Pore volume compressibility in weakly-cemented sandstones

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Contents

- Definition of pore volume compressibility
- Importance of pore volume compressibility
- Measurement of pore volume compressibility
- Some issues of scaling from laboratory to the field
- Implementation in reservoir simulation
- Simulation results & other issues
- Closing remarks

Definition of pore volume compressibility

- Simply put, it is the fractional change in pore volume when subjected to a change in pore pressure:

$$C_{pp} = \frac{1}{V_{p0}} \frac{\partial V_p}{\partial p_p}$$

  - need to take into account grain compressibility effects, especially in low porosity rocks.
  - need to consider "poroelastic" effects when pore pressures are very high.
  - mathematically it can get very complicated to describe compressibility, but let's stick to the definition above for now!
- Units of compressibility are often abbreviated to 'microsips' when using oil-field units;
  - 1 microsip = 1×10^{-6} psi^{-1} = 0.145 GPa^{-1}

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- Definition of pore volume compressibility
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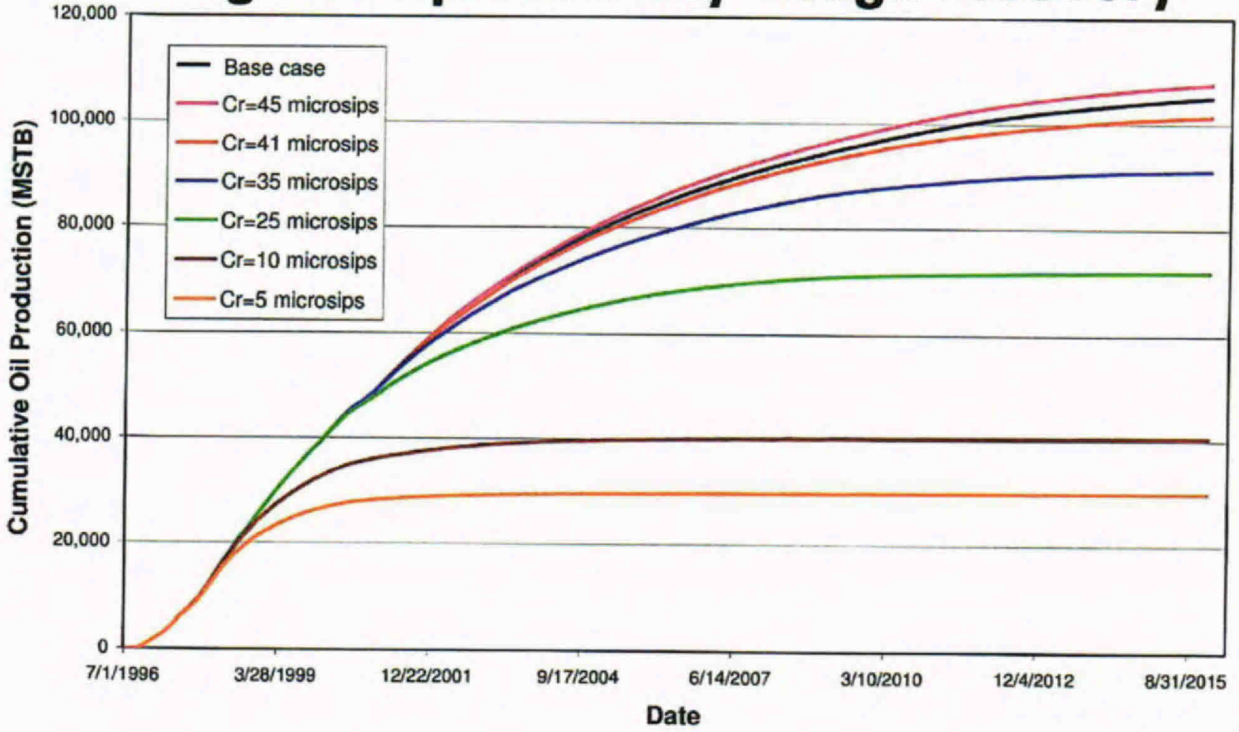
Impact of compressibility on reserves recovery

High compressibility = high recovery



Impact of compressibility on well test analysis (1)

One expression for the radius of investigation of a well test is:

$$r = 0.03\sqrt{\frac{k.t}{\phi.\mu.c_t}}$$

where: t = time, k = permeability, ϕ = porosity, μ = viscosity, c_t = total compressibility

Total compressibility is the sum of the fluid and pore compressibility (c_{pp}):

$$c_t = c_{fluid} + c_{pp} = c_o\,(1-S_w) + c_w\,.S_w + c_{pp}$$

for an oil reservoir with oil compressibility, c_o, formation brine compressibility, c_w and water saturation, S_w.

Impact of compressibility on well test analysis (2)

- For a hypothetical situation where: k = 250 mD; time = 8 hours; μ = 0.8 cP; S_o = 0.7; S_w = 0.3; c_o = 17x10^{-6} psi^{-1}; c_w = 3x10^{-6} psi^{-1}; the radius of investigation varies as a function of rock pore volume compressibility:

C_p (microsips)	**3**	**6**	**10**	**20**	**40**
C_p (GPa^{-1})	**0.435**	**0.87**	**1.45**	**2.9**	**5.8**
Radius of investigation (ft)	**7077**	**6488**	**5891**	**4912**	**3871**

Under these circumstances, a low rock compressibility allows a well test to 'see' further into the formation, and so prove more oil in place.

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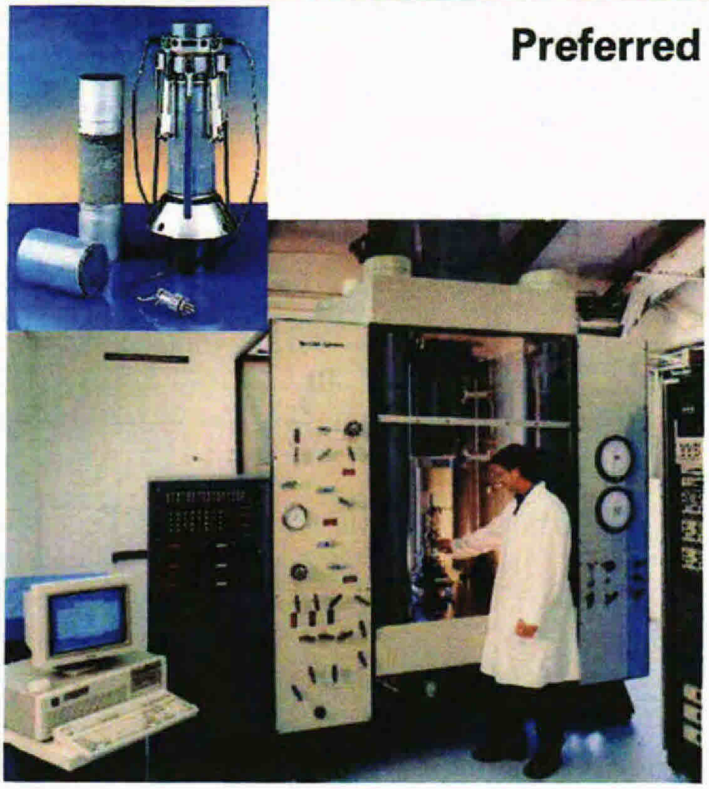
Measurement of pore volume compressibility

