Case Study

EVALUATING FLOW PROPERTIES OF RESERVOIR FAULTS, AN EXAMPLE FROM THE GULLFAKS FIELD

A study carried out for the Norwegian Petroleum Directorate

A fault seal study was performed on faults in the Gullfaks Field, located within Block 34/10 of the Norwegian sector of the North Sea.

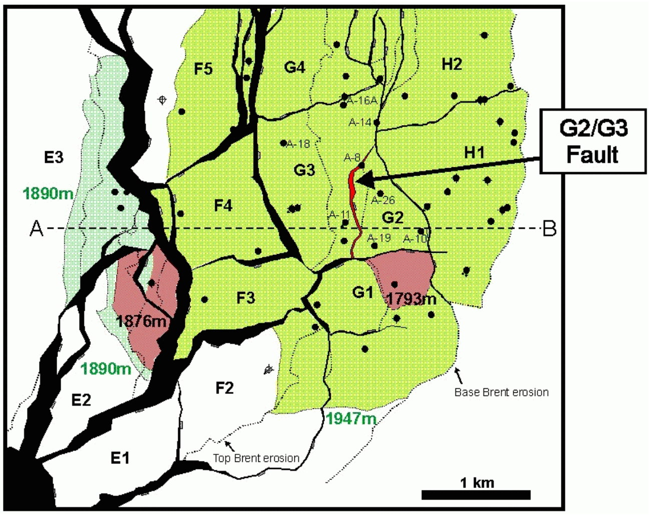
Geological Setting of the Gullfaks Field

Structure of the Gullfaks Field:

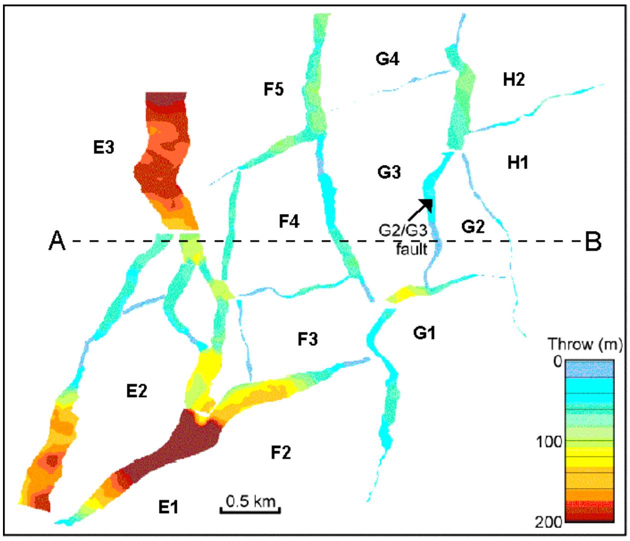
The Gullfaks fault block is highly faulted into two structurally distinct subareas: a major domino system, and an eastern horst complex. These two subareas are separated by an accommodation zone. The two subareas show significant differences with respect to fault geometry, rotation and internal block deformation.

The major internal faults in the studied part of the field are E-dipping with strike approximately NS. EW-striking minor faults, both N- and S-dipping, divide the major domino blocks into smaller fault compartments.

Particular attention was paid to the fault separating the G2 and G3 fault blocks, as this fault is suspected as playing a important role in the communication between these two blocks.



Top Brent Structure map showing fault compartments (e.g. F5, G3, G2) and well locations (dots). Green area is oil-bearing Brent Group (pink areas are gas caps). Fault highlighted in Red is discussed in detail (G2/G3 fault)

