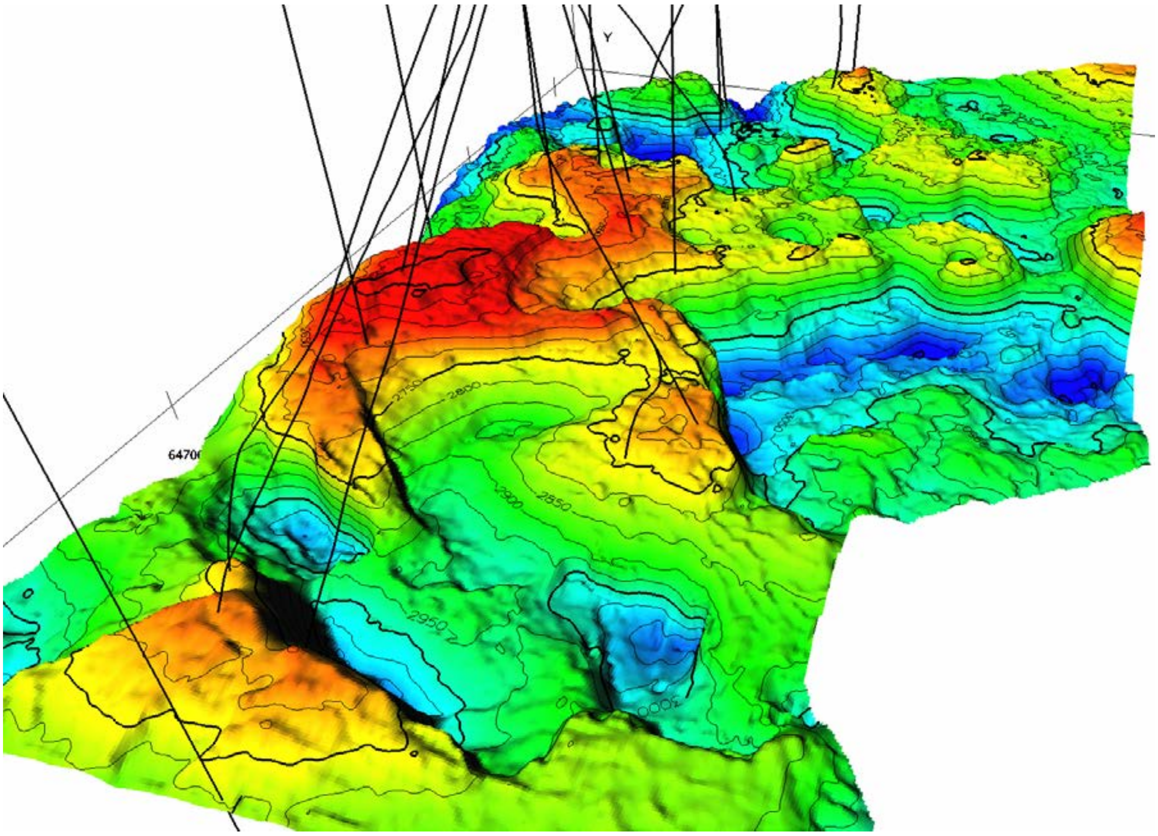

Sleipner Øst and Volve Model 2006
Hugin and Skagerrak Formation
Petrophysical Evaluation

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Summary

A new petrophysical model has been generated for 19 wells over the Hugin, Sleipner and Skagerrak Formation in the Sleipner Øst and Volve Field. The new wells 15/9-A-19 AT2 and 15/9-A-23 A are included in the study.

Pressure data, logs and also strontium data is used to update the fluid- and contact analysis.

The porosity is determined from the density and neutron porosity logs calibrated to overburden corrected core porosity.

Continuous permeability is estimated by multivariable regression analysis between overburden corrected core permeability, porosity and shale volume.

Water saturation is calculated from Archie's equation.

A water saturation model is established for geological mapping purposes. This is modelled as a function of height above the free water level using a J-function approach.

Also an estimate of the uncertainty in the petrophysical parameters has been conducted.

Petrophysical Evaluation

1 Introduction

A new petrophysical evaluation has been done for Sleipner Øst and Volve Field. The evaluation is covering the Hugin and Skagerrak Formation on Sleipner Øst while for Volve the Hugin and Sleipner Formation has been evaluated. The new wells 15/9-A-19 AT2 and 15/9-A-23 A has been included in the study.

A separate collection of Tables and CPI plots are contained in Appendix 1 and 2, respectively, and these tables are in this text noted with an "A" before its number.

The petrophysical analysis is performed by using Geolog software and the resulting curves as well as the continuous raw logs and also core data have been transferred to the Openworks database.

2 Database

2.1 General

The area of interest can be divided into several areas and, from the south, digital data are available from 2 wells on Gungne, 2 wells on My2, 4 wells on Gamma, 6 wells on SLE Hugin, 2 wells on Loke and 3 wells on the Volve Field. An overview of the area is given in Figure 1.

In Table A.1, in Appendix 1, all the wells are listed together with some relevant information from the completion reports.

2.2 Log data

Table A.1 gives an overview of the logging combinations run over the intervals of interest. The log quality is generally good, but especially around coal beds the logs can suffer from wash-outs and effects from rugose borehole.

In the wells 15/9-A-25 and 15/9-A-3 T2 the casing shoe was set some meters into the reservoir section, 23 and 27 m MD RKB, respectively. In this interval only a few logs are available through cased hole, which make the log evaluation uncertain.

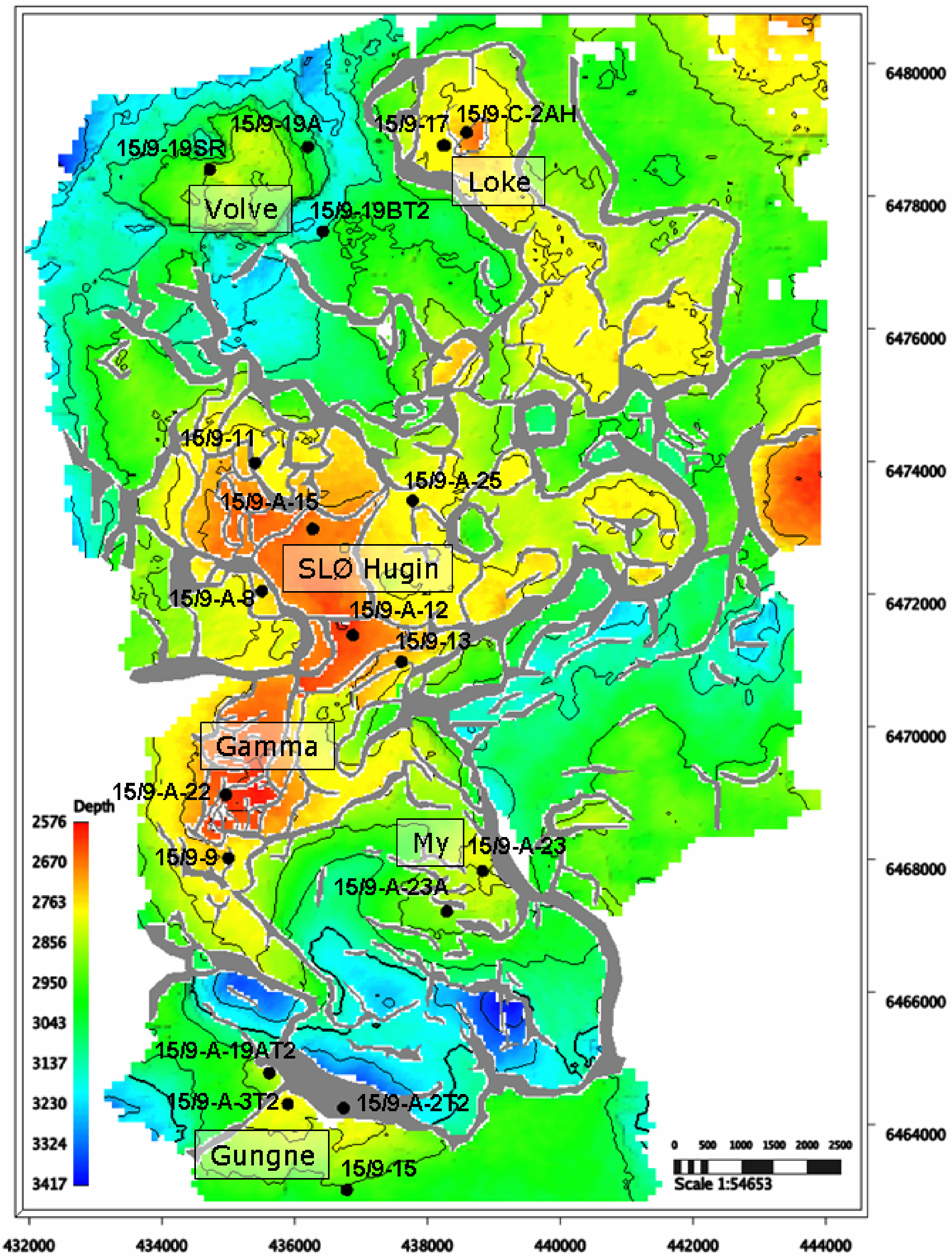

15/9-19A
15/9-19SR
Volve
15/9-17
15/9-C-2AH
Loke
15/9-19BT2
15/9-11
15/9-A-25
15/9-A-15
SLØ Hugin
15/9-A-8
15/9-A-12
15/9-13
Gamma
15/9-A-22
Depth
2576
2670
2763
2856
2950
3043
3137
3230
3324
3417
15/9-9
My
15/9-A-23
15/9-A-23A
15/9-A-19AT2
15/9-A-3T2
15/9-A-2T2
Gungne
15/9-15
0 500 1000 1500 2000 2500
Scale 1:54653
6480000
6478000
6476000
6474000
6472000
6470000
6468000
6466000
6464000
432000
434000
436000
438000
440000
442000
444000

Figure 1 Sleipner Øst and Volve Field, top Hugin Formation map

Area	Well	Date	Company	Tool Combination	Mud Type
Volve	15/9-19 SR	Mar 93	Eastman Teleco Western Atlas	DPR/MDL/MNP/GR DIFL/AC/ZDL/CNGR	OBM Petrofree
	15/9-19 A	Aug 97	Baker Huges Western Atlas	DPR/GR HDIL/MAC/ZDL/CND/ SP/CAL/VSP/GR	OBM Ultidrill
	15/9-19 BT2	Jan 98	Baker Huges Western Atlas	MPR/GR DSL/ZDL/CND/MAC, VSP, FMT/GR	OBM Ultidrill
Loke	15/9-17	Jan 83	Schlumberger	ISF/BHC/GR, LDT/CNL/GR, NGS, DLL/MSFL, RFT	Lignosulphonate
	15/9-C-2 AH	Apr 98	Western Atlas	HDIL/MAC/GR, ZDEN/CND/GR	OBM Ultidrill
SLE Hugin	15/9-11	Nov 81	Schlumberger	ISF/BHC/GR, FDC/CNL/GR, DLL/MSFL/GR/SP, RFT	Gel/Ligno
	15/9-13	May 82	Schlumberger	ISF/BHC/GR, LDT/CNL/GR, DLL/MSFL/GR, RFT	Bentonite
	15/9-A-12	July 95	Baker Inteq Halliburton Schlumberger	DPR/GR Sonic GR/LDL/CNL/AS, RFT/HP/GR	KCL Poly
	15/9-A-15	Feb 95	Baker Inteq Schlumberger	DPR/GR GR/LDL/CNL/BHC, DIT/AS/GR, RFT/HP/GR	OBM Petrofree
	15/9-A-8	May 95	Baker Huges Schlumberger	DPR/GR AS/LDL/CNL/GR, RFT/HP	KCL Pack
	15/9-A-25	July 01	Anadrill Schlumberger	GR/PWD/DEN/ NEU/SONIC/RES/GR GR/RES/PWD/DEN/ NEU	OBM Novatec
Gamma	15/9-9	Jun 81	Schlumberger	ISF/BHC/GR, FDC/CNL/GR, RFT	GYP Polymer
	15/9-A-22	Mar 94	Schlumberger	DIL/BHC/GR, LDL/CNL/GR	OBM Petrofree
My 2	15/9-A-23	Nov 96	Baker Huges Western Atlas	DPR/DEN/NEU/GR FMT/GR	OBM Petrofree
	15/9-A-23 A	May 05	Baker Huges Schlumberger	DPR/DEN/NEU/GR DSI/MDT/GR	OBM Versavert
Gungne	15/9-15	Jun 82	Schlumberger	ISF/SONIC/GR, FDC/CNL/GR, DLL/MSFL/GR, RFT	Bentonite/Ligno-sulphonate
	15/9-A-19 T2	Aug 05	Baker Huges Schlumberger	DPR/DEN/NEU/GR TLD/CNL/HCAL/GR, DSI/GR	OBM Warp
	15/9-A-2 T2	Jan 96	Baker Huges Halliburton	DPR/DEN/NEU/GR LWD Sonic	OBM Novatec
	15/9-A-3 T2	Dec 00	Schlumberger Pathfinder	Vision 475 (GR-Res), ADN, Isonic LWD Sonic	OBM Novatec

Table 1 Log data overview

2.3 Core data

The core data coverage is very good in the Hugin Formation and, in areas, fairly good also in Skagerrak Formation. This is visualized in Table 2 below. Here all the zones are showed, zones that are penetrated by logs are marked with an X and which of these contain core data with C. The double lines separating the Hugin Formation on Volve and the Gungne data from the rest is there to indicate that the geological zonation is different and that correlations across the areas are not intended. No zonation was available in Hugin Formation well 15/9-A-19 AT2, 15/9-A-23 A and 15/9-A-25 and in Skagerrak Formation on Gamma high.