- Pore volume compressibility can be determined by several means:
  - Laboratory measurement
  - Wire-line estimations & correlations
  - Earth-tides effects analysis
- Each has pitfalls and ease of applicability

Laboratory measurement of pore volume compressibility



Preferred method – uniaxial strain compression

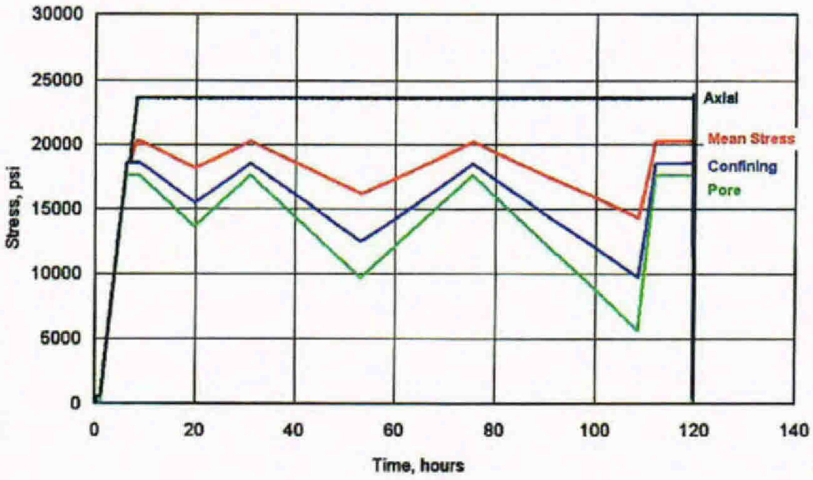
- Simulates stress-path followed during reservoir depletion.
- Can be ran under conditions of constant pore pressure and increasing external stress; or under true in-situ conditions of stress and pore pressure, allowing the pore pressure to reduce.
- Allows the simultaneous measurement of horizontal permeability in an axially compacting sample.
- Permits the direct calculation of modulus and Poisson's ratio.

Laboratory measurement of pore volume compressibility – test conduct

- BP preferred methods:
  - pore pressure depletion at constant applied axial total stress; confining stress is reduced to maintain zero radial strain.
  - increase axial total stress at constant internal pore pressure; confining stress is increased to maintain zero radial strain.
- Variants include:
  - unload / load cycles during the test to differentiate elastic and inelastic deformation.
  - "Rate-type compaction model" (RTCM) testing to characterize rate-effect scaling of compressibility.
  - creep "hold periods" to characterize non-stabilized time-dependent deformation.

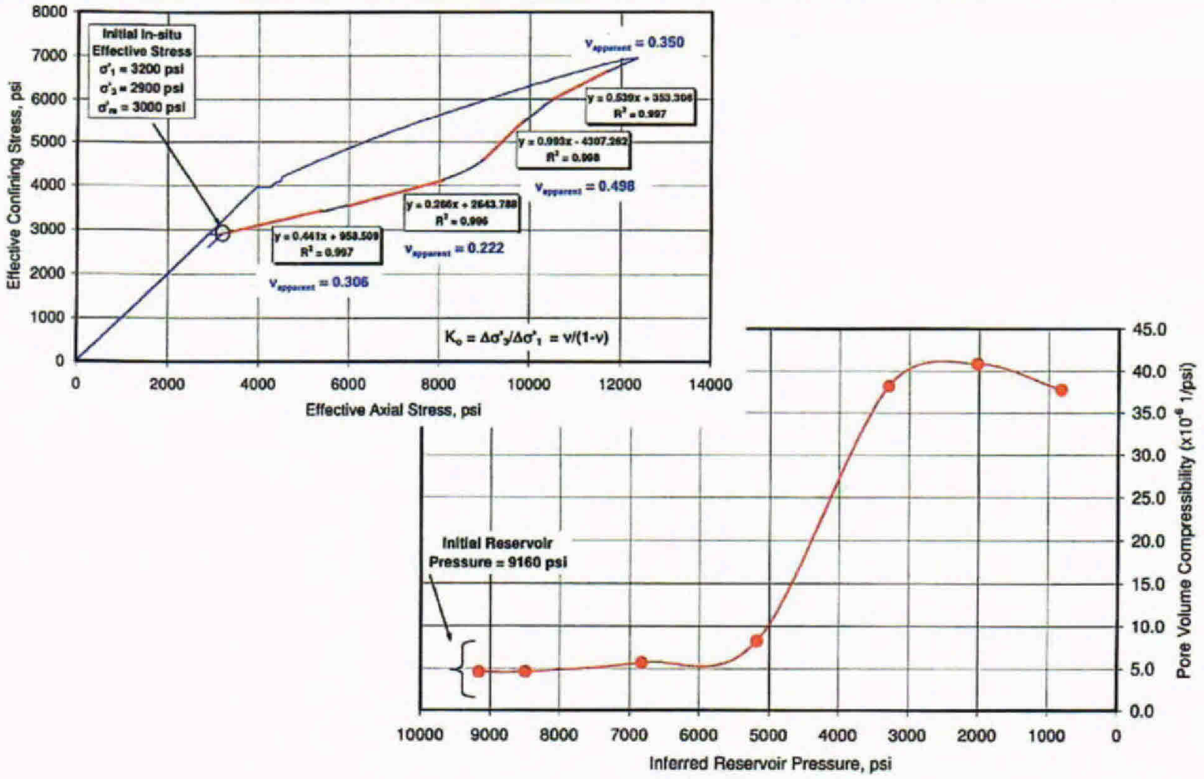
Laboratory measurement of pore volume compressibility – test conduct

- Additional comments:
  - preferred stress application or pore pressure depletion rate of ~0.1 psi/sec (0.75 kPa/s) for moderately-porous rocks.
  - tests are of long-duration, but loading-rate effects are minimized (or are at least constant)

