Simulation results
LYBCO2 DH4 Minifrac and
5-Day Injection Test

or

The final nail in the coffin…

Øystein Pettersen

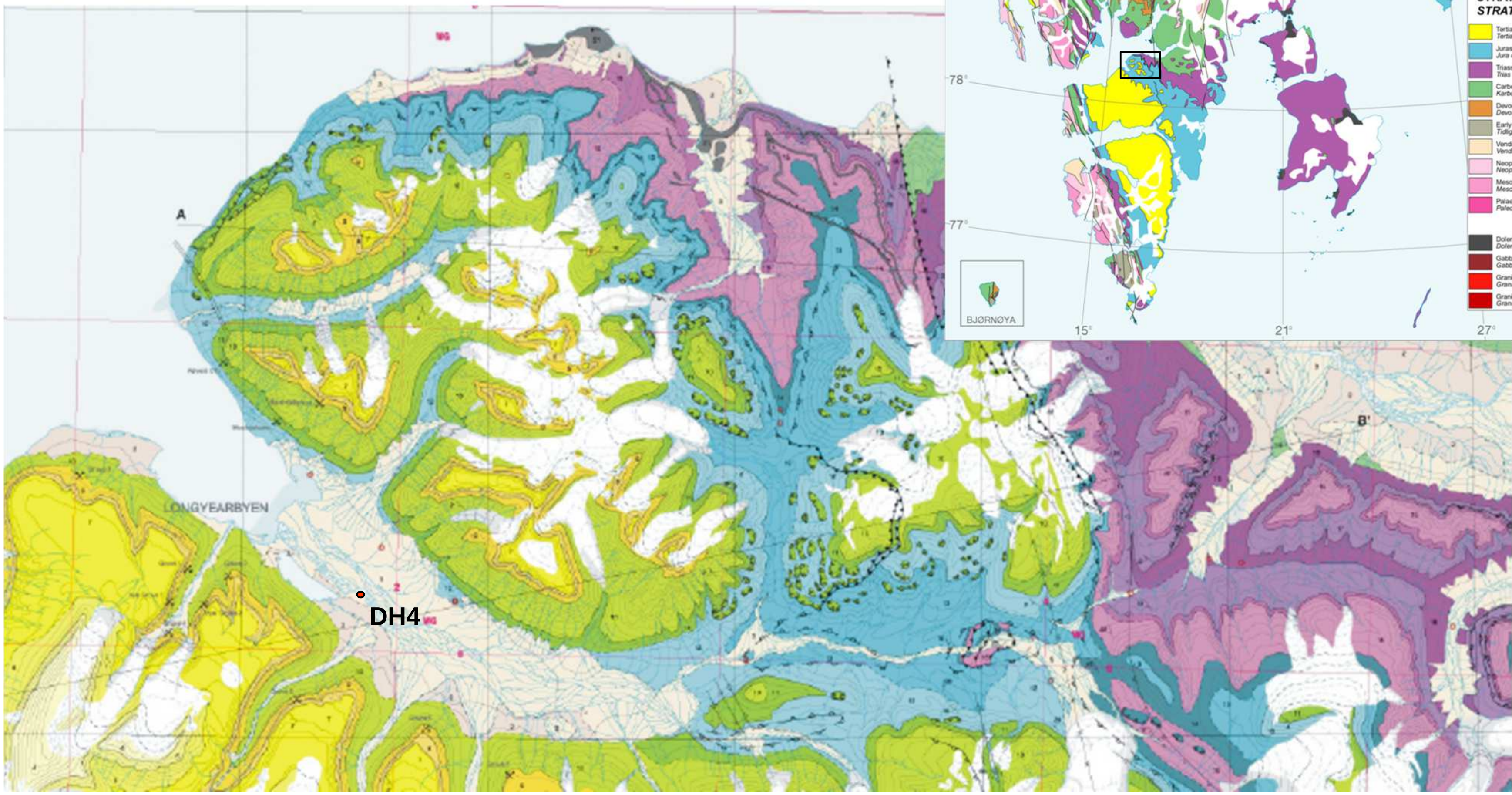
March 2013

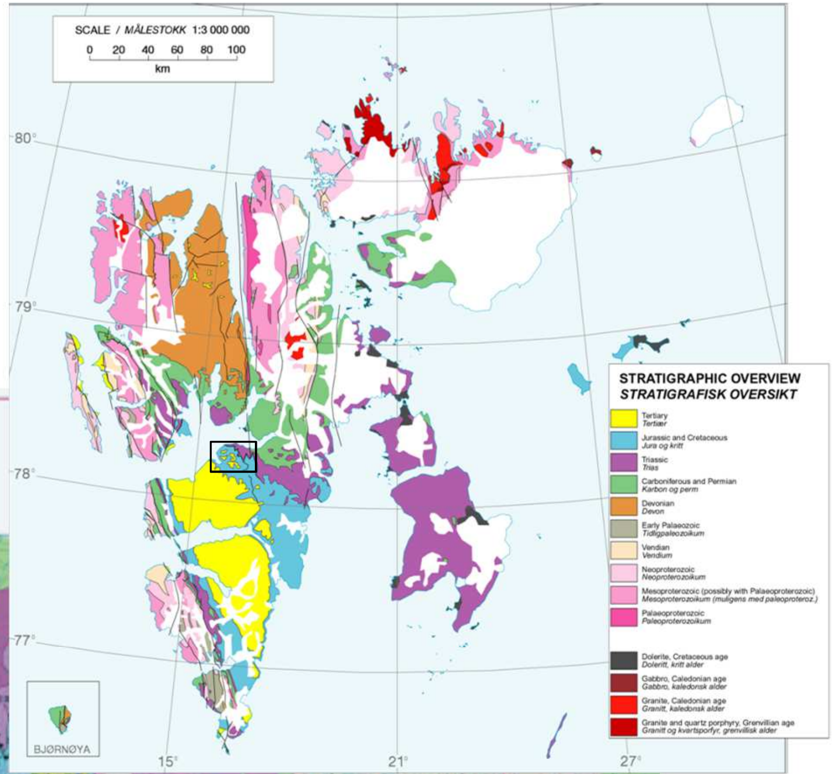
Longyearbyen seen from Isfjorden

Longyearbyen downtown

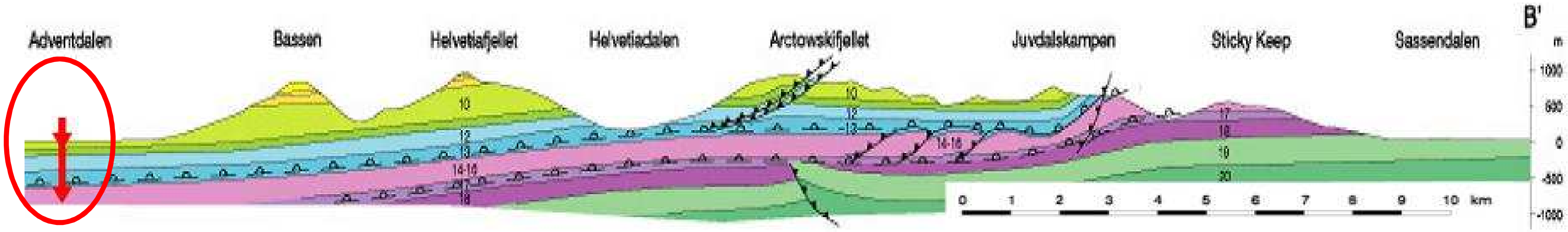
University center at Svalbard, UNIS

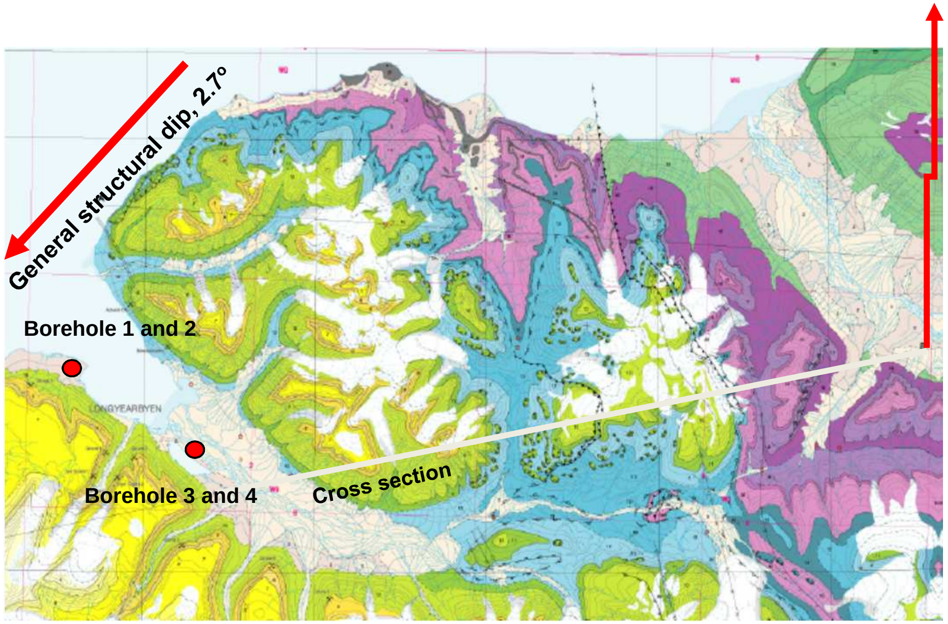
Location

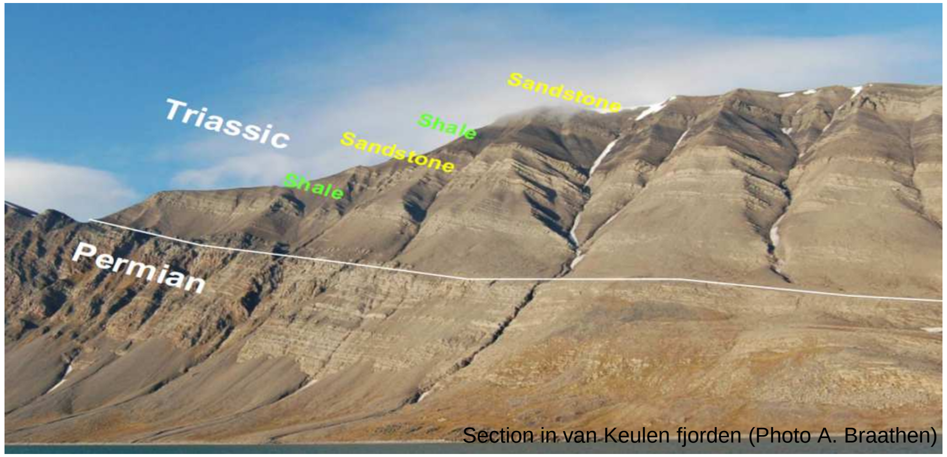

A
B'
LONGYEARBYEN
DH4


SCALE / MÅLESTOKK 1:3 000 000
0 20 40 60 80 100
km
80°
79°
78°
77°
15°
21°
27°
BJØRNØYA
STRATIGRAPHIC OVERVIEW
STRATIGRAFISK OVERSIKT
Tertiary
Tertiær
Jurassic and Cretaceous
Jura og kritt
Triassic
Trias
Carboniferous and Permian
Karbon og perm
Devonian
Devon
Early Palaeozoic
Tidligpaleozoikum
Vendian
Vendium
Neoproterozoic
Neoproterozoikum
Mesoproterozoic (possibly with Palaeoproterozoic)
Mesoproterozoikum (muligens med paleoproteroz.)
Palaeoproterozoic
Paleoproterozoikum
Dolerite, Cretaceous age
Doleritt, kritt alder
Gabbro, Caledonian age
Gabbro, kaledonsk alder
Granite, Caledonian age
Granitt, kaledonsk alder
Granite and quartz porphyry, Grenvillian age
Granitt og kvartsporfyr, grenvillisk alder

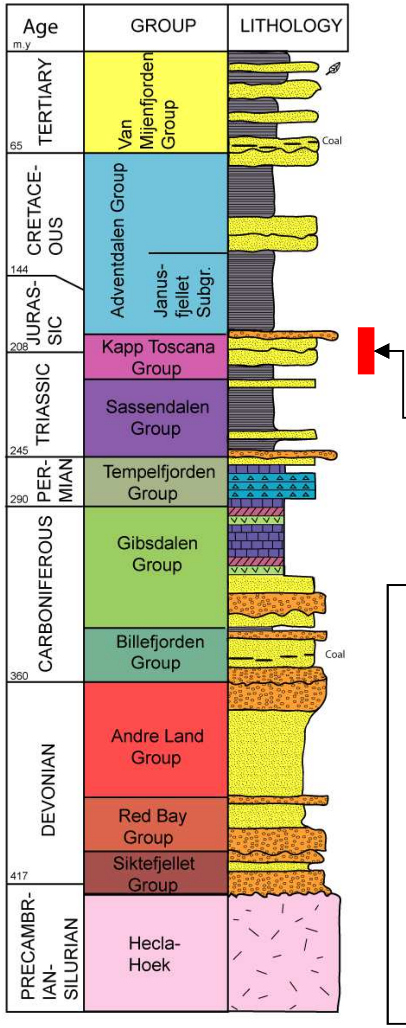
Adventdalen – top-of-storage







Section in van Keulen fjorden (Photo A. Braathen)



Target interval – shallow marine sst at ~**670-970m depth** In borehole 4 De Geer Fm. and Wilhelmøya Subgroup

- Shallow marine and sand and shale
- Regional dip towards SW
- Lower parts of stratigraphy exposed in outcrops some 15 km NE of planned injection site
- The reservoir is located between large, low angle thrust faults in Jurassic and Early Triassic section

Wellsite

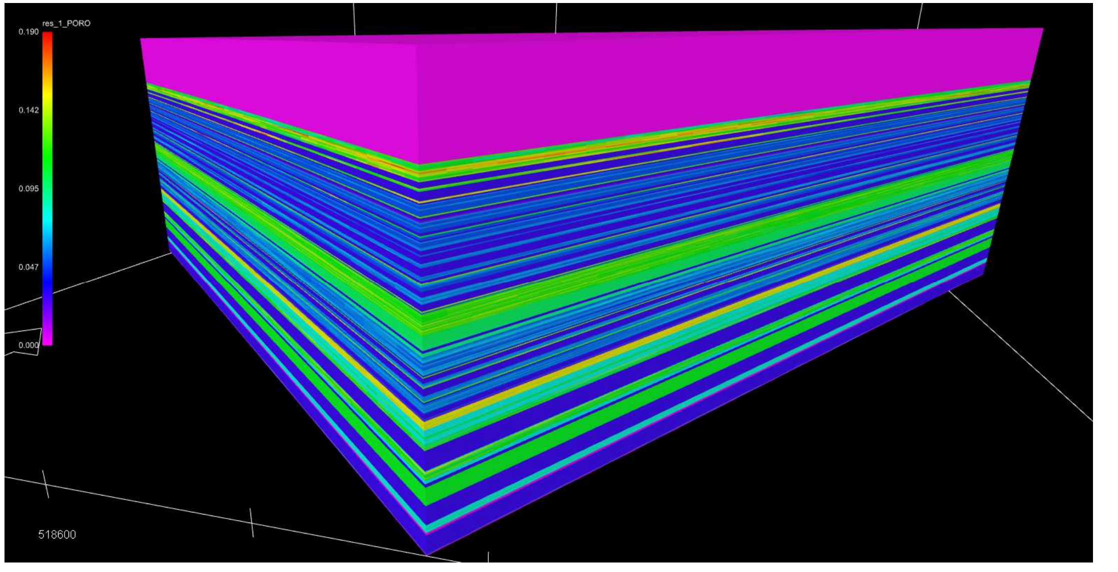
Wellsite

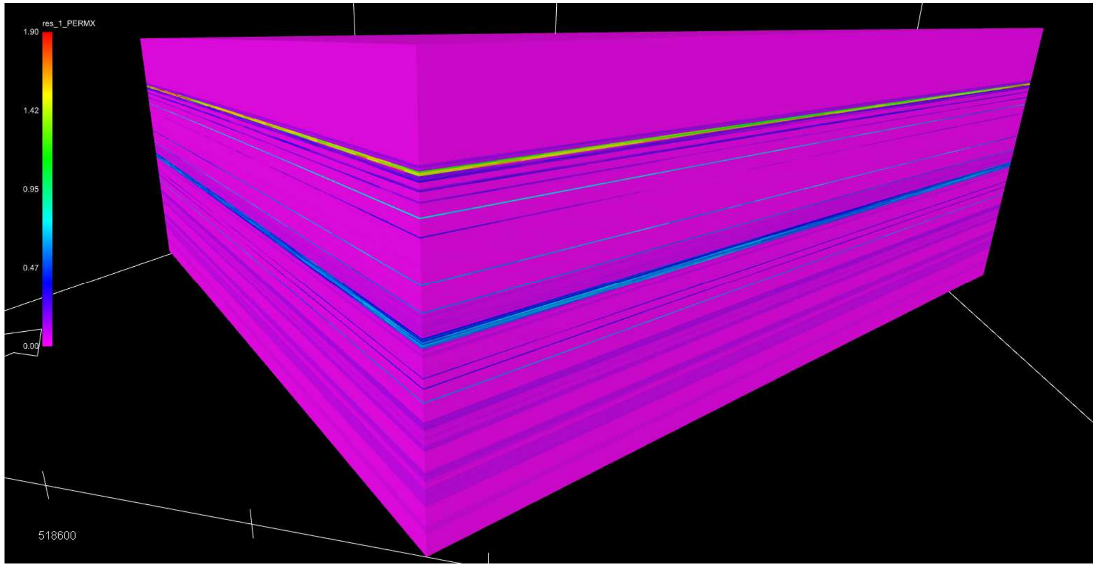

Wellsite looking towards mine


Outcrop – storage reservoir exposed

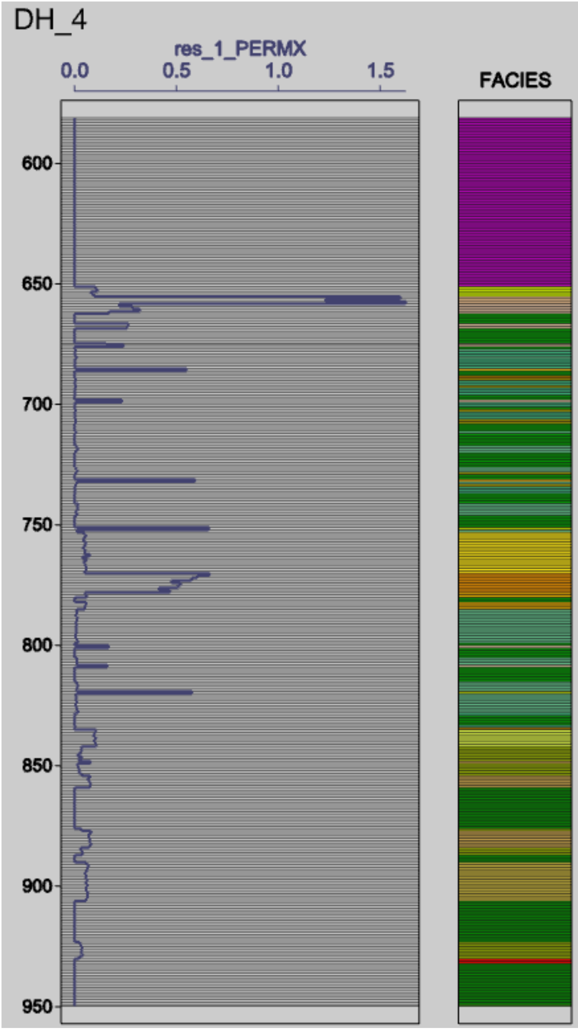
Porosity and permeability in near-well model

