Volve

15/9-F-11
15/9-F-11 T2
15/9-F-11 A
15/9-F-11 B

Petrophysical (static) well evaluation

Interpreter: Torill Vee

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1 Introduction

1.1 Introduction 15/9-F-11 / 15/9-F-11 T2

Objective of the 15/9-F-11 pilot well was to prove oil in the Volve North prospect segment and to define the field OWC. If the pilot revealed an ODT situation, an optional openhole side-track further down flank would be considered.

In addition the pilot was placed such that it could also prove a shallower Hugin interpretation based on the previous 2009 interpretation, which represents an additional prospect upside. Fluid sampling, both oil and water samples (with Sclumberger's MDT on TLC) for PVT analysis, was planned if any commercial find scenario.

1.2 Introduction 15/9-F-11 A

Objective of the second pilot 15/9-F-11 A was to prove oil and sufficient reservoir thickness in the Northwest fault segment. If the pilot revealed an 'oil above water column' situation, a water sample (with Sclumberger's MDT on TLC) was to be taken to prove for initial (perched water) or flooded conditions.

1.3 Introduction 15/9-F-11 B

Dependent of the results from 15/9-F-11 / F-11 T2, the objectives of 15/9-F-11 B were the following two:

If 15/9-F-11 / F-11 T2 encountered sufficient oil column in Volve North segment, well F-11 B was to be drilled to an optimal location further upflank and completed as a producer. An injection well would then later be required for pressure support (2nd well in drilling campaign from F-1), even if the segment is in communication with the main field.

If 15/9-F-11 / F-11 T2 found no or insufficient oil in the Volve N prospect, the well was to be side-tracked to an infill location between existing producers F-12 and F-14 in the main field and downflank towards existing injector F-5. The aim was then to geosteer the well in the upper part of the Hugin reservoir, which was expected to be only partially drained.

2 Summary

2.1 Summary 15/9-F-11 / 15/9-F-11 T2

15/9-F-11 well path did not achieve sufficient separation from nearby wells, hence P&A before a technical side-track was performed. TD of 15/9-F-11 was 347 m MD RKB.

The technical side-track, 15/9-F-11 T2, was kicked off from F-11 @ 257 m MD RKB. TD @ 4562 m MD RKB.

Top Hugin was encountered 27 m deeper than prognosed.

Hugin Fm. was water filled, except of two pockets of residual oil that seem to be structurally trapped. (Lowest Sw achieved in these is ~ 0.4) One residual oil pocket is situated below Heather Fm. and the other below the “Offshore Shale” which is separating Upper Hugin and the “Thief Zone” (Middle Hugin).

These 2 residual oil pockets are observed in the following intervals:
4393.8 – 4399 m MD RKB / 3182.3 – 3187.3 m TVD MSL,
4415.8 – 4419.7 m MD RKB / 3203.6 – 3207.4 m TVD MSL.

Oil show is described on cuttings @ 4411 m MD.

The rest of Hugin Fm. which was water filled, showing very low resistivities < 0.05 ohmm in the best sands, is reflecting the very saline formation water in Volve (~ 130000 ppm). This might indicate that Hugin Fm. never has been oil filled, and that the two observed oil pockets are results of hydrocarbon migration.

Hugin Fm. properties seem to be poorer than in Hugin Fm. in previous Volve wells, with an average porosity of 0.17. This is 4 p.u. less than the porosity in Hugin Fm. in the exploration well 15/9-19 BT2, which is the closest well with respect to TVD depth. Net/Gross is however high as expected in Hugin (> 0.8); in this well 0.81.

Porosity from MagTrak is a lithology independent porosity, and MagTrak porosity in F-11 T2 confirms in general the porosity from the density log.

Formation pressure points in Hugin Fm. were 13.7 bar above initial fm. pressure measured in 15/9-19 BT2 (January 1998). This indicates communication with Hugin Fm. in the Volve main field, since reservoir pressure has been increased ~12 bar above initial pressure by injection, prior to this drilling campaign.

LWD log data is of good quality.

No oil and water samples were taken since no commercial find.

2.2 Summary 15/9-F-11 A

15/9-F-11 A was side-tracked from F-11 T2 with KOP @ 2586 m MD RKB. TD @ 3762 m MD RKB.

Top Hugin was encountered 25 m deeper than prognosed.

Hugin Fm. was oil filled, with porosity being slightly lower and water saturation being higher than previous Hugin wells. An average porosity of 0.21 in F-11 A is 2 p.u. less than the porosity in Hugin Fm. in 15/9-F-4 and 15/9-F-15 A, which are the most comparable wells with respect to TVD depth. Net/Gross is however as expected > 0.8, in this well 0.86.

Oil Down To (ODT) ~ 3702 m MD RKB / 3025.5 m TVD MSL which corresponds to Top Sleipner Fm.

Formation pressure points in Hugin were 12 bar above initial fm. pressure measured in 15/9-F-12 (February 2008). This indicates communication with Hugin Fm. in the Volve main field, since reservoir pressure has been increased ~12 bar above initial pressure by injection, prior to this drilling campaign.

To get a picture of the time lapse effect, injection was closed, and a second set of formation pressure (only 5 depth stations were repeated) was logged 48 hours after the first formation pressure data set. This showed only minor decrease in formation pressure, in the range: 0.2 – 0.9 bar.

LWD log data is of good quality.

No water sample was taken since water was not encountered below the oil column.

2.3 Summary 15/9-F-11 B

Since 15/9-F-11 T2 did not find commercial oil in the Volve N prospect, 15/9-F-11 B was side-tracked to an infill location between existing producers F-12 and F-14 in the main field and downflank towards existing injector F-5.

15/9-F-11 B was side-tracked from F-11 T2 with KOP @ 2585 m MD RKB. TD @ 4770 m MD RKB.

Top Hugin was encountered 7 m shallower than prognosed.

Baker Hughes' AziTrak was used for geosteering.

Hugin Fm. was oil filled in large parts of the well, and encountered also oil in the first part (shallowest) of Hugin Fm., which was not expected from 4D and simulation model.
Averages for Hugin are given in table in chapter 7.3

Flooded intervals are given in table in chapter 4.7. A flag curve showing flooded intervals is named FLOODED_FLAG (in flooded intervals is FLOODED_FLAG = 1), and plotted as turquoise intervals in track no. 8 in the CPI plot.

Below ~ 4701 m MD RKB / 3148 m TVD MSL (a coal layer) the water seems to be initial, due to the low resistivity. This is plotted as dark blue interval in track no. 8 in the CPI plot.
Hence F-11 B might indicate a WUT = 3148 m TVD MSL, which is not in conflict with the observed ODT (= 3145 m TVD MSL) in the main field.

Since there is a huge contrast between the very saline Hugin formation water and the fresh, low saline Utsira formation (injection) water, 3 cases with different formation water salinity are presented in the F-11 B CPI in order to illustrated the impact on water saturation. The details of these cases are given in the header of the CPI.

LWD log data is of good quality.

8 intervals have been perforated. These are listed in table below and plotted as light green intervals in the rightmost track (no. 18) in the F-11 B CPI (chapter 8.3).

15/9-F-11 B PERFORATIONS					
Run no.	**Depth [m MD RKB]**	**Date**	**Shot Density**	**Open / Closed**	**Formation**
1	4527-4539	11.07.2013	4SPF	Open	Hugin
2	4488-4500	12.07.2013	4SPF	Open	Hugin
3	4355-4367	14.07.2013	4SPF	Open	Hugin
4	4304-4316	19.07.2013	4SPF	Open	Hugin
5	4286-4295	18.07.2013	4SPF	Open	Hugin
6	4268-4280	19.07.2013	4SPF	Open	Hugin
7	4065-4075	20.07.2013	4SPF	Open	Hugin
8	4031-4043	20.07.2013	4SPF	Open	Hugin

3 Data Acquisition and QC

3.1 15/9-F-11 / 15/9-F-11 T2 Measurement While Drilling (MWD) / Logging While Drilling (LWD)

The MWD / LWD logging contractor for the entire 2 wellbores was Baker Hughes.
Mud type in the 8 ½” reservoir section of 15/9-F-11 T2 was OBM, named Enviromul Yellow Spec 12. Name of base oil was EDC 95-11.
(Mud filtrate is considered to consist mainly of base oil.)
No cores were taken.

		15/9-F-11 MWD Run Summary						
		Contractor: Baker Hughes						
LWD Run	**Hole Section [inch]**	**Logging service (tool combination)**	**Pass**	**Pass direction**	**Logging speed**	**Bit depth Interval [m MD RKB]**	**Logging Interval [m MD RKB]**	**Remark**
1	17 ½ x 36	OnTrak	Drill	Down	ROP	146 - 208	-	Tool was lost in hole / seabed.
2	26	OnTrak	Drill	Down	ROP	208 - 224	-	MWD tool failure. No data in memory. Interval was re-logged in LWD Run #3.
3	26	OnTrak	Drill*)	Down	ROP	224 - 347	188 - 331	Good logging run, despite one resistivity transmitter failure. *) See re-log remark for Run #2.

		15/9-F-11 T2 LWD Run Summary						
		Contractor: Baker Hughes						
LWD Run	**Hole Section [inch]**	**Logging service (tool combination)**	**Pass**	**Pass direction**	**Logging speed**	**Bit depth Interval [m MD RKB]**	**Logging interval [m MD RKB]**	**Remark**
4	26	OnTrak	Drill	Down	ROP	257 - 454	238 – 439	Good logging run.
5	26	OnTrak	Drill	Down	ROP	454 – 1365	390 – 1349	Good logging run.
6	17 1/2	OnTrak / ZoneTrak G	Drill	Down	ROP	1365 – 2574	1250 – 2570	Good logging run.
7	8 1/2	AziTrak / LithoTrak / MagTrak / SoundTrak / TesTrak / CoPilot	Drill*)	Down*)	ROP	2577 - 4562	2522 - 4553	Good logging run including 2 re-logs. *)Fm. pressure points with TesTrak were taken when re-logging Hugin while POOH after TD.

Re-log no. 1 in Bit depth interval 4478.9 – 4560.8 m MD RKB, was logged while backreaming 7 – 19 hours after being drilled.
Re-log no. 2 in Bit depth interval 4392.5 – 4480.0 m MD RKB, was logged while backreaming 24 – 38 hours after being drilled.

Memory data:
All data was in memory, except for run 2 in 15/9-F-11 (Overburden). The data quality is in general good.

3.2 15/9-F-11 A Logging While Drilling (LWD)

The LWD logging contractor for the entire well was Baker Hughes.
Mud type in the 8 ½" reservoir section was OBM.
No cores were taken.

		15/9-F-11 A LWD Run Summary						
		Contractor: Baker Hughes						
LWD Run	**Hole Section [inch]**	**Logging service (tool combination)**	**Pass**	**Pass direction**	**Logging speed**	**Bit depth Interval [m MD RKB]**	**Logging interval [m MD RKB]**	**Remark**
8	8 1/2	OnTrak / LithoTrak / TesTrak / SoundTrak / CoPilot	Drill*)	Down*)	ROP	2586 – 3762	2457 - 3754	Good logging run. *)Fm. pressure points with TesTrak were taken while POOH after TD.

Memory data:
All data was in memory. The data quality is in general good.

3.3 15/9-F-11 B Logging While Drilling (LWD)

The LWD logging contractor for the entire well was Baker Hughes.
Mud type in the 8 ½” reservoir section was OBM.
No cores were taken.

