Geomechanical Response of the Tubåen Fm, a Compartmentalized CO$_2$ Storage Reservoir, Snøhvit Norway*

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Abstract

The pressure build-up of large scale CO$_2$ injection projects is one of the biggest challenges towards the development of a carbon sequestration technology. The pressure front creates stress gradients in the subsurface that can lead to dilation or slip along faults or fractures, hydro-fracturing of the caprock, and potentially microseismicity. Furthermore potential compartmentalization of the storage reservoir can not only reduced the original estimated reservoir capacity, but exacerbates the pressure increase and associated hazards.

In this work we investigate the geomechanical response to the CO$_2$ injection in the Tubåen Fm at the Snøhvit site focusing on the potential compartmentalization of the storage reservoir. This compartmentalization has been suspected due to the unexpected pressure rise during operations in the storage reservoir that has led to a considerable decrease in the estimated total capacity and to the abandonment injection operations.

The Snøhvit gas field is located offshore in the northern Norwegian Sea (Barents Sea). CO$_2$ is separated from the produced gas and until 2011 it was stored underground in the Tubåen Fm. at approximately 2600 m depth. The Tubåen Fm. corresponds to a delta plain environment dominated by fluvial distributary channels and some marine-tidal influence. It is separated by the producing gas reservoir (Stø Fm.) by the Nordmela 1 and 2 Fms. that contain wide shale layers expected to act as flow barriers. The channelized nature of the Tubåen Fm. suggests the possibility of stratigraphic compartmentalization.

Structurally this area is extensively faulted, characterized by a dominant east-west-trending fault system, where the majority of the faults dip toward the basin axis and define typical horsts and graben geometry. However, it also present faults at high angles to this trend, leading to complex fault interactions and making fault compartmentalization a strong possibility as well.

Given the geometry of major faults and fractures in and above the reservoir, available estimates of the in situ stress tensor, and reservoir characteristics, we use a coupled hydromechanical approach to understand the geomechanical response of the system to the CO$_2$ injection,

focusing in particular on addressing the potential reservoir compartmentalization and its impacts on injection performance, CO_2 distribution and migration outside of the storage interval.

References Cited

Hansen, B.M.S., and N. Murray, 2012, Migration then assembly; formation of Neptune-mass planets inside 1 AU: The = Astrophysical Journal, v. 751/2, 16 p.

Spencer, J.E., P.A. Pearthree, and P.K. House, 2008, An evaluation of the evolution of the latest Miocene to earliest Pliocene Bouse lake system in the lower Colorado River valley, southwestern USA, *in* M.C. Reheis, R. Hershler, and D.M. Miller, (eds.), Late Cenozoic Drainage History of the Southwestern Great Basin and Lower Colorado River Region: Geologic and Biotic Perspectives: Geological Society of America Special Paper 439, 432 p.

Wennberg, O.P., O. Malm, T. Needham, E. Edwards, S. Ottesen, F. Karlsen, L. Rennan, and R. Knipe, 2008, On the occurrence and formation of open fractures in the Jurassic reservoir sandstones of the Snohvit Field, SW Barents Sea: Petroleum Geoscience, v. 14/2, p. 139-150.

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AAPG 2013 ACE, Pittsburgh, PA

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Snøhvit CO$_2$ Project

- Gas fields discovered in the '80s with a 5 – 8 % CO$_2$ content

- Producing natural gas with 5-8% CO$_2$ content, which needs to be reduced before liquefaction