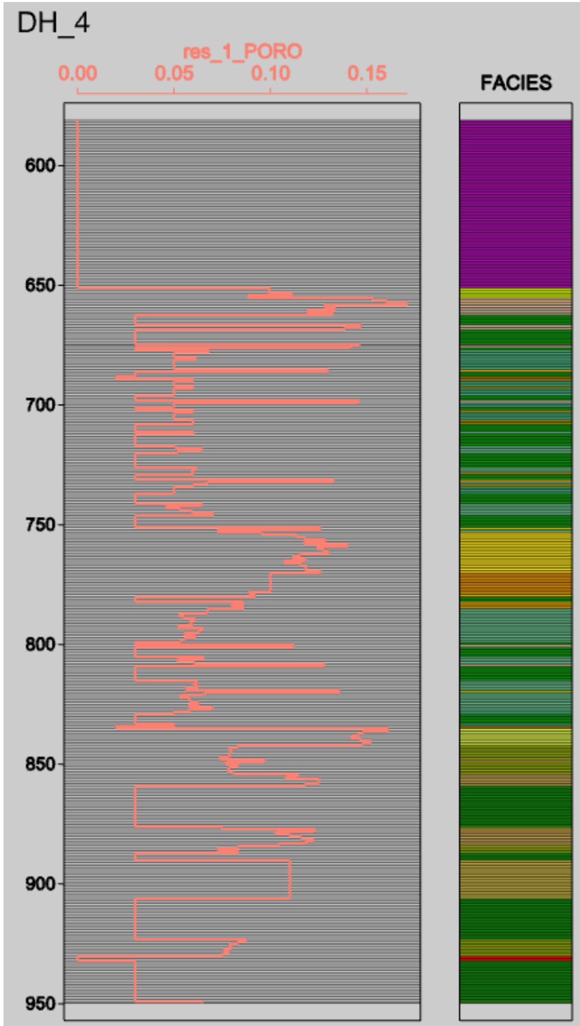
- 21 facies identified and described and included in the models
- Simple layercake model supported by observed lateral continuity of beds
- Net sandstone 25-30%
- Permeable sandstone 10-15%



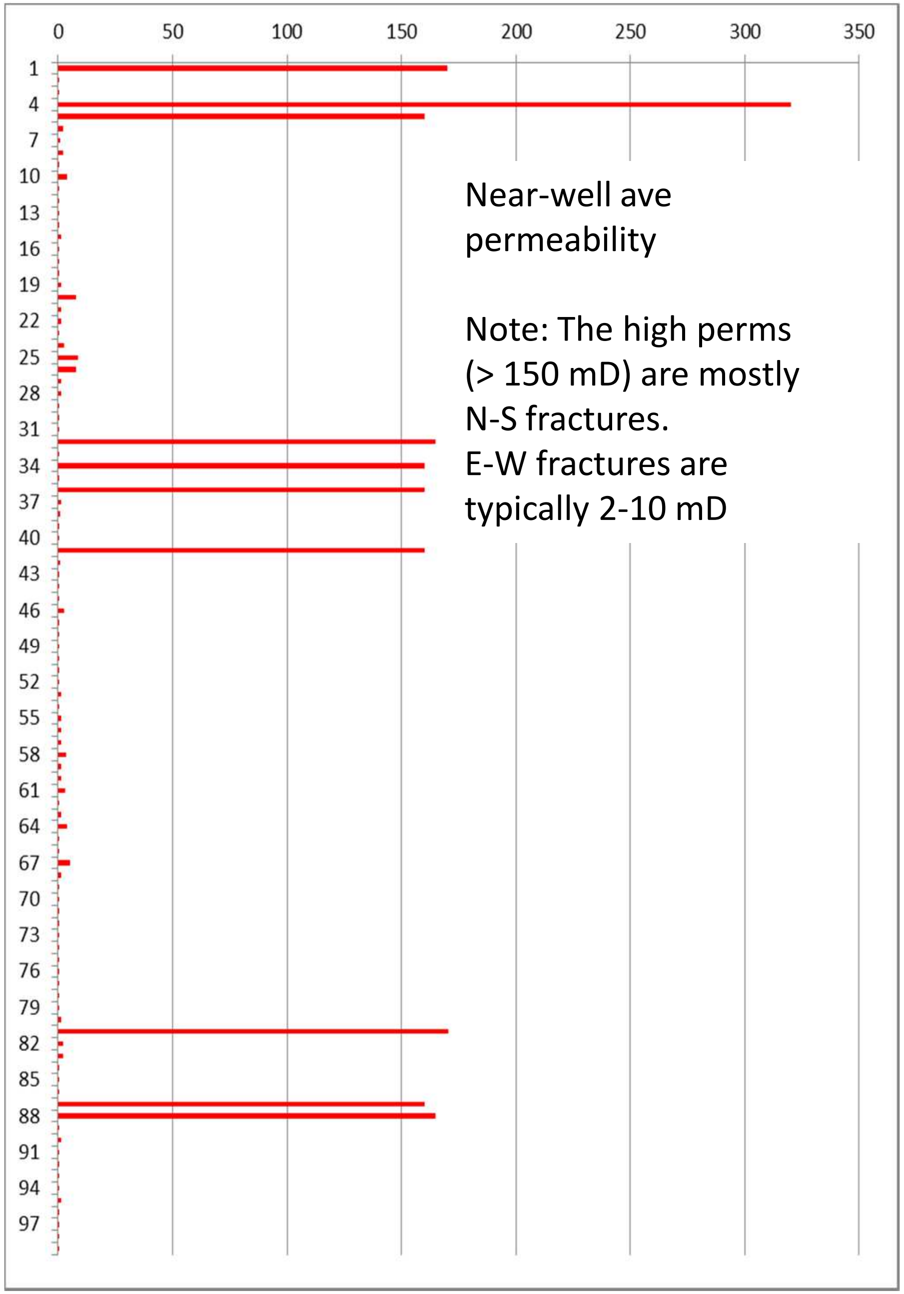


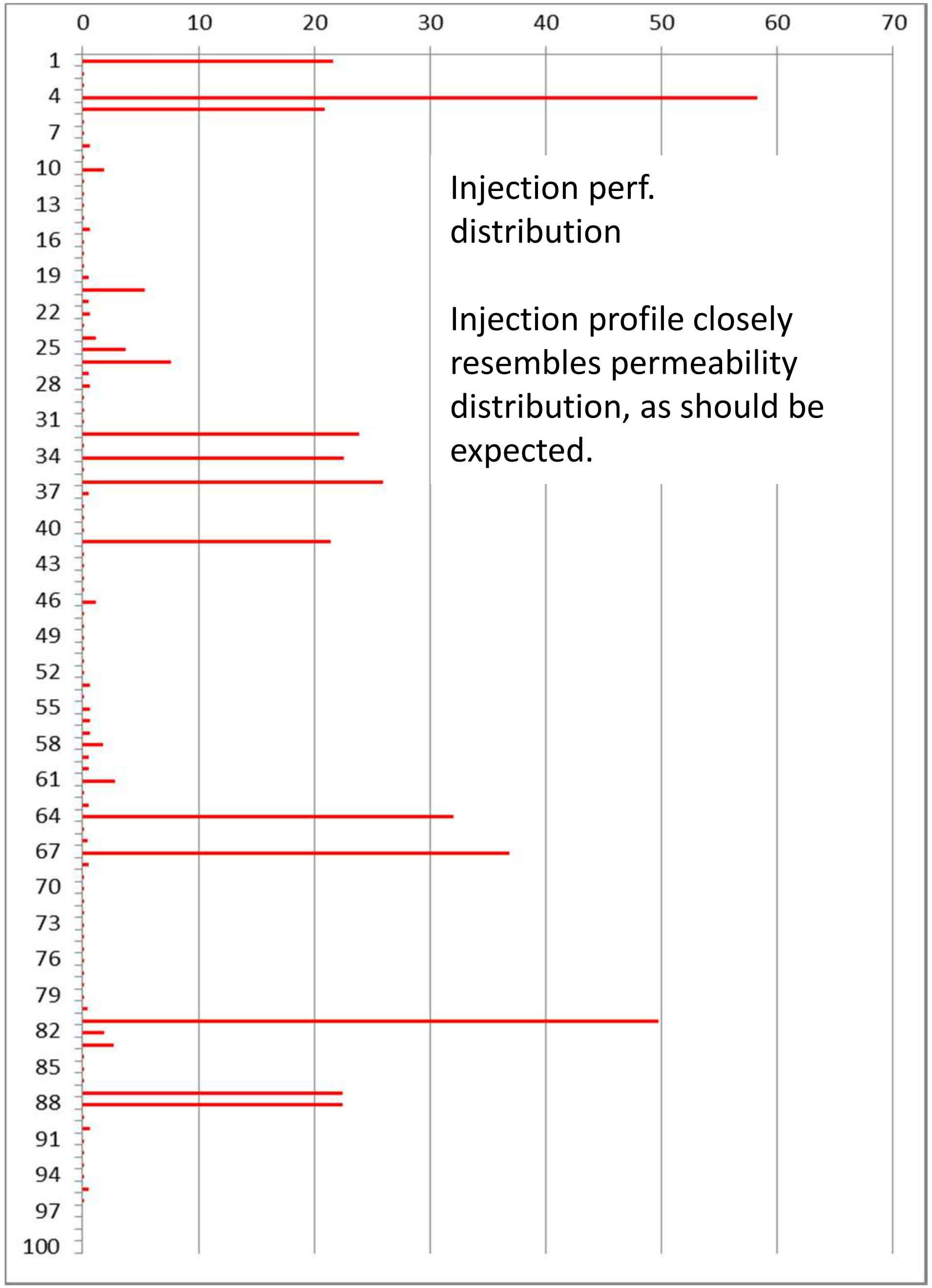
Modelled matrix permeability and porosity in DH4



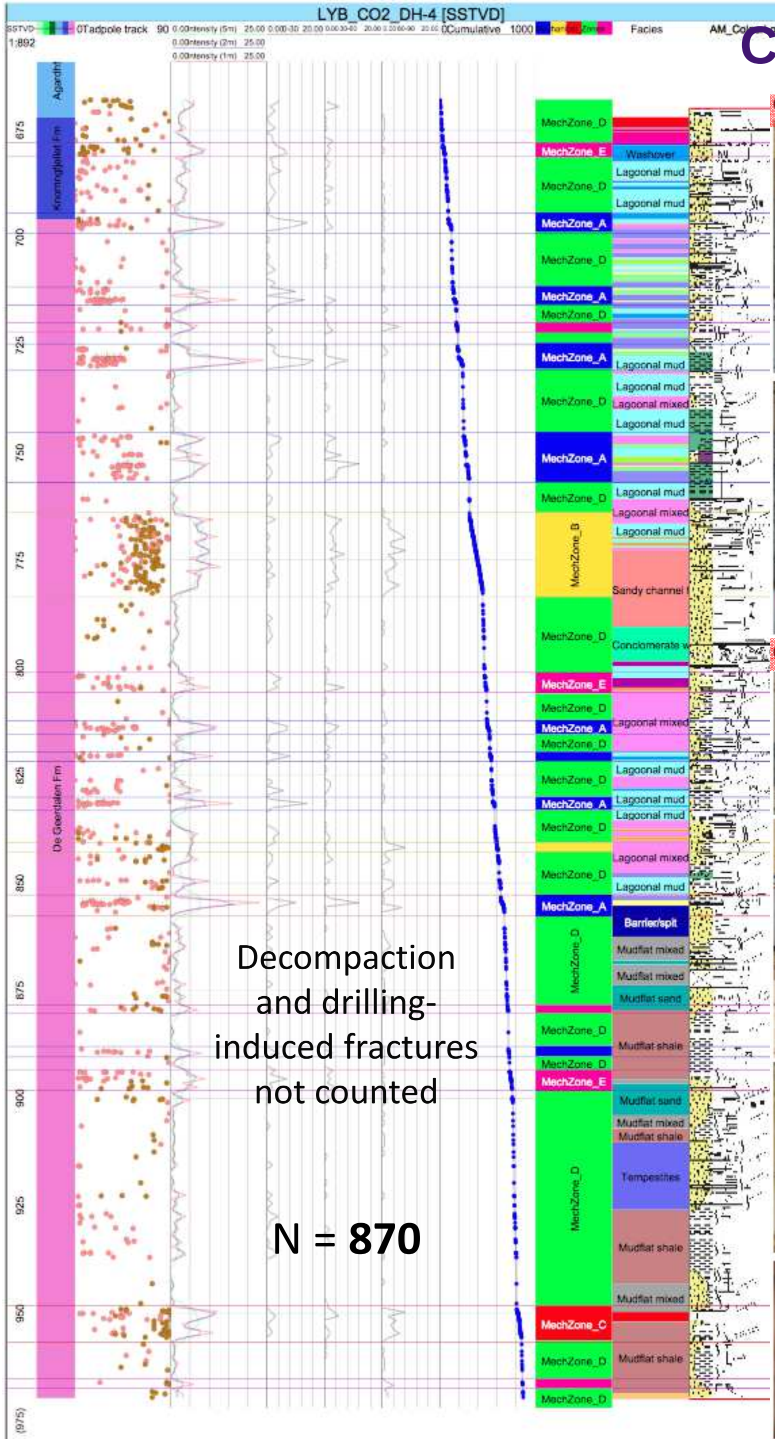


Layer Permeability and Connection flow rates in simulation model





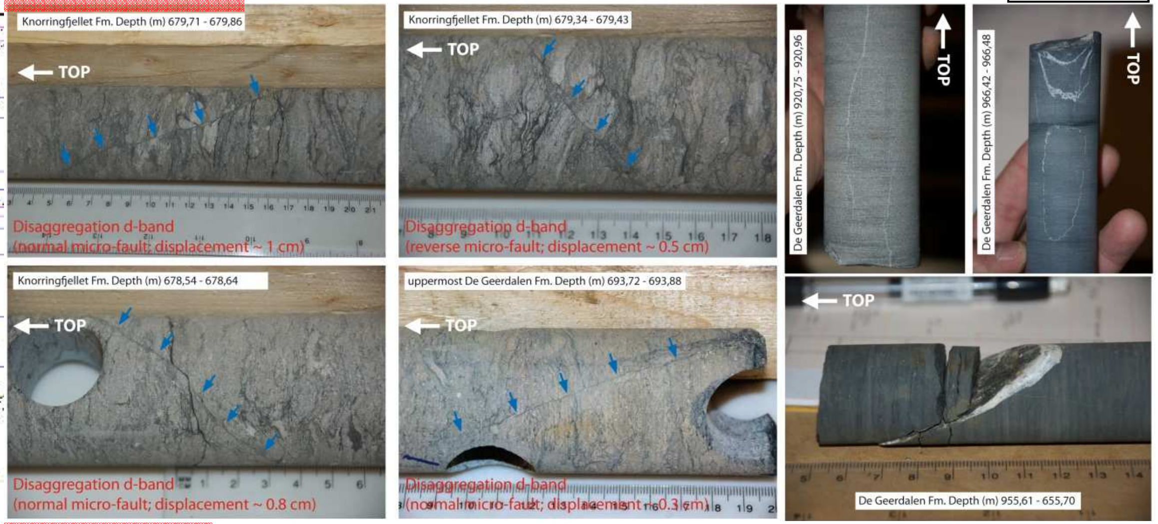
Core fracture count and characterization



