Is Our Carbonate Reservoir Fractured or Not?*

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Abstract

Information on fractured reservoirs is often controversial. Engineers see lost circulation, negative skin and fracture well test signatures. Geologists see only matrix properties in their cores. Geologists see fractures but engineers see only radial flow on their well tests. In many cases, the two lines of information concur and the evidence is uncontroversial. In other cases the information is not so clear. Engineering data is notoriously non-unique and because carbonate reservoirs have such high heterogeneity – over 30 possible forms of porosity – and many ways this can be connected (or not!) this is a real challenge. What is seen by geologists in small cores may not be seen in larger well tests. Alternatively what is 'seen' in the well tests may bear no link to the observed rocks. It is in these circumstances that the two specialists need to come together and understand each other's points of view and the limitations of each other's data. This requires specialist knowledge with geoengineering insights to try and reach unification of geological and engineering models. All models are wrong – but the one both disciplines agree with is probably useful.

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AAPG Distinguished Lecture May 2014

Is our Carbonate Reservoir **Fractured or Not**?

Patrick Corbett

BG Group Professor

Carbonate Petroleum Geoengineering

Fractured or not?

″ Reservoir Engineering – YES

  . Well test response

  . Finite conductivity Fracture

  . Negative skin

  . Cross-flow

″ Geology – NO

  . No core

  . No image logs

  . No losses
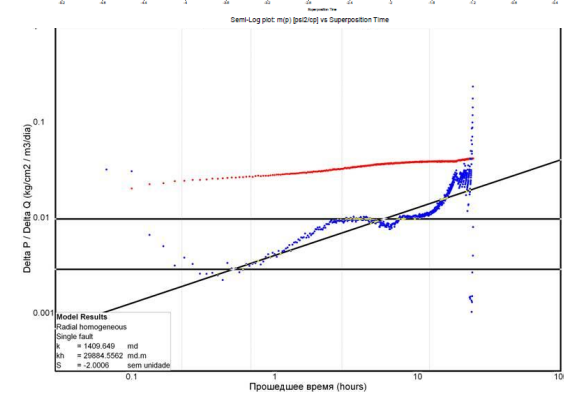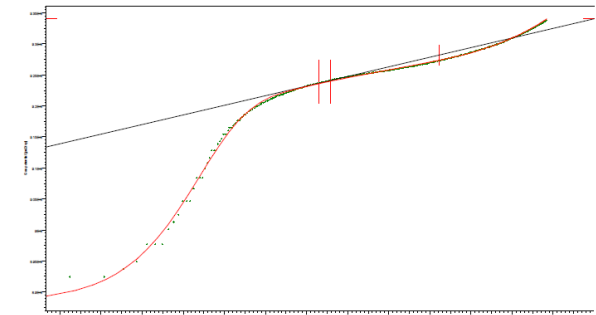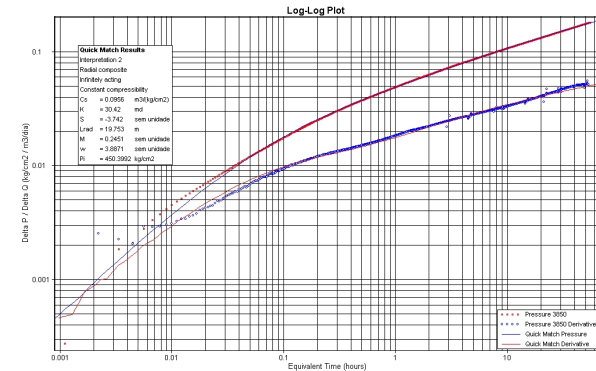
Three "fractured" reservoir well tests

Fractured or not?

″ Reservoir Engineering – YES

  - Well test response

  - Double porosity response

  - Negative skin
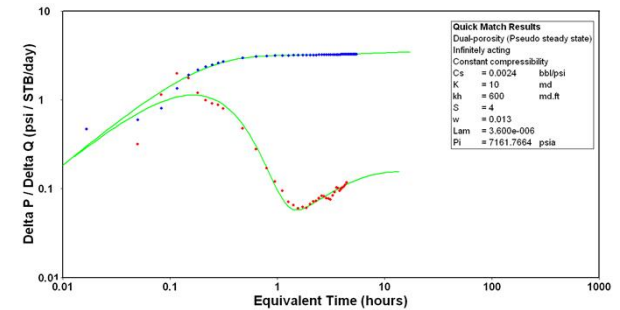
″ Geology – NO or maybe

  - No naturally fractured core

  - No open fractures on image logs

  - No significant losses
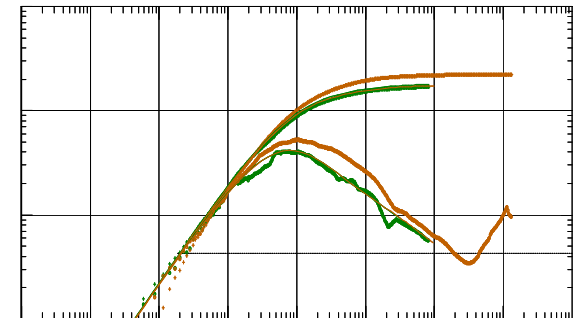
Two "fractured" reservoir well tests

Fractured or not?

˝ Reservoir Engineering – NO

  . Well test response

  . Radial flow

  . No skin

˝ Geology – YES

  . Core

  . Image Log

  . Drilling losses
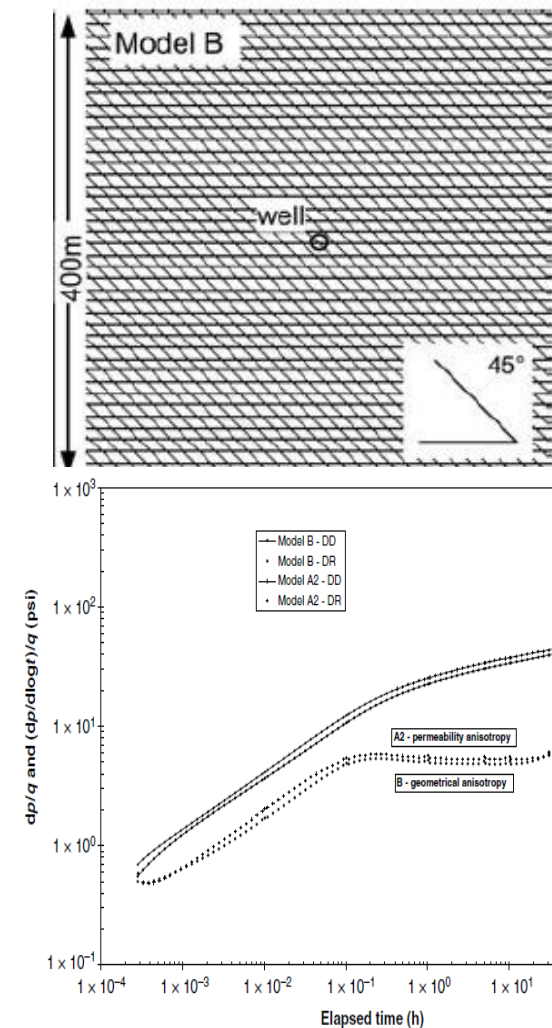
Leckenby et al, 2007,
Soc Spec Publ 270, "Fractured Reservoirs"

Fractures occur where you least expect them!
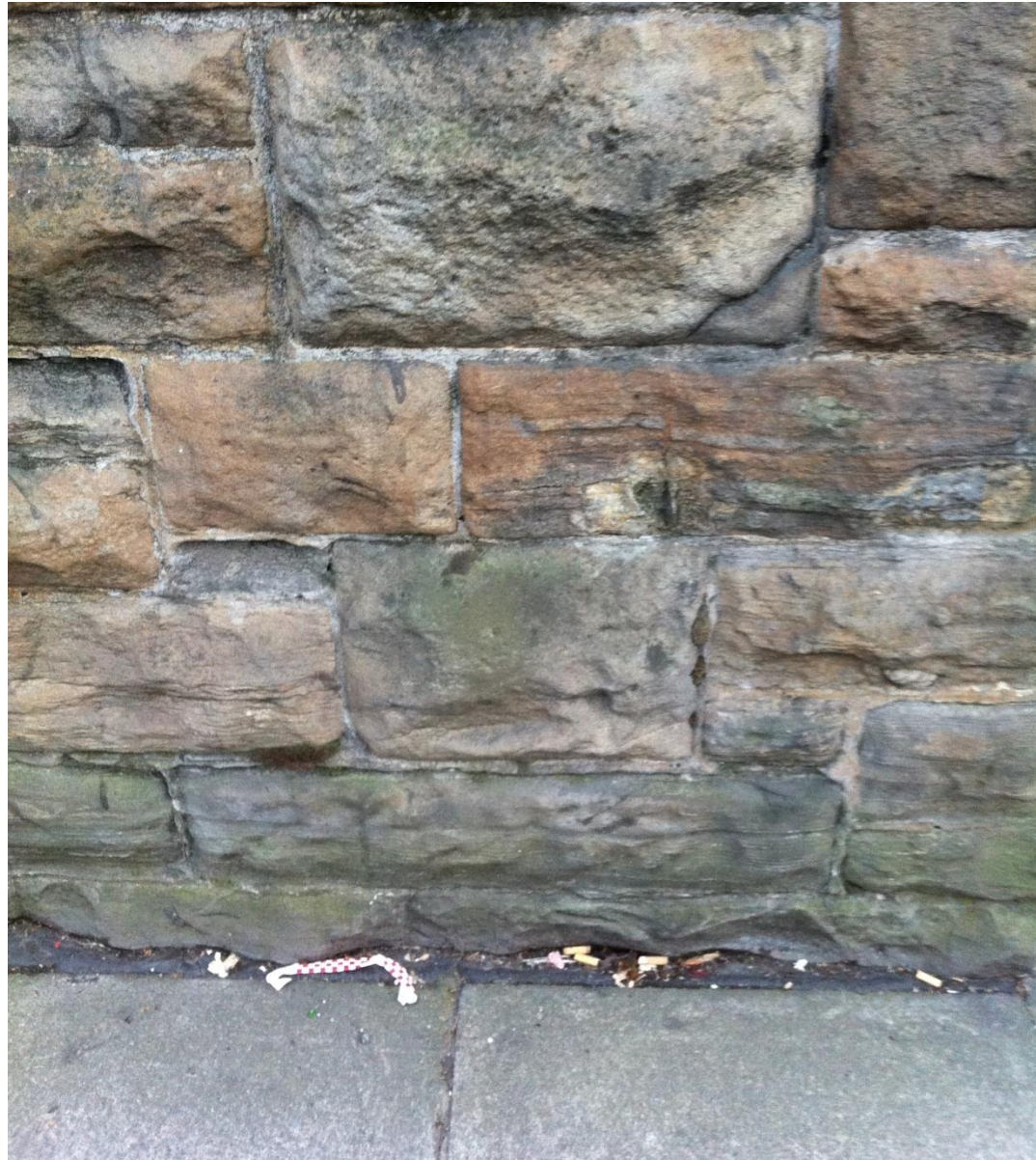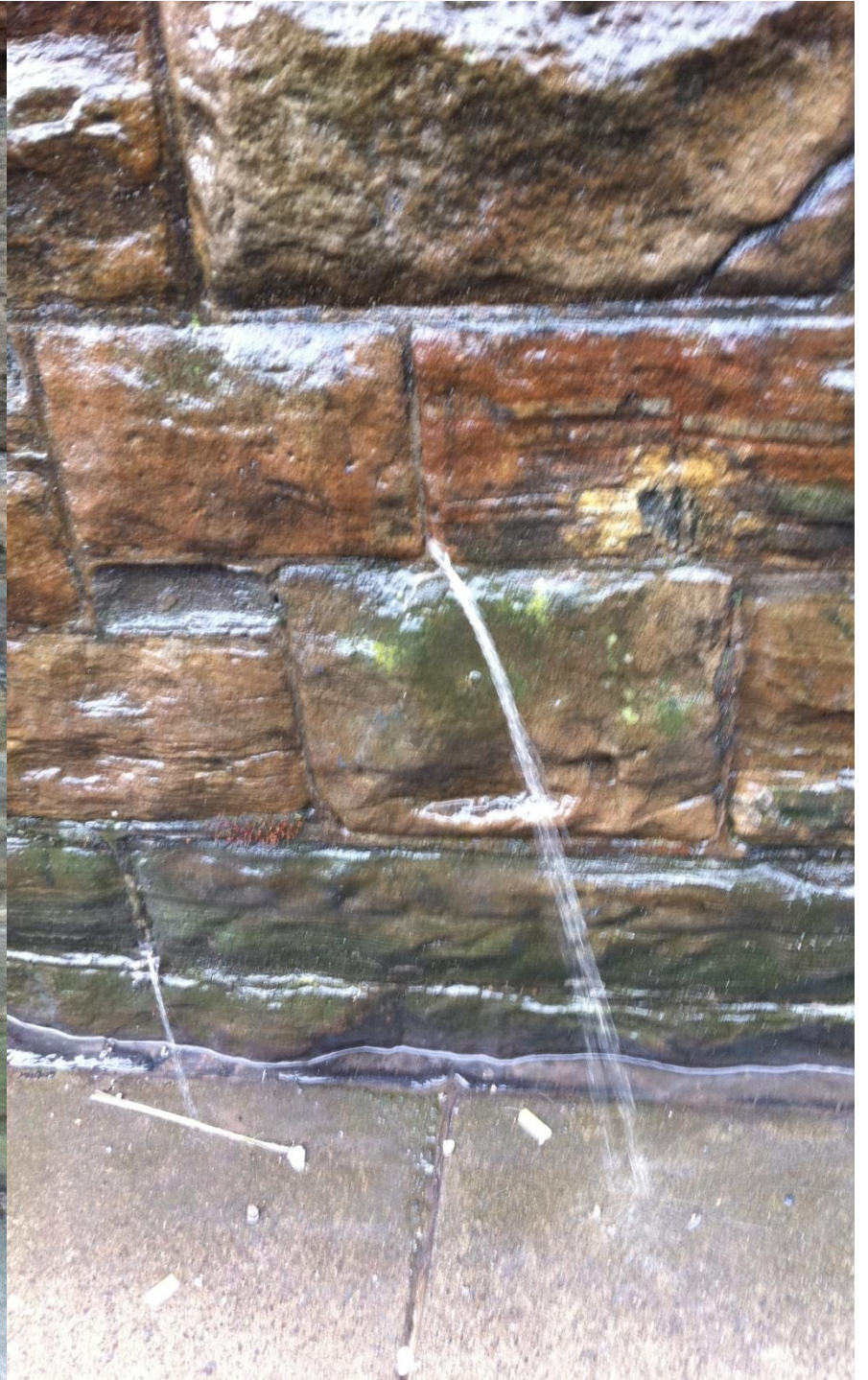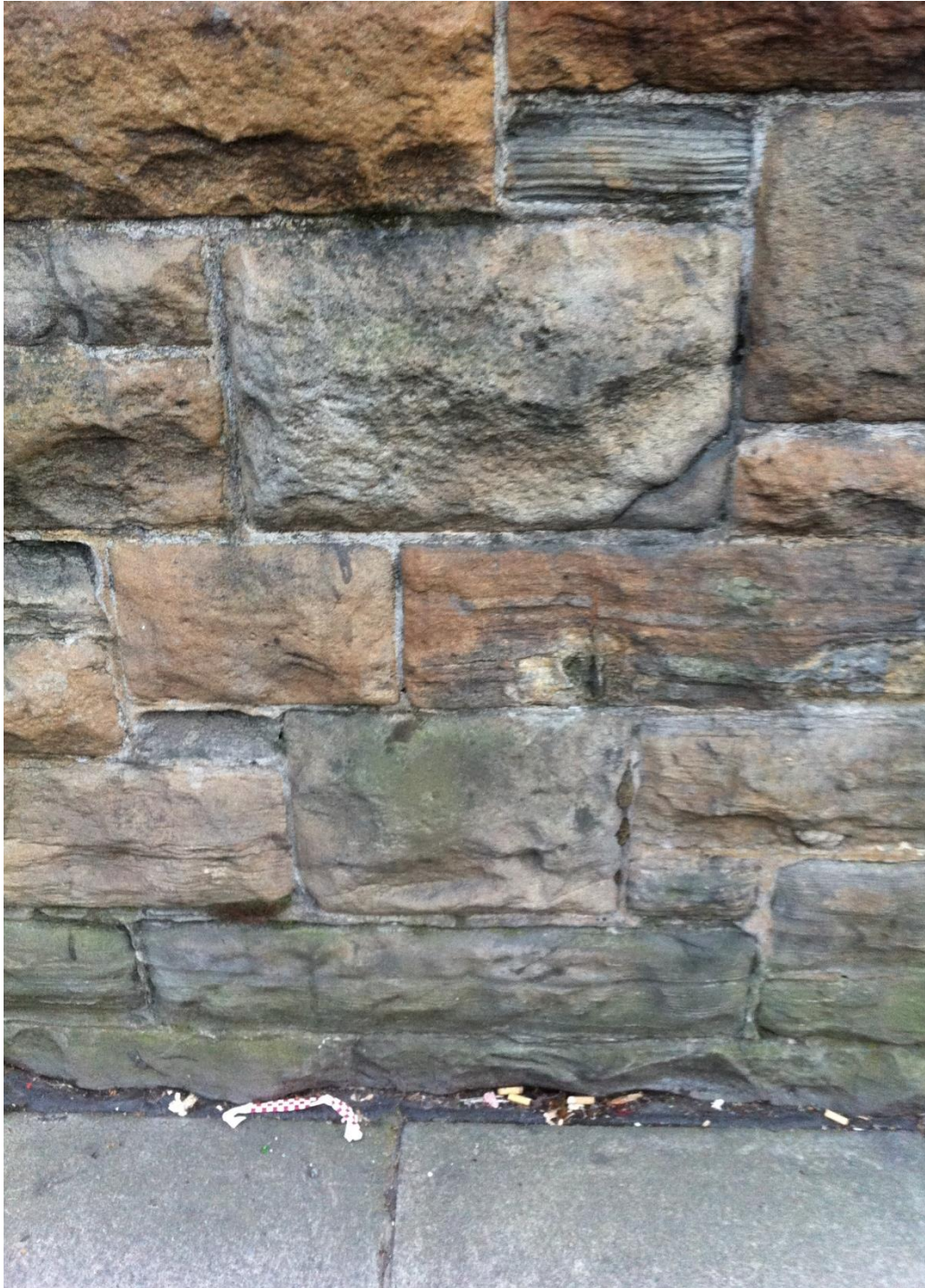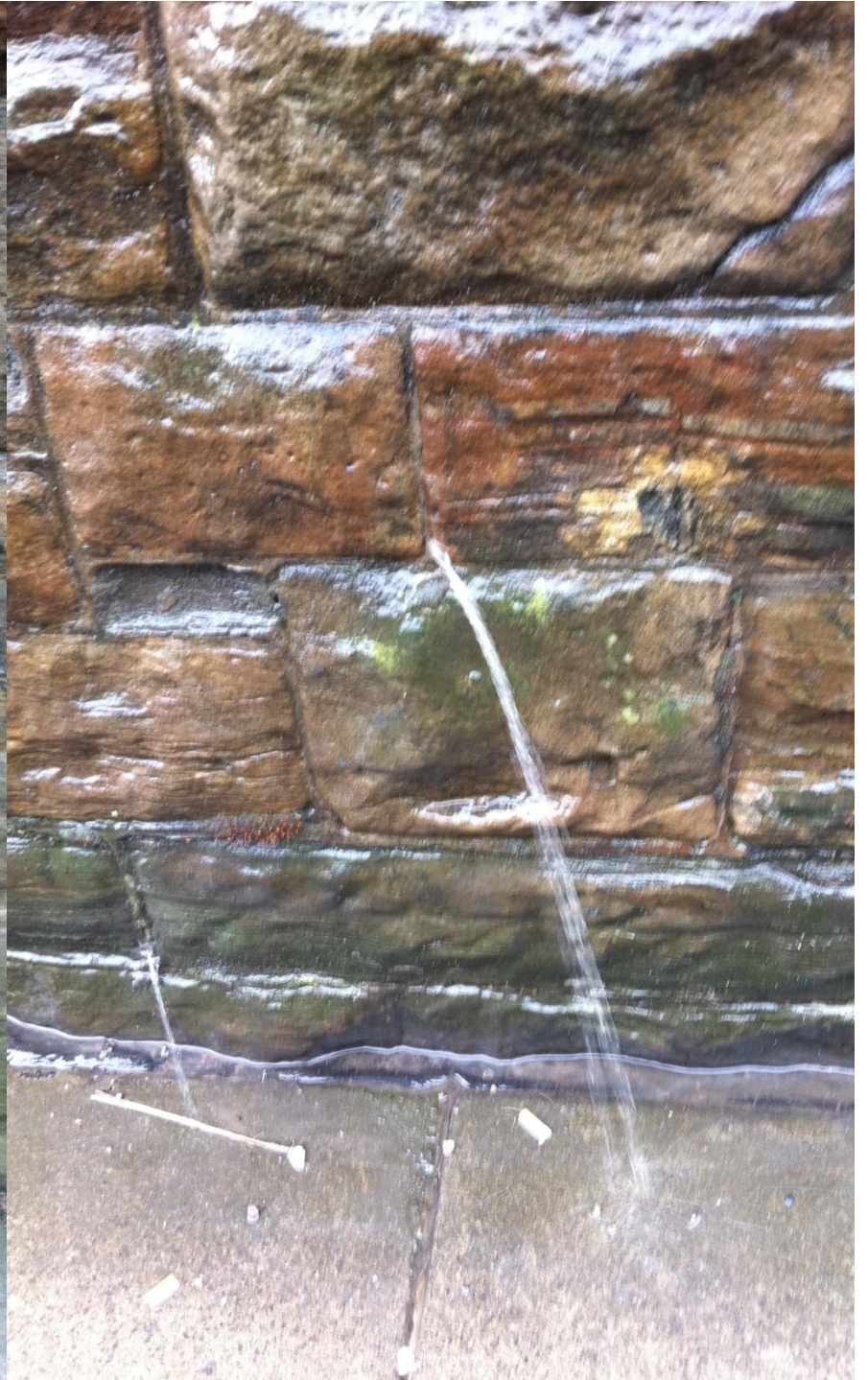
Fractured Reservoirs
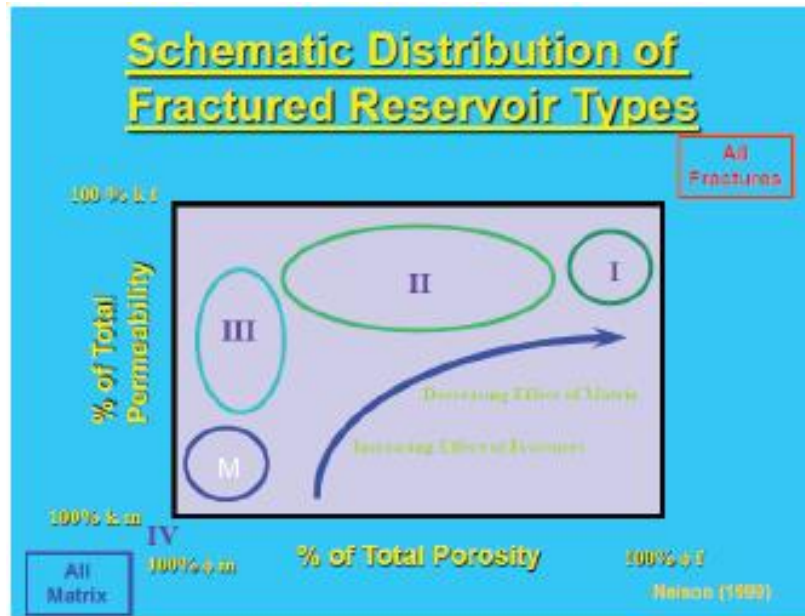
Nelson (1999) defined four types of fractured reservoir

Type I: Fractures provide the essential storage capacity and permeability in a reservoir. The matrix has little porosity or permeability.

Type II: Rock matrix provides the essential storage capacity and fractures provide the essential permeability in a reservoir. The rock matrix has low permeability, but may have low, moderate, or even high porosity.

Type III: Fractures provide a permeability assist in an already economically producible reservoir that has good matrix porosity and permeability.

Type IV: Fractures do not provide significant additional storage capacity or permeability in an already producible reservoir, but instead create anisotropy. **(Barriers to Flow)**

Fractured Reservoir Evaluation

Integration of:

"Lost Circulation (Drilling/Mud Log)

"Core Recovery (Mud Log)

"Core slabs

"Log Interpretation methods

   "Sonic/Total Gas

   "Caliper/Sonic porosity

"Borehole Image logs

"Fracture Identification Log

"Well test interpretation (Double Porosity)

"Modified Lorenz Plot (Core poroperms)

"Production Log Interpretation (PLT)

(Etminan and Sefti, 2008)
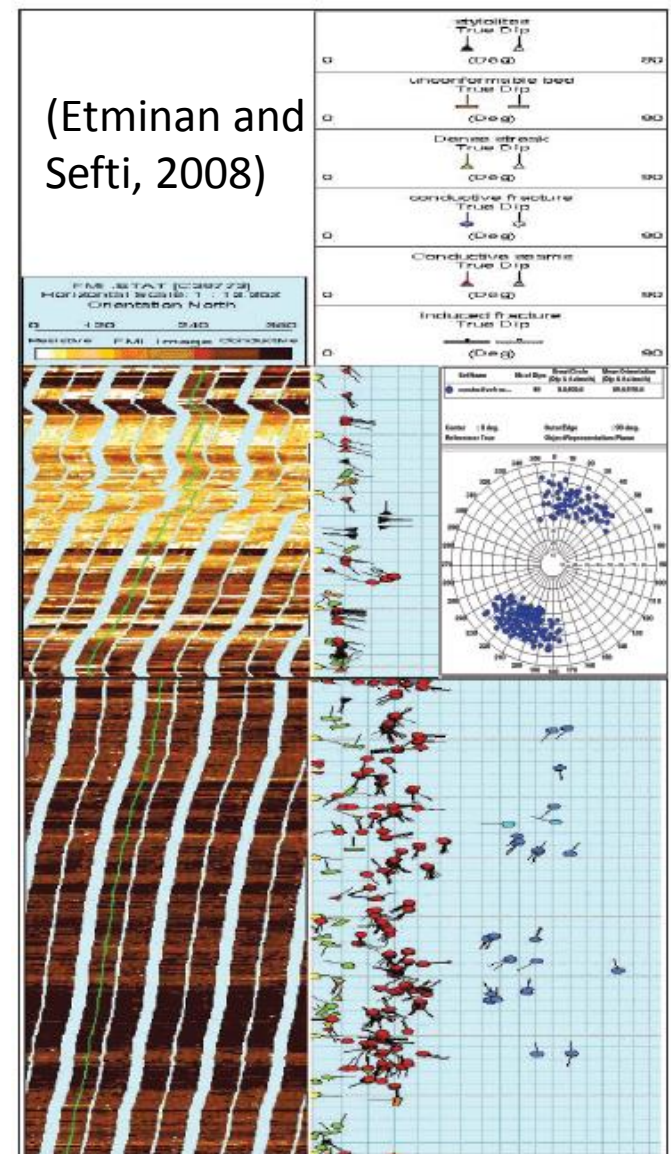
Fracture Permeability Calculations

Heriot-Watt Notes
k = 54,000,000 x Width $(^2)$ (inches)
Fracture 0.001" >>>> 54,000mD

Crain:
PHIfrac = 0.001 * Wf * Df * KF1
Kfrac = 833 * 10^2 * Wf^2 * Df * KF1
PHIfrac = fracture porosity (fractional)
Df = fracture frequency (fractures per meter)
Wf = fracture aperture (millimeters)
Kfrac = fracture permeability (millidarcies)

http://www.spec2000.net/15-permfrac.htm

NUMERICAL EXAMPLE
Df = 1 fracture per meter
Wf = 1.0 millimeters
PHIfrac = 0.001 * 1 * 1 = 0.001 fractional (0.1%)
Kfrac = 833 * 100 * 1^2 * 1 * 1 = 83300 millidarcies

KF1 = number of main fracture directions
= 1 for sub-horizontal or sub-vertical
= 2 for orthogonal sub-vertical
= 3 for chaotic or brecciated

Fracture Permeability Calculations

Glover:

Solution Channel	$k = 0.2 \times 10^8 \times d^2$	k = permeability (D) d = channel diameter (inches)
Fractures	$k = \dfrac{0.544 \times 10^8}{}$ W^2	k = permeability (D) h = fracture width (inches) w = fracture aperture (inches)

http://www2.ggl.ulaval.ca/personnel/paglover/CD%20Contents/GGL-66565%20Petrophysics%20English/Chapter%203.PDF

Note the additional effect of fracture curvature, roughness and presence of asperities

Fracture Permeability Calculations

Geiger:

$$kf\ (m^2) = a(m)^2/12$$

a

Fracture Permeability Calculations

Fracture permeability equations	Aperture (inch)	Aperture (mm)	Aperture (m)	k (mD)	k(D)
HWU notes	1	25.44	0.02544	54000000	54000
HWU notes	0.039308176	1	0.001	83437.16625	83.43716625
Crain	1	25.44	0.02544	53911226.88	53911.22688
Crain	0.039308176	1	0.001	83300	83.3
Glover	1	25.44	0.02544	54400000	54400
Glover	0.039308176	1	0.001	84055.21933	84.05521933
Geiger	1	25.44	0.02544	53932800	53932.8
Geiger	0.039308176	1	0.001	83333.33333	83.33333333
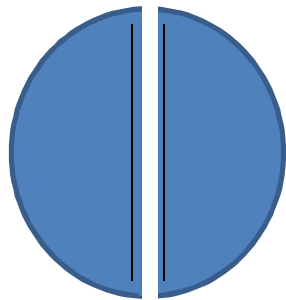
Applicable to plane parallel fractures
at the core plug scale (ignoring the rock!)

Sample PET 8, Morro do Chaves

Horizontal Plug (#50)
Porosity = 6.5%
Permeability = 0.145mD

Vertical Plug (#51)
Porosity = 5.8%
Permeability = 0.031mD
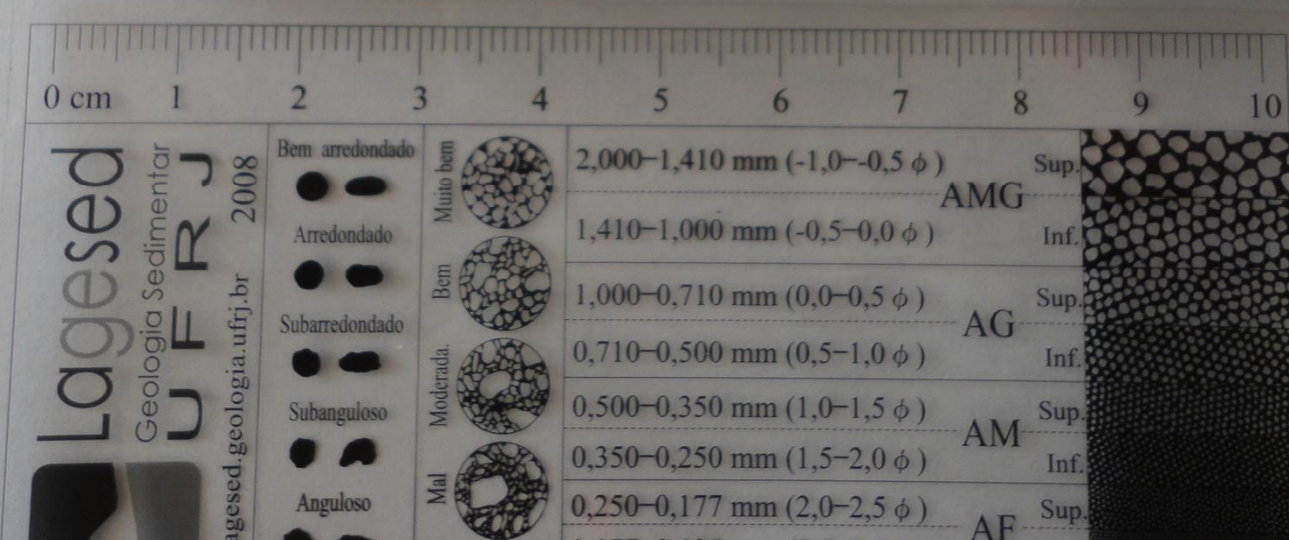
Split into two plugs

Horizontal Plug
Porosity = 6.5%
Permeability = 0.145mD

Estimate Properties
Porosity = ????%
Permeability = ????mD

Assume Vertical Plug Properties
Porosity = 5.8%
Permeability = 0.031mD

Whatever the plug 50a perm, can't make total 0.145mD!!