- Separated CO$_2$ was re-injected into Tubåen Fm. at approx. 2600m depth

- Injection began in 2008, but in 2010 Statoil announced storage capacity in Tubåen was lower than expected. Have since moved to another formation
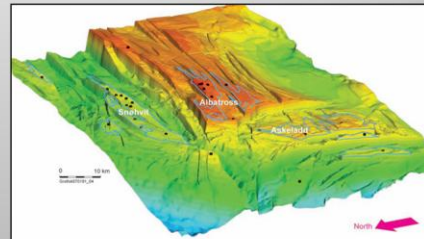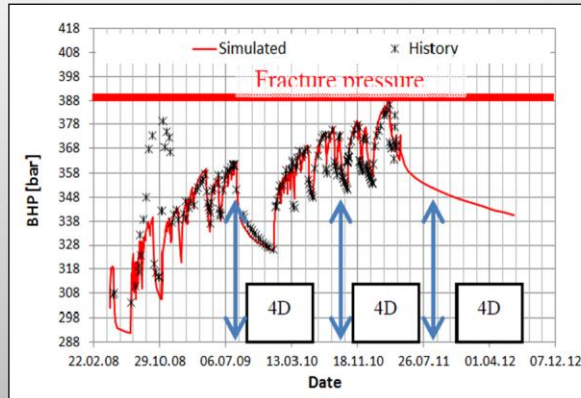
Structural diagram of Hammerfest Basin

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Presenter's notes:
- Rate: 2000 t/day (In Salah 3500 t/day, Sleipner 2700 t/day)
- Total storage: 23,000 kt (In Salah 17,000 kt, Sleipner 20,000 kt)
- Basin at Middle Jurassic level (approx. age of producing reservoir). Blue lines outline the gas fields [from Spencer et al., 2008].

Storage capacity lower than expected

- Maximum reached overpressure <10 MPa
- Control data: well pressure & 4D seismic
- Injection in 3 perforations
- Lower perforation took ~ 90% CO_2

Hansen et al, 2012

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Presenter's notes: Total overpressure < 10 MPa (100 bars). System was not drove to failure

Statoil pressure analysis: flow barriers at 150m & 3km from injector in agreement with 4D seismic analysis

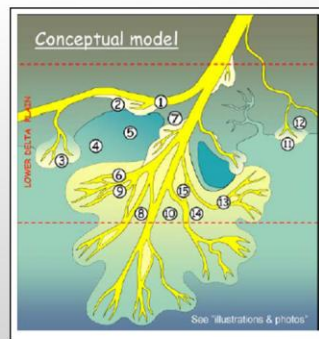4D difference amplitude map

Increasing ampli
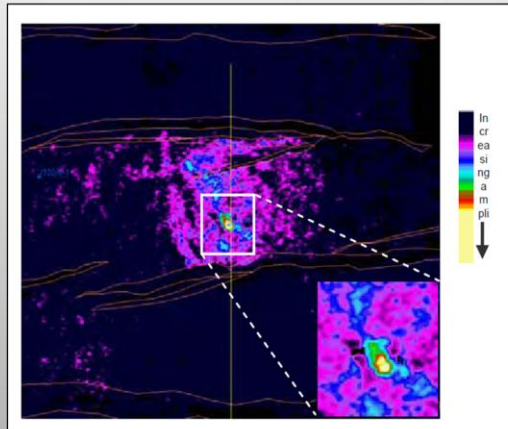
Hansen *et al*, 2012

Stratigraphy

- Storage target: **Tubåen Fm.** ~2600 m depth.
  - 45-130 m clastic wedge (over ~50 km)
  - Individual channels & subordinate shales
  - Porosity 1-16%, Permeability 130-880 mD
- Caprock: Nordmela Fm.
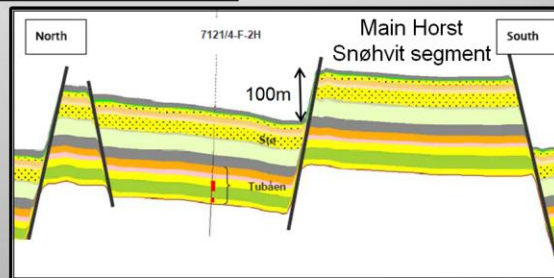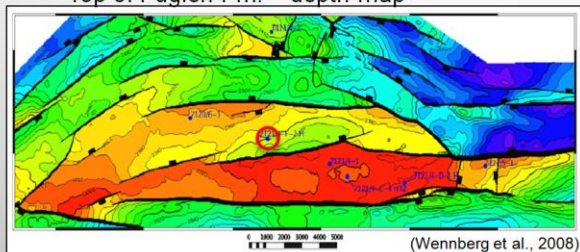 - Porosity ~13%, Permeability 1-23 mD

