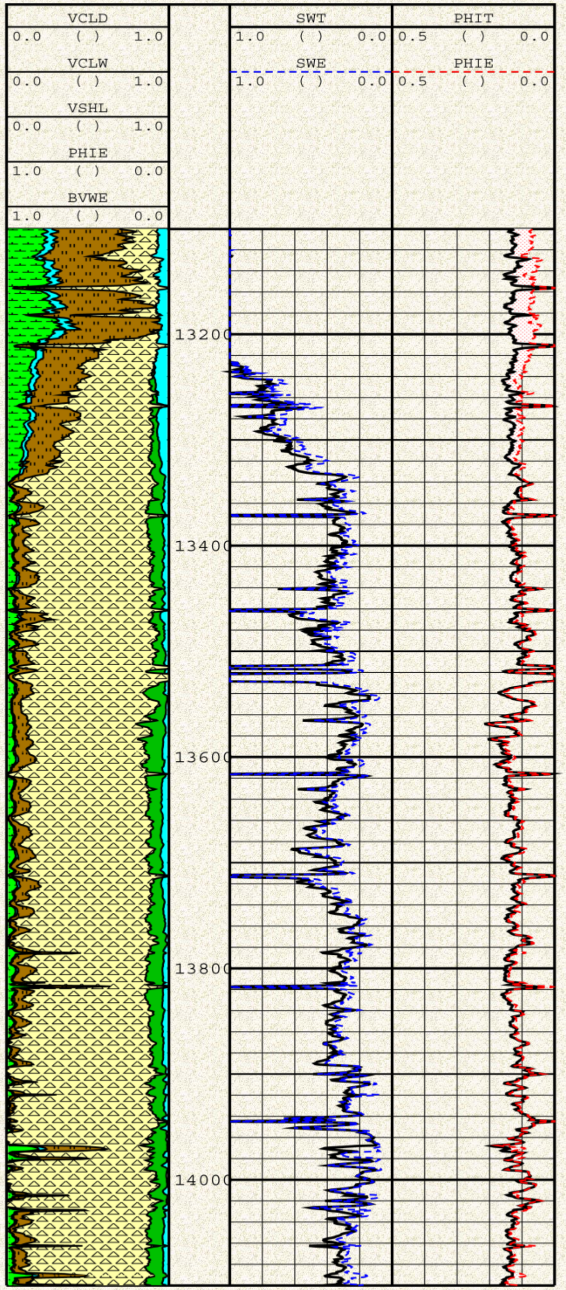


Results from Standard Petrophysical Analysis

If you use conventionally acceptable parameters for clean siliceous rocks at depths >12000’, and Rw consistent with ~30K ppm, this is what you get from the analysis. Oil everywhere!

But the mudlog says:

“No cuttings gas, no significant hydrocarbon indicators”



What Happened???

The mudloggers missed the shows, it was LVT mud

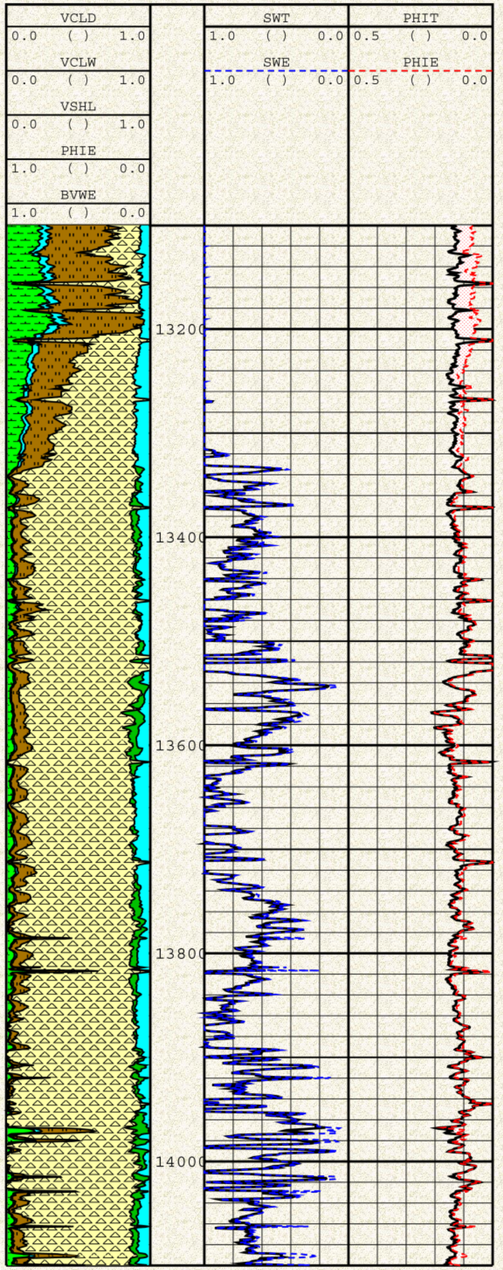
But these guys are good, they know LVT and PDC bits, they even mention that there are no HC indicators beyond the LVT background

The mud was too heavy and therefore suppressed the shows

Well, maybe, but if there's this much oil is it reasonable that there are no shows anywhere in the zone?

It's deep, it's all gas

Could be, but there are oil indications at similar depths elsewhere, and there are shallower sections definitely in the oil window that look just like this



What Happened??? (continued)

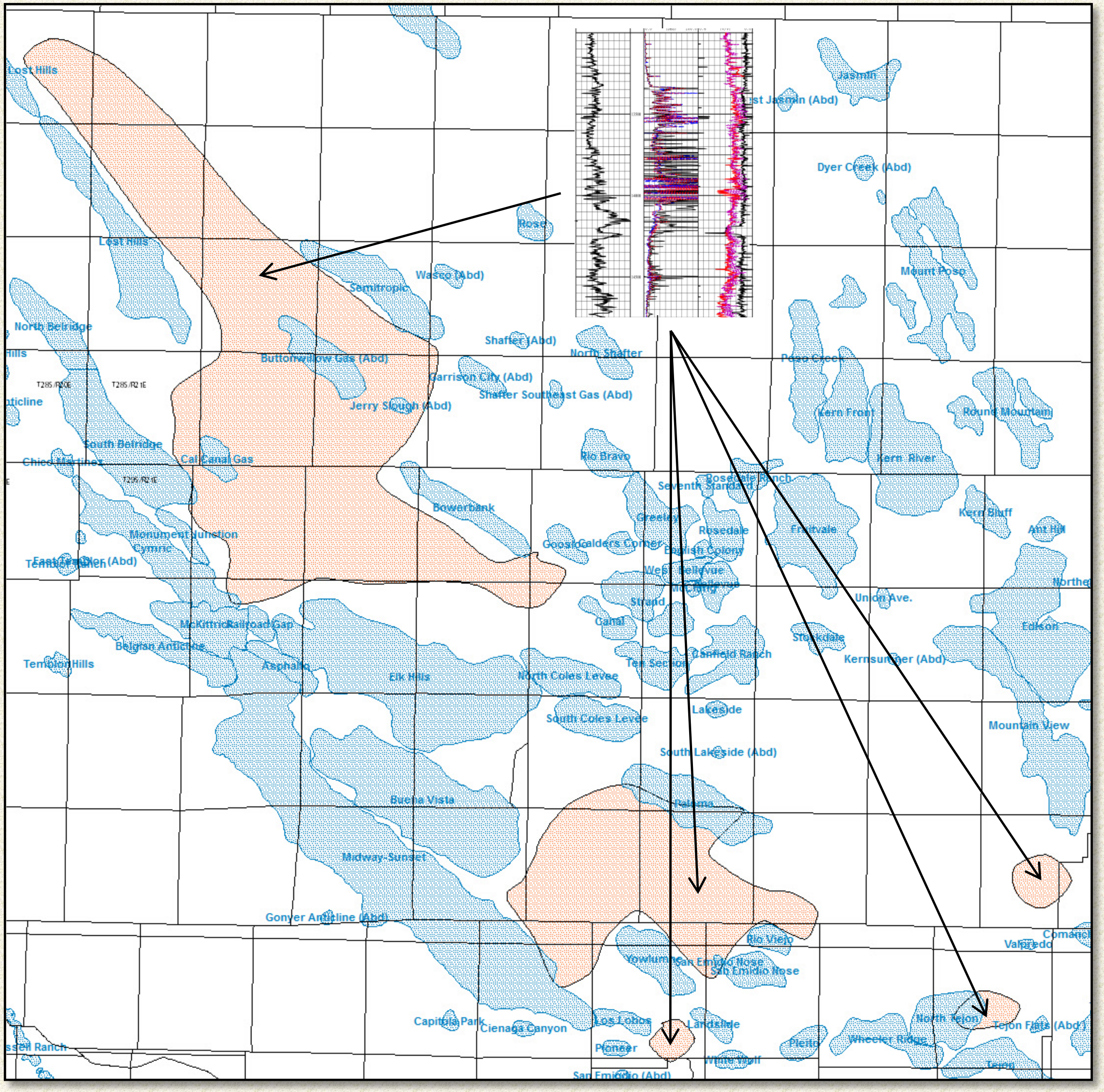
Connate water salinity can vary in the SJV, maybe we have fresher water than 30K ppm

Well, OK, let's try varying Rw. Here is the section run at Rw = 2 ohm-m @75deg F. Better, but still has Sw some people would consider testing.

Does anybody believe the deep Buttonwillow basin has water at 2800 ppm?

Is This Important?

- We believe that it is very important to understand this Monterey facies
- It is not an isolated occurrence in a few areas, and it can be very thick (>1000')
- The potential Monterey "resource play" as identified by the USGS and others is probably based, in part, on the high-resistivity log signature of this facies in the deep basin areas
- The "classic" occurrence of this facies, as shown in this example, is present mostly in the deep basin, but we have seen several sections in wells on structure where we believe that the rock is transitional to this facies, and that the same analytical principals must be applied to avoid overestimating So and interconnected porosity



Areas of the SJV Where High-Resistivity Deep Monterey is Present

This is not a comprehensive map. Some deep basin areas are undrilled to sufficient depth, and we have not looked at all the deep wells which exist. This Monterey facies probably is present in much of the deep Maricopa basin, as it is in the Buttonwillow basin. It is also present in places west of the Belridge trend.