Plug 50a

Plug 50b

←———————————→

Estimate Properties
Porosity = ????%
Permeability = ????mD

Assume Vertical Plug Properties
Porosity = 5.8%
Permeability = 0.031mD

	Plug 50a	Plug 50b	Plug 50	Fract	Matrix	Harm Av
Porosity	7.2	5.8	6.5	1.4	5.8	
Permeability (mD)	100000	0.031	0.145	100000	0.031	0.0620000

Gary Couples' "Unconnected Highways"

Nice multi-lane highway that does
not have any traffic – cuz it doesn't
connect to anything!

Fractures in Whole Core
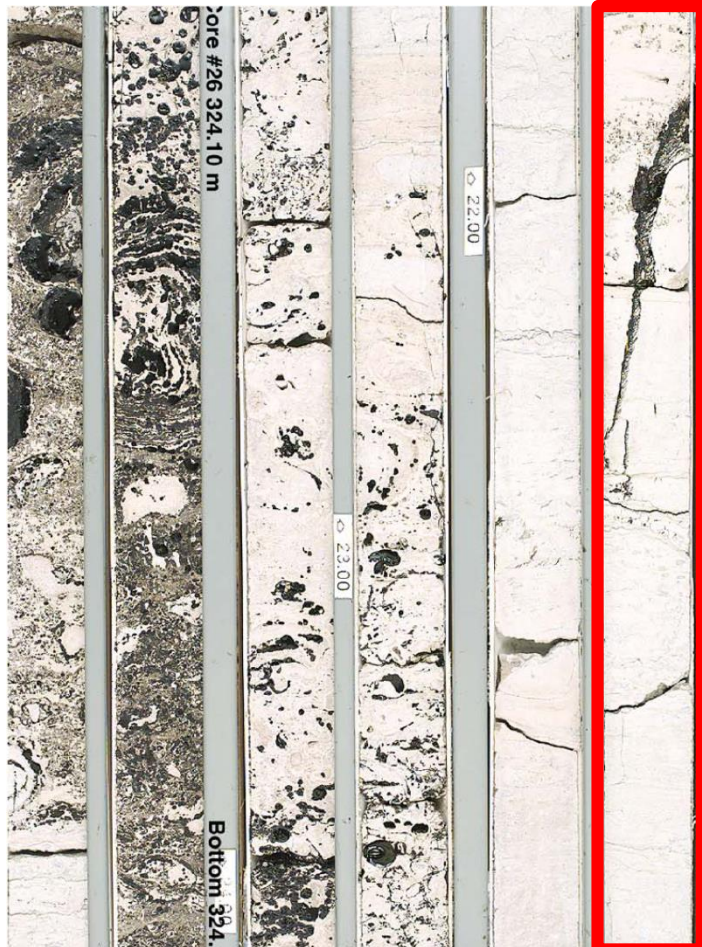
Fractures in core		
Core		
Length	1000	mm
Diameter	100	mm
Volume	7853982	cu mm
Fracture		
Angle	45	deg
Width	1	mm
Diameter	100	mm
Volume	15708	cu mm
Matrix Porosity	0	
Total Porosity	0.002	
Fracture porosity	0.002	Dec
Matrix Permeability	0	mD
Total Permeability	83	mDm
Fracture Permeabiliy	83333	mD

Fracture Equations are simplification

Don't take into account:

1. The interaction between fracture and pore matrix

2. Aperture variation

3. Fracture wall roughness

4. Aperture spatial correlation

Jiang et al, 2013

Fractures from logs

˝ Estimate using Sonic and Neutron Porosity logs

. Sonic >> Matrix Porosity

. Neutron >> Total Matrix plus Fracture Porosity

. Determine Fracture Porosity

˝ Estimate using Aguilera Method

. Estimate Matrix Porosity and Cementation (m) exponent

. Determine Matrix and Reservoir Formation Factor

. Determine Fracture Porosity

Source: Pritchard, 2013

Fractures from logs (Cont.)

″ Estimate from Shallow and Deep Resistivity logs
  - You know $1/R_{xo}$ and $1/R_t$
  - Determine Porosity Partitioning Coefficient
  - Determine Fracture Porosity (% of Φ_T held by fractures)

″ Other methods
  - Caliper log
  - Gamma Ray (Heavy mineral veins)
  - Array Sonic (Chevrons)
  - Fracture Identification Logs (FIL)
  - Image logs

Fractures using well test (2)

2 Classic 'V' shaped deriviative
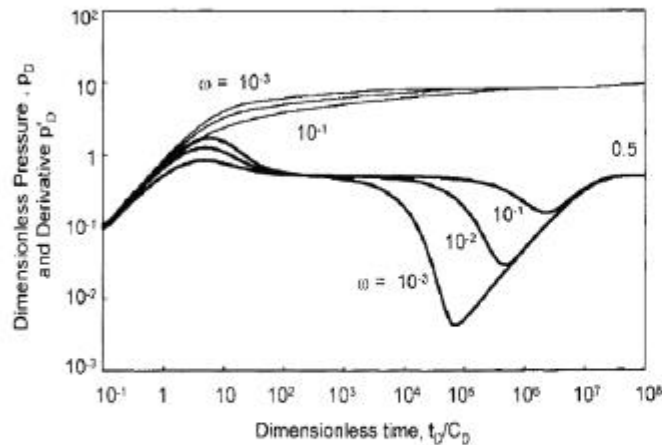
"ω defines the contribution of the fissure systems to the total storativity"
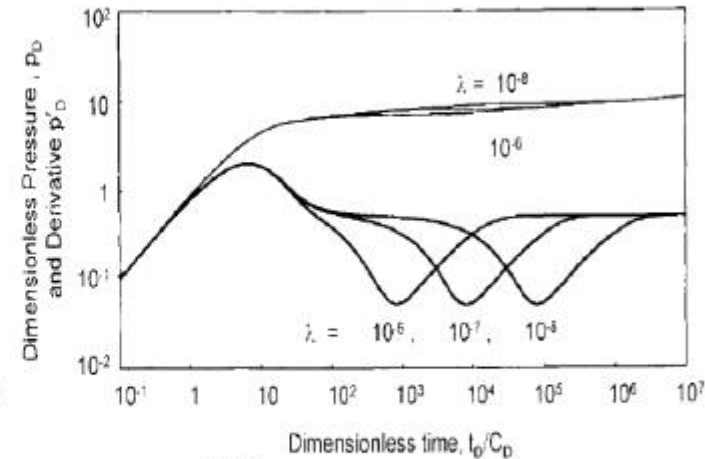
"λ defines the ability of the matrix blocks to produce to the system"

Nelson Type II Fractures Double Porosity System
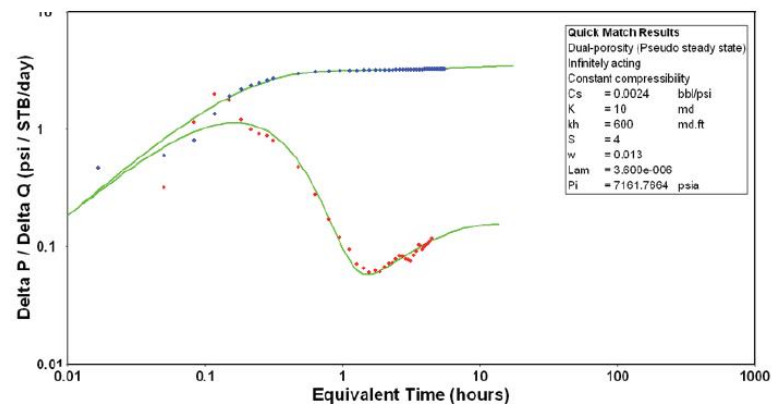
Fracture Reservoir Recovery (1)

Fracture Reservoir recovery mechanisms

Storage Classification

From a storage point of view the fractures can be classified[1] as being of Type A, B or C. Many reservoirs that would otherwise be

Schematic Distribution of Fractured Reservoir Types

All Fractures

100 % L t

% of Total Permeability

III
A

II B

I C

M

Decreasing Effect of Matrix

Increasing Effect of Fractures

1000s k m

IV

100% ф m

% of Total Porosity

100% ф f

Nelson (1999)

All Matrix
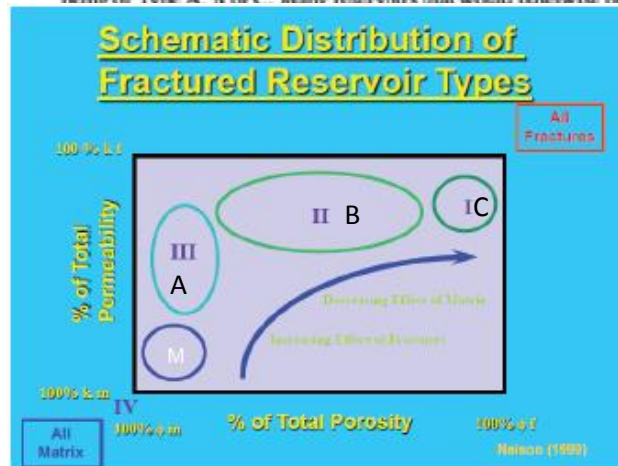
In reservoirs of Type C all the hydrocarbon storage is in the fractures with no contribution from the matrix. Thus in this instance the fractures provide both the storage and the necessary permeability to achieve commercial production.

Roberto Aguilera
Journal of Canadian Petroleum Technology
July 1999, Volume 38, No. 7

TABLE 2: Typical oil recoveries from naturally fractured reservoirs as a per cent of original oil in place.

RECOVERY MECHANISM	RESERVOIR TYPE		
	A	B	C
Depletion Drive	10-20	20-30	30-35
Depletion Drive plus Gas Injection	15-25	25-30	30-40
Depletion Drive plus Water Injection	20-35	25-40	40-50
Depletion Drive plus Water Inj plus Gas Inj	25-40	30-45	45-55
Gravity Segregation with Counterflow	40-50	50-60	>60
Depletion Drive plus Water Drive	30-40	40-50	50-60
Depletion Drive plus Gas cap	15-25	25-35	35-40
Depletion Drive plus Gas Cap plus Water Drive	35-45	45-55	55-65

TABLE 3: Typical gas recoveries from naturally fractured reservoirs as a per cent of original gas in place.

RECOVERY MECHANISM	RESERVOIR TYPE		
	A	B	C
Without Water Drive	70-80	80-99	>90
With Moderate Water Drive	50-60	60-70	70-80
With Moderate Water Drive and Compression	20-30	30-40	40-50
With Water Strong Drive	15-25	25-35	35-45

Recovery increases >>>>>>>

Source: Pritchard, 2013

Fractured Reservoir Recovery (2)

Critical Exploration & Development Issues by Fractured Reservoir Type
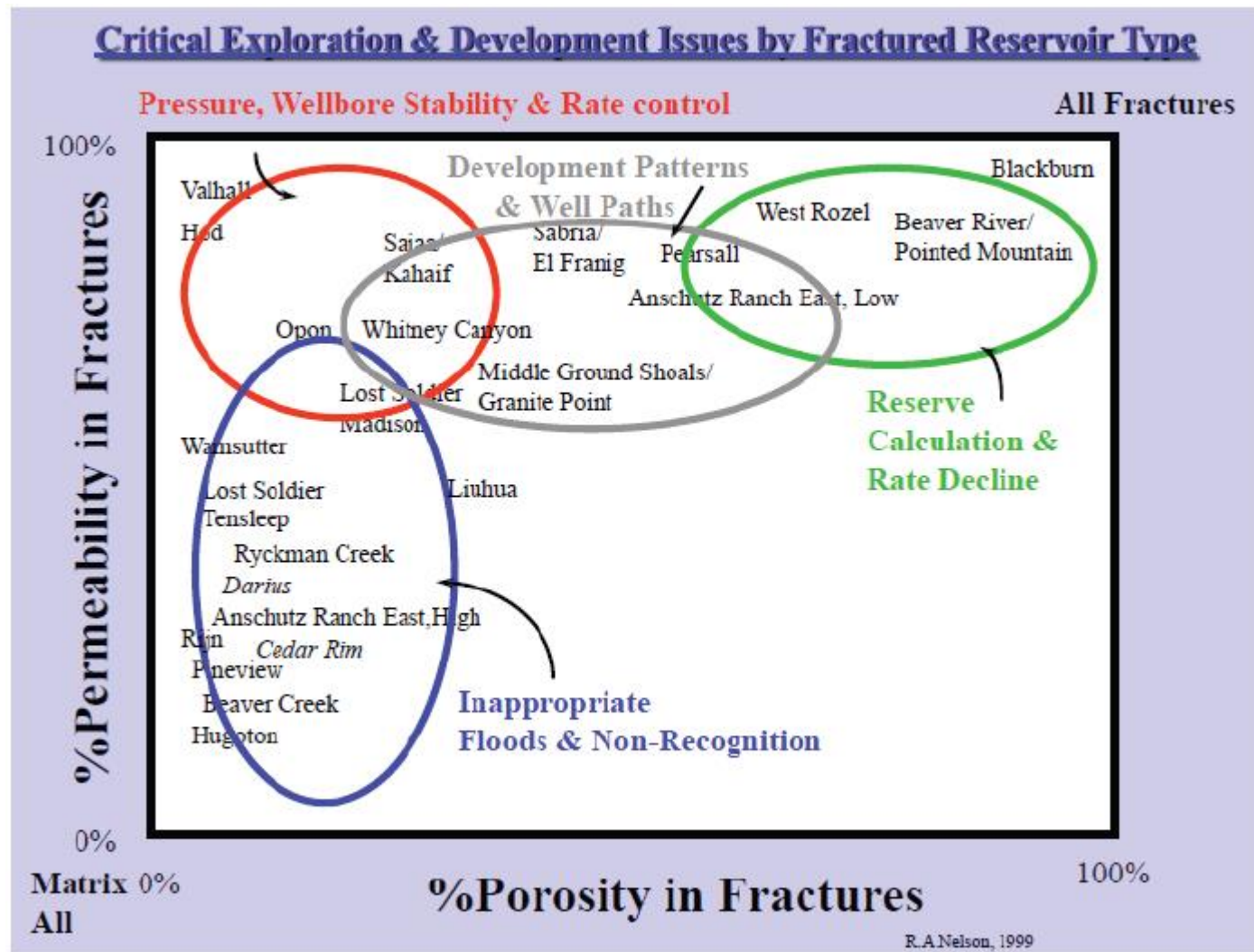
Some Definitions

" Single Porosity – Matrix only

- Classic "Double Porosity" - Fractured Reservoirs

- "Double Matrix" Porosity Reservoirs – New awareness

- "Triple Porosity" - Fractured Double Matrix Reservoirs or Triple Matrix Porosity

- Numerical (geological) well testing – emerging standard workflow – "Geotesting"

- Petroleum Geoengineering – integrated geo-petrophys-eng workflow

Corbett et al., 2010, Petroleum Geoscience

Double Matrix Geological Model

Rock Types (Martin et al 1997)

Rock Type	Pore Throat Size (µm)	Mean K (mD)	Swi	Sro	Rock Fabric
Macroport	2 - 10	250	0.15	0.2	Grainstone oolitic
Mesoport	0.5 - 2	50	0.25	0.3	Grainstone oolitic
Microport	< 2	5	0.35	0.35	Grainstone oolitic
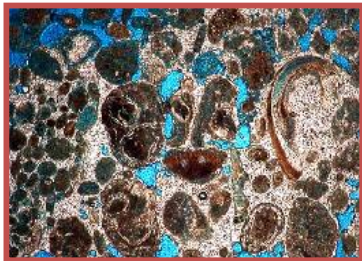
a) Mesoport

Phi=25%, K=50mD
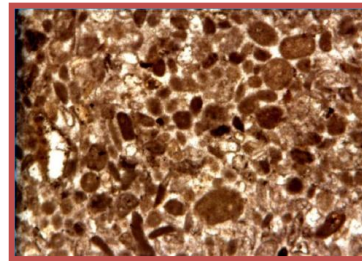
c) Microport

Phi=10%, K=5mD
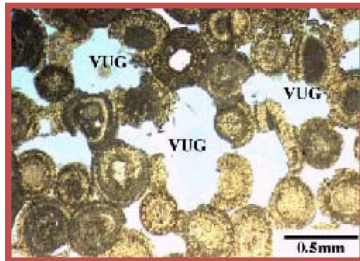
b) Macroport

Phi=25%, K=250mD
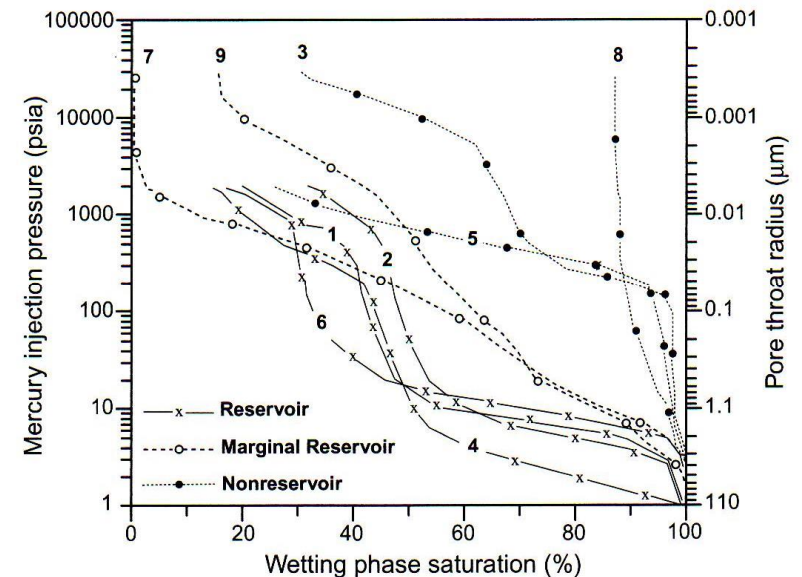
Ahr, 2008

Morales, 2009

Double Matrix Porosity
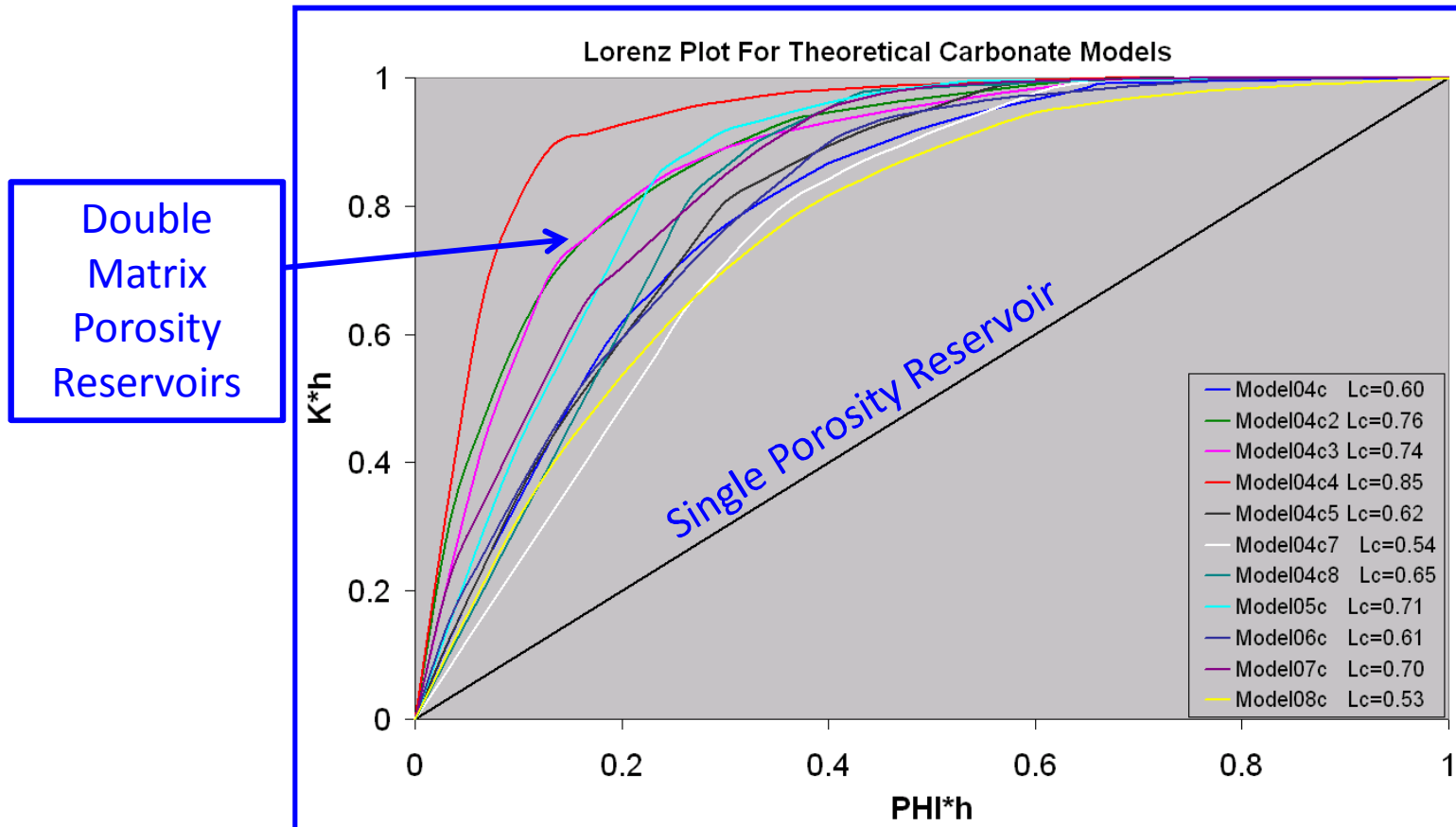
Double Matrix Porosity Reservoirs

Lorenz Plot For Theoretical Carbonate Models

Single Porosity Reservoir

K*h

PHI*h

Model04c	Lc=0.60
Model04c2	Lc=0.76
Model04c3	Lc=0.74
Model04c4	Lc=0.85
Model04c5	Lc=0.62
Model04c7	Lc=0.54
Model04c8	Lc=0.65
Model05c	Lc=0.71
Model06c	Lc=0.61
Model07c	Lc=0.70
Model08c	Lc=0.53

- Lorenz coefficient (Lc) is related to local heterogeneity (close to the well), and the pressure response investigates bigger volume of reservoir.

Double Matrix Porosity
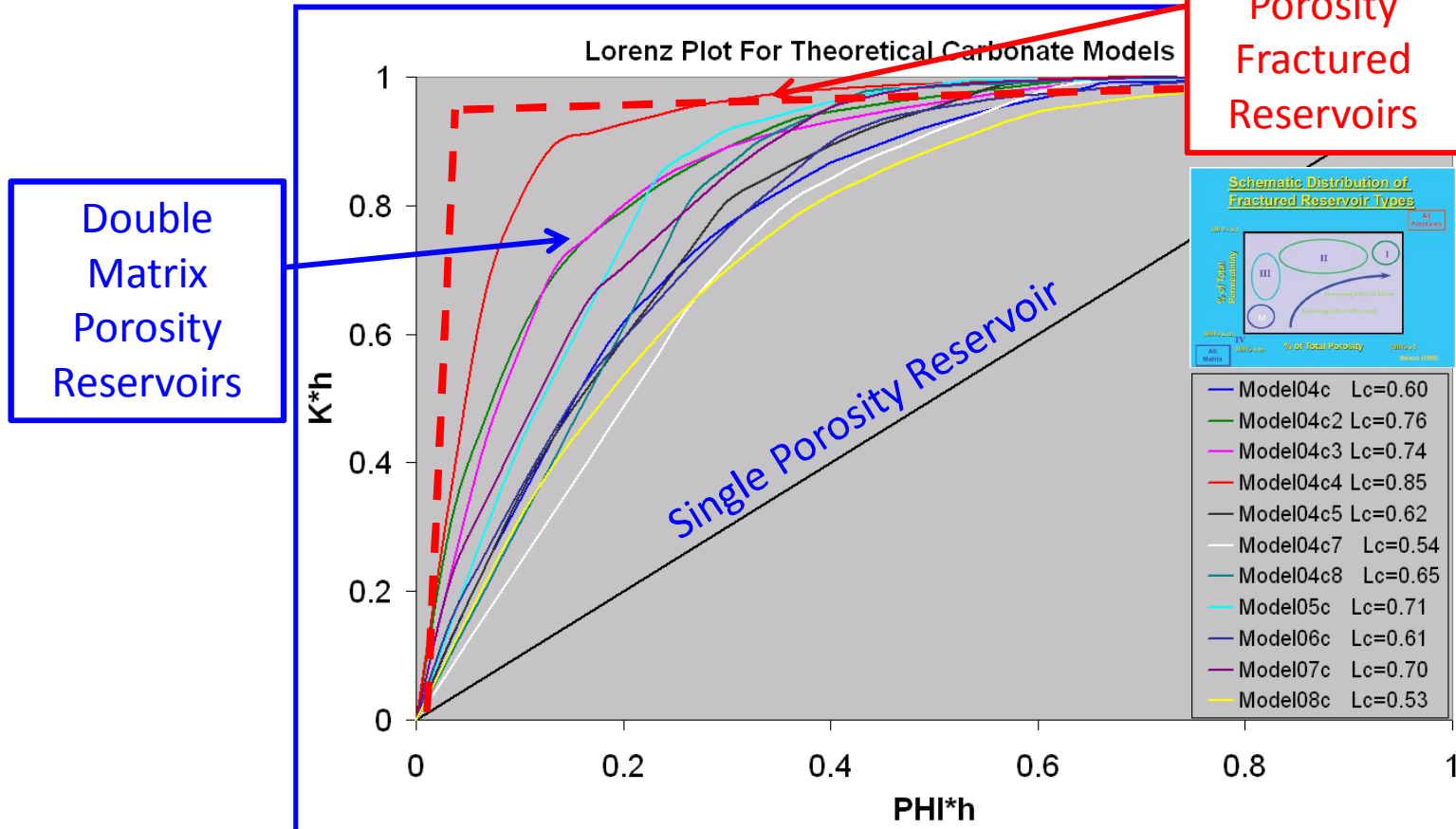
- Lorenz coefficient (Lc) is related to local heterogeneity (close to the well), and the pressure response investigates bigger volume of reservoir.

What is Well Testing?