Conceptual model
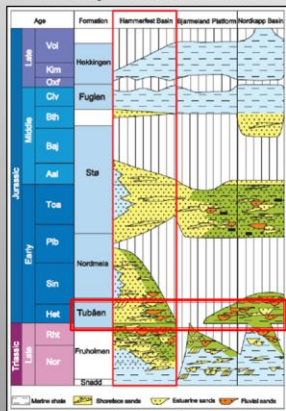
Wennberg et al., 2008

- Delta plain depositional environment, with fluvial distributary channels & some marine-tidal influence

- Highly variable sandstone facies, interbedded with siltstones & mudstones

Structural Configuration

Top of Fuglen Fm. – depth map

(Wennberg et al., 2008)

Structural complexity of the site raises many interesting hydromechanical questions

1. What is the role of the bounding faults at the site? Are they reservoir seals or potential leakage pathways?

2. Why was storage capacity lower than expected? Is it a function of the depositional setting? What is the role of observed faults/fractures?

3. Is there a risk of contaminating the producing gas?

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Presenter's notes:
• Gaseous CO_2: rho=2g/m^3=0.002 kg/m^3
• Supercritical CO_2: rho= ~500 kg/m^3
• Point source sequestration at power generation facilities
• Describe elements of a successful storage scenario
  • Reservoir is ideally high permeability (accessible) and high porosity (capacity)
  • Overlying rock (caprock) is low permeability
• Tools appropriate for this specific scenario have potential for improving other techniques: shale

1.- What is the role of the bounding faults

- Fault Stability Analysis: Coulomb Criteria considering thermo poro-elasticity

- Uncertainty Analysis using PSUADE (Problem Solving environment for Uncertainty Analysis and Design Exploration)

- Data input:
  - From Statoil
    - Intersection of fault surface with top of reservoir
    - S_{hmin} magnitude (from XLOT)
    - Rock mechanical properties
    - P_p & T
  - From literature
    - S_{Hmax} Azimuths
    - Tectonic Environment
    - Regional lithostatic stress (S_v)

Stress Uncertainty

- Up to 90 degrees variations in reported S_{Hmax} Azimuths at Snøhvit

- Both **Strike Slip** & **Reverse faulting** indicators in nearby areas

  - Statoil: horizontal S_{hmin} (less than regional S_v)

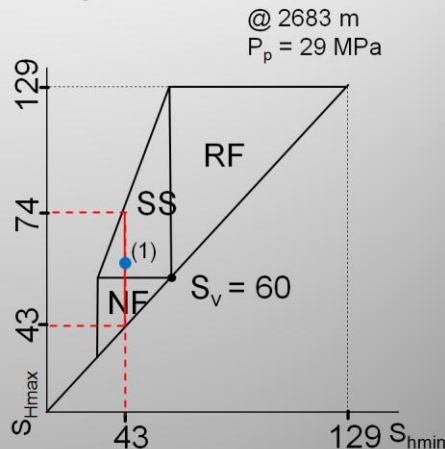- Vertical stress estimated from regional lithostatic gradients due to lack of data
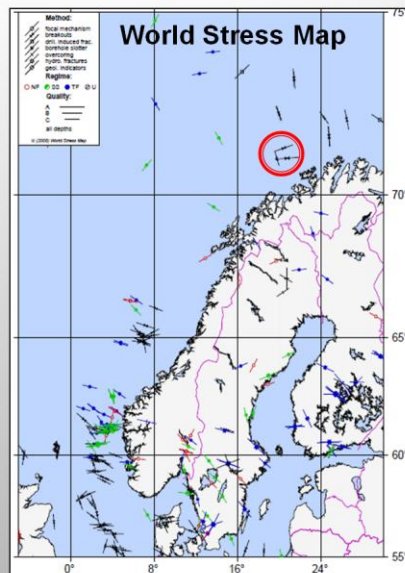
Modeled Stress State