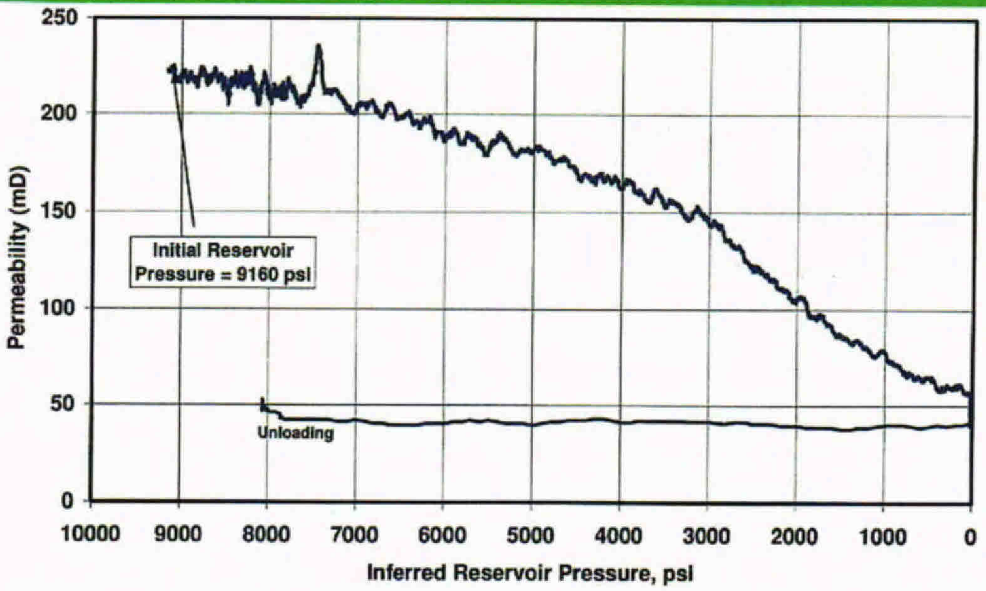


Typical test duration (5 days) for pore volume compressibility determination in deepwater, overpressured reservoirs

Laboratory measurement of pore volume compressibility – typical results



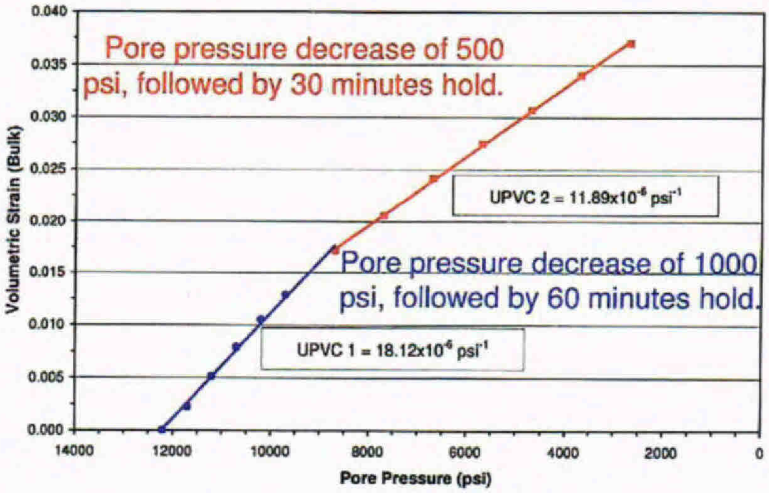
Measurement of permeability decline with depletion



- Example shows increased permeability reduction after the onset of accelerated compaction. Causes include pore throat constriction and fines generation from grain rearrangement and/or crushing.

Laboratory measurement of pore volume compressibility – untypical results

- BP recommended practices not implemented.
- Pore pressure is depleted by 500 psi in two minutes, followed by a 30 minute hold period; or reduced by 1000 psi in four minutes, followed by a 60 minute hold period.
- Tests completed within one day (ca. 3 times faster than is recommended).



Pore volume compressibility magnitudes impacted by pressure decrease and hold duration. What should be appropriately used in reservoir simulation in this instance?

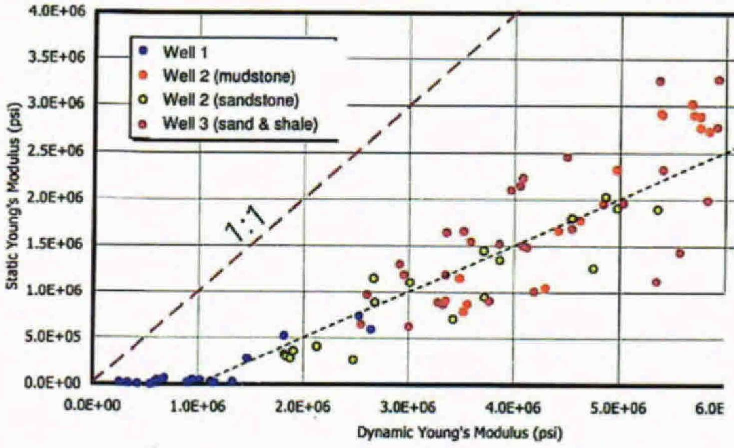
Laboratory measurement of PVC – a note of caution for HPHT fields

- Significant new interest in HPHT fields – especially in GoM deepwater and shelf. PVC and rock mechanical properties determinations pose some additional challenges:
  - perform selected tests at simulated in-situ conditions (in terms of applied stresses & pressure, or temperature)
  - may require axial stresses >20,000 psi and pore pressures up to 20,000 psi (or more)
  - temperature capability up to 300°F (or more)
  - need to determine Biot's poroelastic parameter <u>up-front</u>, in order to get in-situ effective stresses correct.
- Evaluate the impact of temperature on strength and accelerated compaction. Limited evidence shows a potentially greater influence on accelerated compaction than triaxial strength.

Wire-line estimation & correlations for pore volume compressibility

- PVC is calculated from combinations sonic velocities (compression and shear) and density, via calculation of Young's modulus, E; Poisson's ratio, ν; and porosity.
- Compressional velocity will be influenced by the saturating fluid (oil, gas, water) and needs to be corrected to the appropriate "dry frame" value.
- Need to make dynamic-to-static corrections:
  - influences moduli, as well as Biot's poroelastic constant.
- Predicts only elastic compressibility. Methods to predict onset of pore collapse (accelerated compaction) from wire-line log data are not considered trustworthy at this point in time, though more research could be done.

Importance of dynamic-to-static correlations when using wire-line data



Dynamic moduli are always greater than the equivalent static moduli.

Biot's poroelastic parameter, α, (= 1 – K_b/K_g) is similarly affected from dynamic estimates of bulk modulus. (e.g. dynamic α of 0.8 is equivalent to a static α of 0.96.)