		15/9-F-11 B LWD Run Summary						
		Contractor: Baker Hughes						
LWD Run	**Hole Section [inch]**	**Logging service (tool combination)**	**Pass**	**Pass direction**	**Logging speed**	**Bit depth Interval [m MD RKB]**	**Logging interval [m MD RKB]**	**Remark**
9	12 1/4	OnTrak / CoPilot	Drill	Down	ROP	2585 – 2917	2538.2 – 2898.5	Good logging run.
10	12 1/4	OnTrak / CoPilot	Drill	Down	ROP	2917 – 3197	2847.2 – 3177.3	Good logging run.
11	8 1/2	AziTrak / LithoTrak / CoPilot	Drill	Down	ROP	3197 - 4770	3146.1 – 4761.5	Good logging run including 1 re-log.

Re-log in Bit depth interval 3451 – 3508 m MD RKB, was logged while backreaming 91 – 105 hours after being drilled.

Memory data:
All data was in memory. The data quality is in general good.

3.4 Electrical Wireline Logging

No electrical logging performed in open hole.

4 Petrophysical Evaluation

Petrophysical evaluation is performed according to the Volve petrophysical field model, described in report: “Sleipner Øst and Volve Model 2006, Hugin and Skagerrak Formation, Petrophysical Evaluation”. November 2006. Author: Elin Solfjell, Karl Audun Lehne.

The petrophysical evaluation software used is Geolog, and the Geolog project is SLEIPNER_OST (at Stavanger server: FROST_SVG).

4.1 Porosity

Total porosity, PHIF (ϕ_F), is derived from the density log which is calibrated to overburden corrected core porosity for wells drilled with either OBM or WBM.

The Neutron log, NPHI, has been used to correct for varying mud filtrate invasion.

$$\phi_F = \phi_D + A \times (NPHI - \phi_D) + B$$

where:

$$\phi_D = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_{fl}} \quad \text{[fraction]}$$

ρ_{ma} is the matrix density [g/cm^3]
ρ_b is the measured bulk density (RHOB), [g/cm^3]
ρ_{fl} is the pore fluid density [g/cm^3].

A and B are regression coefficients.

NPHI: Neutron log in limestone units [fraction]

4.2 Shale volume

To determine VSH, the standard model VSH_{GR} from linear GR relationship is applied:

$$VSH = VSH_{GR} = \frac{GR - GR_{\min}}{GR_{\max} - GR_{\min}}$$

where:

GR = gamma ray log reading [API]
$GR_{\min}$ = GR reading in clean sand [API]

GR_{max} = GR reading in shale [API]

VSH is used quantitatively in deriving permeability, and quantitatively indirectly in Netsand cutoff.

In order to pick GR_{min} and GR_{max} in a more objective way, and to avoid over-estimating of VSH, GR is "normalized" against VSHDN (VSH from density / neutron) by cross plotting GR versus VSHDN. VSHDN is considered to be the most reliable shale indicator (except in intervals dominated by mica and heavy minerals). This shale indicator compares porosity derived from the Density log with porosity from the Neutron log. If the Neutron log reads higher porosity than the density, is this believed to be due to the hydrogen content of present clay minerals.

VSHDN is derived from the response equation for the Neutron log:

$$VCLDN = \frac{NPHICS - (PHIT * HIFL)}{HICL}$$

$$VSHDN = \frac{VCLDN}{(1 - PHISH)}$$

where:

VCLDN = Dry shale volume from density / neutron logs [fraction]
NPHICS = Neutron log corrected to sandstone matrix [fraction]
PHIT = Total log porosity [fraction]
HIFL = Hyrdogen Index to fluid
HICL = Hydrogen Index to clay
PHISH = Shale porosity [fraction]

In table below are the general parameters used in Hugin Fm. for deriving VSHDN, given the assumption that Kaolinite is the dominant clay mineral:

VSHDN Parameters		
HIFL (oil / water)	**HICL**	**PHISH**
0.95 / 1	0.5	0.07

4.3 Water saturation

Water saturation is calculated using Archie equation, giving a total water saturation:

$$Sw_t = \left(\frac{a \times R_w}{\phi_F^m \times R_t} \right)^{\frac{1}{n}}$$

where:

a = Archie (tortuosity) factor
R_w = resistivity of formation water [Ohmm]
ϕ_F = Total porosity [fraction]
m = cementation exponent
R_t = true resistivity [Ohmm]
n = saturation exponent

4.4 Permeability

The horizontal log permeability, KLOGH, is derived from the following equation based on multivariable regression analysis between log porosity and shale volume ("normalized" against VSHDN) against overburden corrected core permeability:

Hugin Fm.: $KLOGH = 10^{(2+8\times PHIF - 9\times VSH))}$

Sleipner Fm.: $KLOGH = 10^{(-3+32\times PHIF - 2\times VSH))}$

Skagerak Fm.: $KLOGH = 10^{(-1.85+17.4\times PHIF - 3\times VSH))}$

4.5 Composite curves

The following composite curves are used for the petrophysical evaluation:

GR	: GRCFM*) from OnTrak
RHOB	: BDCFM from LithoTrak
NPHI	: NPCKLFM from LithoTrak
PEF	: DPEFM from LithoTrak
RT	: RPCEHM from OnTrak
DRHO	: DRHFM from LithoTrak
CALI	: CALCM from UltraSonic Caliper, part of LithoTrak

Note in general that Baker considers the GRAFM curve as the best GR reading for large hole sizes > 17 ½" hole. The reason is as follows:

GRCFM is corrected for sensor type, collar size, carbonate content in mud, mud weight and hole size.
GRAFM is only corrected for sensor type, collar size and carbonate content in mud.
The hole size correction for GRCFM is performed by "normalising" GRAFM to a standard which is: 6 ¾" tool, 10" borehole with 8 ppg mud. The large discrepancy between 26" hole and "the normalised standard" is the reason for why the GRAFM is considered to be the best GR in large holes > 17 1/2".

*) Hence in 26" section GRAFM is used as GR (applies only for 15/9-F-11 and F-11 T2).

15/9-F-11 T2: Note that in the 17 ½" section a re-scaled NearBit GR (NBGRCFM) is spliced into GR for the ~ 9 last meters. NearBit GR has been re-scaled by -12 API in order to match GRCFM level.

Note also in general that the final «average» density curve - RHOB (BDCFM) - from Baker is weighted with respect to which of the 16 sectors / bins that provide the best density measurement (smallest standoff).

NPHI (NPCKLFM) is in limestone units, Caliper and salinity corrected and filtered.

The composite curves were created by Logtek from the memory data delivered by Baker Hughes.

Logtek's RDEP (Resistivity Deep) curve = RPCELM, named RD in the OW Volve project.
Logtek's RMED (Resistivity Medium) curve = RPCEHM, named RM in the OW Volve project.

No depth shifting has been applied, except in limited overlap intervals around kick off depths and hole sections in Overburden. These depth shifts and the splicing of the individual runs are reported in Logtek's info file for each well; WLC_COMPOSITE_1_INF_1.PDF which is stored in Petrobank.
All depths are referenced to Driller's depth.

Logtek's general "philosophy" with respect to depth shifting in the transition zone between a mother well and a kick off well is as follows: aim to keep the stop-coupled depths as shallow as possible, preferably at KOP. But sometimes it has to be sat deeper (a few meters deeper, preferably in a shale if possible) due to a) if overlapping curves are not on depth at KOP, or b) if the depth shifts have been so large, that the logs else will be too compressed. This "philosophy" also applies of course for depth shifting in overlap between hole sections.

4.6 Evaluation parameters

The following evaluation parameters are used for calculation of porosity, shale volume and water saturation:

15/9-F-11 T2 Evaluation parameters			
	Formation name		
Parameter	Heather Fm.	Hugin Fm.	Sleipner Fm.
ρ_{ma}	2.66	2.65	2.65
ρ_{fl}	1	0.9	0.9
A	0	0	0
B	0	0	0
$GR_{\min}$	4	4	4
$GR_{\max}$	120	184	105
a	1	1	1
m	2	*)	*)
n	2	2.45	2.45
*) $m = 1.865 \times \left(KLOGH^{(-0.0083)}\right)$			
R_w = 0.07 ohmm @ 20 ^{o}C.			
Temperature gradient = 2.6 ^{o}C / 100 m. Reservoir temp.: 111 ^{o}C @ 2800 m TVD MSL.			

15/9-F-11 A Evaluation parameters			
	Formation name		
Parameter	Heather Fm.	Hugin Fm.	Sleipner Fm.
ρ_{ma}	2.66	2.65	2.65
ρ_{fl}	1	0.9	0.9
A	0	0.4	0.4
B	0	0.01	0.01
$GR_{\min}$	7	7	7
$GR_{\max}$	120	150	105
a	1	1	1
m	2	*)	*)
n	2	2.45	2.45
*) $m = 1.865 \times \left(KLOGH^{(-0.0083)}\right)$			
R_w = 0.07 ohmm @ 20 ^{o}C.			
Temperature gradient = 2.6 ^{o}C / 100 m. Reservoir temp.: 111 ^{o}C @ 2800 m TVD MSL.			

15/9-F-11 B Evaluation parameters			
	Formation name		
Parameter	Heather Fm.	Hugin Fm.	Sleipner Fm.
ρ_{ma}	2.66	2.65	2.65
ρ_{fl}	1	0.9	0.9
A	0	0.4	0.4
B	0	0.01	0.01
$GR_{\min}$	5	5	5
$GR_{\max}$	120	127	105
a	1	1	1
m	2	*)	*)
n	2	2.45	2.45
*) $m = 1.865 \times \left(KLOGH^{(-0.0083)}\right)$			
R_w = 0.07 ohmm @ 20 ^{o}C.			
Temperature gradient = 2.6 ^{o}C / 100 m. Reservoir temp.: 111 ^{o}C @ 2800 m TVD MSL.			

Note that the RT curve in 15/9-F-11 B used for saturation calculation, has been edited in intervals where RPCEHM is affected by polarization horns or is saturated. This editing is kept on a specific curve in Geolog, named RT_EDIT.

4.7 Flag curves

Netsand flag:

Cutoffs on PHIF and VSH are used to determine Netsand; SAND_FLAG = 1.
Hugin Fm.: SAND_FLAG = 1 when PHIF > 0.10 and VSH < 0.50.
These cut offs correspond to a overburden corrected core permeability of 0.5 mD, and are also applied for the other formations.
In addition some manual editing might have been performed on the SAND_FLAG curve.

Carbonate flag:

A carbonate flag curve, CARB_FLAG, has been determined manually by visual inspection of the logs. Whenever CARB_FLAG = 1 is SAND_FLAG = 0.

Coal flag:

15/9-F-11 T2: 2 coal layers were observed in Sleipner Fm.

15/9-F-11 A: No coal layers were observed.

15/9-F-11 B: 2 coal layers were observed in Hugin Fm.

The coal flag curve, COAL_FLAG, has been determined by a manually decided cut off on the density log. In addition some editing was needed due to shoulder effects. Whenever COAl_FLAG = 1 is SAND_FLAG = 0.

15/9-F-11 B: Flooded interval flag:

A flag curve showing intervals which are flooded is named FLOODED_FLAG. When flooded intervals is FLOODED_FLAG = 1.

Flooded intervals are given in table below, and are also plotted as turquoise intervals in track no. 8 in the CPI plot for 15/9-F-11 B.

15/9-F-11 B FLOODED INTERVALS		
DEPTH [m MD RKB]	**DEPTH [m TVD MSL]**	**ZONE**
3527.5 – 3538.5	2846.7 – 2849.3	Hugin 3.1 (10)
4116.0 – 4187.5	2919.1 – 2933.6	Hugin 2.3 (9)
4577.5 – 4605.2	3061.8 – 3079.2	Hugin 2.2 (8), Hugin 2.3 (9)
4642.0 – 4700.0	3104.2 – 3147.0	Hugin 1.5 (5), Hugin 1.6 (6), Hugin 2.1 (7), Hugin 2.2 (8)

Table 4.7.