- NS S_{Hmax} Az, S_{hmin}, S_v
- Control on S_{Hmax} → Jaeger & Cook equation for critically stressed faults (a) & Anderson's faulting theory
- P_p = 28 MPa at injection depth
- μ = 0.6
- Base case Stress Tensor (1):
- $S_{Hmax} > S_v > S_{hmin}$ → SS regime

(a) $\sigma_1/\sigma_3 = (S_1 - P_p)/(S_3 - P_p) = [(\mu^2 + 1)^{1/2} + \mu]^2$

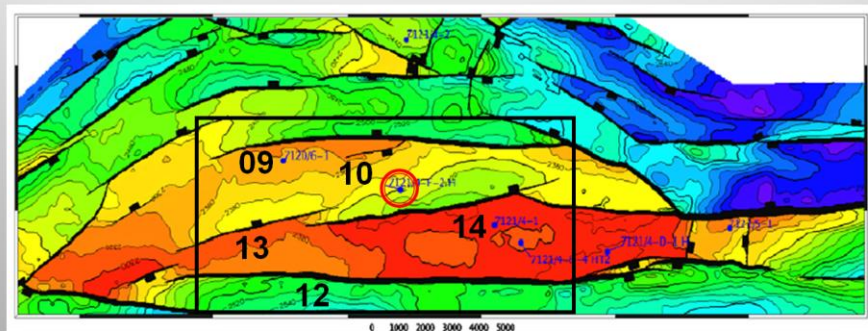Normal Faulting $\dfrac{\sigma_1}{\sigma_3} = \dfrac{S_v - P_p}{S_{hmin} - P_p} \le [(\mu^2 + 1)^{1/2} + \mu]^2$

Strike Slip Faulting $\dfrac{\sigma_1}{\sigma_3} = \dfrac{S_{Hmax} - P_p}{S_{hmin} - P_p} \le [(\mu^2 + 1)^{1/2} + \mu]^2$

Reverse Faulting $\dfrac{\sigma_1}{\sigma_3} = \dfrac{S_{Hmax} - P_p}{S_v - P_p} \le [(\mu^2 + 1)^{1/2} + \mu]^2$

@ 2683 m
P_p = 29 MPa

RF

SS

(1)

NF

S_v = 60

129
74
43

S_{Hmax}

43   129 S_{hmin}

Presenter's notes: The likely magnitudes for SHmax can then be calculated by combining the equations that relate σ1 and σ3 for a critically oriented fault at the frictional limit Eq. (2) [15] with Anderson's faulting theory which determines which principal stress (SHmax, Shmin, Sv) corresponds to S1, S2 and S3 respectively [16]. Therefore by using the corresponding equation for a SS environment, Eq. (3), the upper bound of allowable values of SHmax can be found:
*xLOT at 2400m and extrapolated to 2683 m with a grad of: 2.33 g/cm³ (= 0.0226 MPa). S3 = 42.88 [MPa] at 2683 m