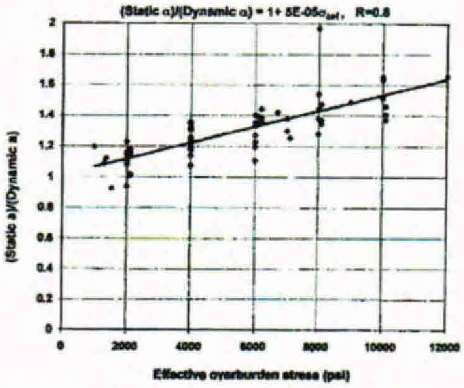
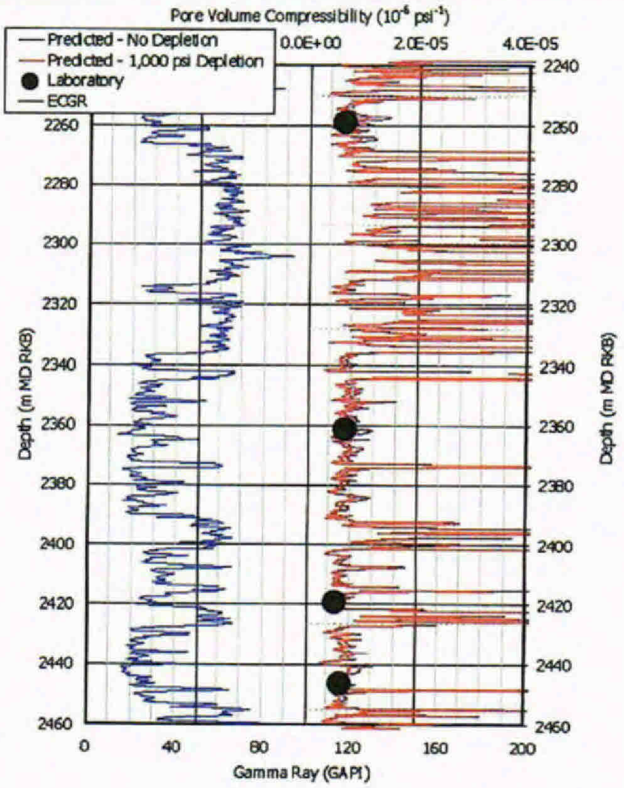


Fig. 4—Comparison between dynamic and static Biot constant as a function of effective overburden stress.

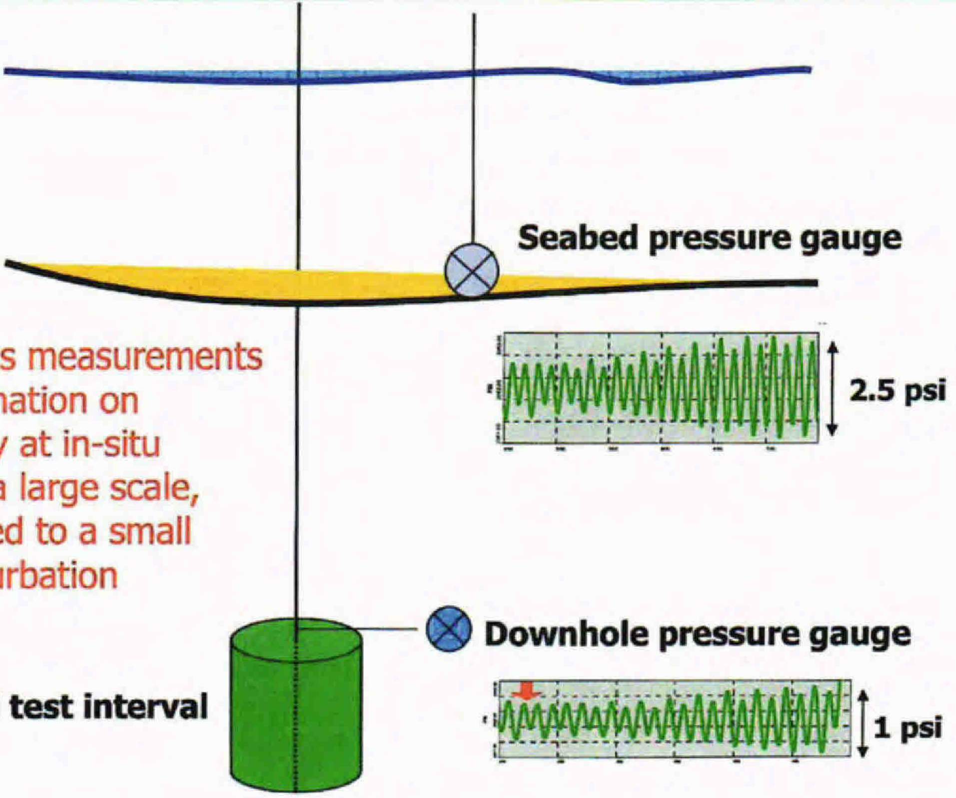
Klimentos et al, SPE Reservoir Evaluation & Engineering, February 1998

Pore volume compressibility from wire-line data

- Used judiciously, wire-line correlations do provide a means of extrapolating PVC values outside of cored intervals, and to provide a means of up-scaling to reservoir simulations.
- Onset of accelerated compaction is still uncertain.



Measurement of Earth Tides Stresses



The earth tides measurements capture information on compressibility at in-situ conditions at a large scale, when subjected to a small pressure perturbation