˝ Production of a limited amount of fluid from the reservoir

$$\frac{\partial^2 P}{\partial X^2}\eta_x + \frac{\partial^2 P}{\partial Y^2}\eta_y + \frac{\partial^2 P}{\partial Z^2}\eta_z = \frac{\partial P}{\partial t}$$

˝ Pressure changes in space and time controlled by the Diffusivity equation

$$\eta_j = \frac{k_j}{\phi \mu C_t}, j = x, y, z$$

˝ Hydraulic diffusivity - Is this a constant

Simple Well Test History

q

Rate

Well producing   Well shut-in

0

t_p Δt

t

Time >>

P

Pressure

Draw-down   Build-up

0

t_p Δt

t
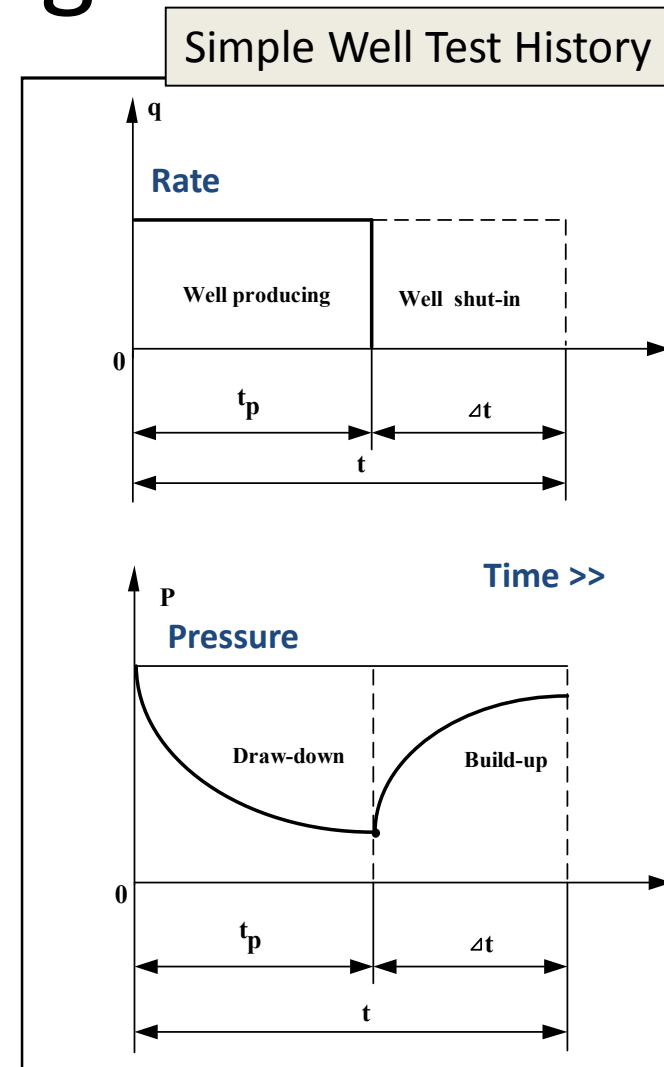
(From Corbett, DISC, 2009, after Zheng)

Well Test Skin

˝ Difference between pressure at shut-in and after 1hr (on the Horner straight line) (Bourdarot, 1998)

Producing Well

Pressure increases into the formation >>>>>>

P2

−ΔPskin

Build-up when well shut

P1

+ve : Extra pressure drop at wellbore

-ve : Reduced pressure drop at wellbore

+ΔPskin
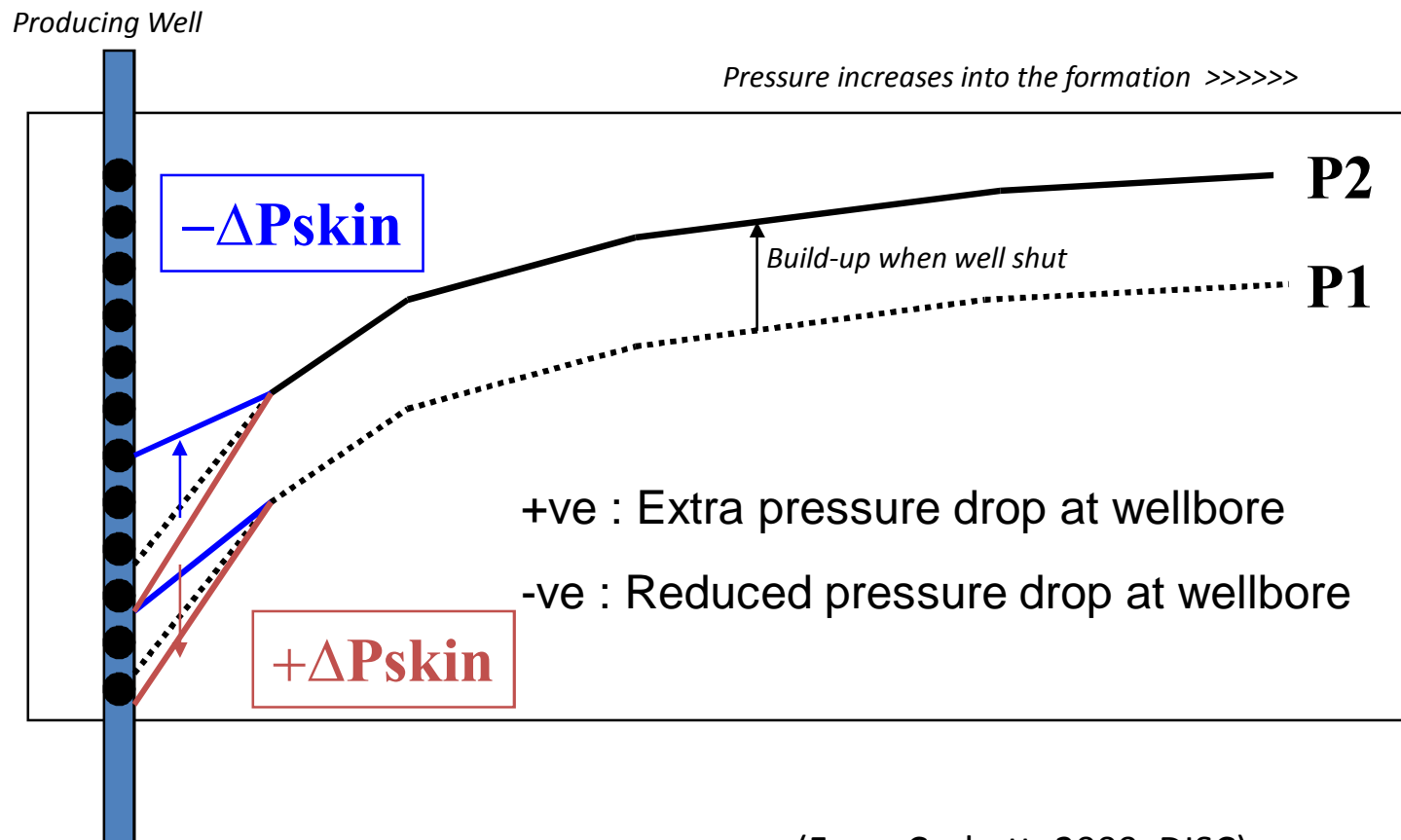
(From Corbett, 2009, DISC)

Pressure derivative plots
(in an rectangular sand pit)

1 Pressure contour in an infinite linear strip

Infinite extent

2 Flow lines in an infinite linear strip

Infinite extent

3 No flow boundary with pressure depletion

W

L

Sst

LOG(DPD/DTD) (Dimensionless)

Pressure

1

2

3

Unit slope PSS

Half slope linear flow

MTR Radial Flow infinite acting
Derivative

LOG(TD) (Dimensionless)
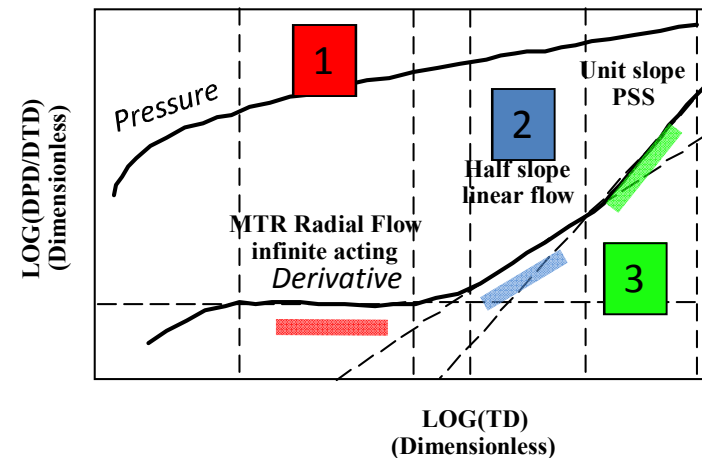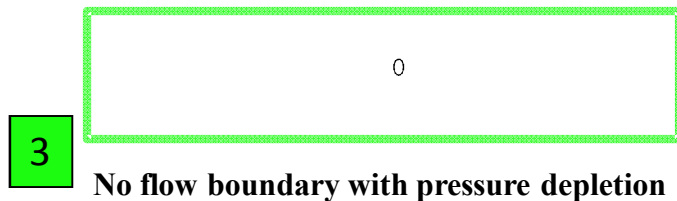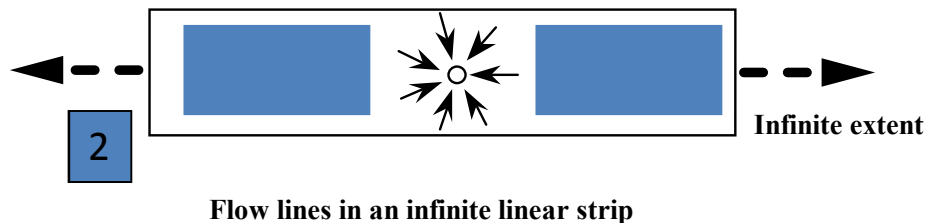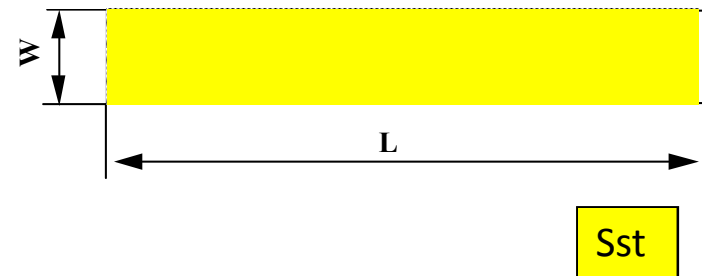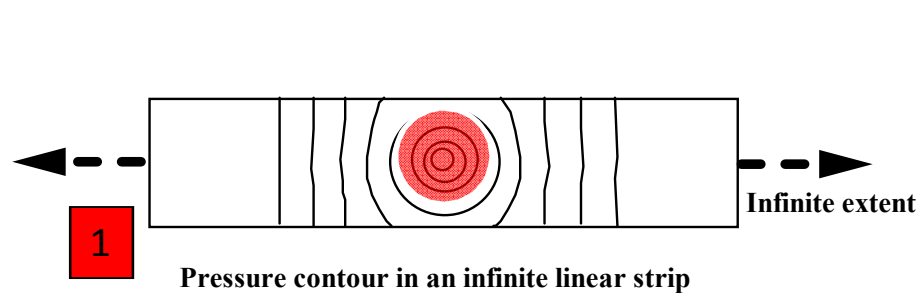
Flow regimes 1 >> 2 >> 3

(From Corbett, DISC, 2009, after Zheng)

Well Testing Derivative - Simplified

Early Time Region   Middle Time Region   Late Time Region

ETR   **MTR**   **LTR**

$\dfrac{DP}{DT}$

Lower Perm

Higher Perm

+ve Skin

-ve Skin

Lower Perm

Higher Perm

ETR - near well bore phenomena, skin

MTR - radial flow, kh

LTR - Boundaries, pressure support, contacts

Log(t)

The rate that the pressure change moves away from the well is a function of the diffusivity (k/$\mu\phi$c)
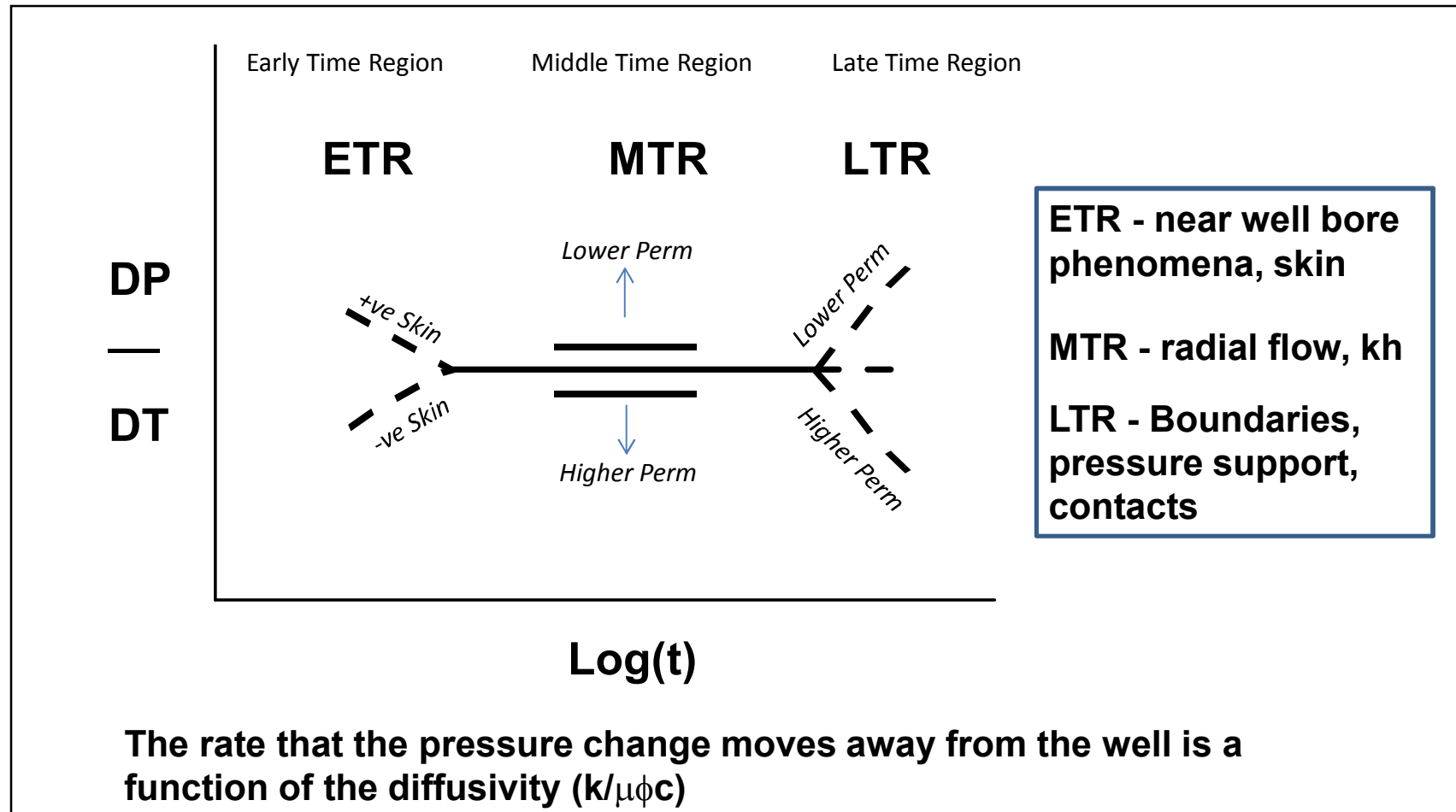
(From Corbett, DISC, 2009)

Finite Conductivity Fracture
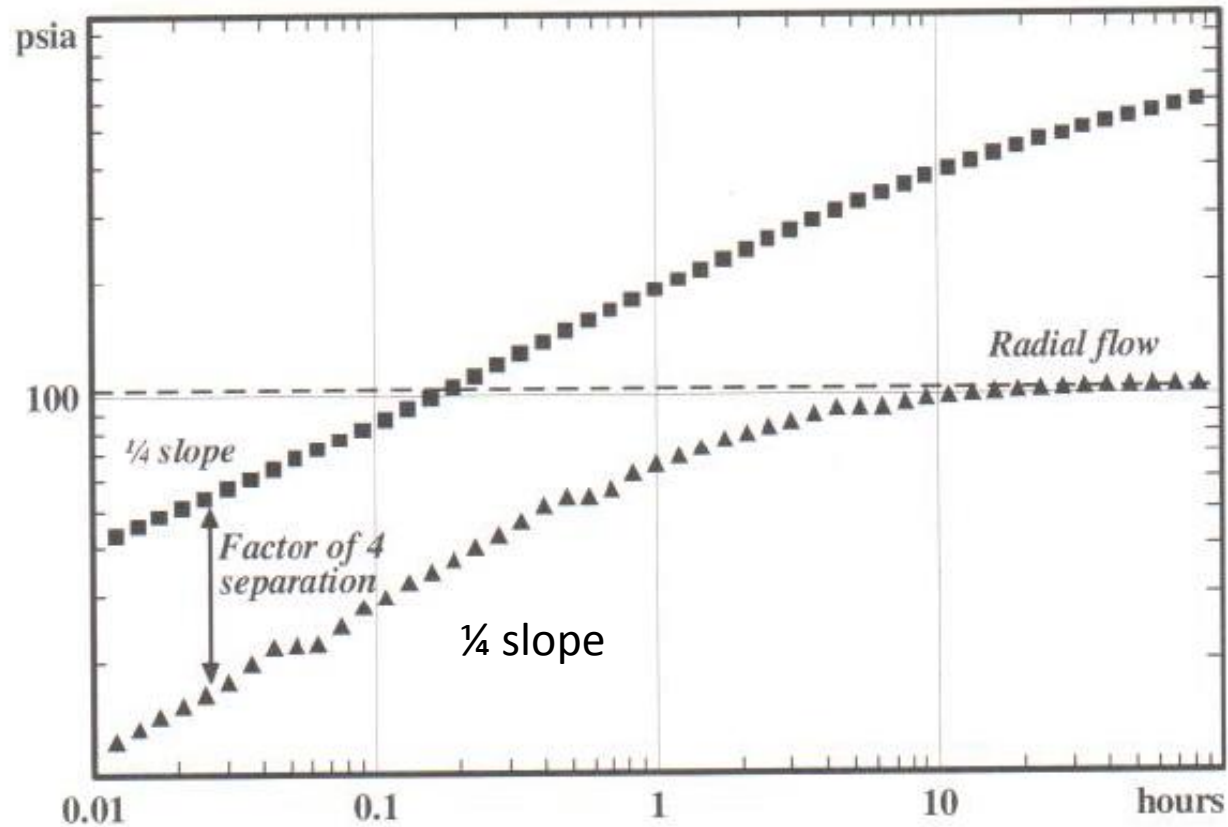
Infinite Acting Fracture ½ slope and separation of 2

From Horne, 1995

Numerical Well Test Workflow

Geological Model

Model 04c

Flow Simulation

Initial Pressure Condition

Final Pressure Condition

Pressure (PSIA)

2308   2347   2386   2425   2465
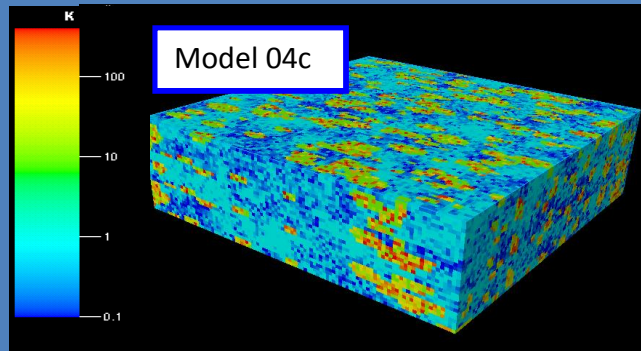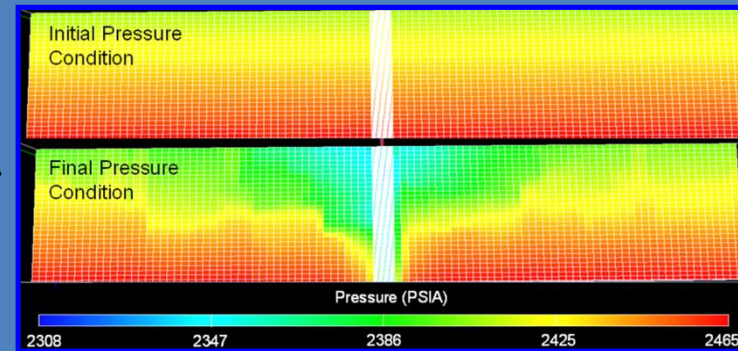
Forward problem where the model
is built and then the pressure
response is simulated and
analyzed

Model 04c

Pressure #2
Pressure #2 Derivative

Delta P (psi)

Drawdown Analysis

Elapsed Time (hours)

psia

Radial flow

¼ slope

Factor of 4
separation

Finite Conductive Fracture

0.01   0.1   1   10   hours
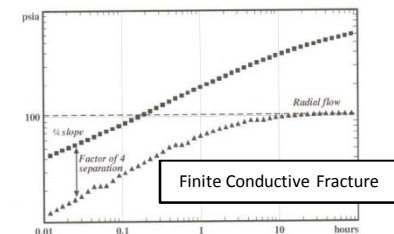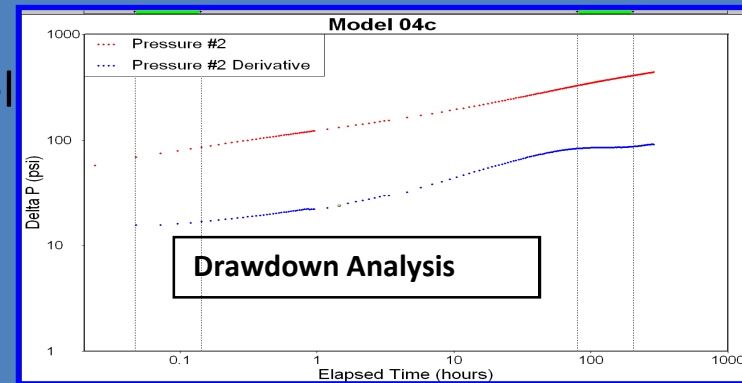
Geological Model

- Very low permeability rock type (microport) was distributed as background

- Good permeability rock type (macroport) was distributed as objects (ellipse and quart ellipse)
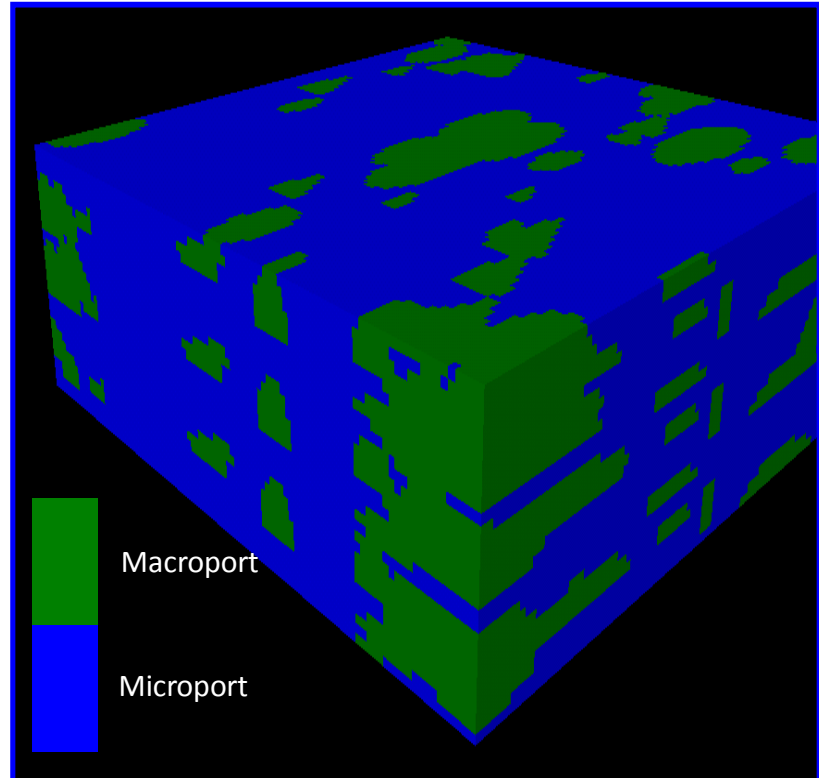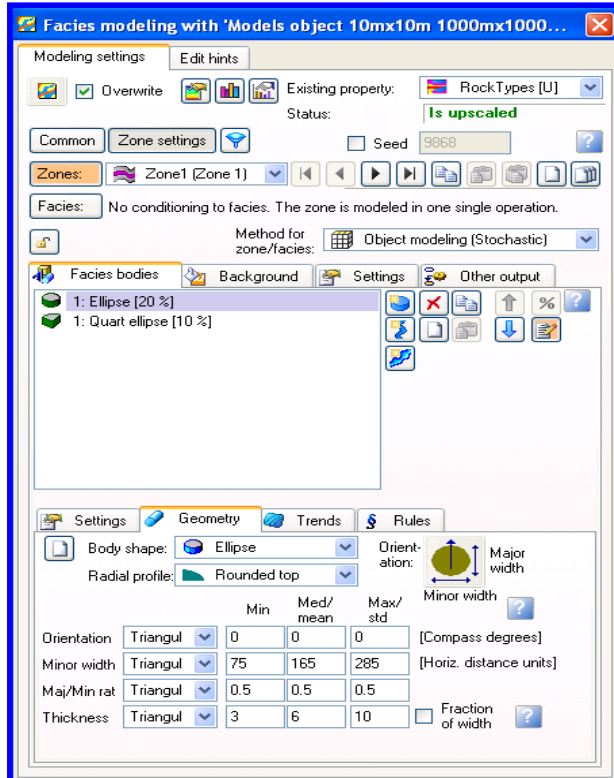
Geological Model

- Porosity was set constant value for the whole model

- Permeability was distributed using Sequential Gaussian Simulation (SGS) - variogram (spherical type)

- Very low permeability was distributed in the background rock type

- High permeability was distributed in the objects
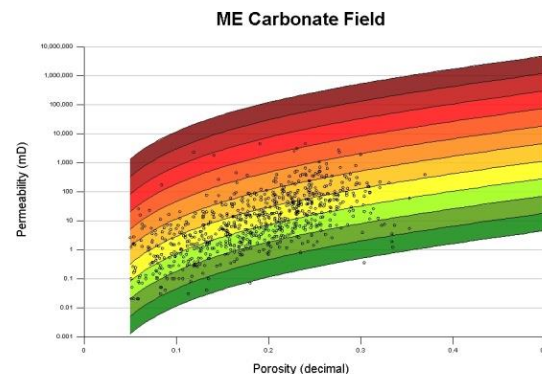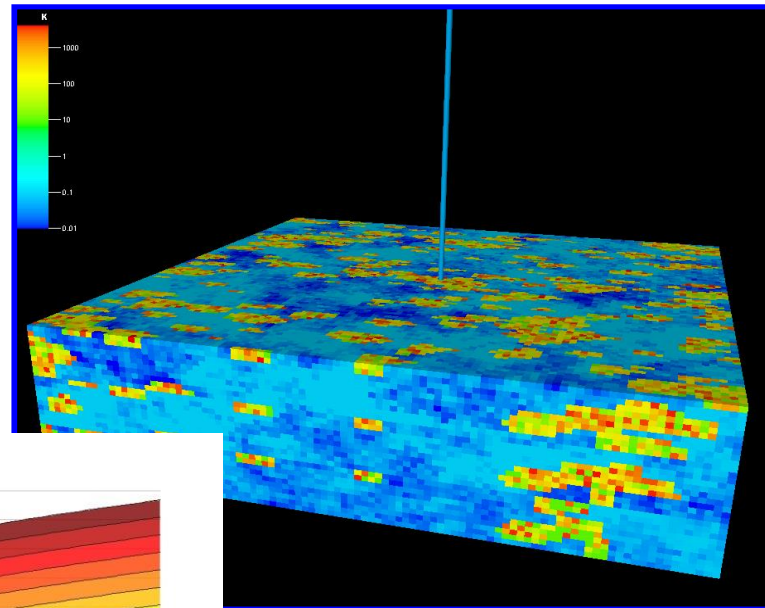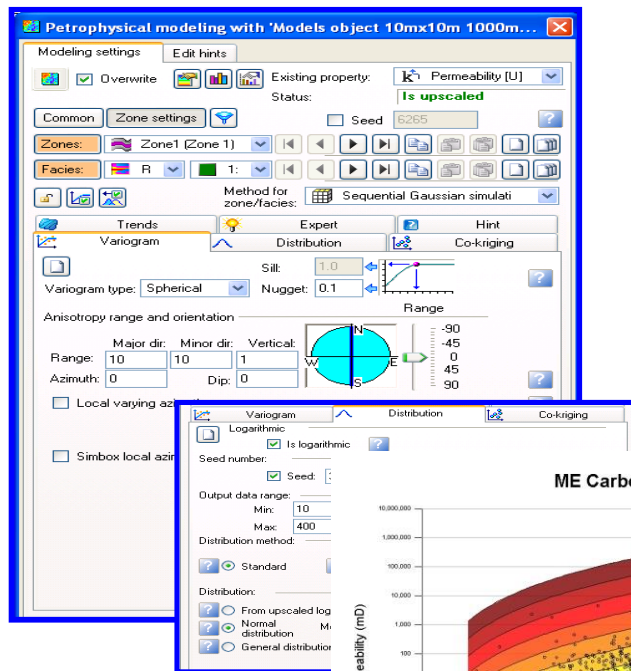
Flow Simulation (Eclipse Model)

- Model size 1000m x 1000m x 50m

- Grid size 10mx10mx1.67m ; Cells NX=100, NY=100, NZ=30 (300,000 cells)

- Refinement close to the well - cell of 1m x 1m x 1.67m
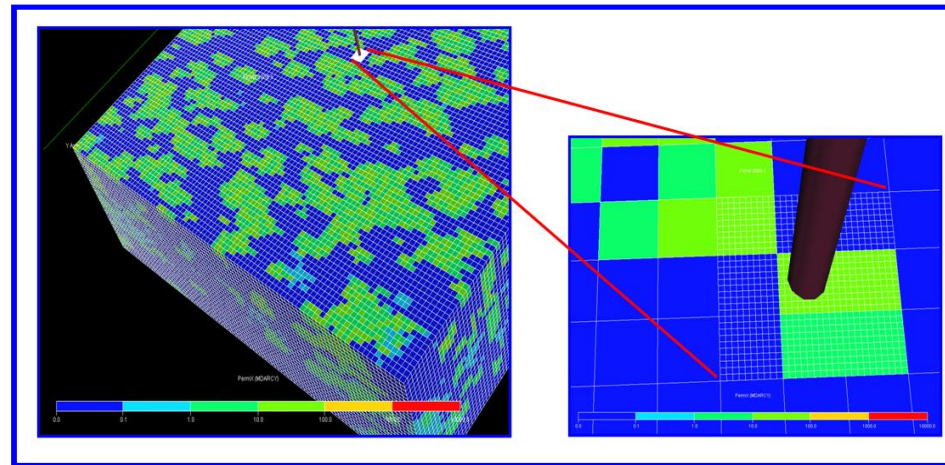
- Oil properties from North Sea Field

- Oil rate constant 500 stb/day ; BHP limit of 1000 psia (single phase flow)

- Oil density of 42 API (50.9 lb/ft3 or 0.815 g/cc) ; μ = 0.82 cP, Bo = 1.21 rb/stb, Pb = 980 psia, Pi = 2436 psia @ 1585m (5200 ft)

Flow Simulation Generates Derivative
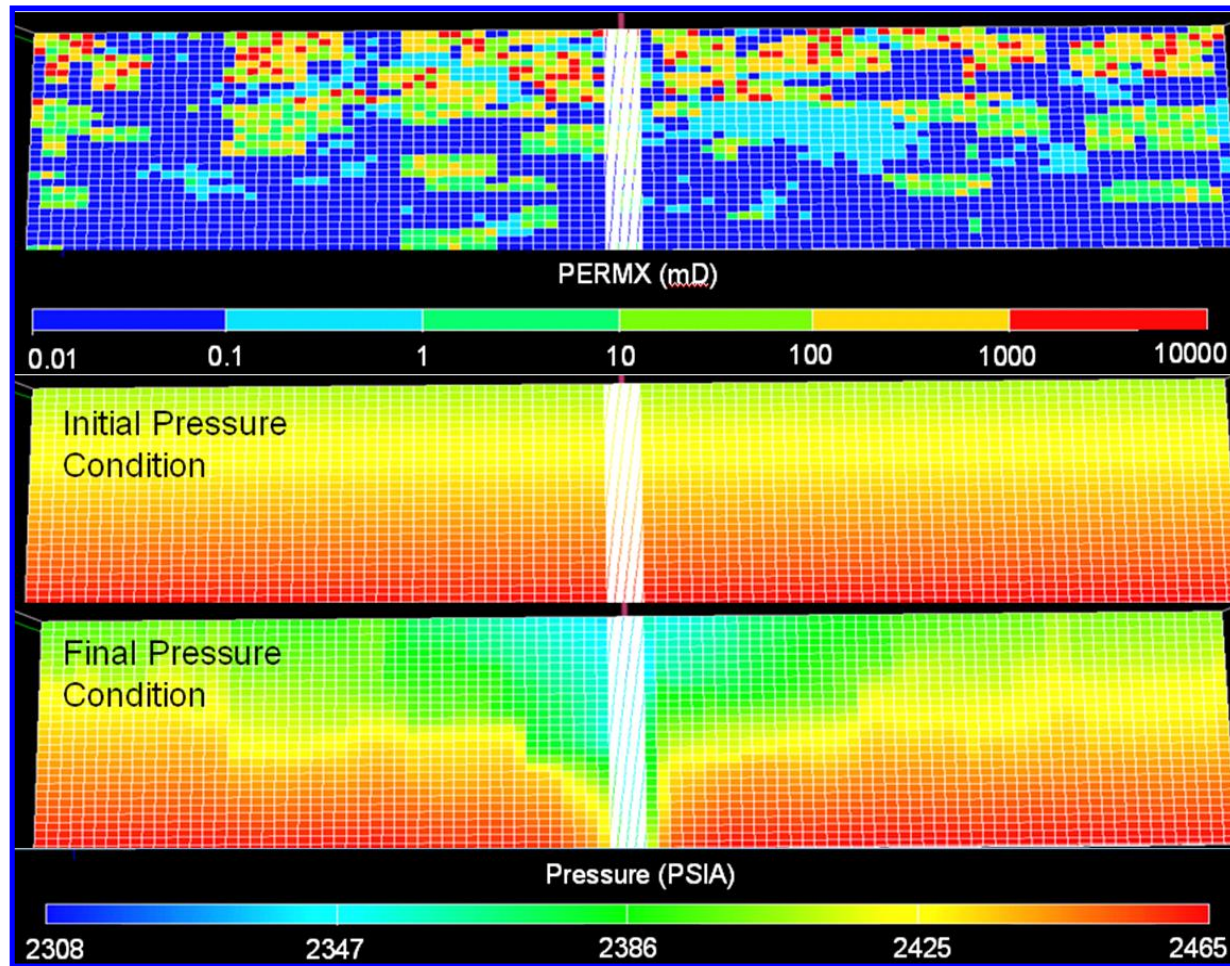
Cross section showing k distribution (Model 04c5)
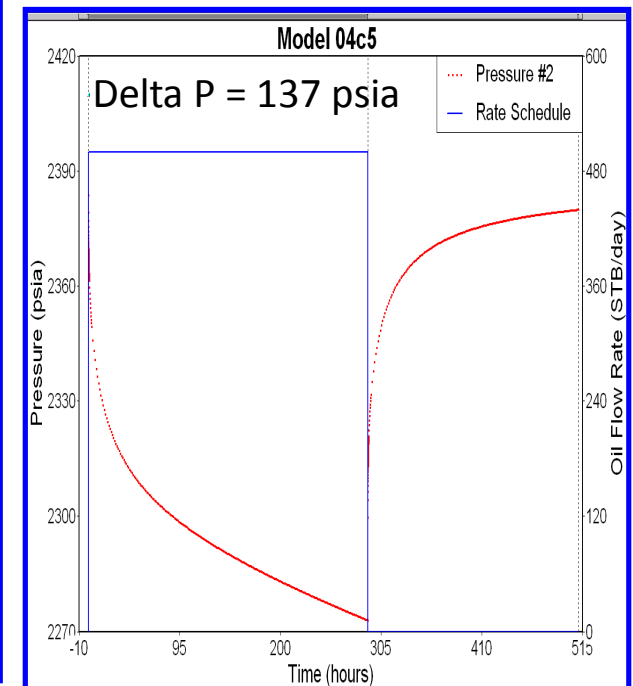
Cross section showing the pressure behaviour during the drawdown