5 Evaluation of Formation Pressure Data

Baker's TesTrak Formation Pressure While Drilling tool was run in the 8 ½ section of 15/9-F-11 T2 and 15/9-F-11 A.

In both wells the formation pressures were taken after reached TD while re-logging while POOH (15/9-F-11 T2) and while POOH (15/9-F-11 A).

5.1 General remarks about Baker's TesTrak type

In general the test type choosen will have no influence on the acquired pressures – there might however be slight differences in mobility estimates from the second and third drawdown.

If "tight supercharged" test in a Darcy sand is chosen, one will still get the same pressure as a "high mobility" test. As seen from the table below all test types are volume controlled for the first drawdown (DD) anyway – it is only the second and third DD that are different. (The only difference between High and Low Mobility is the third drawdown).

Test Type	**First DrawDown (DD)**	**Second DD**	**Third DD**
High Mobility	Volume	DeltaP	Steady State
Low Mobility	Volume	DeltaP	DeltaP
Tight Supercharged	Volume	Volume	DeltaP
Unconsolidated Sand	Volume w/ initialization	Volume	Volume

The "Unconsolidated Sand" test includes a initialization sequence which might be beneficial to use for the first test. It is also the safest test to run if experiencing problems with the testing. The initialization sequence does however take about 1 min extra time, so if doing a large number of tests one would save some rig-time by doing one of the other types. Under normal conditions any of the tests could be chosen and would give good results.

Test time will be dictated by the formation mobility, independent of the test type (except the 1 extra minute of the "Unconsolidated Sand") – the "smart test" downhole logic will determine when it has 3 stable formation pressures and automatically finish the test. If 3 pressures are not obtained within the specified 10 minutes, the test will abort and the recorded pressures will be transmitted to surface.

To sum up:

Picking the most permeable zones for testing and having proper depth control is far more important than worrying about which test type to choose.

5.2 General remarks about temperature measured by Baker's TesTrak

The TesTrak temperature is the temperature on the quartzdyne pressure sensor, which will require exact temperature correction. This temperature measurement is therefore strongly affected by the temperature of the drilling fluid (and also by annulus temperature and steel temperature), but minor affected by the volume of formation liquid which is drawn in (30 cc).

The temperature of the drilling fluid will also change when circulating: downhole it warms up by the formation and cools down when coming up at the rig, hence will probably be somewhat lower than absolute formation temperature. If extensive pumping it will therefore also be difficult to see relative temperature trends from TesTrak measurements.

To sum up:

TesTrak temperature measurements cannot be used for absolute formation temperature, and most likely cannot be trusted for looking for relative temperature trends either.

5.3 Evaluation of Formation Pressure Data 15/9-F-11 T2

6 of 6 tests were successful and of good technical quality (all reached a stable pressure). When judging the pressure quality by mobility range (flag curve in OpenWorks: PRES_QUAL), the tests can be summarized as 1 very good quality pressure, 3 good quality pressures and 2 poor quality pressures.

Formation pressure points in Hugin Fm. were 13.7 bar above initial fm. pressure measured in 15/9-19 BT2 (January 1998). This indicates communication with Hugin Fm. in the Volve main field, since reservoir pressure has been increased ~12 bar above initial pressure by injection, prior to this drilling campaign.

The results are shown in table below and in plot of all formation pressures in Hugin Fm. at Volve (F-11 T2 formation pressures are marked as red balls) at the end of this chapter. The initial water gradient of 0.103 bar/m has been forced through the F-11 T2 pressure points, drawn as a blue, dashed line.

In addition is the drawdown mobility plotted in the permeability track in the CPI plot for F-11 T2, and the formation pressure is plotted in the density / neutron track, both marked as red balls.

	Well: 15/9-F-11 T2 Date: 04. May – 05. May 2013 Rig: Mærsk Inspirer RKB: 54.9 m Baker's TesTrak tool								PORE PRESSURE (s.g ref. RKB) = 10.195*FORM. PRESSURE / mTVD RKB		
ZONE NAME	**Log Run No.**	**Test No.**	**DEPTH [m MD RKB]**	**DEPTH [m TVD RKB]**	**FORM. PRESS. [bar]**	**TEMP. [°C]**	**GOOD SEAL (Y/N)**	**REMARKS**	**DrawDown MOBILITY [mD/cP]**	**PORE PRESS. s.g ref. RKB [g/cm3]**	**MUD+ECD PRESS. s.g ref. RKB [g/cm3]**	
Hugin 1.1	7	1	4490.1	3330.7	367.51	97.2	Y	OK	17.1	1.125	1.432	
Hugin 1.4	7	2	4468.3	3309.5	364.53	97	Y	OK	17.2	1.123	1.433	
Hugin 2.1	7	3	4451.4	3293.1	362.77	96.3	Y	OK	123.6	1.123	1.432	
Hugin 2.3	7	4	4417	3259.7	361.09	96	Y	OK	7.1	1.129	1.432	
Hugin 3.1	7	5	4408.9	3251.8	356.71	95.7	Y	OK	6.9	1.118	1.431	
Hugin 3.3	7	6	4395.1	3238.4	356.75	95.2	Y	OK	22.3	1.123	1.430	
Total number of tests: 6							No. of Successful tests: 6			No. of Fluid samples: none		
							Hydrostatic gradient in logged interval: -					
Minimum measured pore pressure (ref. RKB): 1.118 g/cm^3							Maximum measured pore pressure (ref. RKB): 1.129 g/cm^3					
Using LWD/GR for depth correlation.							All pressure tests were taken as Test Type Option = "High Mobility".					
Formation pressure data is entered into OW. The curve is named PRES_FORM. Mobility is named PRES_MOBL and temperature PRES_TEMP. Formation pressure test quality in OW is called PRES_QUAL; 0: lost seal, 1: Tight, 2: Poor (<10mD/cP), 3: Good (10-100 mD/cP), 4: Very Good (>100 mD/cP).												

5.4 Evaluation of Formation Pressure Data 15/9-F-11 A

18 of 24 tests (2 sets of data with time delay) were successful and of good technical quality (one *might* be supercharged). 6 tests were tight. When judging the pressure quality by mobility range (flag curve in OpenWorks: PRES_QUAL), the tests can be summarized as 7 very good quality pressures, 5 good quality pressures and 6 poor quality pressures.

Formation pressure points in Hugin were 12 bar above initial fm. pressure measured in 15/9-F-12 (February 2008). This indicates communication with Hugin Fm. in the Volve main field, since reservoir pressure has been increased ~12 bar above initial pressure by injection, prior to this drilling campaign.

To get a picture of the time lapse effect, injection was closed, and a second set of formation pressure (only 5 depth stations were repeated) was logged 48 hours after the first formation pressure data set was measured. This showed only minor decrease in formation pressure, in the range: 0.2 – 0.9 bar.

The results are shown in table below and in plot of all formation pressures in Hugin Fm. at Volve (F-11 A formation pressures are marked as yellow balls) at the end of this chapter. Note that only the first pressure data set (logged 21. May) in F-11 A is plotted. The initial oil gradient of 0.0704 bar/m has been forced through the F-11 A pressure points, drawn as a green, dashed line.

In addition is the drawdown mobility plotted in the permeability track in the CPI plot for F-11 A, and the formation pressure is plotted in the density / neutron track, both marked as red balls.

	Well: 15/9-F-11 A Date: 21. May – 23. May 2013 Rig: Mærsk Inspirer RKB: 54.9 m Baker's TesTrak tool								PORE PRESSURE (s.g ref. RKB) = 10.195*FORM. PRESSURE / mTVD RKB		
ZONE NAME	**Log Run No., Date**	**Test No.**	**DEPTH [m MD RKB]**	**DEPTH [m TVD RKB]**	**FORM. PRESS. [bar]**	**TEMP. [°C]**	**GOOD SEAL (Y/N)**	**REMARKS**	**DrawDown MOBILITY [mD/cP]**	**PORE PRESS. s.g ref. RKB [g/cm3]**	**MUD+ECD PRESS. s.g ref. RKB [g/cm3]**
Hugin 1.1	8, 21.May	1	3694.5	3074.7	346.41	84.9	Y	OK	62.8	1.149	1.411
Hugin 1.1	8, 21.May	2	3688.1	3069.8	346.05	83.3	Y	OK	50.5	1.149	1.411
Hugin 1.2	8, 21.May	3	3681	3064.4	345.54	82.6	Y	OK	101.9	1.150	1.412
Hugin 1.3	8, 21.May	4	3671.1	3056.8	345.05	82.4	Y	OK	22	1.151	1.411
Hugin 1.4	8, 21.May	5	3665.9	3052.8	344.72	83.1	Y	OK	4.9	1.151	1.409
Hugin 1.6	8, 21.May	6	3657.3	3046.2	344.4	82.1	Y	OK	3.9	1.153	1.406
Hugin 2.1	8, 21.May	7	3651	3041.4	343.78	81.1	Y	OK	1235.7	1.152	1.404
Hugin 2.2	8, 21.May	8	3635.2	3029.3	342.87	80.6	Y	OK	12.4	1.154	1.401
Hugin 2.2	8, 21.May	9	3632	3026.8	342.72	80.6	Y	OK	5.7	1.154	1.400
Hugin 2.3	8, 21.May	10	3624	3020.7	342.13	81.4	Y	OK	968.8	1.155	1.402
Sleipner	8, 21.May	11	3711.1	3087.5	-	83.6	Y	Tight	-	-	1.405
Sleipner	8, 21.May	12	3705.1	3082.9	-	81.1	Y	Tight	-	-	1.403
Sleipner	8, 21.May	13	3704.5	3082.4	-	79.8	Y	Tight	-	-	1.402
Sleipner	8, 21.May	14	3711.5	3087.8	-	79.7	Y	Tight	-	-	1.401
Hugin 2.3	8, 21.May	15	3617.2	3015.5	341.69	80.1	Y	OK	358.3	1.155	1.403
Hugin 3.1	8, 21.May	16	3608.2	3008.6	340.52	80.1	Y	OK	3.3	1.154	1.402
Hugin 3.2	8, 21.May	17	3602.2	3004	342.14	79.2	Y	OK (supercharged ?)	0.6	1.161	1.401
Hugin 3.2	8, 21.May	18	3599.8	3002.2	-	78.8	Y	Tight	-	-	1.400
Hugin 3.3	8, 21.May	19	3596.3	2999.5	-	78.8	Y	Tight	-	-	1.400

