PS Assessment of Storage and Productivity Potential of a Frontier Unconventional Shale Oil Play, Lower Barmer Hill Formation, Barmer Basin, India*

Utpalendu Kuila[1], Sandipan Dutta[1], B.N.S. Naidu[1], V.R. Sunder[1], Dennis Beliveau[1], John Dolson[2], Arpita Mandal[1], Soumen Dasgupta[1], Premanand Mishra[1], and Pinakadhar Mohapatra[1]

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Abstract

The Eocene Lower Barmer Hill (LBH) Formation is the major regional source rock in the Barmer Basin rift, located in Rajasthan, India. Thick sections of organic-rich black shales reaching 400 meters thickness with TOC up to 14 wt. %, were deposited during a period of widespread basin deepening. Type 1 oil prone kerogens dominate the north, with mixed type 1 and III kerogens in the south. Thermal maturity varies across the basin, from early oil in the north to dry gas in the south.

Extensive Rock Eval pyrolysis and source rock kinetic databases were combined with petrophysical analysis to determine log-based porosity and saturations and productive potential. Basin modeling using Trinity software provided probabilistic ranges of generated and expelled hydrocarbons to determine storage capacity. The modeled oil window storage capacity varies between 6 to 13 mmstb/km^2, comparable to the values observed in Eagle Ford Shale and Bakken Shale plays.

Excess pore pressure was modeled using the kinetics of kerogen-to-oil conversion. These pressure-gradient maps, along with oil properties (viscosity and oil mass fractions) derived from the geochemical model, are used to compute the producibility index. Composited storage capacity and the producibility index maps are high-graded to potential pilot areas. Work is ongoing to understand the rapid syn-rift facies variations of interbedded brittle zones such as silty porcellanites or thin turbidites, which make this play considerably different from established trends such as the Eagle Ford or Bakken Shales. Testing these concepts will be an important step in unlocking future unconventional potential in other rift basins.

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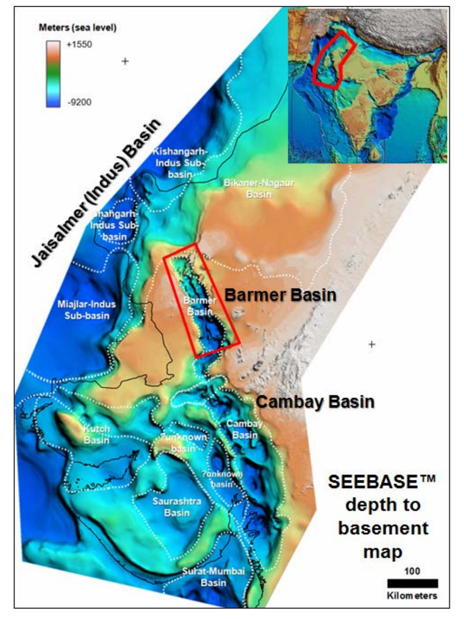
Abstract

The Lower Barmer Hill (LBH) Formation is the major regional source rock in the Barmer Basin rift, located in Rajasthan, India. Thick sections of organic-rich black shales reaching 400 meters thickness with TOC up to 12 wt. %, were deposited during a period of widespread basin deepening. Type I oil prone kerogen dominate the north, with mixed type I and III kerogen in the south. Thermal maturity varies across the basin, from early oil in the north to dry gas in the south.

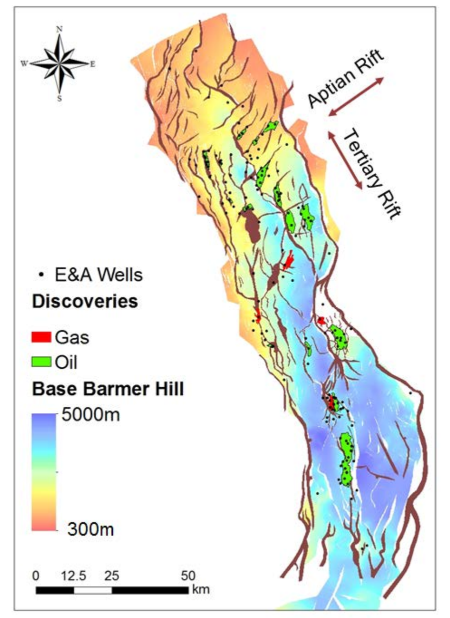
RockEval pyrolysis and source rock kinetic databases were combined with petrophysical analysis to determine log-based porosity and saturations and productive potential. Basin modeling using Trinity™ software provided probabilistic ranges of generated and expelled hydrocarbons to determine storage capacity. The modeled oil window storage capacity varies between 6 to 12 mmstb/km^2, comparable to the values observed in Eagle Ford and Bakken Shale plays.

Excess pore pressure was modeled using transformation ratio map. These pressure-gradient maps, along with oil properties (viscosity and oil mass fractions) derived from the geochemical model, are used to compute the producibility index. Composited storage capacity and the producibility index maps are high-graded to potential pilot areas. Rapid syn-rift facies variation of interbedded brittle zones such as silty porcellanites or thin turbidites makes this play considerably different from established trends such as the Eagle Ford or Bakken Shales. Testing these concepts will be an important step in unlocking unconventional potential in rift basins.

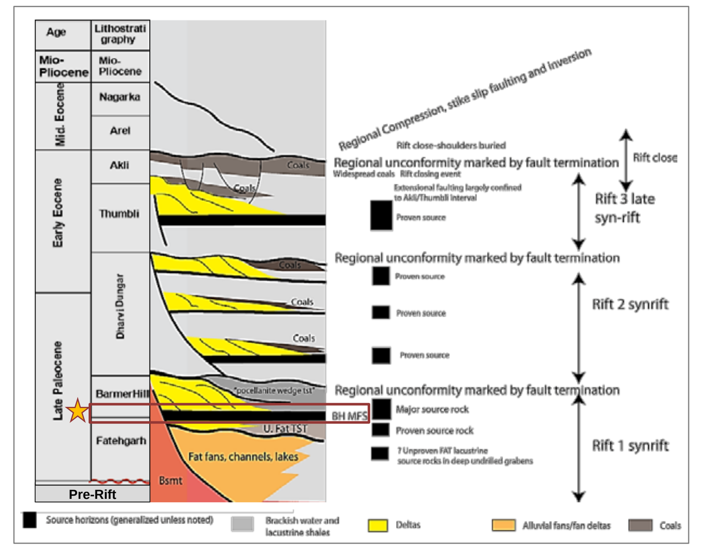
1. Geologic Settings



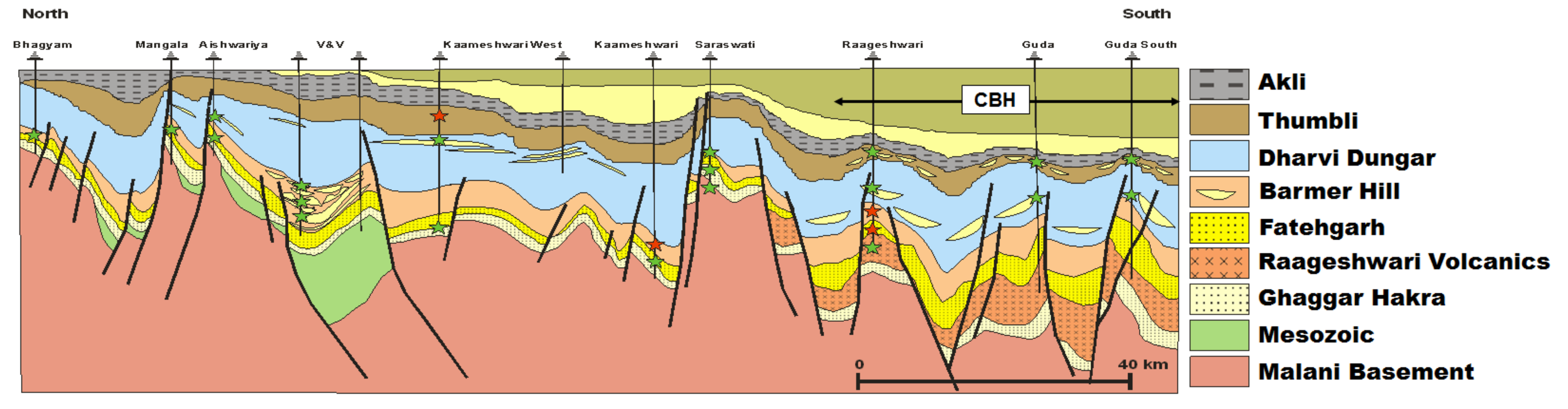
Barmer Basin is the northern end of the West Indian Rift System



This petroliferous basin is a failed intercontinental rift; defined by two non co-axial rifting event

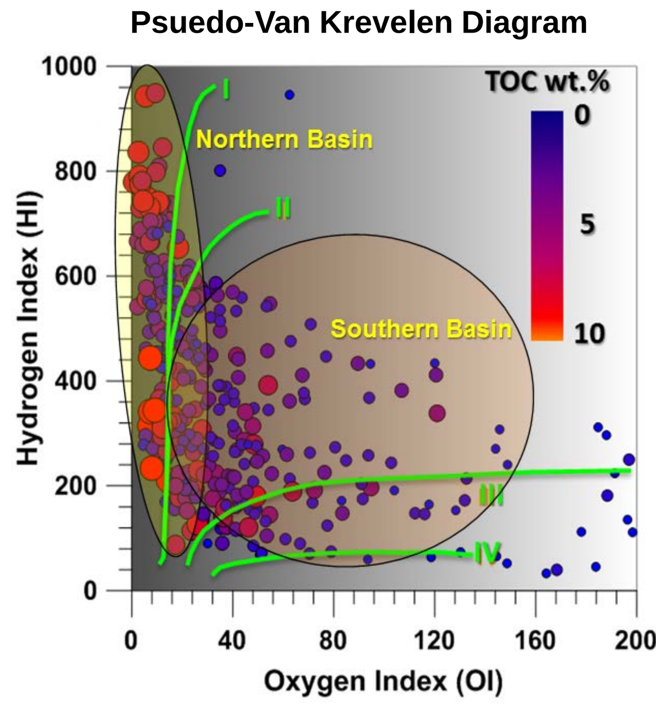


Generalized Tertiary stratigraphy of Barmer Basin, The Lower Barmer Hill records the highest expansion of this lake during early syn-rift (Late Paleocene) as maximum lake level and areal extent were achieved



Representative N-S geological cross section of Barmer Basin showing typical rift basin structural style (horst and graben; and half graben) and the HC discoveries. Note the drilled wells targeted the structural highs in fault-bound closures.

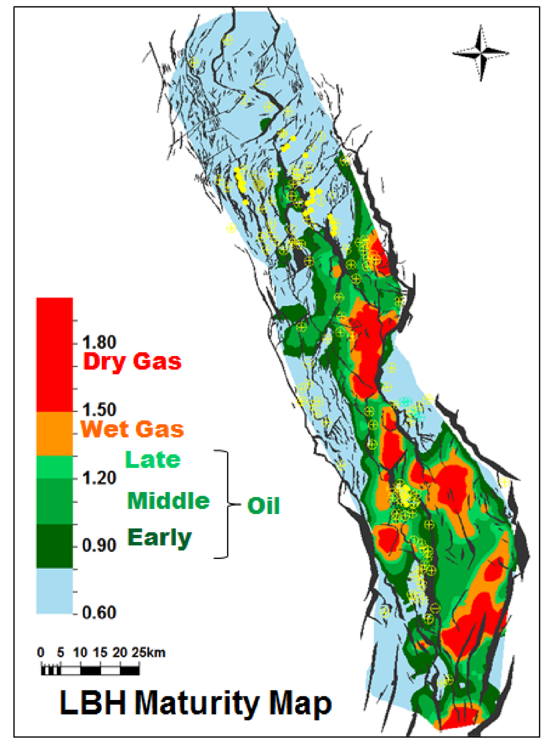
2. Geochemical Considerations



Left: Psuedo – Van Krevelen Diagram from RockEval pyrolysis data for LBH source rocks.