Well Testing Analysis
of generated derivatives

- Transient pressure analysis performed in the drawdown test period
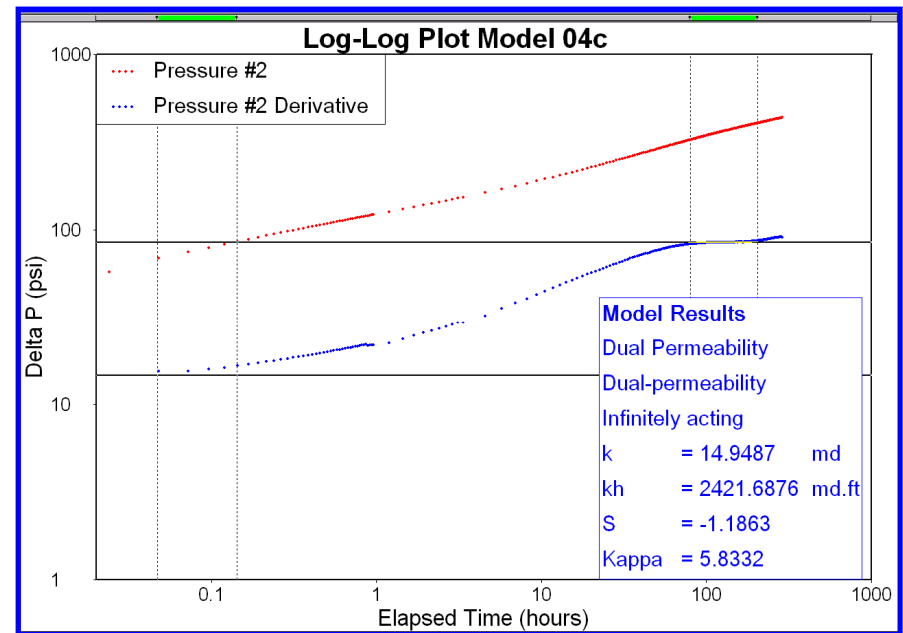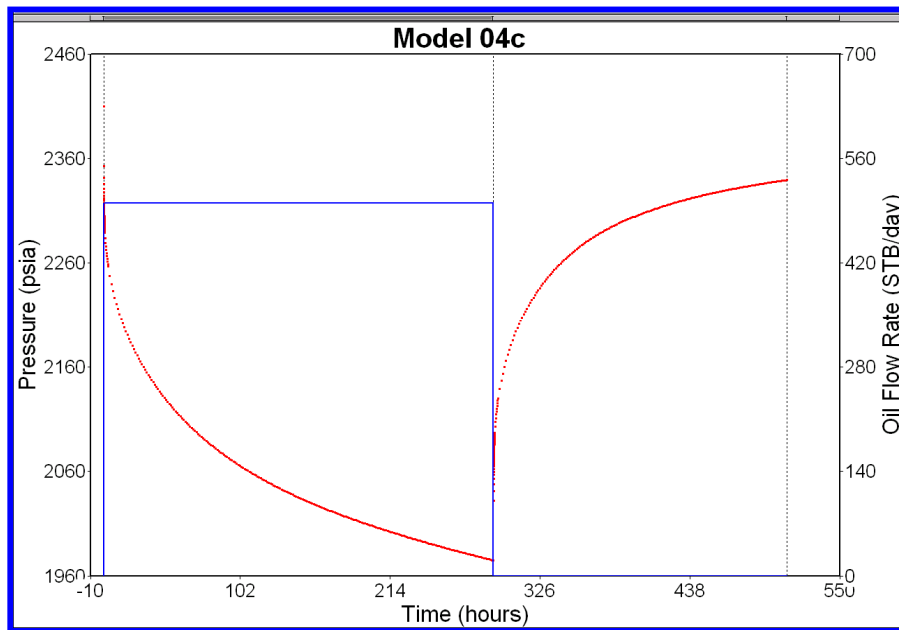
Validation

- Validation of the workflow: transient pressure response is consistent with the geometric average in the case of model 04c and arithmetic average for model 05c
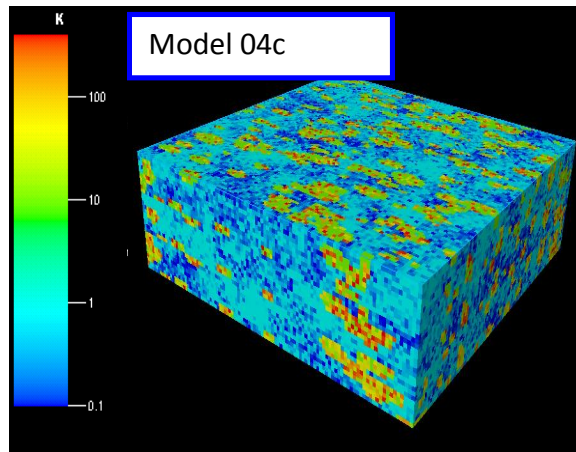
Whole model 04c	
Kar (mD)	31
Kgeo (mD)	**3**

Well location	
Kar (mD)	28
Kgeo (mD)	8
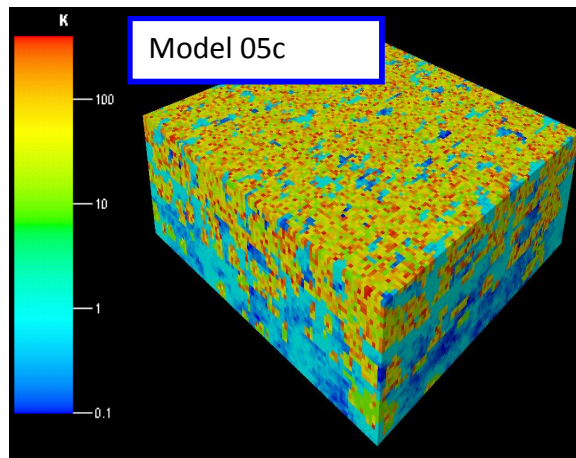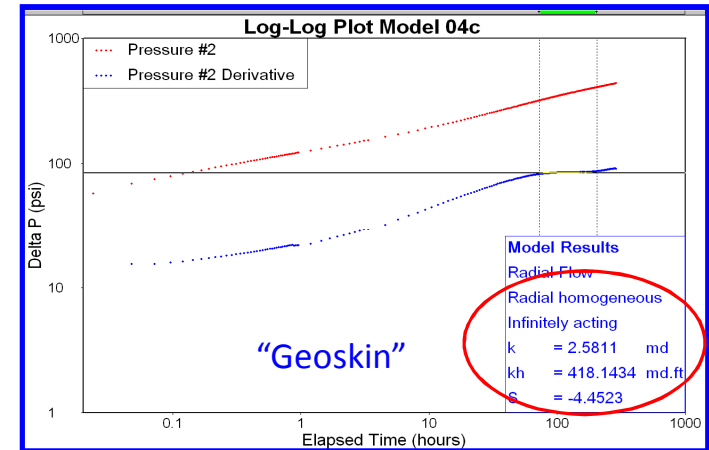
Whole model 05c	
Kar (mD)	**59**
Kgeo (mD)	5.6

Well location	
Kar (mD)	76
Kgeo (mD)	10
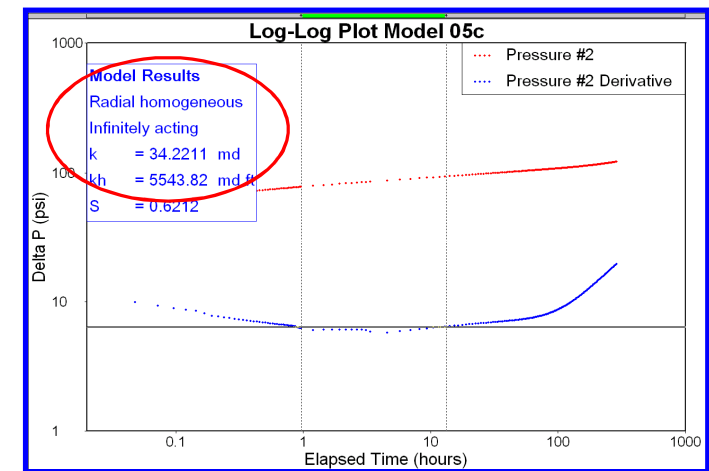
Variability analysis

- Different permeability ranges distributed in models with the same macroport patch arrangement (POD)present similar pressure response.
- Same distribution of in all 3 layers.
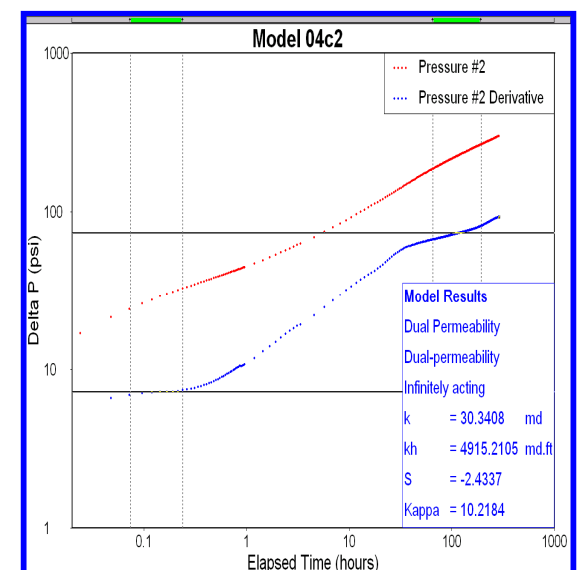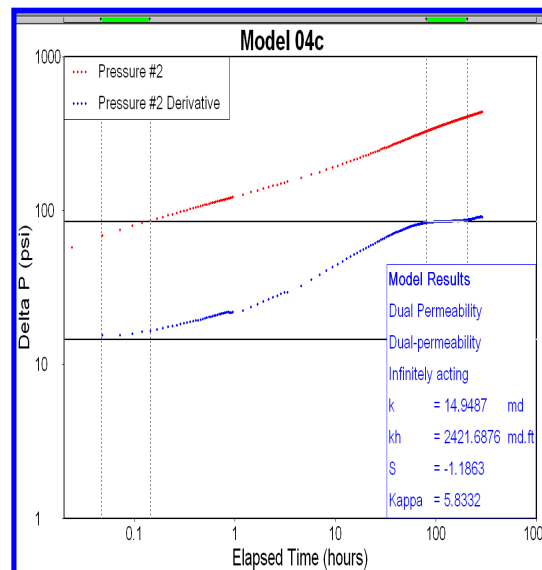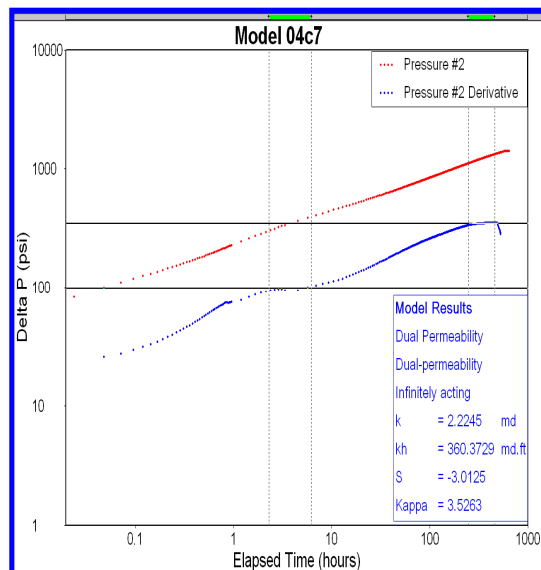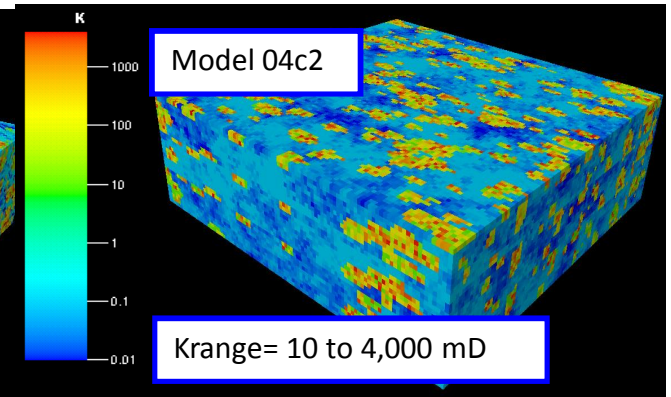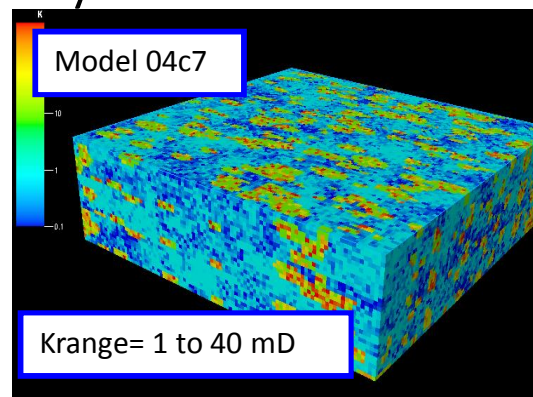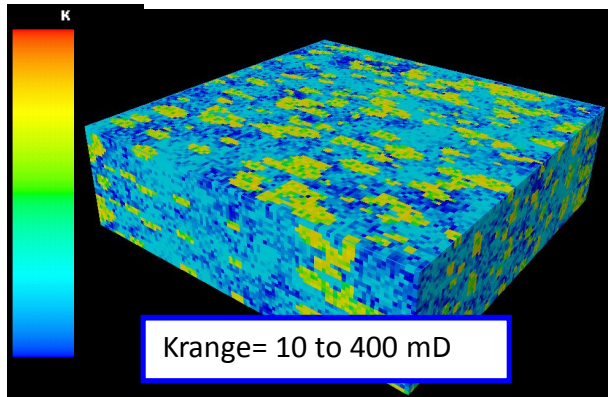
Systematic double porosity, micro-macroporous carbonate geotype curves

Double Matrix Carbonate Conclusions

➢ The obtained results validate the numerical well test workflow applied in this study.

➢ The model dimensions and grid size used in this study were suitable to generate simulated pressure data to be analyzed.

➢ Visualise tortuous flow path to the well

➢ Dual permeability (Dual porosity) flow model was interpreted for all models.

➢ No Fractures in the model but we get a faulted/fracced response

➢ Object modeling good representation of a vuggy carbonate

➢ Methodology to generate Carbonate Geotype curves

Corbett et al., 2010, Petroleum Geoscience

Double Porosity Fractured Reservoirs

Storativity Ratio (ω) and Interporosity flow coefficient (λ)
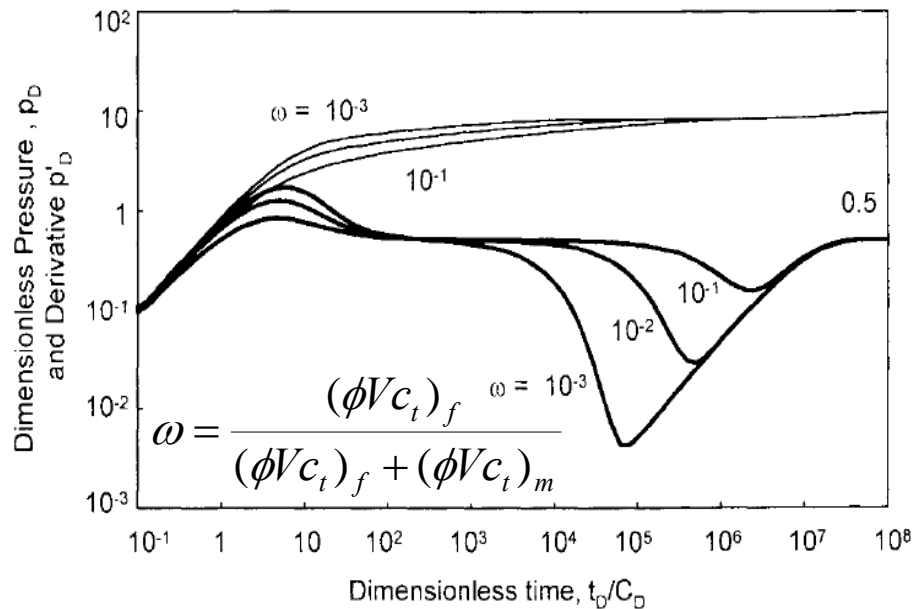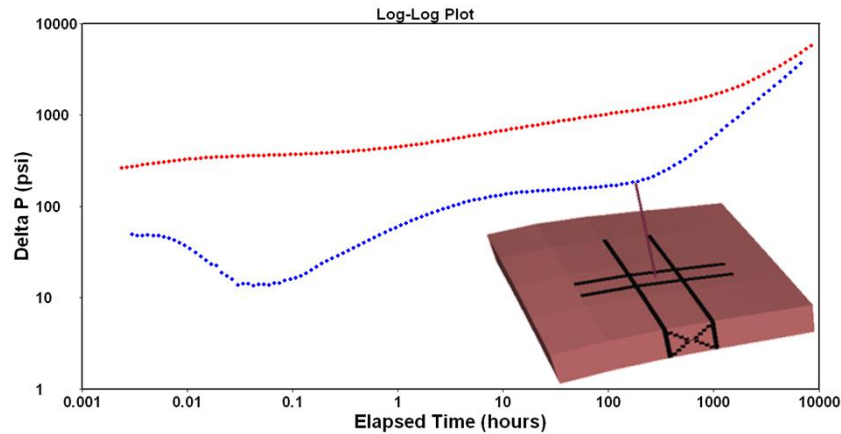

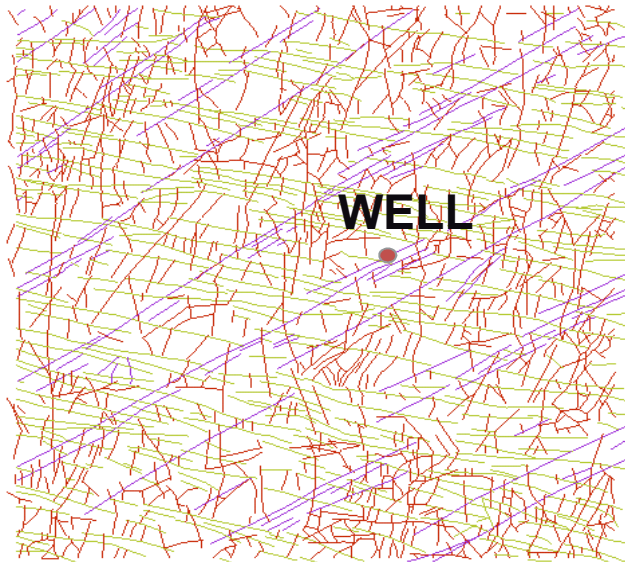"ω defines the contribution of the fissure system to the total storativity"
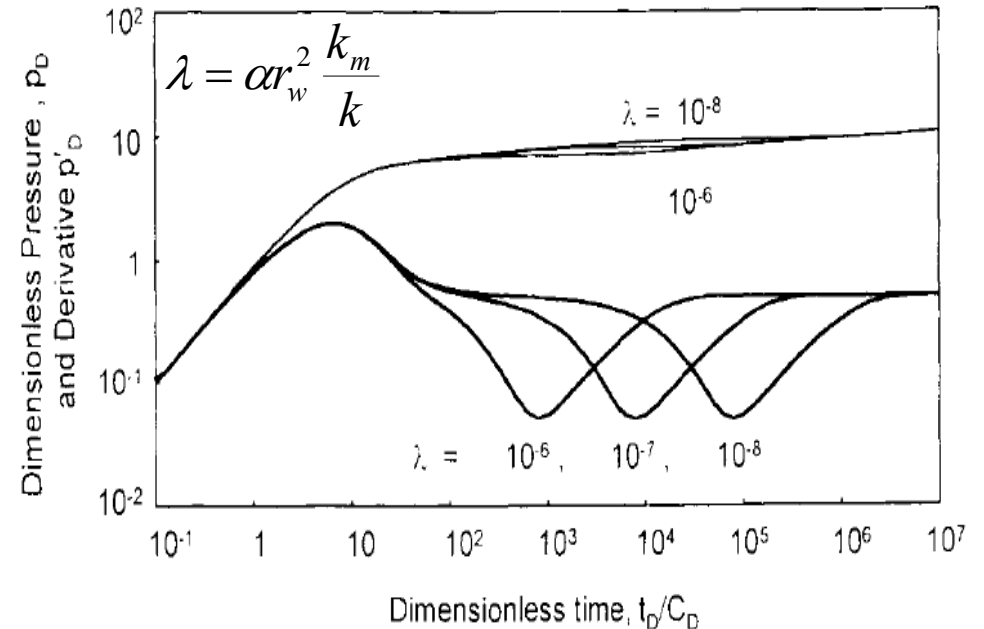
"λ defines the ability of the matrix blocks to produce into the fissure system"

Bourdet, D. (2002). Well Test Analysis: The Use of Advanced Interpretation Models

Analysis of the Fracture Pressure Response

Top left: Log-Log Plot, Delta P (psi) vs Elapsed Time (hours)

Top right: Log-Log Plot, Delta P (psi) vs Elapsed Time (hours)

Bottom left: Log-Log Plot with legend:
- Open all (red)
- Open fractures (blue)

Bottom right: Log-Log Plot, Delta P (psi) vs Elapsed Time (hours)
- $\phi_f=1\%$, $\omega=1.6e\text{-}3$
- $\phi_f=10\%$, $\omega=1.6e\text{-}2$
- $\phi_f=100\%$, $\omega=1.4e\text{-}1$
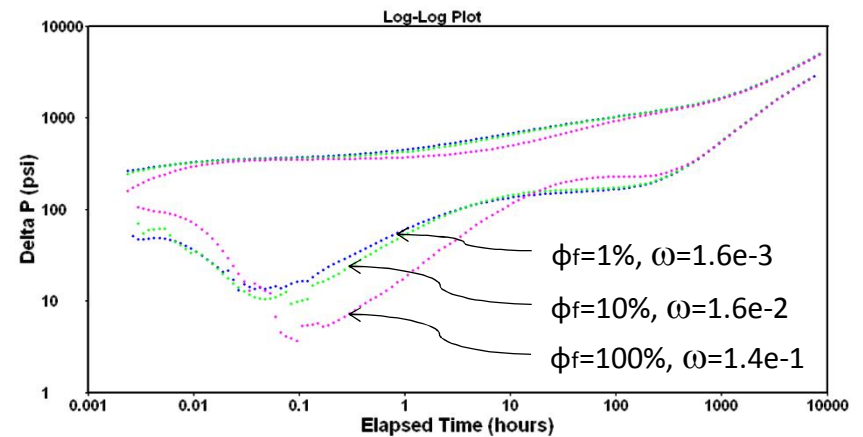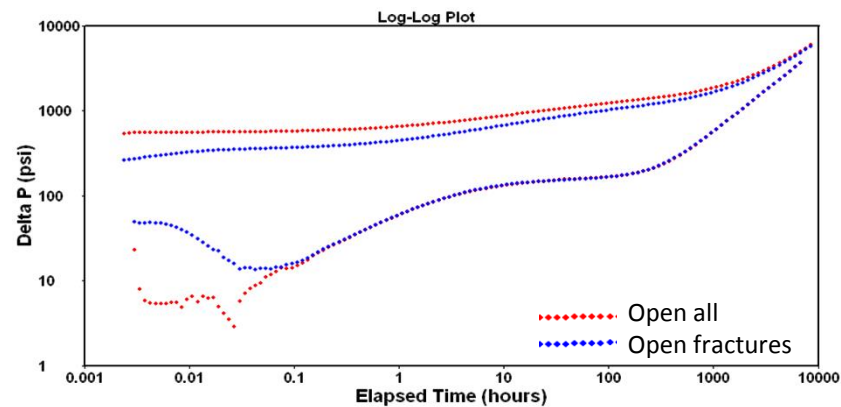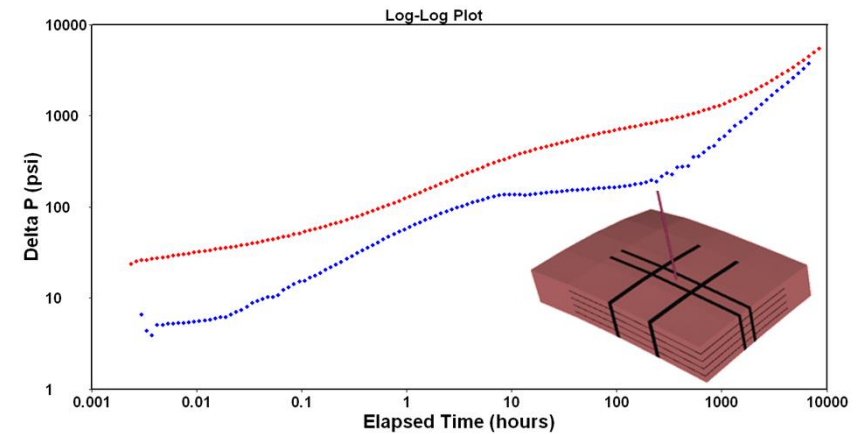
Fractured Reservoirs

WELL

Outcrop-derived Fracture Model

	K (md)	ω	S	Lambda
E-Frac Set	186	0.51	-4.5	1.1e-06
NE- Frac Set	143	0.50	-5	6.72e-07
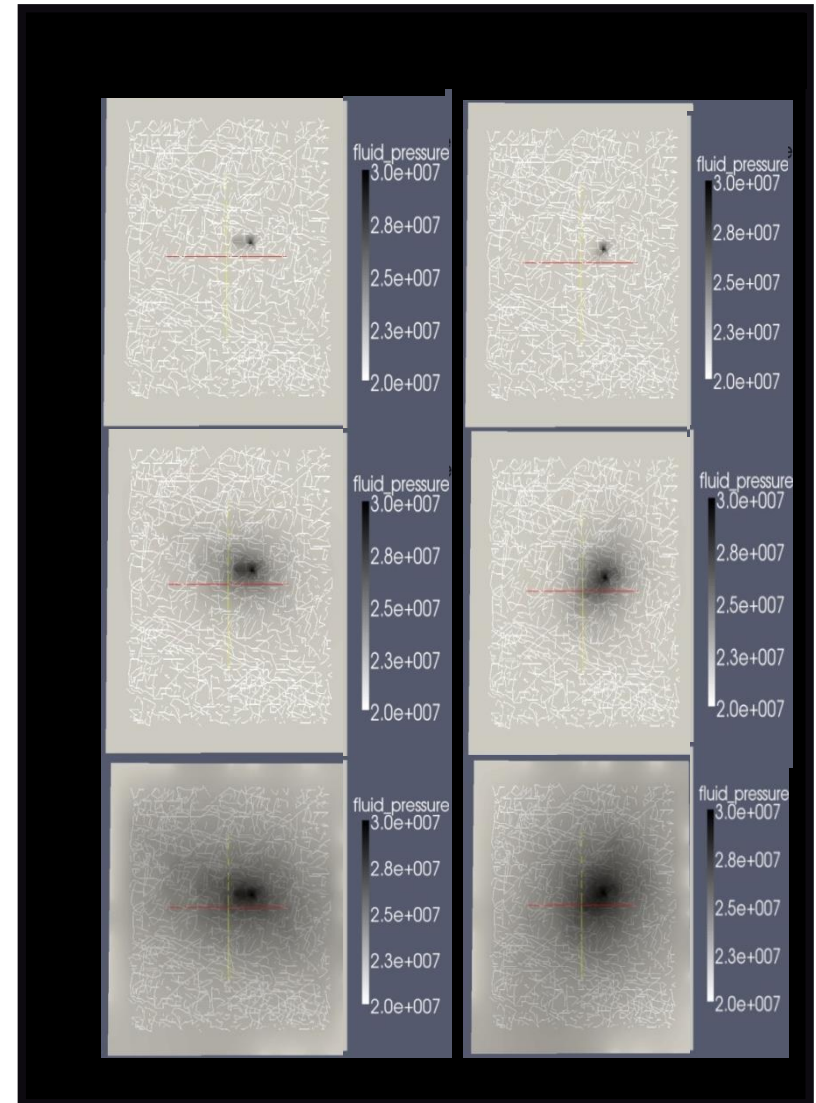
Matrix Permeability – Vuggy zones

Low Permeable Matrix

High Permeable Matrix

	K (md)	ω	S	Lambda
E-Frac Set	210	0.33	-4.6	1e-06
NE- Frac Set	183	0.42	-4.9	3.96e-07
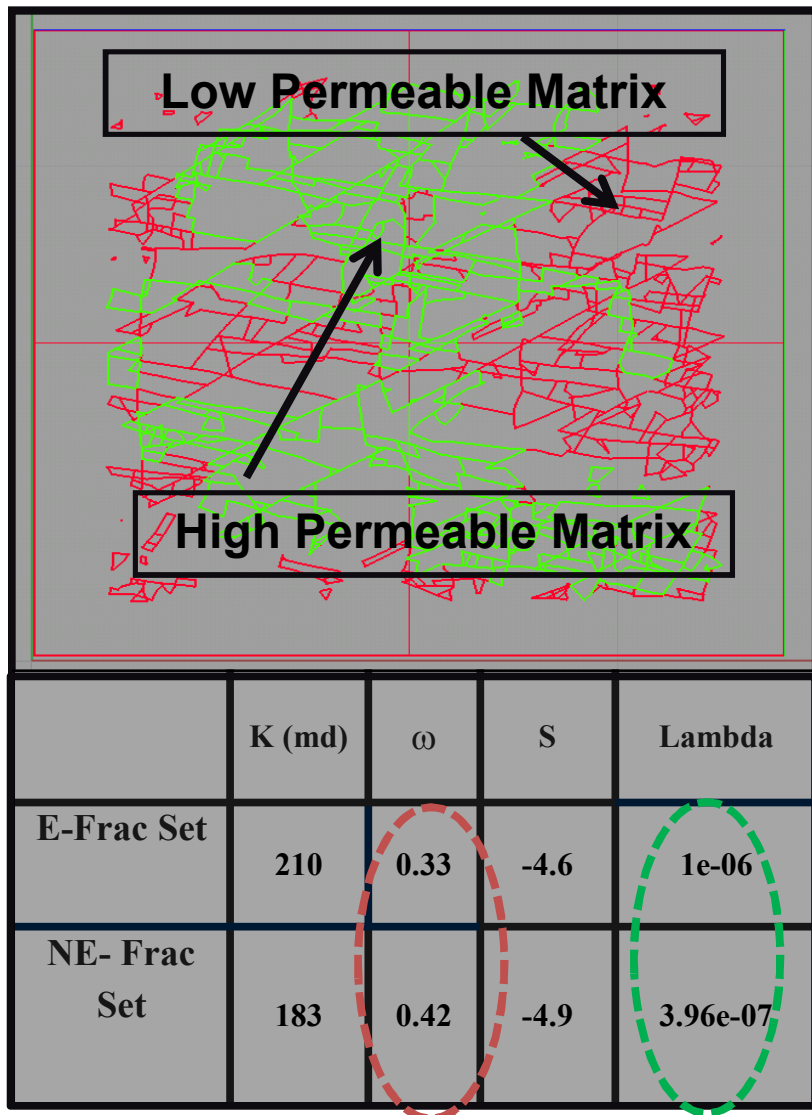
NE set greater storativity

E set has greater matrix productivity
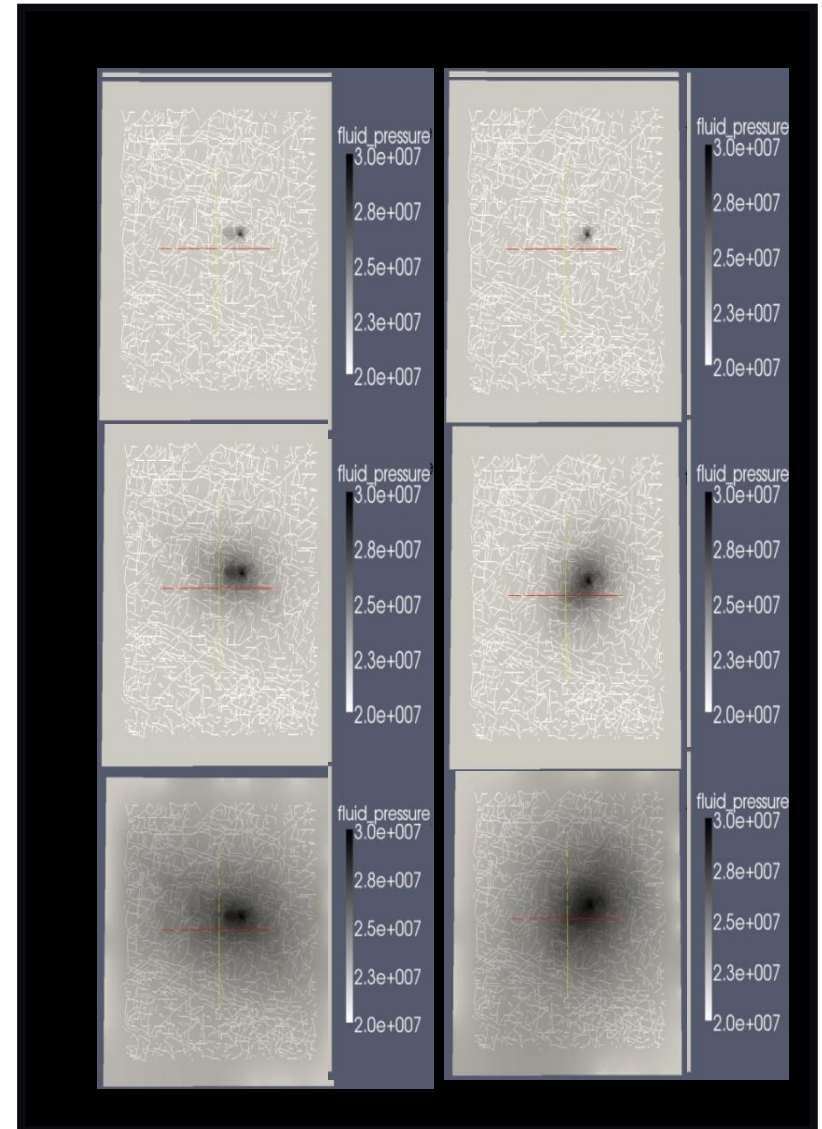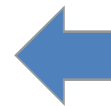
Numerical Well Test Modelling

➤ Numerical solution provides ability to model fractures and matrix

  ➤ Analyse tortuous flow along different fracture sets

  ➤ Investigate effects of different oil viscosities

➤ See typical fracture double porosity response – but not triple porosity response

➤ Difficult to relate WT parameters back to the model and the reservoir description

Fractured Reservoir Well Testing
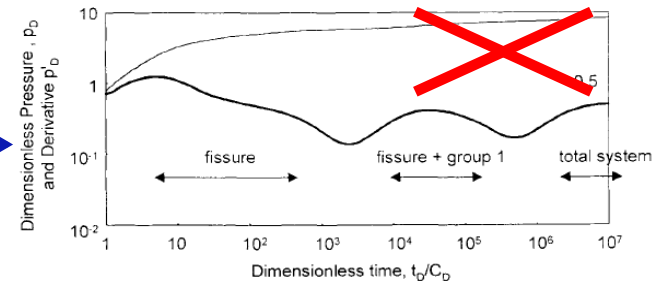
>>>>>>> How do we recover separate matrix and fracture descriptions?