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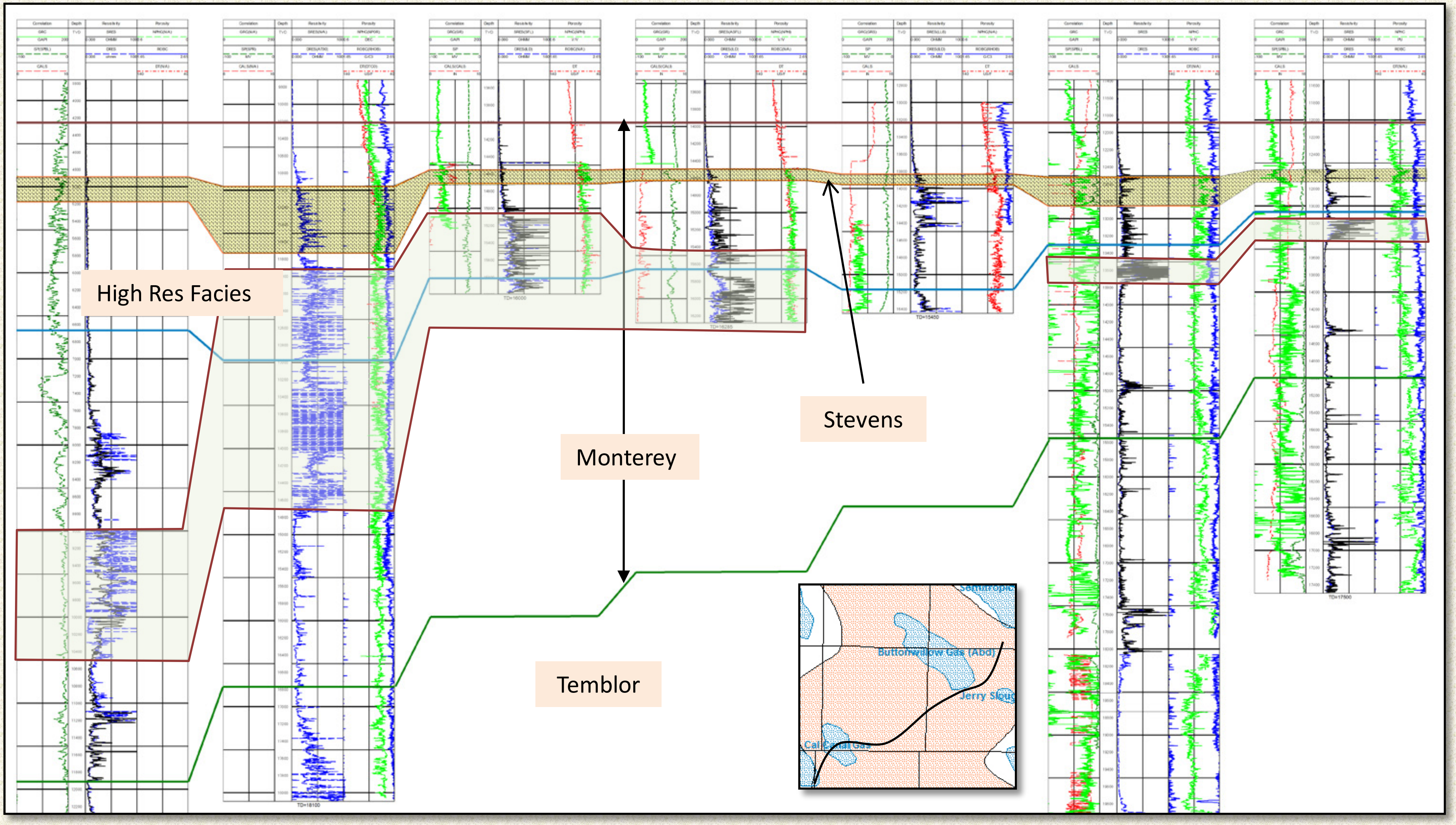
Cross Section Across Buttonwillow Basin from Cal Canal to Near Semitropic



So, What Is This Rock?

- What do we know about it?
  - Clean to very clean siliceous rock, generally described as glassy chert and porcelanite with conchoidal fracture and other indications of high silica and low detrital content, also some pyrite is mentioned
  - Probable high organic content:
    - colors are dark brown to black for all lithologies,
    - mudlogs occasionally mention organic matter
  - Quartz phase diatomite has undergone significant diagenesis and reshaping of the pore network
- It is therefore a sequence of porcelanite and chert with high TOC and probably a significant amount of secondary or at least highly altered primary porosity

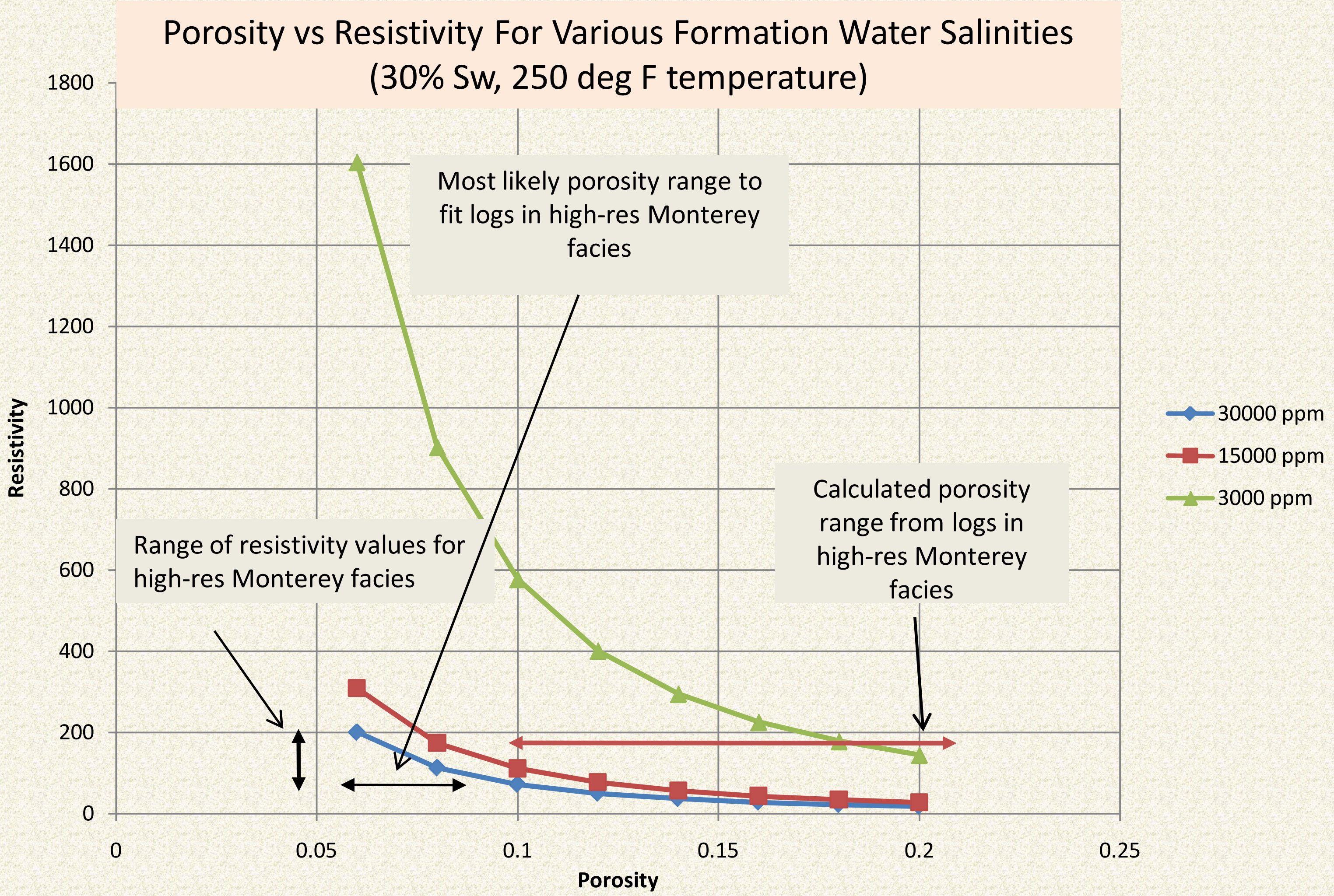
Clues

- Most obvious: high resistivity
- Apparent density/neutron/sonic porosity of (in most occurrences) 10%-25%, depending on depth
- Variable GR, probably affected in part by U associated with the organic matter, but not consistently high
- Standard analysis shows low Sw in intervals with minimal mudlog shows
- Well completions/tests show high water cut, low rate, or other less than satisfactory results
  - There are not many tests or completions in this facies

Unraveling the Mystery

- The main problem, from an analysis standpoint, appears to be that the porosity is too high
  - The resistivity log reading in a given rock is a function of the amount of porosity, the volume fraction of conductive fluid filling that porosity, the conductivity of that fluid, the presence of any conductive clays, and the tortuosity of the current path.
- RT is generally proportional to the bulk volume of water present in the interconnected pore system
- For a given porosity, RT will increase if:
  - Some of the water is replaced by hydrocarbons
  - Some of the water is trapped in isolated pores
  - Cementation or other processes have greatly increased the tortuosity of the current path

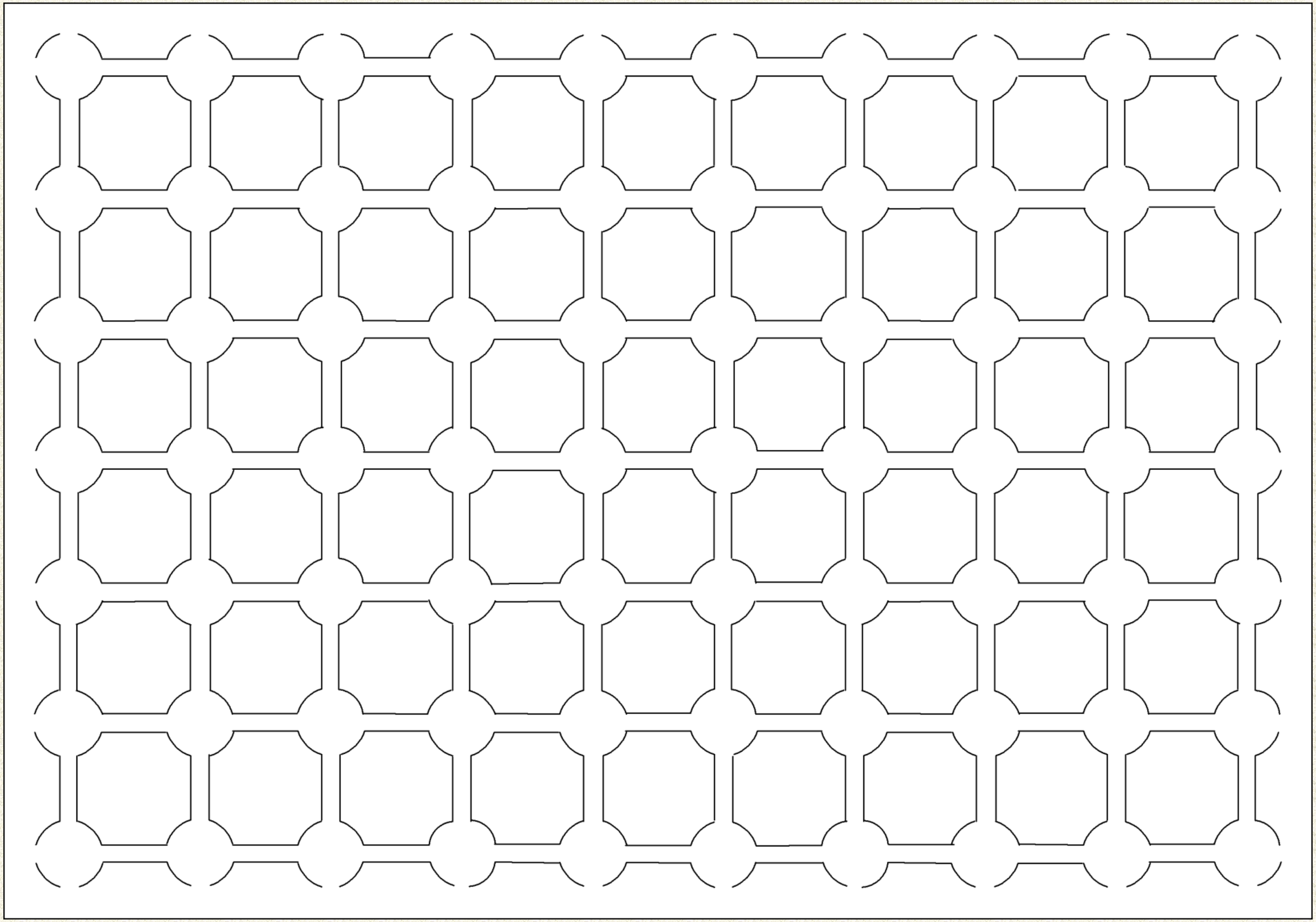
You Can't Get There From Here: The Calculated Porosity is Too High For the Measured Resistivities