Area	Well	Formation																																								
		Draupne	Heather	Hugin																			Bathonian	Sleipner	Skagerrak													Transition Zone				Smith Bank
	Volve zones			18	17	16	15	14	13	12	11	10	9	8	7	6	5	4	3		2	1			13	12	11	10	9	8	7	6	5	4	3	2	1	4	3	2	1	
Volve	15/9-19 A	-	x	-	X	X	X	X	X	C	C	C	C	C	C	C	C	C	C		C	C	-	C	-	-	C	C	C	C	C	X	X	X	X	-	-	-	-	-	-	-
	15/9-19 SR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	X	X		C	C	-	-	-	-	C	C	C	X	X	X	X	X	X	-	-	-	-	-	-	-
	15/9-19 BT2	-	X	C	C	C	C	C	C	C	C	C	C	X	X	X	X	X	X		X	X	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Loke	15/9-17	c	-	-	-	-	-	-	-	-	-	-	-	-			-	-	C	-	-	-	-	-	C	C	C	C	C	C	C	c	X	x	X	X	C	c	X	X	X	X
	15/9-C-2 AH	X	-	-	-	-	-	-	-	-	-	-	-	X			C	C	C	-	-	-	-	-	-	-	C	c	C	C	X	x	X	X	x	x	X	x	X	x	X	-
SLE Hugin	15/9-11	-	-	-	-	-	-	-	-	-	-	-	X	x			X	X	X	X	X	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	X
	15/9-A-15	-	-								-	-	X	c			C	-	C	C	-	C	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	15/9-A-25	-	-								-	-	X										-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	15/9-A-12	-	-								-	-	X	X			C	-	C	-	-	C	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	15/9-13	-	-								-	-	C	x			c	-	C	-	-	C	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	C
	15/9-A-8	-	-								-	-	x	x			X	-	X	X	-	C	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gamma	15/9-A-22	-	-	-	-	-	-	-	-	-	-	-	-	-			x	-	x	-	x	-	-	-	X													-	-	-	-	X
	15/9-9	-	-	-	-	-	-	-	-	-	-	-	-	-			x	-	x	-	-	x	-	-	C													-	-	-	-	X
My2	15/9-A-23	-	-	-	-	-	-	-	-	-	-	-	x	-			X	-	X	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	X
	15/9-A-23 A	-	-	-	-	-	-	-	-	-	-	-	X										-	-	C													-	-	-	-	-
Gungne	15/9-19 AT2	-	-	-	-	-	-	-	-	-	-	-	X										-	-	-	-	-	-	-	-	-	-	X					-	-	-	-	-
	15/9-A-3 T2	-	-	-	-	-	-	-	-	-	-	-	-	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	X	X	X	X	X	-	-	-	-	X
	15/9-15	-	-	-	-	-	-	-	-	-	-	-	-	-			-	-	-	-	-	-	C	-	-	-	-	-	-	-	-	-	C	X	X	X	X	-	-	-	-	X
	15/9-A-2 T2	-	-	-	-	-	-	-	-	-	-	-	-	-			-	-	-	-	-	-	X	-	-	-	-	-	-	-	-	-	X	X	X	X	-	-	-	-	-	-
	SLØ zones												8	7			6	5	4	3	2	1																				

Legend	
-	Not present
X	Log data
C	Core data
x	Few of bad data
c	Few of bad data

Table 2 Log and core data coverage on Sleipner Øst and Volve

Core data is available in 12 of the 19 wells and an overview of the cored intervals is given in Table A.2. Here also the amount of depth shifting which has been used to match the reference density log is given[1,2,3].

Special core analysis measurements such as Formation Factor, *FF*, Resistivity Index, *RI*, overburden measurements, *OB*, and Capillary Pressure, *PC*, measurements has been taken. A list of relevant reports is found in Table A.3. Evaluation of these data is found in Section 3.

2.4 Formation pressure data

The basis for the formation pressure points has been the data reported on the field prints. The data measured before 1983 has in general been corrected for temperature and converted from gauge to absolute values in this stydy, by using that **psia = psig + 14.7**. Then the pressures have been converted from psia to bara by a factor of **0.068948**.

5 wells do not have formation pressure data, wells 15/9-19 SR, 15/9-19 A, 15/9-A-2 T2, 15/9-A-3 T2 and 15/9-A-25. All the pressure points and the corrected data are listed in Table A.4.

3 Core data evaluation

Conventional core data are available in 12 wells. The large amount of measurements of porosity and permeability in Hugin Formation ensures good confidence of the models. Hence the confidence is not equally as good in Skagerrak Formation, especially around 15/9-A-22, 15/9-A-23 A and Gungne. The grain density, see section 3.1, is used in the calculation of porosity from logs.

Table 3 shows all the available petrophysical SCAL data on Sleipner Øst, Volve and Sigyn (southeast of Gungne). Some of these data are from old reports where the information often is limited or absent, and where the procedures may have improved over the years. Therefore data from before 1985 and from 15/9-19 BT2 has not been used in the parameter evaluation. This is due various reasons such as lack of information about procedures or methods, pressure and temperature conditions, too small plug size has been used, and uncertainty regarding porosity and saturation caused by weighing. In the table the data with colours are the data recommended for petrophysical parameter estimation.

The evaluation of saturation- and cementation exponent are presented below, in addition to normalisation of the capillary pressure measurements, see the sections 3.2 – 3.5.

Well	Year	Formation	FF	FF OB	RI (g/w)	RI (g/w) OB	RI (o/w) OB	Pc Hg	Pc (g/w)	Pc (o/w)	OB
15/9-15	1984	Bathonian	14		14			15	14		15
15/9-13	1983	Hugin	5		5				5		
15/9-17	1983	Hugin	1		1				1		
15/9-19 BT2	1998	Hugin	22								
15/9-19 SR	**1995**	Hugin		**3**		**3**	**3**			**3**	
15/9-19 A	**1999**	Hugin/Sleipner		**8**		**3**	**6**		**3**	**6**	
15/9-A-12	**1996**	Hugin		**6**		**6**			**6**		
15/9-A-15	**1996**	Hugin	**6**	**5**	**6**	**5**			**11**		
Total			34	22	12	17	9		20	9	
Recommended			**6**	**22**	**6**	**17**	**9**	**-**	**25**	**9**	**-**
15/9-15	1984	Skagerrak	4		4			3	4		3
15/9-17	1983	Skagerrak	11		13				13		4
15/9-19 SR	**1995**	Skagerrak					**1**			**1**	
15/9-19 A	**1999**	Skagerrak				**2**	**2**		**2**	**2**	
16/7-4	1983	Skagerrak	13		13				13		13
16/7-6	**1999**	Skagerrak		**7**		**7**			**7**		
16/7-7 ST2	**1999**	Skagerrak		**7**		**7**			**7+21**		
Total			28	14	30	16	3	3	39	3	20
Recommended			**-**	**14**	**-**	**16**	**3**	**-**	**37**	**3**	**-**

Table 3 Overview of Petrophysical Special core Analysis data on Sleipner Øst, Volve and Sigyn

3.1 Grain density from cores

The density of the matrix, ρma, is determined from the average core grain density values in each reservoir zone. This is done by plotting the core grain density data in histograms.

The values used are listed in Table 4. In some specified zones other values than the general trend was used in some wells to obtain a better fit with the core data.

Zones Volve	Zones SLE	Grain Density g/cc	Comments
Draupne	Draupne	2.66	2,63 g/cc used in Hugin 14 for 15/9-19 A
Heather	Heather		
Hugin 18-14			
Hugin 13-7	Hugin 8-6	2.65	2,63 g/cc used in Hugin 13 for 15/9-19 A 2,69 g/cc used in Hugin 8 for 15/9-13
Hugin 6-2	Hugin 5-2	2.64	2,63 g/cc used in Hugin 5 and 2, and 2,66 g/cc used in Hugin 6 for 15/9-19 A
Hugin 1	Hguin 1	2.65	
Sleipner	Sleipner		
Skagerrak	Skagerrak	2.68	2,69 g/cc used in well 15/9-9

Table 4 Grain density, Sleipner Øst and Volve

3.2 Overburden corrections

In order to be able to correlate core values of porosity and permeability with the log values the core data has been corrected to reservoir conditions. This was done by the following equations, described for Sleipner Øst in 2000[4] and for Gungne in 2001[5].

Hugin + Sleipner:	$\Phi_{res} = 0.981 \cdot \Phi_{lab} - 0.13 \cdot \Phi_{lab}^2$
Skagerrak + Smith Bank:	$\Phi_{res} = 0.934 \cdot \Phi_{lab}$
Gungne Field:	$\Phi_{res} = 0.93 \cdot \Phi_{lab}$

Hugin + Sleipner:	$K_{res} = \left[0.094 \cdot \log_{10}(K_{lab}) + 0.372\right]$
Skagerrak + Smith Bank:	$K_{res} = \left[0.010 \cdot \log_{10}(K_{lab}) + 0.230\right]$
Gungne Field:	$k_{lab} < 2\,\text{mD} \Rightarrow k_{res} = 0.1 \cdot k_{lab}$ $2\,\text{mD} \le k_{lab} \le 150\,\text{mD} \Rightarrow k_{res} = \left[0.123 \cdot \ln(k_{lab}) + 0.031\right] \cdot k_{lab}$ $k_{lab} > 150\,\text{mD} \Rightarrow k_{res} = 0.65 \cdot k_{lab}$

3.3 Cementation exponent, m

The cementation exponent, m, can be described by the following relationship:

$$FF = \frac{a}{\phi^m} \qquad (3)$$

FF	Formation Factor (fraction)
a	Archie factor (= 1.0)
ϕ	Porosity (fraction)
m	Cementation exponent (fraction)

In Figure 2.a the cementation exponents, m, have been calculated and plotted against the permeability for Hugin and Sleipner Formation and in 2.b for Skagerrak Formation. There were too few data points in the Sleipner Formation to have a different value here. The older data shows lower values for m than the overburden corrected data from the newer wells, and has therefore not been used.

Normally the m exponent decreases with increasing permeability. For the Hugin Formation this could be seen on the Volve field, wells 15/9-19 SR and 15/9-19 A but not on Sleipner Øst, wells 15/9-A-12 and 15/9-A-15. Here the m exponent was established by a regression analysis between the overburden corrected formation factors against the overburden corrected porosity. This value has been verified by Picket plots.

For Skagerrak Formation only the wells 16/7-6 and 16/7-7 ST2 have overburden corrected data. Pickett plots from the water zone in the wells 15/9-9 and 15/9-15 show m values between 2.0 to 2.05. The values listed below are used in the water saturation in Section 4.3.

These values are used in the evaluation:

- Sleipner Øst: Hugin Formation: ***m* = 1.79**
- Volve: Hugin and Sleipner Formation: ***m* = 1.865.K$^{-0.0083}$**
- Skagerrak Formation: ***m* = 2.02**

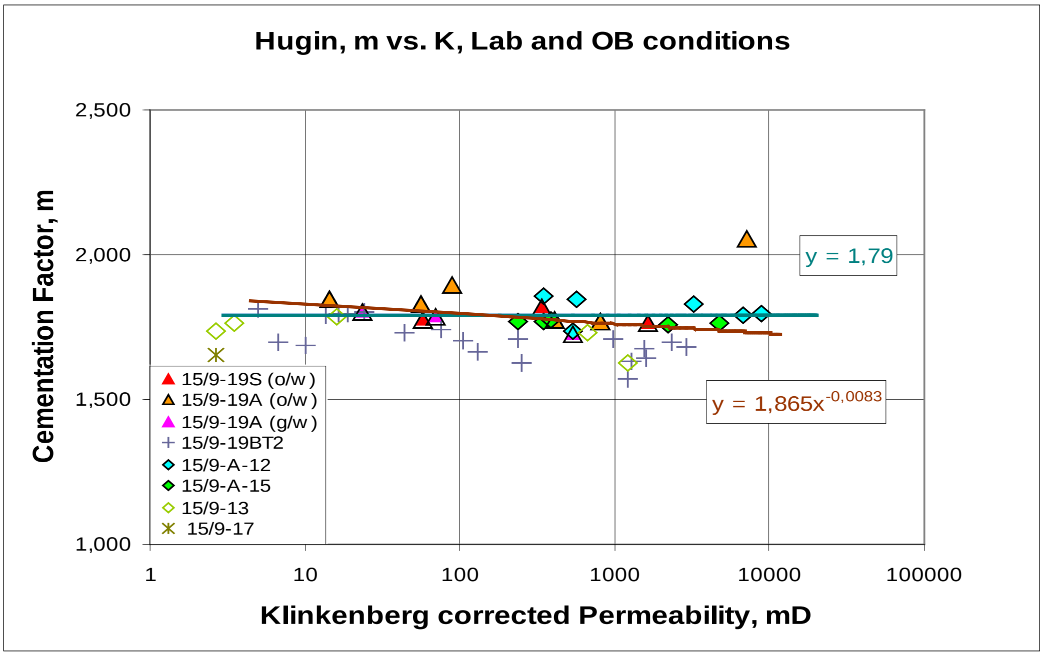


Figure 2.a Cementation exponent vs. permeability for Hugin and Sleipner Formation