Decompaction and drilling-induced fractures not counted

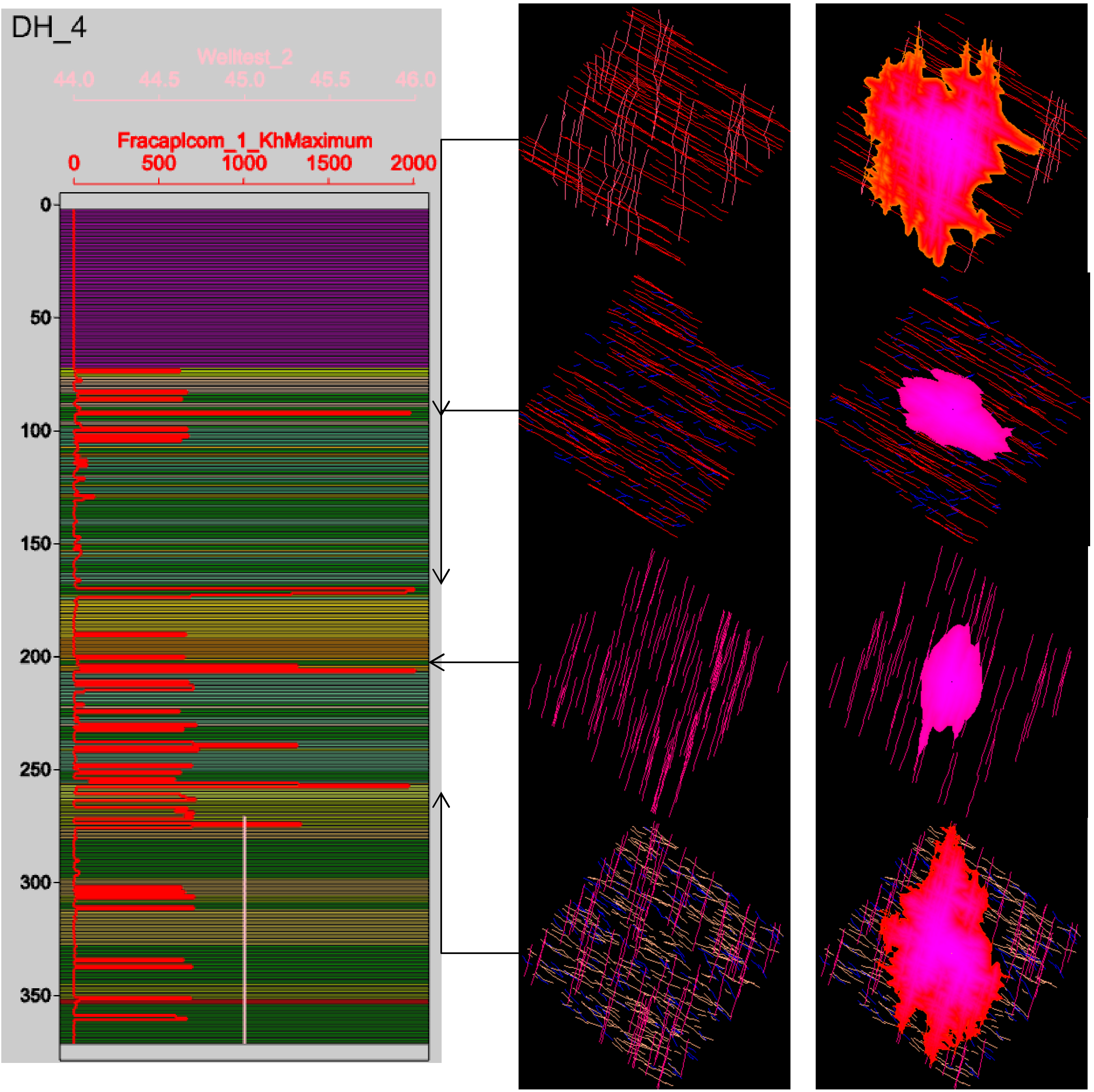
N = **870**

CLOSED FRACTURES



OPEN FRACTURES

Fracture patterns and connectivity



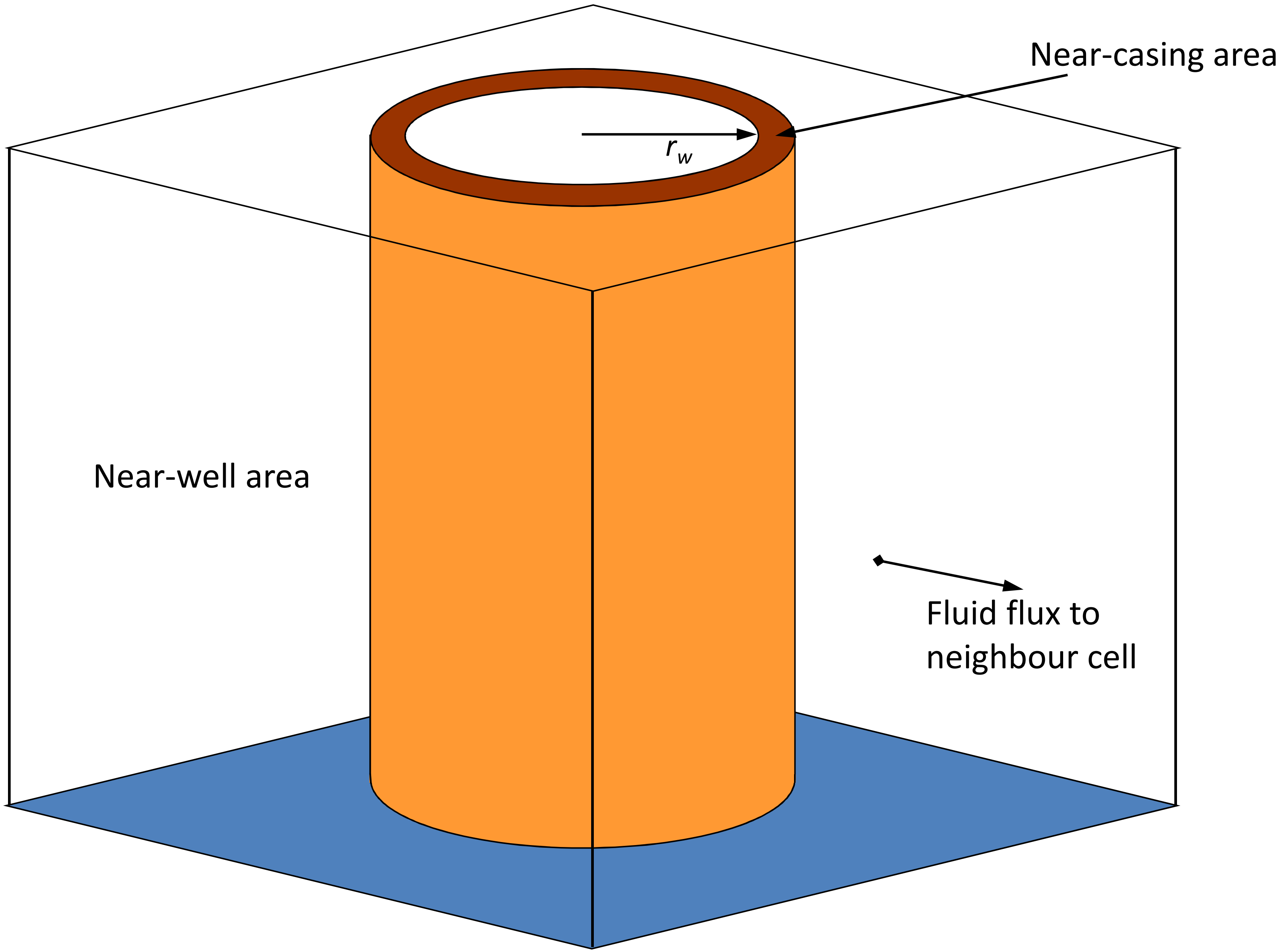

Fracs – “paper” shale
Stress orientation.

Dinosaur site – Jørn Hurum

Land-ho

Termination of Brent group (Gullfaks, Statfjord, Oseberg,….)

Well in a Simulation Grid Cell



Pressure during injection

$$q = \frac{2\pi Kh}{\mu} \frac{p_b - p_{wf}}{\log\left(\frac{r_b}{r_w}\right) + S}$$

or

$$\Delta p = \frac{\alpha q}{Kh} \log\left(\frac{r_b}{r_w}\right)$$

where

p_{wf}:	Flowing bottomhole pressure
p_b:	Average near-well pressure (Cell pressure)
q:	Flow rate
Kh:	Permeability height
α:	Proportionality constant

During injection, injected fluid

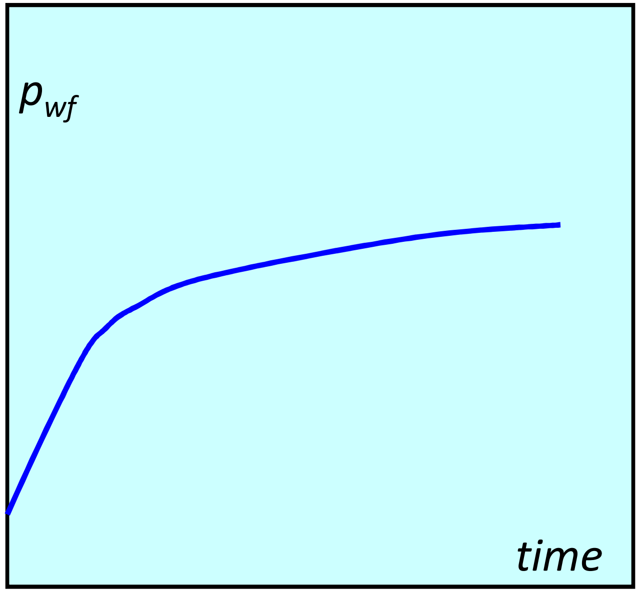
1. must overcome near-casing area (often damaged reservoir)
2. ”fills up” near-well area
3. flows into adjacent volumes (cells in simulation model)

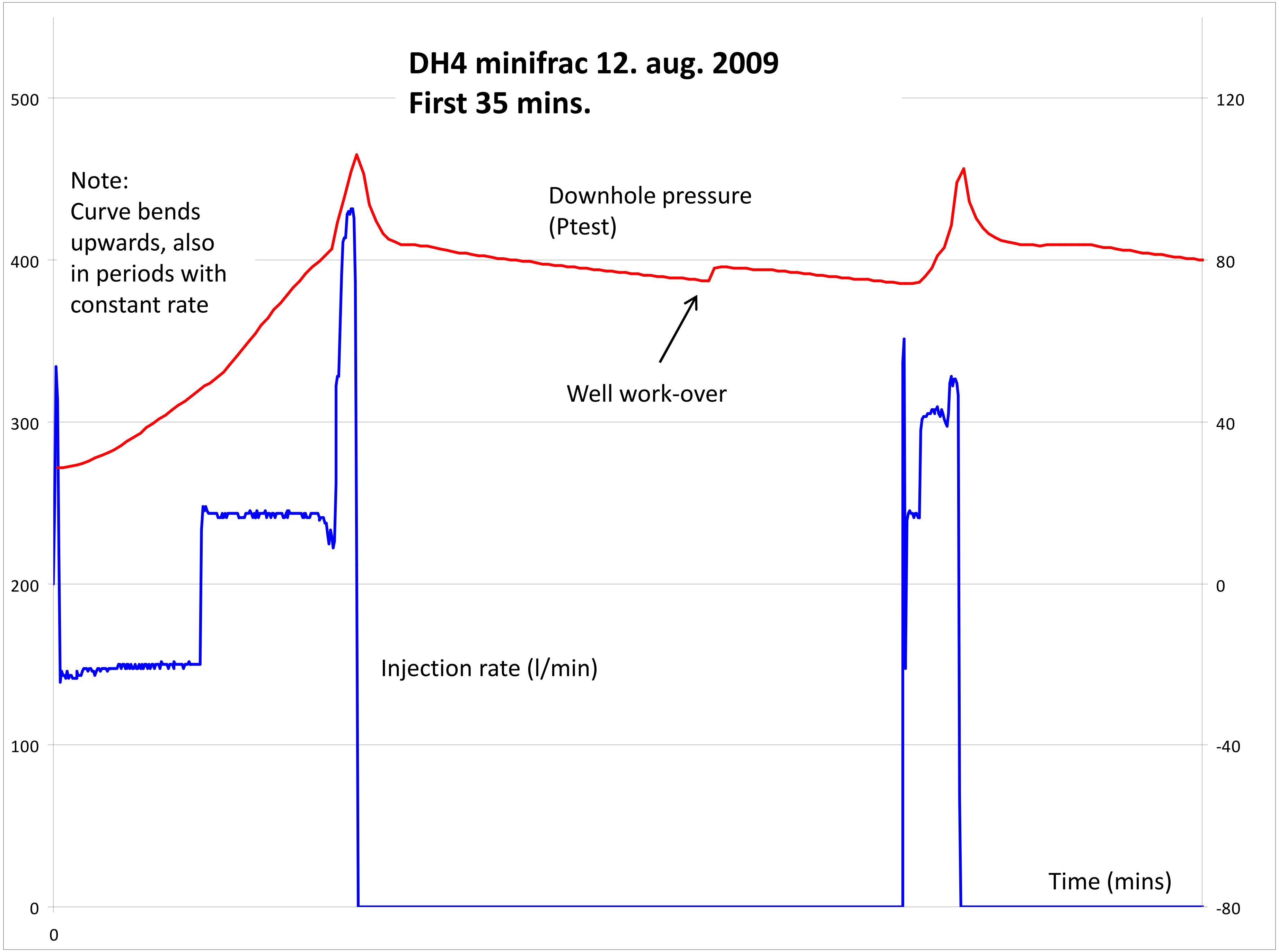
Pressure during injection

Two Extreme Cases:

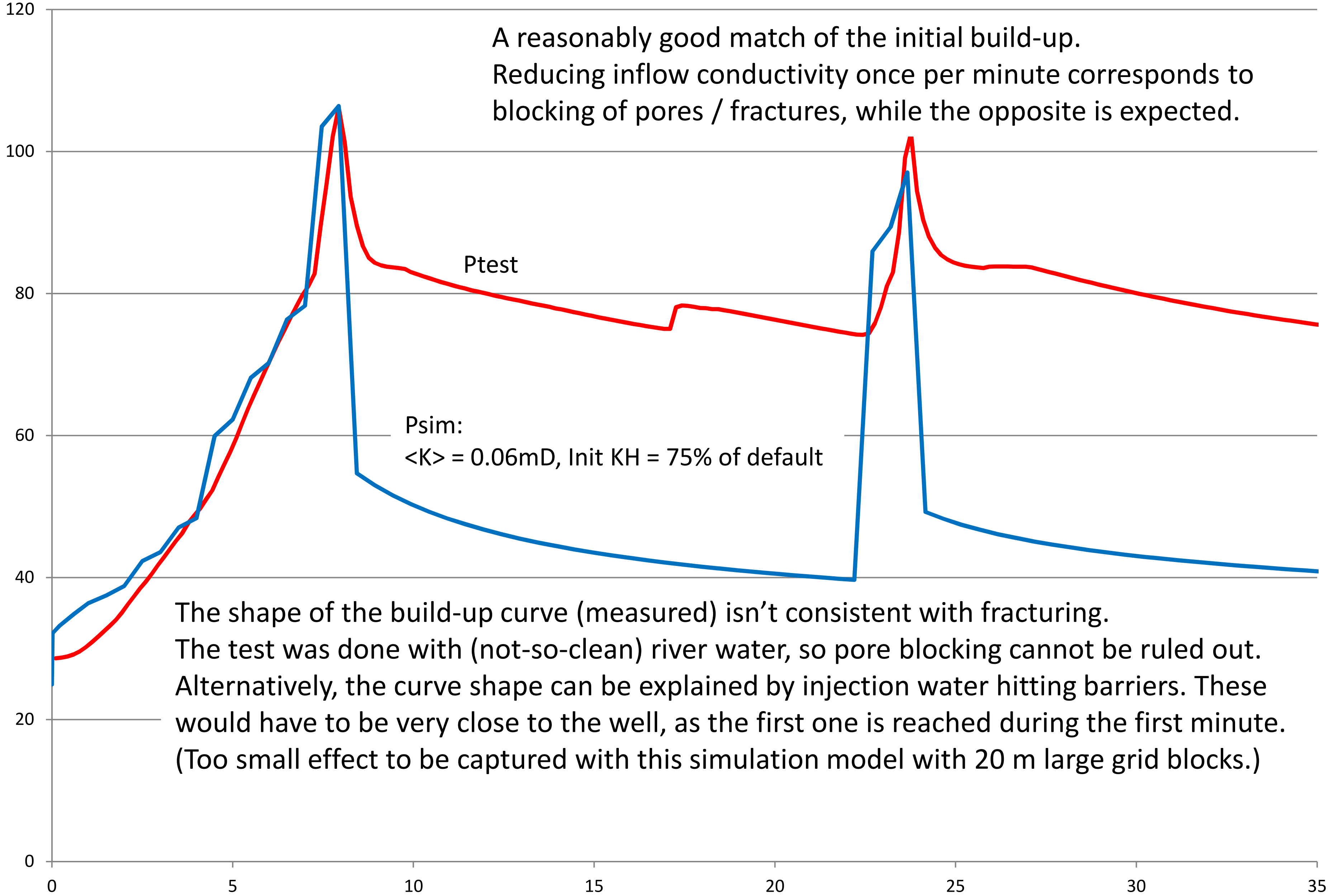
1. ”Zero conductivity” – no flow from near-well area to neighbour cells
   Bottom hole pressure and near-well pressure increase equivalently
2. ”Infinite conductivity” – injected fluid flows to neighbour areas immediately.
   Near-well pressure doesn’t change, bottom hole pressure quickly rises to value defined by Δp, and stays there

Typical behaviour:
Immediate increase in bottom hole pressure as near-well area fills up, then reduced increase as fluid flows into neighbour areas.