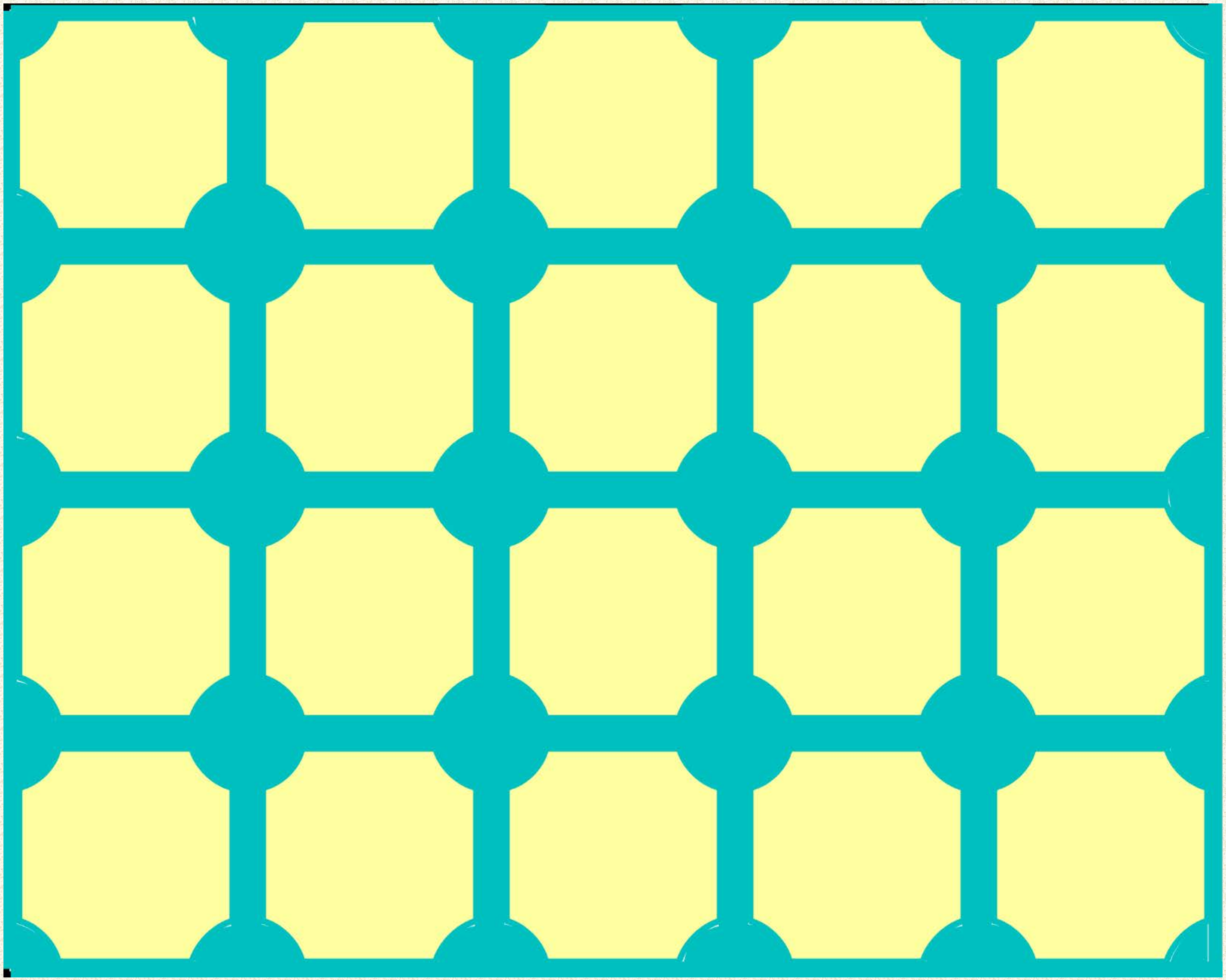
Resistivity Logs

- The induction and laterolog-type resistivity logs “see” the electrical conductivity of materials within interconnected pores of the rock
  - Conductive materials include salt water and clay minerals
  - The magnitude of the measurement depends on the flow of current through the conductive medium
  - If there are pores present which do not communicate with other pores, they look like infinitely resistive rock to the logging tool
- So, the resistivity logs in this Monterey facies are behaving as if they do not “see” all of the porosity apparently measured by the porosity logs

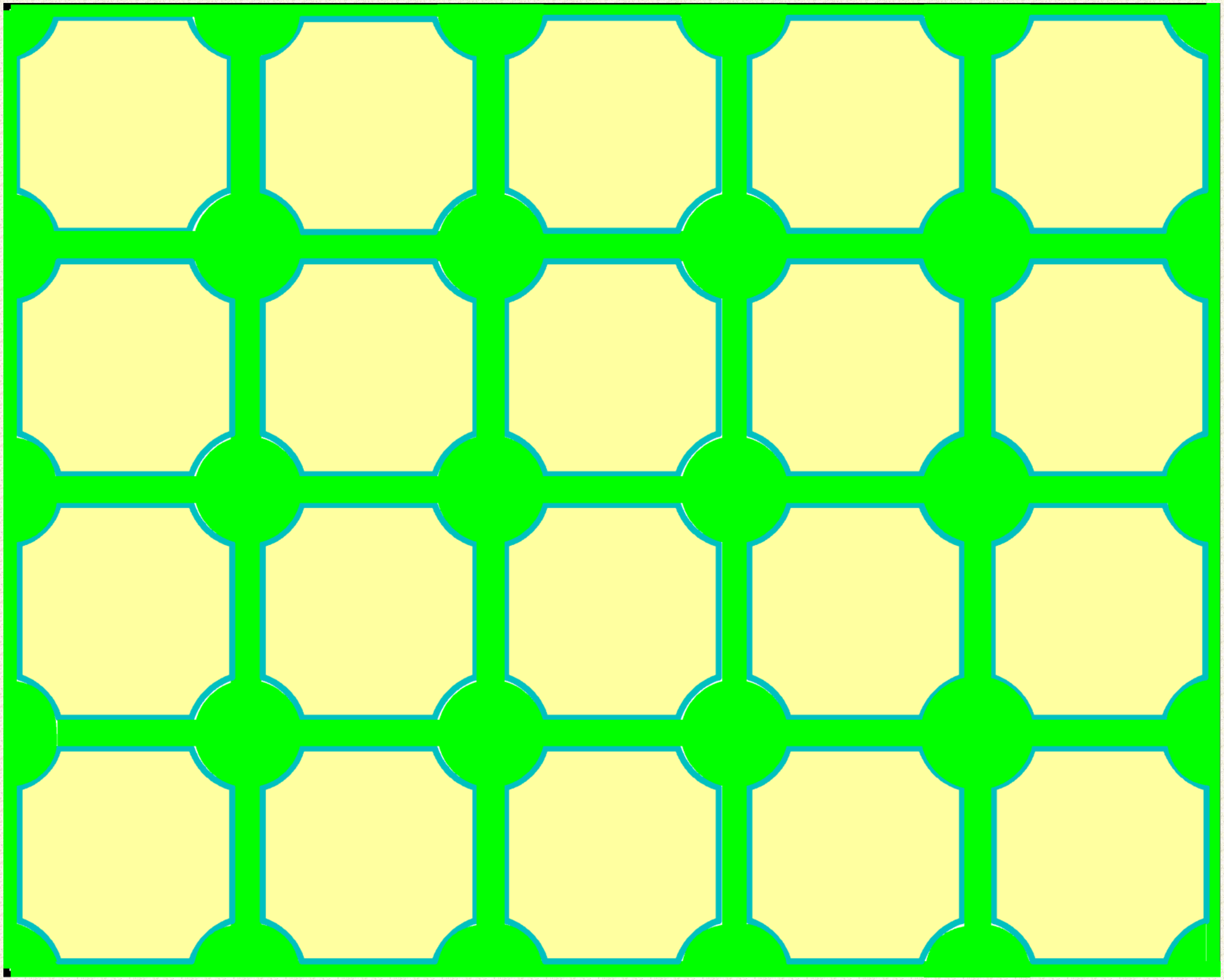
Simple Model of Open Pore System in Biogenic Siliceous Facies