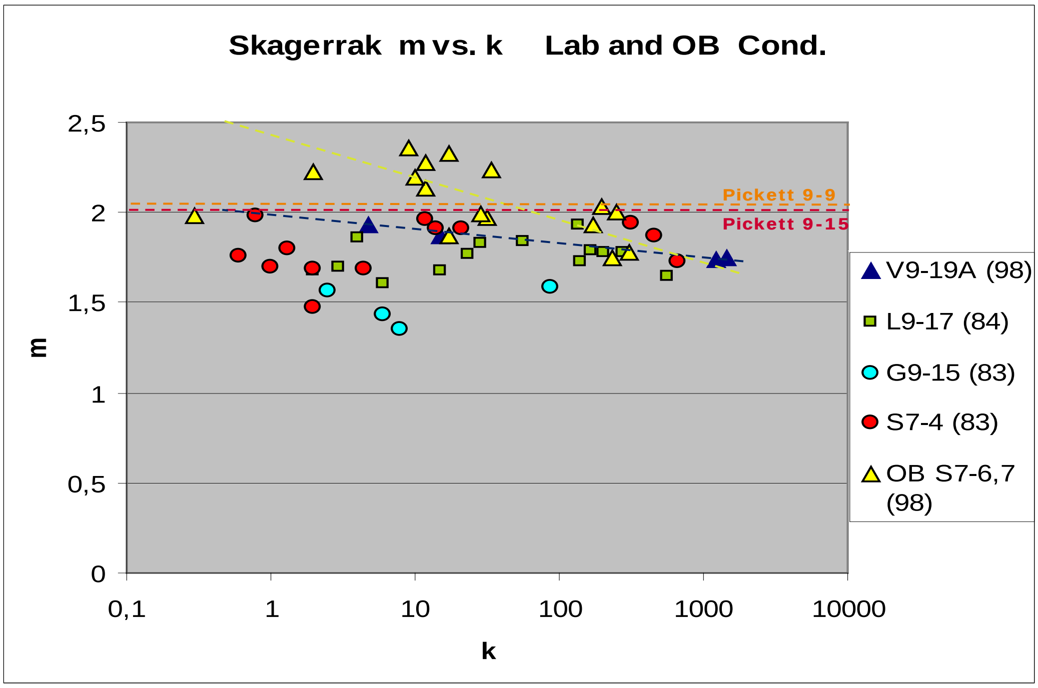


Figure 2.b Cementation exponent vs. permeability for Skagerrak Formation

3.4 Saturation exponent, n

The saturation exponent, *n*, is derived from Archies equation;

$$RI = \frac{R_o}{R_t} = S_w^{-n} \qquad \Leftrightarrow \qquad n = -\frac{\log RI}{\log S_w} \tag{2}$$

Sw	Water saturation (fraction)
n	Saturation exponent
Ro	Resistivity of water saturated formation (Ωm)
Rt	Resistivity of the formation (Ωm)
RI	Resistivity index (Ωm)

The *n* exponents are plotted against porosity in Figure 3.a for Hugin and Sleipner Formation and in 3.b for Skagerrak Formation. The uncorrected data from the older wells shows lower values, below 2 down to 1.4, than the overburden corrected data from the newer wells and has not been used. The final *n* exponent values was found from regression analysis of the resistivity index, *RI*, against water saturation, *SW*, and listed below.

- Sleipner Øst, Hugin Formation: ***n* = 2.14** (15/9-A-12 and 15/9-A-15)
- Volve, Hugin and Sleipner Formation: ***n* = 2.45** (15/9-19 SR and 15/9-19 A)
- Sleipner Øst, Skagerrak Formaiton: ***n* = 2.03** (15/7-6 and 15/7-7 ST2)

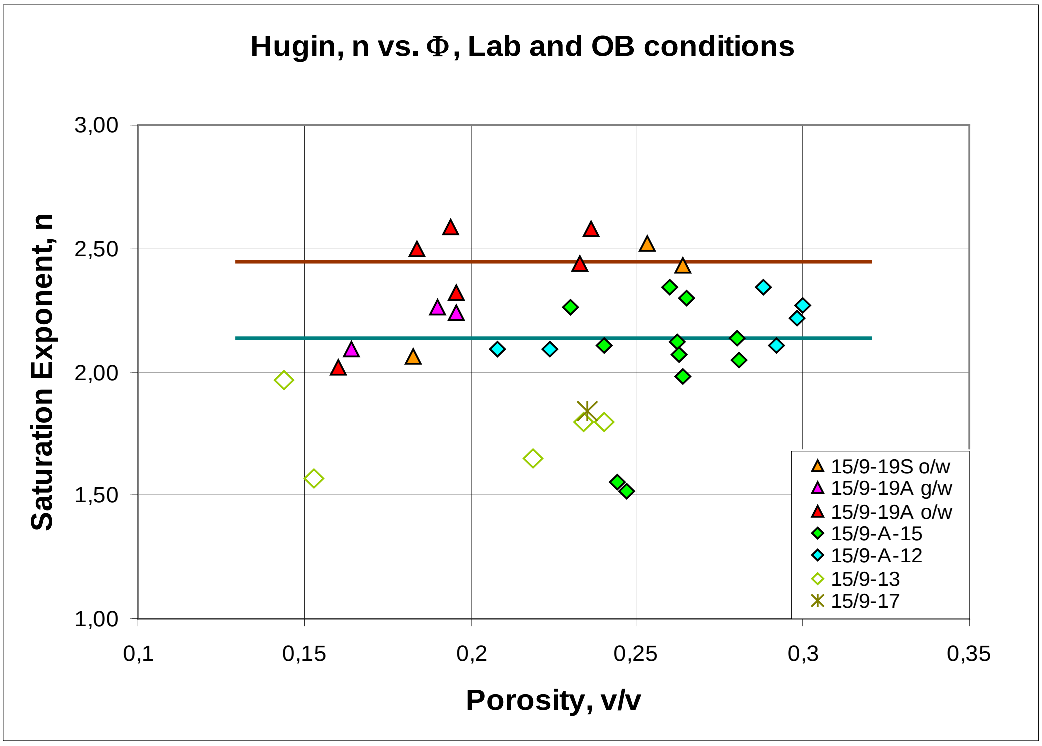


Figure 3.a Saturation exponent vs. porosity for Hugin and Sleipner Formation

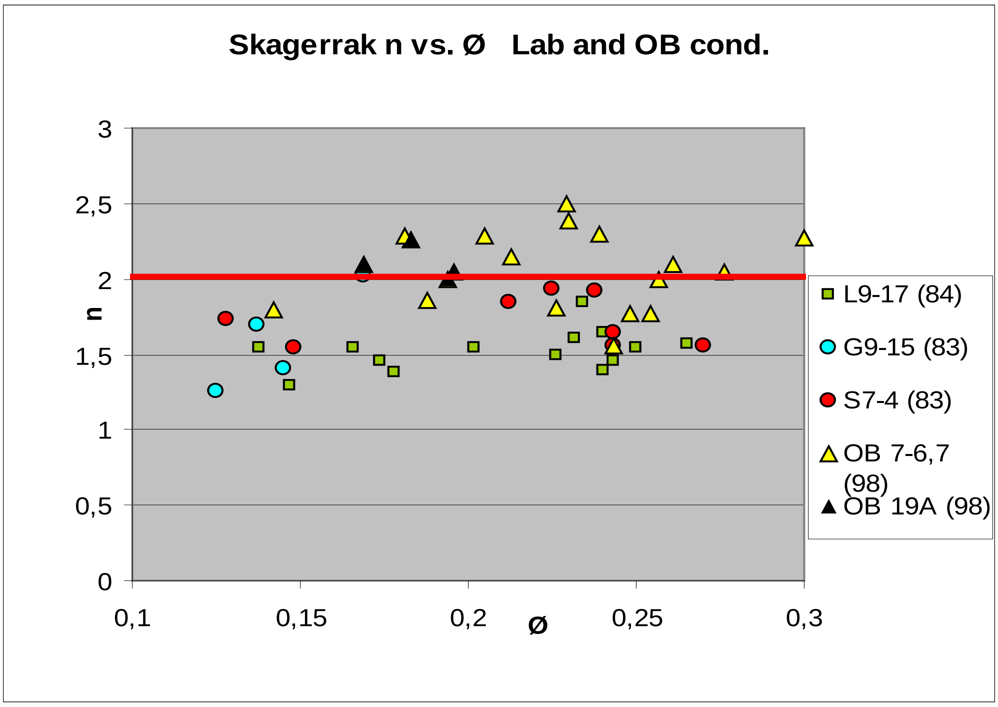


Figure 3.b Saturation exponent vs. porosity for Skagerrak Formation

3.5 Capillary Pressure

Capillary pressure measurements of good quality, done by the porous plate method, are available on 17 plugs of gas/water measurements for the Hugin formation from the wells 15/9-A-12 and 15/9-A-15 and 9 plugs with oil/water measurements in well 15/9-19 A and 15/9-19 SR. For the Skagerrak Formation porous plate measurements are available from the wells 16/7-6, 16/7-7 ST2, 15/9-19 A (all new data, 1999) and 15/9-17 (older data, 1983)

An example of raw capillary data vs. water saturation is shown in Figure 4.a. The legend is showing the permeability value of the samples. These data must first be extrapolated up to irreducible water saturation, as done in Figure 4.b., before they can be normalised.

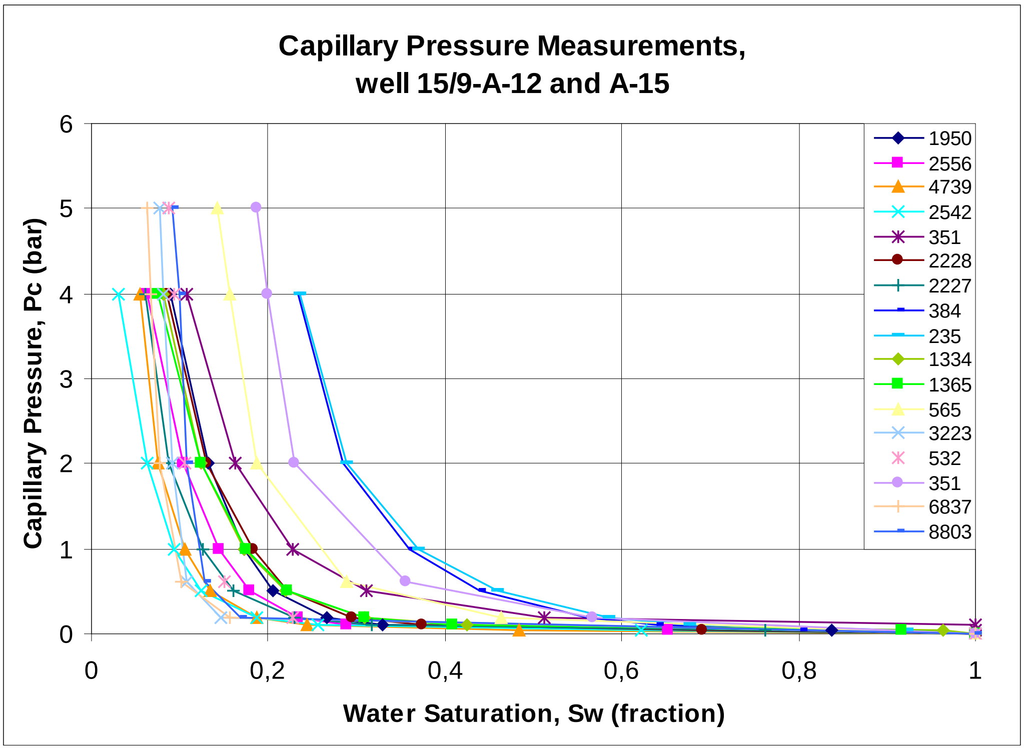


Figure 4.a Gas/water capillary pressure measurements vs. water saturation for wells 15/9-A-12 and 15/9-A-15, Hugin Formation

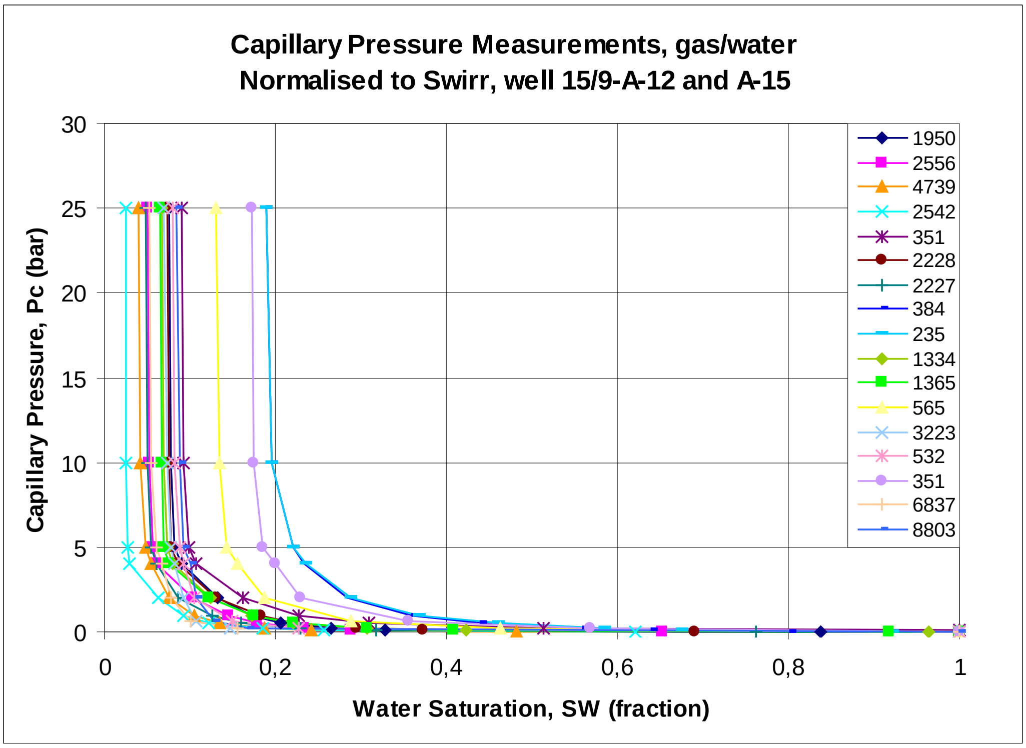


Figure 4.b Gas/water capillary pressure measurements vs. water saturation for wells 15/9-A-12 and 15/9-A-15, Hugin Formation

The shape of the capillary pressure curve is dependent on the porosity and permeability of the plug therefore the measurements must be normalised before they can be used. This has been done by the Leverett's J-function given below. No information of the surface tension and the contact angle in the laboratory is given in any of the reports so the same values as for Sleipner Vest[6] is used; 70 mN/m and 0°, respectively.

$$J = \left(\frac{Pc}{\sigma \cdot \frac{\cos\theta}{3.141}} \right)_{lab} \cdot \left(\sqrt{\frac{k}{\phi}} \right)_{lab} = 0.044867 \cdot Pc_{lab} \cdot \left(\sqrt{\frac{k}{\phi}} \right)_{lab} \tag{4}$$

Pc:	Capillary pressure (bar)
σ:	Surface tension (laboratory conditions) (mN/m)
θ:	Contact angle against the rock (lab cond) (°)
k:	Permeability of the plug (mD)
ϕ:	Porosity of the plug (fraction)

J has been calculated and plotted against the normalised water saturation, *Swn*, for each plug, given by the following relationship.

$$Swn = a'^{*} \cdot J^{-b'} = \frac{Sw - Sw_{irra}}{1 - Sw_{irra}} \tag{5}$$

Swn	Normalised water saturation (fraction)
Sw	Water saturation in the reservoir (fraction)
Sw_{irra}	Irreducible water saturation (fraction)
k	Permeability (mD)
a', b'	Regression constants

The value of Sw_{irra} is taken as the end point of the capillary pressure measurement in the laboratory. The relationship between the water saturation and the J-function is described by the functions below, and the constants *a'* and *b'* are determined by the regression curve given in Figure 5.a for Hugin Sleipner Øst, 5.b for Hugin Volve and 5.c for Skagerrak Formation Sleipner Øst. Conversion of these equations gives the following expressions of normalised water saturation against the J-function.