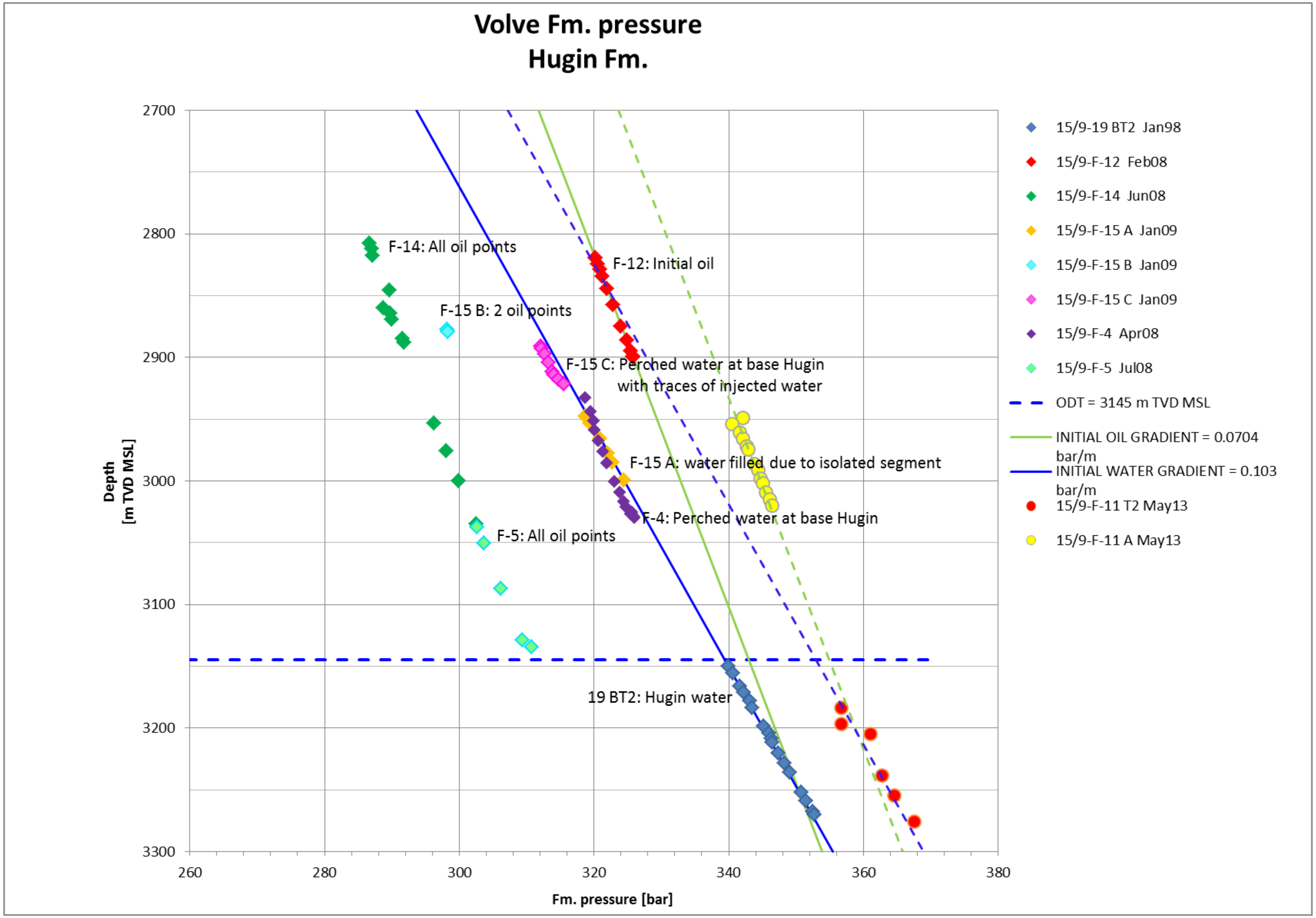
Hugin 1.2	8, 23.May	20	3681	3064.4	345.16	75.2	Y	OK ΔP ~ -0.3 bar	142.2	1.148	1.419
Hugin 2.1	8, 23.May	21	3651	3041.4	343.39	73.4	Y	OK ΔP ~ -0.4 bar	1344.9	1.151	1.418
Hugin 2.3	8, 23.May	22	3617	3015.4	340.84	72.1	Y	OK ΔP ~ -0.9 bar	275.1	1.152	1.418
Hugin 3.1	8, 23.May	23	3607.9	3008.4	340.34	71.2	Y	OK ΔP ~ -0.2 bar	21.4	1.153	1.419
Hugin 3.2	8, 23.May	24	3602	3003.9	341.67	71	Y	OK ΔP ~ -0.5 bar	3.2	1.160	1.416

Total number of tests: 24 19 (21. May 2013) 5 (23. May 2013)		No. of Successful tests: 13 (21. May 2013) 5 (23. May 2013)	No.of Fluid samples: none

Pressure decrease due to time lapse of 48 hour (second data set logged 23. May) after closed injection after logged first fm. pressure data set (dated 21. May): ΔP ~ -0.3 bar, ΔP ~ -0.4 bar, ΔP ~ -0.9 bar, ΔP ~ -0.2 bar, ΔP ~ -0.5 bar.	Hydrostatic gradient in logged interval: -
Minimum measured pore pressure (ref. RKB), 21. May : 1.149 g/cm^3	Maximum measured pore pressure (ref. RKB), 21. May: 1.161 g/cm^3
Using LWD/GR for depth correlation.	All pressure tests were taken as Test Type Option = “High Mobility”, except test no. 13 and no. 14 which were taken as “Low Mobility”.

Formation pressure data is entered into OpenWorks. The curve is named PRES_FORM.
Mobility is named PRES_MOBL and temperature PRES_TEMP.
Formation pressure test quality in OW is called PRES_QUAL;
0: lost seal, 1: Tight, 2: Poor (<10mD/cP), 3: Good (10-100 mD/cP), 4: Very Good (>100 mD/cP).
Pressure data with qualifiers 0 or 1 are however not registered in OW, due to technical issues wrt. plotting.

5.5 Plot of Formation Pressure Data, 15/9-F-11 T2 and 15/9-F-11 A



Volve Fm. pressure
Hugin Fm.
Depth
[m TVD MSL]
Fm. pressure [bar]
2700
2800
2900
3000
3100
3200
3300
260
280
300
320
340
360
380
F-14: All oil points
F-12: Initial oil
F-15 B: 2 oil points
F-15 C: Perched water at base Hugin
with traces of injected water
F-15 A: water filled due to isolated segment
F-4: Perched water at base Hugin
F-5: All oil points
19 BT2: Hugin water
15/9-19 BT2 Jan98
15/9-F-12 Feb08
15/9-F-14 Jun08
15/9-F-15 A Jan09
15/9-F-15 B Jan09
15/9-F-15 C Jan09
15/9-F-4 Apr08
15/9-F-5 Jul08
ODT = 3145 m TVD MSL
INITIAL OIL GRADIENT = 0.0704 bar/m
INITIAL WATER GRADIENT = 0.103 bar/m
15/9-F-11 T2 May13
15/9-F-11 A May13

6 LWD NMR - MagTrak

Baker's LWD NMR tool, MagTrak, was logged in 8 1/2" section.
The tool was ran in silent mode, hence data only in memory. MagTrak sensor offset to Bit was 50.45 m.

6.1 Logging mode and parameters

The tool was logged in "Dual Wait Time" (DTW) mode, also called "PoroPermMT+Light HC" mode, in order to process a salinity independent water saturation.

An average ROP of 15 m/hr (in the Section guidelines a max ROP of 20 m/hr and a optimal ROP of 10 m/hr was specified) was held in the reservoir interval to assure a sufficient vertical resolution of the MagTrak data, and also to keep the Signal/Noise ratio high.

Vertical resolution with DTW mode and ROP = 20 m/hr was calculated to be 1.7 m. Vertical resolution with DTW mode and ROP = 30 m/hr was calculated to be 2.6 m.

The MagTrak data was logged and final post processed with the following parameters:

Running Average (Data Stacking) of 16: RA = 16
T2 Cutoffs: CBW = 3.3 ms, BVI = 33 ms (standard sandstone T2 cutoffs)
Number of T2 bins: 27 over the range of 0.5 – 4096 ms.

6.2 MagTrak output

In table below are the most important curves from MagTrak listed with explanation:

CURVE NAME	BAKER's CURVE EXPLANATION	"TRADITIONAL" NAME	CURVE RELATION	DEPENDING ON T2 CUTOFF
MBVI	MagTrak Irreducible Fluid Porosity	Capillary Bound Fluid Index	MBVI = MPHE - MBVM	YES
MBVM	MagTrak Movable Fluid Porosity	FFI (Free Fluid Index)	MBVM = MPHS - MBW	YES
MBW	MagTrak Bound Fluid Porosity	BVI (Bound Fluid Index)	MBW = MCBW + MBVI	YES
MCBW	MagTrak Clay Bound Fluid Porosity	Clay Bound Volume Index	MCBW = MPHS - MBVI - MBVM	YES
MPERM	MagTrak Permeability Index		MPERM = $\left[\left(\frac{MPHS}{C}\right)^2 \times \left(\frac{MPHS - MBW}{MBW}\right)\right]^b$ Default parameters are b=2, C=10	YES
MPHE	MagTrak Effective Porosity		MPHE = MPHS - MCBW	YES
MPHS	MagTrak Total Porosity		MPHS = MBW + MBVM	**NO***

*MPHS: MPHS is only dependent on Hydrogen Index (HI). If HI unequal 1, then MPHS is also dependent of T2 cutoffs.
15/9-F-11 T2 is mostly water filled, hence HI ~ 1.

MPHS is comparable with PHIF (= PHIT) from conventional logs.
MPERM is qualitative (semi-quantitative) comparable with KLOGH from conventional logs.
MBW/MPHS is comparable with Swirr from resistivity logs (not applicable in this water filled well).

6.3 MagTrak purpose and achievement

- Purpose with running MagTrak was to achieve:
    - Lithology independent porosity
    - Independent (semi-quantitative) permeability indicator, possibility of detecting thief zone?
    - Salinity independent water/oil saturation
    - Discriminate between movable and bound fluid
    - Irreducible water saturation
    - Independent estimation of saturation exponent, n
    - Pore size distribution

Since the reservoir turned out to be more or less water filled, some of the purposes were not any longer applicable.

- Achievements:
    - MagTrak provides both a total and an effective porosity which is lithology independent. Total porosity from MagTrak, MPHS, is plotted (magenta curve) in same track as total porosity, PHIF, from conventional logs in the F-11 T2 CPI. The overall trend in the Hugin Fm. is that the MPHS matches good with PHIF, which should not be a surprise in a water filled reservoir. MPHS has (and shows) however a poorer vertical resolution than PHIF. In Heather Fm. PHIF is lower than MPHS, indicating perhaps a too low matrix density applied for this formation.

    - MagTrak provides an independent semi-quantitative permeability indicator, MPERM. This curve is plotted (magenta curve) in same track as the permeability from conventional logs and field model, KLOGH, in the F-11 T2 CPI. The overall trend is that MPERM > KLOGH with the applied standard sandstone T2 cutoffs.

      The thief zone is not detected by MPERM. From the T2 distribution (ref. fig. 6.4.2) it is however seen that the sand in interval 4449 – 4453 m MD RKB (Lower Thief zone / Hugin 2.1 (7)) has the complete T2 signal coming from the oil based mud filtrate, hence indicating qualitatively the most permeable zone of this Hugin Fm. Invasion will however of course be dependent of different factors, such as mud properties and ROP.

      SCAL (Special Core AnaLysis) data from 15/9-19 A was investigated to check if the default coefficients for the Coates-Timur permeability (MPERM) equation was appropriate, ref. chapter 6.5. This resulted in a permeability curve called MPERM_ADJUSTED which is plotted (light green curve) in the permeability track (track no. 9) in the F-11 T2 CPI.

    - Since the reservoir was more or less water filled, it was no point to order a processing from Baker to get an independent oil saturation.

    - MagTrak provides a discrimination between movable and bound fluid. This is illustrated in track no. 8 in the F-11 T2 CPI. Brown shading = clay bound fraction, turquoise shading = capillary bound fraction and yellow shading = free or movable fluid fraction.

    - MagTrak provides an irreducible water saturation which is the ratio: bound fluid / total porosity. This is named SWIRR_MTK and is plotted (magenta curve) in same track as the water saturation from the conventional logs. Since ~ water filled reservoir, comparison against water saturation from conventional logs is of course not applicable.

- Since the reservoir was more or less water filled, the method of estimating n from the slope when illustrating Archie Water Saturation equation graphically above transition zone, was not applicable.

- Pore size distribution: this needs 2 more processings (DTW and Grain Size Distribution) from Baker, and has not been ordered.