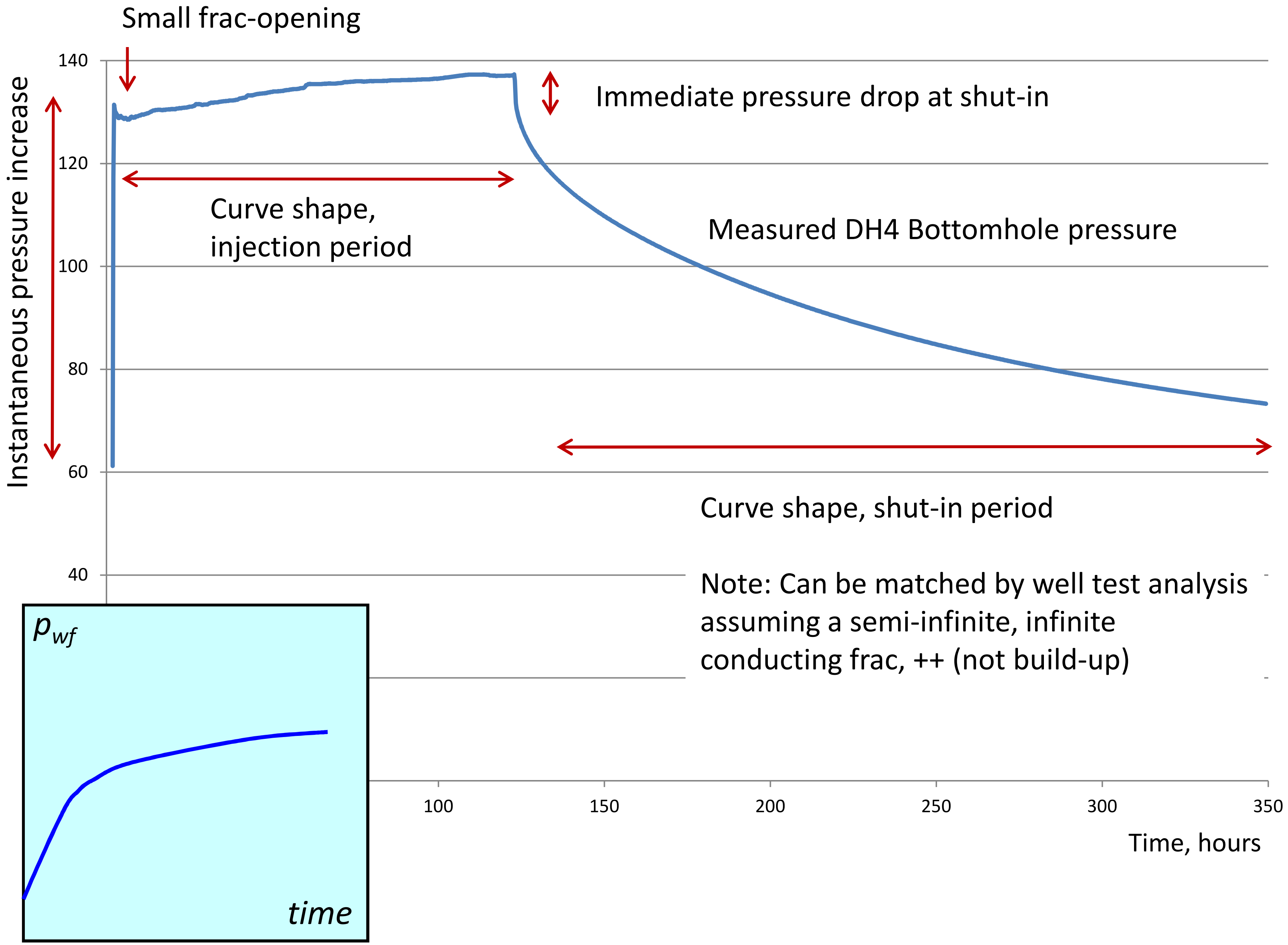



DH4 minifrac 12. aug. 2009
First 35 mins.
Note:
Curve bends
upwards, also
in periods with
constant rate
Downhole pressure
(Ptest)
Well work-over
Injection rate (l/min)
Time (mins)
500
400
300
200
100
0
0
120
80
40
0
-40
-80

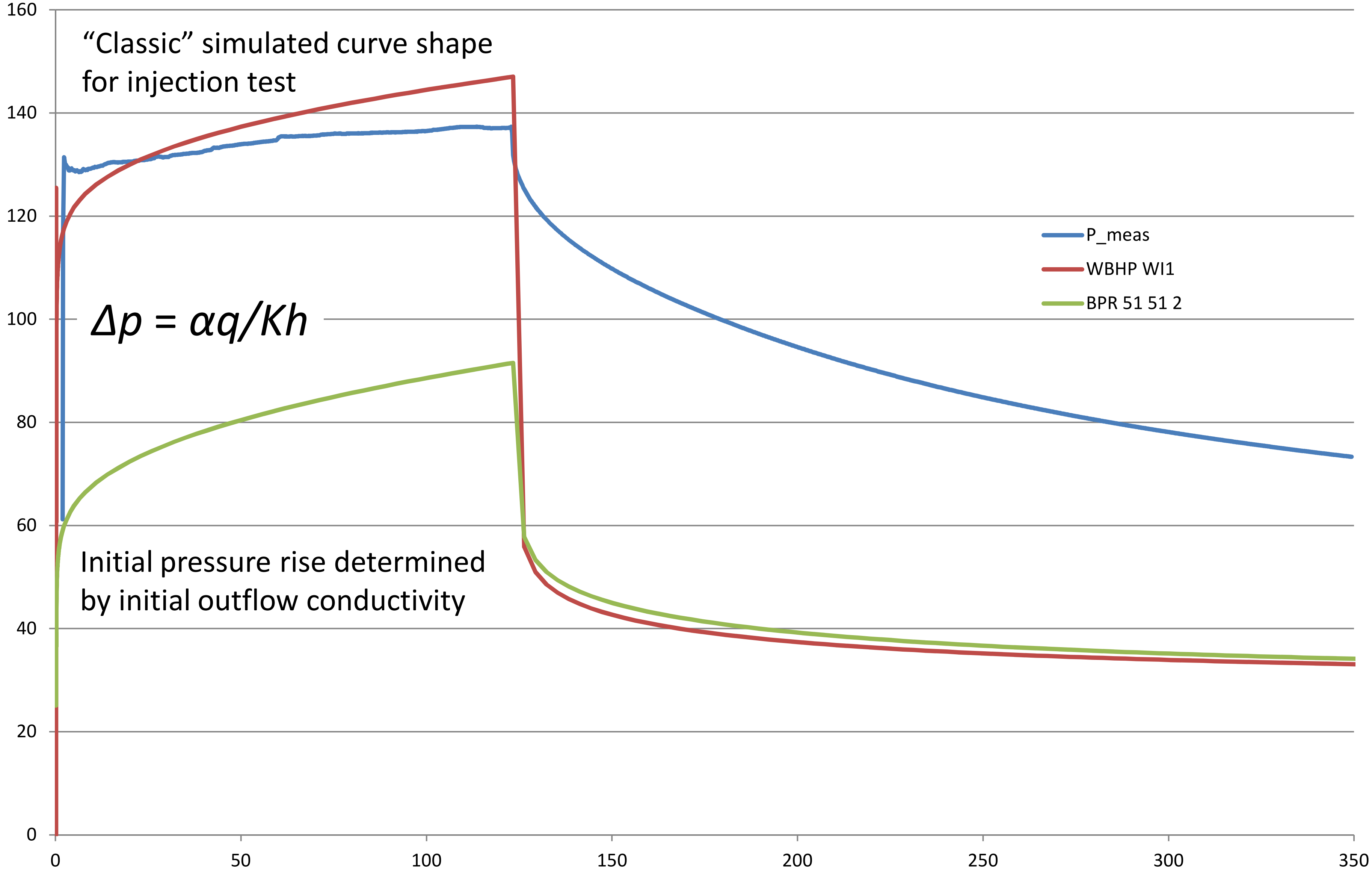
Sensitivity 3: Dynamic near-casing conductivity
KH reduced by 20% every minute (in first build-up)



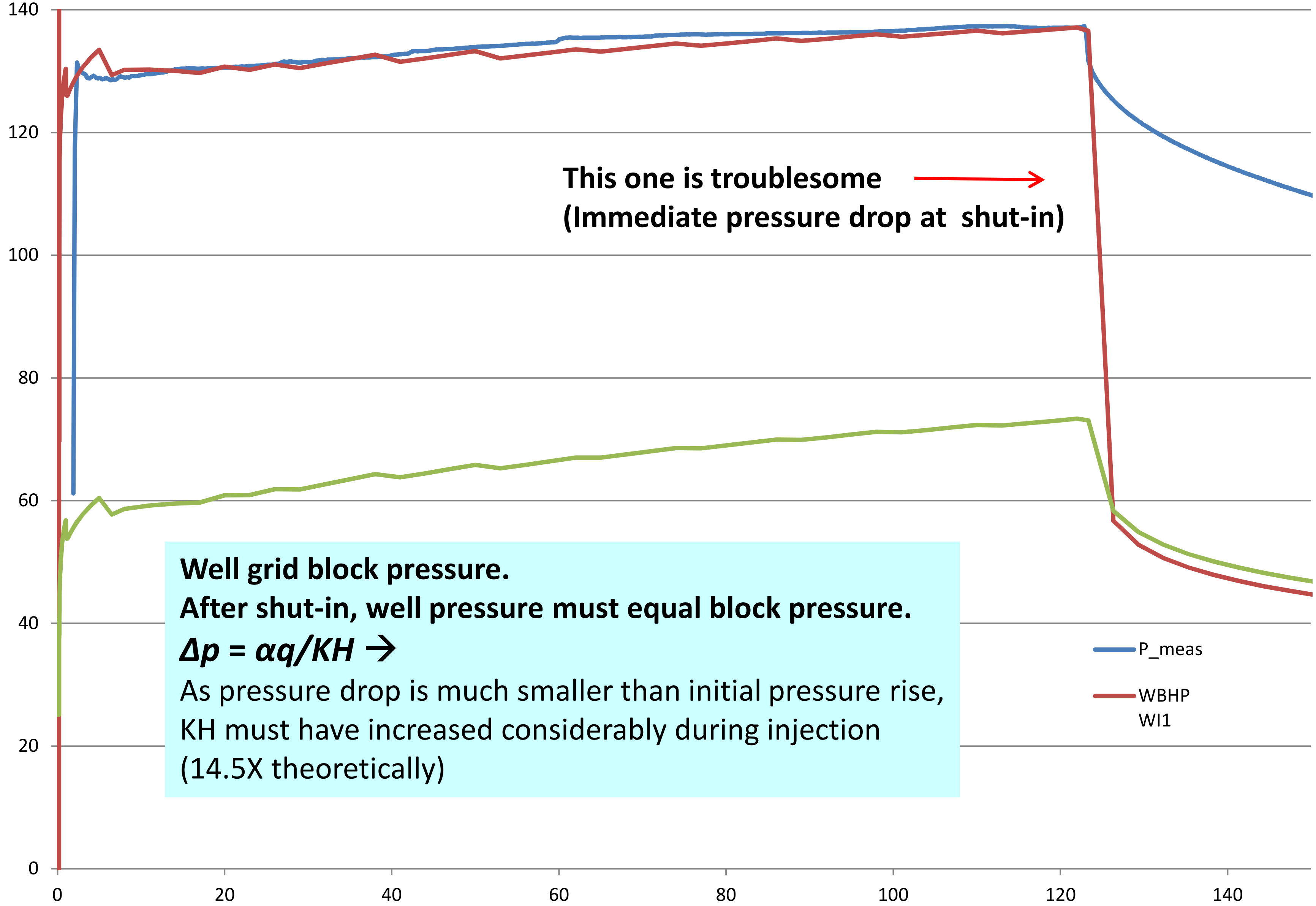
Interesting features to analyze in 5-days test