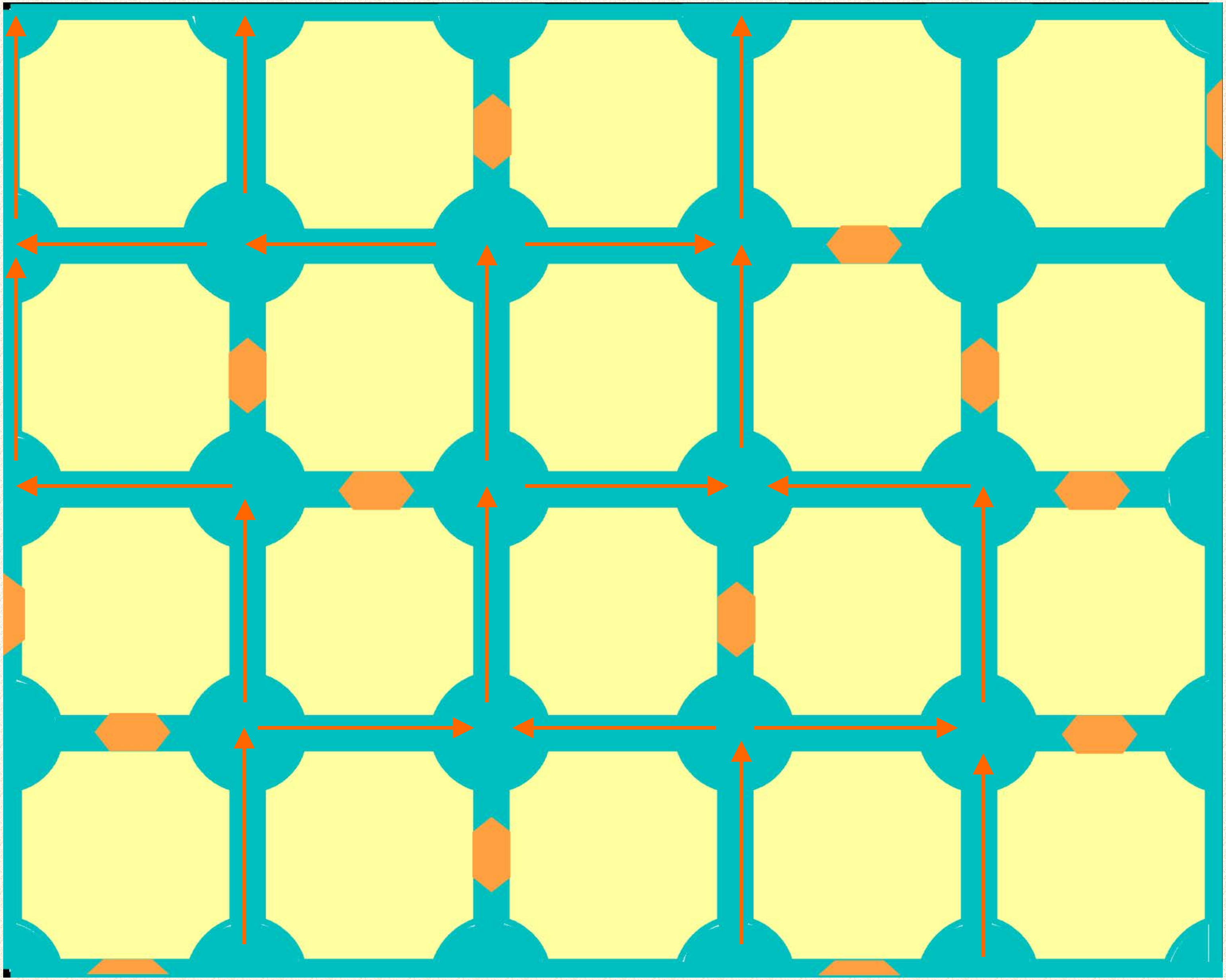
Open Pore System 100% Wet



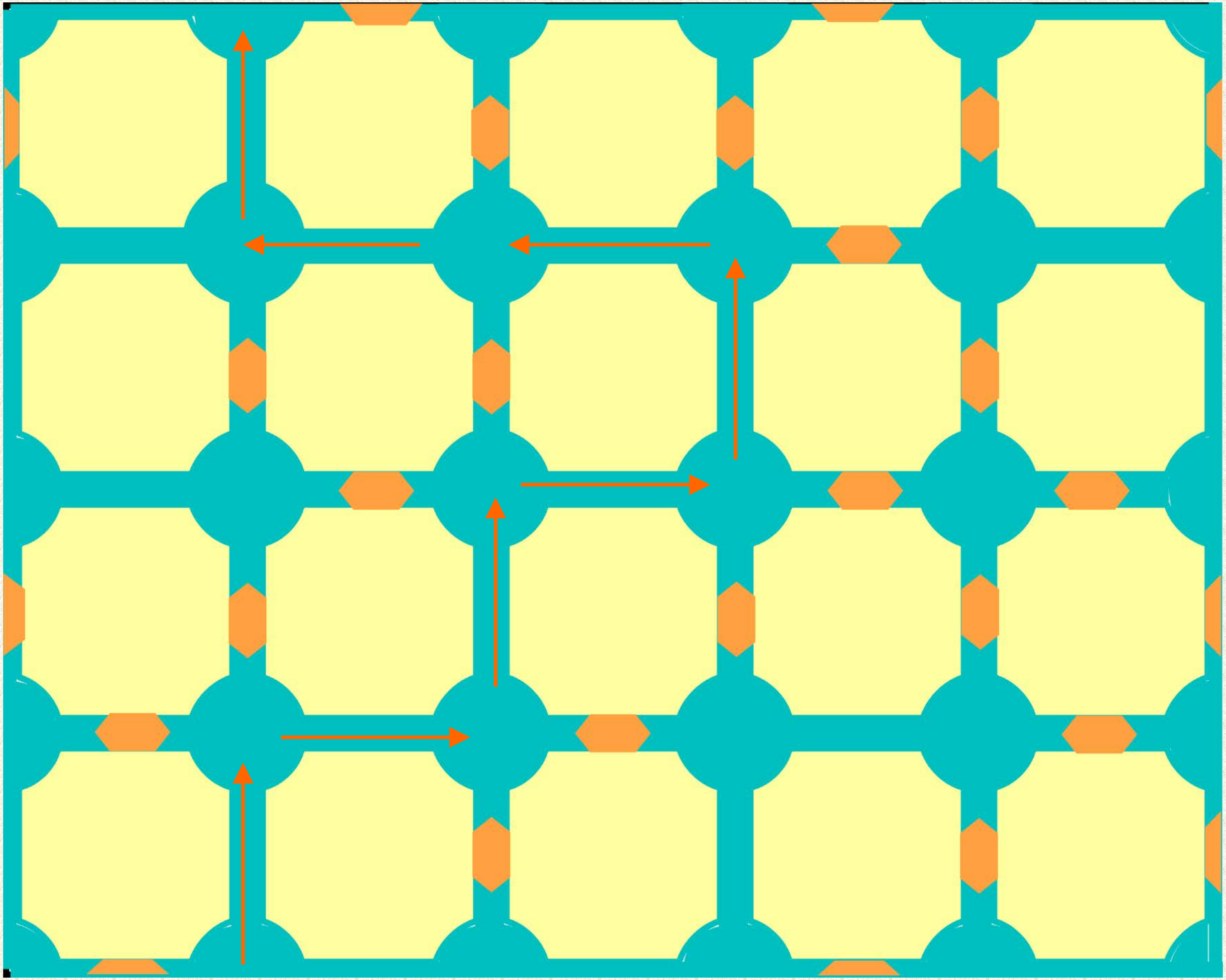
Oil Saturated Water Wet Open Pore System