Seabed pressure gauge

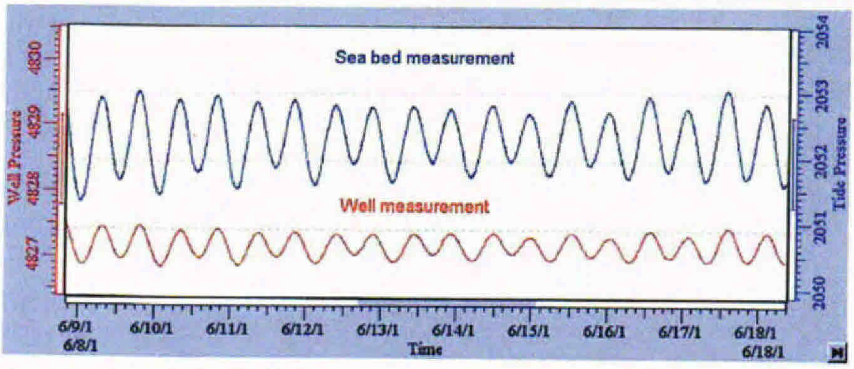
2.5 psi

Downhole pressure gauge

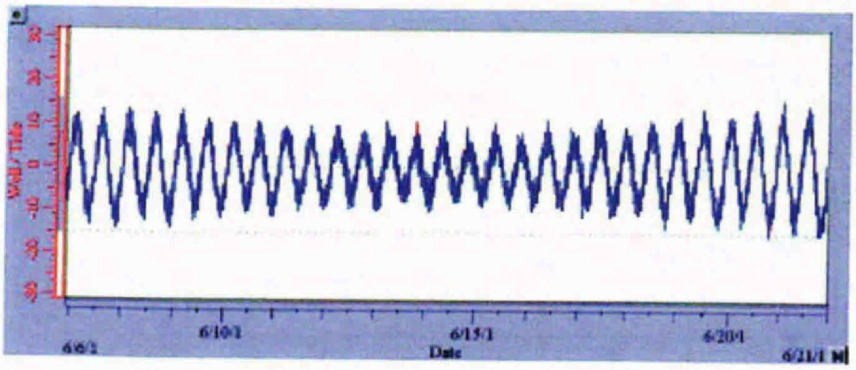
1 psi

Perforated test interval

Transmission efficiency



Transmission efficiency, T, is the scalar factor applied to the seabed data to match the downhole data.



The downhole gauge and the sea bed data multiplied by 0.347 are shown to overlay each other.

Measurement of Compressibility from Reservoir Tides

The net tidal pressure change recorded by a downhole gauge depends on the relative values of rock pore compressibility and the fluid compressibility.

Transmission efficiency, $T = \frac{C_p}{C_p + C_f}$

C_p = formation compressibility

C_f = fluid compressibility

Investment in a seabed gauge allows direct measurement of transmission efficiency. If C_f is known, then formation compressibility can be calculated.

If gas is present $C_f >> C_p$ and T is low (~ 0.1 or less)

Field	Transmission Efficiency (T)	Response Delay (hrs)	Sw	C_{fluid} (microsips)	C_p (microsips)
Field 1	0.35	0.0	15%	12	6
Field 2 – well 1	0.185	0.5	11%	12.4	3.6
Field 2 – well 2	0.347	0.5	60%	6.8	2.8
Field 3	0.09- 0.11(gas?)	0.0 – 1.0	13%	12.0	15 – gas?
Field 4	0.20	0.5	11%	12.4	3
Field 5	0.42	0.5	30%	10	7

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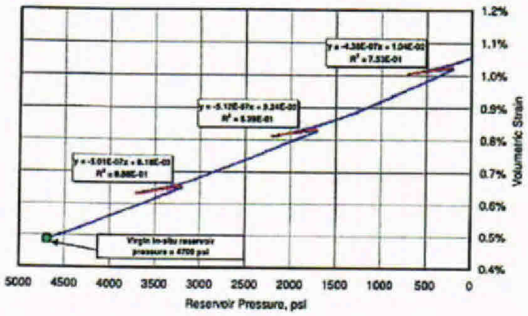
Scaling from laboratory to the field – typical loading rates & magnitudes

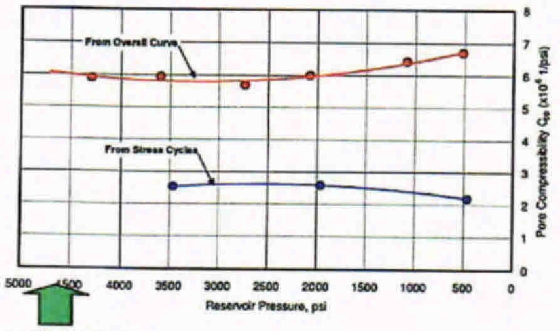
- In the laboratory, a 1000 psi pressure change is imposed over 10,000 seconds, and maybe over 31,536,000 seconds (1 year) in the field – ca. 3000 times slower.
- Compressibility acting over reservoir depletion time-scales will include creep and other "slow deformation" effects.
- Earth-tides impose ca. 0.5 psi pressure change over a period of a few hours.
- What magnitude of perturbation is imposed by well testing and production?
- Wire-line logging perturbations imposes a small pressure change at extremely high frequency. Seismic velocity has a lower frequency, but a similar stress change.

When to use what compressibility?

Reservoir Pressure versus Volumetric Strain



Reservoir Pressure versus PVC (Cpp)
(Calculated from volumetric strain (bulk volume) measurements)



Reservoir Pressure

Assumption of uniaxial compressibility

Plastic vs elastic deformation

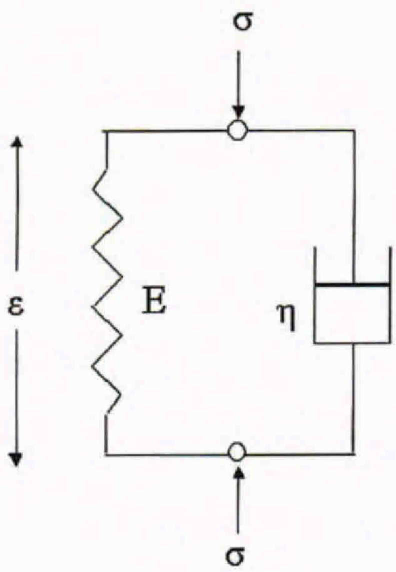
Implications for well test analysis
Radius of investigation
Aquifer response
Material balance calculations

6 x 10^{-6} psi^{-1} (0.87 GPa^{-1}) PVC for reservoir depletion

2.5 x 10^{-5} psi^{-1} (0.36 GPa^{-1}) C_f for use in PFO well test analysis (unload loops in PVC test)