Hugin Formation, Sleipner Øst:	$Swn = 0.526 \cdot J^{-1.087}$	$a = 0.526$, $b = -1.087$
Hugin Formation, Volve:	$Swn = 2.222 \cdot J^{-1.111}$	$a = 2.222$, $b = -1.111$
Skagerrak formation:	$Swn = 0.158 \cdot J^{-0.847}$	$a = 0.158$, $b = -0.847$

These measurements and equations have been used further to express the water saturation as a function of the height above free water level, in Section 6, modelling of the water saturation.

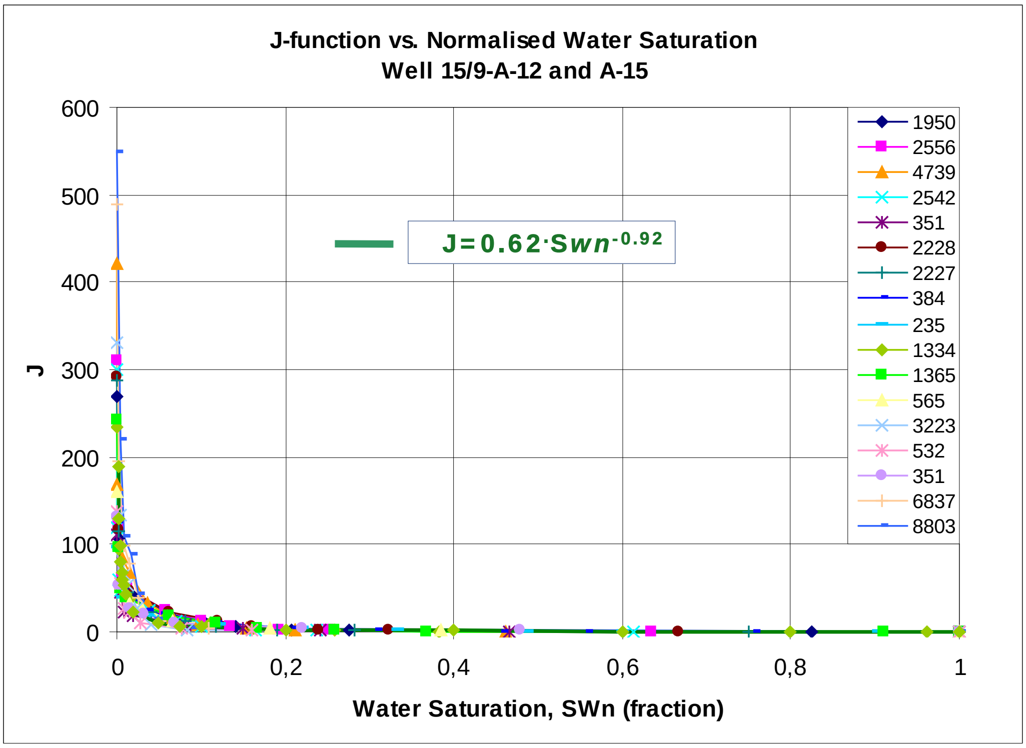


Figure 5.a J-function vs. normalised water saturation for wells 15/9-A-12 and 15/9-A-15, Hugin Formation, Sleipner Øst

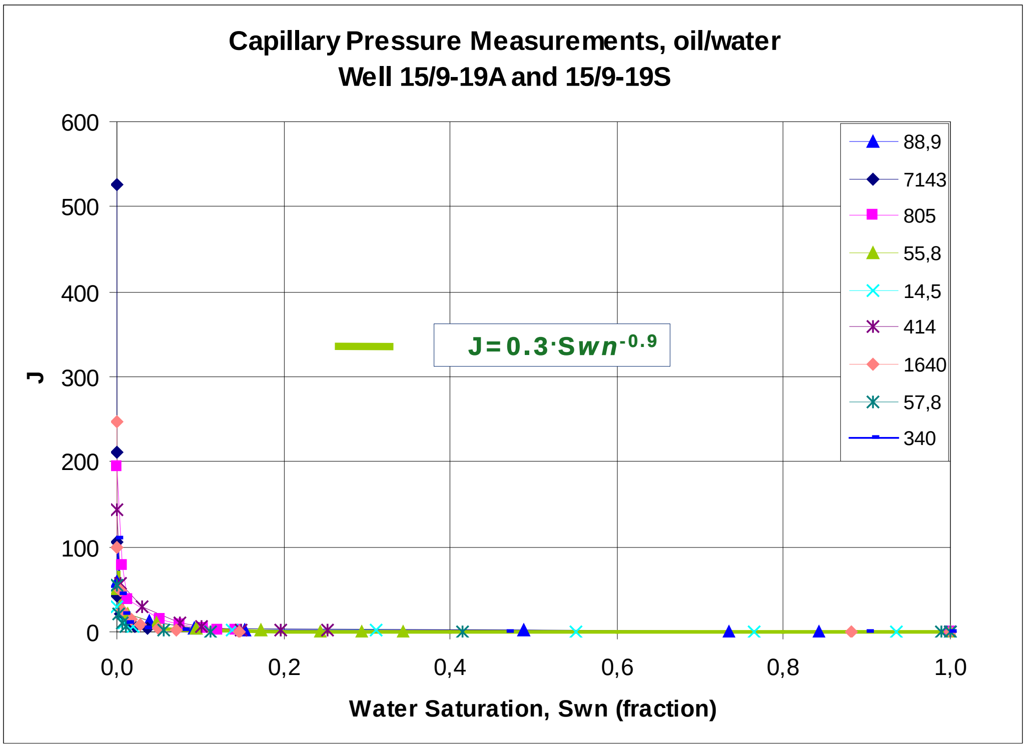


Figure 5.b J-function vs. normalised water saturation for wells 15/9-19 SR and 15/9-19 A, Hugin Formation, Volve

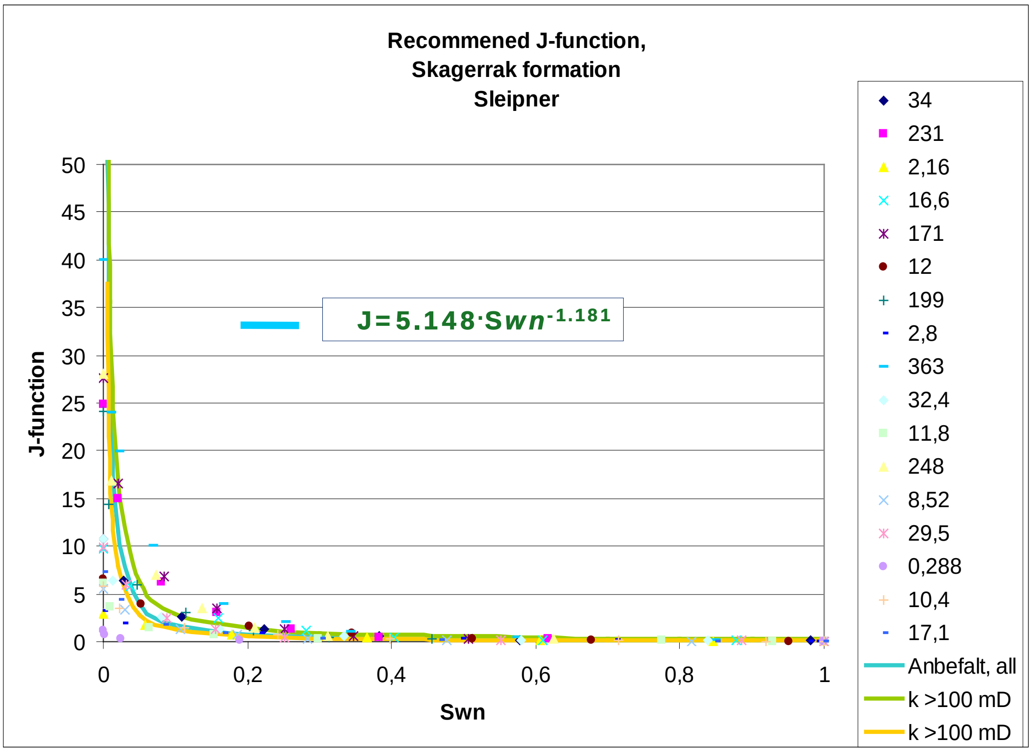


Figure 5.c J-function vs. normalised water saturation for wells 16/7-6, 16/7-7 ST2 and

15/9-19 A, Skagerrak Formation

3.6 Pore throat radius from mercury-injection

For the new wells on Sleipner East and Volve particles like calcium carbonate or graphite can be used in the drilling mud for building filter cake, prevent fracture initiation, prevent propagation of fractures and reduce bore hole friction. To prevent physical damage like blocking of the pore space, the size of these mud particles have to be bigger than the pore throats and this is the reason for pore throat estimation from mercury-injection on core plugs.

Mercury-injection curve has been used to approximate the distribution of pore volume accessible by throats of given effective size using equation:

$$r_c = \frac{2\sigma\cos\theta}{Pc}$$

Where σ is the interfacial tension of air/mercury system, θ is the air/mercury/solid contact angle, Pc is capillary pressure and rc is either the radius of a cylindrical capillary tube (which models the radius of a tubular pore throat) or the distance between two infinite parallel plates. Real pore throats have a more complex geometry and rocks typically contain a variety of pore throats types. Therefore the calculated values represent the effective size of the throats, which may be different from the actual dimensions of the throats in the rock.
To get a good estimate of the pore throats thin sections and SEM is needed.

On Sleipner East we have mercury core measurements from 15/9-5, 15/9-A-15, 15/9-A-25 and 15/9-D-3 H. Mercury injection vs. pore throat radius is plotted in Figures 6.a through d.

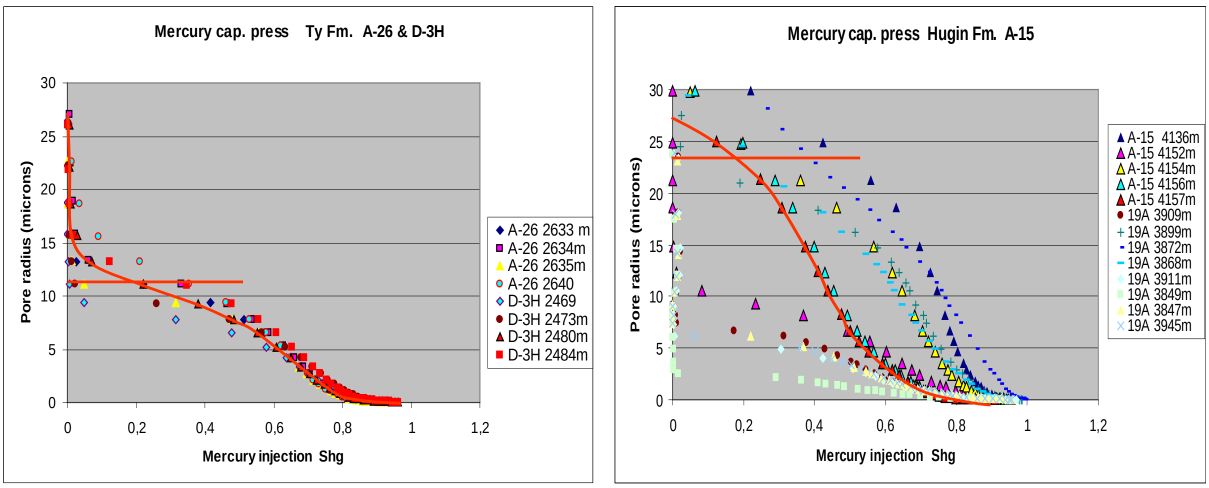
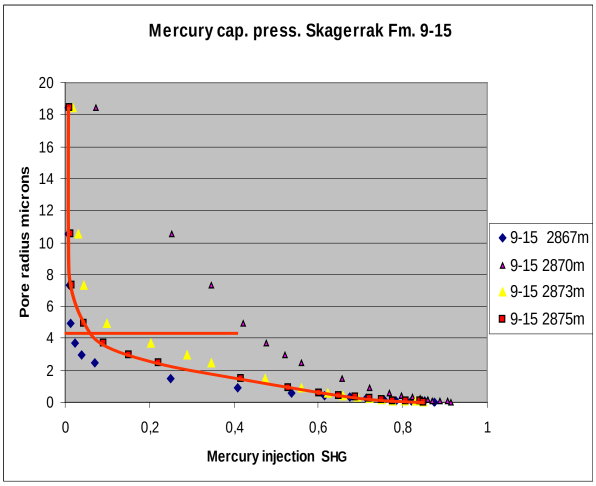


Figure 6 Changes in pore throat radius a. Ty Fm, b. Hugin Fm



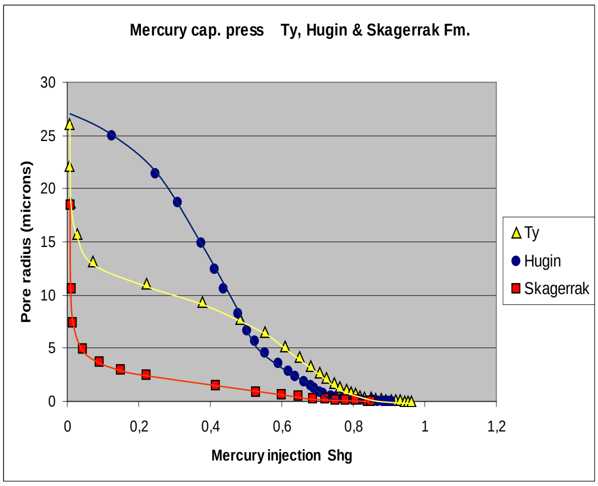


Fig 6 Changes in pore throat radius c. Skagerrak Fm, d. Summarize Ty, Hugin and Skagerrak Fm.