- Oil prone algal Type I kerogen in the north
- Mixed type I and III kerogen in the south

Right: Thermal Maturity map of LBH. The sampled LBH source have low to moderate maturation (up to early oil window) in the drilled wells. No wells drilled in the basinal low. The maturation history is modeled using Trinity™ software



3. Methodology

Lower Barmer Hill chronostratigraphic correlation and GDE

- Well-Log Correlation and seismic interpretation using sequence stratigraphic framework
- Gross Depositional Environment from Well Facies analysis
- Basin scale Petroleum System Model in Trinity™

Shale Oil Assessment

How Much Oil is there? Storage Model

- Modeled Oil Retained Volume from Trinity Petroleum System Model
- Parameters of absorbed oil volume taken from measured kerogen kinetics
- Log-derived TOC, porosity and saturations (Calibration with the Trinity™ Model ongoing)

How much oil will flow NATURALLY ? Productivity Model

$$\frac{\{(k)\ (h)\ (\Delta P)\, OMF\}}{\mu}$$

ΔP estimation: Modeled excess pore pressure created during maturation of kerogen to oil (Berg and Gangi, 1999)

Permeability 500 nD

Net Thickness BH isopach

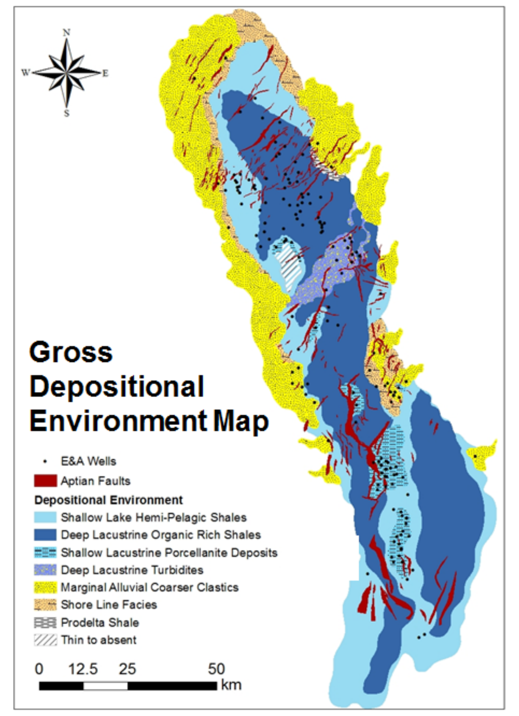
Oil Mass Fraction (OMF) Trinity

Viscosity 1 cp

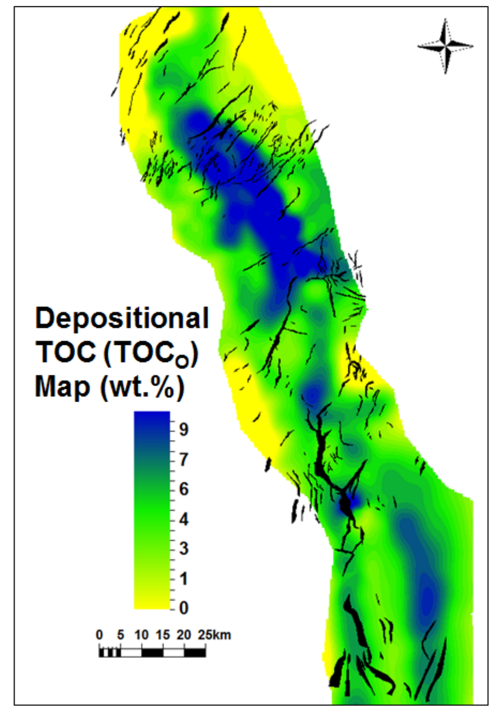
The main results of the work is shown in this central panel. Details about the following is shown in the Appendix panels:

1. Basin Model workflow (Right panel, Top)
2. Petrophysical analysis to derive TOC and Saturation (Right panel, Bottom)
3. GDE workflow (Left panel Top)
4. Productivity workflow (Left Panel Bottom)

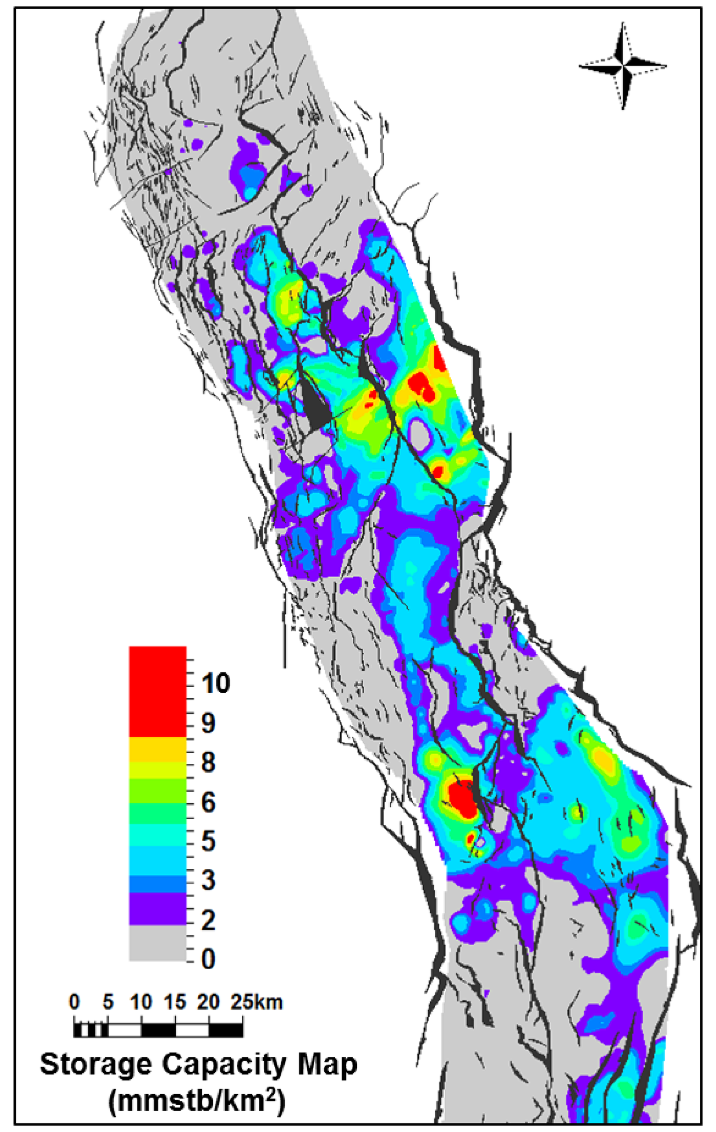
4. Gross Depositional Environment



- Fluvial sediments dominated the early syn-rift time controlled by the NE-SW Aptian faults with a central shallow lake
- Massive lacustrine transgression at the onset of LBH deposition
- Entire basin covered with deep lake with pelagic sedimentation in anoxic condition
- Turbidite deposition in the central basin, originating from western flexural margin and eastern basin margin fault
- Shallow lake with porcellanite deposition at the southern central basin high
- GDE is used to update depositional TOC (TOC_O, Right) and depositional HI (HI_O) maps in basin model



5. Storage Model



Oil retained = 6.29*H*(Rr/Ro)*S*Ci *TOC_O*10^{-3}

Rr = density of source rock; Ro = density of hydrocarbons

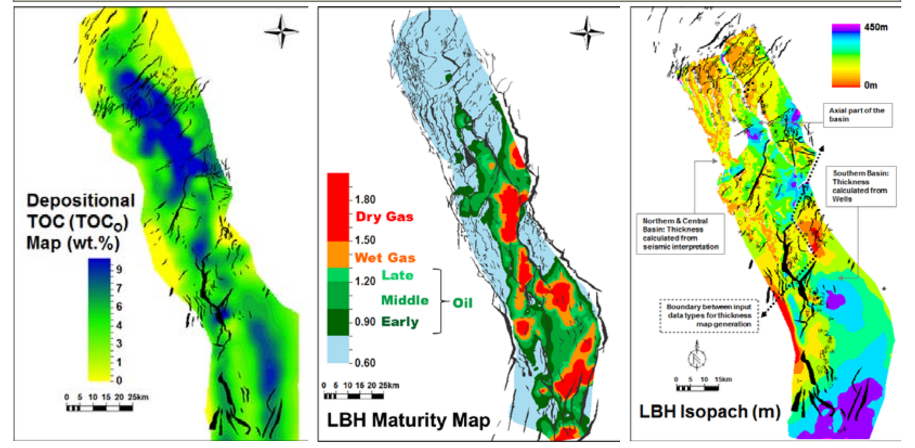
S = Sorption capacity for oil; base case 120 mgHC/g TOC

Ci =The fraction of inert carbon; Ci = (1-HI_O)*Tr*0.85/1000

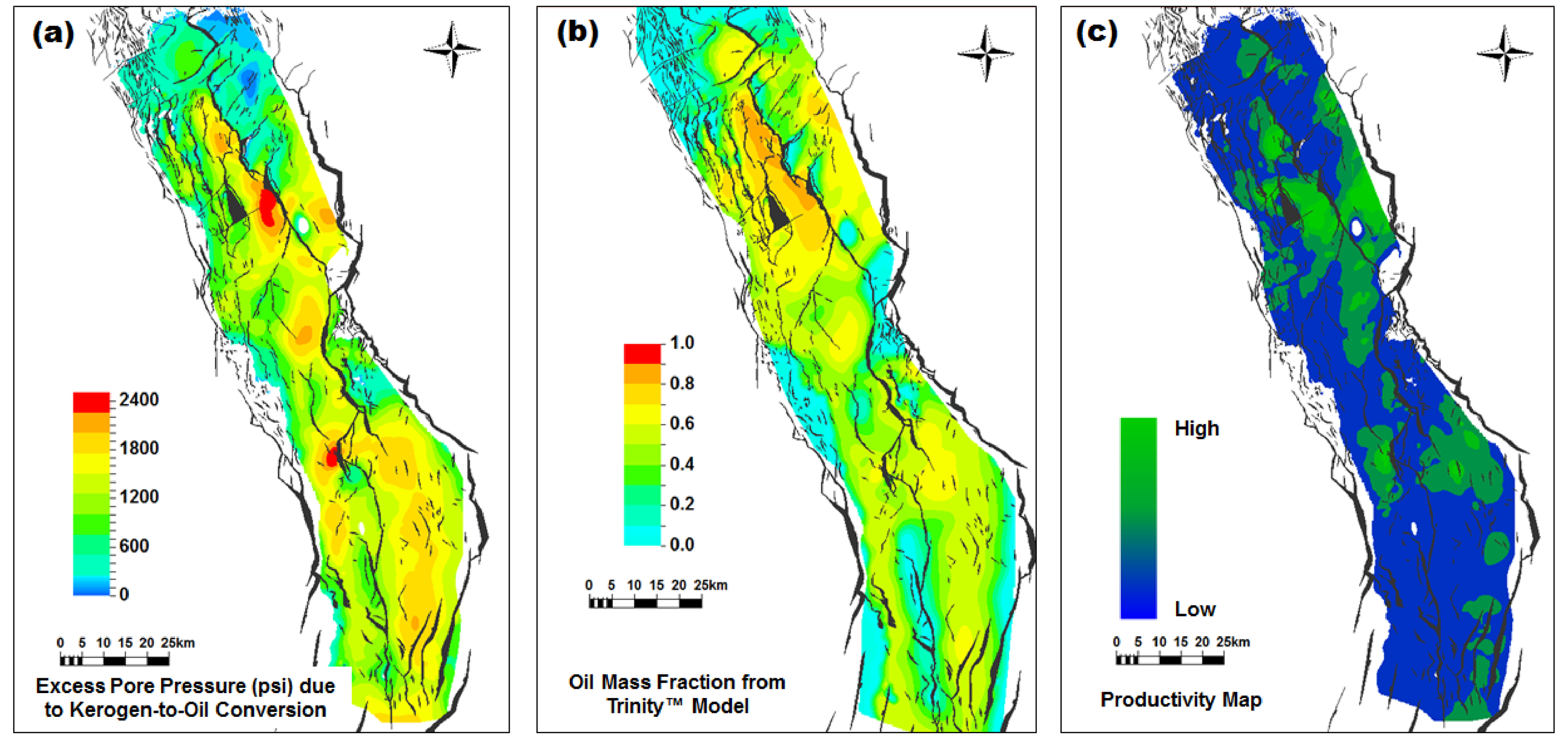
Tr = Transformation Ratio

- High values in the north oil kitchen due to high TOC_O, attributed to type I kerogen deposited in anoxic lake
- High storage capacity in central kitchens attributed to the larger thickness, due to clastic input within deep lake facies
- Storage capacity for oil is low in the southern kitchen due to higher maturity and oil-to-gas conversion.