6.4 MagTrak T2 distribution plots

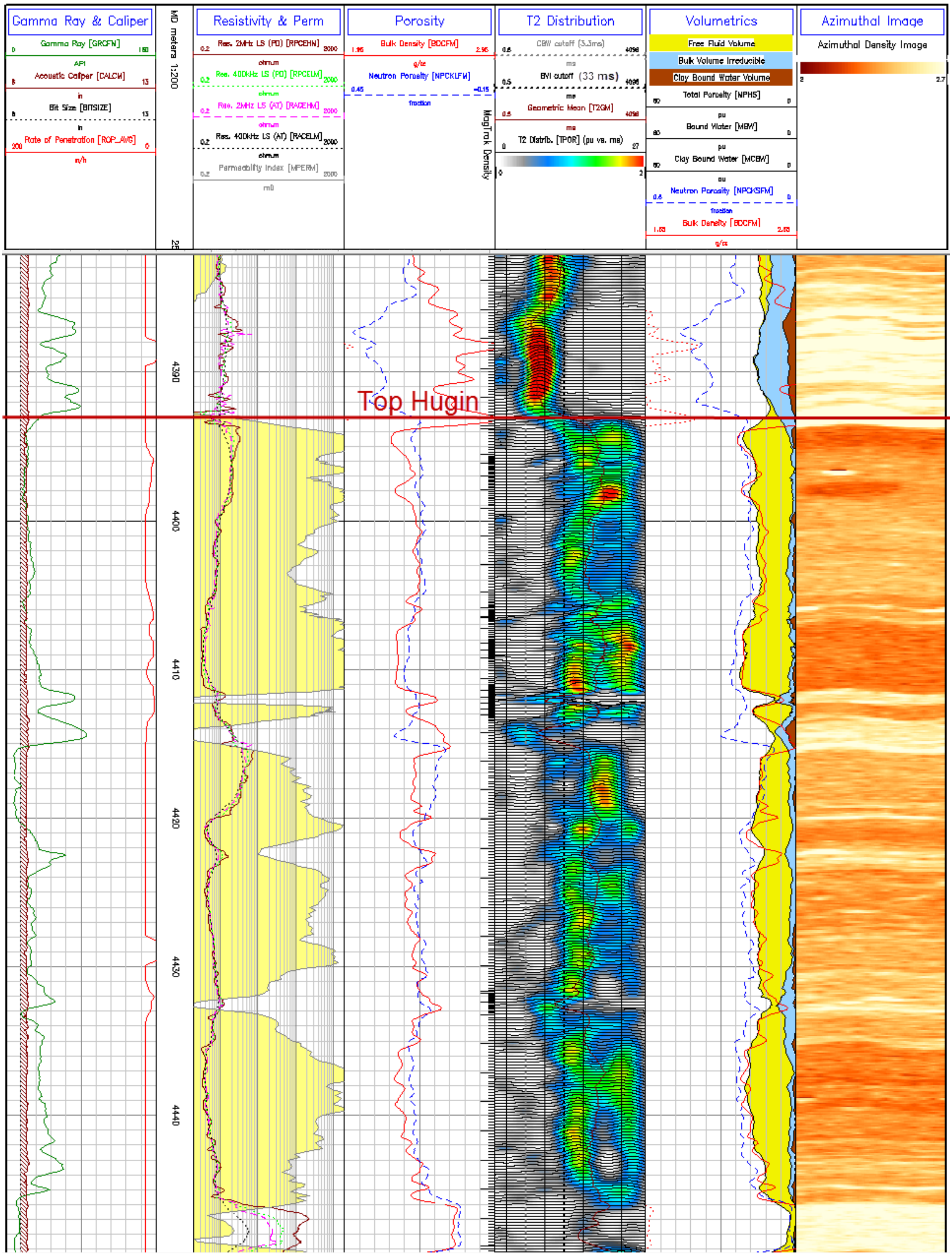


Figure 6.4.1 showing T2 distribution from MagTrak in track no. 5.
Hugin Fm. shows bimodal T2 distribution of the Free Fluid fraction due to invasion of mudfiltrate (OBM). OBM filtrate signal to the right and formation water signal to the left.

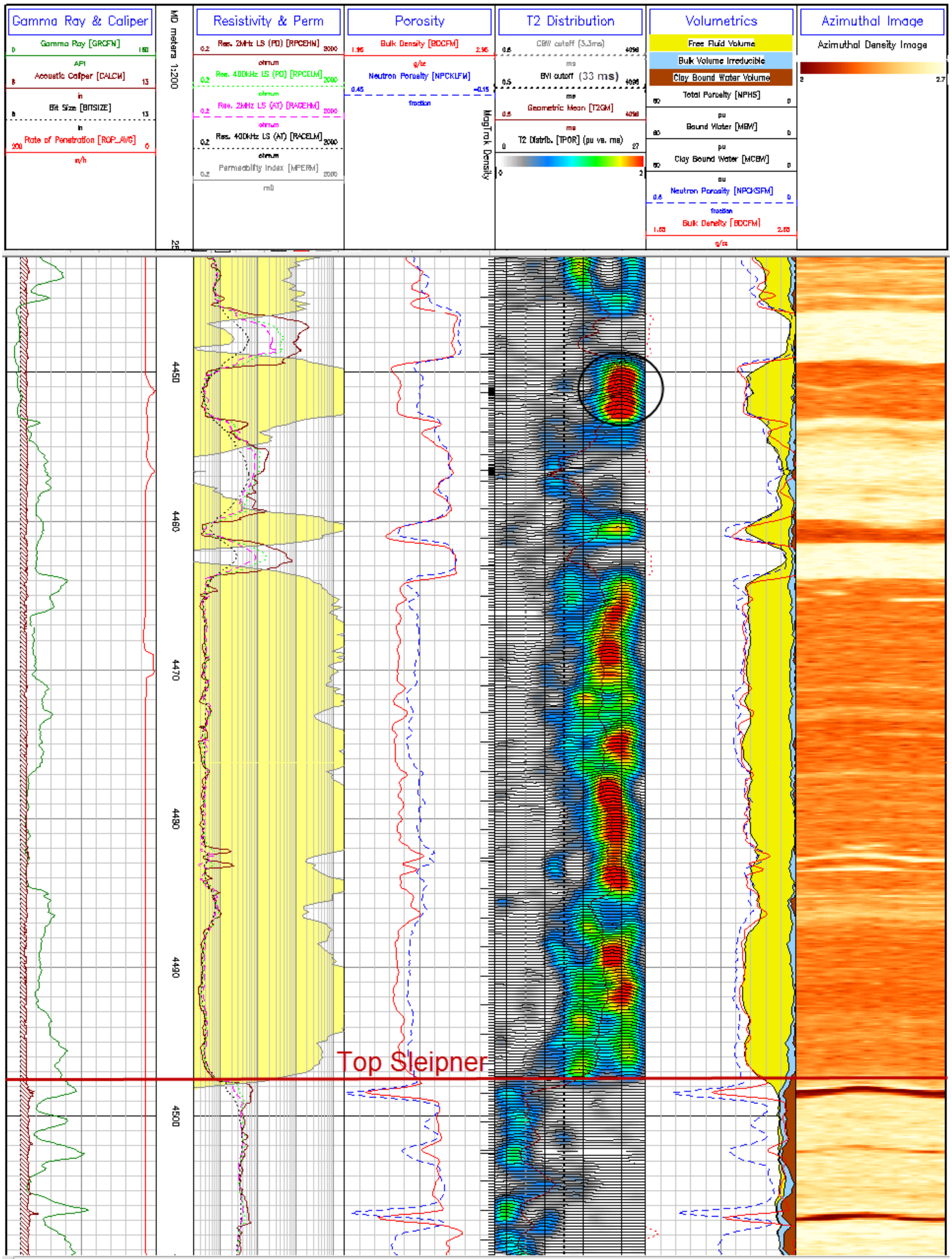


Figure 6.4.2.
T2 distribution in the black circled area shows full invasion (Lower Thief zone / Hugin 2.1 (7)). Hence indicates qualitatively the most permeable zone, this is however not seen directly from MPERM.

6.5 Coates-Timur permeability

A verification / check of the coefficients in the Coates-Timur permeability equation has been done.

Due to lack of cores in 15/9-F-11 T2, the SCAL data in 15/9-19 A was reviewed. An overview over SCAL permeability versus irreducible water saturation from different methods is given in figure 6.5.1.

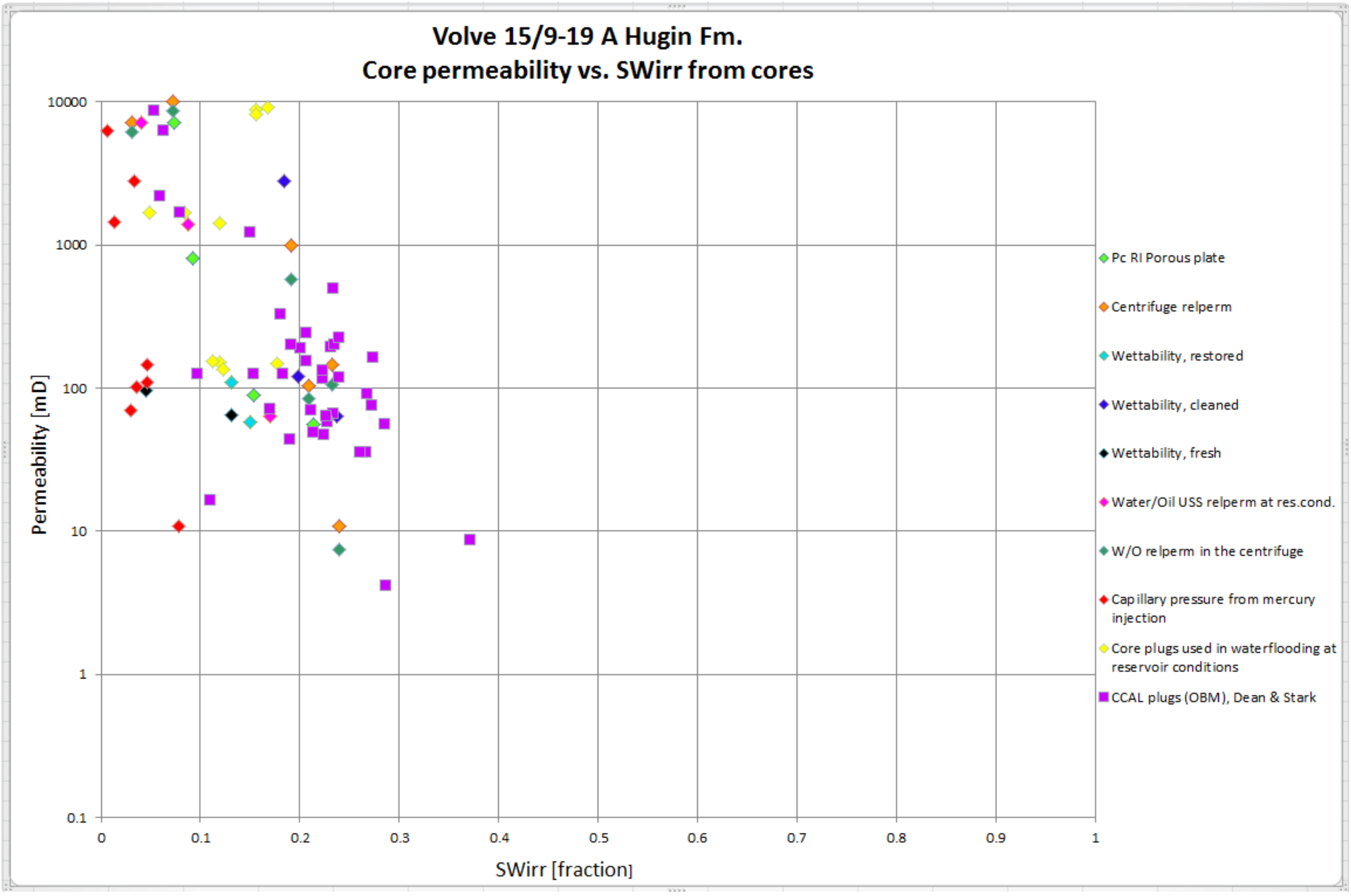


Figure 6.5.1. SCAL data from well 15/9-19 A.
All permeability data versus irreducible water saturation data derived from different methods listed to the right and separated by different colors. The data from mercury injection should be disregarded.