Black Rectangle Shows Area of Analysis
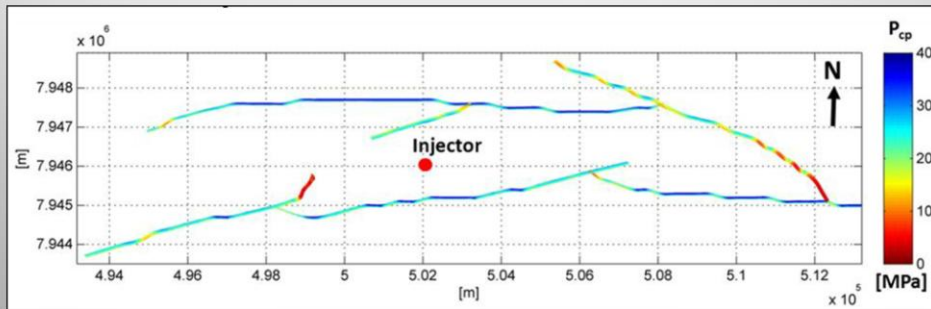
Fault traces color-coded by amount of extra pressure (P_{cp}) necessary to initiate slip (Base Case scenario: SS environment with NS S_{Hmax} direction)
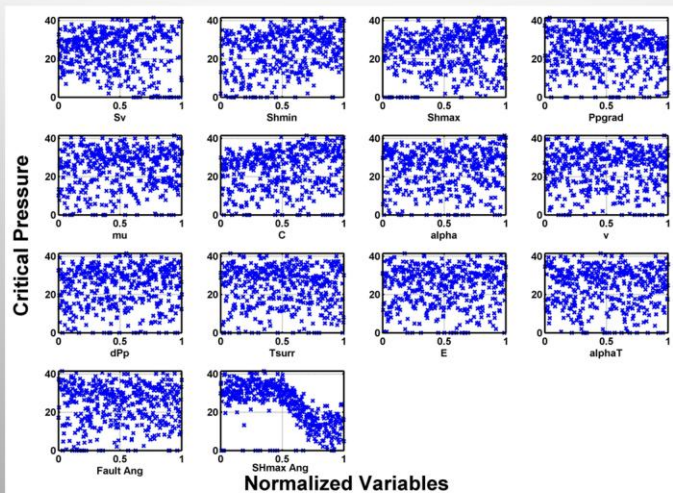
Presenter's notes: By comparing Pc with the reference pore pressure (Pp) in the reservoir we obtain the critical pressure perturbation (Pcp) that indicates the pore pressure change for a fault segment to slip given the stress state, fault orientation and reference Pp. When using this type of analysis to evaluate the risk of leakage, it is assumed that active faults are potential conduits for fluid migration, so that Pcp indicates the leakage potential for each portion of the fault.

Uncertainty Analysis - PSUADE

- 14 Parameters

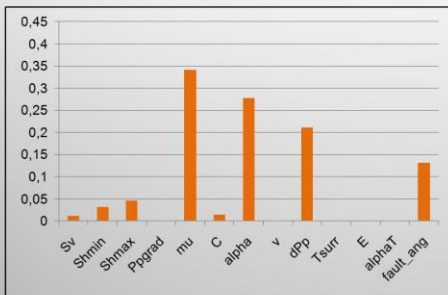- 1000 samples produced with Latin hypercube sampling method

Variable	BC	Min	Max	Units
S_v	60.6	51.5	69.7	MPa
S_{hmin}	43	38.6	47.2	MPa
S_{Hmax}	65	60.6	74.3	MPa
P_p	28	25.2	30.8	MPa
μ	0.6	0.35	0.85	
C	0	0	5	
α	1	0	1	
v	0.25	0.25	0.35	
dP_p	10	0	10	MPa
T	95	85	105	°C
E	35	22	36	GPa
αT	$1.5e^{-5}$	$1e^{-6}$	$1.5e^{-5}$	1/°C
Fault ang	-85	-55	-89	°
S_{Hmax} Az	0	345	105	°

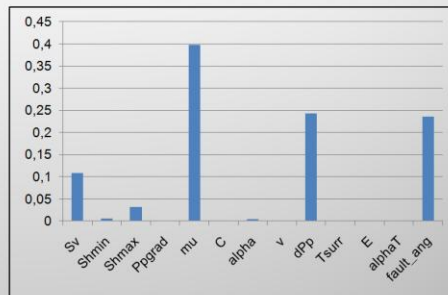# UQ Analysis indicates S_{Hmax} Az as main uncertainty