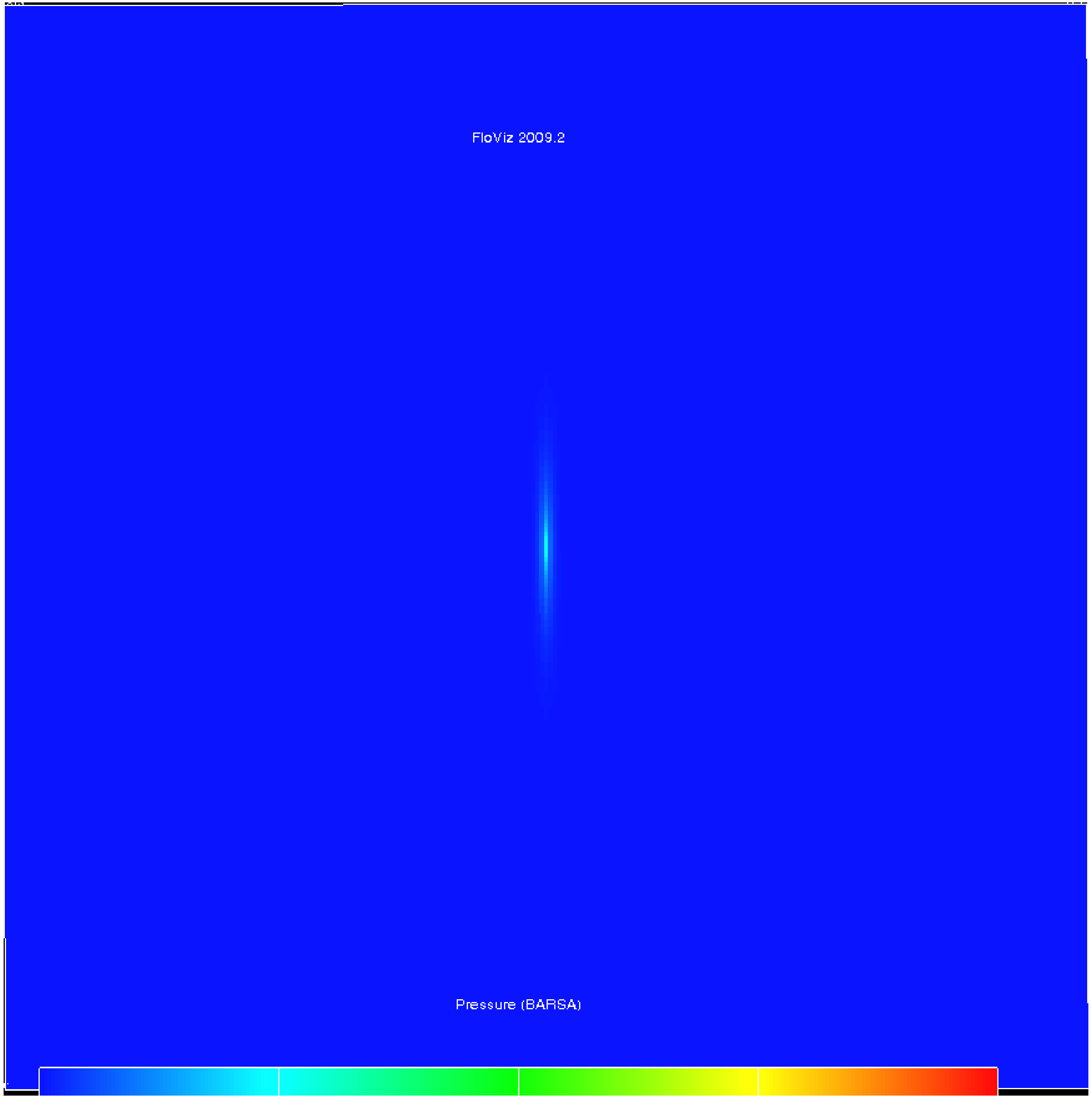


Screening simulation:
“Best” match assuming permeability doesn’t vary with time

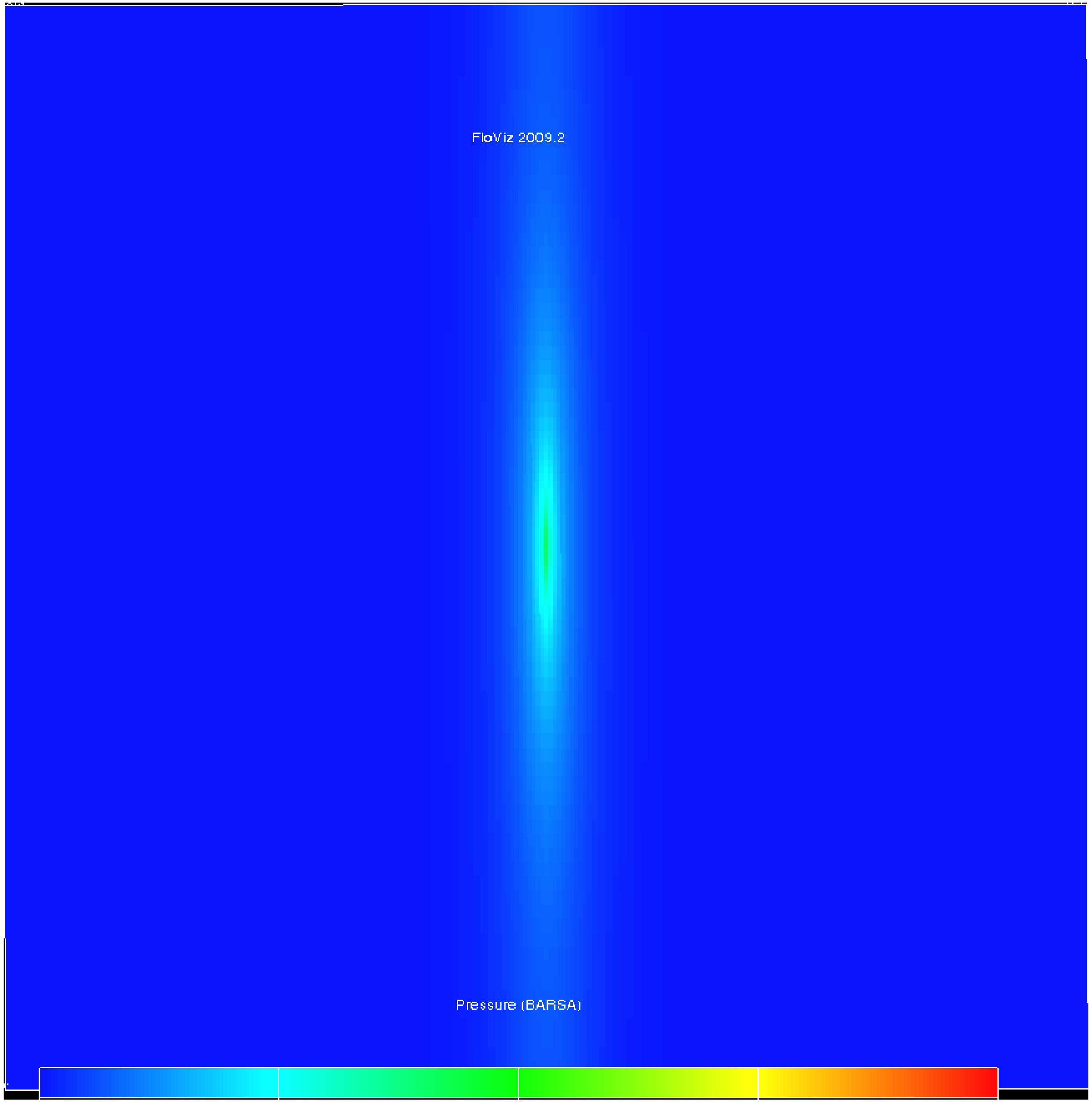


Example of match obtained by increasing near-well permeability with time

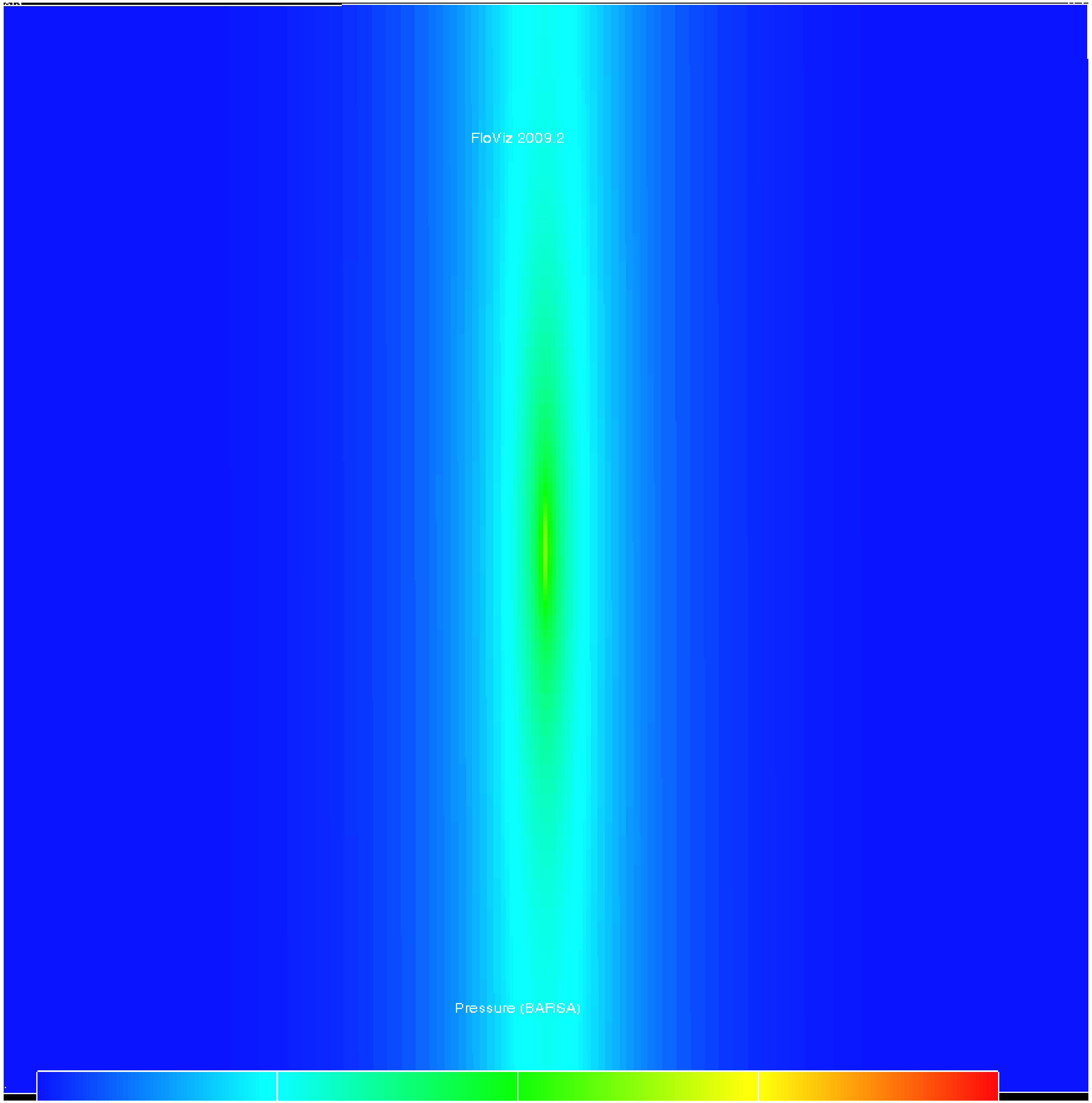




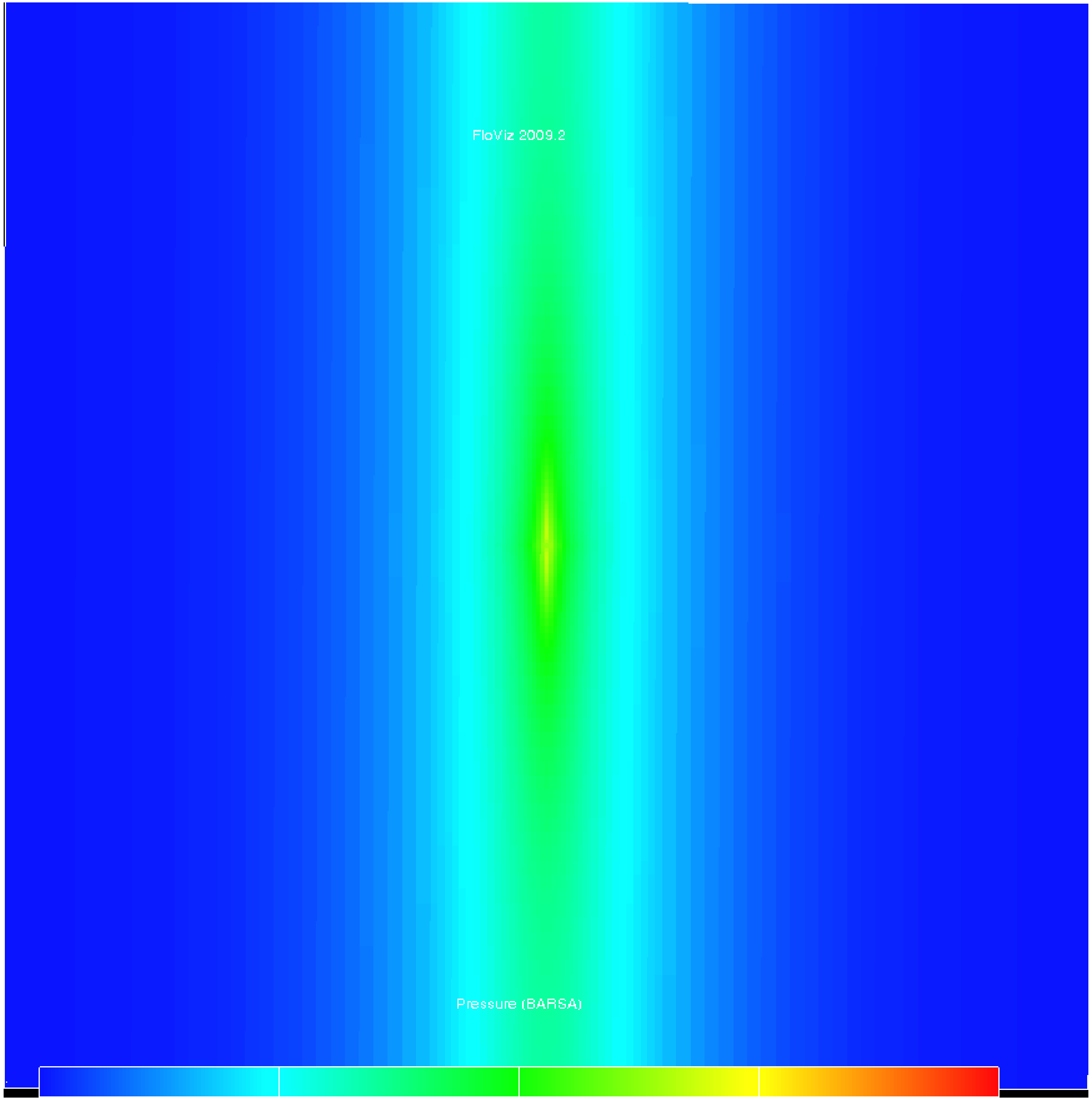
Layer 2
T = 23 mins



Layer 2
T = 11 h

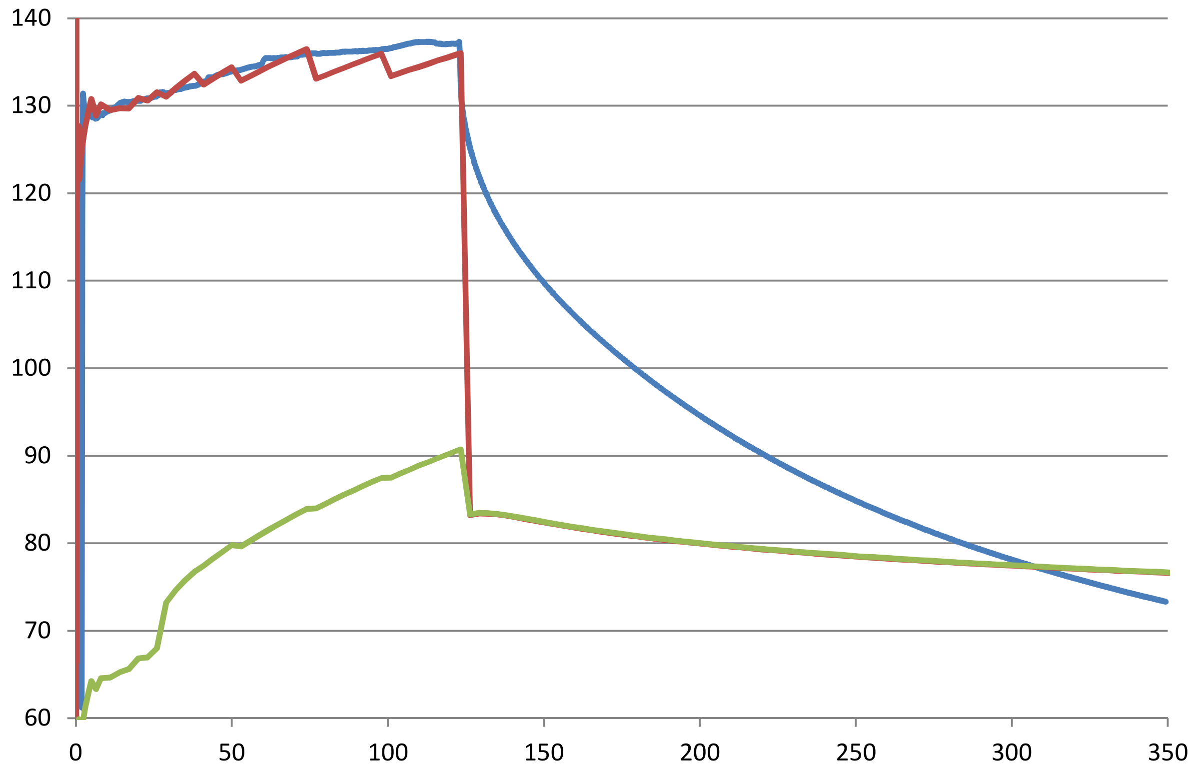


Layer 2
T = 2d



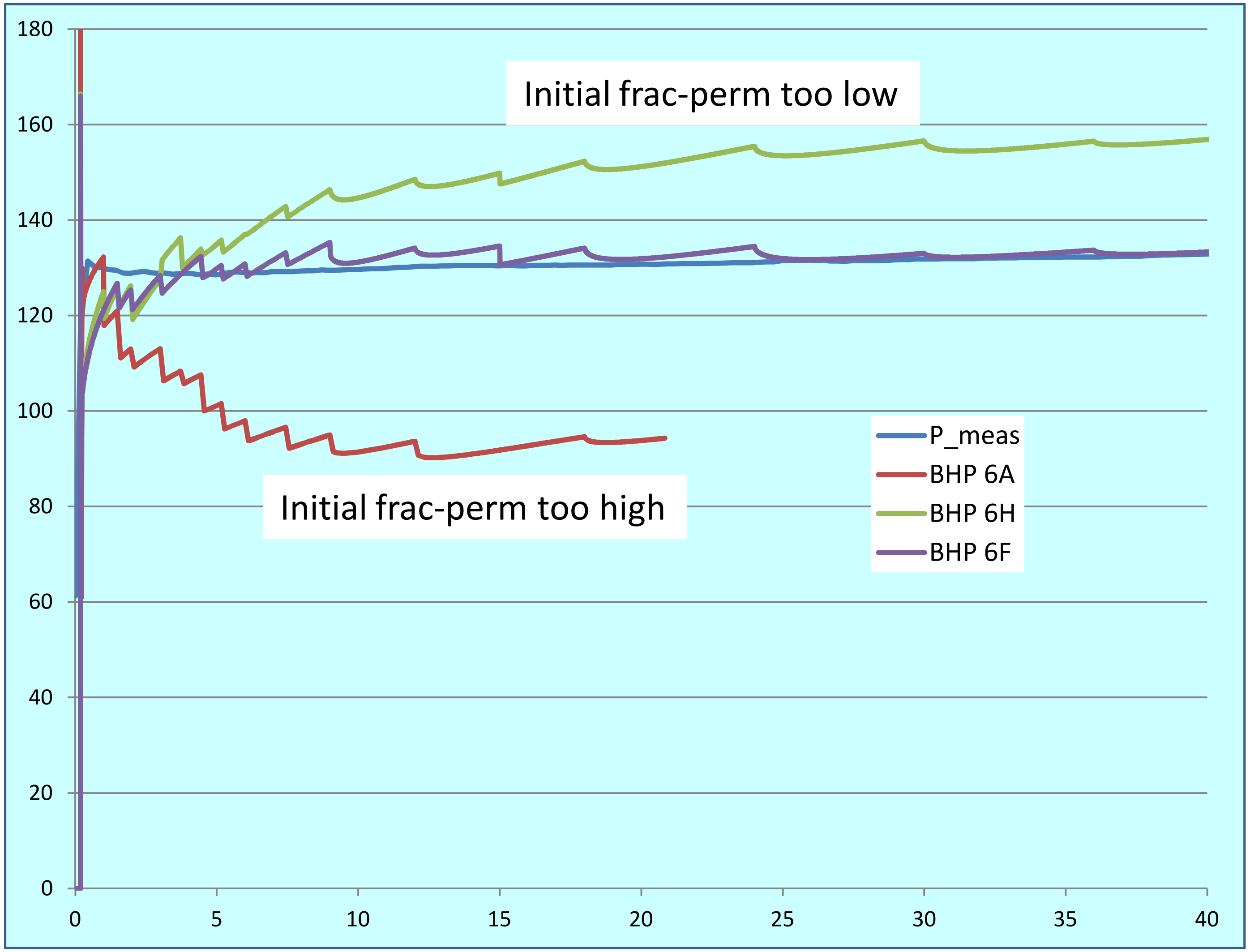
Layer 2
T = 5d

Purpose / goal of new generation of models



- Understand why shut-in pressure drop is so much larger than measured
- Make model with more realistic shut-in shape
- Eliminate alternative / competing explanations

Sensitivity on initial frac perm estimate



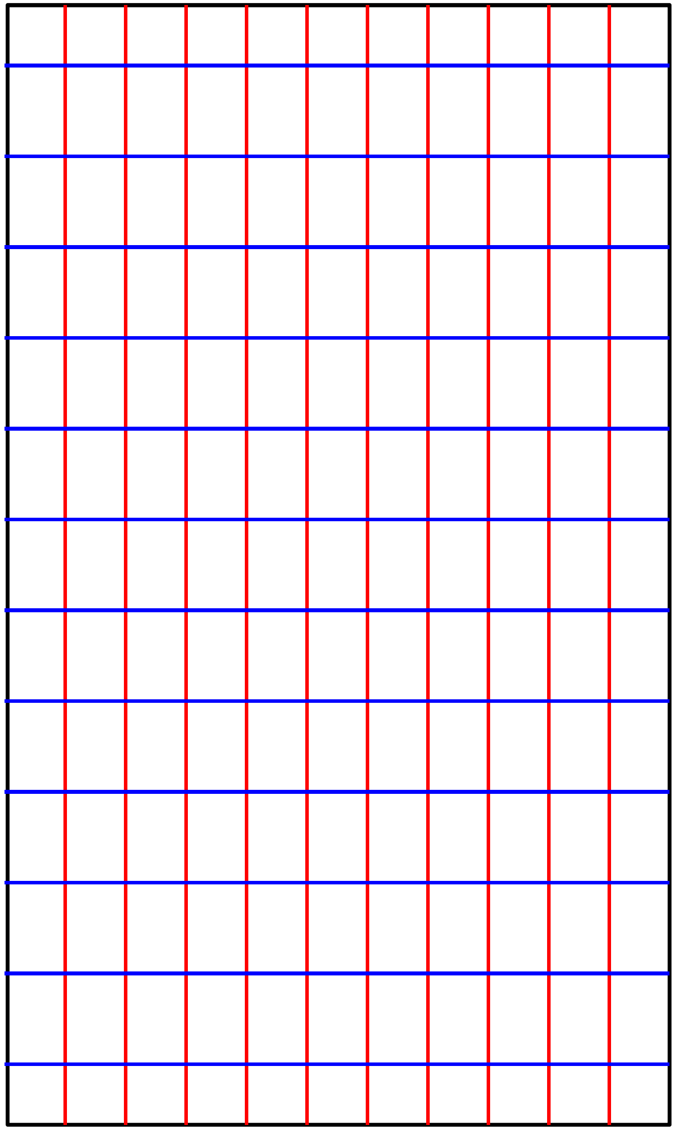
Shape and position of build-up curve is dependent on:

- Initial Kh
- Initial frac-perm
- frac-perm & Kh increase (frac opening)

However initial frac-perm is reasonably restricted, more than 10-20% off: Pressure fall-off; or unrealistic frac opening needed.