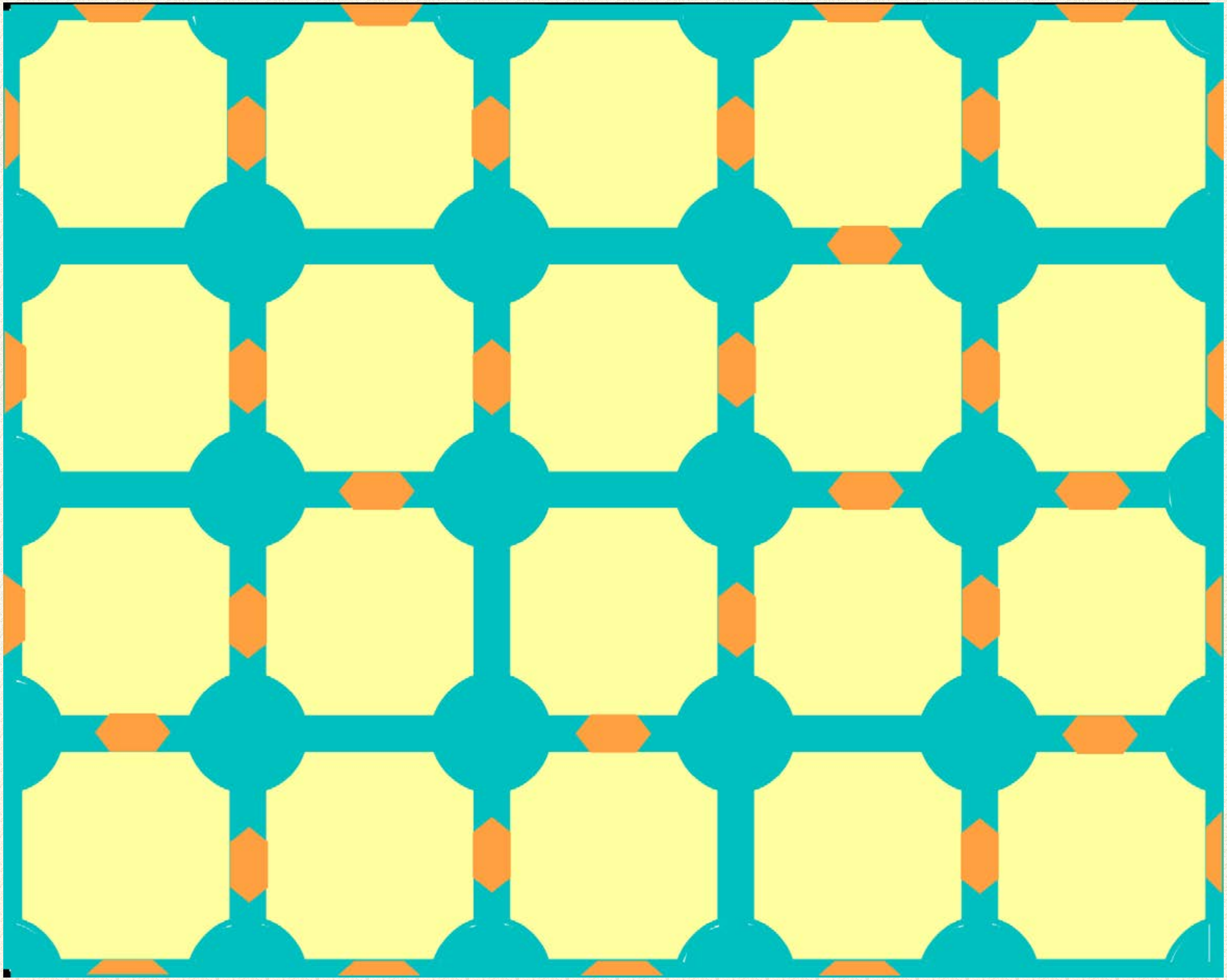
Partially Cemented 100% Wet Pore System



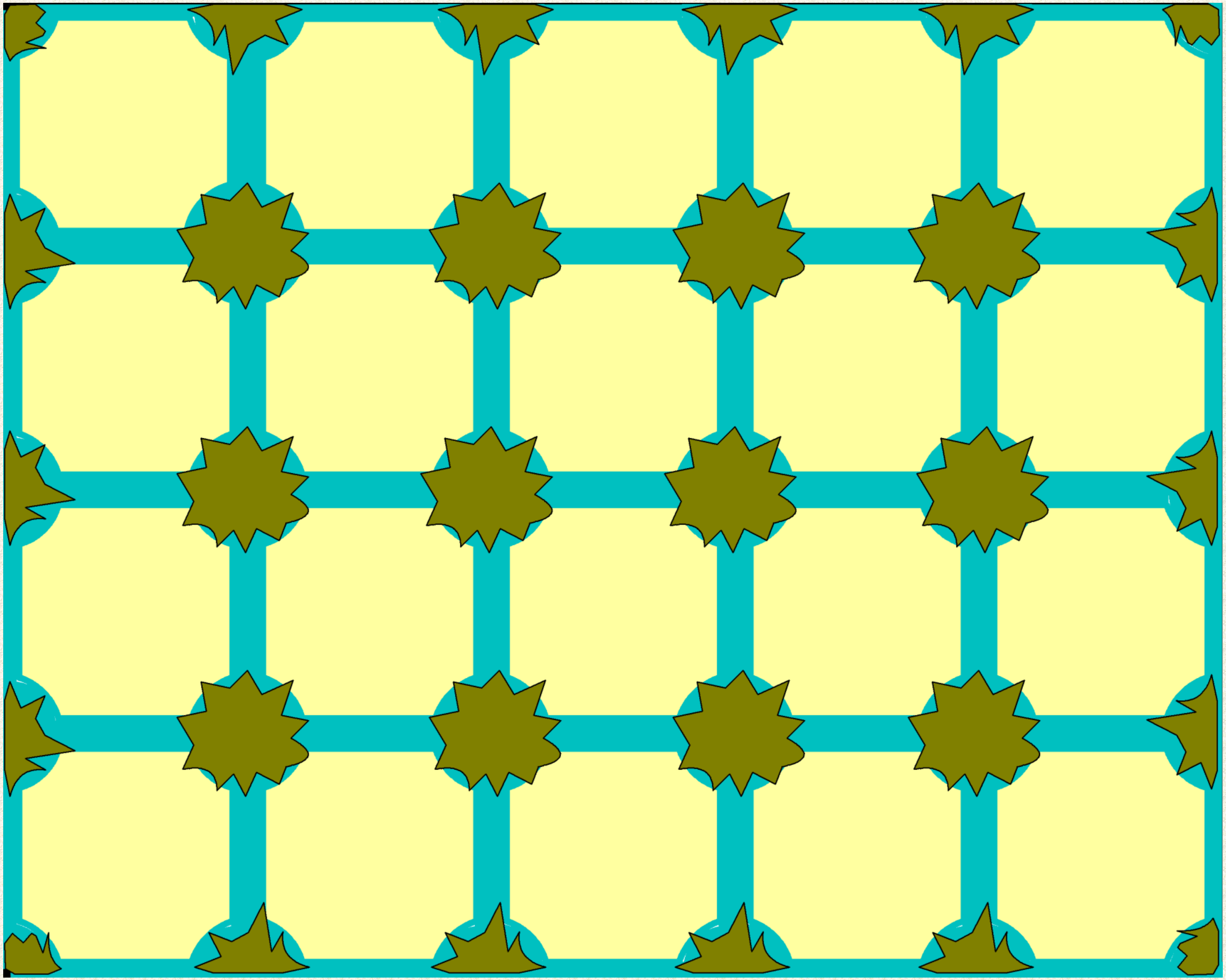
Heavily Cemented 100% Wet Pore System



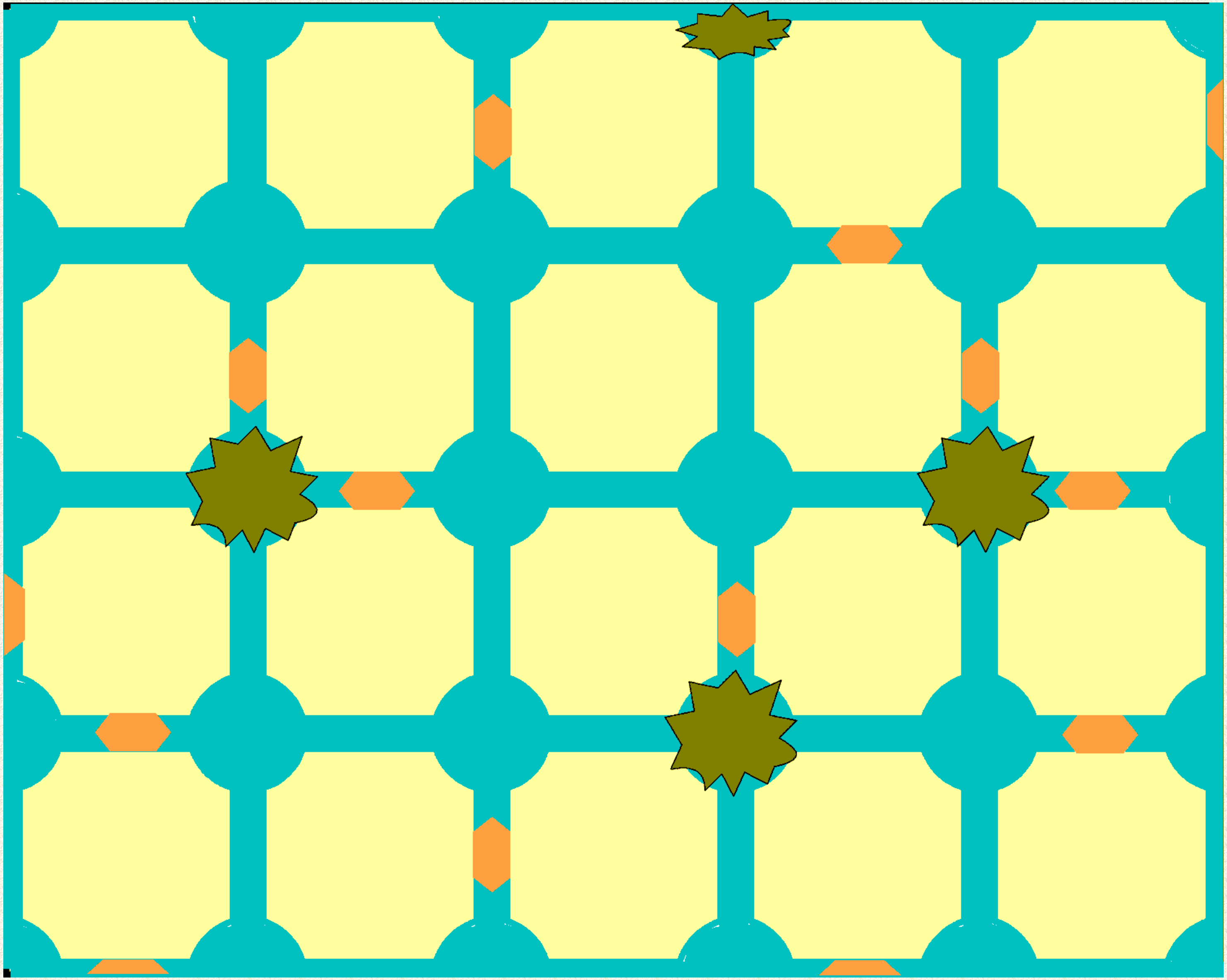
Fully Cemented 100% Wet Pore System



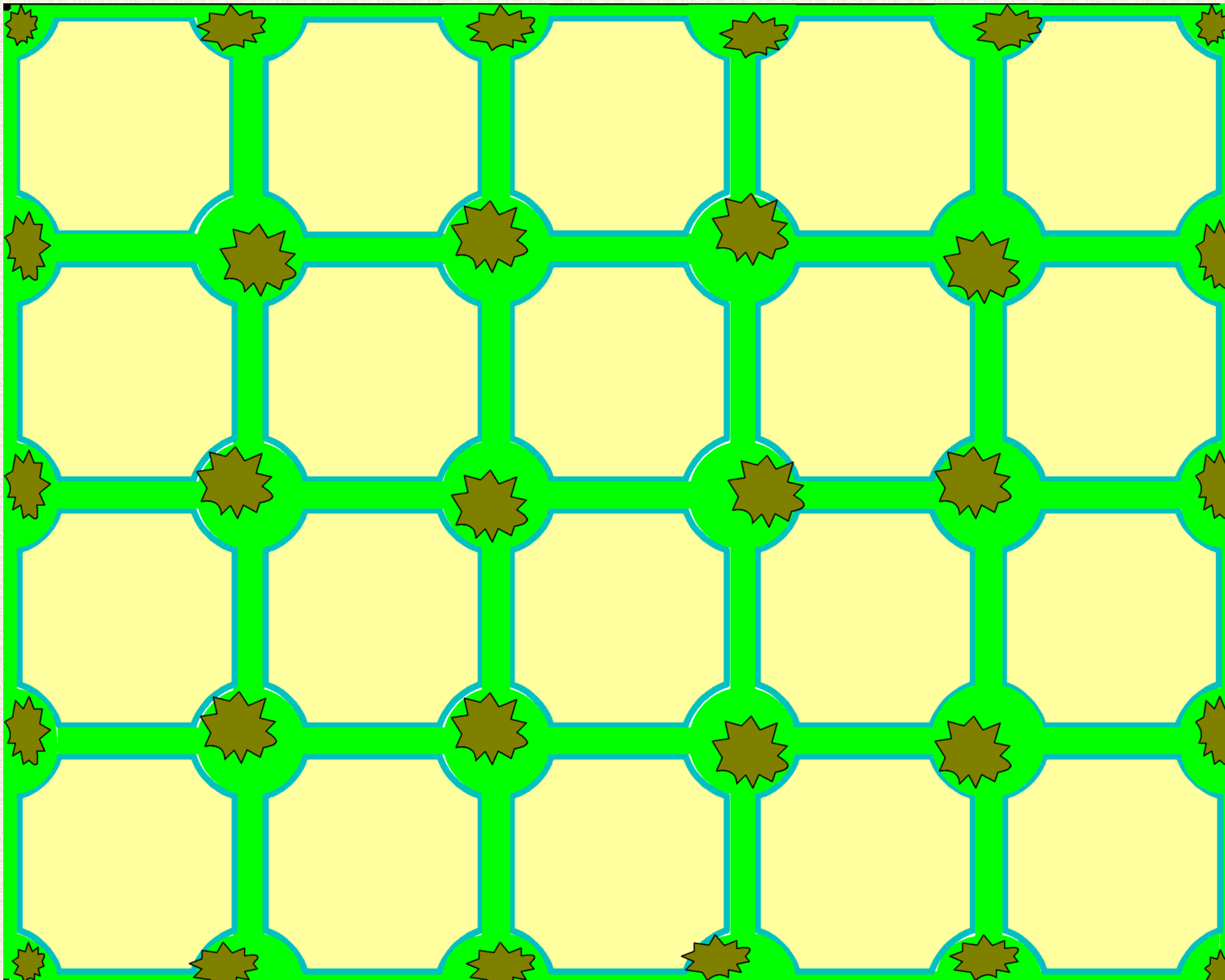
Immature Kerogen in 100% Wet Pore System



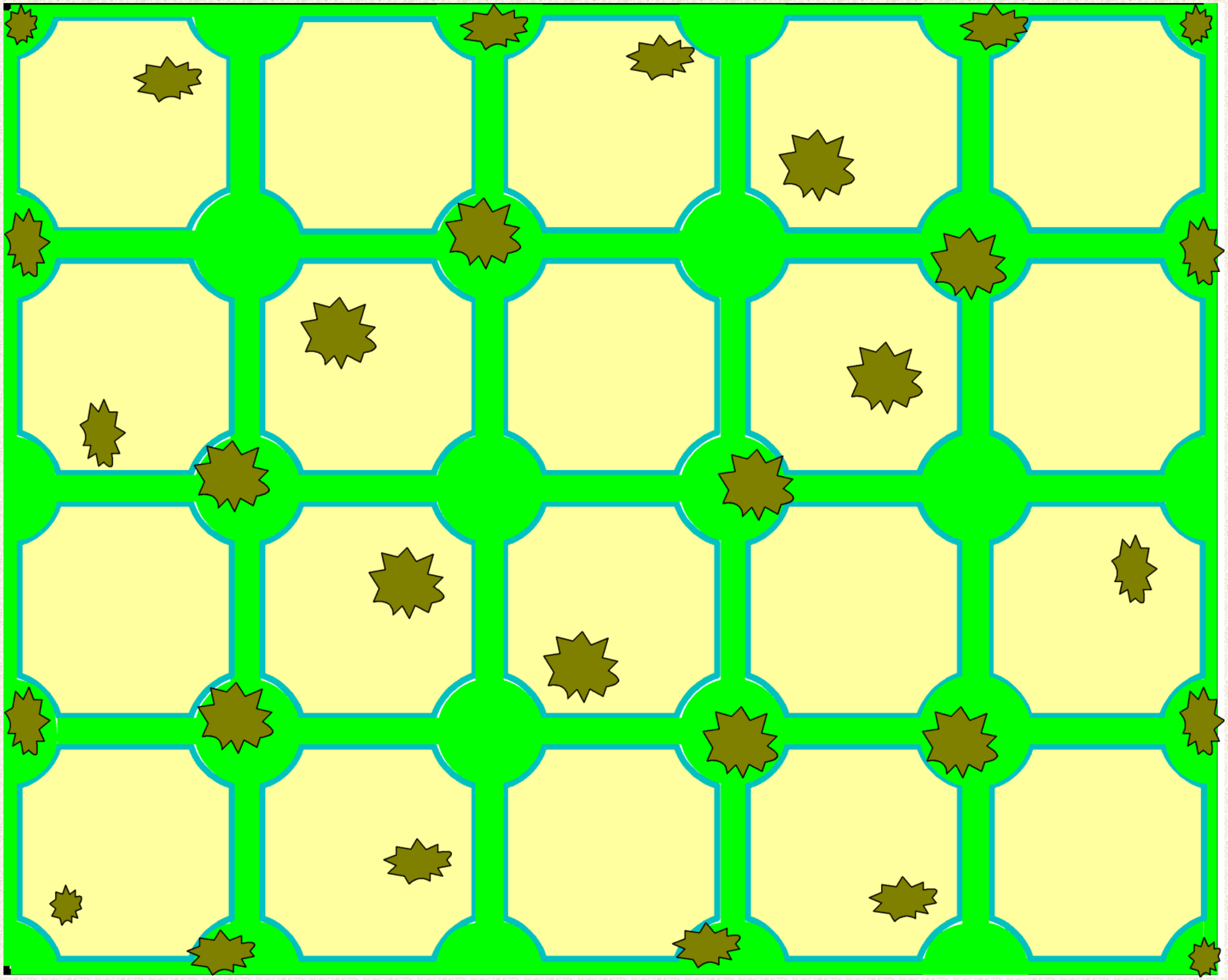
Partially Cemented & Kerogen in 100% Wet Pore System



Mature Kerogen & Oil in Open Pore System



Mature Kerogen in Matrix & With Oil in Open Pore System



Porosity Logs

- Modern wells drilled through the high-res Monterey facies generally have density, neutron, and often sonic logs in addition to the resistivity logs.
  - The density log counts gamma rays back-scattered by collisions with orbital electrons, which are proportional to the nuclear mass of the entire rock fluid system. Through a simple partitioning equation which accounts for the density of all of the components, we can derive porosity.

Porosity Logs

– Neutron tools detect neutrons slowed and back scattered by collisions with hydrogen nuclei, which are primarily found in water and organic matter. Thus, porosity is derived by a non-linear proportionality where the hydrogen ratio per molecule is roughly the same for water and most hydrocarbons. Porosity is proportional to the population of H because there is very little or no hydrogen in the minerals comprising the rocks.

Porosity Logs

– Sonic logs measure the travel time of sound waves through the rock fluid system. The non-linear proportionality of p wave travel time to porosity is a function of fluid properties, acoustic properties of the rock matrix, the degree of cementation, and the influence of overburden on grain to grain contacts.