Data from the CCAL (Conventional Core AnaLysis) plugs are shown as purple squares in fig. 6.5.1. The water saturation is measured by Dean and Stark method (OBM) and is measured together with porosity at vertical plugs. Permeability is however not measured on same vertical plugs, but on horizontal plugs. Due to this, permeability has been picked from adjacent plugs with approximately same porosity.

The overall trend is quite a large scatter in the data range, hence corresponding large uncertainty.The mercury injection data is however clear outliers, and data from this method should be disregarded.

In order to illustrate Coates-Timur permeability equation graphically (ref. fig. 6.5.2) to verify / check the default coefficients, b=2 and C=10, the equation was split into a linear equation as shown below:

$$K = \left[\left(\frac{\phi}{C} \right)^2 \times \left(\frac{FFI}{BVI} \right) \right]^b$$

$$LOGK = LOG\left[\left(\frac{\phi}{C} \right)^2 \times \left(\frac{FFI}{BVI} \right) \right]^b$$

$$LOGK = LOG\left[\left(\frac{1}{C^2} \right)^b \times \left(\phi^2 \times \frac{FFI}{BVI} \right)^b \right]$$

$$LOGK = bLOG\left(\frac{1}{C^2} \right) + bLOG\left(\phi^2 \times \frac{FFI}{BVI} \right)$$

$$LOGK = b\left(LOG(1) - LOG(C^2) \right) + bLOG\left(\phi^2 \times \frac{FFI}{BVI} \right)$$

$$LOGK = b(-LOG(C^2)) + bLOG\left(\phi^2 \times \frac{FFI}{BVI} \right)$$

$$LOGK = -2bLOG(C) + bLOG\left(\phi^2 \times \frac{FFI}{BVI} \right)$$

$$\underbrace{LOGK}_{\text{Y-axis}} = \underbrace{-2bLOG(C)}_{\text{Intersection Y-axis}} + \underbrace{b}_{\text{slope}}\underbrace{LOG\left(\phi^2 \times \frac{FFI}{BVI} \right)}_{\text{X-axis}}$$

Fig. 6.5.2 shows that the default coefficients (solid line) in the Coates-Timur equation is not appropriate when comparing to the core data from Hugin Fm. in 15/9-19 A. Despite large scattering in the data, a new regression line has been suggested, ref. dashed line, giving the coefficients: b=2.5 and C=17.8.

New adjusted MPERM, named MPERM_ADJUSTED, according to these new parameters is plotted (light green curve) in the permeability track, track no. 9, in the F-11 T2 CPI. In general MPERM_ADJUSTED is closer to KLOGH from field model than MPERM. MPERM_ADJUSTED is truncated at permeability > 15 D, which corresponds to very low BVI.

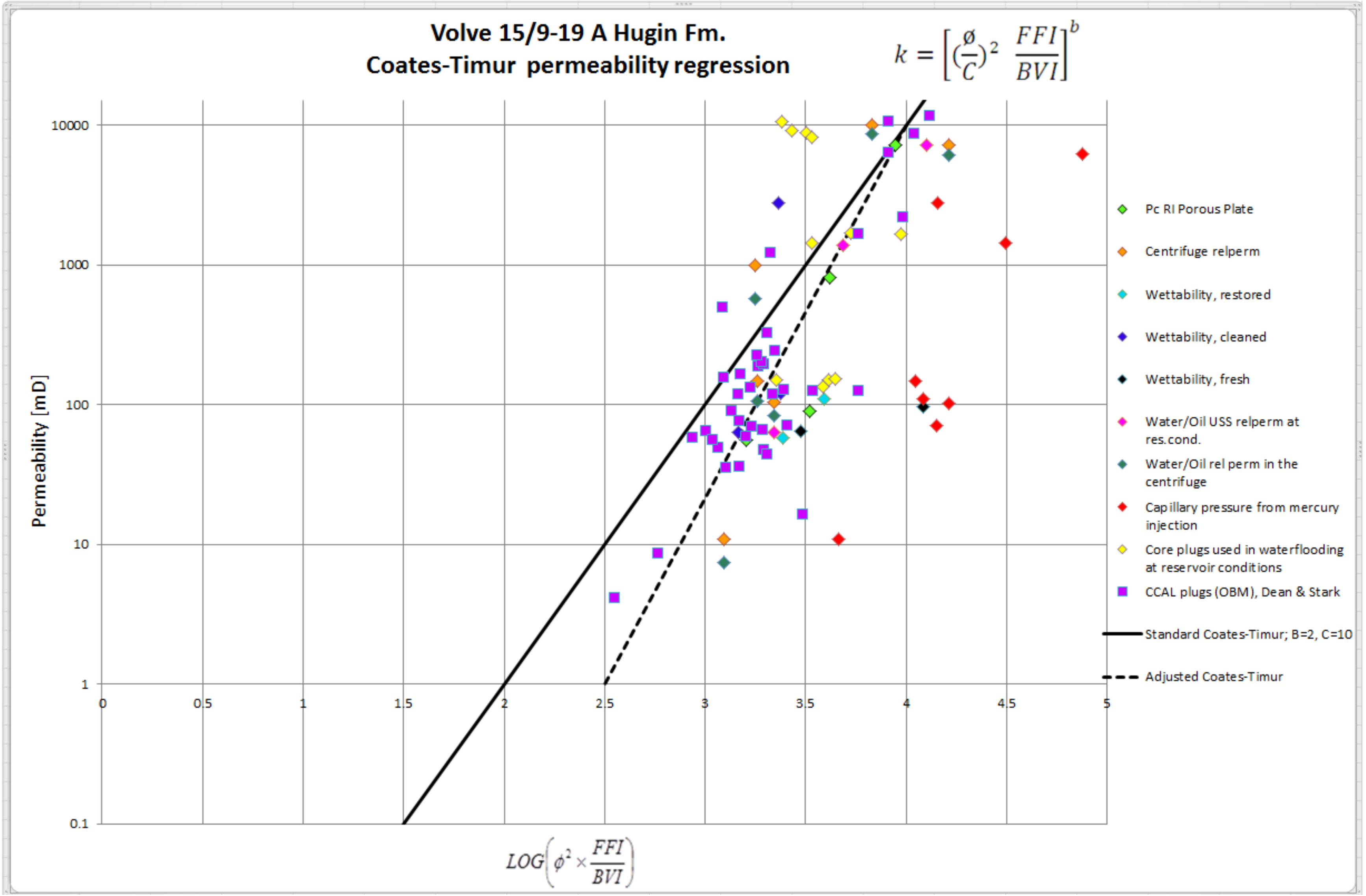


Figure 6.5.2. SCAL data from well 15/9-19 A illustrating Coates-Timur permeability equation. Solid regression line is with default coefficients; b=2 and C=10. This line seems to be off compared to the core data, resulting in a too high MagTrak permeability, MPERM. Dashed line is with adjusted coefficients: b=2.5 and C=17.8. This line seems more reasonable compared to the core data.

7 Petrophysical results

Tables below in this chapter are showing average values of Net/Gross (N/G), total porosity (PHIF), total water saturation (SW) and horizontal permeability from logs (KLOGH) in Netsand.

Note that for F-11 B the reported water saturation averages are from case calculated with pure Hugin formation water salinity, as if no flooding.

7.1 Petrophysical results 15/9-F-11 T2

15/9-F-11 T2 Averages								
Formation / Zone	**Top [m MD RKB]**	**Base [m MD RKB]**	**N/G [fraction]**	**PHIF [fraction]**	**SW [fraction]**	**KLOGH arithmetic [mD]**	**KLOGH harmonic [mD]**	**KLOGH geometric [mD]**
Heather	4334.7	4393.0	0	-	-	-	-	-
Hugin	4393.0	4497.4	0.808	0.168	0.934	243	39	118
Upper Hugin	4393.0	4415	0.864	0.158	0.836	248	63	165
Middle Hugin (“Thief Zone”)	4415	4455	0.765	0.155	0.932	330	36	131
Lower Hugin	4455	4497.4	0.821	0.186	0.981	163	34	90
Hugin 3.3 (12)	4393.0	4399.0	0.875	0.178	0.506	491	358	422
Hugin 3.2 (11)	4399.0	4407.0	1	0.127	0.982	135	107	119
Hugin 3.1 (10)	4407.0	4415.0	0.719	0.184	0.987	183	27	111
Hugin 2.3 (9)	4415.0	4422.0	0.836	0.142	0.689	480	302	409
Hugin 2.2 (8)	4422.0	4444.0	0.873	0.154	0.994	89	24	60
Hugin 2.1 (7)	4444.0	4455.0	0.505	0.174	0.951	1003	187	587
Hugin 1.6 (6)	4455.0	4463.5	0.176	0.193	0.97	116	65	90
Hugin 1.5 (5)	4463.5	4466.0	0.82	0.181	0.962	17	9	13
Hugin 1.4 (4)	4466.0	4471.0	1	0.195	0.98	223	191	210
Hugin 1.3 (3)	4471.0	4476.4	1	0.198	0.969	97	62	82
Hugin 1.2 (2)	4476.4	4485.0	0.988	0.176	0.976	343	233	300
Hugin 1.1 (1)	4485.0	4497.4	0.996	0.183	0.995	74	20	39
Sleipner	4497.4	4562	0	-	-	-	-	-

7.2 Petrophysical results 15/9-F-11 A

15/9-F-11 A Averages								
Formation / Zone	**Top [m MD RKB]**	**Base [m MD RKB]**	**N/G [fraction]**	**PHIF [fraction]**	**SW [fraction]**	**KLOGH arithmetic [mD]**	**KLOGH harmonic [mD]**	**KLOGH geometric [mD]**
Heather	3574.9	3594.6	0	-	-	-	-	-
Hugin	3594.6	3702.0	0.862	0.209	0.323	513	18	129
Upper Hugin	3594.6	3612.5	0.648	0.172	0.443	121	4	33
Middle Hugin (“Thief Zone”)	3612.5	3653	0.894	0.208	0.295	1024	26	216
Lower Hugin	3653	3702.0	0.913	0.22	0.32	201	46	122
Hugin 3.3 (12)	3594.6	3599.0	0.557	0.153	0.269	326	162	248
Hugin 3.2 (11)	3599.0	3605.5	1	0.169	0.462	85	3	22
Hugin 3.1 (10)	3605.5	3612.5	0.379	0.196	0.529	22	7	13
Hugin 2.3 (9)	3612.5	3627.5	0.9	0.215	0.192	2140	63	1193
Hugin 2.2 (8)	3627.5	3647.0	0.936	0.211	0.412	82	15	40
Hugin 2.1 (7)	3647.0	3653.0	0.742	0.171	0.091	1501	510	1231
Hugin 1.6 (6)	3653.0	3663.0	0.575	0.2	0.319	46	29	36
Hugin 1.5 (5)	3663.0	3665.0	1	0.209	0.304	7	5	6
Hugin 1.4 (4)	3665.0	3667.3	1	0.209	0.279	151	67	120
Hugin 1.3 (3)	3667.3	3674.3	1	0.242	0.31	147	134	141
Hugin 1.2 (2)	3674.3	3684.0	1	0.193	0.234	440	338	393
Hugin 1.1 (1)	3684.0	3702.0	1	0.236	0.367	170	83	126
Sleipner	3702.0	3762.0	0.157	0.136	0.864	87	1	4