Hence can expect to get these approx. correct.

Overview of Models



All models have a fracture system as defined (described) in Jan Tveranger's geo-model:

Major fracs in direction ~NW to SE, relatively high frac-perm (red)

Secondary fracs perpendicular to the major fracs, and with somewhat lower frac-perm (blue)

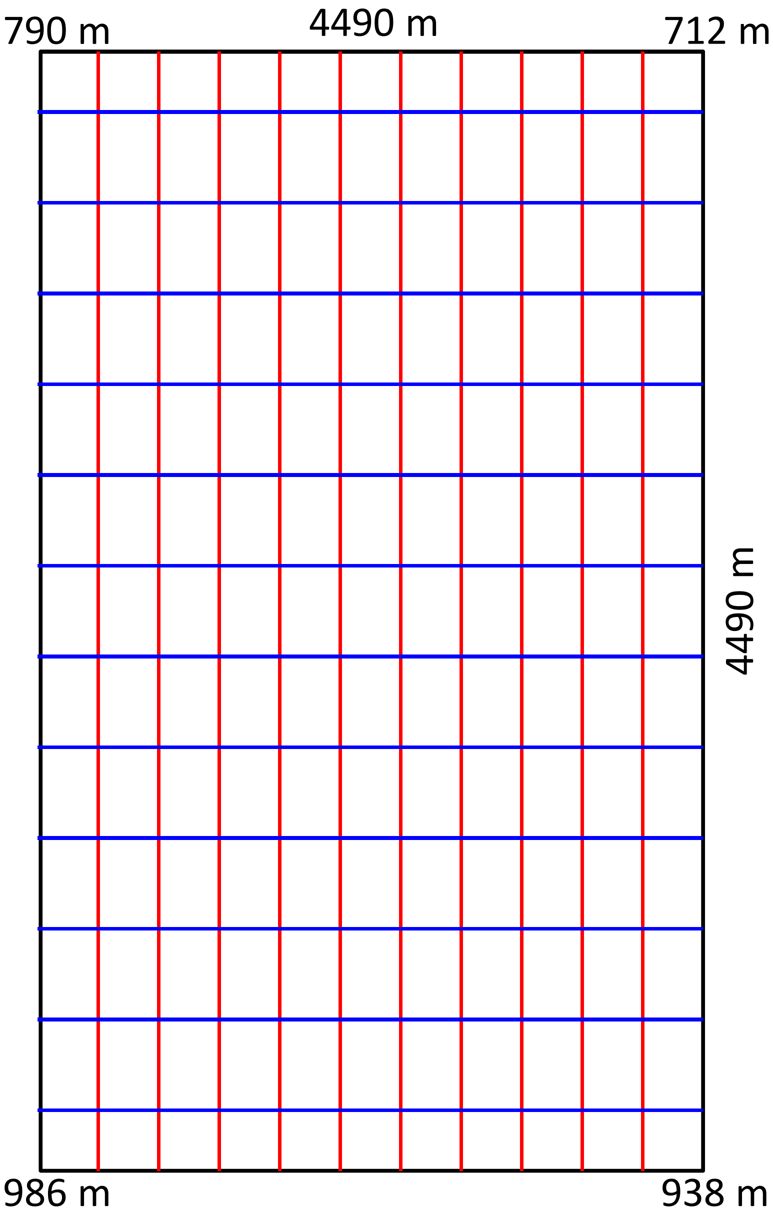
Major and secondary fracs generally occur at different depths.

Only section 850 – 950 m depth modeled, entire section perforated.

Matrix generally low-perm.

"Realistic" dip included (see comment later)

Generation 3 (LYB3)



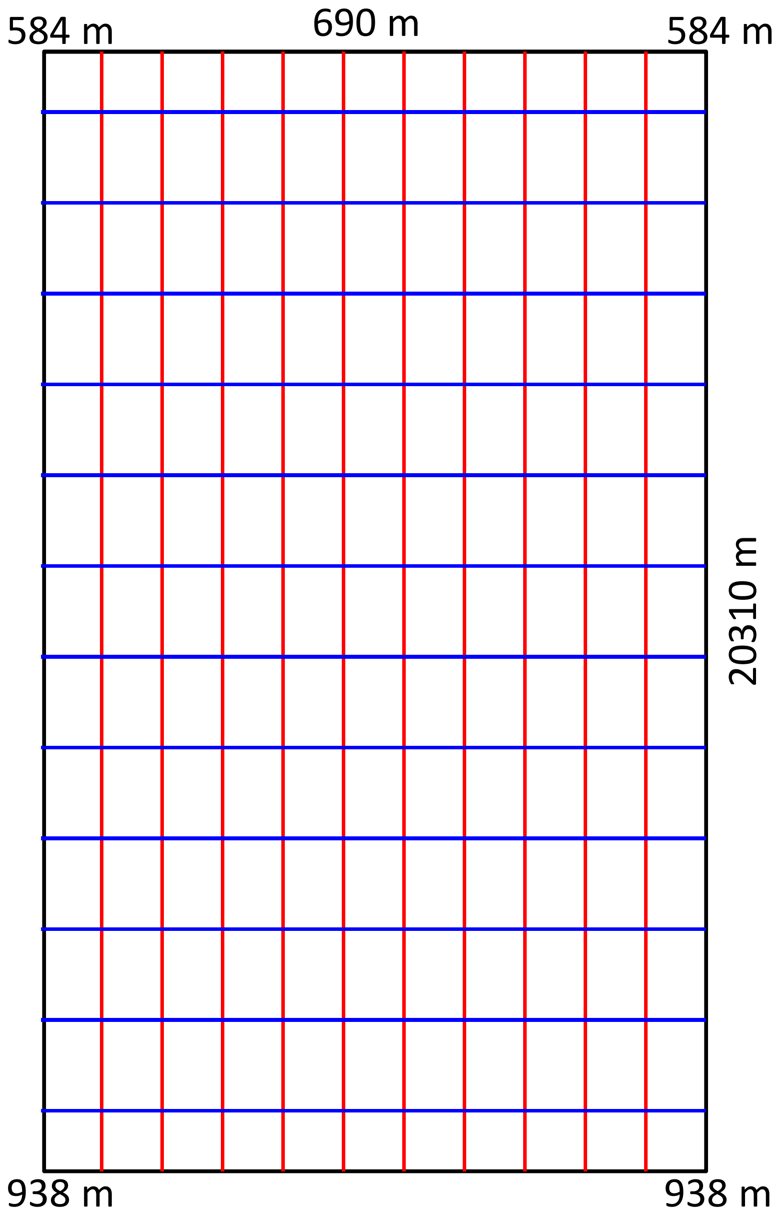
Purpose: Increase modeled area and resolution compared to gen. 2-models

- 159 x 159 x 51 cells (1,289,331)
- LGR (5x5) near well
- Cell size: 10m near well (2m in LGR), incr. to 50m far from well.
- Quadratic, i.e. identical in X and Y-direction.
- Ky >> Kx (and ratio growing…)

- Model too small:
  Pressure wave hits boundary and is reflected.

  On the other hand, pressure change dies out a short distance from well in secondary direction → can reduce width

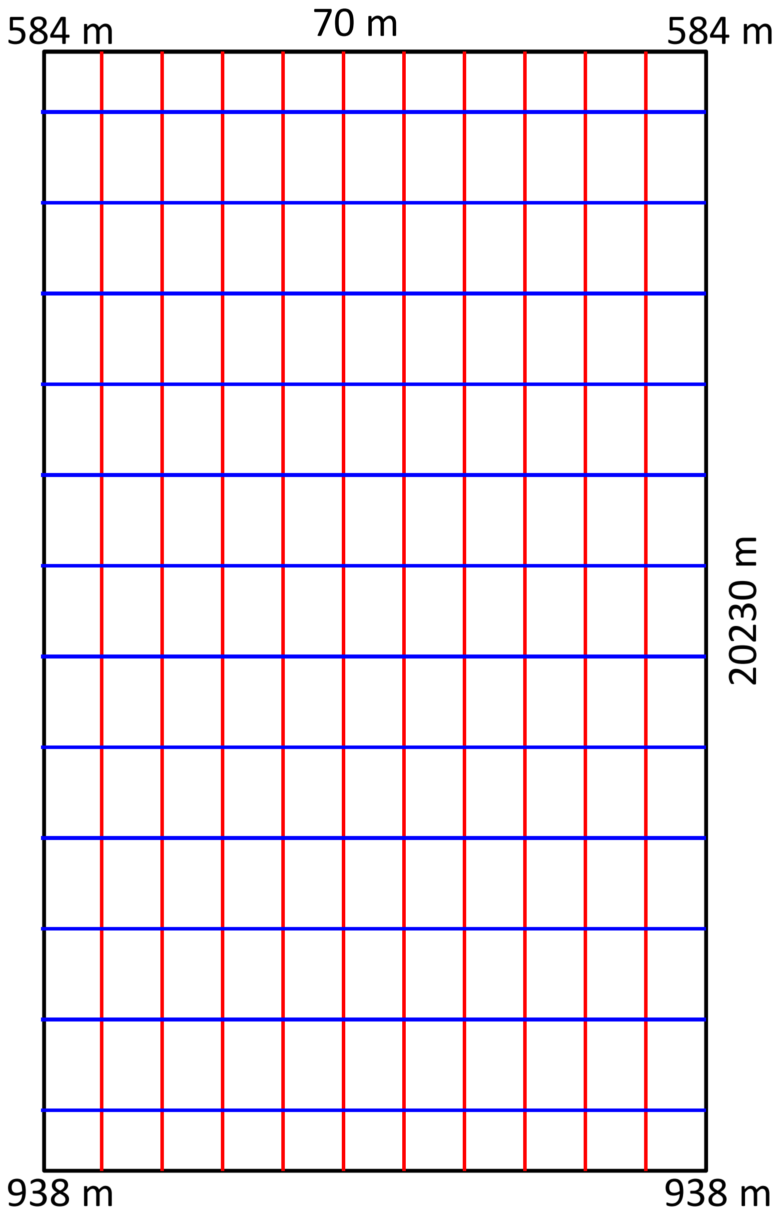
Generation 4 (LYB4)



- 59 x 363 x 51 cells (1,092,267)
- LGR (5x5) near well
- Cell size: 10m near well (2m in LGR), incr. to 80m far from well.
- Long and narrow (From "airport" to outcrop)
- Realistic dip could no longer be implemented
  Surface "Outcrop" → Negative initial pressure
  Hence initial pressure is confined to some isolated compartment (max ~4km long)
- "Amusing" convergence observation:
  TS=35 secs → 1 Newton iteration
  TS=1 min → Failure after 30 iterations

- Unfortunately a bug in eclipse prevents correct modeling of frac perm increase in LGRs
  Hence had to rebuild model with smaller near well cells.

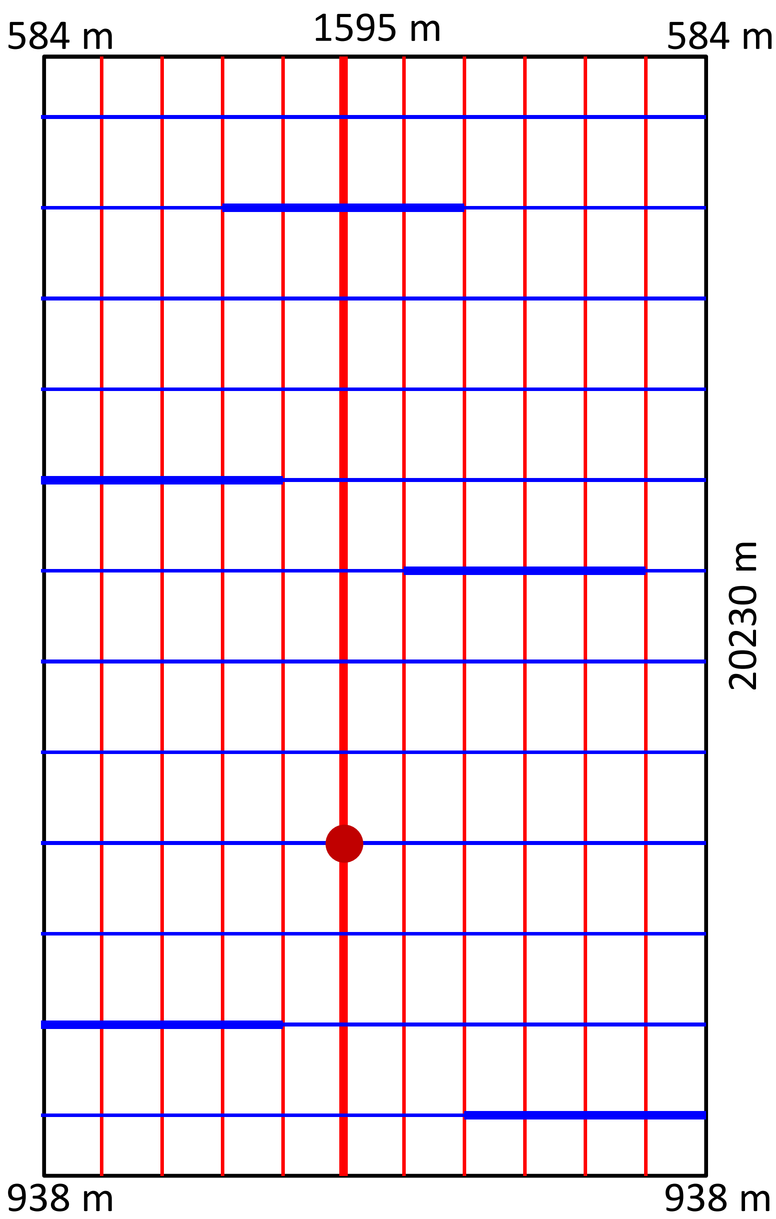
Generation 5 (LYB5)



- 21 x 389 x 51 cells (416,619)
- Cell size: 2m near well, incr. to 80m far from well.
- Long and even narrower

- Using very low frac-normal perm moved shut-in curve in correct direction, and was an indication we're on the right path.
- Injected fluid is now (almost) restricted to a single fracture (or a small bundle of fractures), with a total volume too small to accept the injected fluid.
- Next attempt: Some transverse pressure relief.