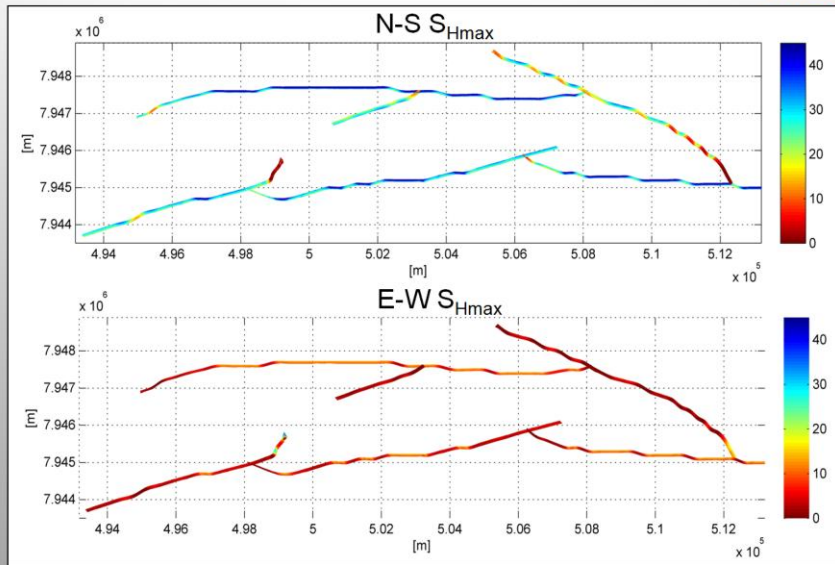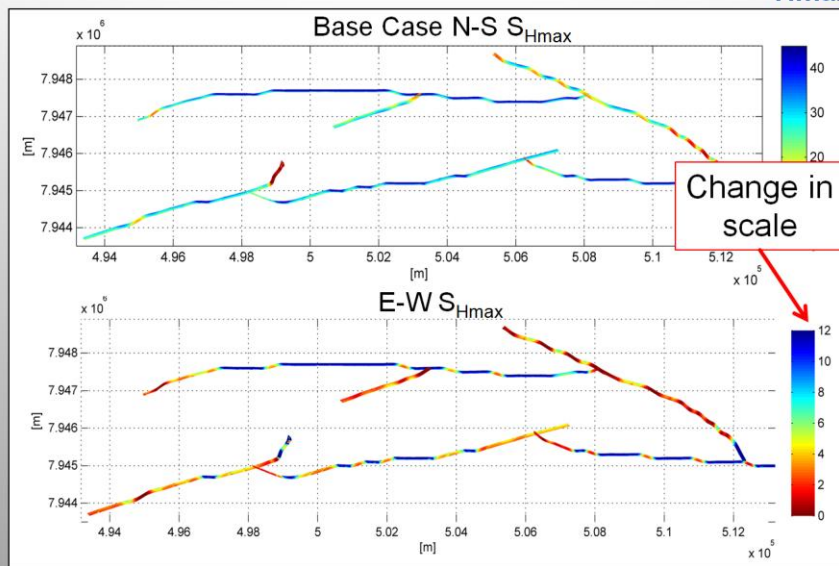# Refined Uncertainty Analysis (13 variables) – Fault 10 example
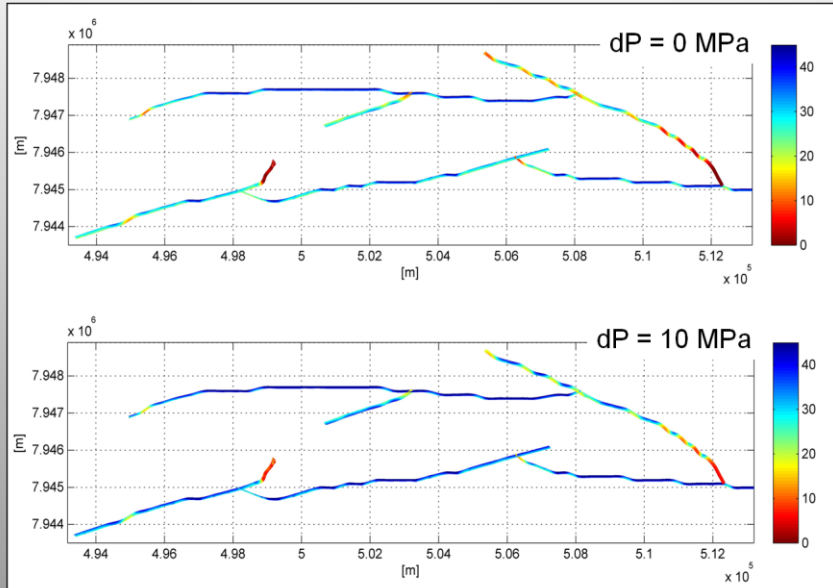
NS S_{Hmax}