7.3 Petrophysical results 15/9-F-11 B

15/9-F-11 B Weighted averages from all observations of a Formation / Zone								
Formation / Zone	**Top [m MD RKB]**	**Base [m MD RKB]**	**N/G [fraction]**	**PHIF [fraction]**	**SW* [fraction]**	**KLOGH arithmetic [mD]**	**KLOGH harmonic [mD]**	**KLOGH geometric [mD]**
Heather	3351 3812 3934 4374	3467.5 3894 3952 4483.5						
	Weighted Heather averages:		0.089	0.136	0.638	10	1	2
Hugin	3467.5 3894 3952 4483.5	3812 3934 4374 4732						
	Weighted Hugin averages:		0.888	0.207	0.232	512	2	123
Upper Hugin	3467.5 3894 3952 4187.6 4483.5	3812 3934 4092 4374 4573						
	Weighted Upper Hugin averages:		0.887	0.211	0.170	459	2	103
Middle Hugin (“Thief Zone”)	4092 4573	4187.6 4681.5						
	Weighted Middle Hugin averages:		0.924	0.193	0.381	789	2	290
Lower Hugin	4681.5	4732	0.765	0.187	0.78	137	3	47
Hugin 3.3 (12)	3467.5 3663 3894 3952 4337 4483.5	3504 3812 3934 4027.2 4374 4510						

	Weighted Hugin 3.3 (12) averages:		0.965	0.217	0.122	795	122	532
Hugin 3.2 (11)	3504 4027.2 4238 4510	3663 4063 4337 4555						
	Weighted Hugin 3.2 (11) averages:		0.813	0.199	0.236	89	1	12
Hugin 3.1 (10)	4063 4187.6 4555	4092 4238 4573						
	Weighted Hugin 3.1 (10) averages:		0.854	0.232	0.17	266	1	110
Hugin 2.3 (9)	4092 4573	4187.6 4601						
	Weighted Hugin 2.3 (9) averages:		0.932	0.197	0.379	916	1	396
Hugin 2.2 (8)	4601	4647	0.885	0.187	0.35	89	14	43
Hugin 2.1 (7)	4647	4681.5	0.945	0.189	0.426	1216	683	1034
Hugin 1.6 (6)	4681.5	4698	0.558	0.188	0.583	32	2	19
Hugin 1.5 (5)	4698	4701	0.65	0.165	0.790	74	65	69
Hugin 1.4 (4)	4701	4710	0.983	0.18	0.769	129	79	101
Hugin 1.3 (3)	4710	4715	0.87	0.18	0.849	50	1	13
Hugin 1.2 (2)	4715	4725	0.915	0.195	0.919	371	170	231
Hugin 1.1 (1)	4725	4732	0.736	0.197	0.83	21	2	10
Sleipner	4732	4770	0.068	0.116	0.833	4	1	2

***** Note that for F-11 B the reported water saturation averages are from case calculated with pure Hugin formation water salinity, as if no flooding.

8 CPI plots of evaluated curves and raw data

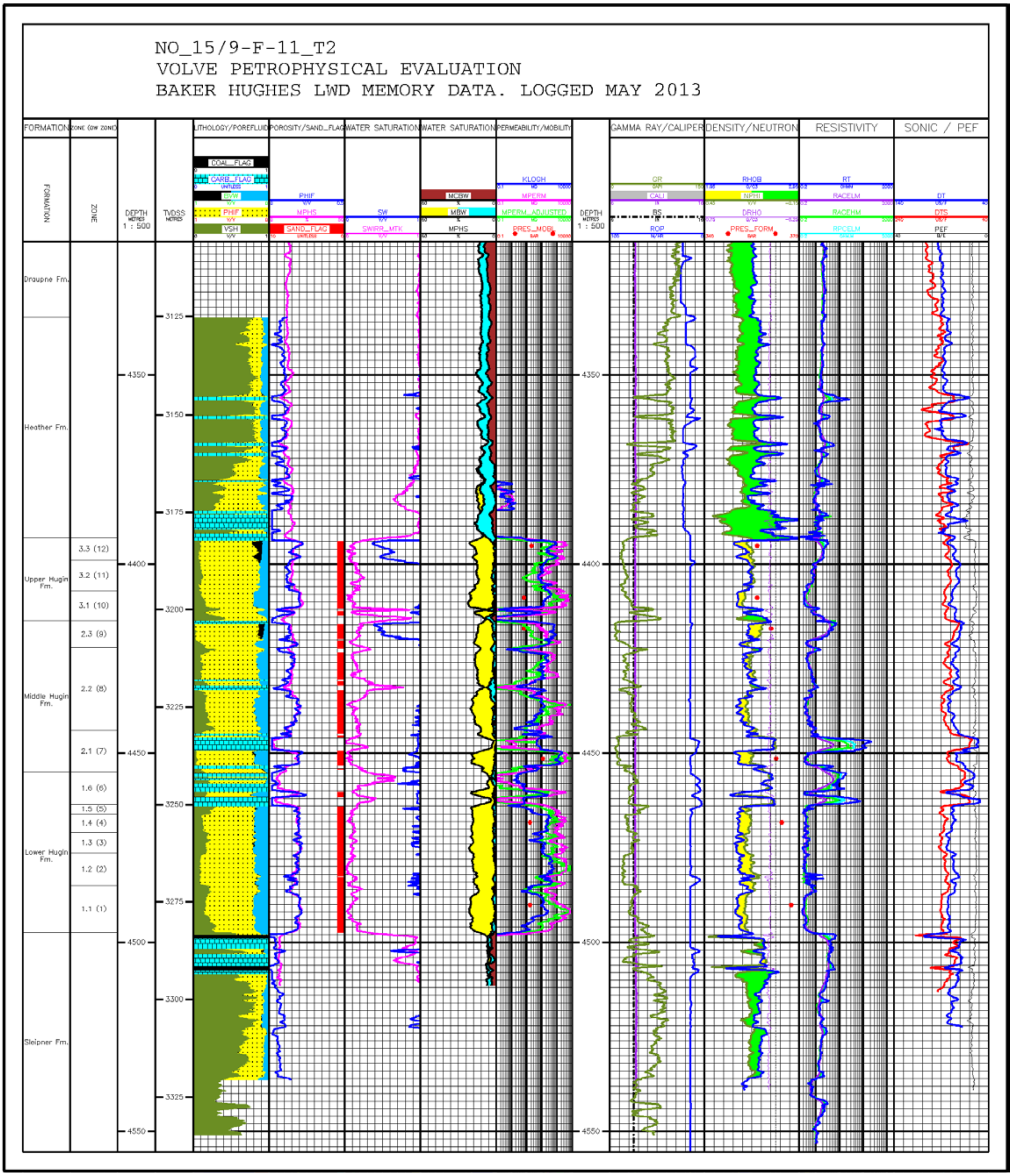
Remarks regarding F-11 B CPI:

Note that for F-11 B is the CPI separated in 3 parts for better visualization.

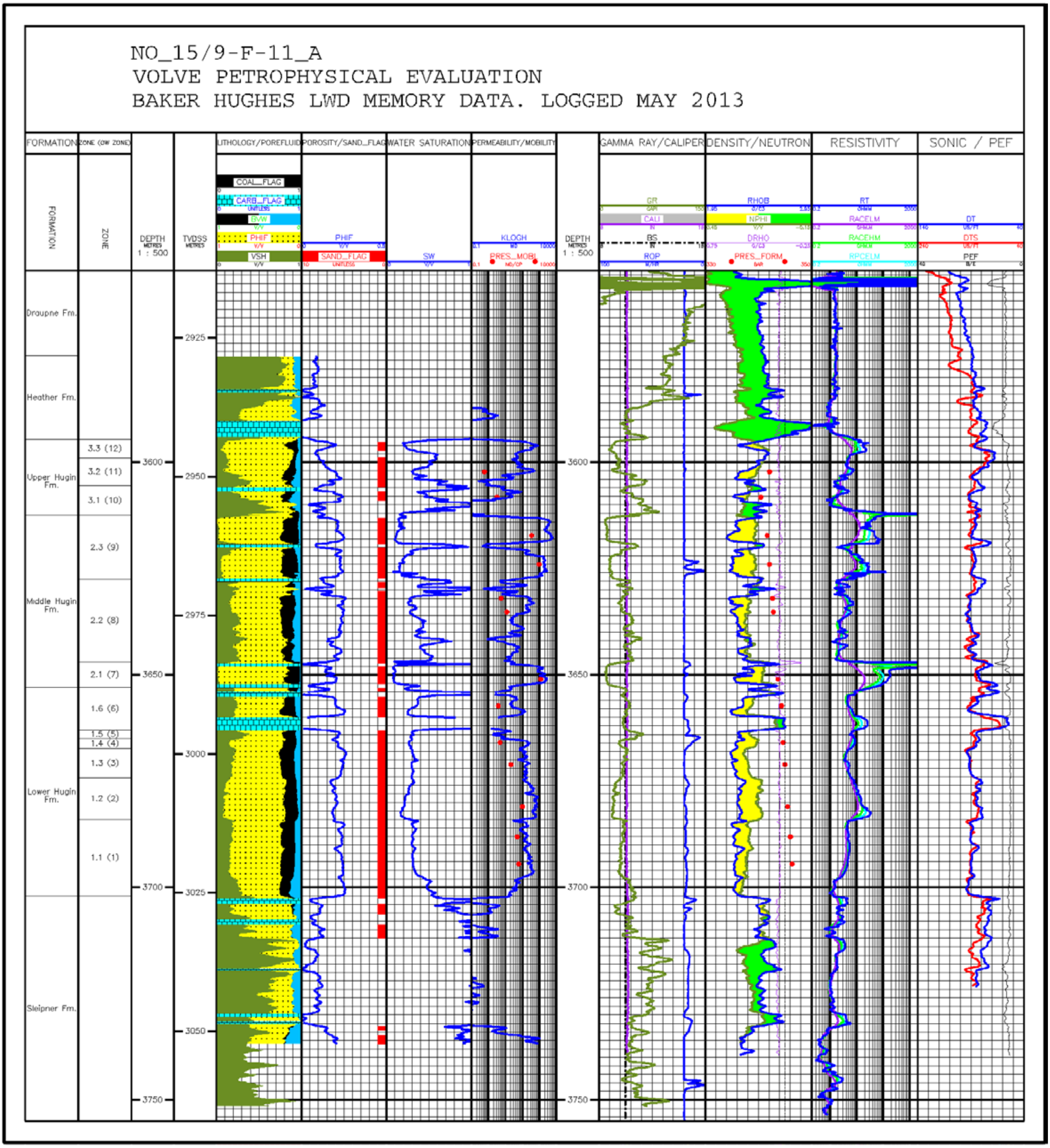
Note also that the F11 B CPIs include 3 different formation water salinity cases:
First case is Hugin formation water salinity,
second case is a mixture of Hugin and Utsira formation water salinity,
third case is pure Utsira formation water salinity.
The details in difference and color coding are explained in the header of the CPIs. There is a huge contrast between the very saline Hugin formation water and the fresh, low saline Utsira formation water (injection water), and the different cases illustrate the impact on the water saturation.

Note also that the salinity is changed in the whole evaluated intervals, and that all other parameters are kept unchanged.