Controls on Storage Capacity

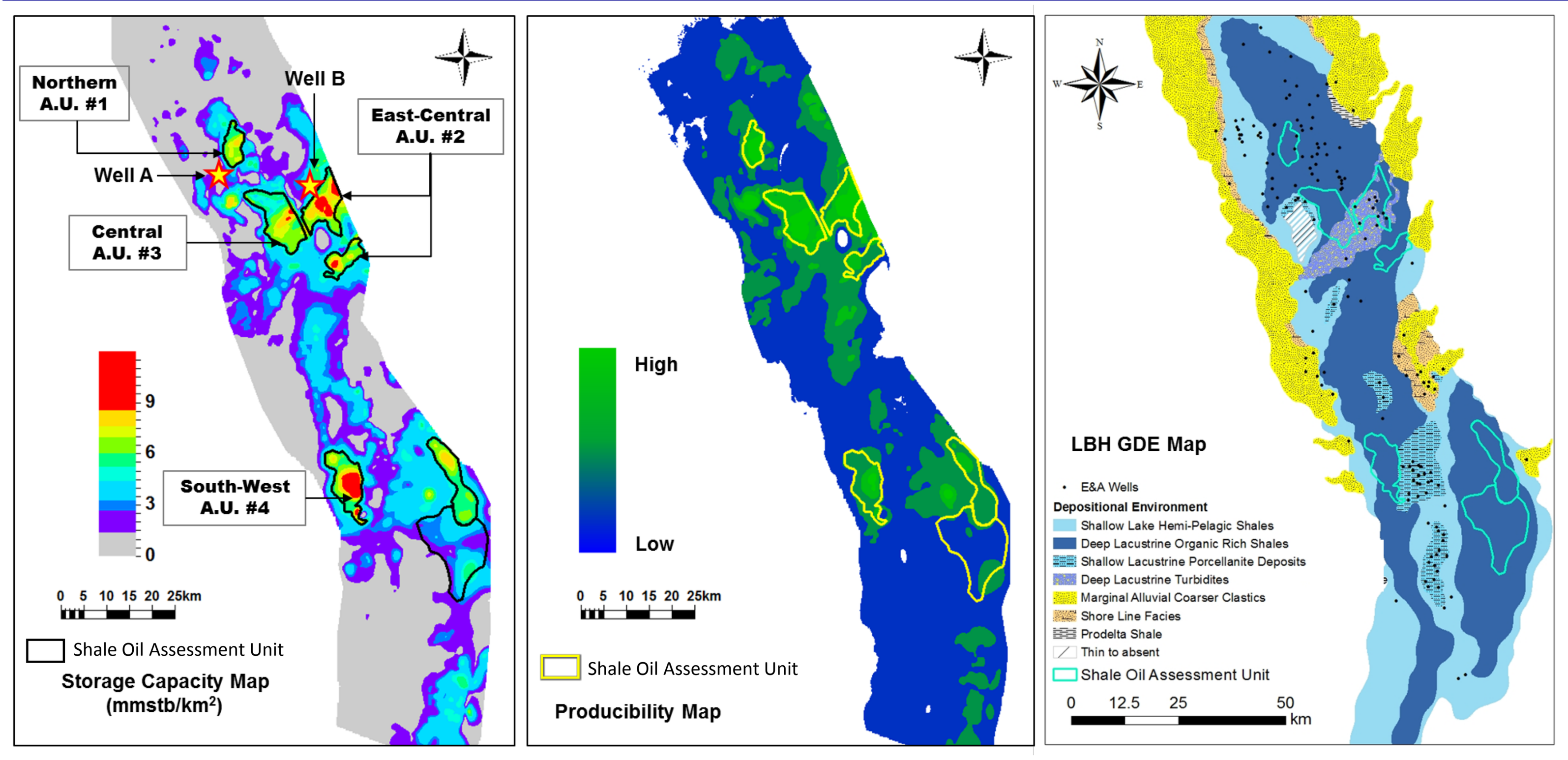


6. Productivity Model



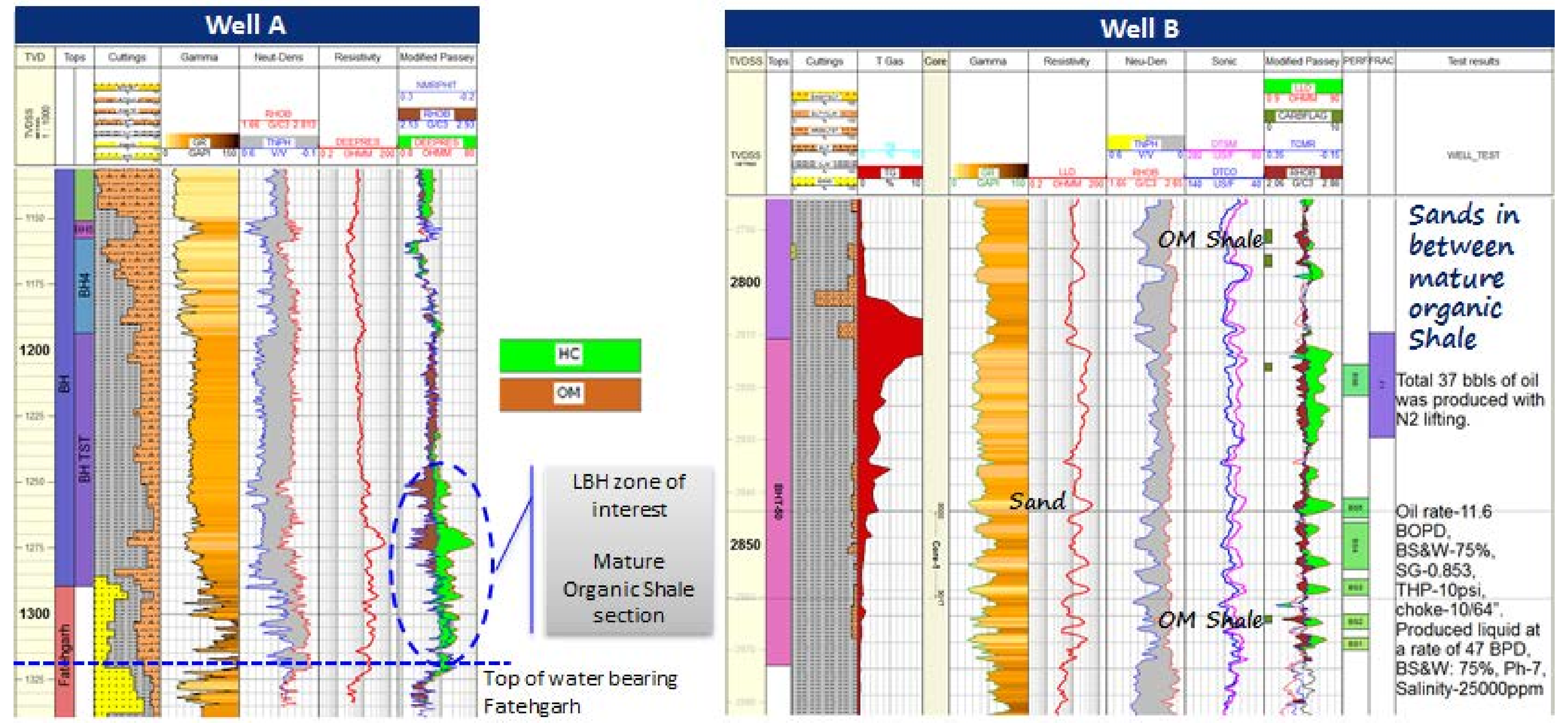
- Overpressures and Fluid Properties (viscosity and GOR) important for successful liquid-rich shale plays
- Excess pore pressure (left fig. a) modeled using the approach in Berg and Gangi (1999), which converts the transformation ratio maps into excess pressure created by oil generation using some simplifying assumptions
- The oil-mass fraction (center fig. b) and viscosity inputs are taken from Trinity model using in-house kinetic models
- Productivity index (right fig. c) shown in a relative color scale with green areas highlighting better areas for optimum properties

7. Assessment Units



Assessment units (A.U.) delineated based on the composite of storage model (>5 mmbbls/km^2) and the producibility model. Substantial facies variations occur due to local input of clastics and variable turbidite geometries in each A.U.

8. Proof of Concept Wells



9. Conclusion

Encouragement	Challenges
Type I kerogen, high HI	Areal extent limited
Optimal Thermal Maturity	Deeper Occurrence (2500-5000m)
Thickness (>100 m)	No well penetration in thermally mature areas
Siliceous mudstone (with biogenic silica) and clastic turbidite sands	Rift structural settings with rapid variations