Fracture Well Test Analysis
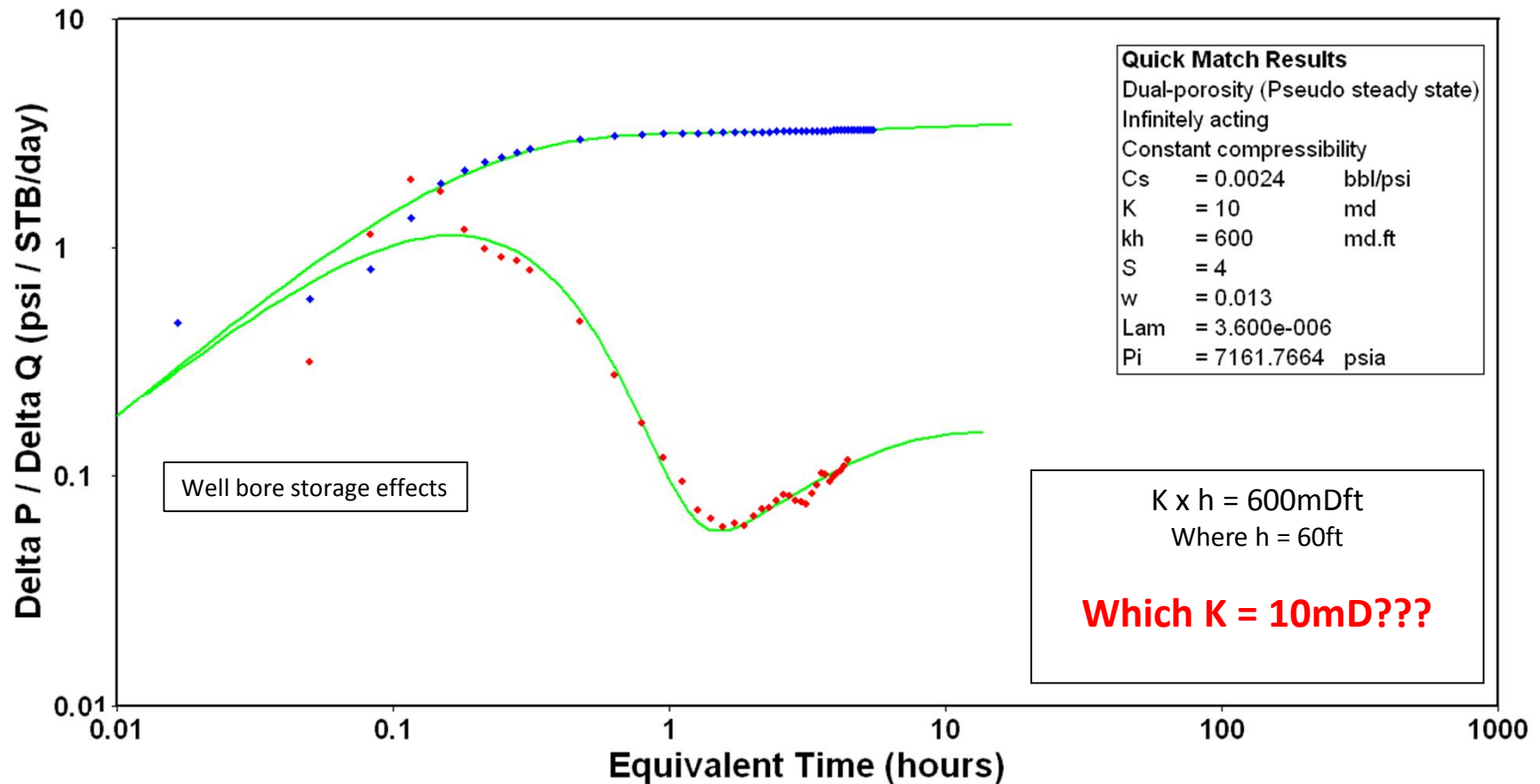
Conclusion

➤ Reservoir Matrix in Carbonate Reservoirs prone to double matrix porosity (WT) behaviour

➤ Add fractures and carbonate reservoirs tend to triple-porosity system: matrix (micro), vuggy (macro) and fractures with high tortuosity

➤ Well testing response doesn't show triple porosity

➤ Well Testing response is "effective" double porosity

➤ How do we extract the double matrix and fracture characteristic parameters?

➤ Role of numerical well test modelling in carbonates crucial to well test interpretation and reservoir characterisation.

➤ Limitations in the models and/or in the responses?

Corbett et al., 2010, Petroleum Geoscience

Outcrops and Well Testing 1

″ San Andres Example

″ Permeability characterisation

″ Numerical Well test modelling
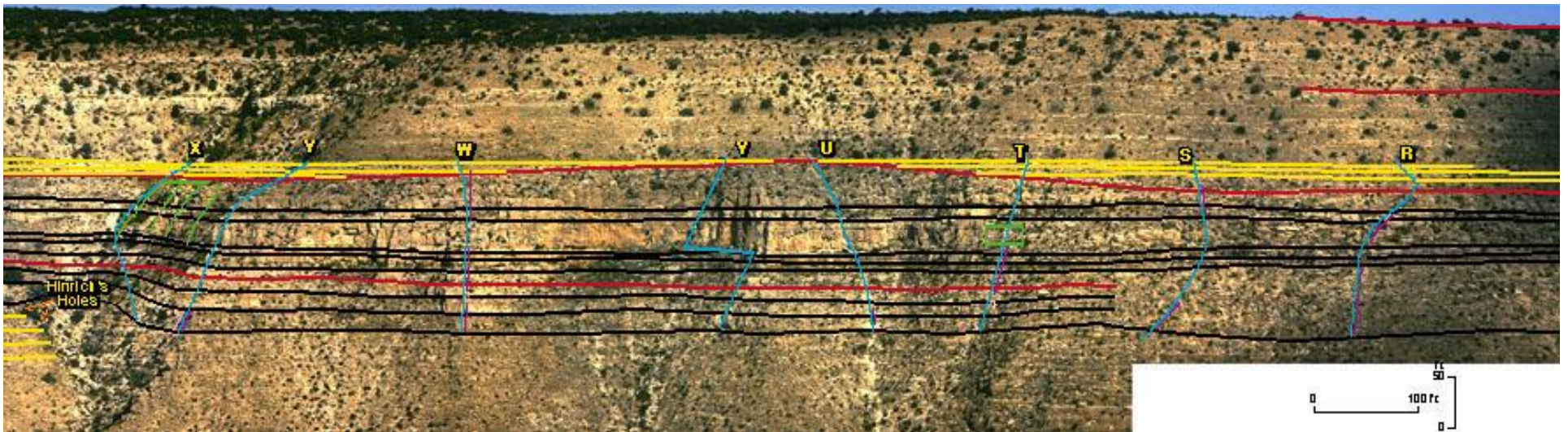
Image from Charlie Kerans (BEG)
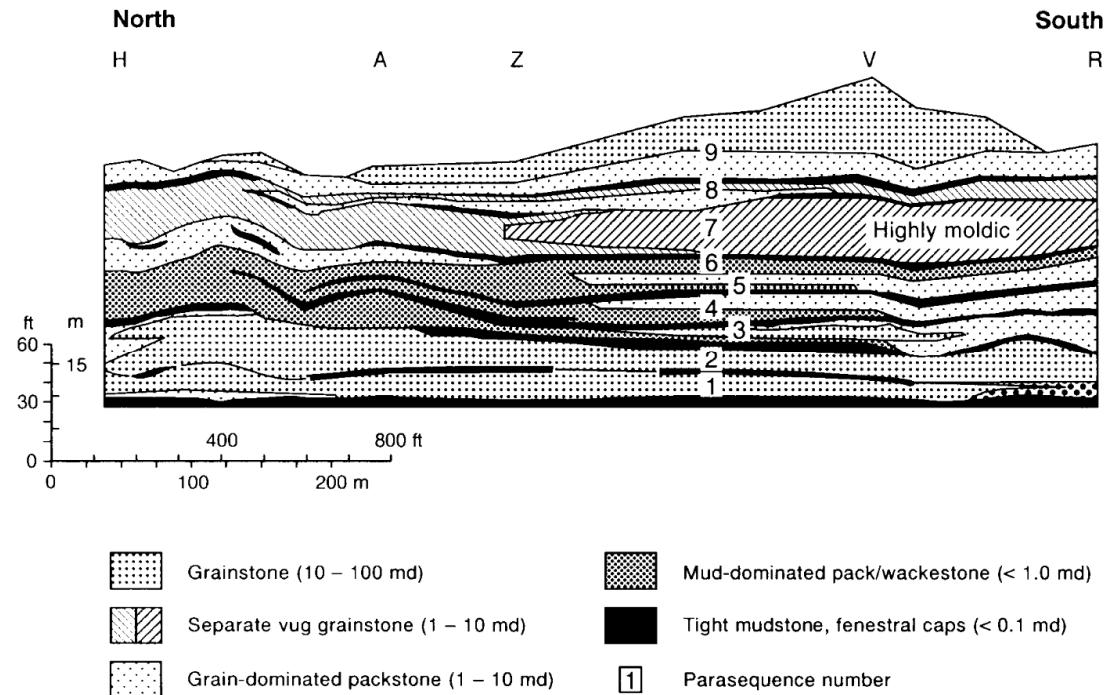
General San Andres information

San Andres Formation
30% oil recovery
Shallow water
OPT=9 billion bbl

Sequence stratigraphy:
1. Depositional sequence
2. High-frequency sequences
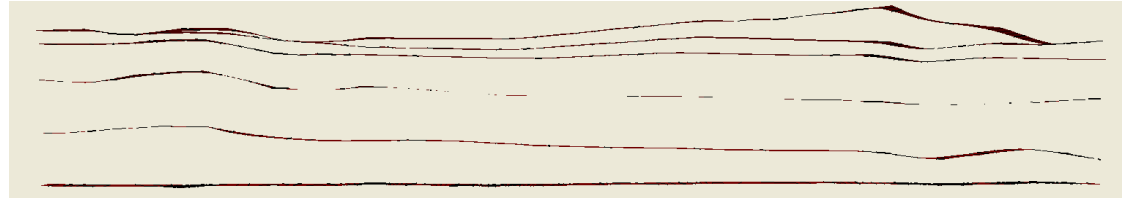3. Cycles

Six rock fabrics dominated by:
1. Intergranular
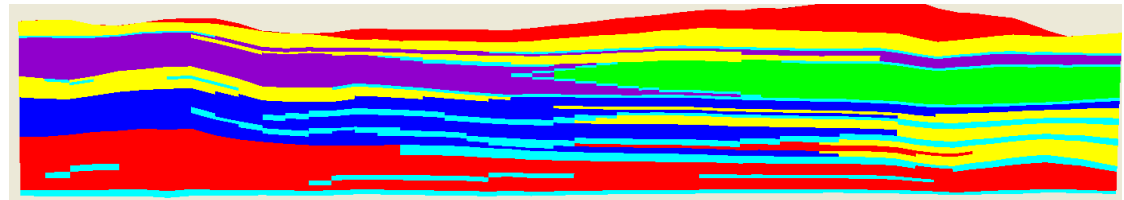2. Separate vug
3. Dense intercrystalline pore types

North   South
H   A   Z   V   R

9
8
7   Highly moldic
6
5
4
3
2
1

ft   m
60   15
30
0
0   100   200 m
400   800 ft

Grainstone (10 – 100 md)   Mud-dominated pack/wackestone (< 1.0 md)

Separate vug grainstone (1 – 10 md)   Tight mudstone, fenestral caps (< 0.1 md)

Grain-dominated packstone (1 – 10 md)   1 Parasequence number

Kerans et al 1994

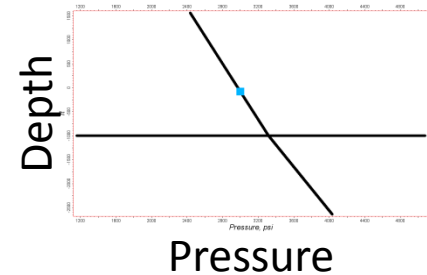# Simulation workflow

HFS Framework modelling

Property modelling

Facies

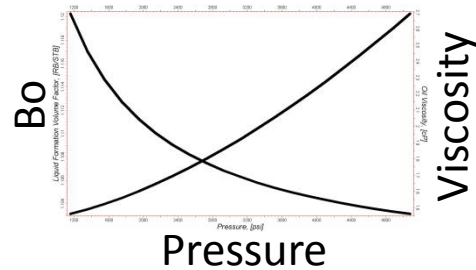Porosity and permeability

Development strategy

Bo

Viscosity

Pressure

Depth

Pressure

Kro

Krw

Sw

Kazemi et al 2011
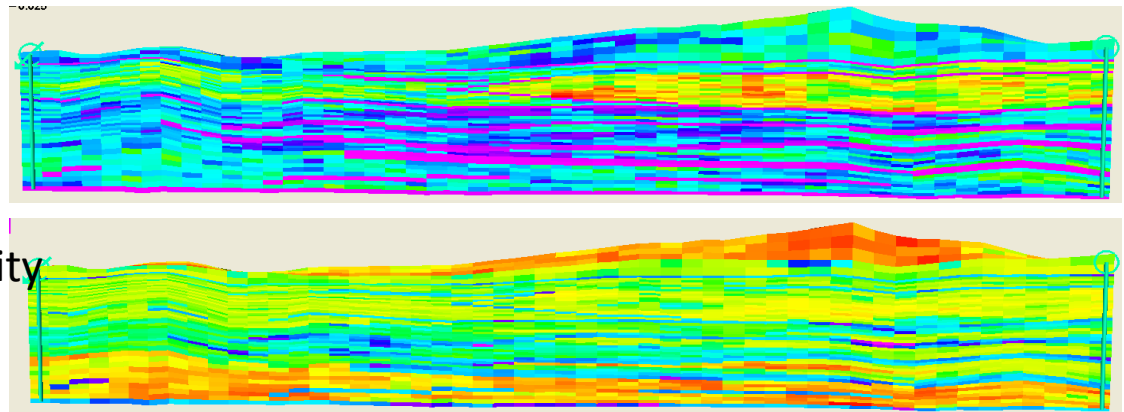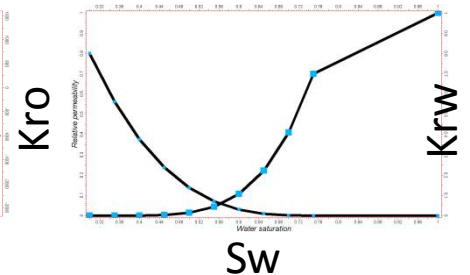
Some simulation results

Porosity

SGS
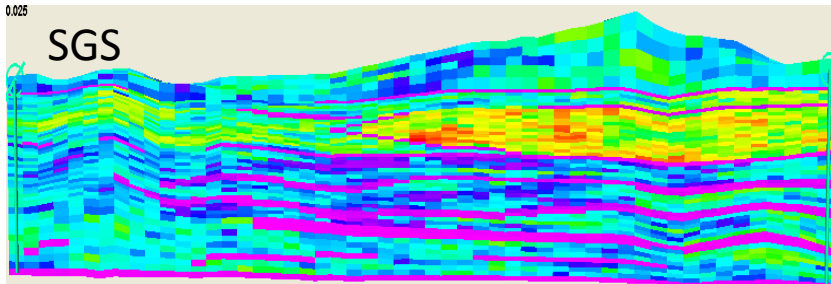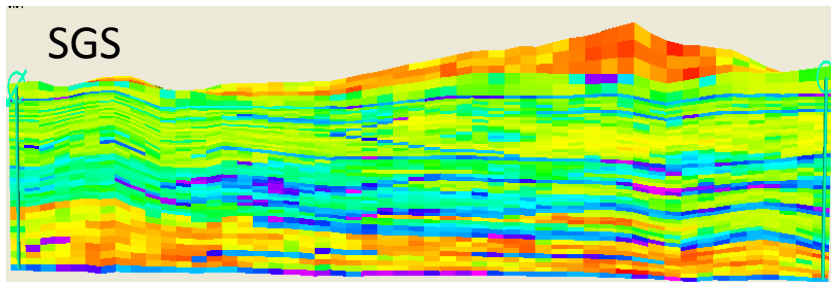
Rock types (Por) Cv = 0.5	min	max	mean	SD
Grainstone	0.06	0.2	0.12	0.06
Grain dominated packstone	0.06	0.2	0.14	0.07
Mud dominated packstone	0.04	0.16	0.105	0.05
Highly moldic grainstone	0.17	0.3	0.23	0.12
Moldic grainstone	0.07	0.23	0.16	0.08
Tight mudstone	0.01	0.05	0.02	0.01

Permeability

SGS

Rock types (Perm) Cv = 2.0	min (mD)	max (mD)	Geomean	SD
Grainstone	0.5	700	17	34
Grain dominated packstone	0.01	8	2.5	5
Mud dominated packstone	0.01	2	0.4	0.8
Highly moldic grainstone	0.06	30	2.5	5
Moldic grainstone	0.01	100	2.2	4.4
Tight mudstone	0.001	0.1	0.05	0.1

Variogram range 400 ft
Kz=0.1*Kh
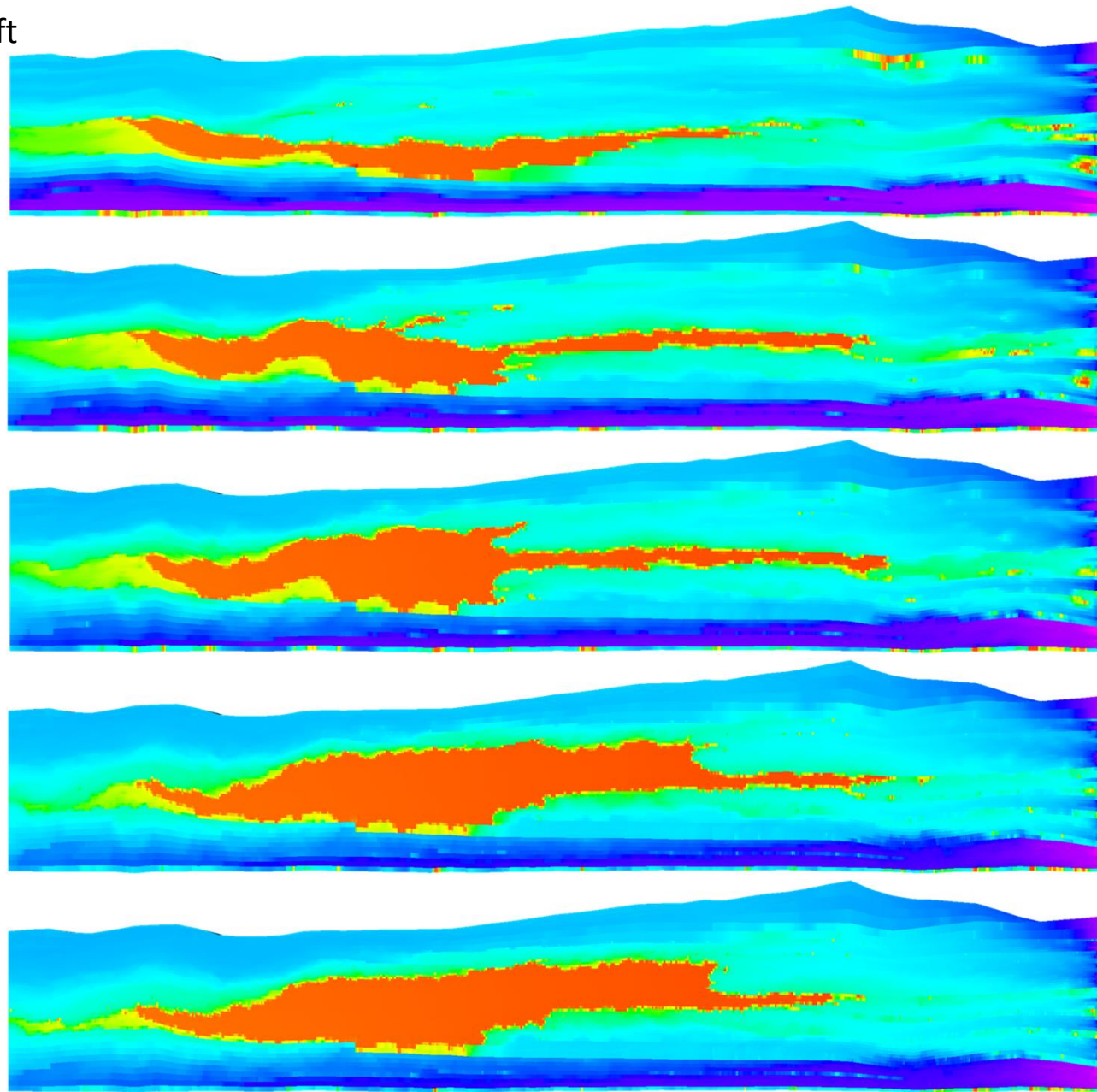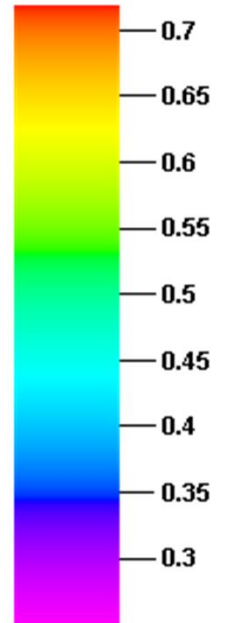

Kerans et al 1994

Variogram range, ft

400

100

50

10

4

Porosity

— 0.3
— 0.25
— 0.2
— 0.15
— 0.1
— 0.05
— 0
— -0.05
— -0.1

Kerans et al 1994

Variogram range, ft
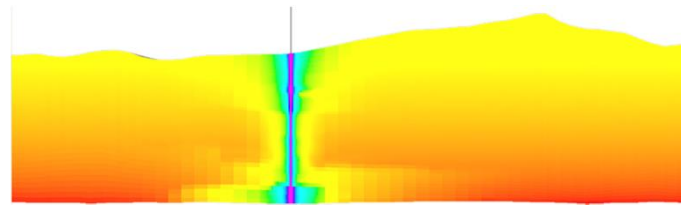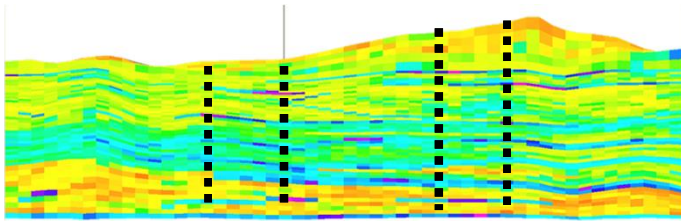
400
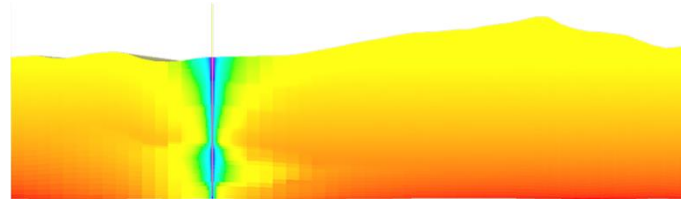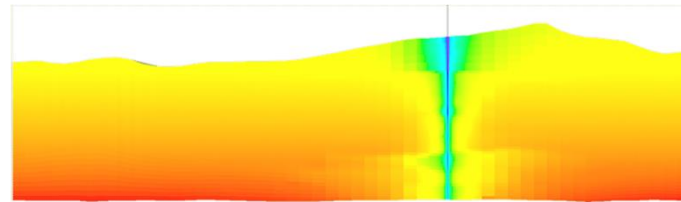
100

50

10

4

So

— 0.7
— 0.65
— 0.6
— 0.55
— 0.5
— 0.45
— 0.4
— 0.35
— 0.3
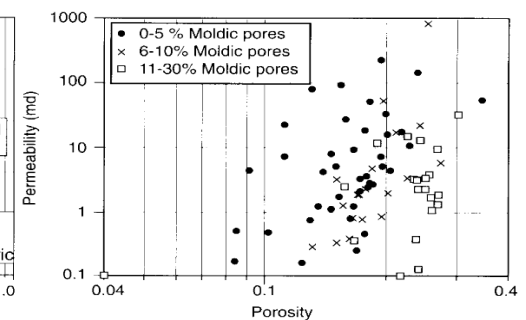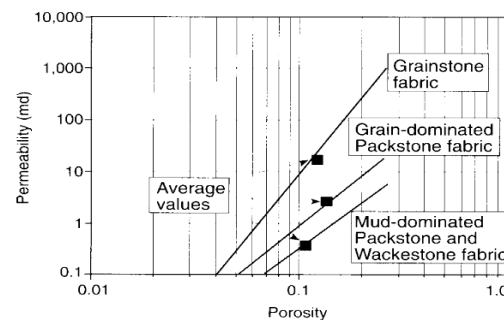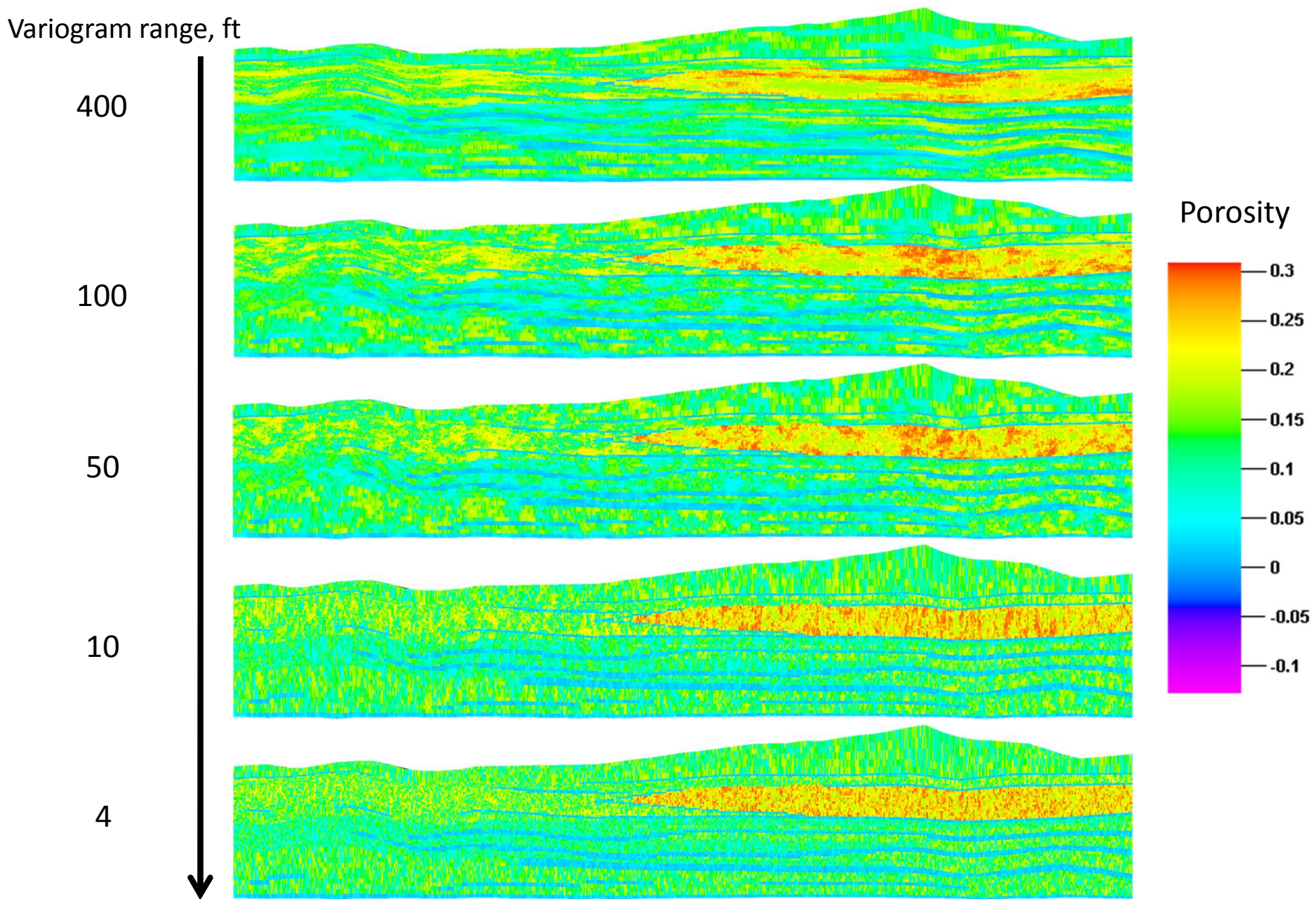
Kerans et al 1994