Ty Formation, Figure 6.a has a pore throat radius close to 12 microns for the first 40% mercury injection. The particle size in the mud must be more than 10 microns in radius with overburden correction to prevent blocking of the pore space. Hugin Formation, Figure 6.b, has the highest pore throat radius and the particle size in the mud must exceed 22 micron in radius with overburden correction. Skagerrak Formation, Figure 6.c has the smallest pore throat radius and the particle size in the mud must be more than 3 micron in radius with overburden correction.

Figure 6.d summarizes the changes of the pore throats for the Ty, Hugin and Skagerrak Formation and shows quite different pore throat systems. The Hugin and Ty Formation have the biggest radius and smallest radius is found in Skagerrak Formation.

4 Petrophysical Model

The petrophysical model is based on total porosity from density and neutron log, section 5.2, with water saturation from the Archie equation, see section 5.3. Shale volume, section 5.1, however, has proven to be useful both in the evaluation of the continuous permeability, see section 5.4, and as an additional cut off when determining the net sand, section 5.5.

4.1 Shale volume

The shale volume is derived from the gamma ray, GR, log using a linear relationship, as shown in the equation below.

$$VSH = \frac{GR_{\max} - GR}{GR_{\max} - GR_{\min}} \qquad (6)$$

GR_{max}	Clean gamma ray value (API)
GR_{min}	Shale gamma ray value (API)

To estimate the gamma ray clean and shale parameters histograms of the gamma ray curve has been examined and also the gamma ray log vs. depth. Gamma ray parameters are listed in Table 5. No XRD analysis is available from Sleipner Øst.

		Formation			
		Hugin		Skagerrak	
Well	Area	GRmin	GRmax	GRmin	GRmax
		GAPI		*GAPI*	
15/9-19 SR	Volve	17	135	-	-
15/9-19 A	Volve	12	115	-	-
15/9-19 BT2	Volve	8	100	-	-
15/9-17	Loke	37	150	35	95
15/9-C-2 AH	Loke	25	140	23	110
15/9-A-8	SLE Hugin	55	165	-	-
15/9-11	SLE Hugin	18	125	-	-
15/9-A-15	SLE Hugin	15	140	-	-
15/9-A-25	SLE Hugin	20	140	-	-
15/9-A-12	SLE Hugin	50	170	-	-
15/9-13	SLE Hugin	10	110	-	-
15/9-9	Gamma	-	-	28	88
15/9-A-22	Gamma	-	-	32	110
15/9-A-23	My	25	95	-	-
15/9-A-23 A	My	-	-	23	92
15/9-15	Gungne	-	-	30	85
15/9-A-19 AT2	Gungne	-	-	37	90
15/9-A-2 T2	Gungne	-	-	33	87
15/9-A-3 T2	Gungne	-	-	28	92

Table 5 Gamma ray parameters for shale volume calculation

4.2 Porosity

The porosity is derived from the density log calibrated to overburden corrected core porosity. The neutron porosity log has been used to correct for varying mud filtrate invasion.

The following equation is used:

$$\phi_F = \phi_D + \alpha \cdot (NPHI - \phi_D) + \beta \tag{7}$$

ϕ_F: Final porosity (fraction)
ϕ_D: Density porosity (fraction)
α, β: Regression constants
$NPHI$: Neutron porosity, limestone units (fraction)

The parameters used for porosity above are summarised in Table 6.

Wells	Formation	Mud	ρfl	α	β	$\Phi_{N} - \Phi_{D}$
15/9-11, 15/9-13, 15/9-17	Hugin	WBM	1.00	0.285	-0.02	0.00
15/9-19 SR, 15/9-A-12, 15/9-A-15, 15/9-C-2 AH	Hugin	OBM	0.90	0.400	0.01	0.00
15/9-19 A	Hugin and Sleipner	OBM	0.80	0.400	0.01	0.00
15/9-19 BT2 (Water filled)	Hugin	OBM	0.90	$\Phi_T = \Phi_D$		
15/9-9 (Water filled)	Skagerrak	WBM	1.00	$\Phi_T = \Phi_D$		
15/9-A-2 T2, 15/9-A-3 T2, 15/9-A-19 A, 15/9-A-22, 15/9-A-23 A	Skagerrak	OBM	0.85	0.400	0.01	0.00
15/9-17	Skagerrak	WBM	1.00	0.37	-0.01	0.00
15/9-C-2 AH (Transition)	Skagerrak	OBM	0.97	$\Phi_T = \Phi_D$		
15/9-15	Bathonian and Skagerrak	WBM	0.60 (hc) 1.00 (gas)	$\Phi_T = \Phi_D$		

Table 6 Parameters used for porosity calculation

4.2.1 Density porosity

The density porosity is based on a linear relationship between bulk density and overburden corrected porosity from the cores:

$$\phi_D = \frac{(\rho_{ma} - \rho_b)}{(\rho_{ma} - \rho_{fl})} \tag{8}$$

ϕ: Porosity (fraction)
ρ_{ma}: Matrix density (g/cc)
ρ_b: Bulk density from log reading (g/cc)

ρ_{fl}: Fluid density (g/cc)

The evaluation of the matrix density, ρma, is described in section 3.1.

The fluid density, ρfl, is estimated from correlations of compaction corrected core porosity and the density log in water zones. Core data from water zones are only available in three wells, 15/9-19 BT2 (OBM), 15/9-9 (WBM) and 15/9-A-23 A (OBM), see Figure 7.

From these data a value of **1.0 g/cm^3** is used for wells drilled with water based mud while for oil based mud more variation is seen. Mainly a value of **0.9 g/cm^3** are used for Hugin Formation and **0.85 g/cm^3** in Skagerrak Formation, but further calibration was done in the gas zones, and from this a value of 0.8 g/cm^3 was used in well 15/9-19 A, see all details in Table 6.

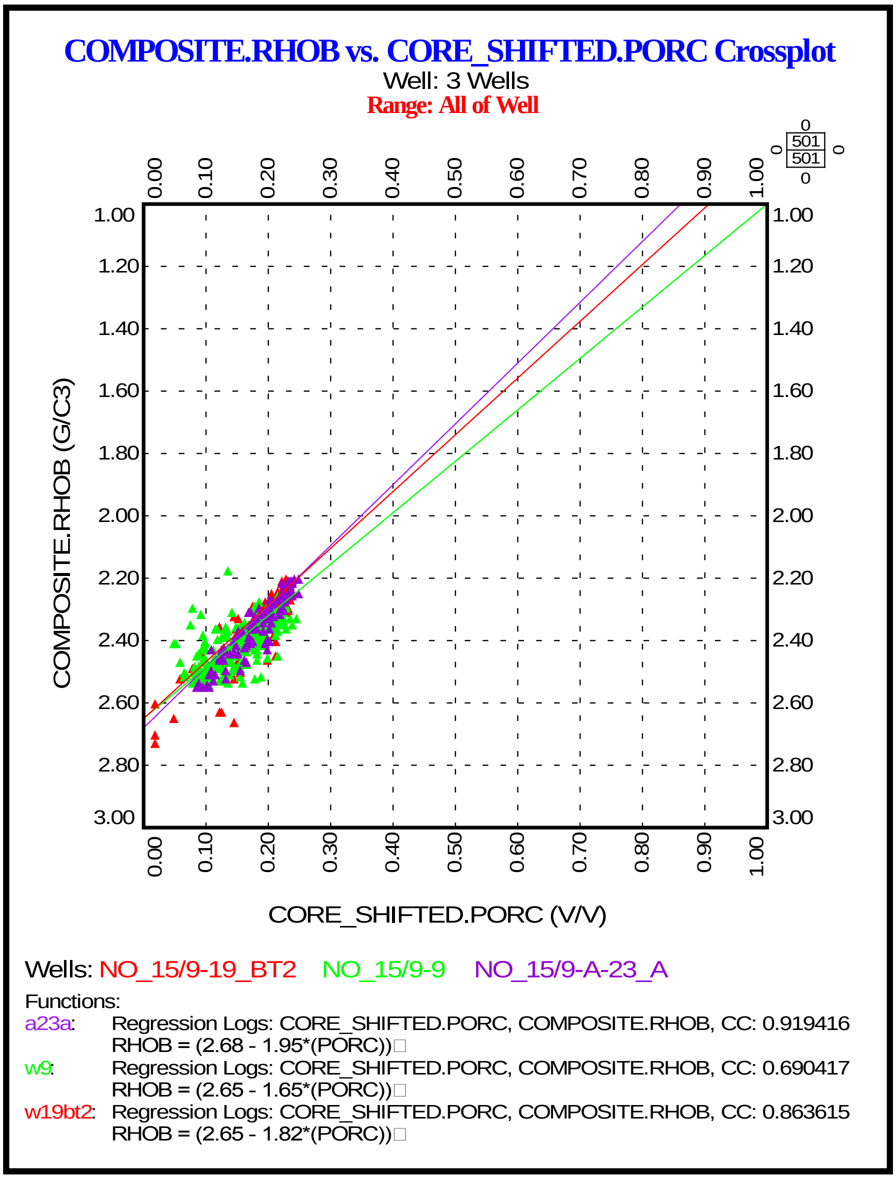


Figure 7 Density log vs. core porosity, well 15/9-19 BT2, 15/9-9 and 15/9-A-23 A

4.2.2 Mud filtrate invasion

The neutron density separation, ($\phi_N - \phi_D$), is used as a measure of mud filtrate invasion, as this separation is sensitive to the presence of gas. Neutron porosity is taken as the value of the neutron porosity log, *NPHI*, at each depth increment. α and β are the constants estimated from the linear regression between ($\phi_N - \phi_D$) vs. ($\phi_C - \phi_D$), where ϕ_C is the overburden core porosity, see Figure 8.a and b for water based and oil based mud, respectively.

$$(\phi_C - \phi_D) = \alpha \cdot (\phi_N - \phi_D) - \beta \qquad (9)$$

ϕ_C: Core porosity (fraction)
ϕ_D: Density porosity (fraction)
α, β: Regression constants
NPHI: Neutron porosity, limestone units (fraction)

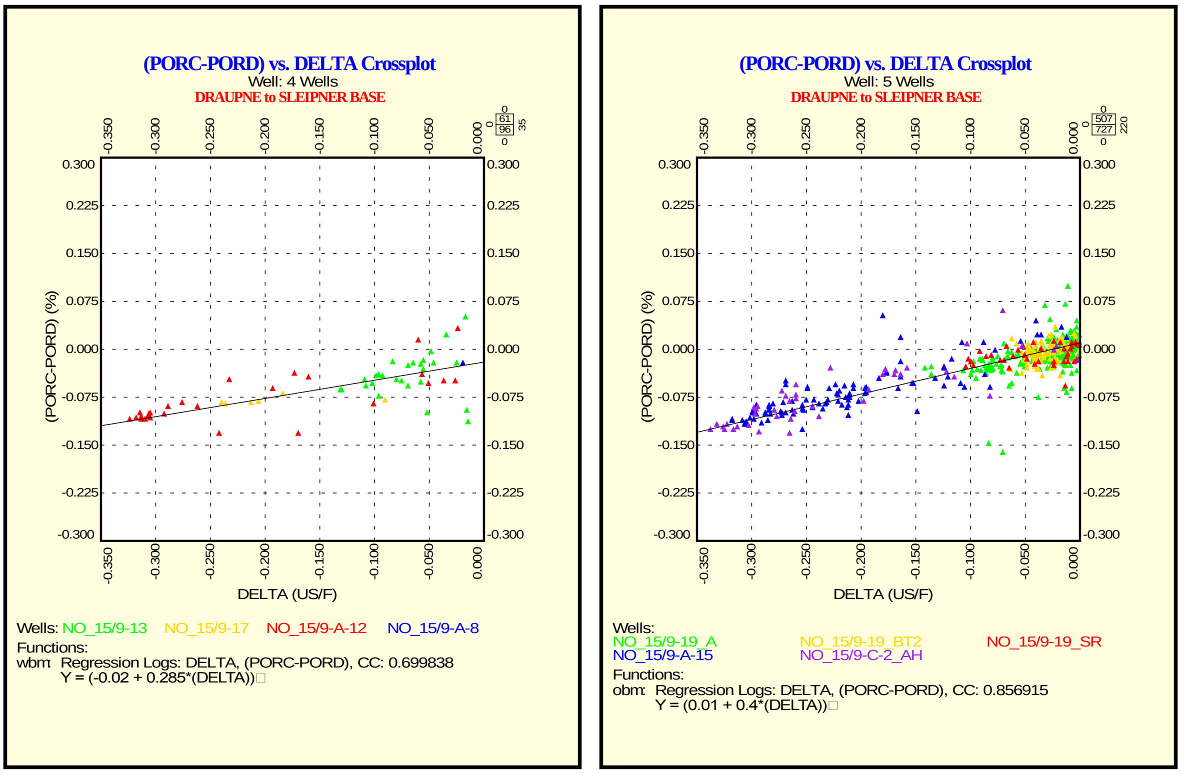


Figure 8 Correlation of core porosity v.s. Density/Neutron separation for wells with a. water based mud an b. oil based mud, Hugin Formation