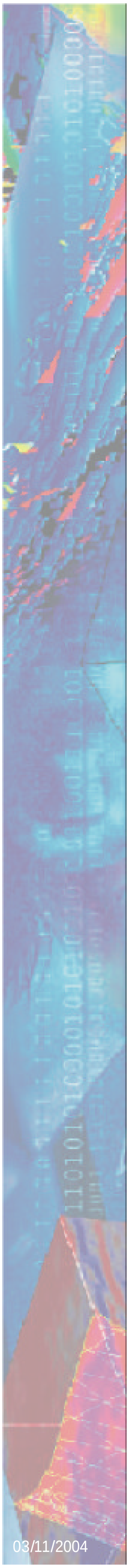


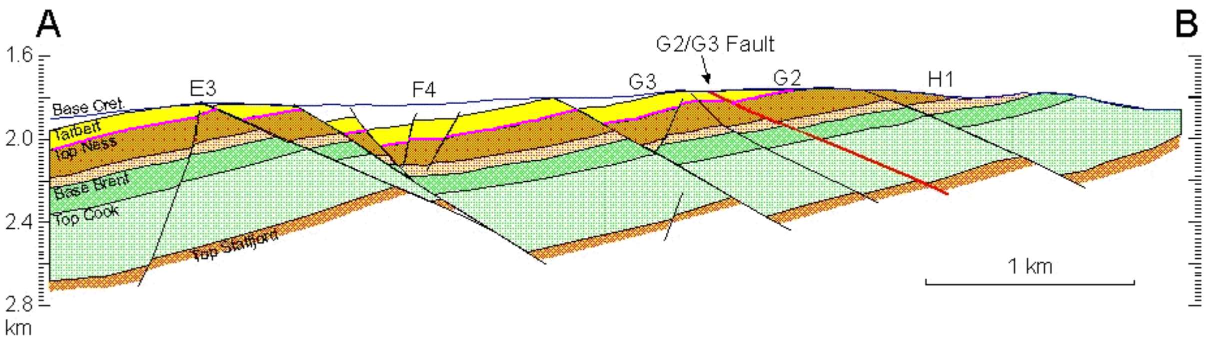
Map view of the faults showing the throw distribution at the level of Top Ness. The throw at the Top Ness is less than the thickness of the Brent Group.

Reservoir Properties:

The Brent Group reservoir consists of sandstone units within the:

- ***Tarbert Formation*** consisting of massive, homogeneous and highly permeable (3-10 Darcy) sandstone units with a few shale, coal and carbonate layers,
- ***Ness Formation*** consisting of thin sandstone units interbedded with shale and coal layers, which act as vertical flow- and pressure barriers,
- ***Etive Formation*** consisting of massive sandstone with excellent reservoir properties (2-7 Darcy),
- ***Rannoch Formation*** consisting of sandstones with poor reservoir properties (0.05 -2 Darcy).





Cross-section along line A-B. Top Ness is highlighted by purple line

Although the study was focused on the Brent reservoir, parameters for the overlying Upper Jurassic Shale (Viking Group) and the underlying Dunlin Group were added to be able to calculate fault properties where these units juxtapose the Brent reservoir.

Most of the Brent Group reservoir in the Gullfaks Field has a common oil/water-contact of 1947 m msl. The exceptions are the westernmost fault blocks, E2 and E3, which have a shallower oil/water-contact. In addition a small gas cap is observed in fault block G1. Pressure measurements taken early in the production history, before the start of water injection, are expected to show a more unique relation to the fault properties, than the complex pressure situation experienced after years of production and injection. Particularly suitable calibration points are pressure measurements in 'undrained' fault blocks that showed pressure drops caused by the production in adjacent blocks.

Production from the Gullfaks Field commenced in December 1986. In the planning and early production phase, it was realised that the extent of faulting on the field would have a major impact on the strategy for reservoir management .

Pressure measurements made during production, in new wells and with permanent downhole gauges, indicated that some pressure communication existed between separate fault compartments. Furthermore, it was found that surplus gas, reinjected to improve the displacement of oil, was been produced back from unexpected well locations, often within a relatively short time

The ***Norwegian Petroleum Directorate*** was interested in evaluating the possibility of applying gas injection on a larger scale as an integrated part of the reservoir management. One obvious requirement to be able to achieve this goal is a better understanding of the flow and pressure patterns in the reservoir.

The objectives of the study were:

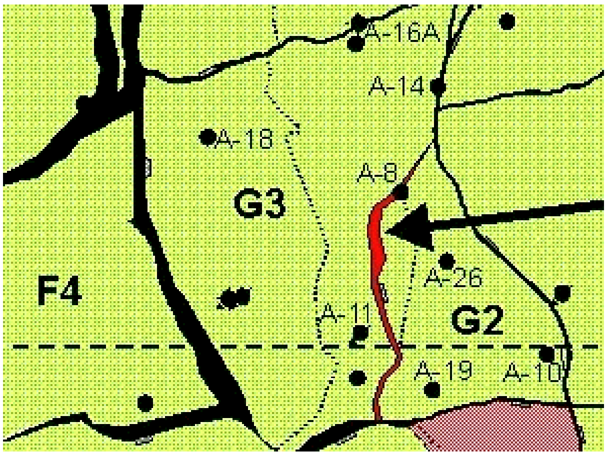
1: To investigate the flow properties of the internal faults in the Gullfaks field, both with regard to a static model (pre-production conditions) and with regard to a dynamic model (production history).