Well location effect

A1

A2

A3
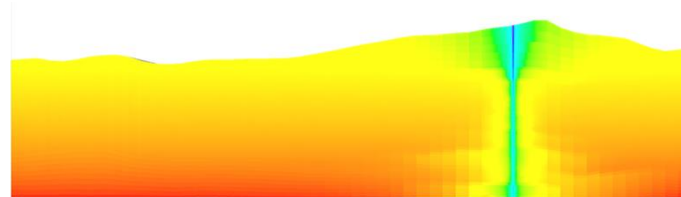
A4

Kerans et al 1994
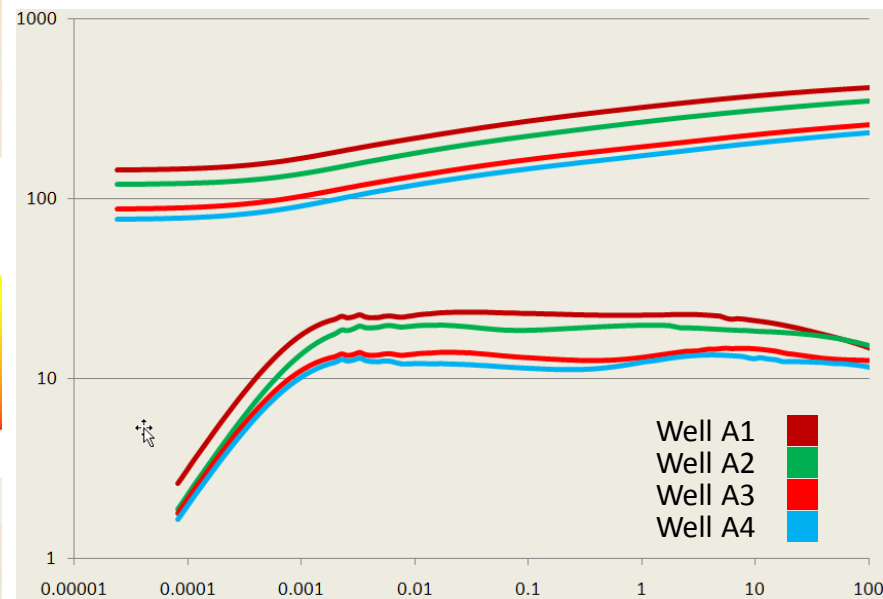
Interpretation

Well A1	Constant average kh
Well A3	Mobility reduction (kh/mo)

Legend:
- Well A1
- Well A2
- Well A3
- Well A4

Low perm HFS effect

A1   A4
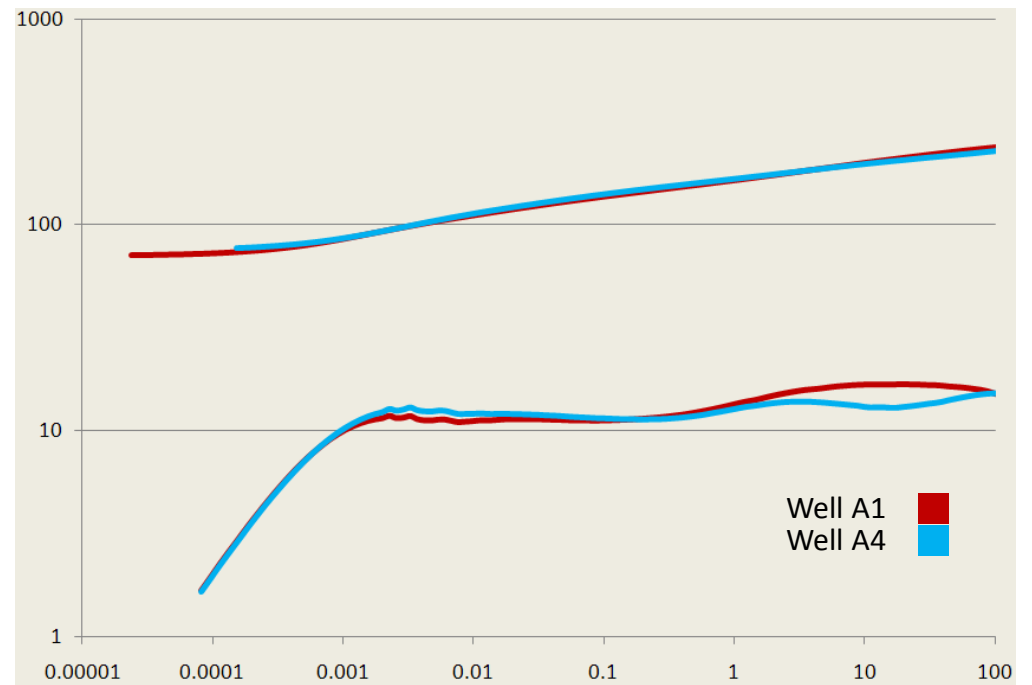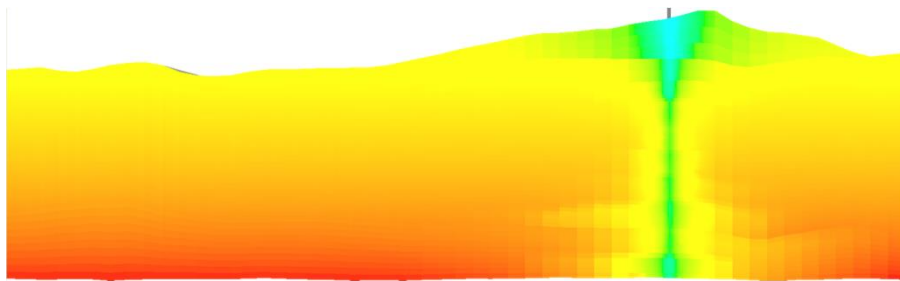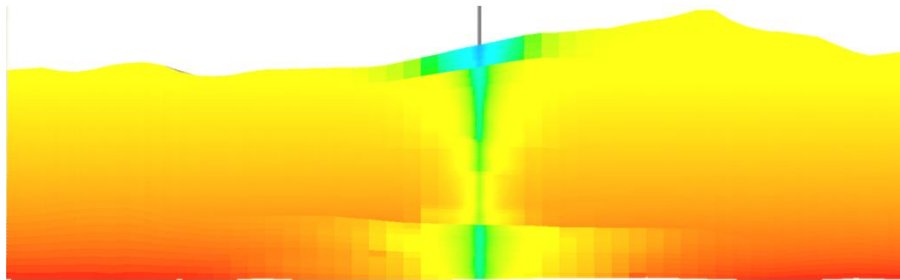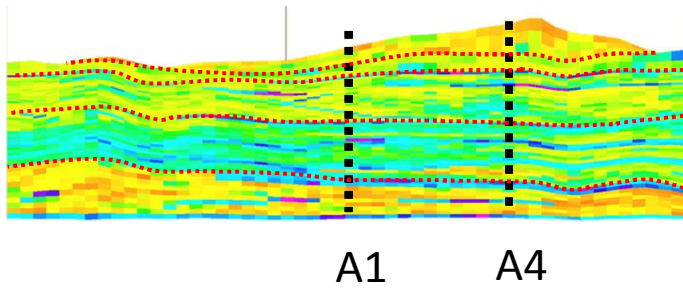
Well A1   RAMP effect (pressure encapsulation within each layer)

Kerans et al 1994

Variations with intra-POD correlation length
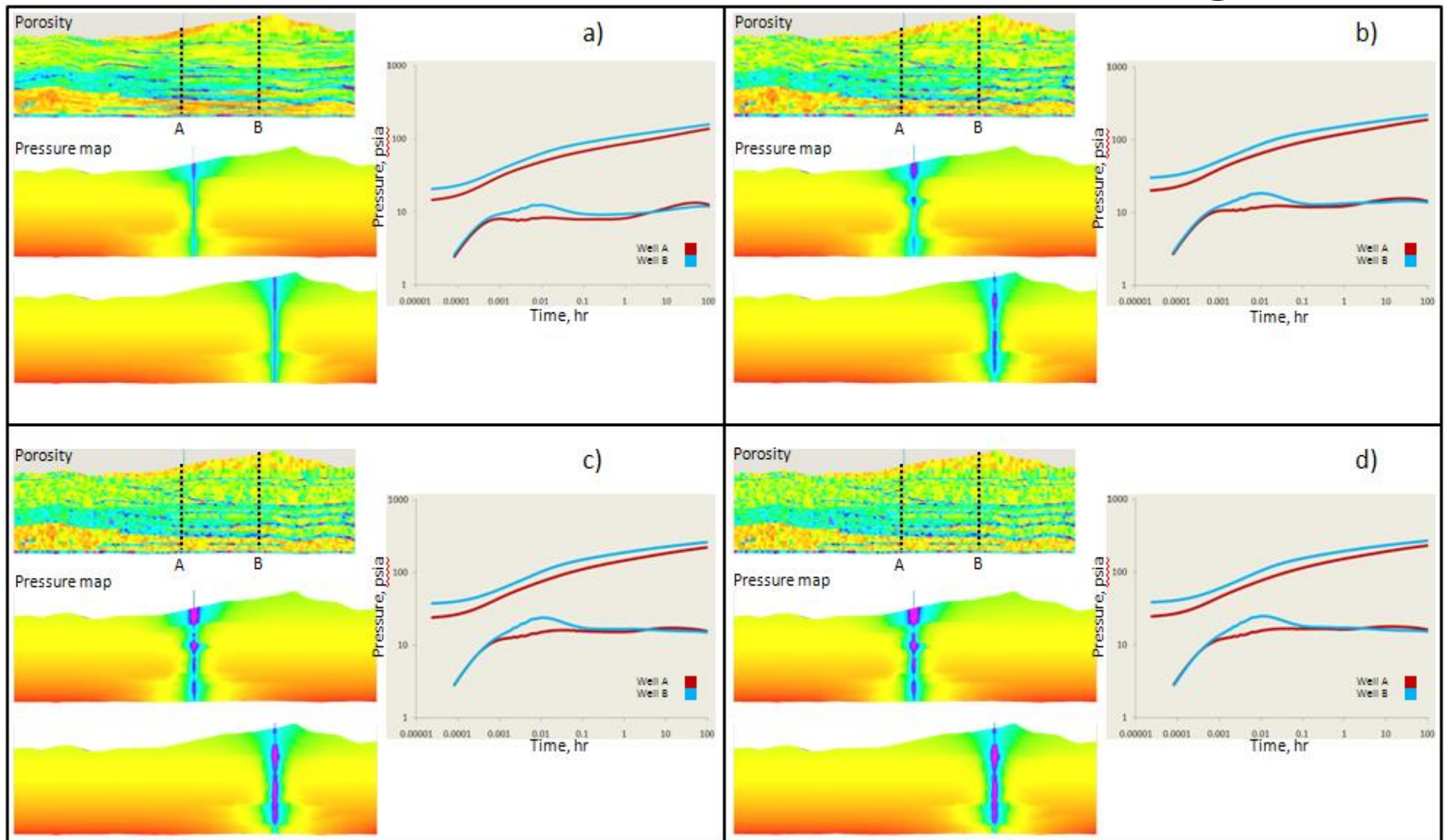
Model comparison

After 100 hrs

After 3000 days

Depth, ft

STB/day

400
100
40
20
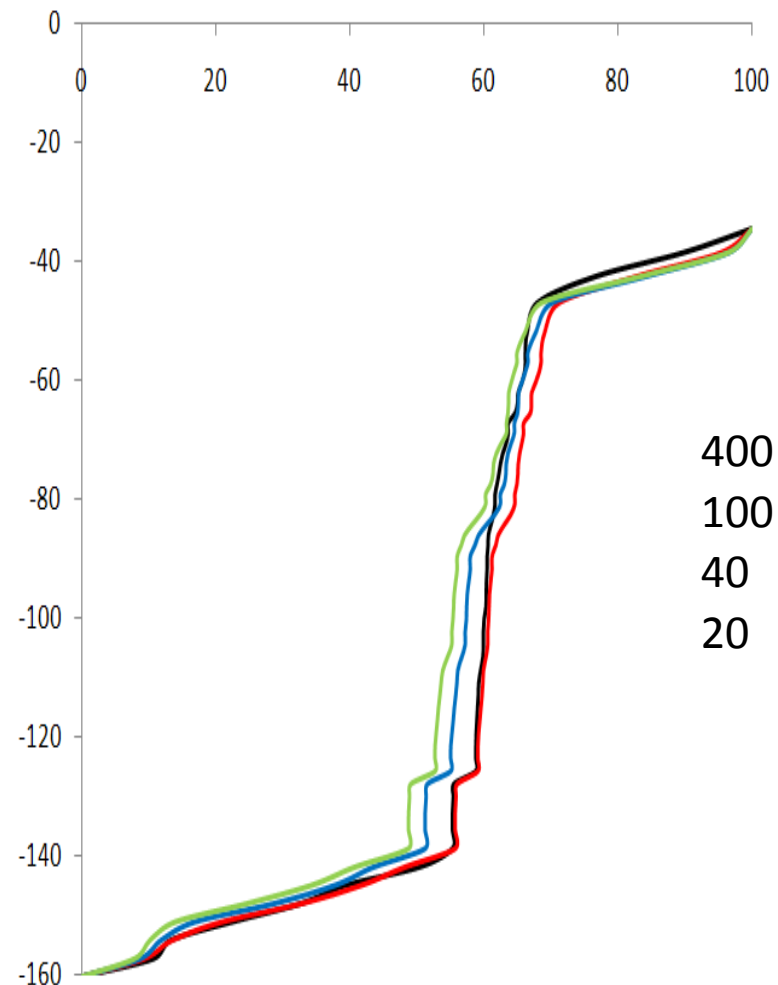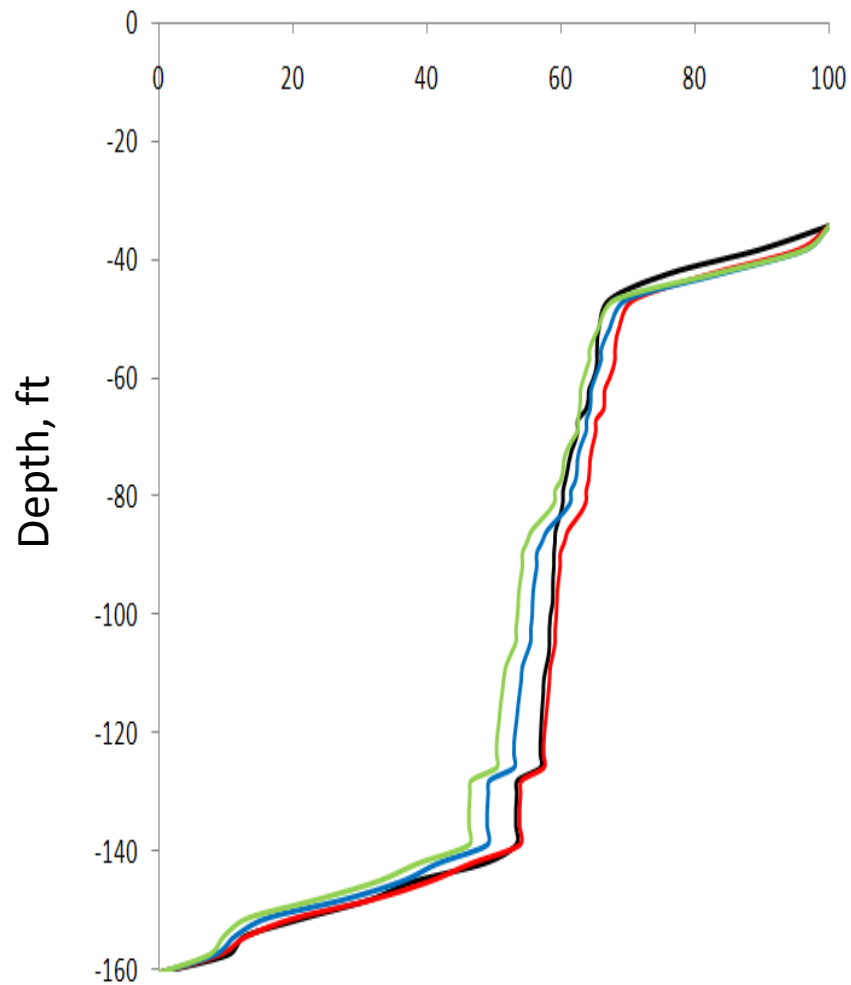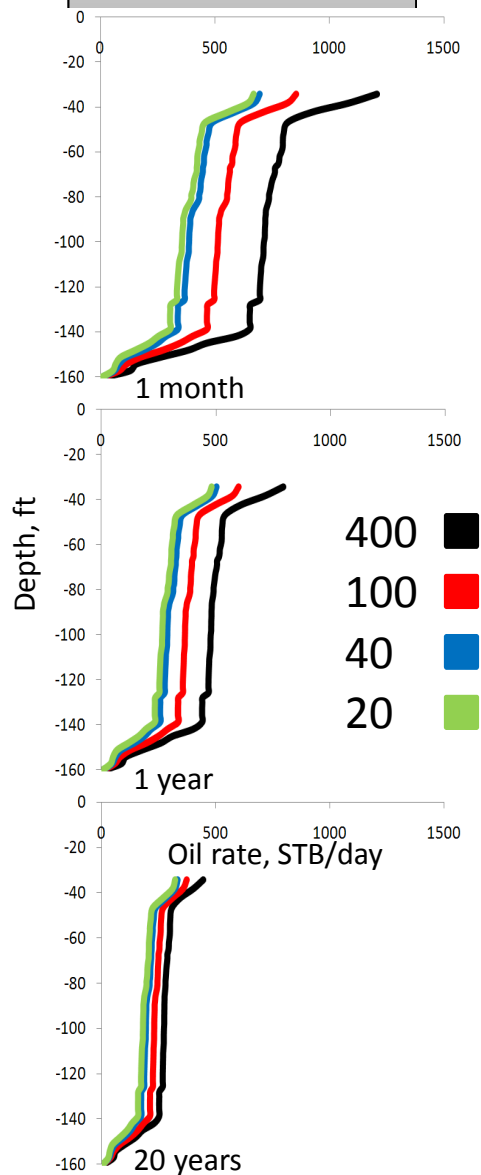
Kerans et al 1994

Model comparison

Kerans et al 1994

Oil saturation @ 20 years

Storage capacity
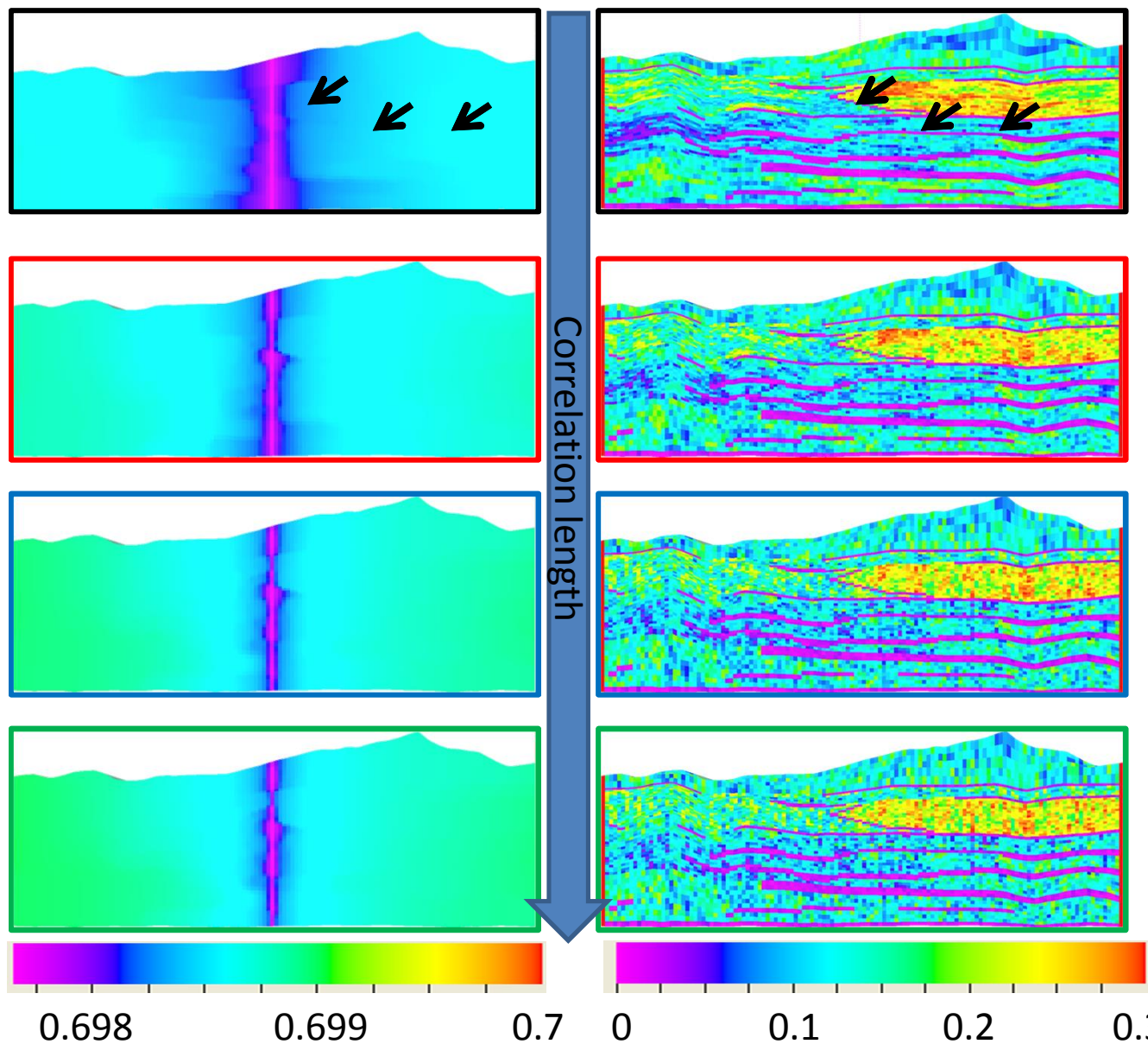
Outcrops and Well Testing 2

˝ Coquina limestone reservoirs are important component of Brazil's Pre-Salt reservoirs.

˝ Subsurface heterogeneities and geometries are poorly quantified in Coquina reservoirs

˝ Well test interpretation in carbonates can be ambiguous

Kerans et al 1994

Background

" Important component of Brazil's Pre-Salt reservoir.
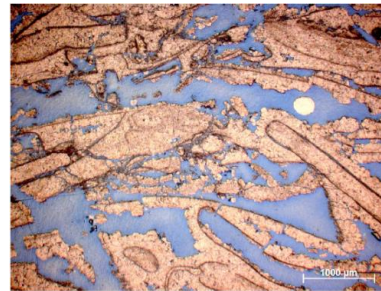
Libra Field – Coquinas
ANP promotional document
http://www.brasil-rounds.gov.br/arquivos/Seminarios_P1/Apresentacoes/partilha1_tecnico_ambiental_ingles.pdf

" Subsurface poorly quantified in Coquina reservoirs
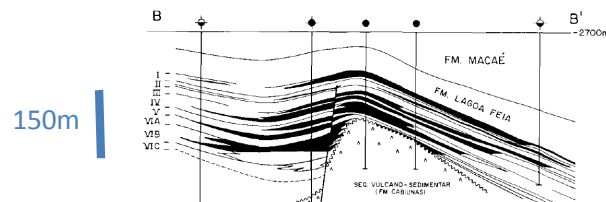
Barremian Syndepositional faulting
(Horschutz and Scuta, 1991)

Depositional heterogeneities, Morro de Chaves, Se-Al, Brasil

" Ambiguous well test interpretation in carbonates

Pressure

Derivative

Time →
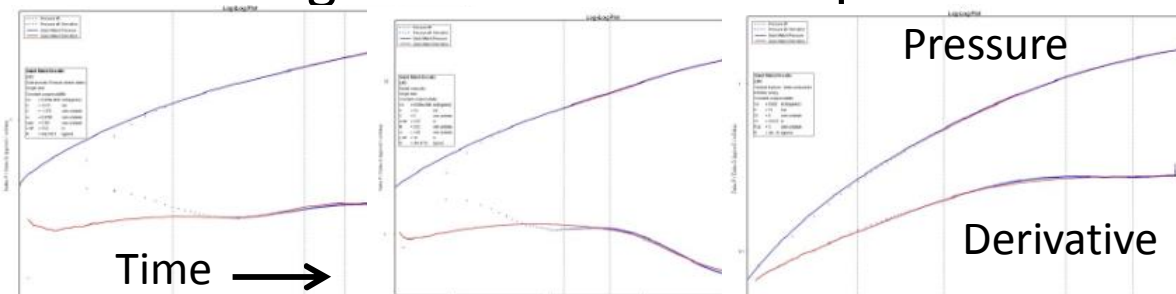
"The double porosity behaviour is consistent with the fact that the reservoir is composed of calcites and dolomites where it can be noticed a difference between the contribution of the matrix and fractures"

Warszawski and Fereira, 2013

Conversion of Outcrops to Well Test

Carbonate Samples

Geological Statistics

Reservoir Model

Pressure Transient Analysis

Well Test Analysis

Lipovetsky et al 1994

Well Test Analysis Plots. Fekete website, 2013.

Outline

″ Background to the outcrop study

″ Numerical (Geological Well Testing)

″ Interpretation Ambiguities

″ Future work

Location Sao Sebastiao (Atol/Cimpur) Quarry

Alagoas State, NE Brazil

SUB-BACIA DE ALAGOAS

OSCAR PESSOA DE ANDRADE CAMPOS NETO et al.

Possible Pre-Salt Analogue

Ma	GEOCRONOLOGIA			NATUREZA DA SEDIMENTAÇÃO	AMBIENTE DEPOSICIONAL	DISCORDÂNCIAS	LITOESTRATIGRAFIA			ESPESSURA MÁXIMA (m)	SEQUÊNCIAS
	PERÍODO	ÉPOCA	IDADE				GRUPO	FORMAÇÃO	MEMBRO		

GEOCRONOLOGIA

PLEISTOCENO
PLIOCENO — GELASIANO / PIACENZIANO — ZANCLEANO
MESSINIANO
NEOGENO — MIOCENO — TORTONIANO
SERRAVALIANO
LANGHIANO
BURDIGALIANO
AQUITANIANO