What Causes the Apparent Porosity Anomaly?

- Grain density is 2.65 g/cc or higher, so we cannot look to a low matrix density to reduce the computed porosity
- Our research and observations indicate that the high-resistivity, apparent high porosity Monterey facies is:
  - A rock whose **high kerogen content** is plugging a significant fraction of the porosity
  - And/Or
  - A rock in which extensive diagenetic alteration of the siliceous material has created a number of **isolated pores** filled with non-movable fluid
- Most likely, these rocks have both kerogen plugging and diagenetically-isolated pores

Proof?

- We do not have sufficient laboratory measurements for robust quantification of either the isolated pore or the kerogen filling attributes in the Monterey.
- Our models were programmed years ago to account for an isolated pore network that was cored and described in highly siliceous shales in **Pennsylvania**. The same algorithm, modified to account for Kerogen, can be used effectively in the **Monterey**.
- The descriptive work of others found in recent literature is sufficient to characterize the role of immature kerogen in the partial or complete occlusion of an otherwise open pore system.
- In the few instances where core data covered the high-res rocks, we have interpreted anomalously low core measured porosity as having isolated pores that were not measured by the lab porosimeter.
- While the data are sparse, low lab measured values of matrix density (<2.65 in chert) suggest the rock contains isolated pores.
- The theory fits the available data and explains the high resistivity readings in rocks with apparently normal formation water salinity but low free hydrocarbon content

Analytical Options in Conventional Petrophysical Models

- Tamper with the porosity logic parameters to derive better estimate of interconnected porosity:
  - Create pseudo matrix values for porosity functions
    - Artificially reduce matrix density
    - Artificially rescale neutron porosity
    - Artificially change delta T matrix or rescale Raymer transform
  - Drawbacks:
    - Pseudo matrix parameters must be varied in proportion to change in porosity.
    - Very awkward when using cross plot porosity logic

Analytical Options in Conventional Petrophysical Models

- Simple Archie: Sw = ((F*Rw)/Rt)^(1/n)
- Tamper with formation factor: F = a/(PHI^m)
  - Varying "m" effectively increases the theoretical value of Ro
  - Careful tuning can derive a reasonable estimate of bulk volume hydrocarbon in total rock
- Drawbacks:
  - Sw is misleadingly high as it is of the total pore system inclusive of interconnected and isolated pores
  - Shaly sand models become unstable with artificially high values of "m"

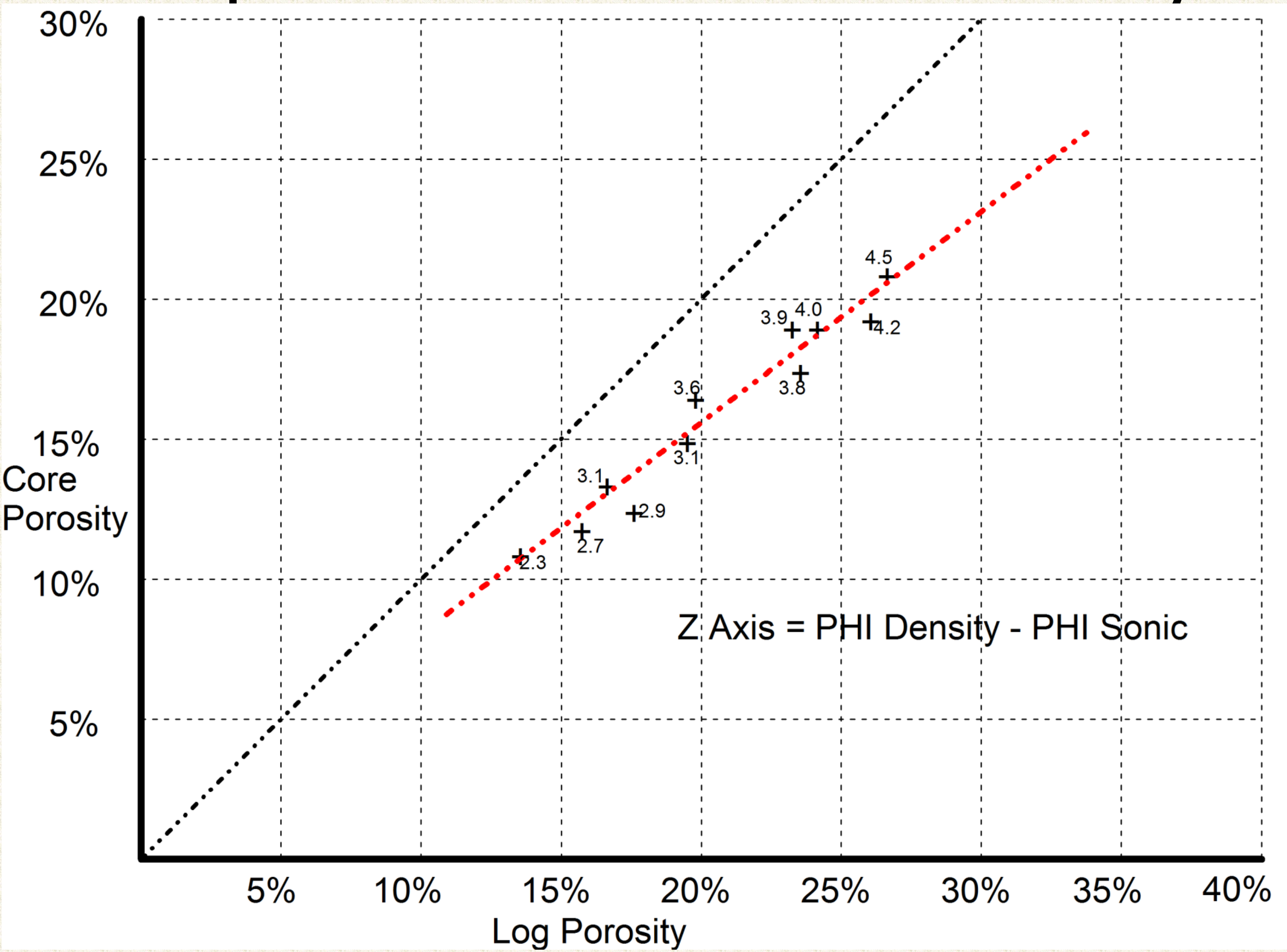
Introducing: "**Isolated Porosity Factor**"

- The Isolated Porosity Factor (ISOP) quantifies the fraction of the porosity which is not interconnected with the fluid system in the rock.
  - PHIc = connected porosity
  - PHIi = isolated porosity
  - PHIlog = f(PHIc + PHIi)
  - PHIi = PHIlog * ISOP
  - PHIc = PHIlog * (1-ISOP)

Solving for "Isolated Porosity Factor"

- The "Pennsylvania solution"
  - Crossplot laboratory measurements of porosity vs log values.
    - Provided core samples are not damaged, the lab only measures interconnected pore volume. Isolated pores are not measured.
    - The degree of non-coherence is proportional to the variance of ISOP
    - On the same cross plot, make z axis plots of all other log measurements.
  - Derive an empirical function to predict ISOP
  - Effectively, the isolated pores are treated as rock

Cross plot of Core PHI vs Density PHI



Solving for "Isolated Porosity Factor"

- The "California Solution"
  - To quantify ISOP, crossplot laboratory measurements of porosity (corrected for TOC) vs log values. Evaluate in same manner as in the "Pennsylvania solution" to quantify ISOP.
    - Where possible, use local geochem data to estimate TOC for the intervals of interest.
    - TOC is often expressed as % by weight. A density correction must be made to derive the volume fraction of total rock that is occupied by Kerogen.
    - Add volume % Kerogen to lab porosity so that the cross plot anomaly only represents isolated porosity.
    - This simple approach assumes that all kerogen is in the interconnected pore system. However, it may be necessary to account for kerogen that is not in the interconnected pore system.

Solving for "Isolated Porosity Factor"

- The "California Solution"…continued
  - In determining interconnected porosity, isolated pores are treated as "rock"
  - Interconnected porosity is the porosity used in the shaly sand analysis model (generally use Dual Water)
  - Use conventional parameters for F = a/(PHI^m)
  - Shaly sand model now yields Sw of the interconnected porosity system.

Solving for "Isolated Porosity Factor"

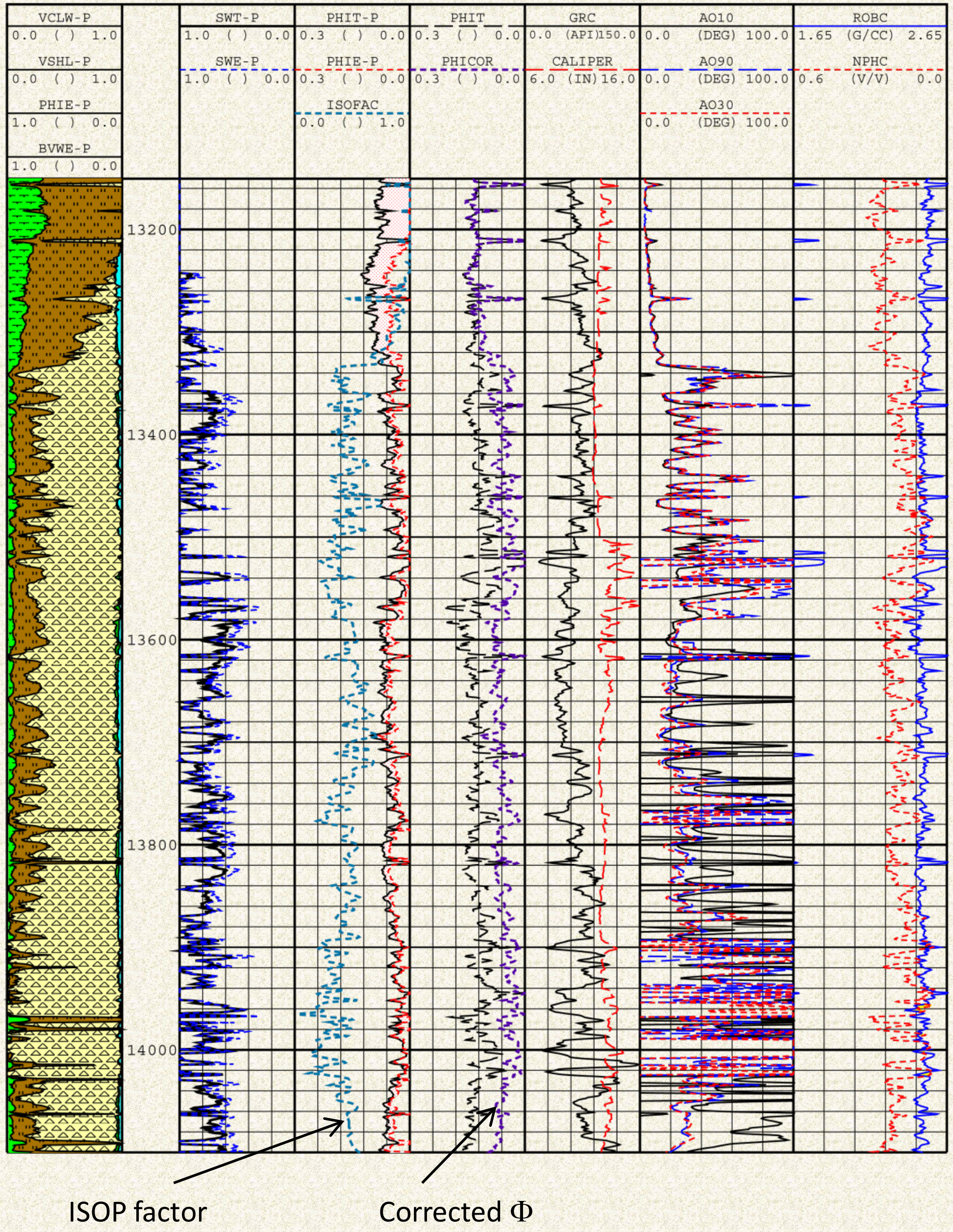
- The "California Solution"…continued
  - Kerogen in the interconnected pore system is assumed to be included in So = 1-Sw
  - TOC % by wt is converted to % of rock volume
  - TOC% of rock volume is converted to % pore volume = Sk
  - BVH = PHIc * (1-Sw) includes kerogen
  - BVO = PHIc * (1-Sw-Sk) oil in place excluding Kerogen

Introducing: “Isolated Porosity Factor”

- Limitations:
  - Very little conventional core porosity data are available.
  - Sidewall sample core porosity measurements are not reliable because percussion fractures connect the isolated pores.
  - TOC data are rarely available, at least on older wells, so average or trend values must often be used

What Logs & Data Are Needed For This Approach?