2: To produce a quantitative expression, in grid format, of the fault-zone properties (i.e. permeabilities and fault transmissibility modifiers) for input into reservoir simulation models.

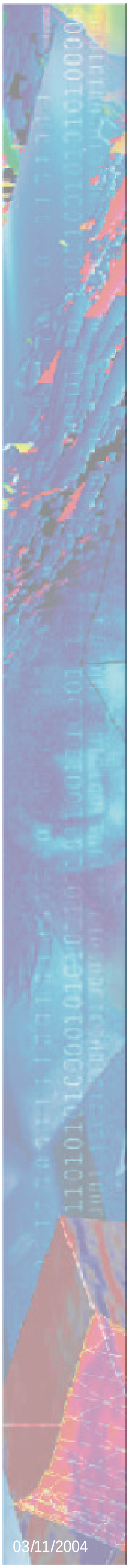
Achieving the Objectives through TrapTester Fault Seal Analysis

A total of 23 fault segments in the Gullfaks field were analysed using TrapTester Fault Seal Analysis. In this discussion we concentrate on the fault separating the G2 fault block from the G3 fault block.

Fault-blocks G2 and G3 originally had the same oil-water contact. Therefore, on a geological time-scale, the G2/G3 fault probably did not constitute a 'sealing' fault. However, the two fault-blocks underwent differential depletion once production had started, implying that the fault was a barrier to flow on the production time-scale.

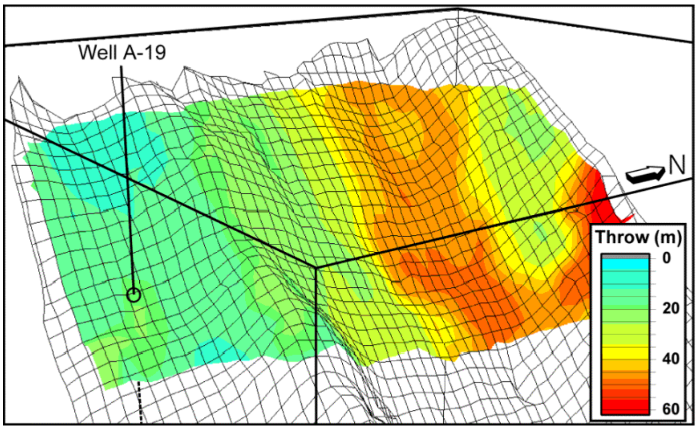


Map showing the G2/G3 fault (arrowed)



Fault Throw

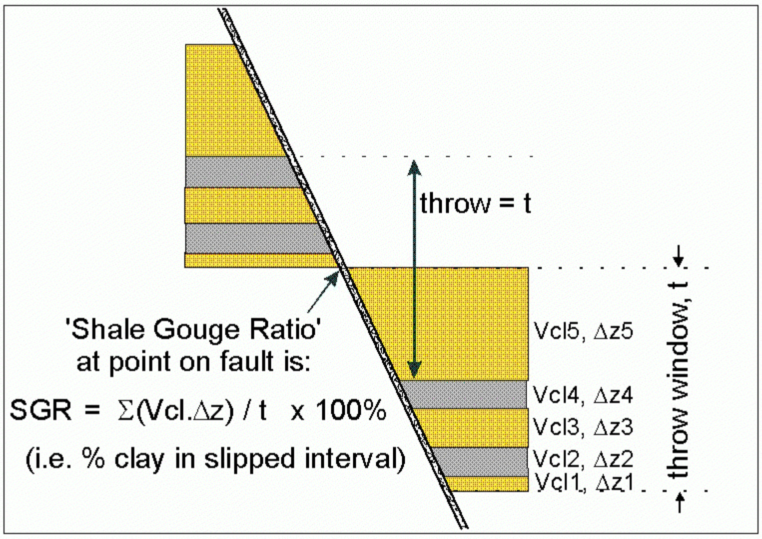
The fault throw reaches about 50m on the northern part of the fault but is much less in the south (c.10-20m). At both ends the G2/G3 fault links onto other faults, i.e. there are no lateral tips. The fault was penetrated near its southern end by well A-19 (but unfortunately the fault plane was not cored).