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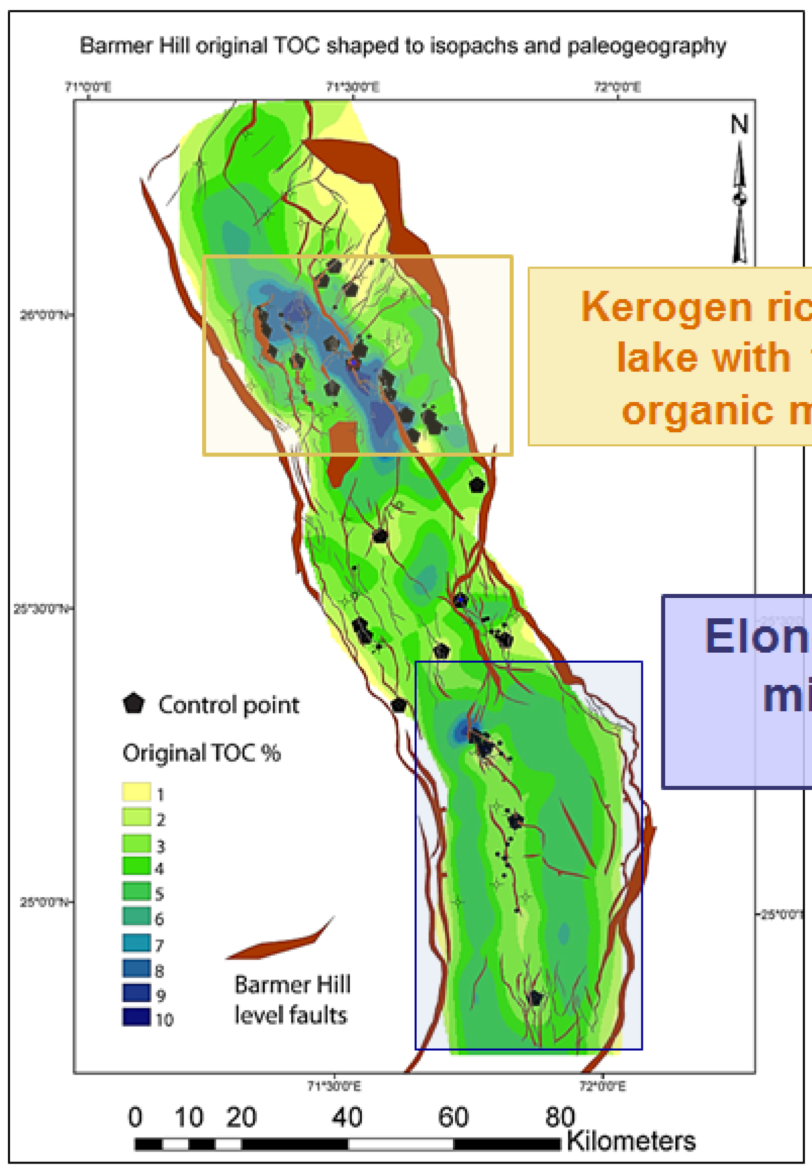
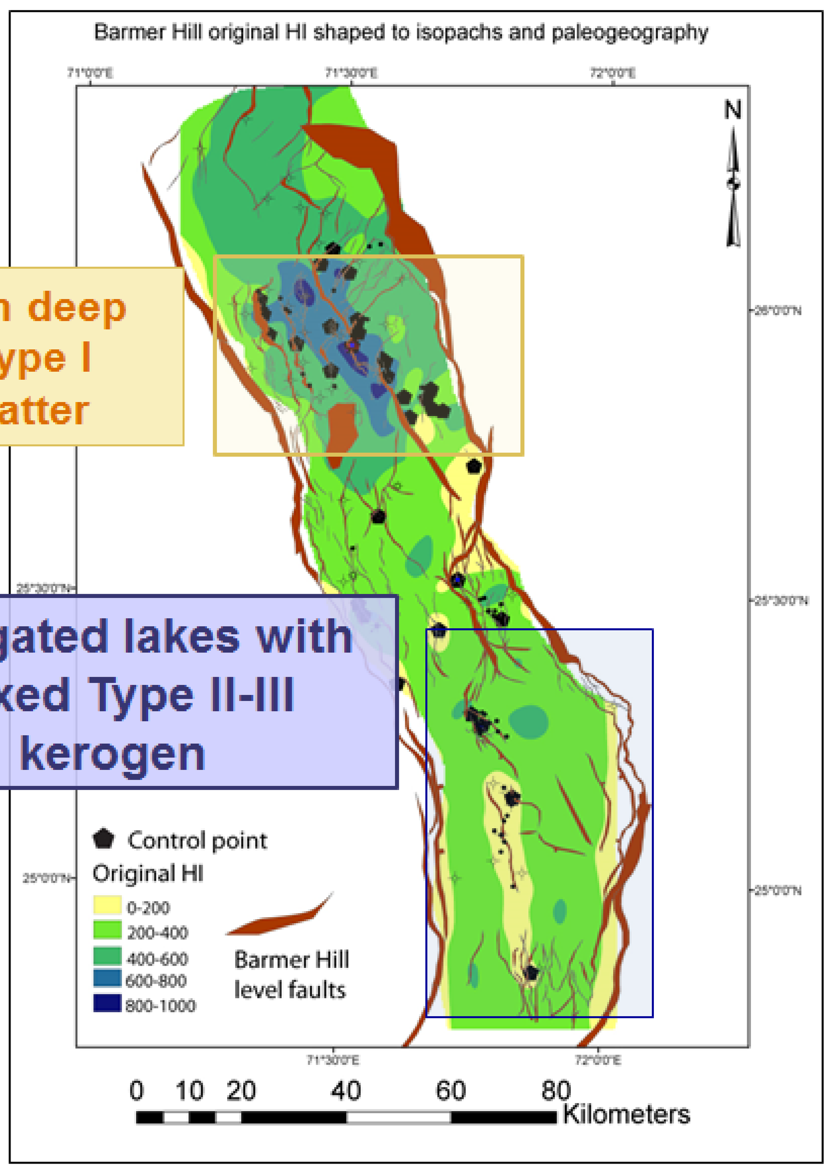
Petroleum System Model Workflow (after Naidu et. al. 2017)

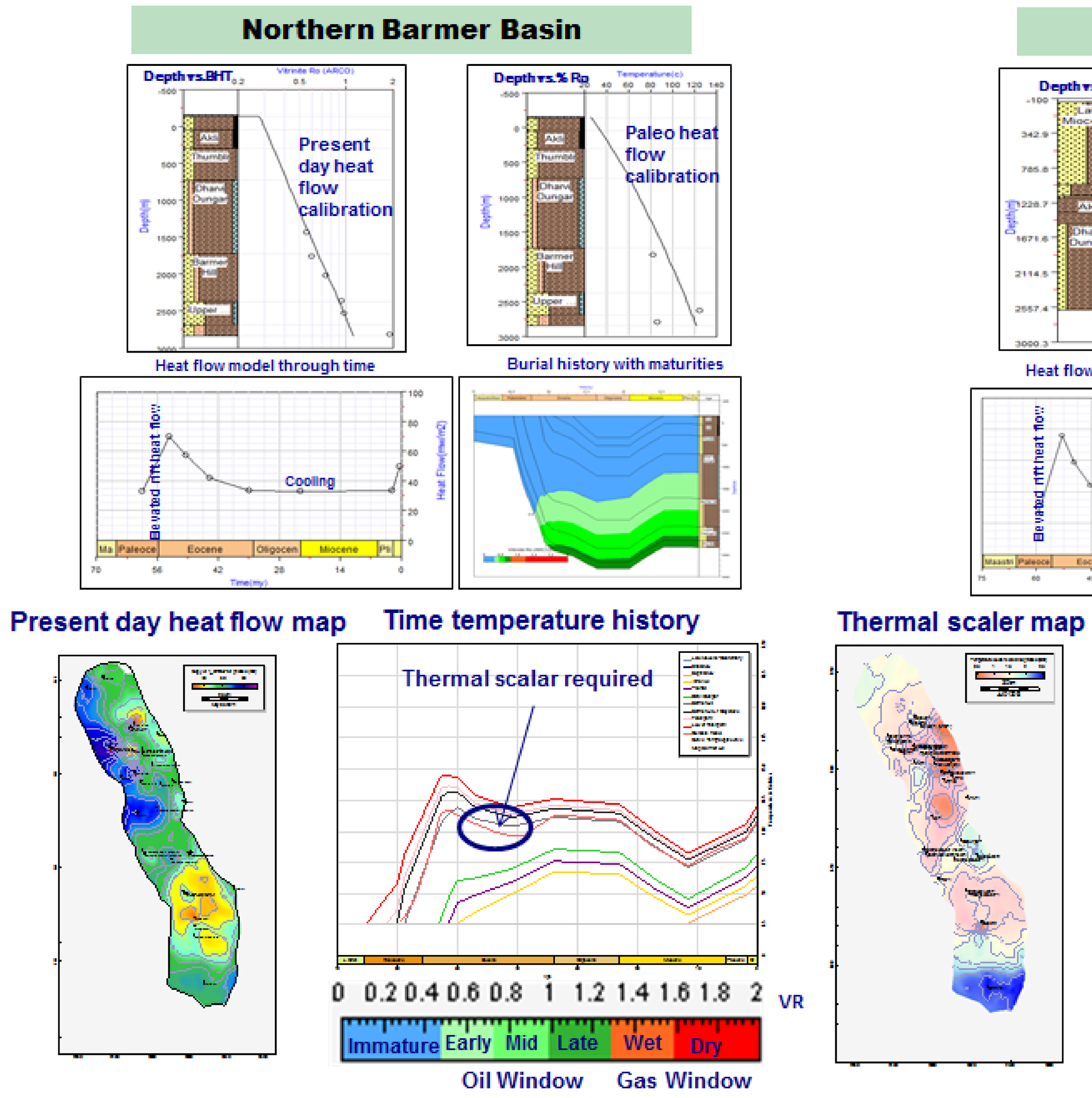
Depositional TOC



Depositional HI

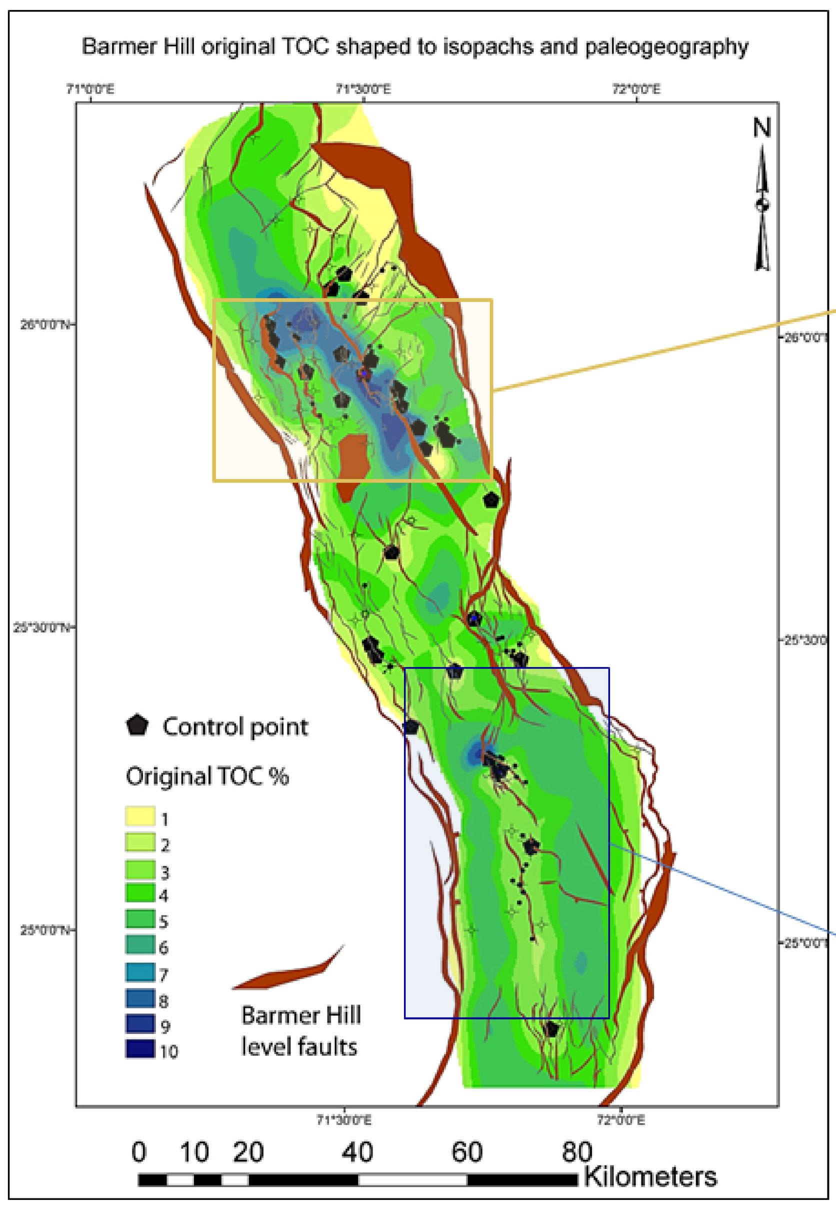


1 D burial history and heat flow models

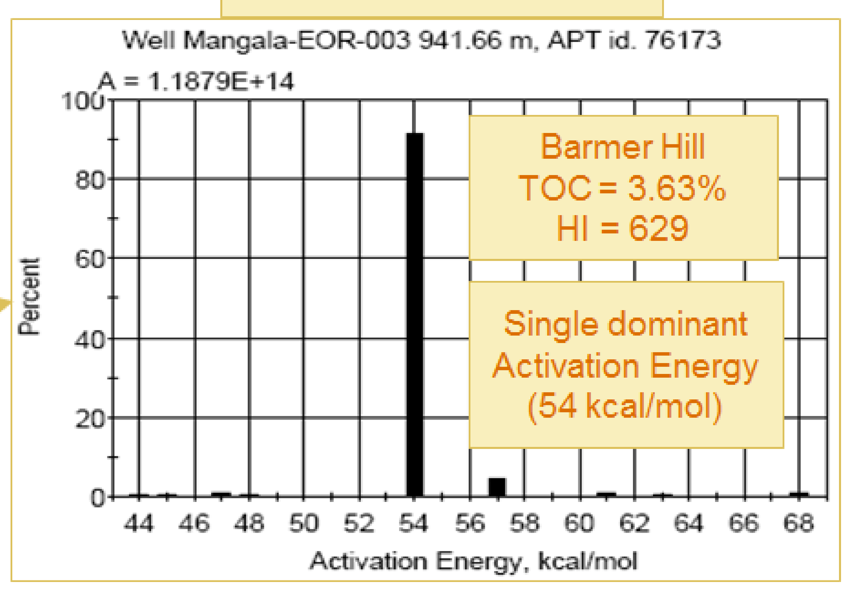


- Formation tops from the drilled wells used to build burial history diagram
- Seismic depth maps used for building the pseudo-burial history diagrams
- Present heat flow calculated using corrected borehole temperatures
- Palaeo-heat flows calculated using Ro%
- Thermal scalar maps used to calculate thermal variations through geological time