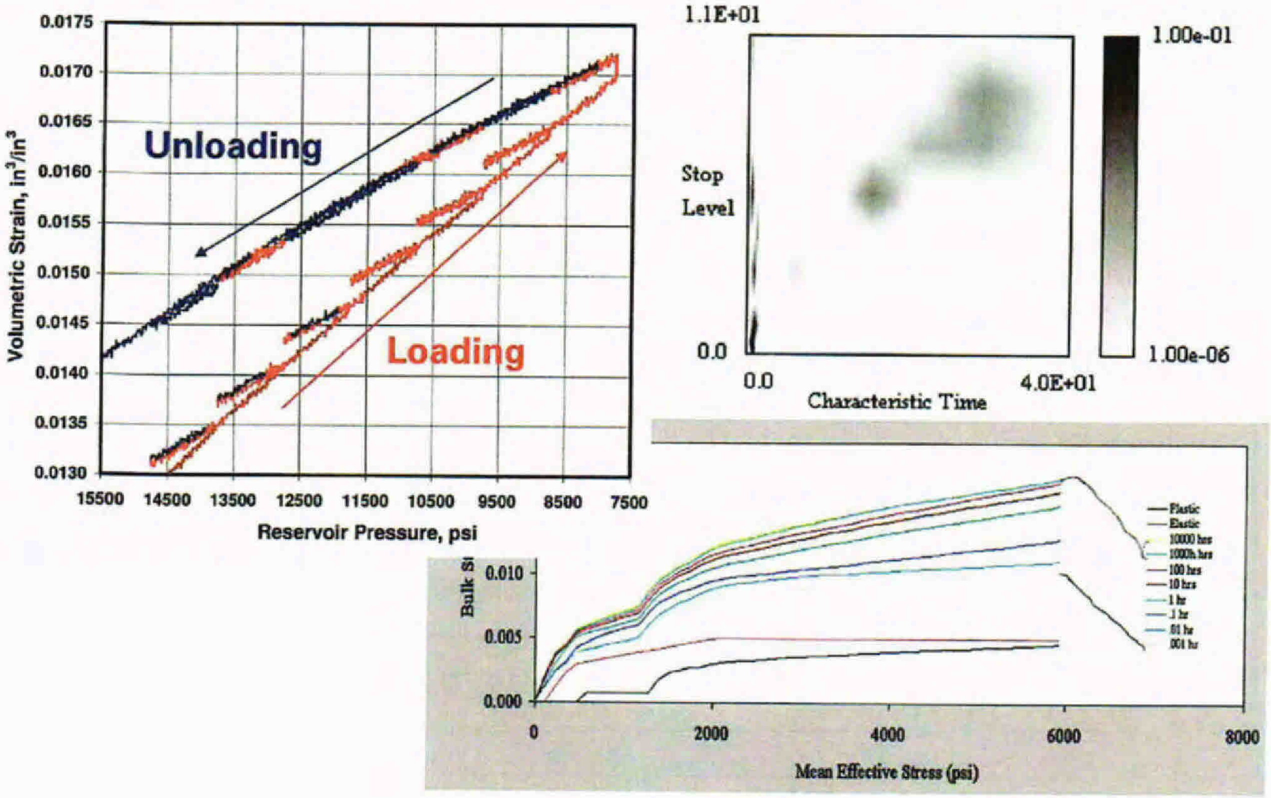
2.8 x 10^{-6} psi^{-1} (0.41 GPa^{-1}) C_f from earth tides

Theoretical model for 'perturbation dependent' compressibility



- 'stopped Kelvin-Voight' model, enhanced to include rate-independent plastic straining.
  - Instantaneous elastic straining (also includes some viscoelastic straining occurring faster than the shortest time interval assumed in the model)
  - Instantaneous plastic straining obeying a Critical-State Soil Mechanics model.
  - 'viscoelastic' response included by a continuous distribution of superimposed Kelvin Voigt units where individual strains are 'stopped' at a specific value. A physical interpretation of a stop might be the closure of a set of active cracks.

Steps followed in analysis



Example application – North Sea weakly-cemented sandstone

Application	Reservoir Stress/ Pressure Change	Effective compressibility ($x\ 10^{-6}\ psi^{-1}$ / GPa^{-1})	
		Pore	Total
Seismic	1 Pa ($1.5x10^{-4}$ psi) @ 10Hz	**3** / 0.435	**8** / 1.16
Tidal	1 psi over 12.5 hrs	**3.5** / 0.508	**8.5** / 1.23
Pressure Fall Off Test (after injection period)	2-days pressure fall-off after injecting at 5000 bbl/d for 2 days	**3.7** / 0.537	**8.7** / 1.26
Pressure Build Up (after production period)	2-days pressure build-up after producing at 5000 bbl/d for 2 days	**14.7** / 2.13	**19.7** / 2.86
Reservoir Depletion	Reservoir pressure reduction at 1000 psi/yr.	**36** / 5.22	**41** / 5.95
Reservoir Repressurisation	Reservoir pressure increase at 1000 psi/yr.	**19** / 2.75	**24** / 3.48

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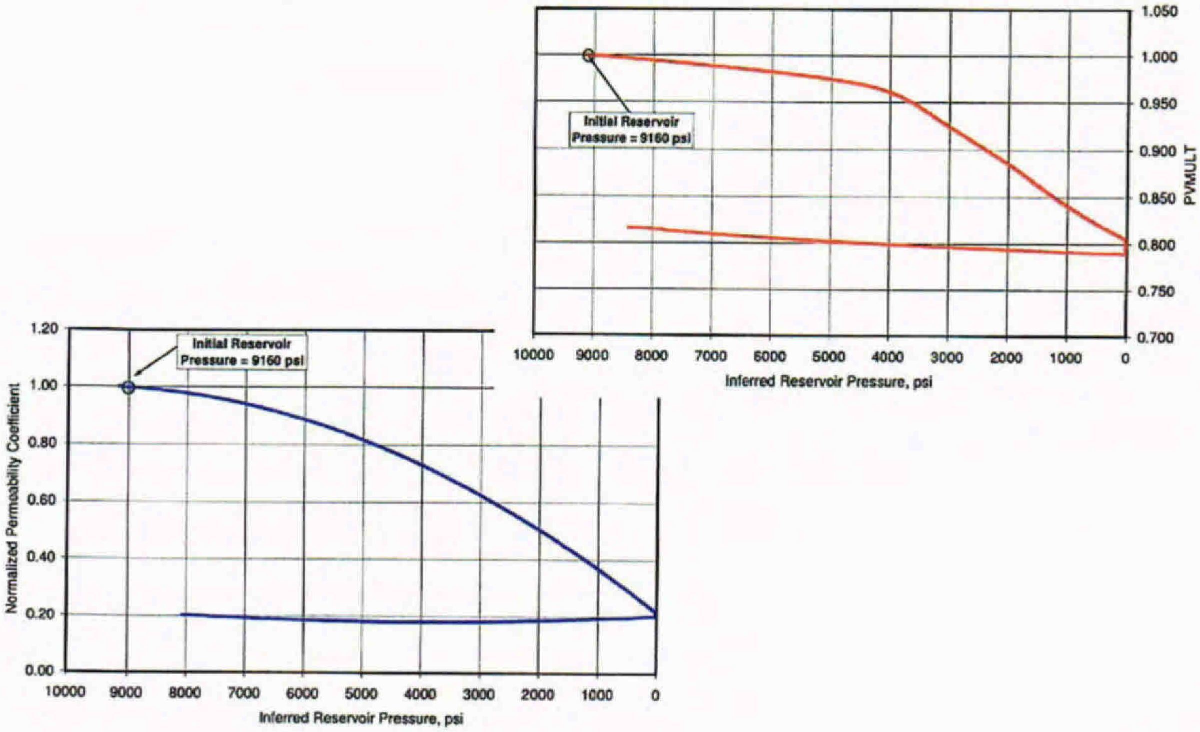
Implementation in reservoir simulation

- Constant value of compressibility.