Perspective view of the fault surface, viewed towards WNW. Colour-coded by the fault throw. Fault grid-cell size is 25m x 25m

Shale Gouge Ratio:

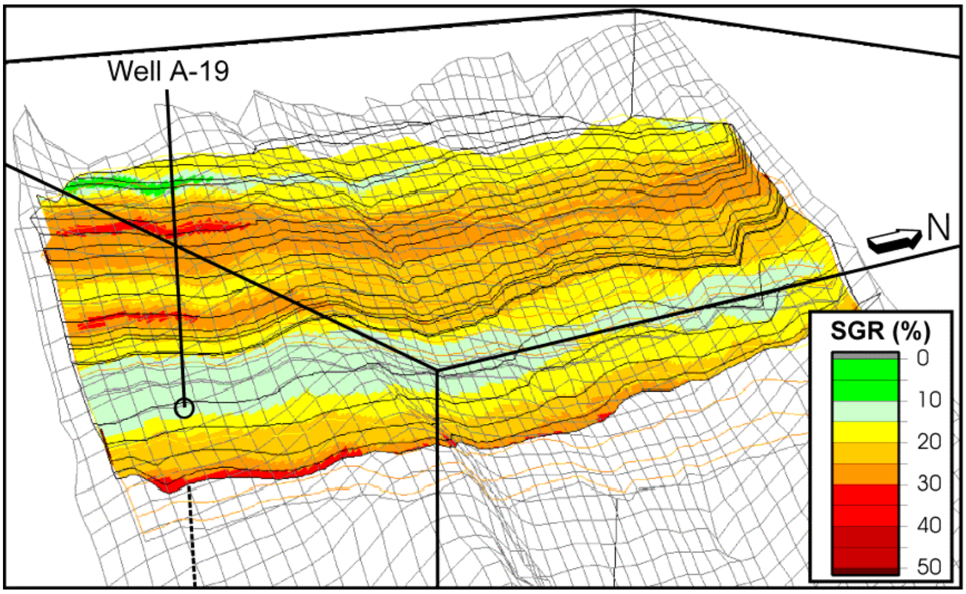
Shale Gouge Ratio is the percentage shale or clay material that has slipped past a point on the fault.



The shale gouge ratio was calculated using Vshale values from adjacent wells. The shale gouge ratio (SGR) provides an estimate of the composition of the fault zone (fault-zone % shale).

Measurements taken on fault gouge samples indicate that there is a first-order correlation between phyllosilicate content (~SGR) and fault-zone permeability. For example, a phyllosilicate content of <15% in the fault zone is characteristic of cataclasites with permeability c.0.5mD, whereas archetypal clay smears have phyllosilicates >40% and permeability < 0.003mD.

The SGR distribution on the modelled fault surface can therefore be used as a prediction of fault-zone permeability.

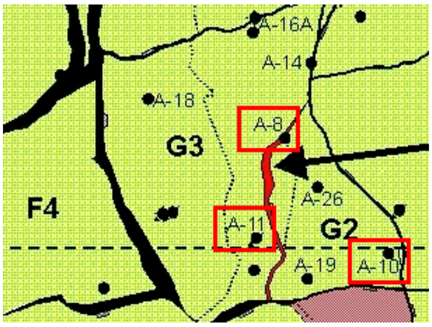


A prominent feature of the SGR plot is the area of lower SGR values in the Lower Brent, especially on the southern half of the fault. The small offset of the clean Etive Formation is the main cause of this.

Perspective view of the fault surface, viewed towards WNW. Shale Gouge Ratio in the reservoir-reservoir overlap areas.

Review of Pressure and Tracer data

Pressure data obtained in 1987

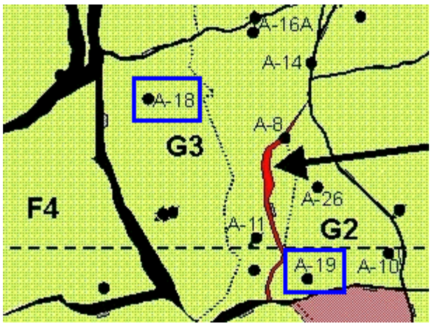


The first well in block G3 (west of the fault) was well A-8 in mid-1987; RFT data showed only very minor depletion from earlier production to the north-east. A-8 production began in June 1987.