EW S_{Hmax}

Presenter's notes: Map view of faults color coded with pressure perturbation (P_{Ppert}) needed for reactivation Color code represents pressure in MPa
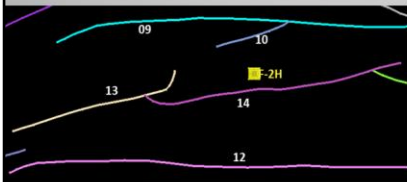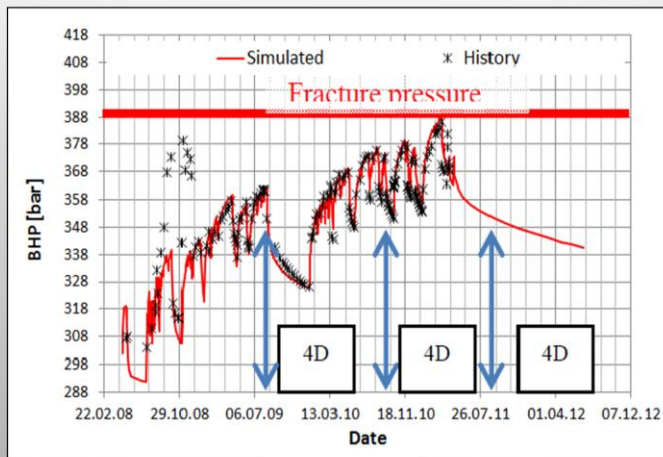
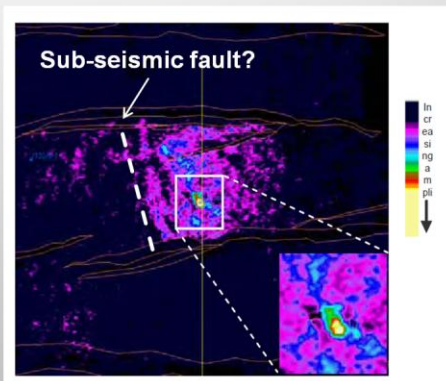# Faults ~ 8-20% less stable with E-W S_{Hmax}
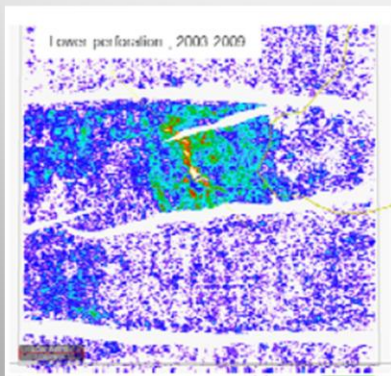

Change in scale

Faults 16 to 36% more stable when considering poroelasticity (dP = 10 MPa)