- Pore volume compressibility multiplier: $PVMULT = \frac{V_p(P_p)}{V_{pi}(P_{pi})}$
  - V_p = pore volume at pressure P_p
  - V_{pi} = initial pore volume at initial pore pressure P_{pi}.
  - PVMULT = 1 at initial pore pressure conditions.

- Use caution when using one PVC look-up table in fields with large relief (i.e. significant pressure change initially within one formation layer). You may end up with an incorrect initial pore volume and oil-in-place.

PVMULT & Permeability for a sample undergoing accelerated compaction



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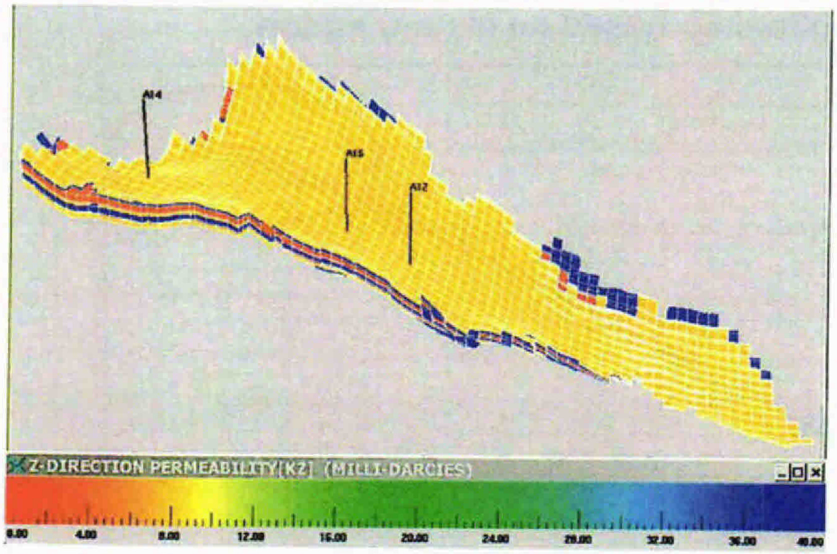
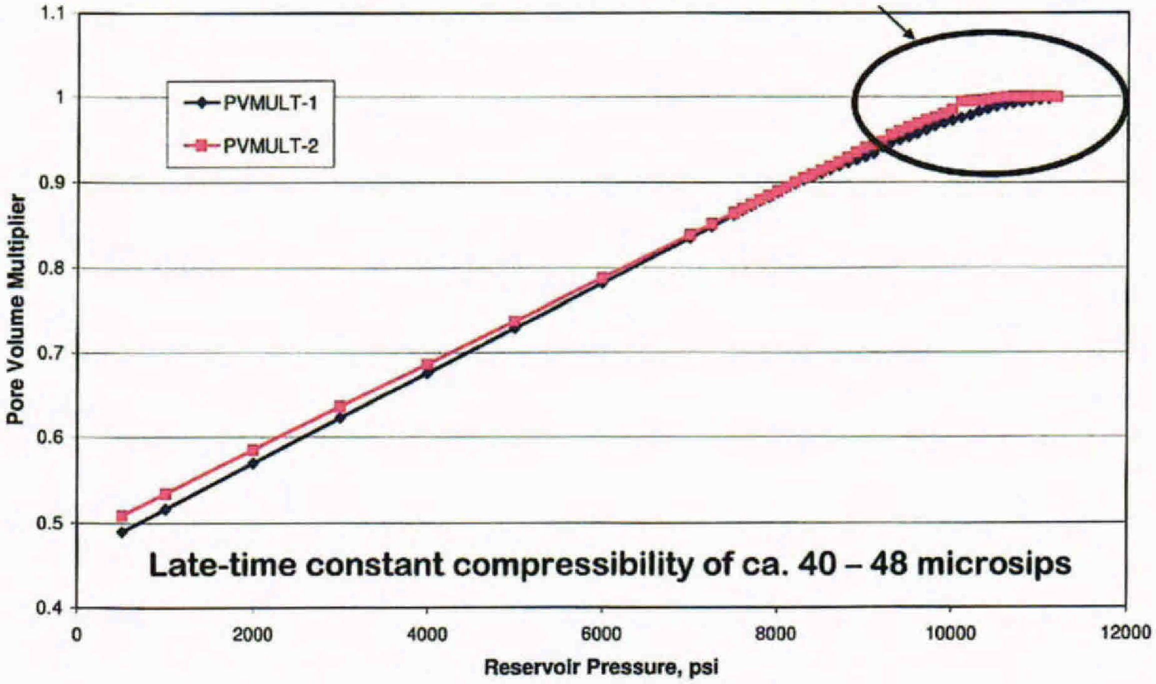
Example simulation results & other issues



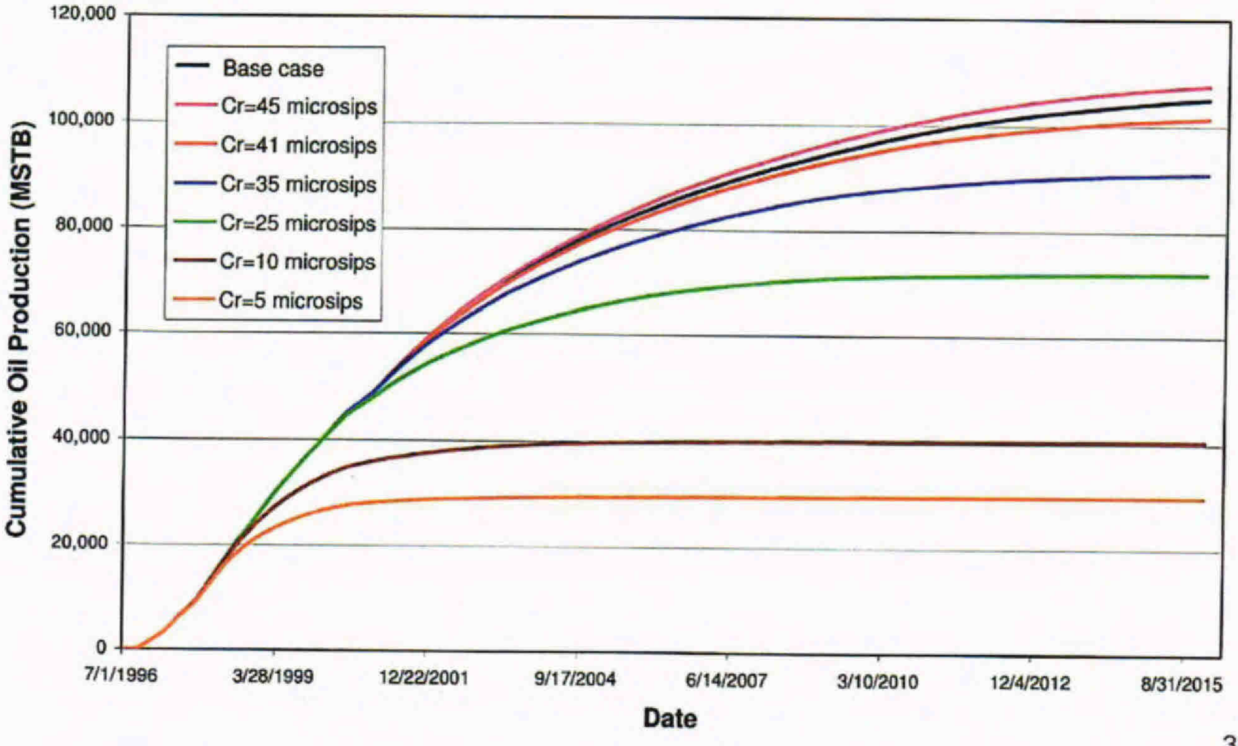
- 9 layers.
- First three layers – upper "L" sand.
- Bottom 6 layers - "L2" sand.
- 3 wells (A12, A14 and A15)
- 2 compaction tables (L Sand and L2 Sand) based on lab data and adjusted by history-matching.