Well A-10 was drilled into block G2 (east of the fault) in July 1987 and found 7.5 bar depletion in the Rannoch/Etive. This must have been caused either by A-8 production in G3, or by ongoing production to the east in block H1, or both. Well A-11 (RFT pressure measurements made in September 1987) in G3 found that drawdown by A-8 production had now reached 24 bar.

Pressure measurements taken at wells in 1987 (red squares). G2/G3 fault is arrowed

Pressure data obtained in 1988



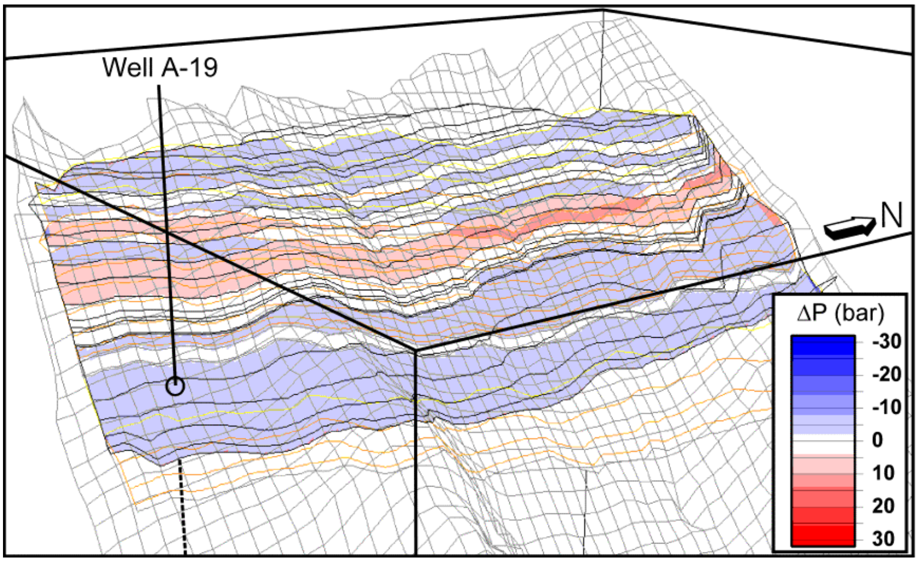
RFT measurements were taken in rapid succession in well A-18 (block G3) and well A-19 (G2/G3).

Well A-19 penetrated the G2/G3 fault, passing from Etive in the downthrown block G2 to Rannoch in upthrown block G3. Between these units, well A-19 found a 6 bar pressure difference. In every other well, the Rannoch/Etive forms a continuous pressure compartment because of the lack of shaly breaks. Well A-19 is therefore directly sampling the pressure drop at one point on the fault surface.

Pressure measurements taken at wells in 1988 (blue squares). G2/G3 fault is arrowed

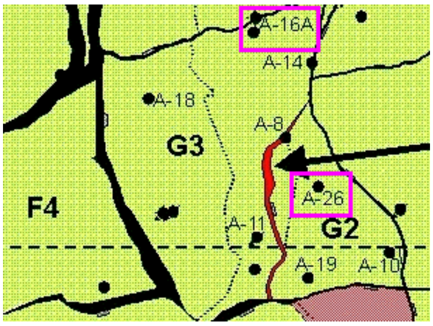
Wells A-18 and A-19 together provide pressure profiles for both sides of the fault for late 1988. In the footwall (G3 block in the west) depletion was greatest in the Rannoch/Etive (>15 bar) and in the upper Ness (produced in A-14). In the hangingwall (G2 block in the east) depletion was more uniform (Rannoch and Ness production from A-10). Comparison of monitored pressures in every zone on each side of the fault allows us to generate a display of across- fault pressure difference, shown in the next figure.

In general, block G3 is more depleted than block G2 (area shown as blue on figure below) as there were more producing wells in G3. However the central part of the Brent-Brent overlap zone shows G2 (hangingwall) depletion locally greater than G3 (red), depending on the precise juxtaposition of Ness zones. The complexity of this plot is illustrative of the complex nature of the fault response to production.