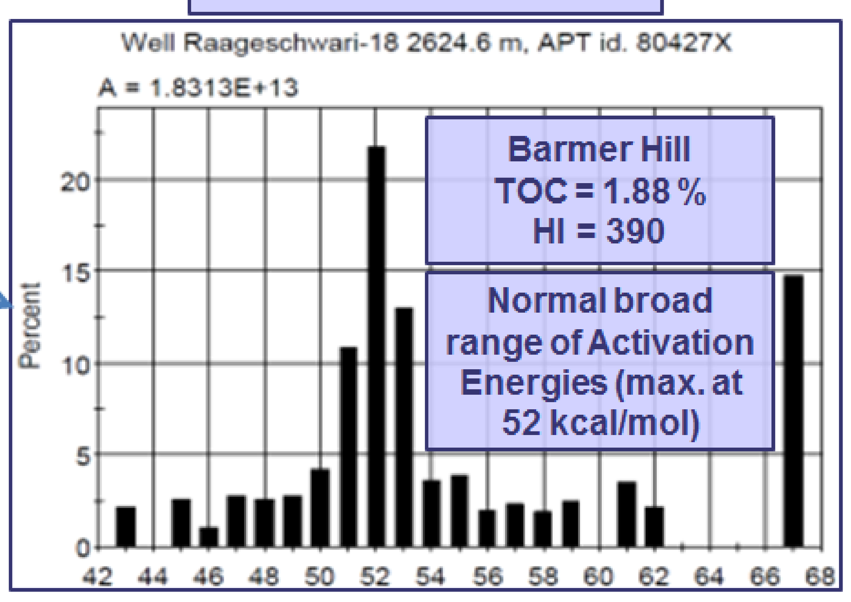
In-house kerogen kinetics

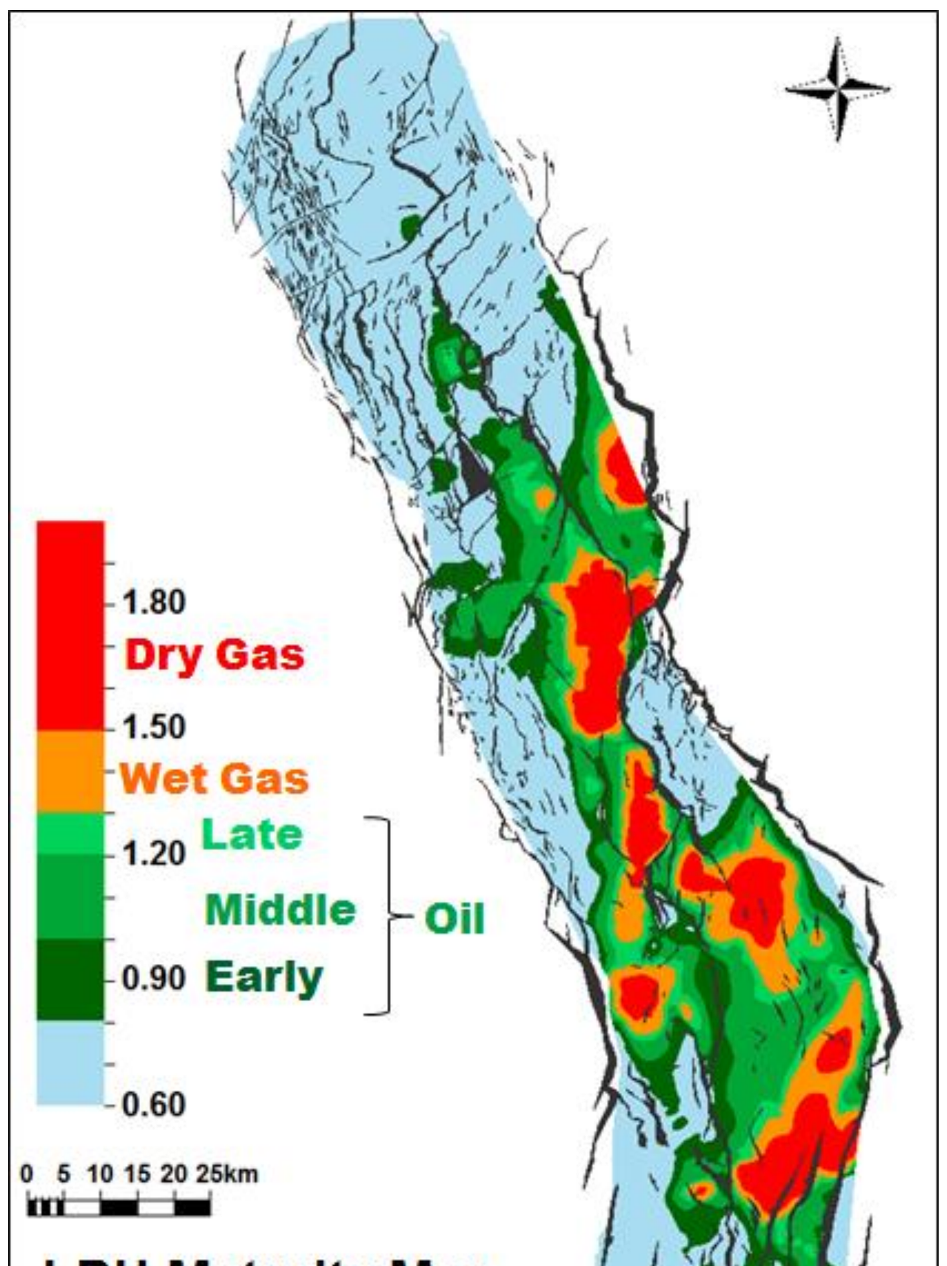


North Barmer Basin

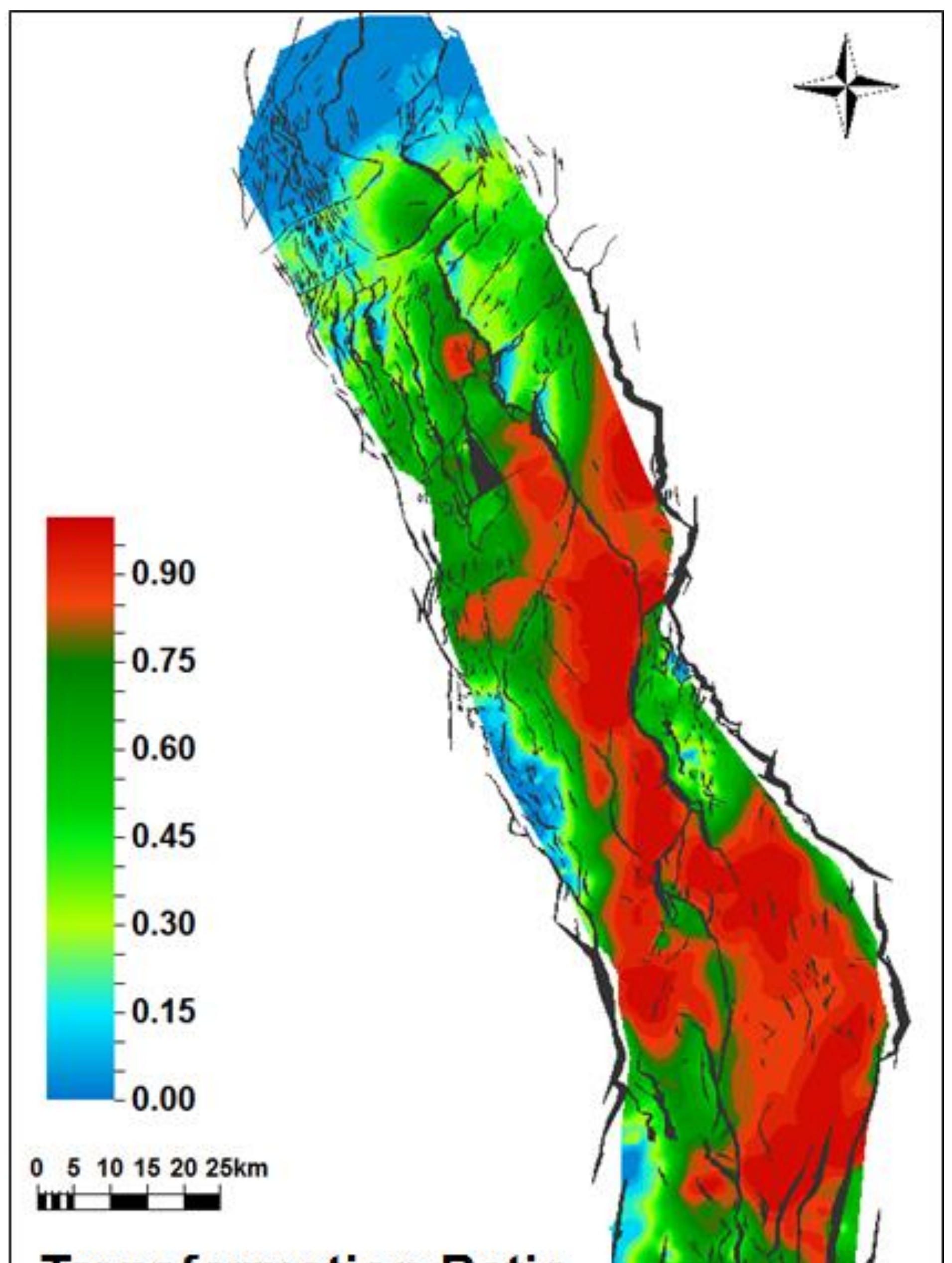


South Barmer Basin





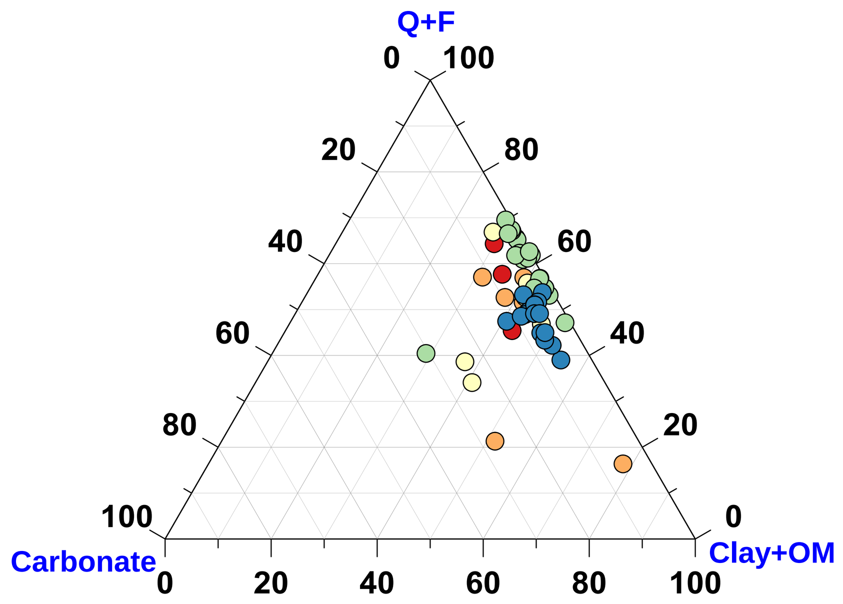
LBH Maturity Map



Transformation Ratio

Petrophysical Workflow

TRA and Mineralogy



Well	TOC (wt.%)	Tmax Calc. %Ro	Maturity Zone	Φ_{eff}	So_{eff}	Oil Content (% BV)	Perm @ 1500 psi (µD)
Bhagyam-5	4.06	435°C 0.67%	Oil window	17.90	7.30	1.29	10.9
Mangala-72	6.57	435°C 0.67%	Oil window	10.57	8.98	0.94	0.65
MEOR-003	8.65	437°C 0.71%	Oil window	9.37	7.14	0.67	30.9
V2Y Channel	4.61	446°C 0.87%	Oil Window	2.92	20.95	0.61	0.29
Raageshwari-BH-1	1.61	438°C 0.73%	Oil window	7.55	8.96	0.63	36.5