PVMULT values


Early-time stiffening, based on history match

Late-time constant compressibility of ca. 40 – 48 microsips

Impact of compressibility on reserves recovery



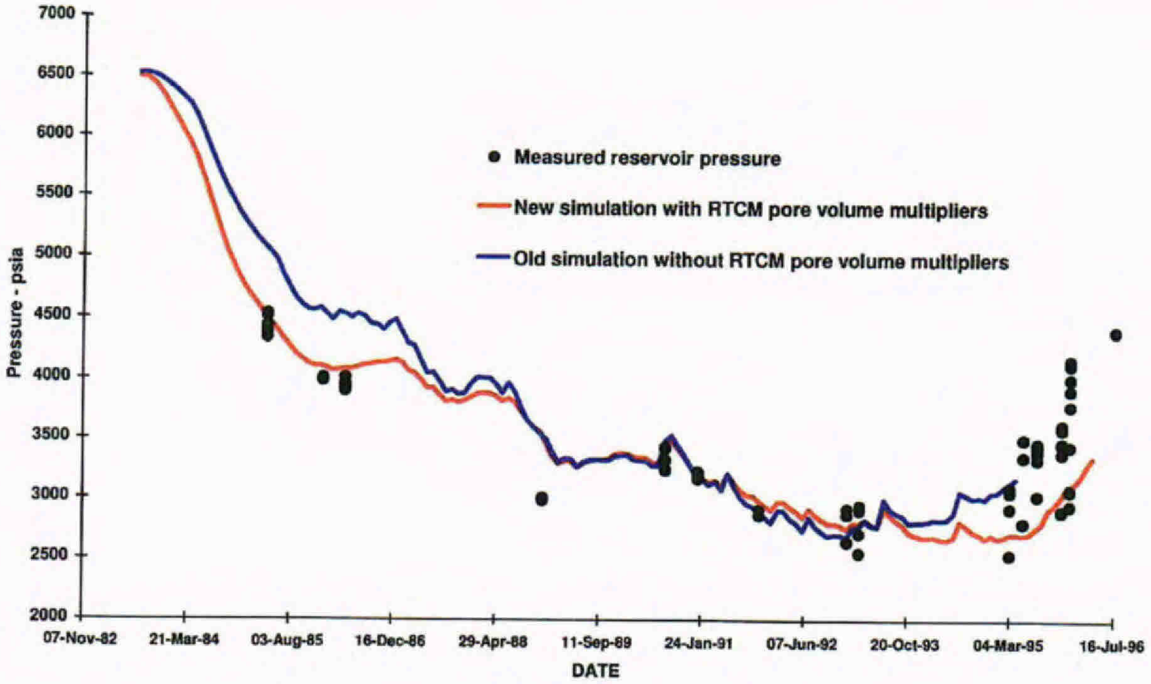
Impact of early-time stiffening

Field	Reservoir	Early Performance PVC (μsips)	Length of Early Performance Time (years)	Pressure Depletion (psi)	Later Performance PVC (μsips)
A	1	9	>0.5	700	?
B	1	<2	1	1000	not known
C	1	18	n/a	1000	80
D	1	10	2 – 4 years	2000	40
D	2	2	2 – 4 years	1500	25
E	1	8	n/a	4000	12
E	2	3	n/a	4000	12
F	1	2	n/a	1000	22
G	1	3	n/a	1500	25
Average DW		7	?	2000	31

Poll of responses from deepwater reservoir engineers – courtesy Gerald Simms.

- Early-time stiffening is commonly – though not always – seen.
- Can be replicated via a "rate-type compaction" model response.
- Could also be an aquifer mobilization issue – e.g. tar-mat at the oil-water contact, mobility or surface tension effects – requiring a certain pressure depletion before the aquifer support kicks in.

North Sea Magnus Field example



"Magnus Field Rock Compressibility During Reservoir Pressure Decline and Recharge : Application of the Rate-Type Compaction Model", BP Research Report POB/040/96, S.M Willson, September 1996.

Other reservoir simulation features

- Implementation depends upon the simulator used:
- Turbidite recharge options:
  - "The turbidite reservoir option models the sand-shale fluid (water) exchange within any simulation grid-block that consists of multiple sand and shale sub-layers using an analytic, linear aquifer model."
  - Can be used to model low-level water production in sands remote from the aquifer.
- Creep options:
  - "The time-dependent compressibility (creep) option includes a time-delayed compaction due to creep in addition to the standard instantaneous compaction represented by rock compressibility."
  - Can be used to model reservoir pressure build-up following extended shut-in conditions.

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Closing remarks ...

- Newer fields (especially sub-salt) now have sufficient production data to test simulation model inputs.
- Smaller supra-salt discoveries are increasingly relying on compaction-drive to validate project economics (e.g. one or two well developments).
- New HPHT exploration areas are challenging some existing rock mechanics laboratory capabilities. "Second-order effects" now warrant "first-order" consideration.

∴ Pore volume compressibility remains an important parameter in GoM deepwater reservoir simulation, but one where some uncertainty in understanding still exists?