- For most projects, we do not have exotic logs. Routinely we only have **resistivity**, **GR** (KUT some-times), **density**, **neutron**, & maybe **sonic**
  - Any analysis methodology must work with this log suite and cannot depend on lab data or logs that are not available
  - The model must be based upon
    - Knowledge of the log measurements
    - Knowledge of the rocks
  - The model must provide reasonable values of Sw and porosity



Application of Isolated Porosity Factor

The ISOP is scaled 0 – 1.0 and represents the fraction of the log porosity which is isolated, or not in communication with the “normal” pore system. The value (1-ISOP) is multiplied by the log-derived porosity to yield interconnected porosity. This value is then treated like total porosity and used in the standard shaly-sand log analysis methodology to derive Sw and PHIE.

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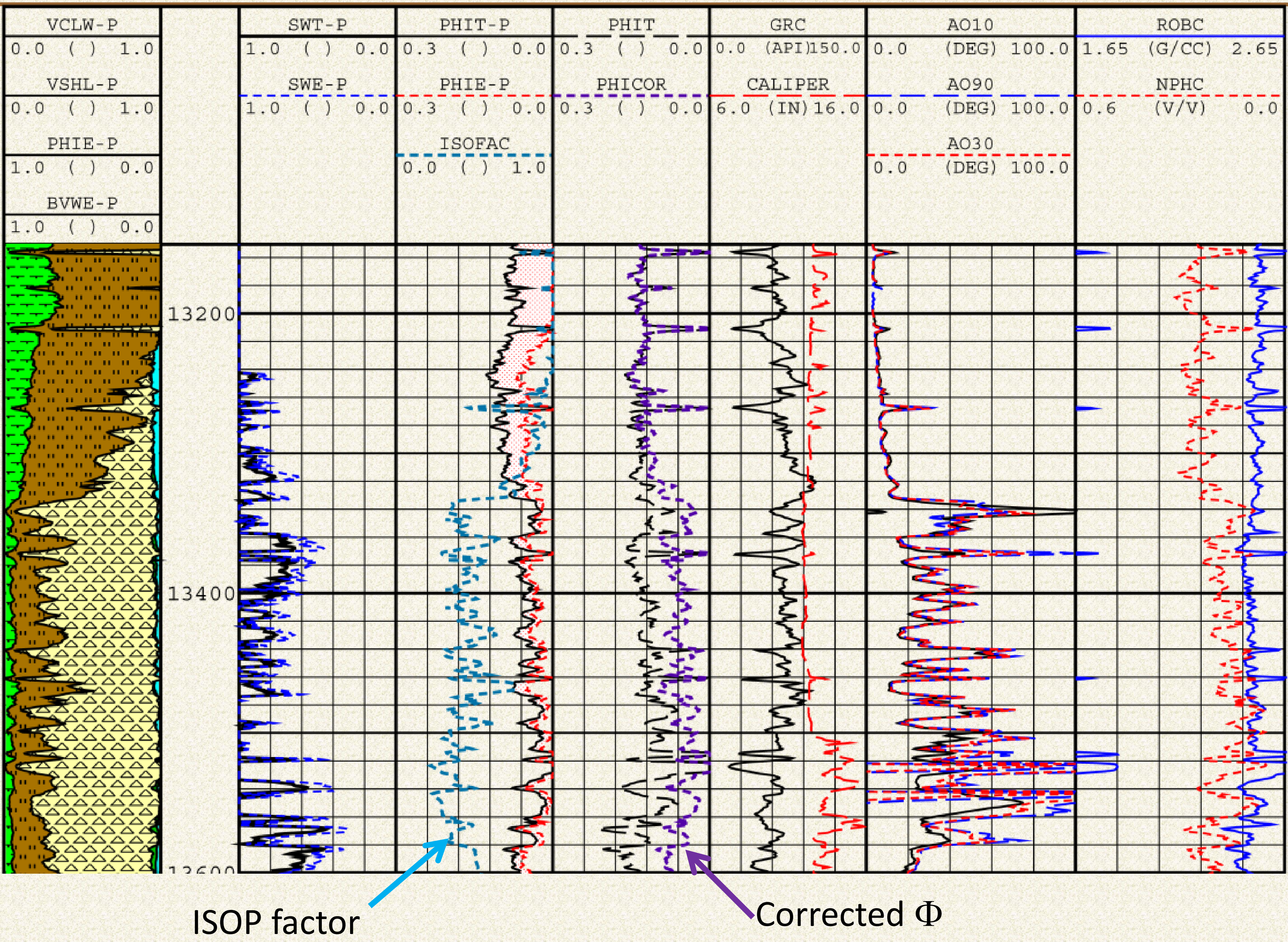

VCLW-P
0.0 ( ) 1.0
VSHL-P
0.0 ( ) 1.0
PHIE-P
1.0 ( ) 0.0
BVWE-P
1.0 ( ) 0.0
SWT-P
1.0 ( ) 0.0
SWE-P
1.0 ( ) 0.0
PHIT-P
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PHIE-P
0.3 ( ) 0.0
ISOFAC
0.0 ( ) 1.0
PHIT
0.3 ( ) 0.0
PHICOR
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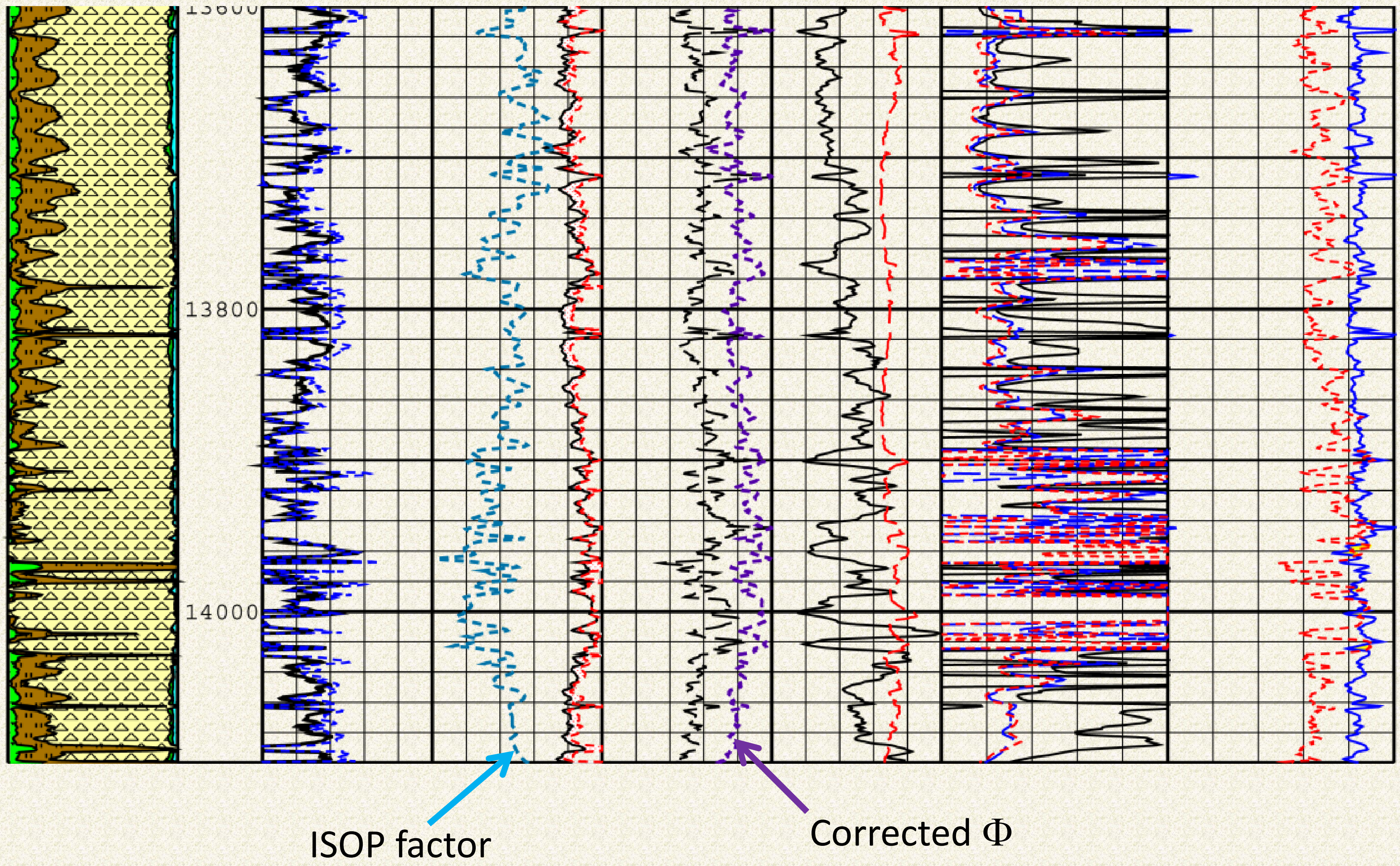
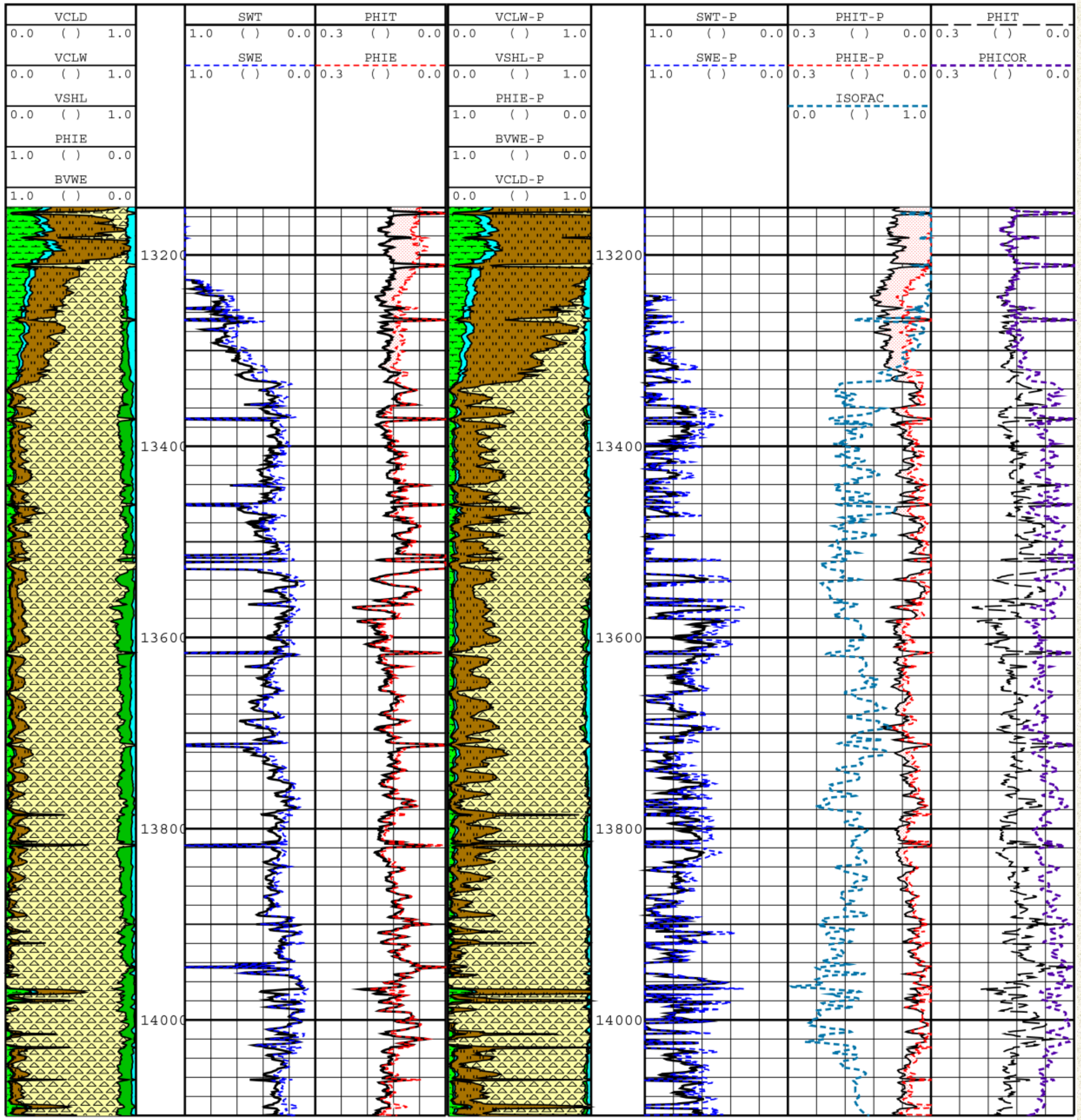
GRC
0.0 (API) 150.0
CALIPER
6.0 (IN) 16.0
AO10
0.0 (DEG) 100.0
AO90
0.0 (DEG) 100.0
AO30
0.0 (DEG) 100.0
ROBC
1.65 (G/CC) 2.65
NPHC
0.6 (V/V) 0.0
13200
13400
ISOP factor
Corrected Φ