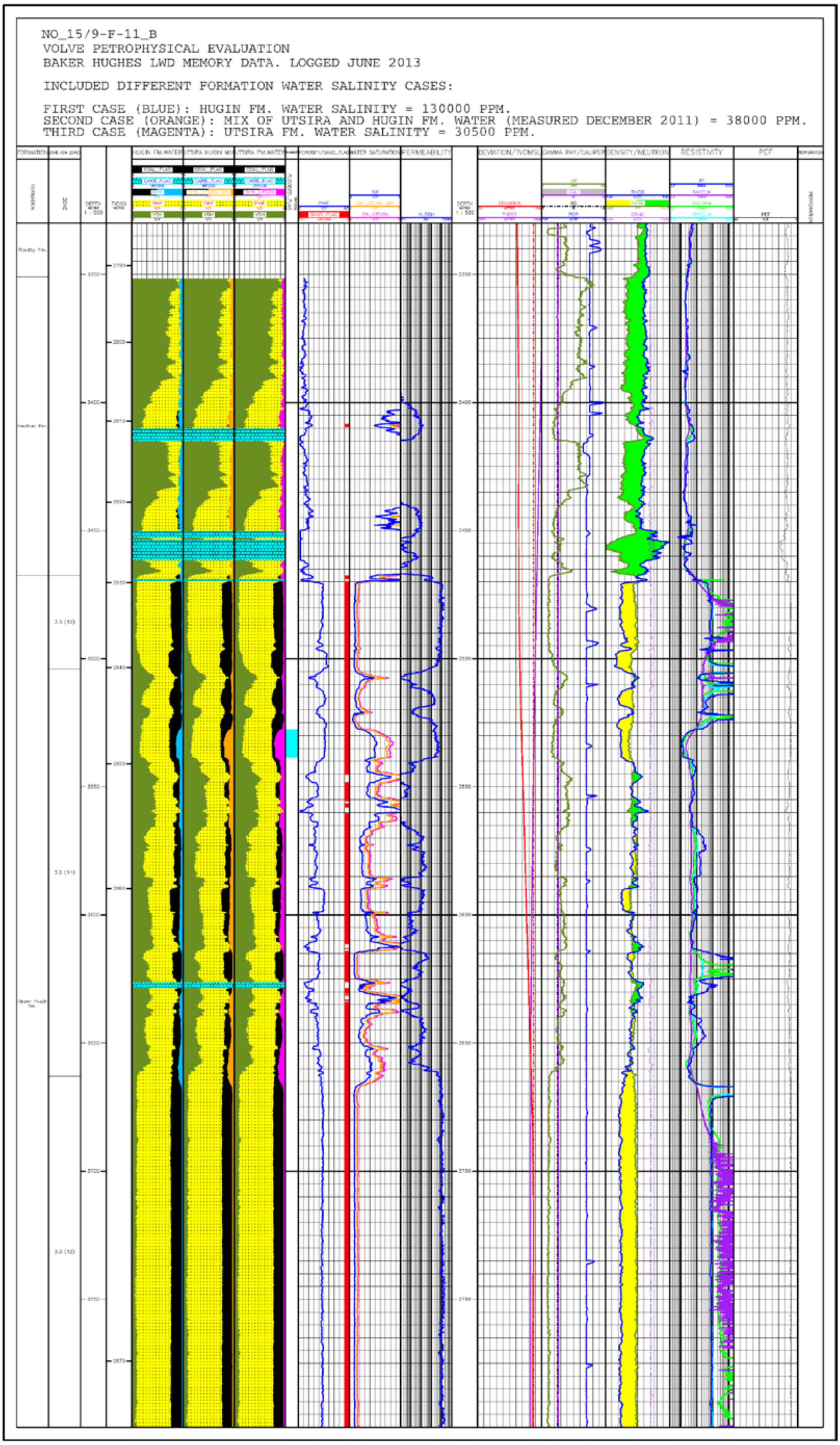
8.1 CPI plot 15/9-F-11 T2



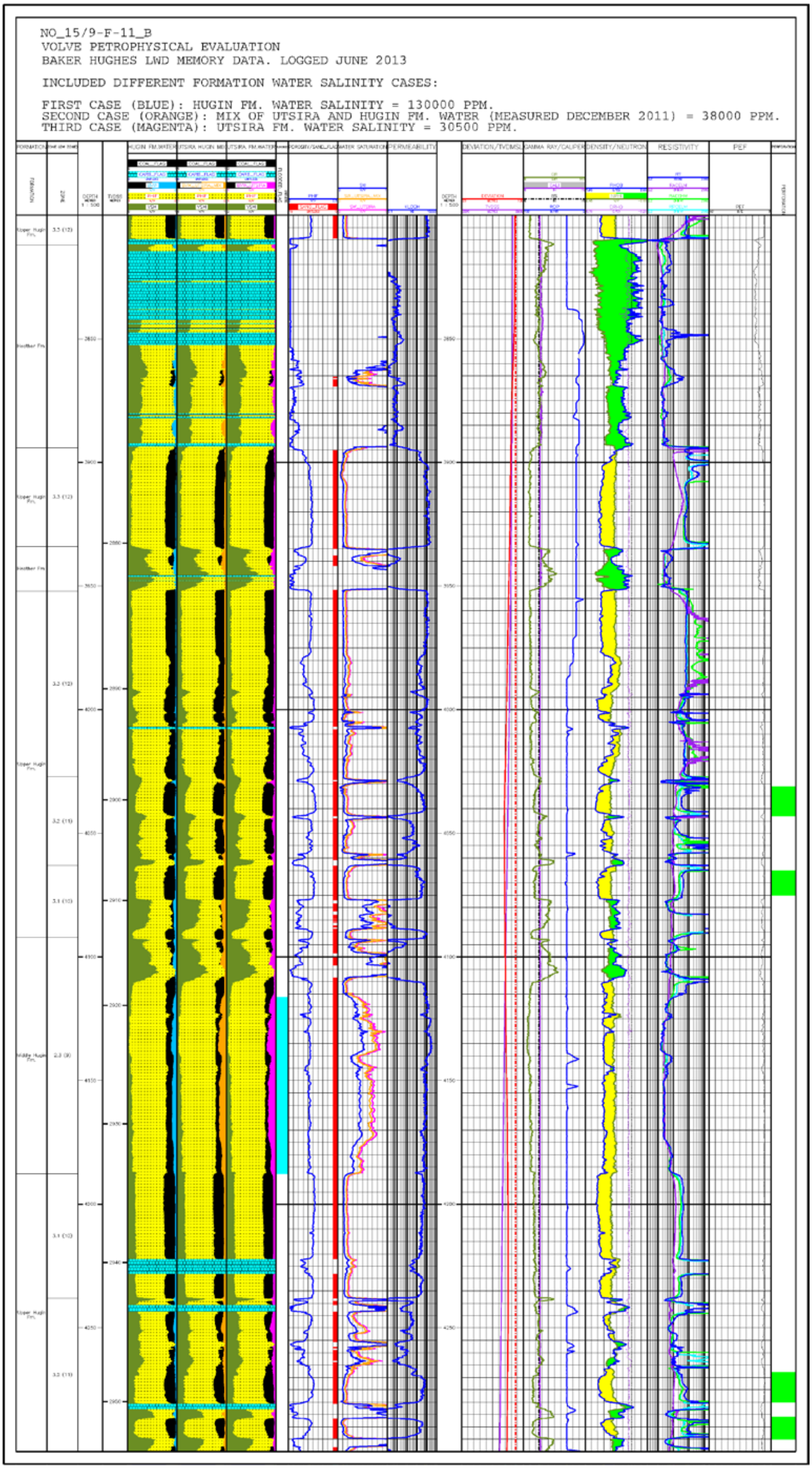
8.2 CPI plot 15/9-F-11 A



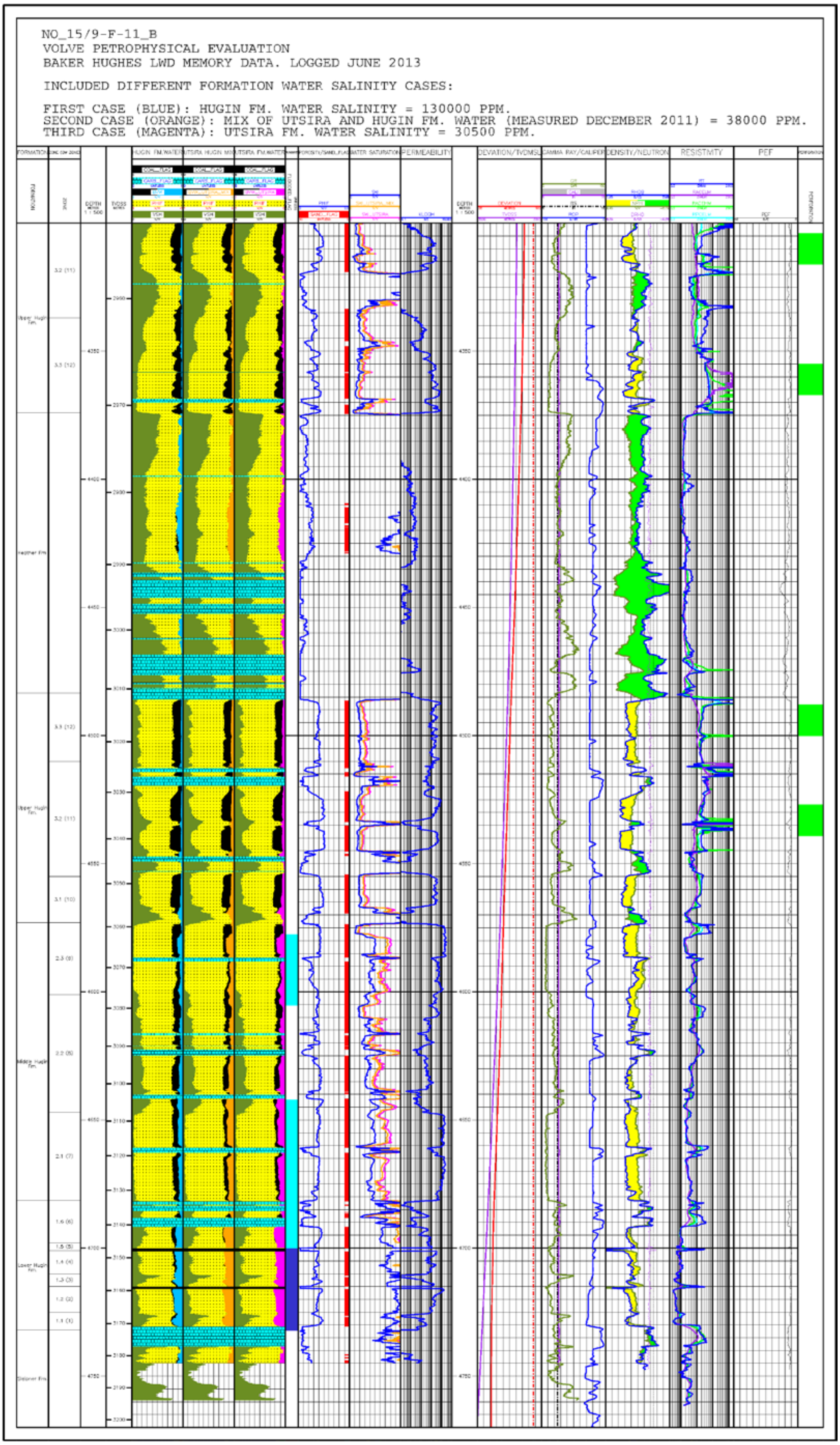
8.3 CPI plot 15/9-F-11 B, interval 3330 – 3800 m MD RKB



CPI plot 15/9-F-11 B, interval 3800 – 4300 m MD RKB



CPI plot 15/9-F-11 B, interval 4300 – 4770 m MD RKB



9 References

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