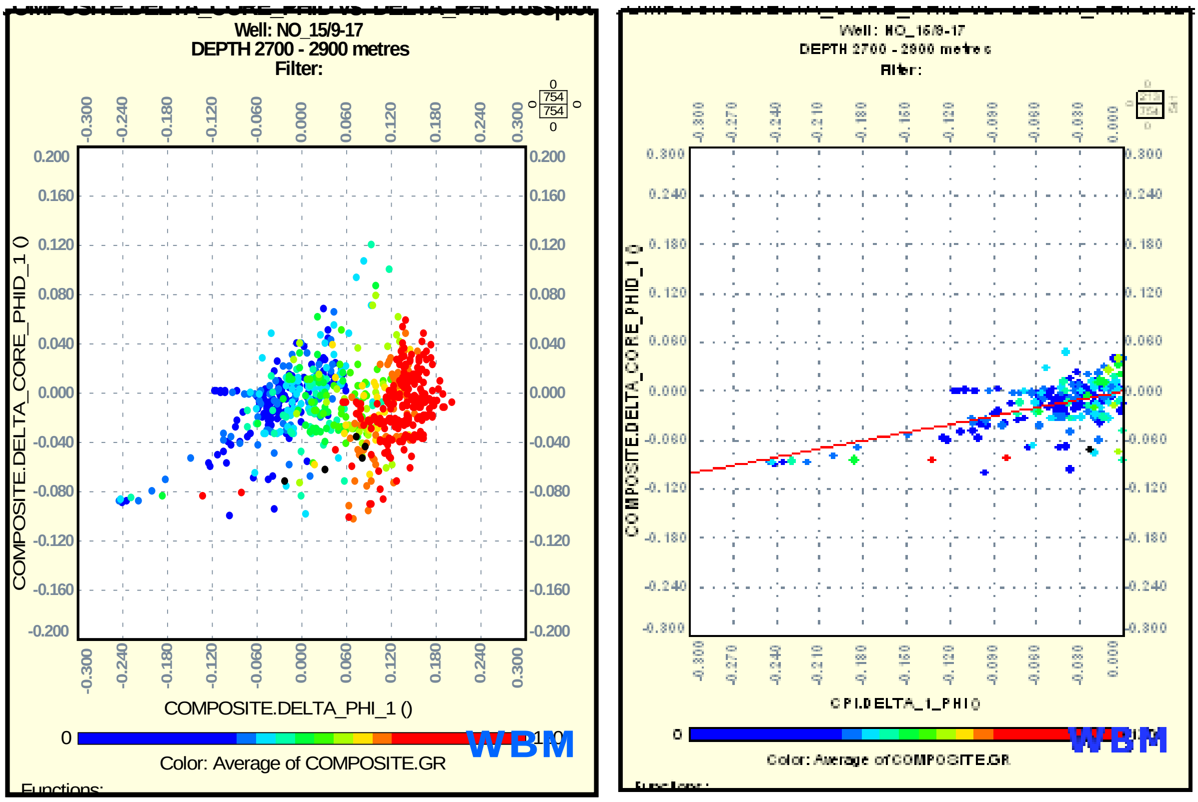


Figure 8 Correlation of core porosity v.s. Density/Neutron separation for 15/9-17, Skagerrak Fm.

The regression constants are given in Table 6.

A cut off value on the density log of 2.0 g/cc was used to initially create a coal flag. This was then manually edited after examining all the logs and core photographs. The log porosity is set to 0.001 v/v where the coal flag equals 1.

4.3 Water Saturation

The water saturation is calculated using the Archie equation

$$S_w = \left(\frac{a \cdot R_w}{R_t \cdot \phi^m} \right)^{1/n} \tag{11}$$

S_w	Water saturation (fraction)
a	Archie constant (= 1.0)
R_w	Formation water resistivity @ formation temperature (Ωm)
R_t	True resistivity measured in formation (Ωm)
ϕ	Porosity (fraction)
m	Cementation exponent
n	Saturation exponent

The values of the parameters for determining water saturation from logs are discussed below.

4.3.1 Formation Temperature

A vast amount of temperature data was analysed in 2001[5]. From this study the reservoir gradient, ΔT, and reservoir temperature, T, on Sleipner Øst is:

ΔT = 2.6°C/100m
T = 111 °C at 2800 m TVDSS

4.3.2 Formation Water Resistivity, Rw

There is no representative formation water sample produced from Hugin Formation in the Sleipner Øst field. However, formation water has been produced from Sleipner Formation in well 15/9-19 A and from Skagerrak Formation in three wells, the latest from 15/9-A-23 A. The relevant reports and the result of these samples are given in Table 7. Also a water sample was taken by RFT in Hugin Formation but this was contaminated by mud filtrate.

Well	Lab.	Title	Date	Rw at 20°C Ωm	Equv NaCl *ppm*	Formation
15/9-11	Statoil-Prolab	Water Analysis, RFT sample at 2825.8 - 2826.5 m, well 15/9-11	Feb 1982	Sample contaminated by mud filtrate		Hugin
15/9-19A	Statoil-Prolab	Characterization of Formation Water Properties, well 15/9-19 A	Apr 1998	0.067	135 000	Sleipner
15/9-A-23 A	West Lab Services	Analyse av vannprøver fra Sleipner A, MDT brønn 15/9-A-23 A	Jun 2005	0.070	130 000	Skagerrak
15/9-C-2 AH	Maritime Well Service	FMT sampling, well 15/9-C-2 AH	Apr 1998	0.071	125 000	Skagerrak
16/7-6	Statoil-Prolab	Transfer and PVT analysis, MDT Water Chambers	Aug 1997	0.067	135 000	Skagerrak

Table 7 Formation water analysis data on Sleipner Øst

The representative samples shows quite similar values of the formation water from Volve and Loke in the north, via the central Sleipner Øst field and further south towards the Sigyn field, represented by well 16/7-6. The Hugin Formation is believed to be in connection to the Skagerrak Formation, such that the overall value of formation water resistivity used in this evaluation is ***Rw* = 0.07 Ωm@20°C** (130 000 ppm equvivalent NaCl concentration) and is taken from the MDT in well 15/9-A-23 A. This value is confirmed by Picket plots using the evaluated m exponents from the available water zones.

This resistivity of the formation water was corrected into reservoir conditions using Arp's formula and the formation temperature:

$$R_w = \frac{R_{w1} \cdot (T_1 + 21.5)}{(T + 21.5)} \tag{12}$$

R_w: Formation water resistivity at reservoir conditions (Ωm)
R_{w1}: Formation water resistivity at surface conditions (Ωm)
T_1: Surface temperature (=20 ºC)
T: Formation temperature (ºC)

4.4 Permeability

The continuous log permeability is based on multivariable regression analysis between log porosity and shale volume (normalised gamma ray log) against overburden corrected core permeability. The following equations were used.

$KLOGH = 10^{(-0.7+17.3 \cdot PHIF - 5 \cdot VSH)}$ Sleipner Øst, Hugin Formation (13)
$KLOGH = 10^{(2+8 \cdot PHIF - 9 \cdot VSH)}$ Volve, Hugin Formation (14)
$KLOGH = 10^{(-3+32 \cdot PHIF - 2 \cdot VSH)}$ Volve, Sleipner Formation (15)
$KLOGH = 10^{(-1.85+17.4 \cdot PHIF - 3 \cdot VSH)}$ Sleipner Øst, Skagerrak Formation (16)

Hugin Fm. (SLØ)
The Equation 13 is based on the cored wells 15/9-13, 15/9-17, 15/9-A-12, 15/9-A-15 and 15/9-C-2 AH and also used for Hugin Formation in the wells 15/9-11, 15/9-A-8, 15/9-A-19 AT2, 15/9-A-23, 15/9-A-23 A and 15/9-A-25. Figure 9.a shows the core permeability against the core porosity with the shale volume on the colour scale. The resulting correlation between core and log permeability is shown in Figure 9.b.

Hugin and Sleipner Fm. (Volve)
Equation 14 , Figure 10.a and b, is used for Hugin Formation on Volve, while for Sleipner Formation, Equation 15 and Figure 11.a and b, only data from 15/9-19 A was available. The figures show that it is difficult to get good correlations between core and log permeability in Sleipner Formation. This is due to that the formation is very heterogeneous with rapid shifts between sand and shale.

Skagerrak Fm. (SLØ)
Figure 12 a. shows the correlation between core porosity and core permeability for all the 6 cored wells in Skagerrak Formation and shows a big variation between the wells. The well 15/9-19 A has an optimistic correlation while the wells 15/9-17, 15/9-19 SR and 15/9-C-2 AH are pessimistic. The two wells 15/9-9 and 15/9-15, Figure 12.b, are in between and therefore these two wells have been used for the field model for Skagerrak Formation, i.e. Equation 16. The correlation for Skagerrak Formation, however, is very poor both between permeability and porosity but also between permeability and shale fraction as seen in Figure 12.b. The Figure 12.c shows that the results is not very good and thus more work is recommended to get a better permeability model for the Skagerrak Fm.

The resulting KLOGH has been set to 0.001 mD in coal intervals as done for the porosity.