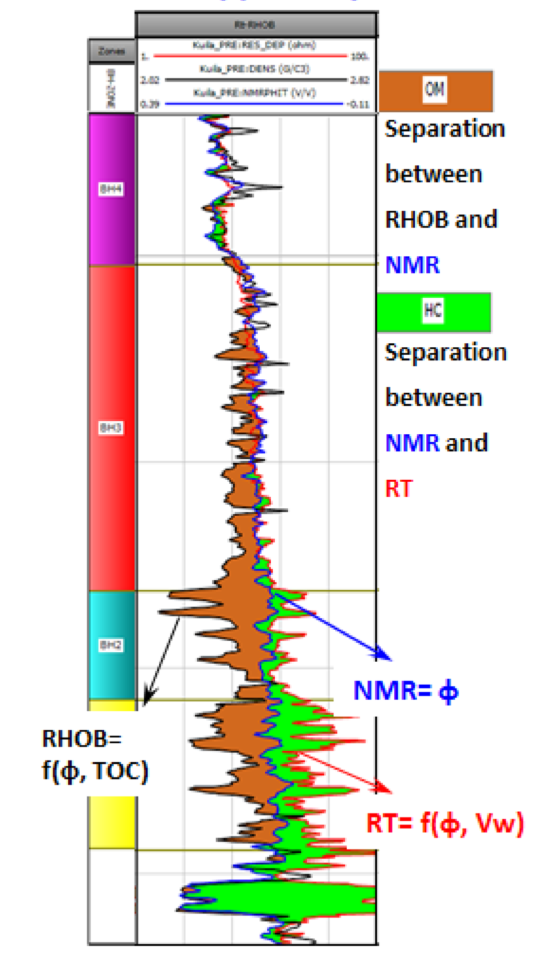
Modified Passey Overlay

Modified Passey's Technique

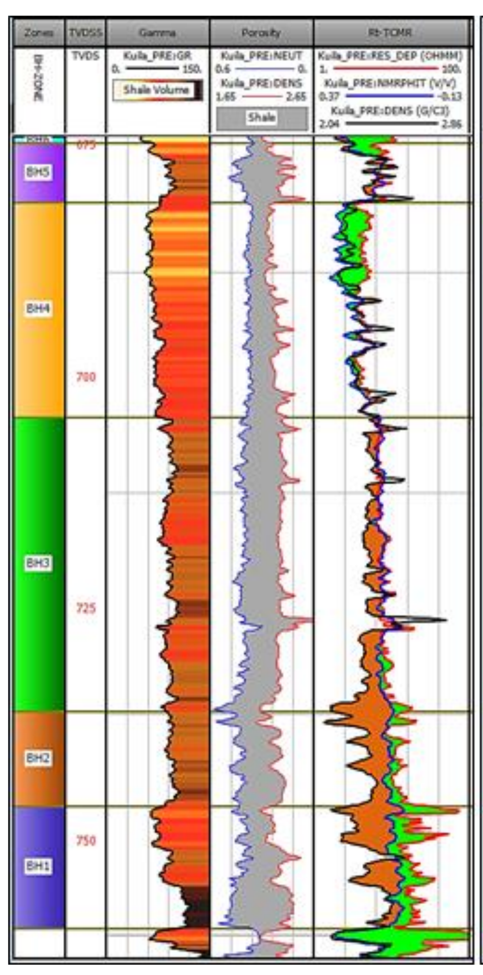
Porosity(ϕ)-Resistivity(RT) Overlay

RHOB responds to both ϕ and TOC

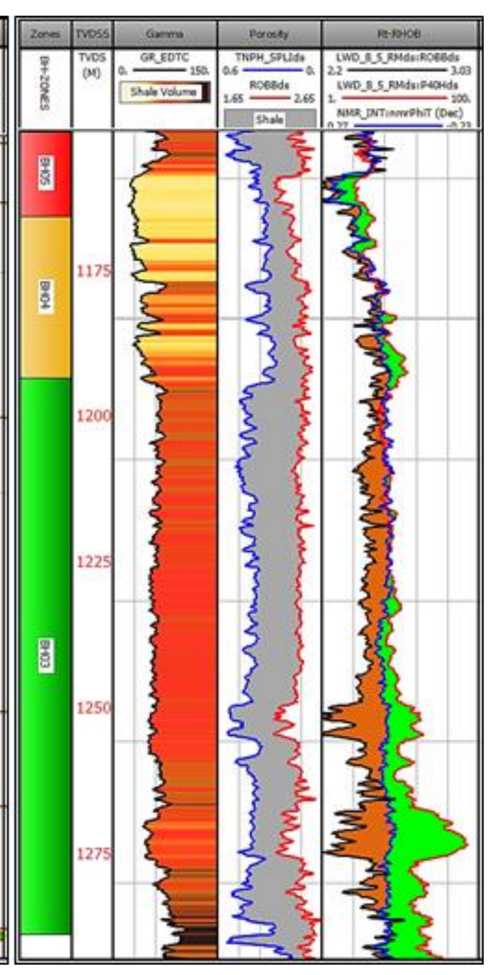
NMR sees only porosity, not TOC



Thermally Immature



Thermally Mature



Petrophysical Property Estimation

$$\rho_B = \rho_{Min}(1-\varphi_T - V_{OM}) + \rho_{OM} V_{OM} + \rho_{FL}\varphi_T$$