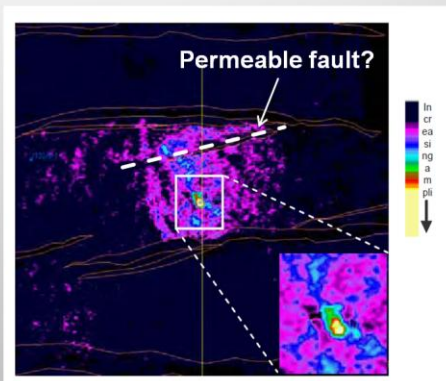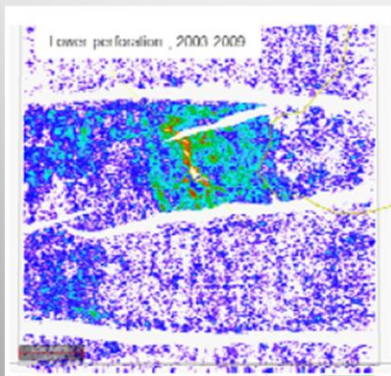# 2.- Why was storage capacity lower than expected

Structural vs. Stratigraphic compartmentalization

4D difference amplitude maps

Hansen *et al*, 2012

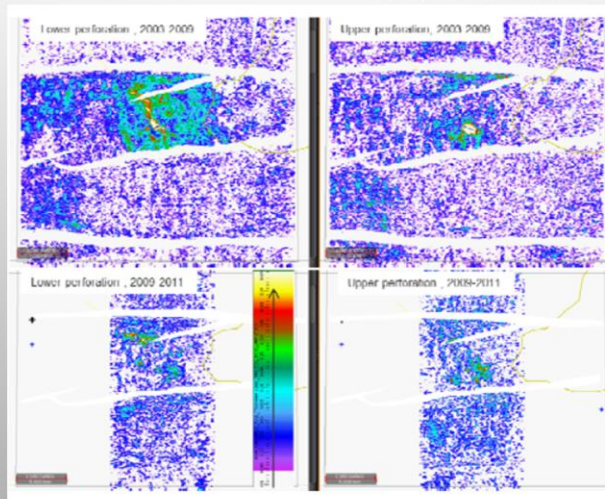# Structural vs. Stratigraphic compartmentalization

Permeable fault?

Increasing amplitude

Hansen *et al*, 2012

4D difference amplitude maps

Possible Local Vertical Migration at F10

Lower Perforation   Upper Perforation

Hansen *et al*, 2012

Summary

Feature	NS S_{Hmax}	EW S_{Hmax}	Juxtaposition Analysis
Bounding Faults (F09, 12 & 14)	Very stable	Segments close to critically stressed (c.s)	Large offsets, contact with low permeability fms. can explain sealing capacity even if c.s.
Fault 10	Stable	Close to critically stressed, would explain apparent local vertical migration	Small offset (< 10 m) could allow pressure and fluid transmition, but not cross-flow is inferred from seismic
Theoretical Subseismic Fault	Critically stressed	Stable	Very low offset could allow pressure or fluid migration even if not c.s.

Summary cont.

- Strong stress uncertainties difficult predictions

- Faults fairly stable under "most likely" stress state: SS & NS S_{Hmax}. Caprock failure would happen before fault reactivation. Under those conditions, it is unlikely that a theoretical sub-seismic fault could act as flow barrier

- Faults are ~ 20% less stable with EW S_{Hmax}, where several segments are close to critically stressed. Fault reactivation could happen before caprock failure if injection continues with risk of gas contamination.

- Snøhvit gas accumulation does not provide extra constraints to assess S_{Hmax} Azimuth (fault sealing capacity):
  - It is underfilled. It appears to have leaked in geological recent times (deglatiation?)
  - Fault juxtaposition could provide effective seal even if bounding faults are critically stressed