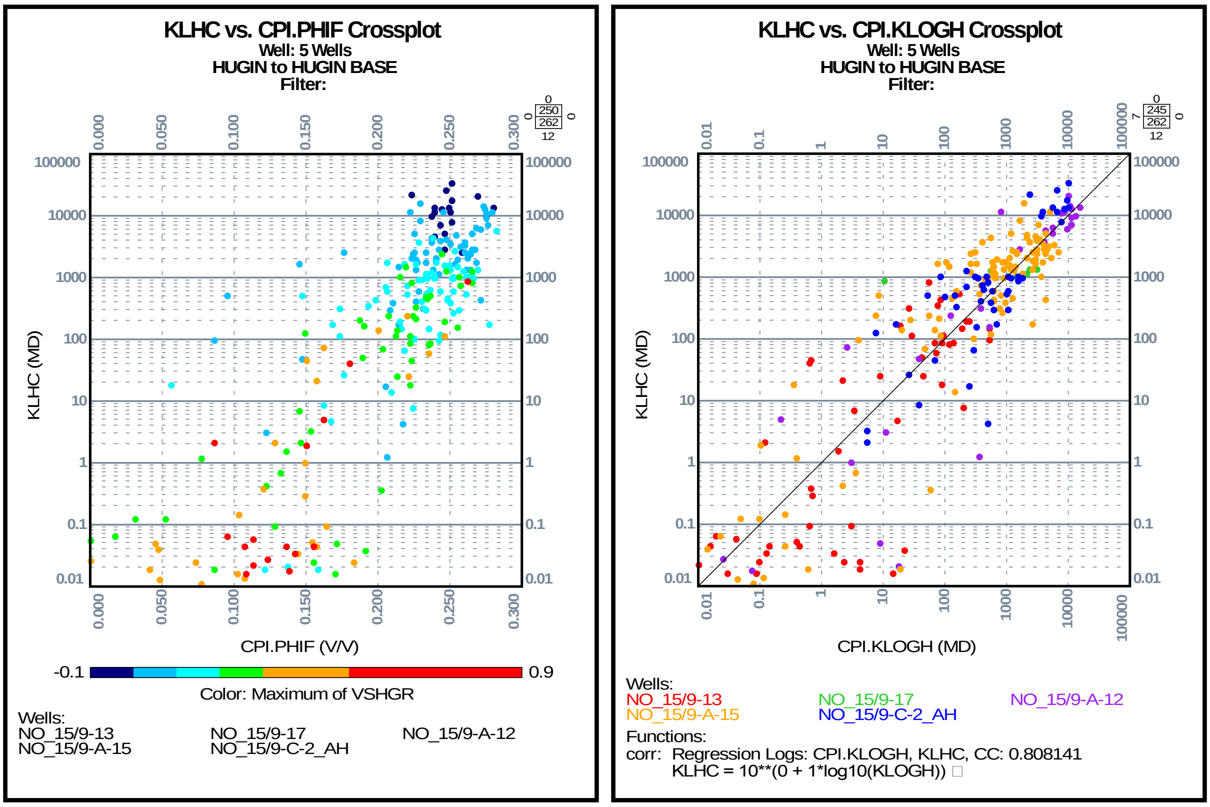


Figure 9 Hugin Formaiton Sleipner Øst, a KLHC vs. PHIF, b KLHC vs. KLOGH

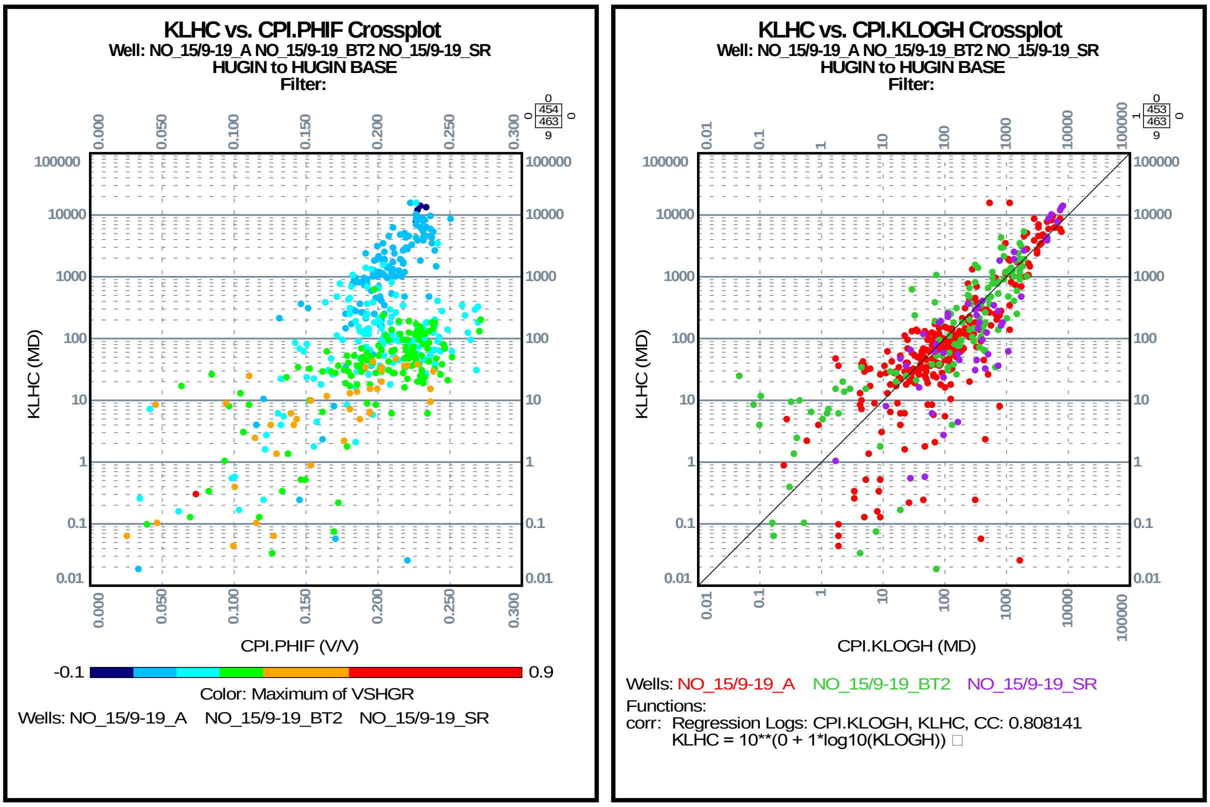


Figure 10 Hugin Formaiton Volve, a KLHC vs. PHIF, b KLHC vs. KLOGH

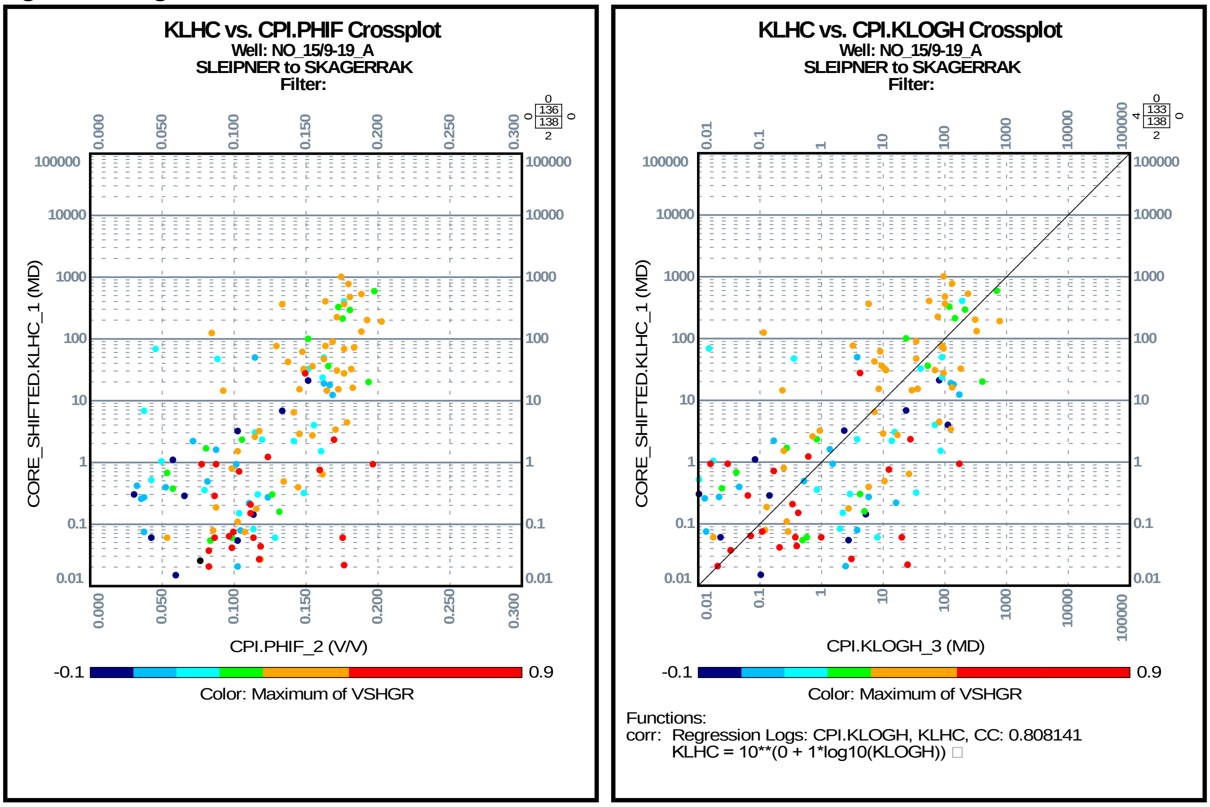


Figure 11 Sleipner Formaiton Volve, a KLHC vs. PHIF, b KLHC vs. KLOGH

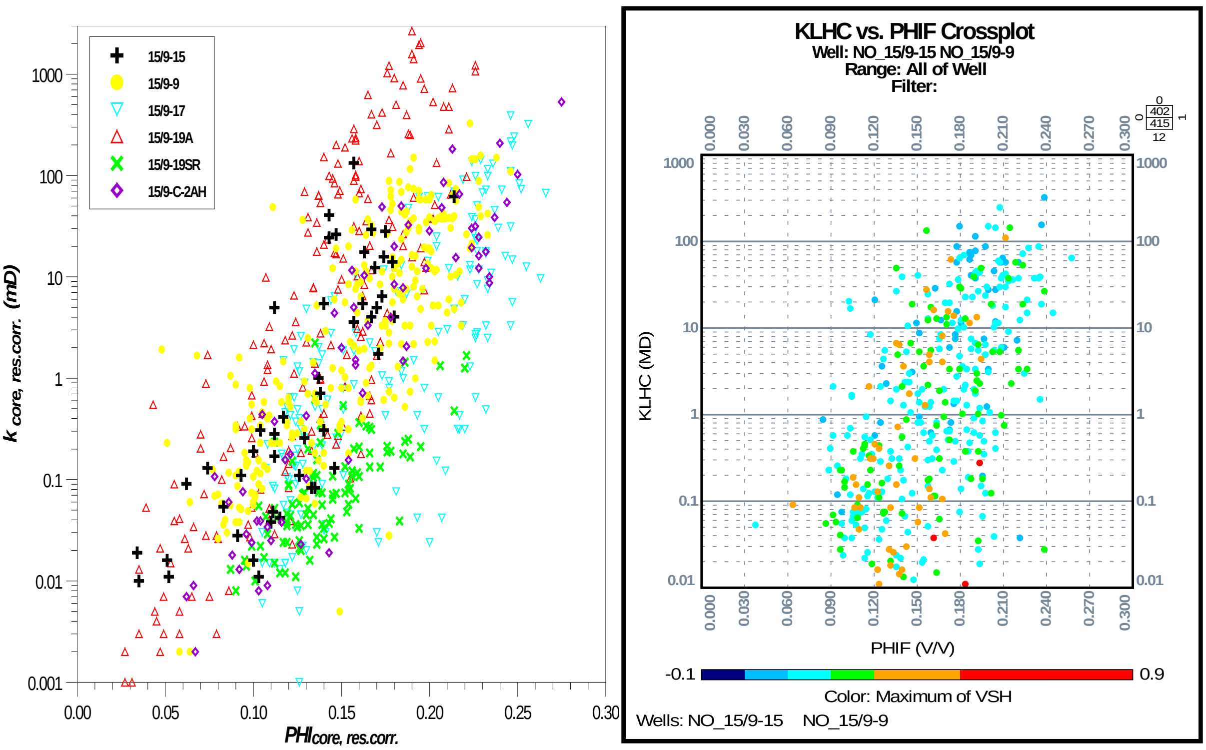


Figure 12 Porc vs. KLHC Skagerrak Formation, a All wells 15/9-9, 15/9-15, 15/9-17, 15/9-19 A, 15/9-19 SR and 15/9-C-2AH, b Wells 15/9-9 and 15/9-15

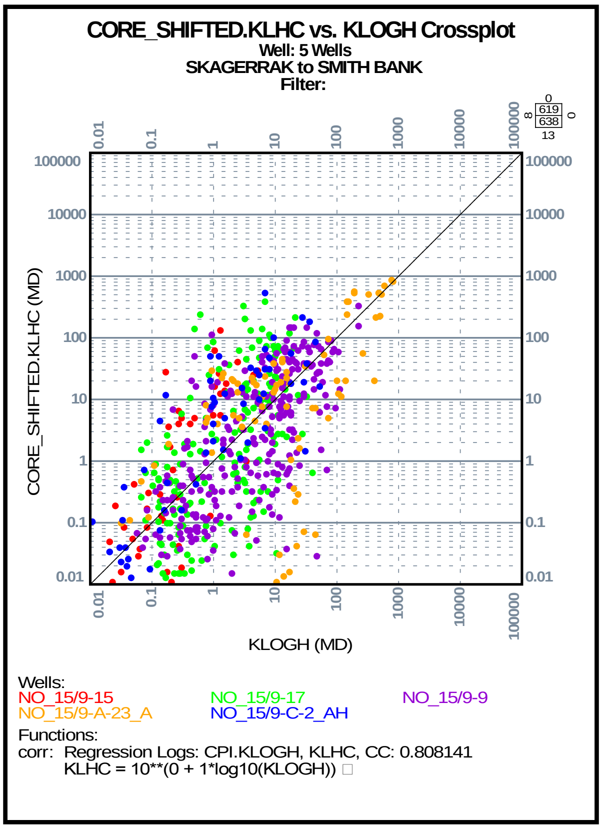


Figure 12.c KLHC vs. KLOGH, Skagerrak Formation

4.5 Results

4.5.1 Net sand

The estimation of net sand is based on a cut off criteria from the overburden corrected permeability of 0.05 mD for gas intervals and 0.5 mD for oil intervals. The corresponding value for porosity has been found from regression analysis of the overburden corrected core permeability versus porosity as shown in Figures 13.a and b, for Hugin Formation and 13.c and d for Bathonian and Skagerrak Formation. The high and low cut off values is used later in the uncertainty study, Section 7. The shale volume was used as an extra cut off except in the highly deviated wells 15/9-A-2 T2 and 15/9-A-3 T2. The Table 8 shows the values used for initial cut off in the different areas.

Field	Formation	Fluid	K *mD*	Φ *v/v*	Vsh *v/v*
Sleipner Øst	Hugin	Gas	0,05	0,10	0,50
Volve	Hugin	Oil	0,50	0,10	0,50
Sleipner Øst	Bathonian	Gas	0,05	0,12	0,60
Sleipner Øst	Skagerrak	Gas	0,05	0,10	0,60

Table 8 Cut off values

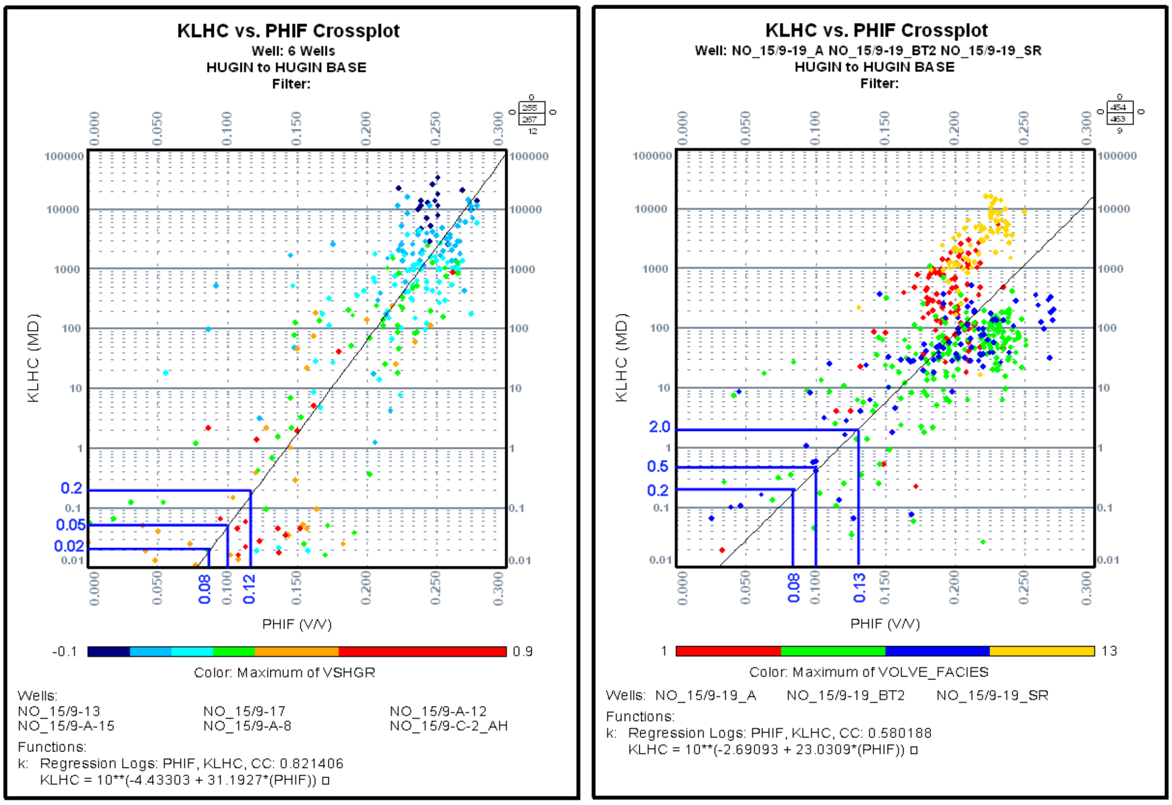


Figure 13 Core permeability vs. porosity and shale volume, Hugin Formation, a SLE Hugin, b Volve