OLIGOCENO — CHATTIANO / RUPELIANO

PALEOGENO — EOCENO — PRIABONIANO / BARTONIANO / LUTETIANO / YPRESIANO

PALEOCENO — THANETIANO / SELANDIANO

MARINHO REGRESSIVO

COSTEIRO / PLATAFORMA

TALUDE

Discordâncias:
MIOCENO MÉDIO
OLIGOCENO INFERIOR
EOCENO SUPERIOR
EOCENO MÉDIO
PALEOCENO

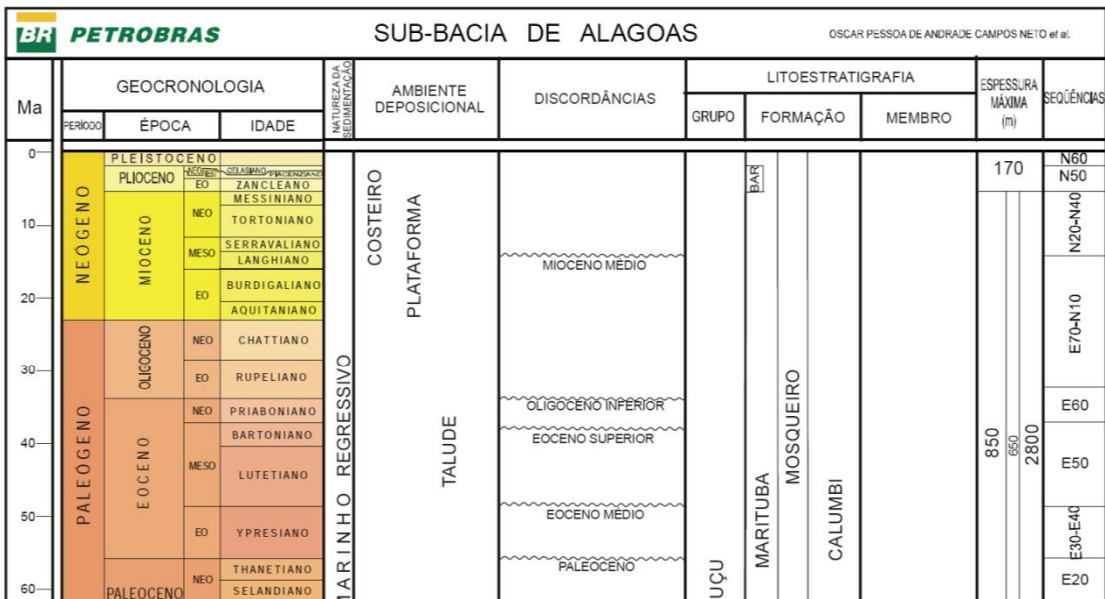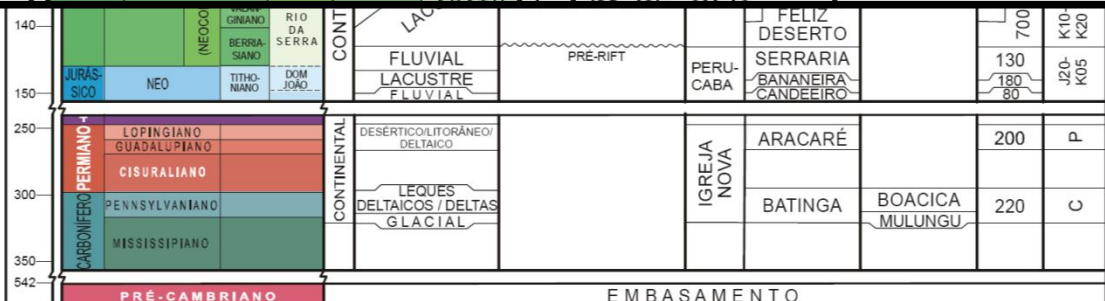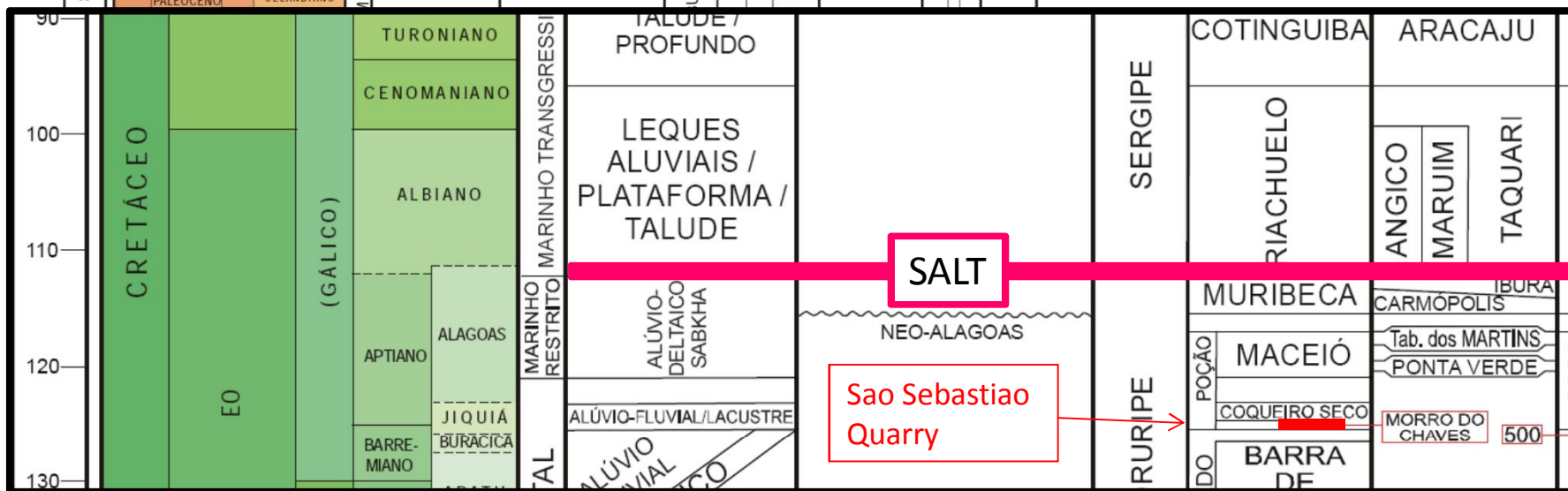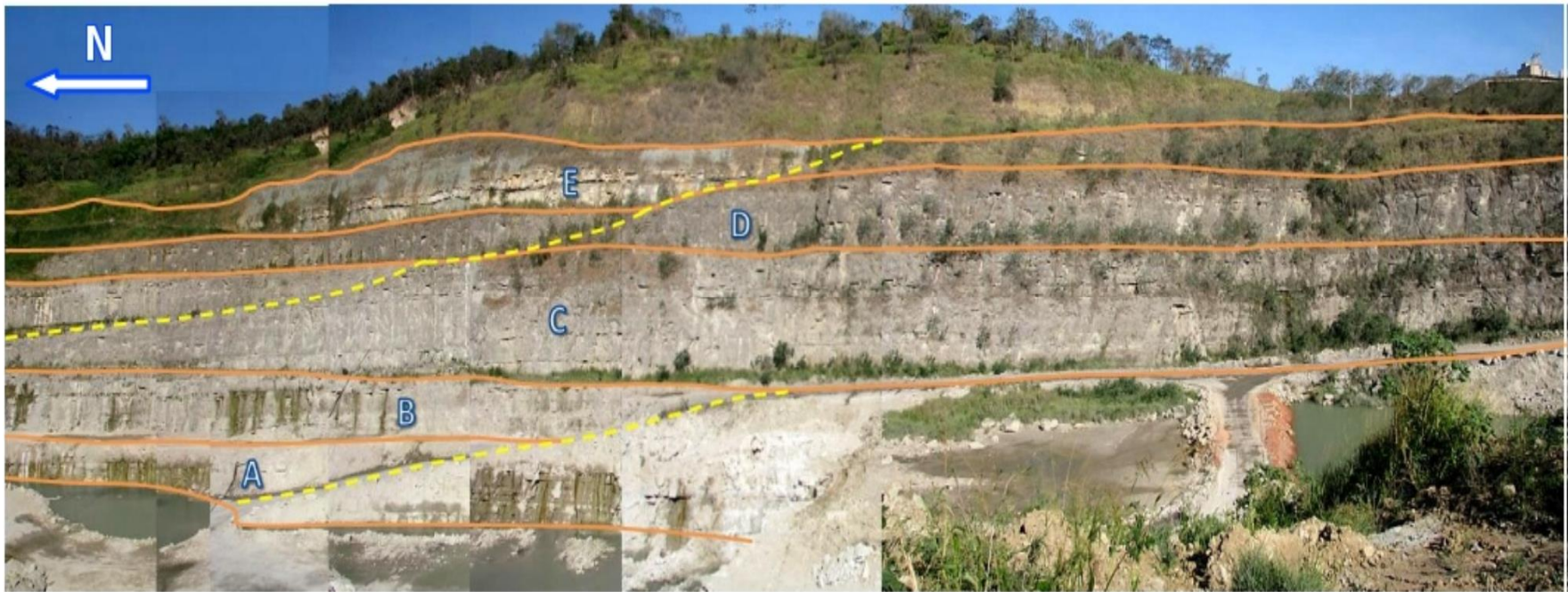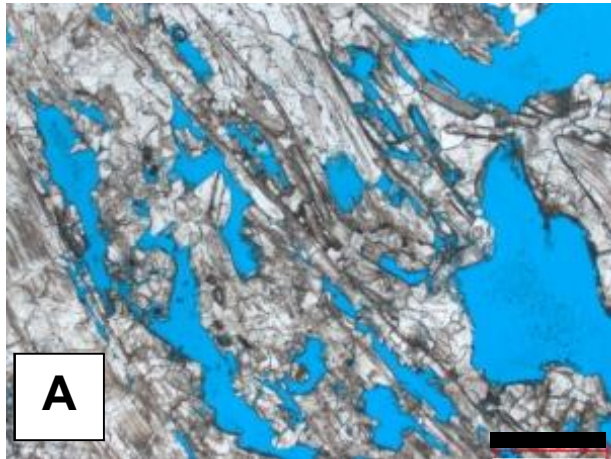Litoestratigrafia: BAR / MARITUBA / MOSQUEIRO / CALUMBI / ...çu

Espessura: 170 / 850 / 650 / 2800

Sequências: N60 / N50 / N20-N40 / E70-N10 / E60 / E50 / E30-E40 / E20

CRETÁCEO — EO — (GÁLICO)

TURONIANO
CENOMANIANO
ALBIANO
APTIANO — ALAGOAS / JIQUIÁ / BURACICA
BARREMIANO

MARINHO TRANSGRESSIVO / MARINHO RESTRITO

TALUDE / PROFUNDO

LEQUES ALUVIAIS / PLATAFORMA / TALUDE

SALT

ALÚVIO-DELTAICO SABKHA

NEO-ALAGOAS

ALÚVIO-FLUVIAL/LACUSTRE

ALÚVIO FLUVIAL

SERGIPE — COTINGUIBA — ARACAJU

RIACHUELO — ANGICO / MARUIM / TAQUARI

MURIBECA — IBURA / CARMÓPOLIS

MACEIÓ — Tab. dos MARTINS / PONTA VERDE

RURIPE — POÇÃO — COQUEIRO SECO — MORRO DO CHAVES — 500

BARRA DE

DO

Sao Sebastiao Quarry

NEOCOM. — RIO DA SERRA — VAL / BERRIASIANO

JURÁSSICO — NEO — TITHONIANO — DOM JOÃO

LOPINGIANO
PERMIANO — GUADALUPIANO
CISURALIANO

CARBONÍFERO — PENNSYLVANIANO / MISSISSIPIANO

PRÉ-CAMBRIANO

CONTINENTAL / FLUVIAL LACUSTRE / FLUVIAL

PRÉ-RIFT

FELIZ DESERTO / SERRARIA / BANANEIRA / CANDEEIRO

PERUCABA

DESÉRTICO/LITORÂNEO/DELTAICO

LEQUES DELTAICOS / DELTAS GLACIAL

IGREJA NOVA — ARACARÉ / BATINGA — BOACICA MULUNGU

EMBASAMENTO

700 / 130 / 180 / 80 / 200 / 220

K10-K20 / J20-K05 / P / C

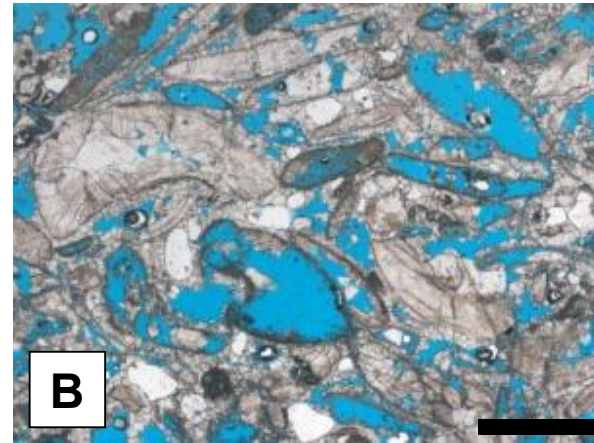Ma scale: 0, 10, 20, 30, 40, 50, 60, 90, 100, 110, 120, 130, 140, 150, 250, 300, 350, 542

Morro de Chaves
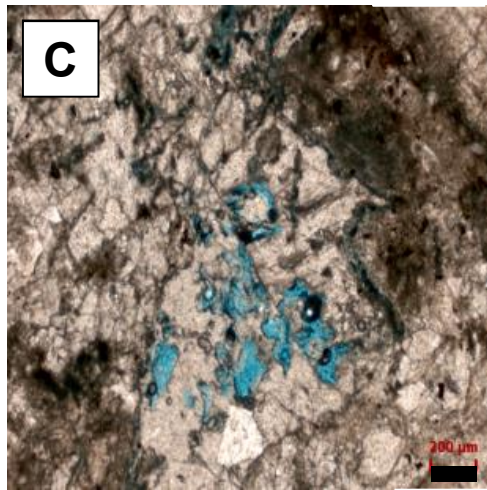

Access to various layers along benches and roads
Stratigraphic profile – yellow dashed line
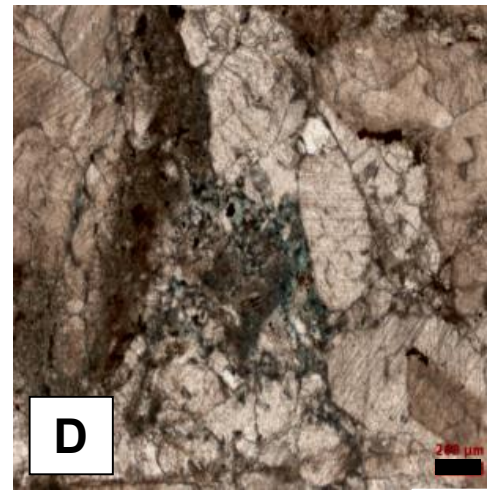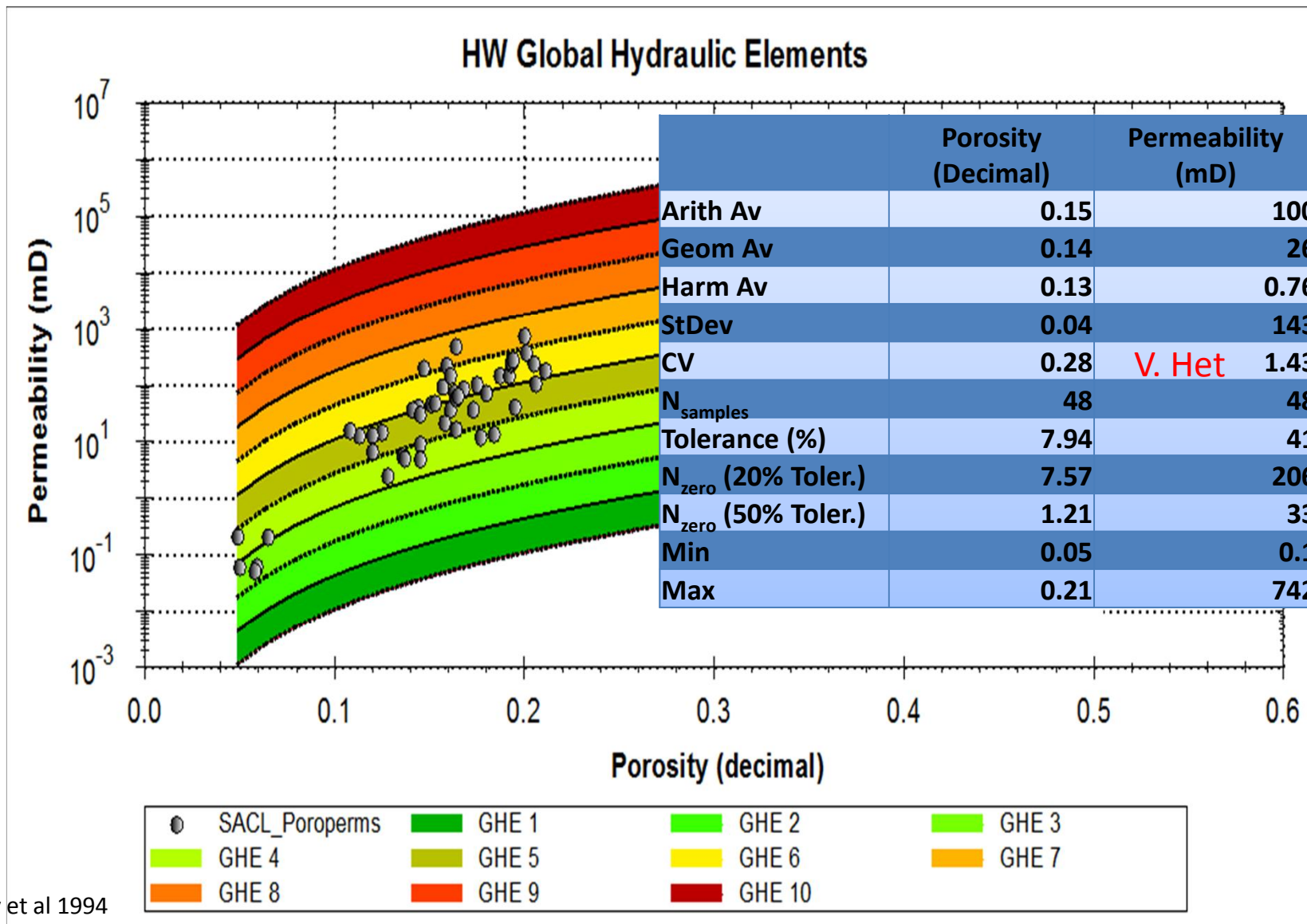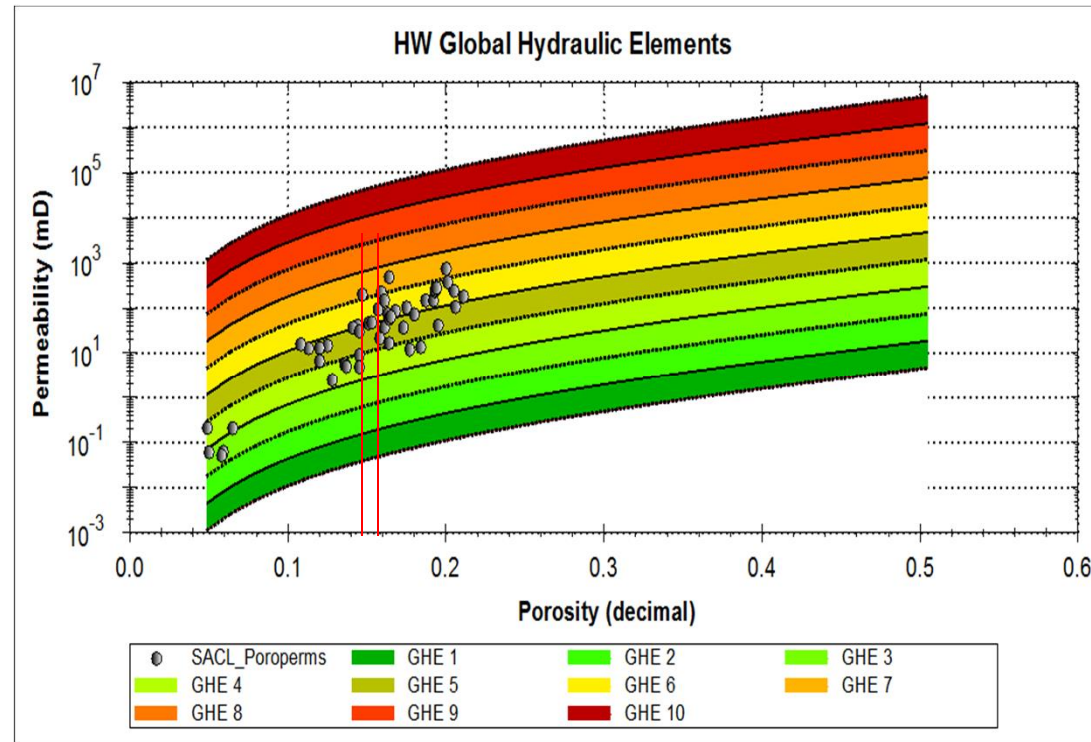
Photomicrographs from the Morro do Chaves Fm coquinas showing porosity (in blue). (A) high degree of corrosion porosity, (B) mouldic porosity, (C) low intercrystalline porosity and (D) patchy microporosity.

SACL poroperm data set

HW Global Hydraulic Elements

	Porosity (Decimal)	Permeability (mD)
Arith Av	0.15	100
Geom Av	0.14	26
Harm Av	0.13	0.76
StDev	0.04	143
CV	0.28 V. Het	1.43
$N_{samples}$	48	48
Tolerance (%)	7.94	41
N_{zero} (20% Toler.)	7.57	206
N_{zero} (50% Toler.)	1.21	33
Min	0.05	0.1
Max	0.21	742

Legend: SACL_Poroperms, GHE 1, GHE 2, GHE 3, GHE 4, GHE 5, GHE 6, GHE 7, GHE 8, GHE 9, GHE 10

Lipovetsky et al 1994

Porosity and Permeability

HW Global Hydraulic Elements

GHU of the Coquinas from the Morro de Chaves. Corbett and Borghi, 2013.

″ Challenge in carbonates:

1 value of – n values of k

$$k \quad \left(\frac{\left(\frac{\emptyset}{1 \quad \emptyset} \right)}{0.0314} \right)$$

FZI: Flow Zone Indicator (defines the petrotypes boundaries).

GHU can be shown as FZI values.

Lipovetsky et al 1994

The Lorenz Plot

″ h *vs.* kh (h = thickness).

″ Obtained from reservoir core samples.

″ Points plotted in order of decreasing k/ .

″ Uniform rock properties: points fall on a diagonal: h is a linear function of kh.

″ Heterogeneous rock: points are shifted further away from the diagonal.
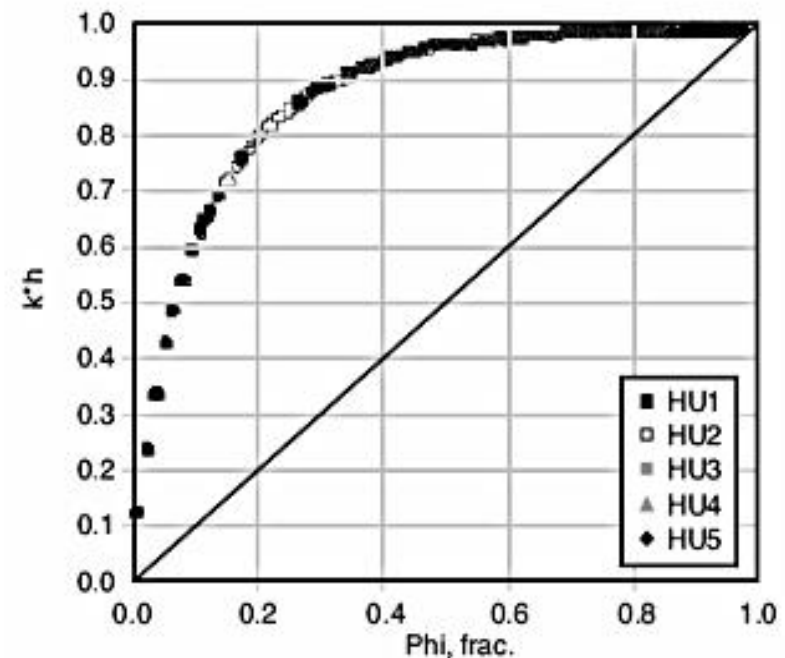
Lorenz Plot example. Corbett *et al.*, 2005.

Lipovetsky et al 1994
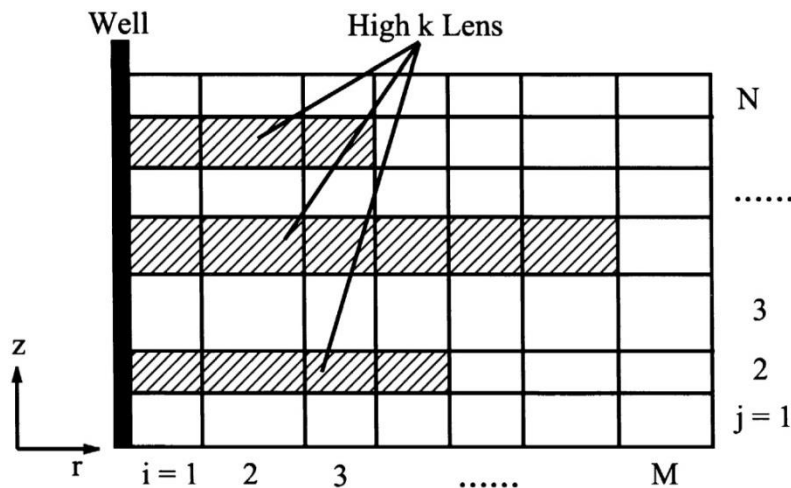
Lenses

Example of Reservoir with high permeability Lenses. In
this case, k means permeability. Sagawa *et al.*, 2000.

˝ Previous clastic work

˝ Coarse grain concentration in
channel deposits: **Great k**;

˝ Vertically and horizontally
limited;

˝ Surrounded by a **low k matrix**;

˝ Many lenses can be modelled as
one equivalent (Sagawa *et al.*,
2000)

˝ *"In carbonates, the presence of
lenses is not so clear, but matrix
heterogeneity exists in many
forms – including lenses."*
(Corbett, *p.c.*)

Lipovetsky et al 1994

Geological Statistics

˝ Entire reservoir parameters are inferred from a few cores;
˝ Averaging methods:

$$\leq \qquad \leq$$

$$K = \left[\frac{1}{\quad} \right]$$

$$K = \left(\quad \right)^{/}$$

$$K = \frac{1}{\quad}$$

Alternative estimators for well test permeabilities depend on the geometry of the lenses at the bed-scale. Corbett, 2013.

Lipovetsky et al 1994

Geological Statistics

″ Entire reservoir parameters
are inferred from a few cores;

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$$\leq \qquad \leq$$

$$K = \left[\frac{1}{} \right]$$

$$K = \left(\right)^{/}$$

$$K = \frac{1}{}$$

Alternative estimators for well test permeabilities depend on
the geometry of the lenses at the bed-scale. Corbett, 2013.

Lipovetsky et al 1994

Morro de Chaves Plugs Analysis

HW Global Hydraulic Elements
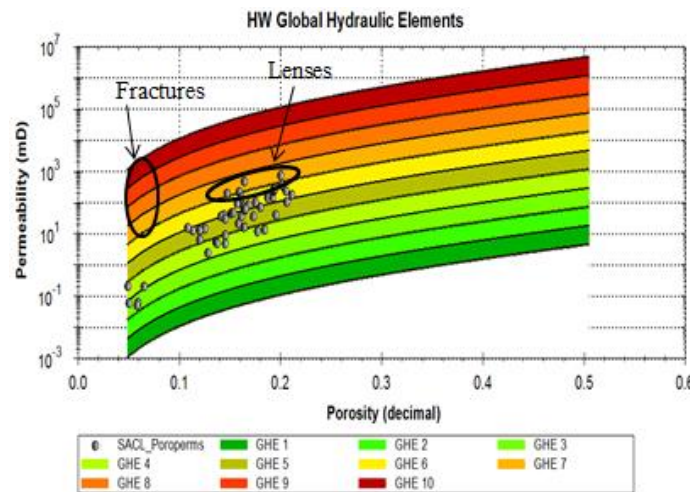
Morro de Chaves Global Hydraulic Elements: Poro-perm distribution (Corbett and Borghi, 2013). If there were a fracture, it would be represented by data in the upper redish-left region (low porosity, high permeability values). The lens data is indicated in the orange band, and corresponds to 33% of the inflow to the well.
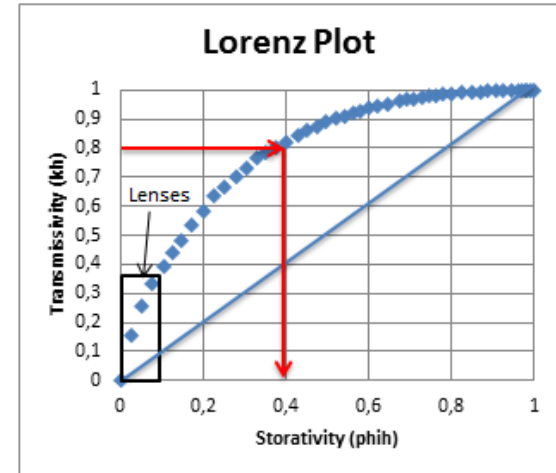
Lorenz Plot

Morro de Chaves Lorenz Plot. (Corbett and Borghi, 2013) Box shares 33% of transmissivity (due to only 3 plugs).

ϕ (decimal)	K (mD)	ϕ (decimal)	K (mD)	ϕ (decimal)	K (mD)	ϕ (decimal)	K (mD)
0,113	12,9	0,164	16,6	0,164	481	0,206	106
0,125	14,7	0,158	21,5	0,128	2,49	0,184	13,6
0,120	13,0	0,137	5,05	0,147	199	0,173	36,7
0,141	36,6	0,145	30,4	0,153	48,0	0,195	41,2
0,108	15,8	0,163	73,9	0,187	148	0,177	12,1
0,161	37,3	0,175	103	0,192	148	0,059	0,062
0,145	9,09	0,164	57,9	0,193	238	0,050	0,061
0,157	93,9	0,211	179	0,200	742	0,065	0,208
0,136	5,55	0,168	86,7	0,193	258	0,058	0,052
0,144	41,0	0,049	0,210	0,205	241	0,180	72,1
0,145	4,90	0,159	224	0,201	375	0,165	63,9
0,151	46,3	0,120	6,70	0,194	281	0,161	147

Porosity-permeability values (Corbett and Borghi, 2013). The shaded values correspond to the orange band.

Lipovetsky et al 1994

The Modelled Reservoir Scenarios

″ Lorenz Plot **average** values:

Values obtained from the **black box** in the **Lorenz Plot**. These will be used to model the lens.

Property	Lens	Reservoir
Porosity (arithmetic average)	18.8%	14.9%
Permeability (geometric average)	533 mD	21.14 mD
Transmissivity	33%	67%

Values obtained from the **Lorenz Plot,** outside the black box.

Transmissivity, Porosity and Permeability values for Lens and Reservoir, through the assessment of the Lorenz Plot
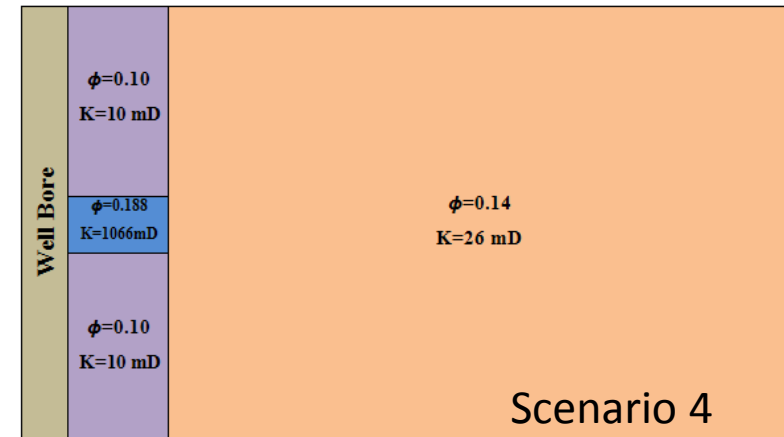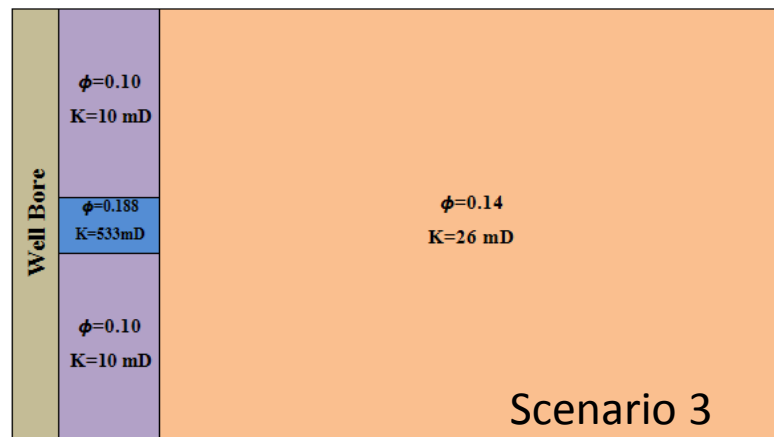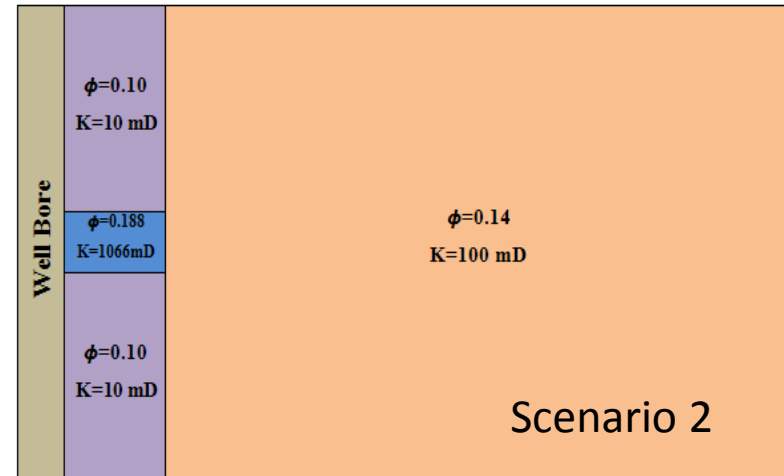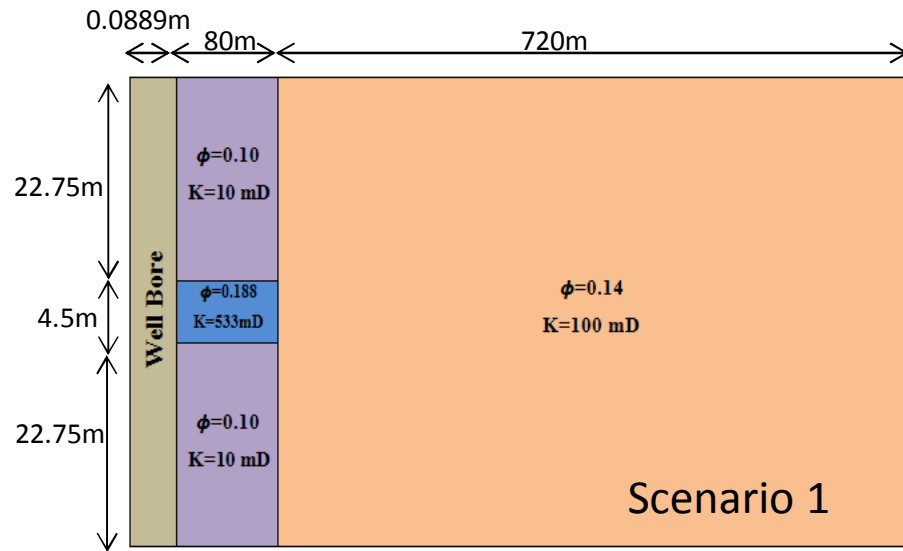
″ Outer Matrix:

k

Obtained from the **geological statistics** for the **outer matrix.**

Statistical Analysis Method	Porosity (Decimal)	Permeability (mD)
Arithmetic Average	0.15	100
Geometric Average	0.14	26
Harmonic Average	0.13	0.76

″ Near wellbore matrix: k and   will have lower values (10mD and 0.10, repectively).