For NMR wells: $\varphi_T = \text{NMRPHIT}$

$$V_{OM} = \frac{TOC}{C_k}\frac{\rho_G}{\rho_{OM}}$$

$$\rho_G = \rho_{Min}(1-V_{OM}) + \rho_{OM} V_{OM}$$

Solve for : φ_T and V_{OM}*

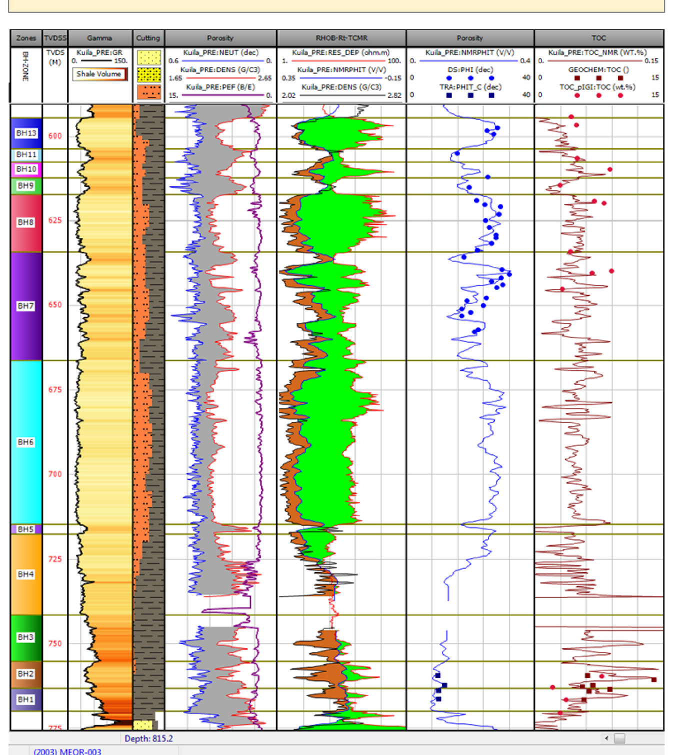
* Note: Here V_{OM} is %BV

Parameters: $\rho_{Min} = f(V_{SH})$

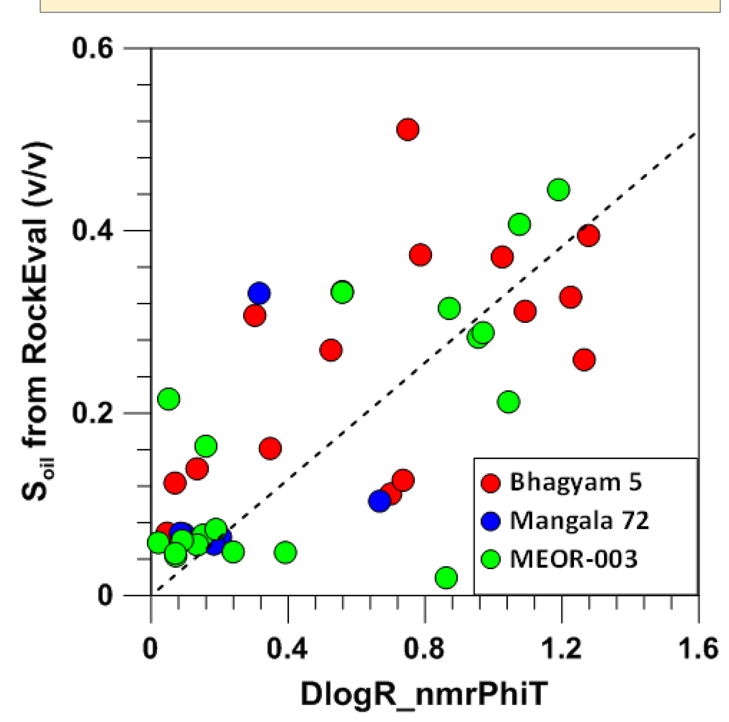
$\rho_{OM} = f(HI)$

$\rho_{FL} = f(k, \text{Mud Type})$

TOC Estimation



Saturation Estimation



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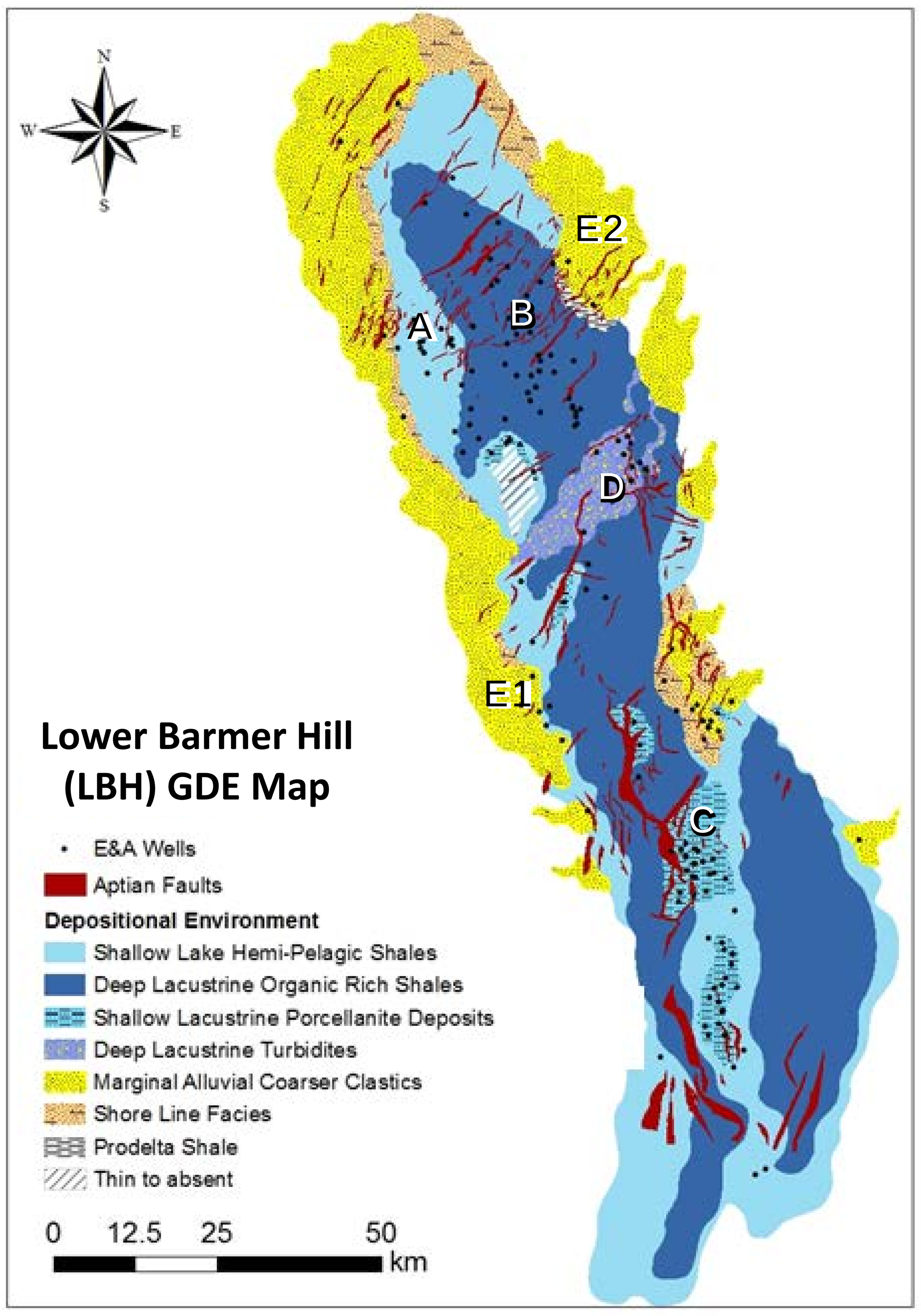
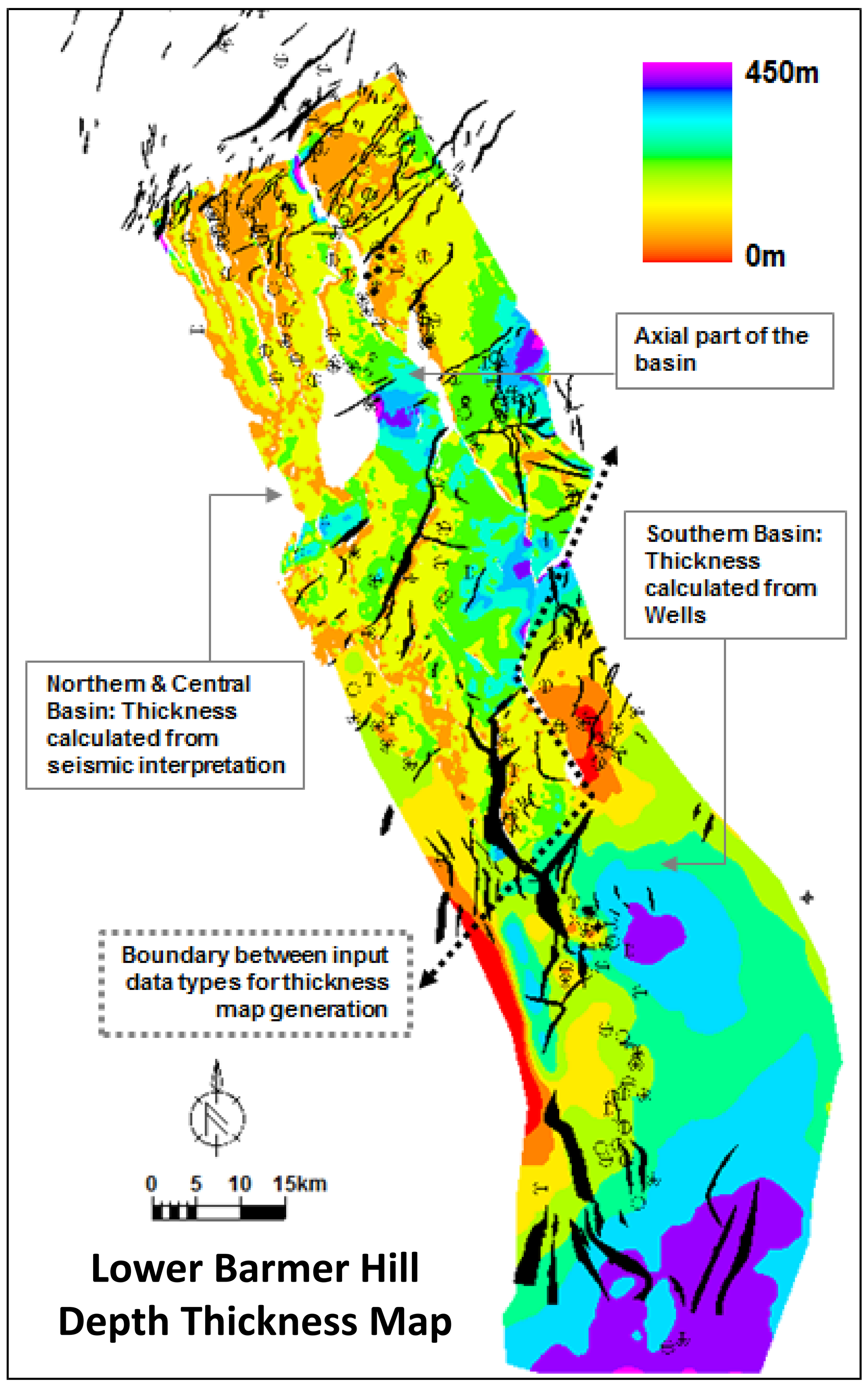
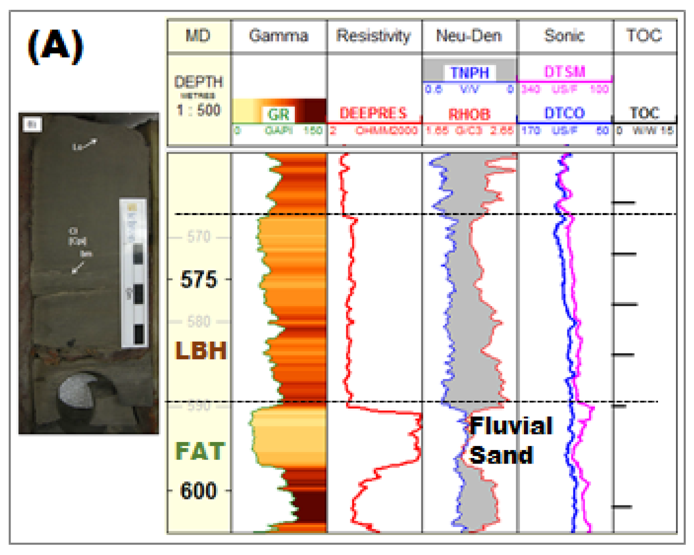
Gross Depositional Environment (GDE) Workflow

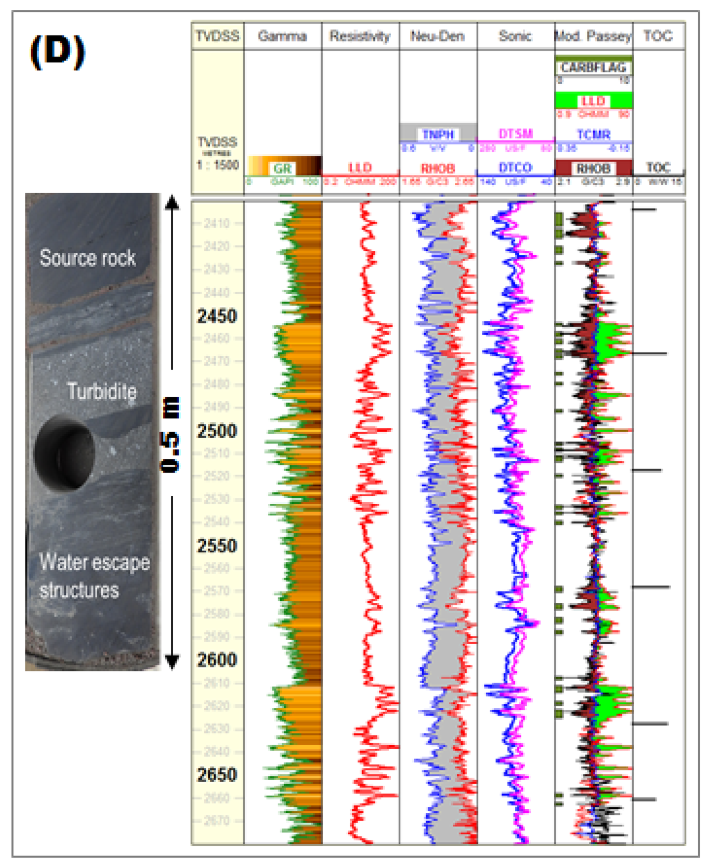




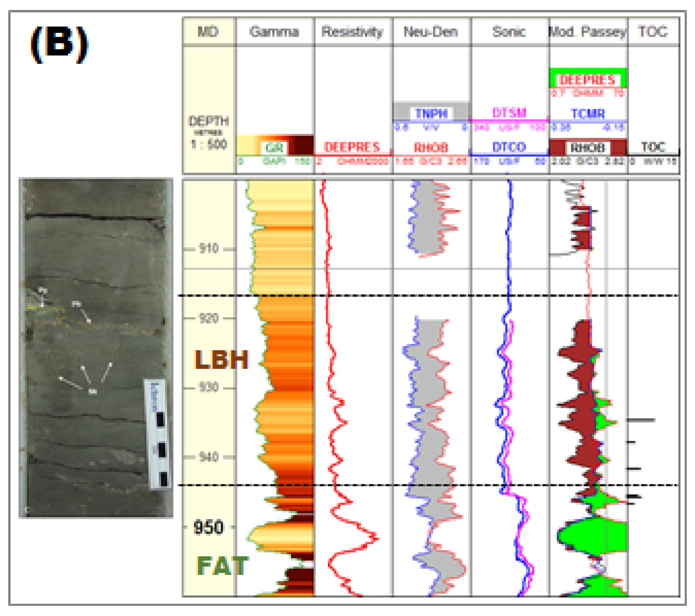
Well Facies Analysis:
Wireline log patterns and available core photographs capture the lithological contrasts