Perspective view of fault surface, viewed towards WNW. Pressure difference across the G2/G3 fault: late 1988

Pressure data obtained in 1989

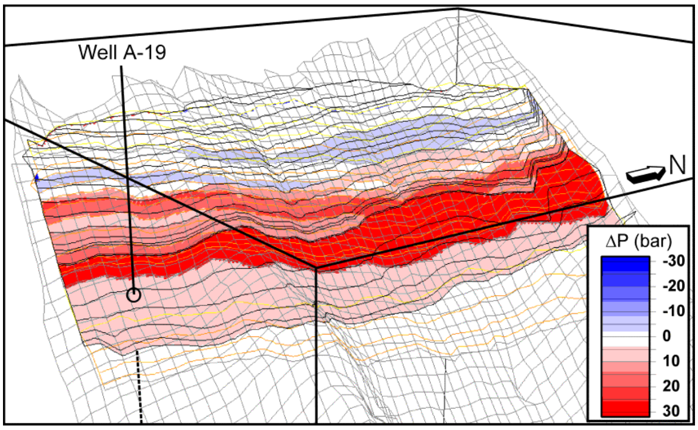


Pressure measurements taken at wells in 1989 (purple squares). G2/G3 fault is arrowed

One year after wells A-18 and A-19 were drilled, another pair of wells (A-16A, A-26) were drilled in blocks G2 and G3, allowing a second measurement of pressures in both blocks.

By this time, the Ness and Tarbert pressures in G2 and G3 had dropped substantially because of production, but pressures in the Lower Brent had recovered to near-original as the rate of water injection in several wells exceeded the rate of production.

Juxtaposition of downthrown depleted Ness against upthrown recovered Lower Brent gives a very large pressure drop (>40 bar) in the central part of the overlap area. This contrasts with the lower part of the overlap area (Lwr Brent against Lwr Brent) where the pressure drop is only about 5 bar from footwall to hangingwall, and also with the upper part of the fault (downthrown Tarbert) where the footwall was slightly more depleted.



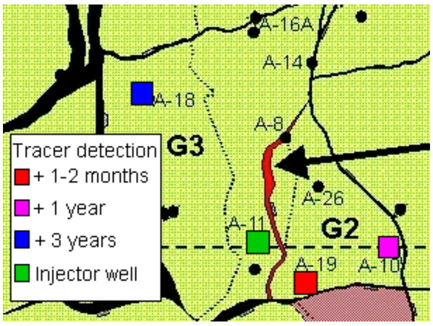
Perspective view of fault surface, viewed towards WNW. Pressure difference across the G2/G3 fault: 1989

Summary of pressure data observations

1: The changing production/injection pattern can produce not only changes in the across-fault pressure drops, but complete reversals in the direction of the pressure drop. If these pressure drops are associated with fluid flow, then the direction of fluid flow across the fault will have reversed between late 1988 and late 1989.

2: The direction of pressure drop (and, therefore, fluid flow) can be in different directions on different parts of the same fault, at the same time.

Non-radioactive Tracer injection during 1991



Non-radioactive tracer was injected into well A-11 in block G3 during a phase of gas injection (Kleven et al. 1995). Tracer injection was into the Rannoch Formation (Lower Brent).

There was very rapid detection of tracer across the fault in block G2 (lower Ness in well A-19) after only 1-2 months. This contrasted with detection in other wells in injection block G3, where the tracer did not appear for more than three years. These observations imply that the dominant flow direction in the G3 Lower Brent at well A-11 was across the fault into block G2.

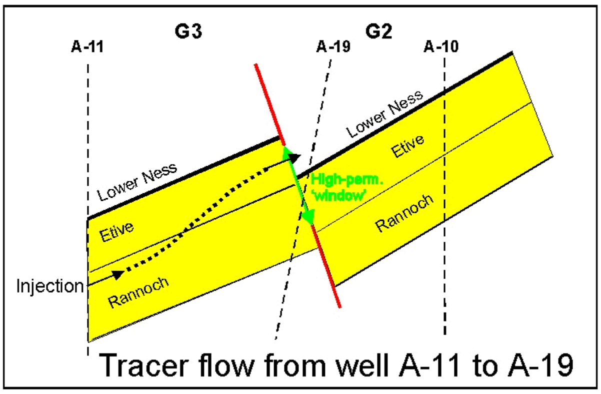
Location of tracer injection into Rannoch Formation (green square)

This flow route can be easily understood in terms of the juxtapositions and gouge ratio on the southern part of the fault, together with the prevailing pressure regime. The juxtaposition geometry is shown simplified in the cross-section below; green colouring on the fault indicates low SGR, while red colouring indicates high SGR.