13600
13800
14000
ISOP factor
Corrected Φ

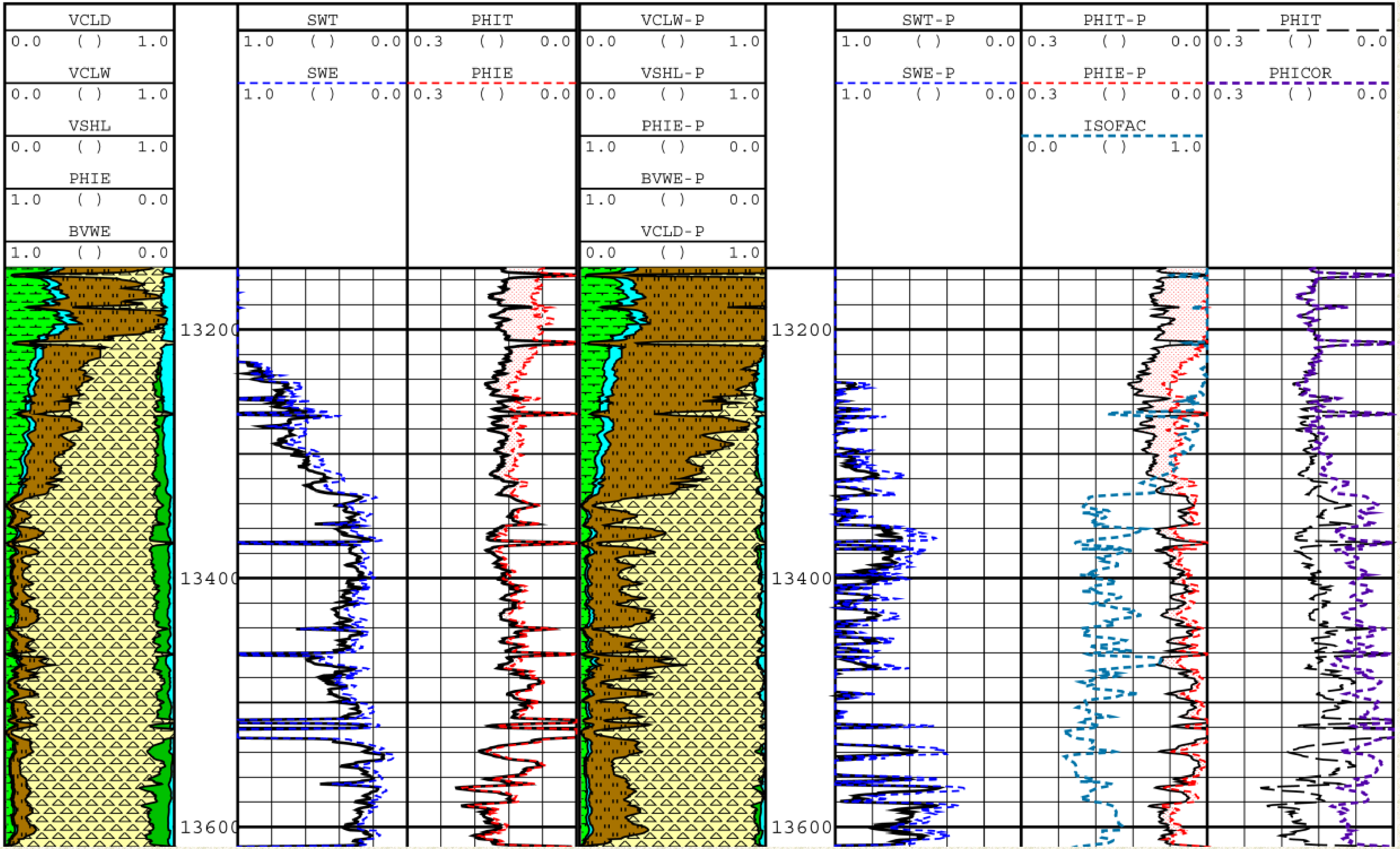
Comparison of results from standard analysis and isolated porosity analysis

Standard Analysis



Isolated Porosity Analysis

Comparison of results from standard analysis and isolated porosity analysis



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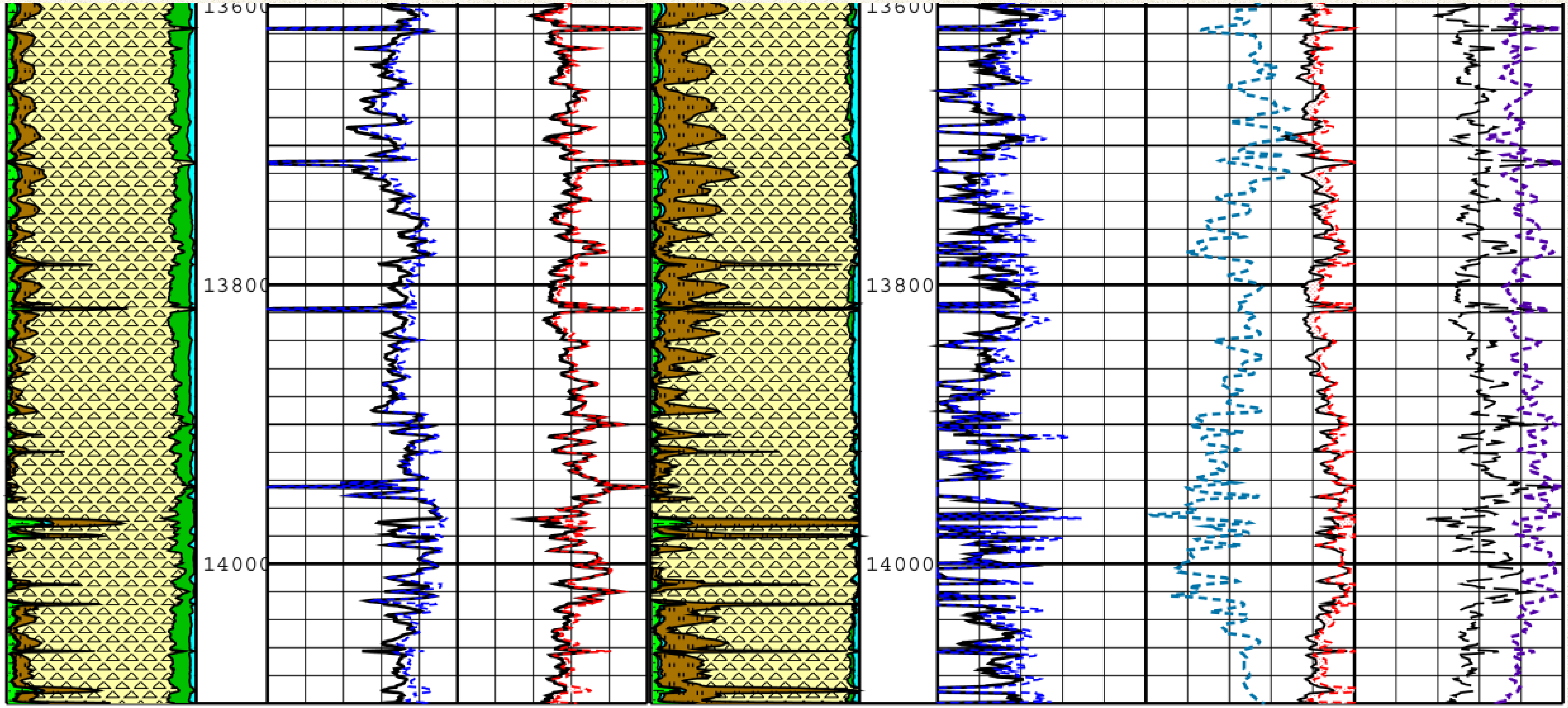
Comparison of results from standard analysis and isolated porosity analysis



The analysis on the left indicates a high amount of hydrocarbons in a seemingly porous interval. An operator seeing these results would be tempted to complete and test the well.

UNFORTUNATELY the results will be very disappointing.

The analysis on the right indicates that the interval has very low interconnected porosity and is either wet or has only residual hydrocarbons.

Bad News & Good News

- The bad news is that conventional analysis of these types of rocks yields profoundly over-optimistic hydrocarbon saturations. This has led operators to spend large amounts of money completing and testing wells that were tight and non productive.
- The good news is that we now have a model that can distinguish between pay and non pay in these very challenging rocks.

Questions that have been asked:

- Are you implying that the transitional Monterey facies*, if thermally oil-mature, would be a good candidate for resource type drilling and completion methods?
  - ***That's the big question***
- 2) Could the pore-plugging kerogen in the transitional facies be migrated-oil trapped by diagenetic processes?
  - ***The logs alone cannot distinguish between the two***
- 3) Do the transitional facies you have documented ever occur where there is a structural trap or recent uplift?
  - ***Yes, I have seen this in client wells that have been sent to us for analysis, located in fields and on structures***

Answer (sort of):

- PayZone's principals have pondered these questions and others with regard to the Monterey. The industry spotlight is now shining in our back yard. The oft-quoted USGS report predicts reserves that we believe to be optimistic. However, if we find only 10% to 20% of what has been suggested, the future for California is bright.
- Unfortunately, there are not sufficient data in the public domain to substantiate conclusive answers.

Finding Answers…..

- Therefore: PZI is presently scoping a proposal for a participatory study of a range of questions about the Monterey. We will focus on:
  - issues that impact or can be answered by the log and core program for new wells.
  - Information that can be obtained from existing log and core data
  - Methods for integrating the existing log and core inventory with the currently evolving geochem based exploration models

Acknowledgements

- The petrophysical models now in use by PZI were first developed by Digital Petrophysics Inc. in the mid to late 1980’s.
- William R. Berry II (Rick) developed the “Pennsylvania” solution while preparing log examples for a school presented in Pittsburg in 1986.
- The staff of PZI have provided great technical support in the preparation and analysis of the data presented here.