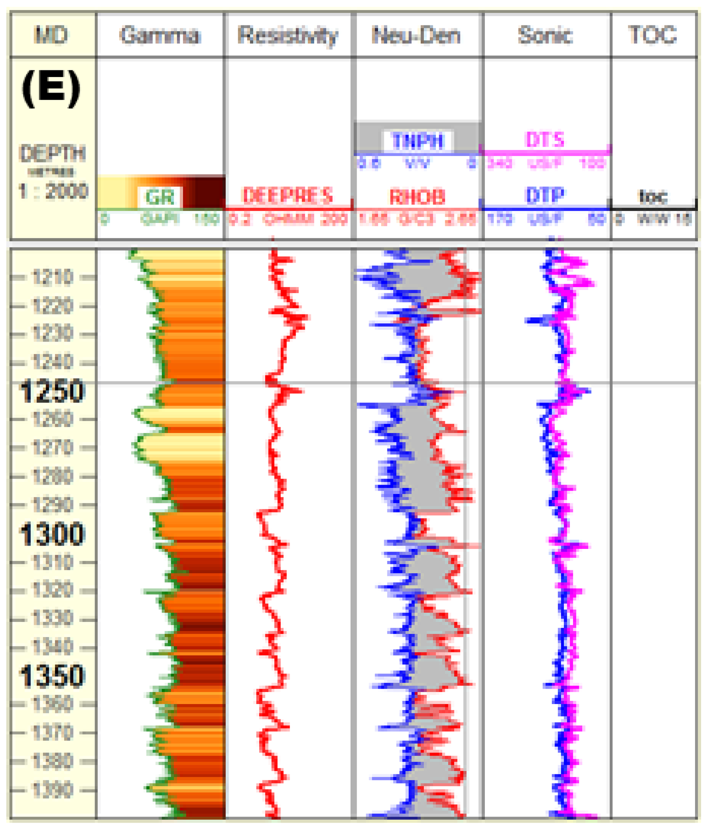
(A) Shallow Lake Hemi-Pelagic Shales



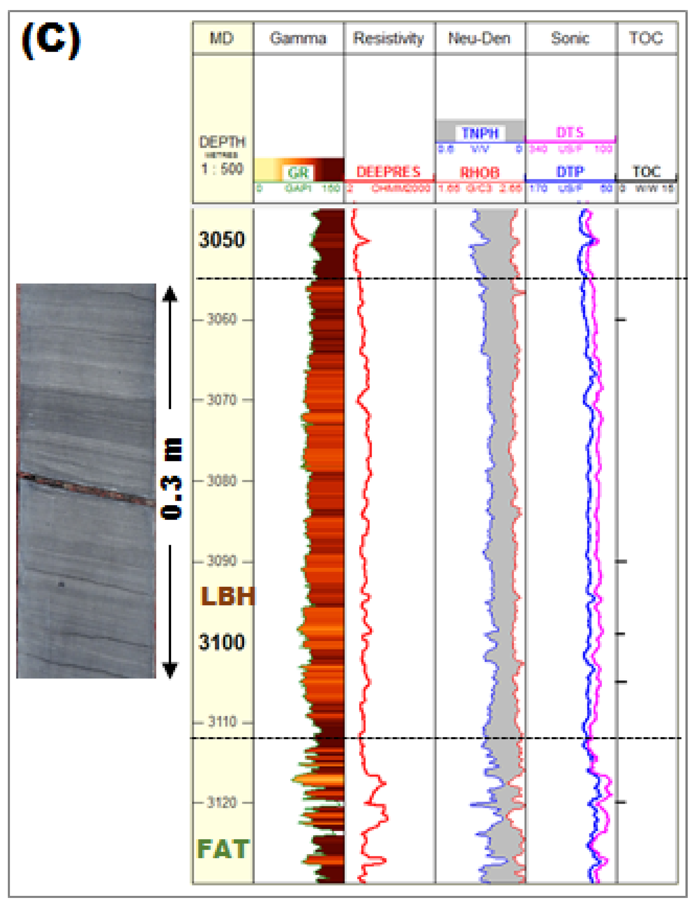
(D) Deep Lacustrine Turbidites



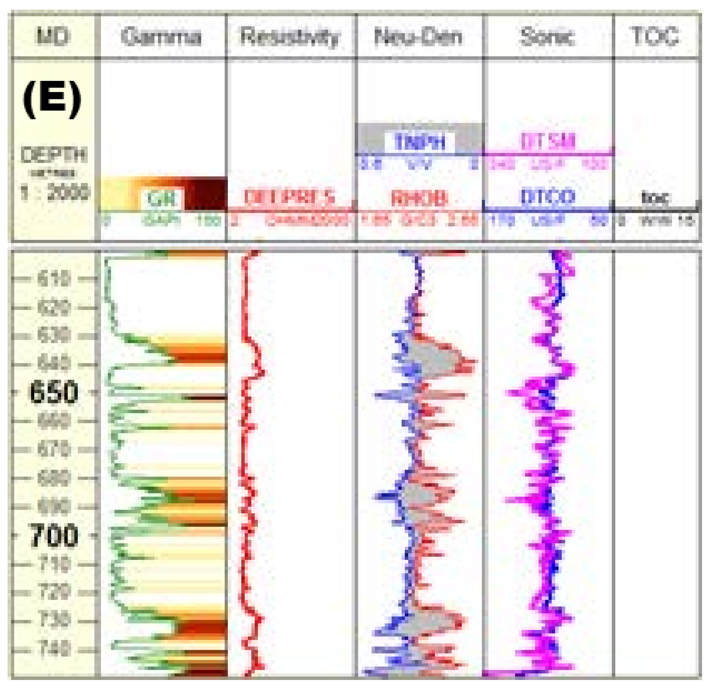
(B) Deep Lacustrine Organic Rich Shales



(E1) Marginal Alluvial Coarser Clastics (western margin fluvial hot sands)



(C) Shallow Lacustrine Porcellanite Deposits

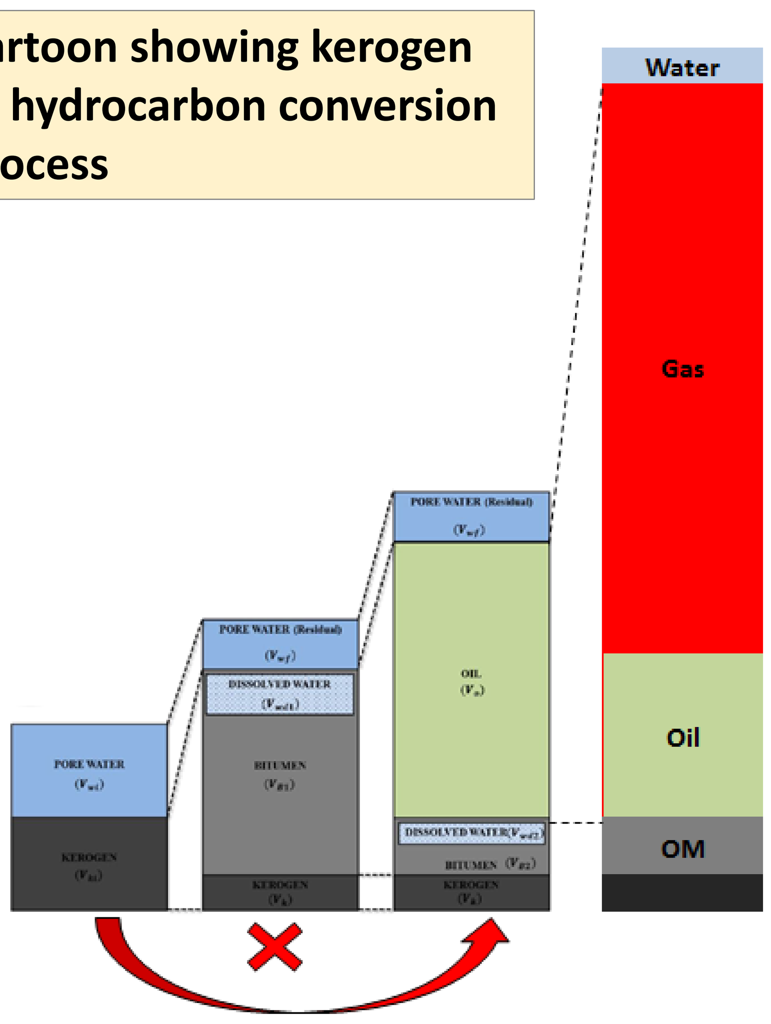


(E2) Marginal Alluvial Coarser Clastics (eastern margin deltaic sands)

- **Depth thickness map** produced from extensive **seismic interpretation (for north and central basin)** and **well log correlation (for southern basin)** shows the local variations of package geometry. Correlation of the isochore map with the active structural trend governed by the Aptian Rift originated faults, indicates presence of all the depocenters or **present day kitchen areas** against the major faults **(cool colors in the thickness map)**.
- **Well facies identification** by the wireline log pattern recognition produced **major five (5) types of well facies** (shown on the right side of this panel), dominated by fine grained clastic and biogenic deposits along with occasional coarser clastic inputs and organic rich intervals.
- **LBH GDE Map** captures the spatial distribution of these 5 well facies in the basin captured from >200 E&A wells. A **central large deep lake** dominated the basin depositing thick transgressive shale **with organic rich shale** streaks and **turbiditic clastics**, near-margin and pre-existing structural highs were covered by shallow lake producing hemi-pelagic shales and porcellanites. All over the margins deltaic and alluvial clastics prevailed.

Productivity Model Workflow

Cartoon showing kerogen to hydrocarbon conversion process



Modelling Approach

Excess Pore pressure
Depositional Kerogen Vol /Water Vol
Kerogen Density / Oil Density

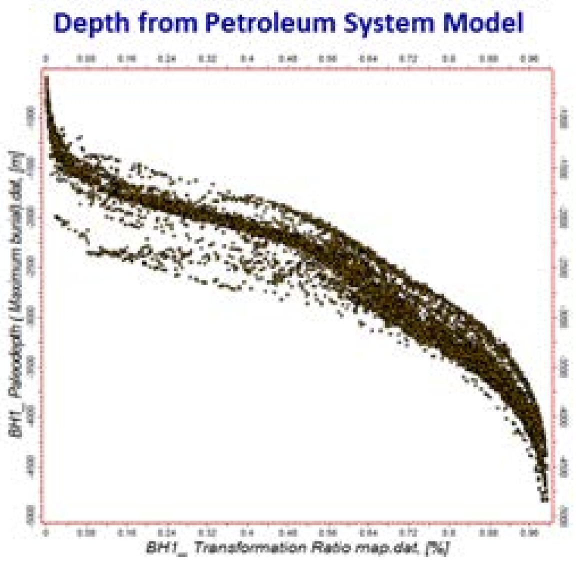
$$\Delta P \approx \frac{vF(D-1)}{(c_w + c_p) + v\left[(1-F)(c_k + c_p) + FD(c_o + c_p)\right]}$$

Compressibilities
Transformation Ratio

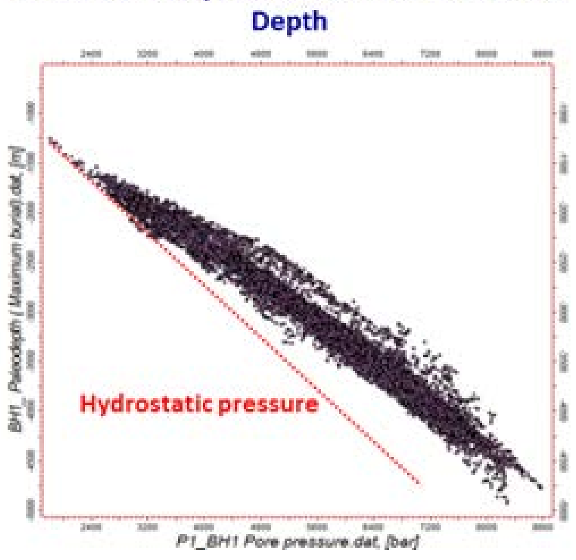
Excess Pore Pressure Estimation

- Modeled excess pore pressure created during maturation of kerogen to oil (Berg and Gangi, 1999)
- Intermediate step of bitumen conversion ignored
- Transformation Ratio maps is converted into pore pressures
- Main Assumptions:
  - No migration of oil,
  - Pressure preserved during uplift in the northern part of the basin

Transformation Ratio vs Maximum Burial Depth from Petroleum System Model



Modeled Pore pressure vs Maximum Burial Depth



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