Injection of tracer was into the Rannoch Formation of well A-11 in block G3, and tracer would therefore have risen into the overlying Etive since the Rannoch/Etive behaves as a continuous sand (no shale breaks). The Etive is juxtaposed against lowermost Ness at the fault, and the SGR plot above suggests that Shale Gouge Ratio is relatively low on this area of the fault (i.e. fault permeability relatively high). Flow across the fault into the lower Ness is therefore possible.

Well A-10 in block G2, the Rannoch producer closest to the A-11 Rannoch injector, did not detect tracer until a year after injection. The cross-section below shows that the route from A-11 Rannoch to A-10 Rannoch would be a difficult one, passing down at the fault offset at a region where the Shale Gouge Ratio is rising (fault permeability decreasing). Thus most of the tracer moving into block G2 would have bypassed the A-10 Rannoch section and is likely to have been higher in the sequence.

Pressure measurements in early 1991 suggest that the pattern seen above was continuing, i.e. strong pressure drive from footwall Etive into depleted hangingwall Ness.



Cross-section showing non-radioactive tracer flow route across the G2/G3 fault

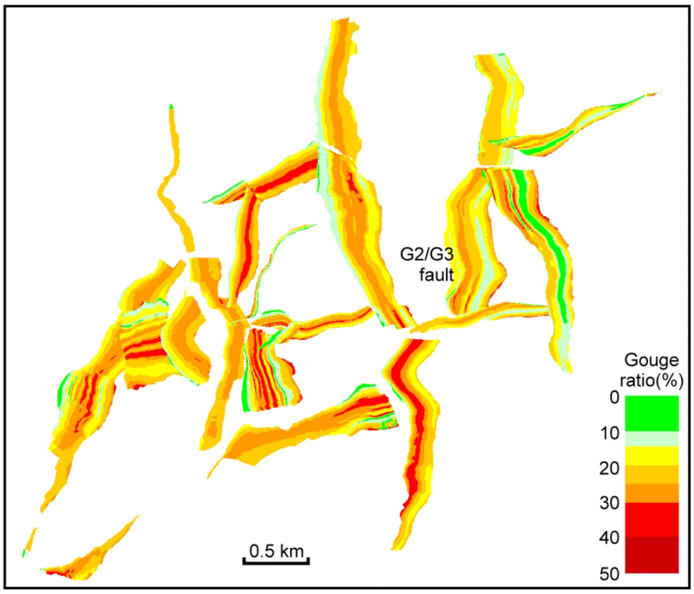
Shale Gouge Ratio at other faults in Gullfaks

Shale Gouge Ratio at the Brent-Brent overlaps was calculated on all 23 analysed fault segments in the Gullfaks area. In the figure below, the colour-coded areas are those parts of the fault planes where there is Brent-Brent overlap. A wide overlap area on the map indicates a relatively small fault displacement, whereas a narrow (or zero) overlap area corresponds to larger displacement.

The shale gouge ratio scale can be considered as representing static seal capacity, or being inversely related to fault-zone permeability.

Faults with small displacements (wide areas on map) have a heterogeneous distribution of Shale Gouge Ratio and therefore a broad range of fault-zone permeabilities.

Faults with large displacements (narrow areas on the map) have a more uniform (and moderately high) SGR distribution. The fault-zone permeability will be relatively low.



Map view of the analysed faults showing Shale Gouge Ratio in the Brent-Brent overlap zones

Key Points arising from the study:

1: Fault-surface modelling of the faults using TrapTester Fault Seal Analysis provided a framework in which to visualise the reservoir juxtapositions, seal attributes and across-fault pressure changes during production.

2: Dynamic pressure drops during production provide a general guide to the permeability of the fault zones once across-fault flow of hydrocarbons has started.

3: Flow direction across a fault can reverse direction as production / injection patterns changes. Flow can be in opposite directions on different parts of the same fault at the same time.

4: Fault-surface modelling also includes predictive algorithms (Shale Gouge ratio) that can be used to derive fault-zone permeabilities and transmissibility modifiers for reservoir simulation studies. Areas of higher shale gouge ratio on the fault surface correspond to lower fault-zone permeabilities.

Based on the publication by Yielding, Øverland & Byberg, "Characterisation of fault zones in the Gullfaks field for reservoir modelling", Proceedings of the 5th Conference on the Petroleum Geology of NW Europe (in press).