Generation 6-7 (LYB6/LYB7)



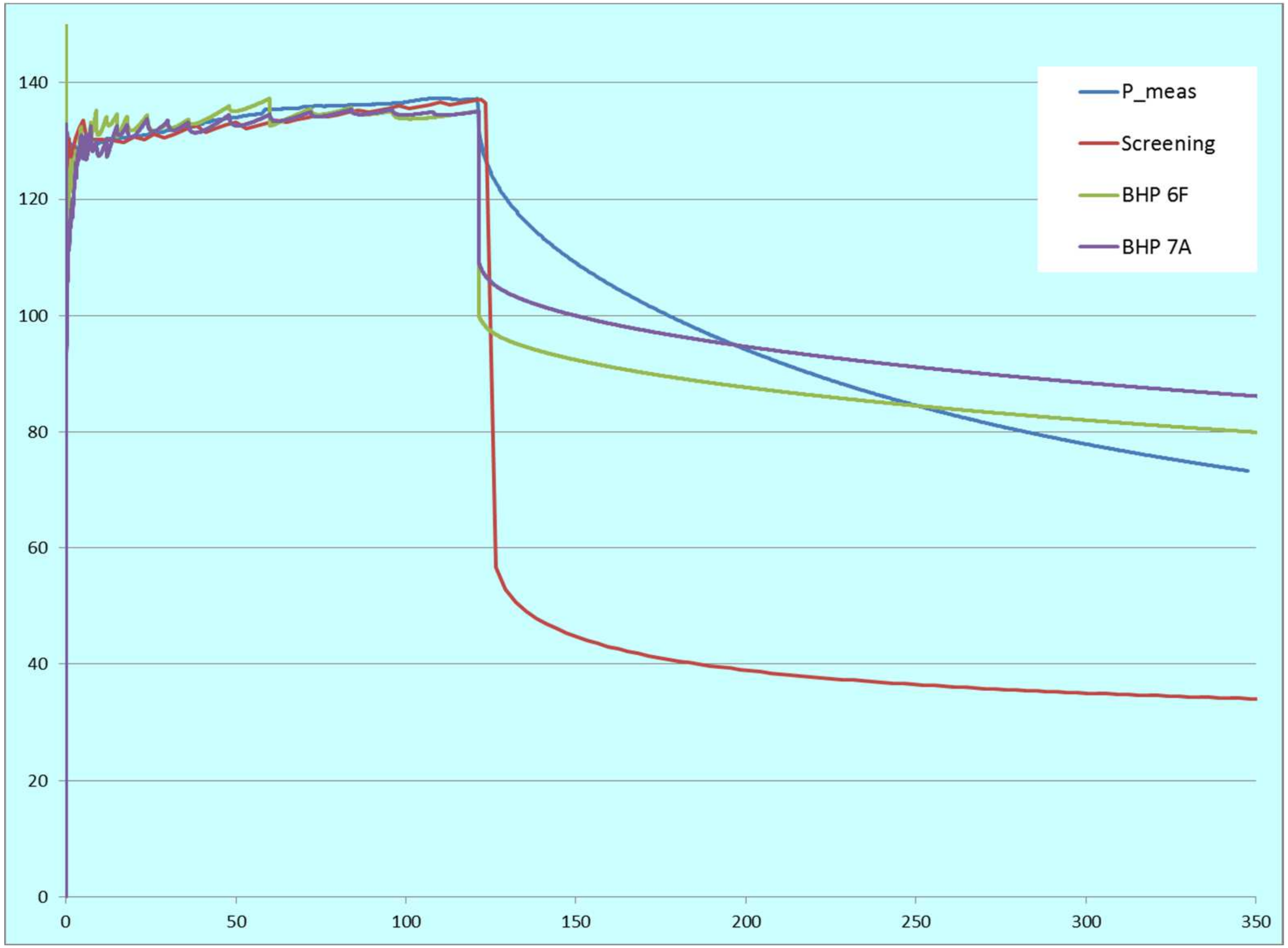
- 67 x 389 x 51 cells (1,329,213)
- Cell size: 5x2 m near well, incr. to 80x40 m far from well.
- Low (or zero) X-perm, but with some open transverse fracs (sketched heavy blue)
  - more or less random
- Found that nearest “relief zone” had to be “far from” DH4 (>4km?), or the flow-off would be too large.

- Promising results, but still not quite there.

- Raised the question of “linear flow”.
  Can this be modeled in Eclipse at all?

- Sensitivity: Identical model with even smaller near-well cells (LGR 1.67x0.67m)
- → As expected (feared), results are grid dependent.

Grid sensitivity

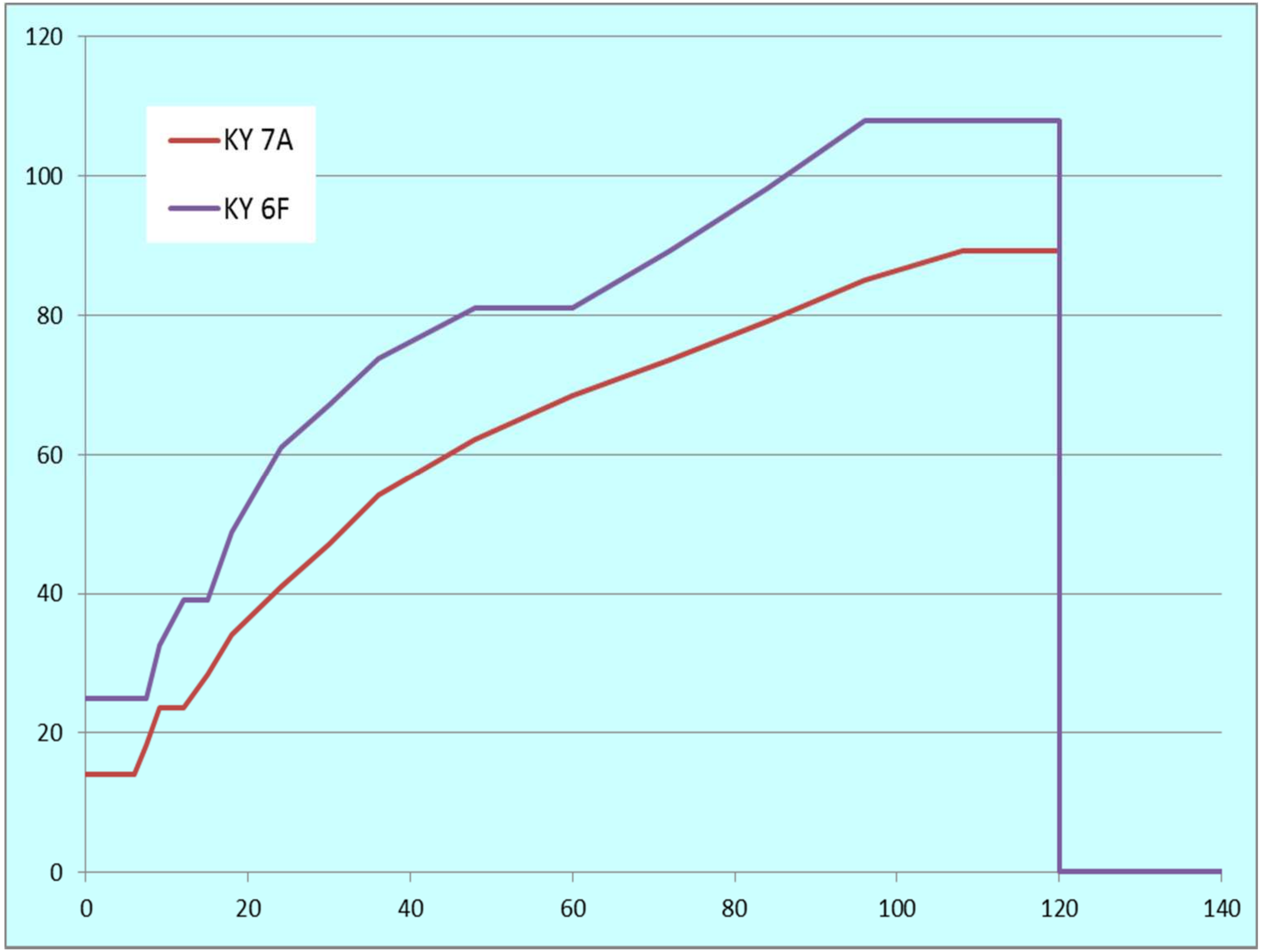


Case 7A is "identical" to 6F, with LGR along main frac. Adjusting for grid effect:

- Reduce initial frac perm
- Reduce initial Kh
- Increase rate of perm increase (frac opening)

- End-of-build-up similar
- Fall-off has changed (!) Hence shape of fall-off is tied to cell size. (Ouch!)
- Has a logical explanation: Simulated flow is almost but not quite linear. Injected water "fills up" well cell before it flows out – depends on volume of grid cell, and will approach linear flow as cell width goes to zero.

Permeability increase (frac opening) during build-up



Curves show increase for primary frac (entire length)

In addition:
Much larger increase near well (not shown)
(Has less effect.)

Storage volume estimate

Assumptions (on the optimistic side…):

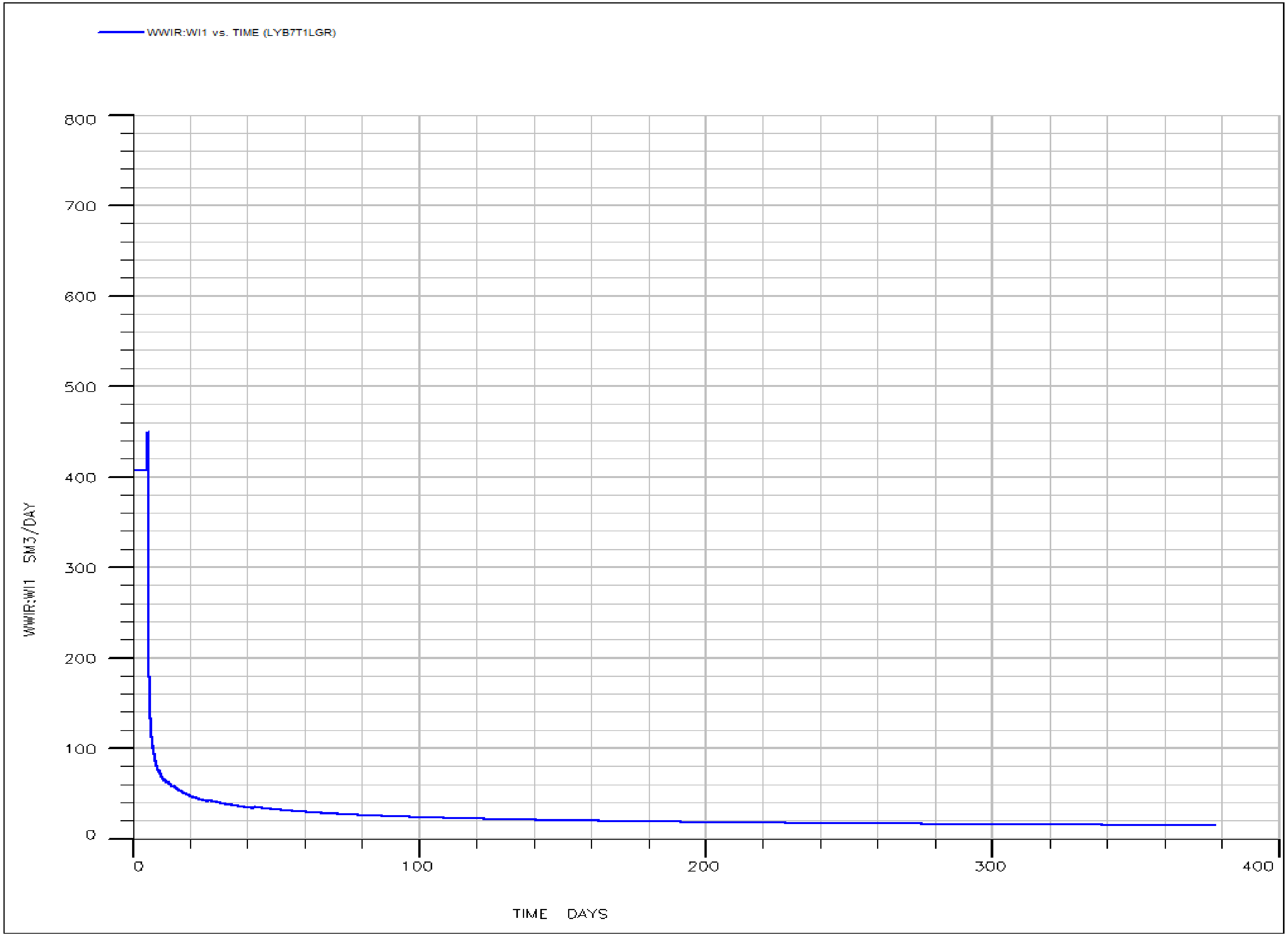
- Average porosity: 0.1
- Fracture conductivity: 20D in a $1mm^2$ fracture
- Primary fractures: 100% effective (in frac connected to well)
- Secondary fractures: 30% effective
- Entire fracture system eventually filled

- Compare simulated cell permeability to the equivalent permeability for a solid rock containing fractures on a layer-by-layer basis

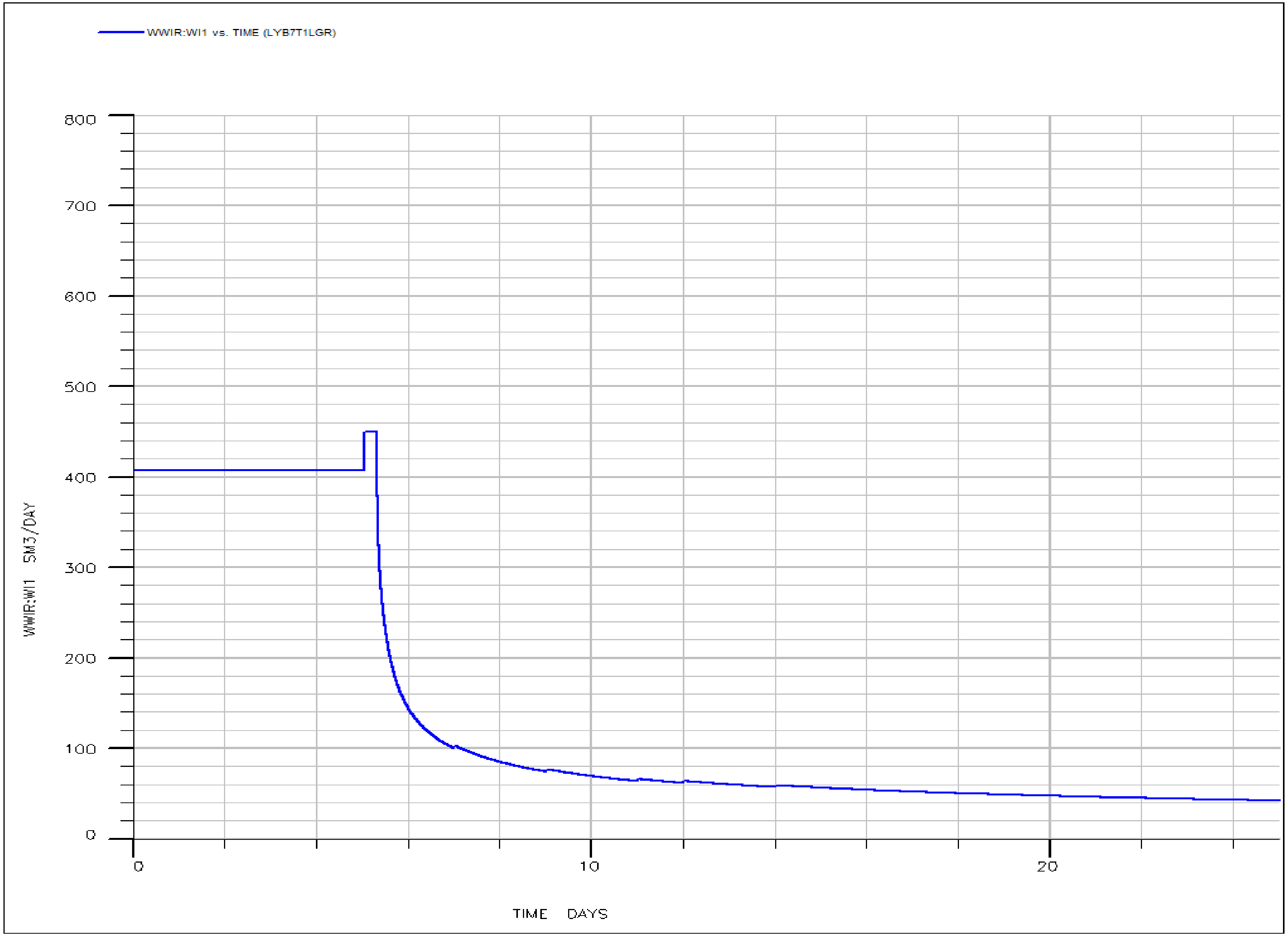
- After a technical computation, came up with an estimated storage volume of,
  - approx. 11 mill m^3.
  - (~ 3% of gross pore volume)

16 month water injection simulation:

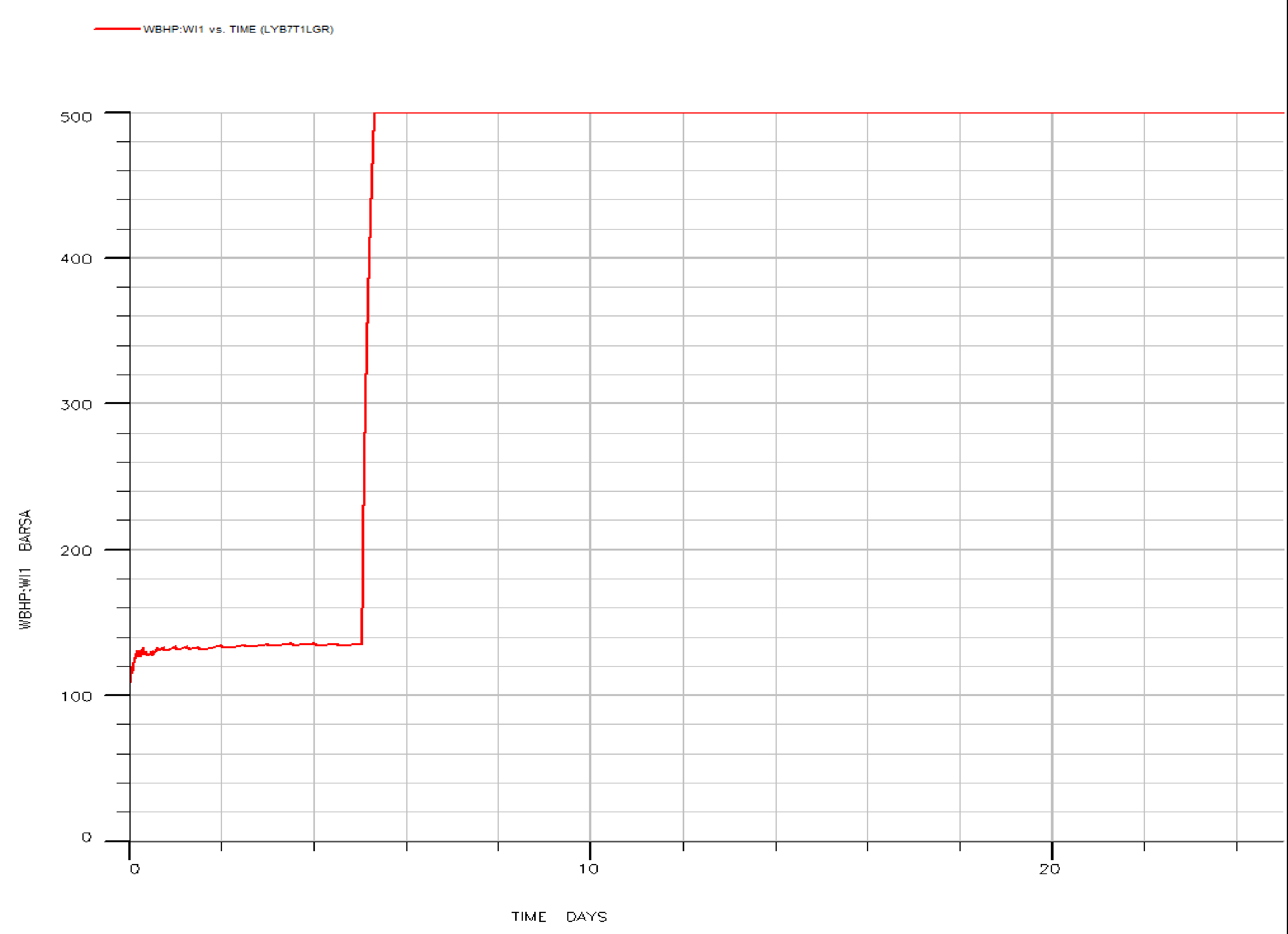
Water injection rate



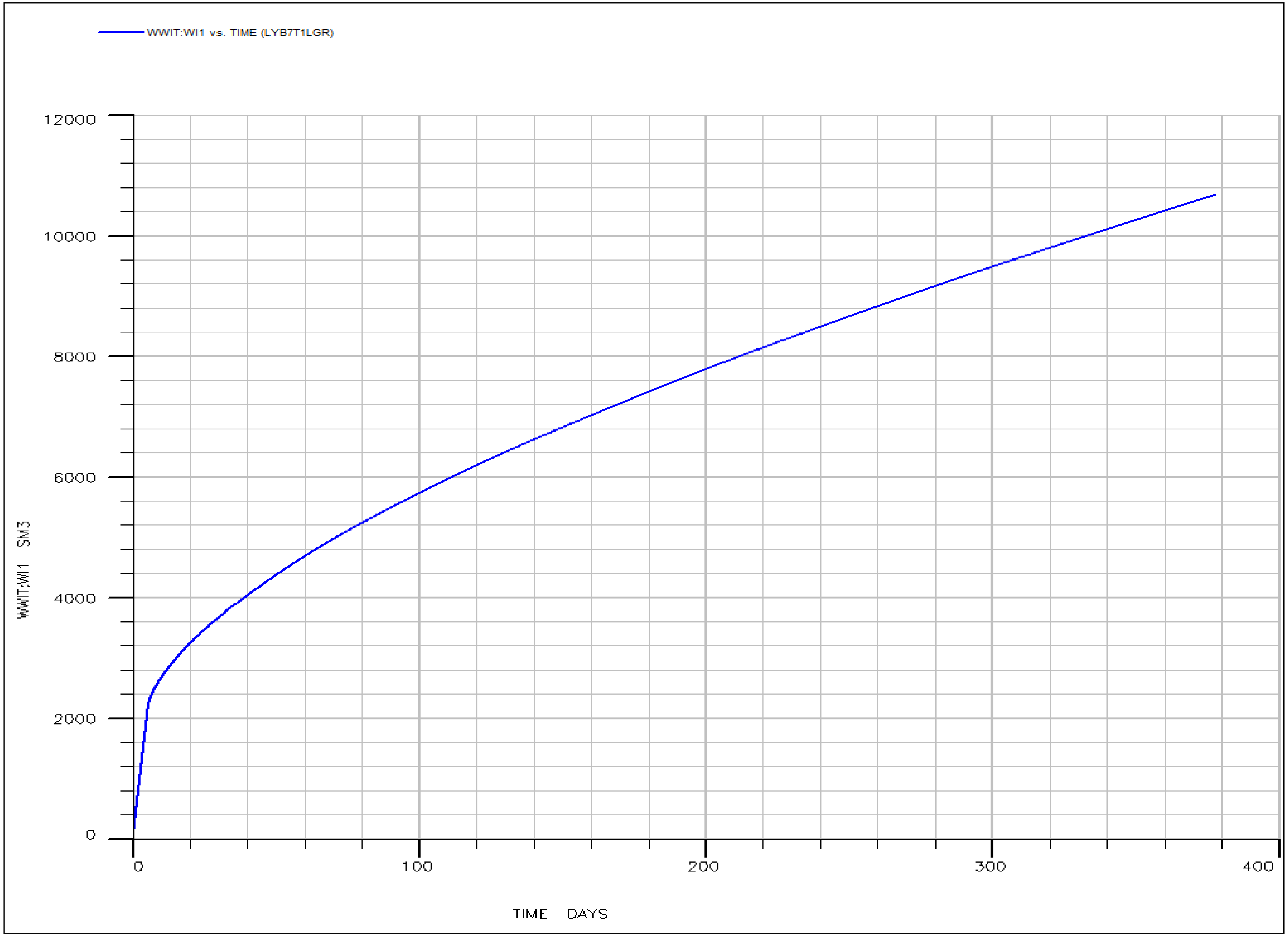
16 month water injection simulation:
Water injection rate (first 25 days)



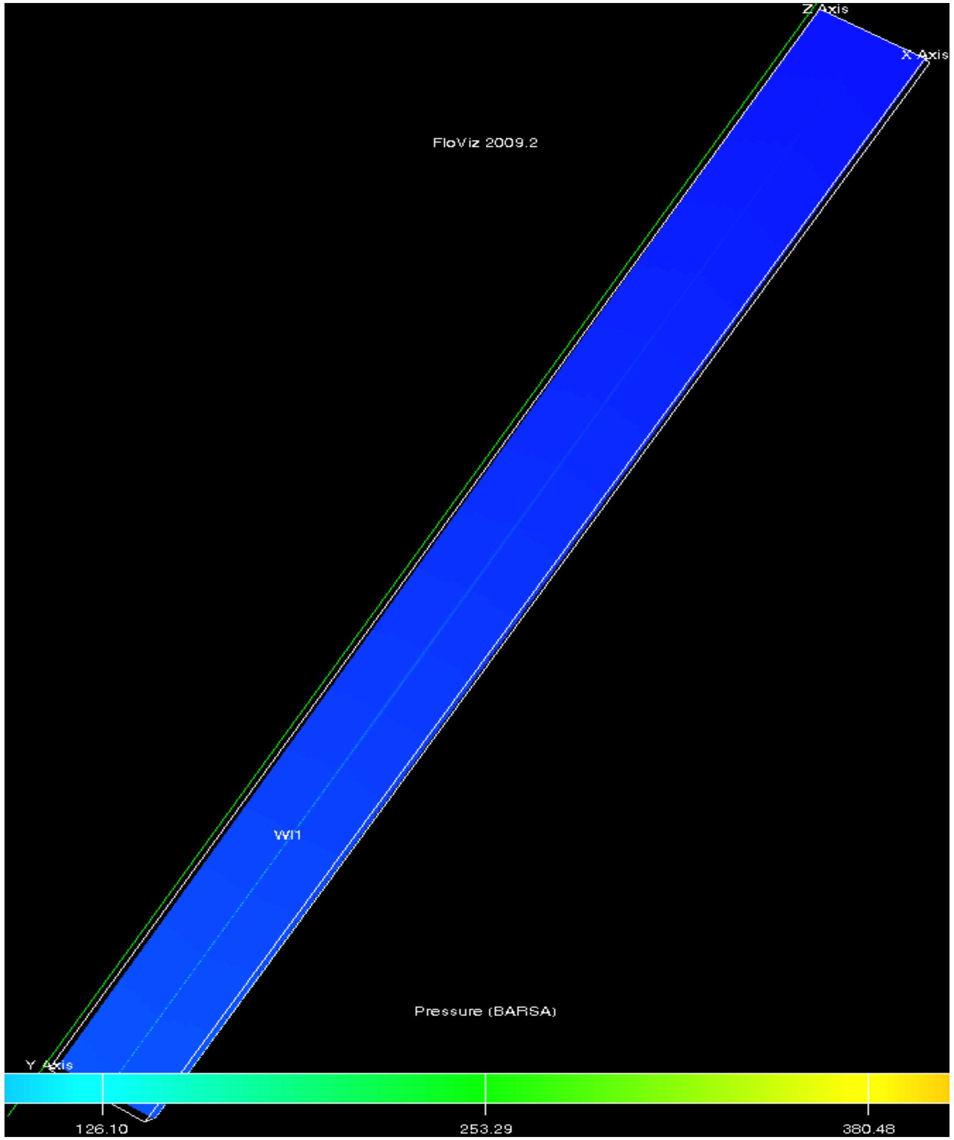
16 month water injection simulation:
Bottom hole pressure

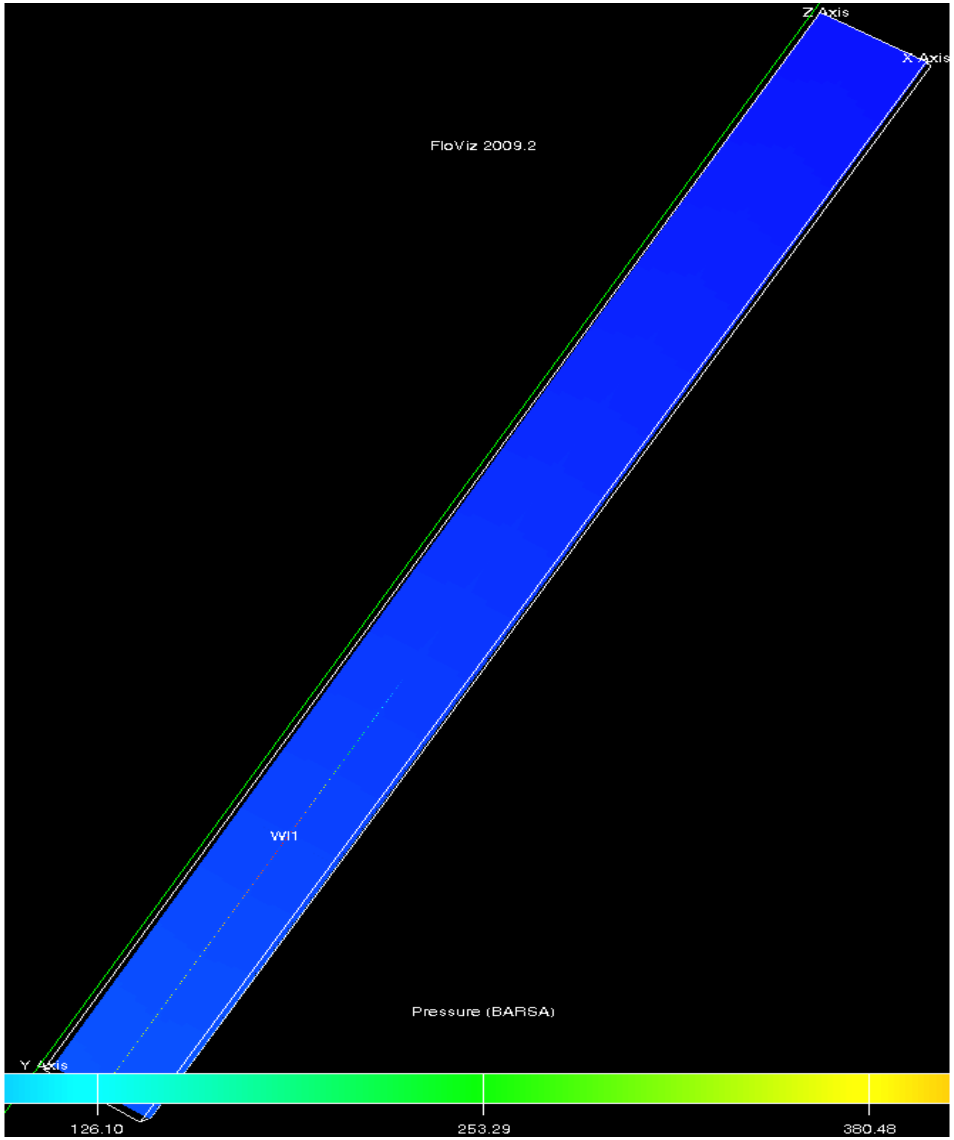


16 month water injection simulation:
Total water injected

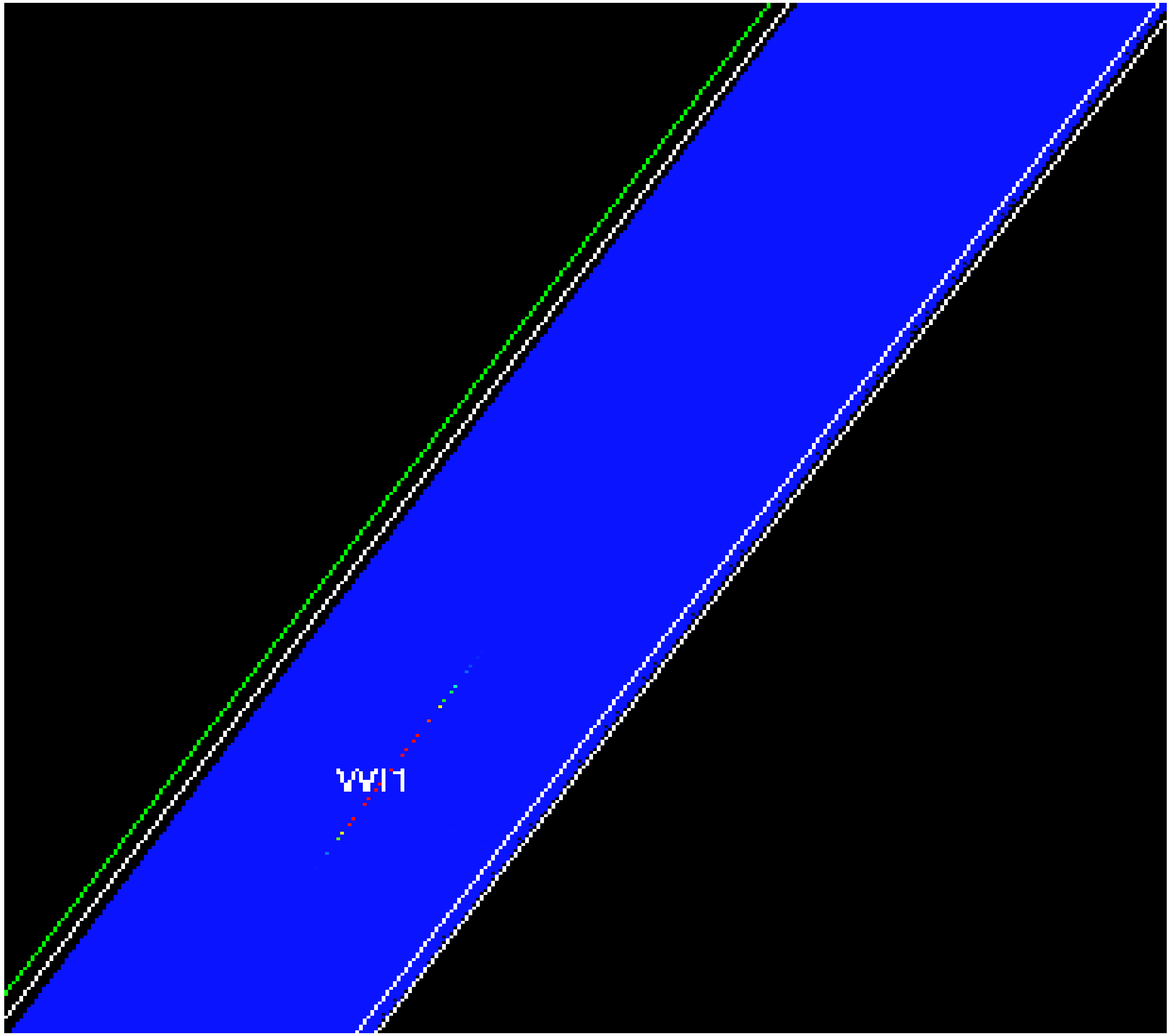


Pressure at end of build-up, and after 1 year injection





Tracer after 1 year injection



Conclusions

- The injected water flows only in the fracture system
- No matrix storage at all
- Linear flow can be understood literally:
  - the water enters only the single (or perhaps a few) fracture(s) connected to the well.
- Primary fracs open (substantially) during injection
- Minifrac & other pre-5-days test indicate fracture closure on shut-in
- There is some (very limited) relief from secondary fracture system
  - Some, but not very much water flows into transverse fractures.
- Total storage volume cannot be very large…

- (Could have included realistic frac-pressure, and porosity increase during frac’ing, but there’s not enough volume from water compression anyway…)