Lipovetsky et al 1994

The Built Scenarios

*Initial Reservoir and Fluid Properties: See the final slide.

Lipovetsky et al 1994

The FVM 2-D Multiphase Flow Simulator

˝ **Black Oil**: recovery processes are intensive to compositional changes in the reservoir fluids.

˝ To simulate how the Scenarios behave, the **Hydraulic Diffusivity Equations** are incorporated, applied to the **FVM** and to the **IMPES** Method.
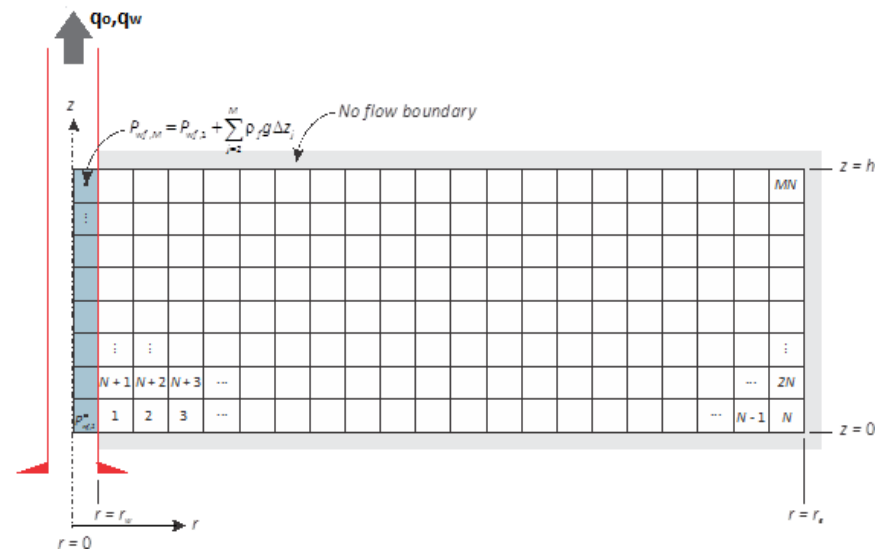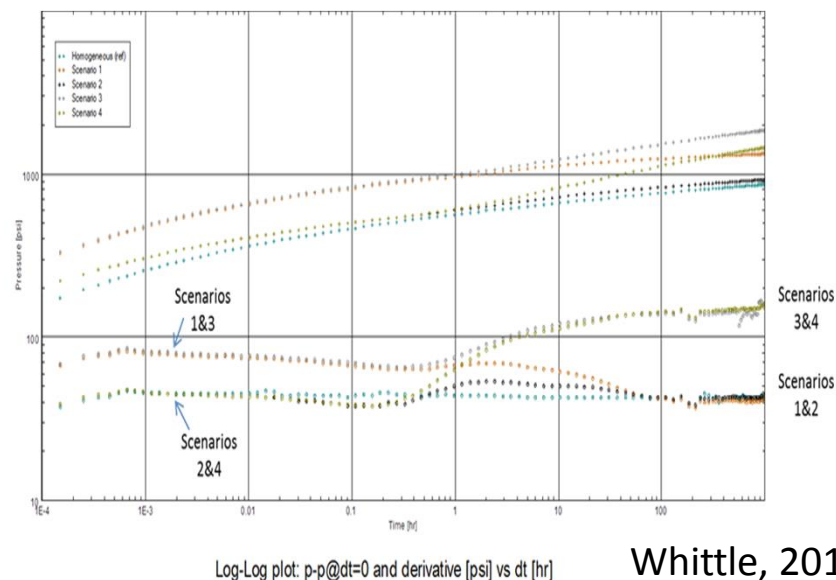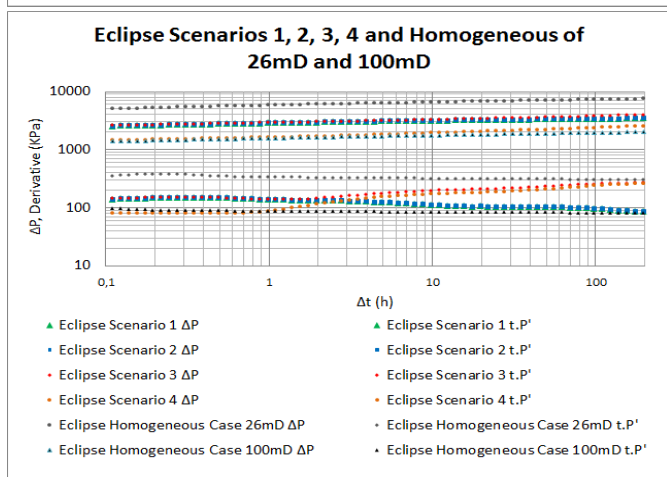

Schematic figure of radial reservoir, with well placed in the middle (represented in blue).

Lipovetsky et al 1994
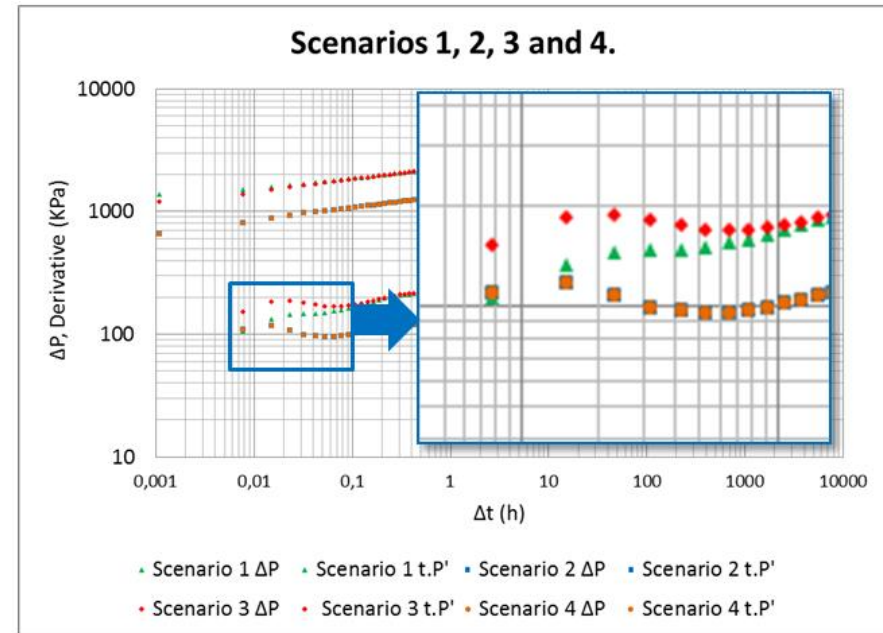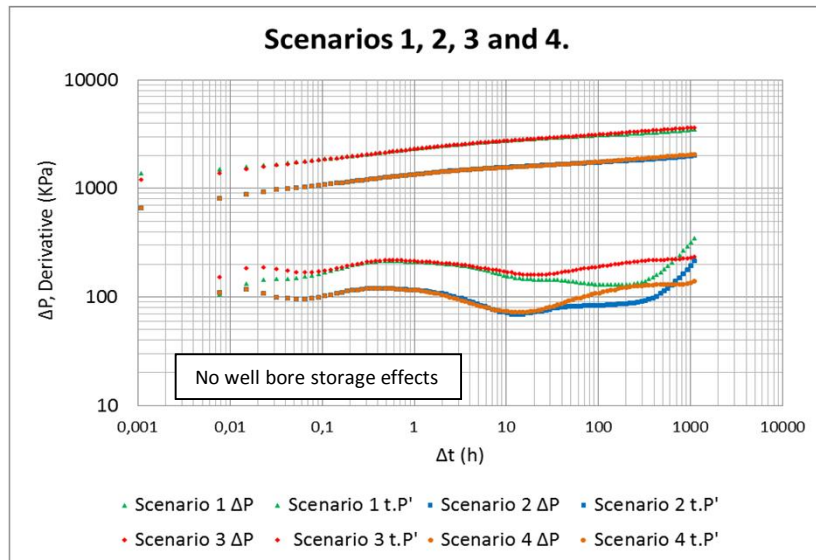
Well Test Analysis

Early time affects might be numerical issues, simulation issues or subtleties associated with the partial perforation effect with 'shoulders'

Lipovetsky et al 1994

Well Test Analyses: Comparison and Validation

Whittle, 2014
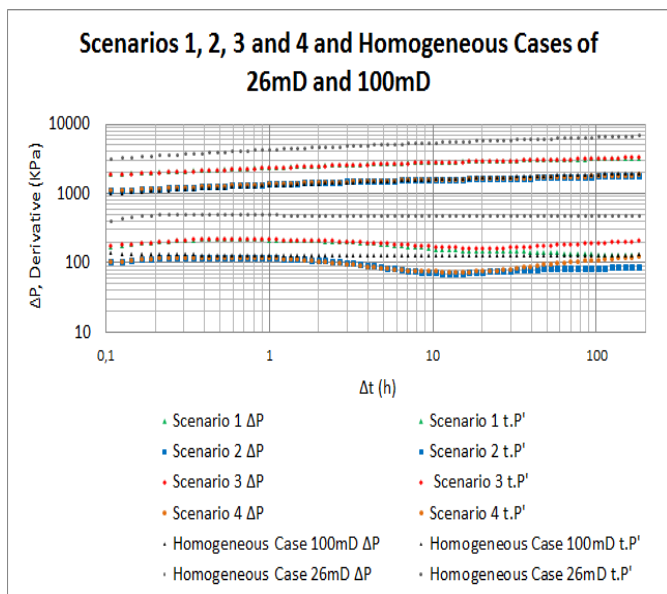
Lipovetsky et al 2014

Three different simulators – broad agreement in the middle time region

Flow simulation (Commercial code FDM)
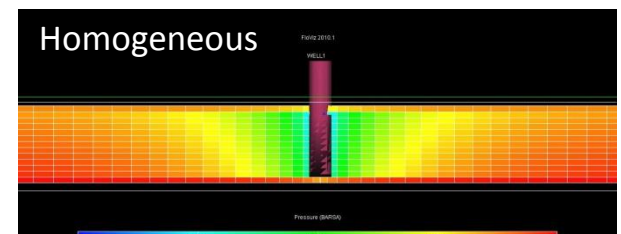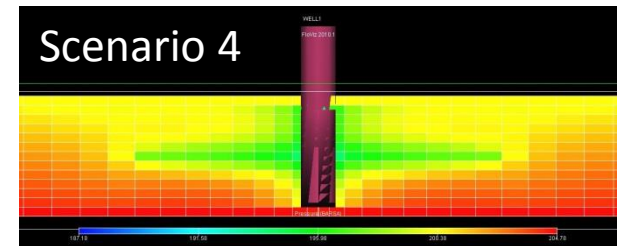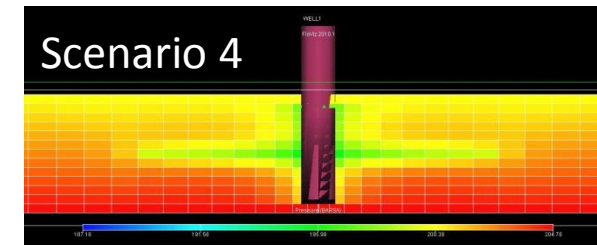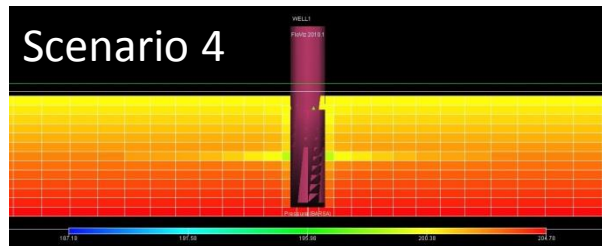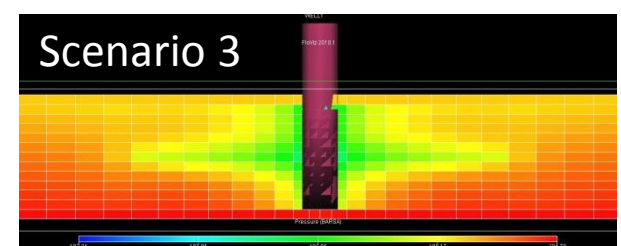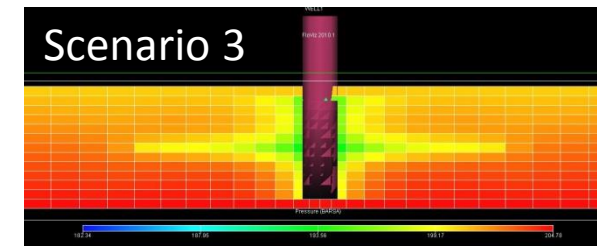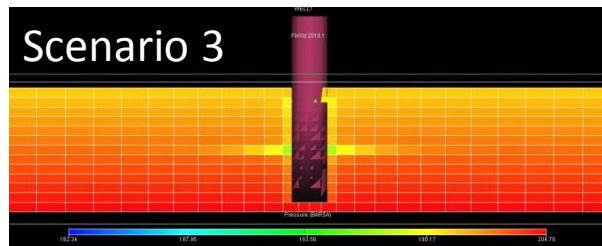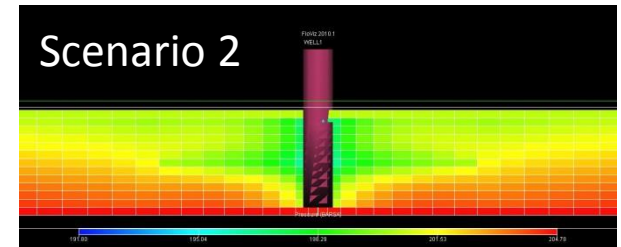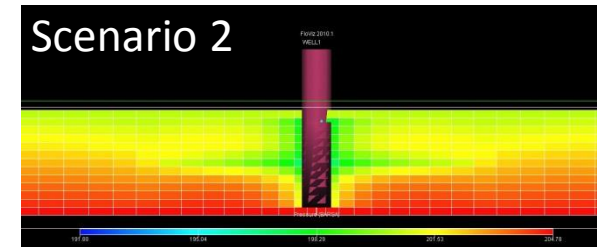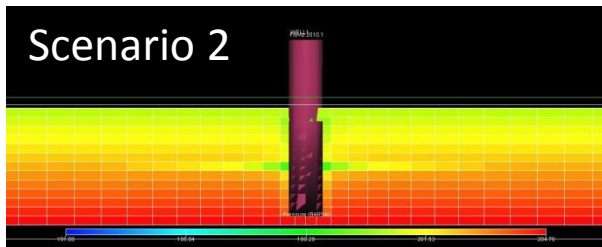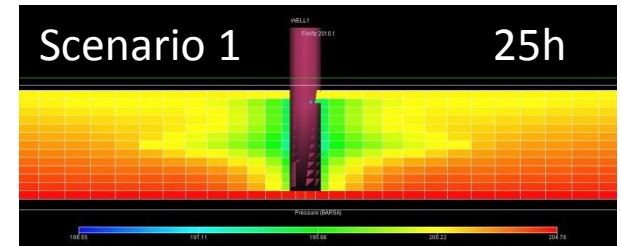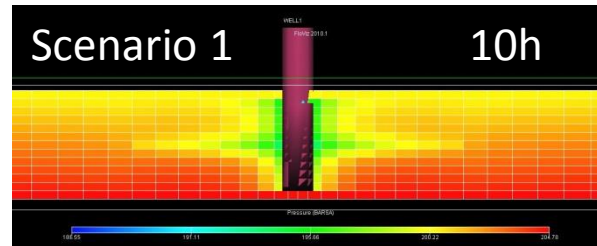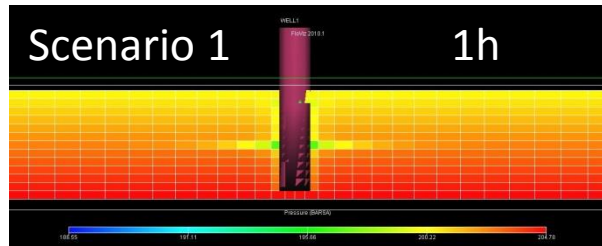
Well Testing Conclusions
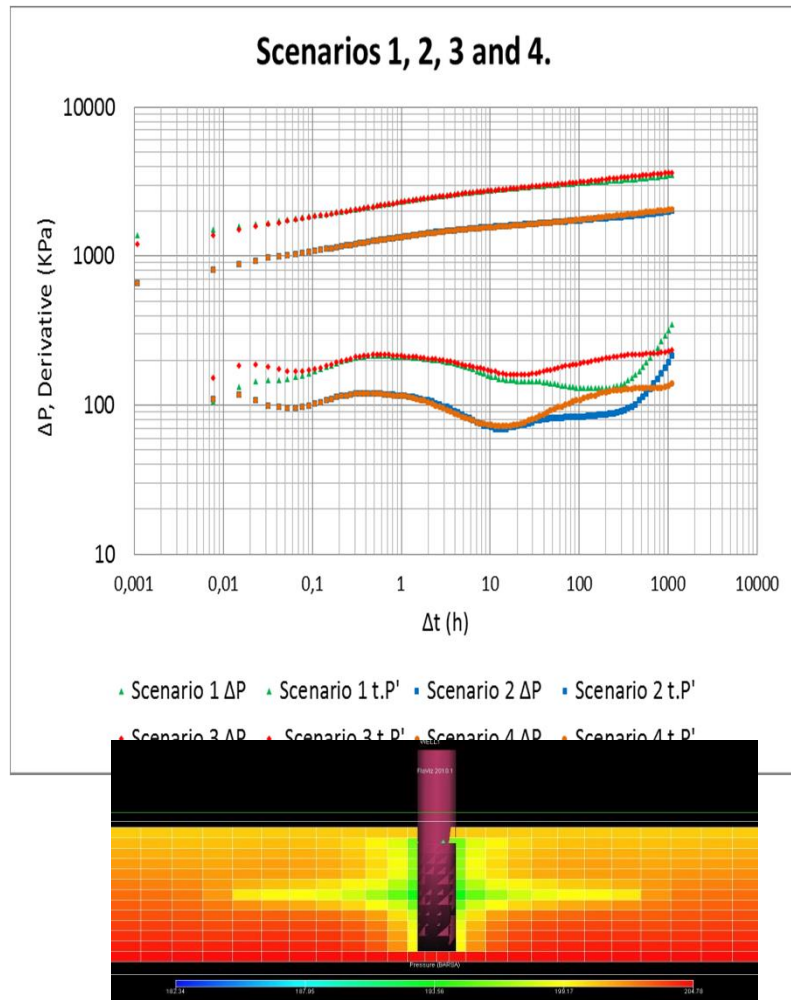
Response to a single pod intercepted by well

Lipovetsky et al 2014
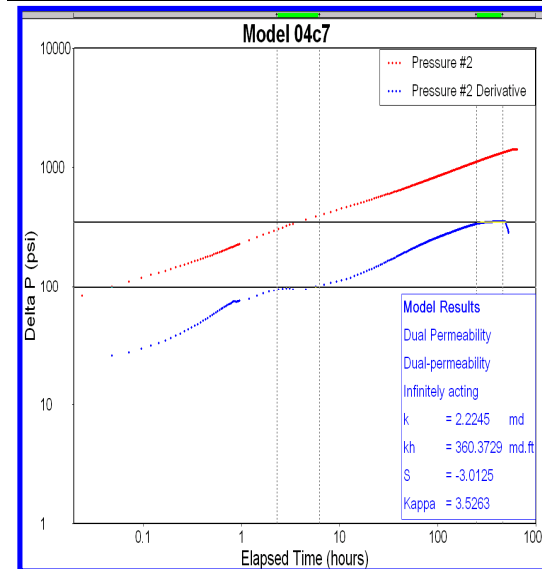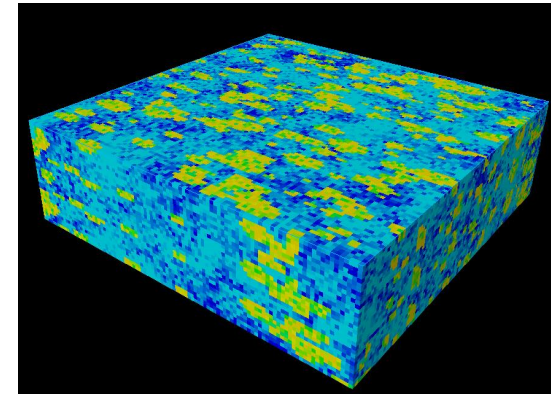
Response to multiple pods intercepted by well

Corbett et al., 2010

Fractured or not?

˝ Reservoir Engineering – YES

. Well test double porosity response

. Negative skin

˝ Geology – YES

. Image Log

Image Log

4330 m

Highly fractured cluster about 4 m thick with preferentially-oriented, intersecting fractures and possible little breccia.

Probable fault zone
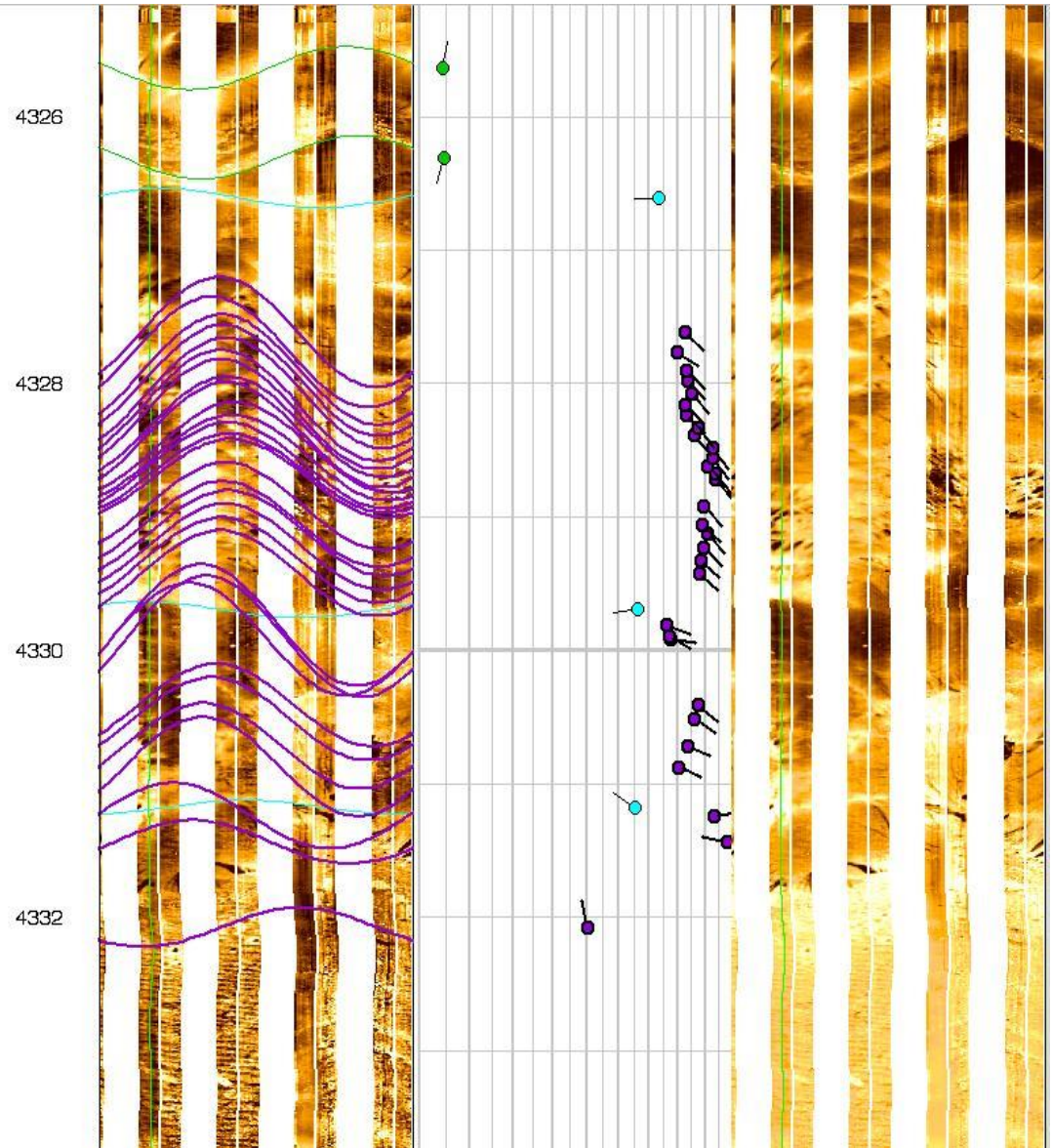
Automated Well Test Analysis

$k = 13 \text{ mD}$

$\omega = 0.14$

$\lambda = 1.1 \times 10^{-6}$

$S = -5,4$

$l = 0.1 \text{ m}$

$k_m = 0.35 \text{ μD}$

Well bore storage effects ?
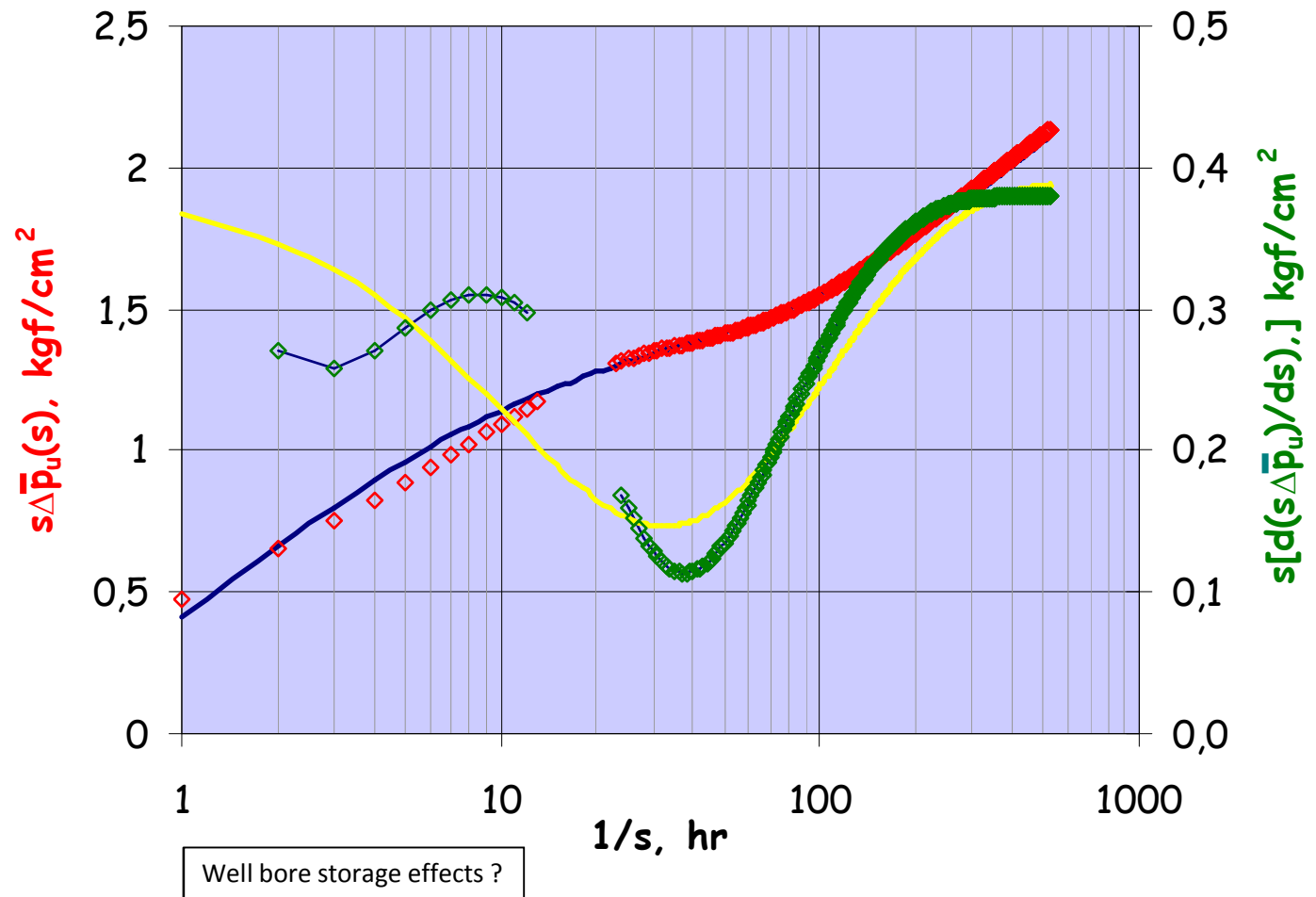
Fractured or not?

˝ Reservoir Engineering – YES

- . Well test response
- . Negative skin
- . Cross-flow

˝ Geology – NO

- . No fractured core
- . No open fractures on image logs
- . No significant losses

Fractured or not?

˝ Reservoir Engineering – YES >>> NO

- Well test response
- Negative skin >> not fractures >> double matrix
- Cross-flow >> not fractures >> double matrix

˝ Geology – NO

- No fractured core
- No open fractures on image logs
- No significant losses

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˝ Geotipe Project (1997 – 2003)

˝ International Centre for Carbonate Reservoirs

˝ Schlumberger (Eclipse) Weatherford (PanSystem)

Fractured Reservoir Myths

˝ Fractures mostly have a high angle origin – but only to bedding (Lewis, HWU)

˝ Is use of curvature good – OK for thinly bedded systems (Couples, HWU)

˝ Is fracture porosity always low (1-2%) – yes generally but not always (Quenes, Sigma[3])

˝ is the fractal model a good one – there are length scales, layering and the mechanical stratigraphy is important (Couples, HWU; Riva GE Plan),

˝ Mechanical fractures follow existing fracture patterns (Alverellos, Repsol)

˝ Thermal Fracturing in low permeability rocks – also high permeability sandstones (Tovar, IES)

˝ Continuum fracture models vs Discrete Fracture models – upscaling DFN is very challenging (Geiger, HWU)

˝ There is no REV in fractured reservoirs – except possibly at the seismic bin scale (Quenes, Sigma[3]) and at the bed scale (Couples, HWU; Riva GEPlan)

˝ Basement provide seals and migration barriers – but not if fractured (Hartz, Det Norske Oljeselskap)

˝ Ruger equation can give fracture orientation and density – simple laboratory models show this equation sometimes holds (Chapman, Edinburgh University)

Fracture Reservoir Agreement

˝ Fractures are difficult to locate but easy to predict with the correct structural model (Lewis, HWU)

˝ Fracture Models should be driven by data and concepts (Riva, GE Plan)

˝ Fractures develop though complex history of burial and many stress episodes(Bezerra, UFRN; Betotti (TUDelft)

˝ Lithology and facies have an impact on fracture distributions (Cazarin, Petrobras)

˝ Need to model fractures in 3D (Hartz, Det Norske Oljeselskap; Moos, Baker-Hugues)

˝ A multidisciplinary approach to tackle fractures is necessary

Source: EAGE-SBGf Fracture workshop – Rio Nov 2013

New Myths

˝ "v" shaped response >> not always fractures

˝ "vv" response >> not common

˝ Infinite/Finite conductivity fracture (before fraccing) >> Double Matrix X-Flow

˝ Triple porosity >> Difficult to detect in Well Test

˝ Matrix reservoirs with strong contrasts (carbonates) can flow like fractured reservoirs

˝ Geologist must engage more effectively with well testing community and *vice versa*

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Patrick Corbett's AAPG tour May/June 2014

Flight
Train

12th – 16th May
19th – 21st May
30th May – 6th June