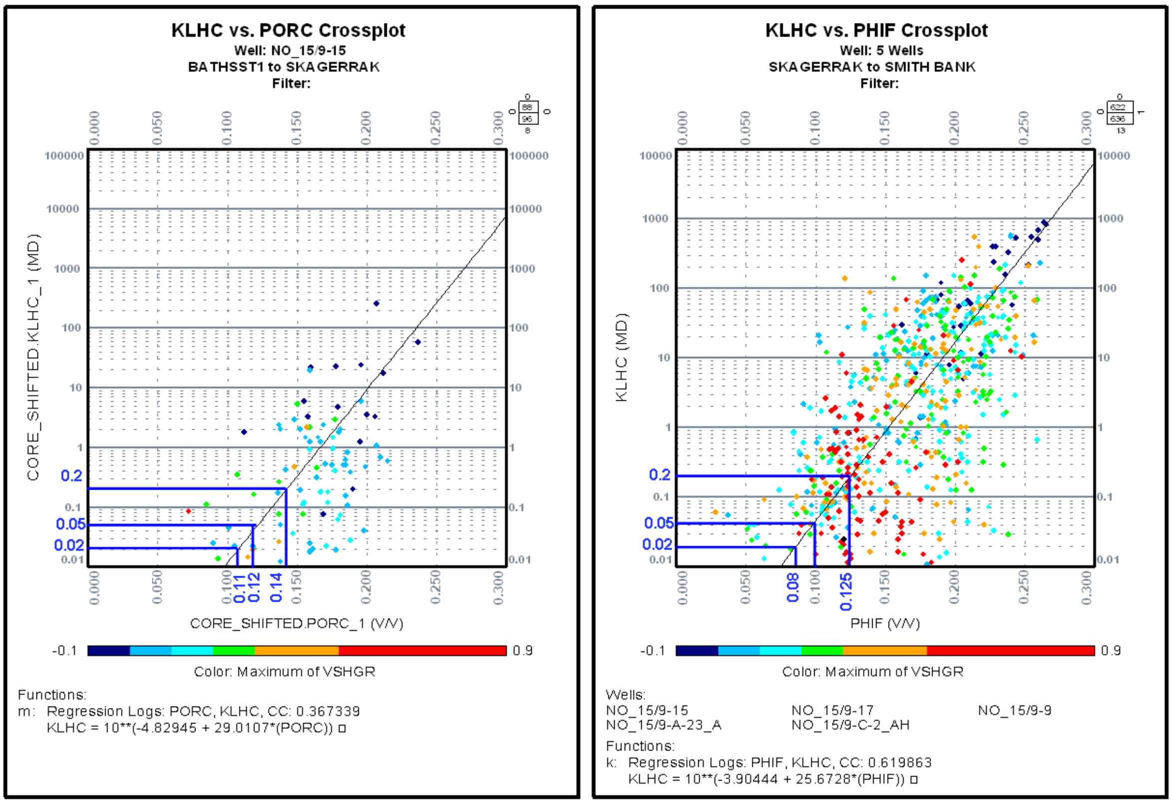


Figure 13 Core permeability vs. porosity and shale volume, a Bathonian, b Skagerrak Formation

The resulting net sand flag was quality controlled against information from all the other logs and also core descriptions and then manually edited to give the final net sand flag.

Figures 14 a through d shows how the net reservoir changes with varying porosity cut off values used in Section 7. These figures show that the porosity has very little influence on evaluation of net reservoir, especially for the gas cut off in Hugin 2, where the properties of the formation lie well above the cut off criteria.

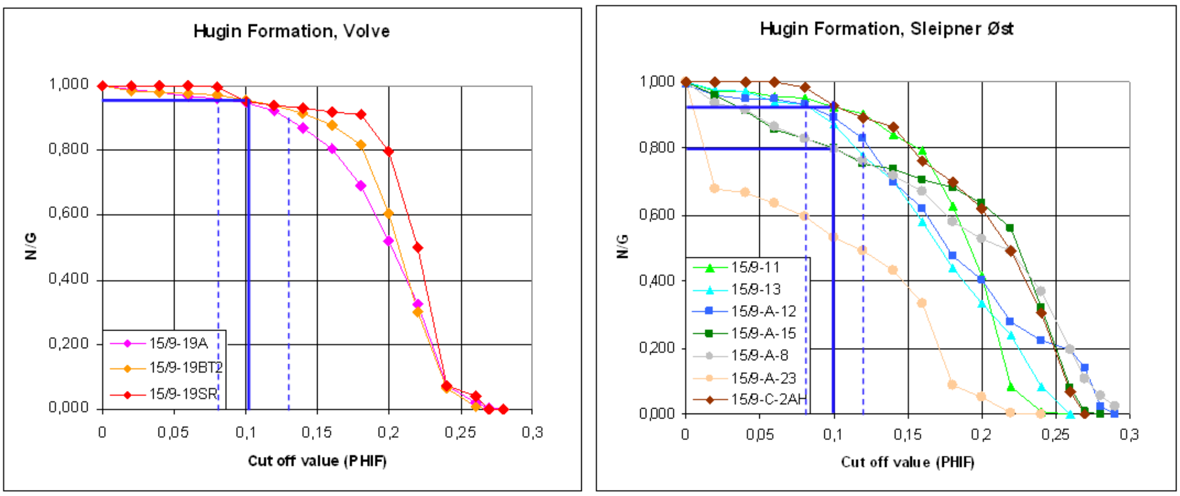


Figure 14 N/G change due to changes in porosity cut-off values, Hugin Fm, a Volve, b SLE Hugin

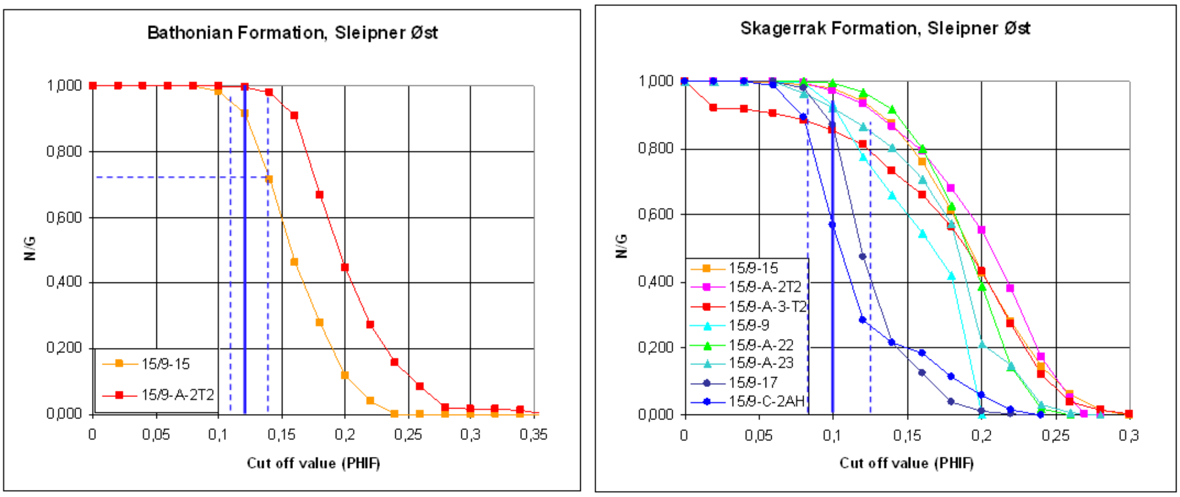


Figure 14 N/G change due to changes in porosity cut-off values, c Bathonian Fm, d Skagerrak Fm

4.5.2 Results

The resulting composite logs (CALI, GR, DT, RHOB, NPHI, RD) and evaluated result curves (VSH, PHIF, SW, KLOGH, SAND_FLAG, COAL_FLAG, LIME_FLAG) are copied from Geolog to Openworks.

The result is available on CPI plots in the scale 1:500 down to the base of Skagerrak Formation in Appendix 2, which contains the geological zonation processed raw logs and evaluated data.

The average values from the log evaluation of porosity, water saturation, permeability and net/gross ratio are summarised in Table 9.a through e for the individual reservoir zones where available, else for the whole Formation interval.

Volve Well	Formation	Interval Top	Interval Base	Gross	Net	N/G	PHIF	SW	VSH	KLOGH
		m md rkb		*m*	*m*					*md*
15/9-19 SR	Hugin 6	4304.1	4309.2	5.2	0.0	0.000	-	-	-	-
	Hugin 5	4309.2	4316.3	7.0	0.1	0.008	0.133	0.353	0.104	20.4
	Hugin 4	4316.3	4321.0	4.8	4.8	1.000	0.214	0.211	0.011	1203.0
	Hugin 3	4321.0	4322.5	1.5	1.5	1.000	0.219	0.204	0.098	116.9
	Hugin 2	4322.5	4328.1	5.6	5.6	1.000	0.229	0.097	0.040	5525.2
	Hugin 1	4328.1	4339.9	11.8	11.3	0.955	0.208	0.180	0.150	437.9
	Hugin	4316.3	4339.9	23.6	23.1	0.977	0.215	0.166	0.092	1803.9
15/9-19 A	**Heather**	3767.0	3821.5	54.5	8.1	0.149	0.125	0.756	0.245	10.7
	Hugin 17	3821.5	3825.0	3.5	3.2	0.928	0.136	0.328	0.143	67.8
	Hugin 16	3825.0	3830.1	5.2	5.1	0.981	0.193	0.209	0.101	602.9
	Hugin 15	3830.1	3832.3	2.2	1.9	0.874	0.210	0.165	0.088	976.0
	Hugin 14	3832.3	3836.6	4.2	3.8	0.911	0.242	0.172	0.165	579.6
	Hugin 13	3836.6	3838.8	2.2	2.2	1.000	0.166	0.271	0.130	165.2
	Hugin 12	3838.8	3847.4	8.6	8.3	0.971	0.200	0.218	0.146	308.2
	Hugin 11	3847.4	3853.0	5.6	4.3	0.776	0.205	0.210	0.230	49.4
	Hugin 10	3853.0	3855.1	2.1	1.1	0.523	0.165	0.346	0.265	16.0
	Hugin 9	3855.1	3859.8	4.7	3.8	0.814	0.180	0.215	0.233	48.1
	Hugin 8	3859.8	3864.1	4.3	4.3	1.000	0.227	0.094	0.049	2832.8
	Hugin 7	3864.1	3867.1	3.0	3.0	1.000	0.234	0.079	0.031	4176.5
	Hugin 6	3867.1	3875.9	8.8	8.8	1.000	0.218	0.102	0.060	3190.4
	Hugin 5	3875.9	3885.8	9.9	8.4	0.849	0.199	0.216	0.243	51.6
	Hugin 4	3885.8	3891.6	5.8	5.8	1.000	0.205	0.223	0.168	220.9
	Hugin 3	3891.6	3898.4	6.8	6.1	0.908	0.189	0.253	0.246	36.9
	Hugin 2	3898.4	3908.2	9.8	9.8	1.000	0.188	0.220	0.102	621.1
	Hugin 1	3908.2	3919.6	11.4	11.2	0.983	0.206	0.268	0.226	68.1
	Hugin	3821.5	3919.6	98.1	91.4	0.932	0.201	0.203	0.157	791.5
15/9-19 BT2	**Heather**	3946.0	4035.8	89.8	22.0	0.245	0.162	~~0.910~~	0.329	8.1
	Hugin 18	4035.8	4046.4	10.6	10.5	0.991	0.199	~~0.984~~	0.056	1513.9
	Hugin 17	4046.4	4051.2	4.9	4.9	1.000	0.203	~~0.958~~	0.186	171.9
	Hugin 16	4051.2	4062.9	11.6	11.2	0.959	0.225	~~0.987~~	0.179	246.3
	Hugin 15	4062.9	4066.1	3.2	2.6	0.829	0.203	~~0.941~~	0.267	45.9
	Hugin 14	4066.1	4072.5	6.5	4.4	0.675	0.209	~~0.984~~	0.208	131.8
	Hugin 13	4072.5	4077.6	5.0	2.3	0.446	0.210	~~0.903~~	0.090	890.7
	Hugin 12	4077.6	4087.4	9.8	9.0	0.916	0.202	~~0.985~~	0.107	719.7
	Hugin 11	4087.4	4094.4	7.0	7.0	1.000	0.187	~~0.988~~	0.121	366.4
	Hugin 10	4094.4	4099.3	5.0	4.7	0.950	0.215	~~0.953~~	0.338	13.7
	Hugin 9	4099.3	4105.1	5.8	4.4	0.761	0.179	~~0.938~~	0.351	16.1
	Hugin 8	4105.1	4110.8	5.7	5.7	1.000	0.195	~~0.992~~	0.078	825.5
	Hugin 7	4110.8	4116.7	6.0	6.0	1.000	0.210	~~0.993~~	0.097	730.8
	Hugin 6	4116.7	4140.7	23.9	23.6	0.984	0.204	~~0.967~~	0.074	1142.7
	Hugin 5	4140.7	4149.2	8.6	8.6	1.000	0.218	~~0.927~~	0.368	5.8
	Hugin 4	4149.2	4154.4	5.2	5.2	1.000	0.210	~~0.828~~	0.168	250.7
	Hugin 3	4154.4	4155.7	1.3	1.3	1.000	0.184	~~0.959~~	0.317	4.3
	Hugin 2	4155.7	4166.3	10.6	10.6	1.000	0.192	~~0.858~~	0.227	186.6
	Hugin 1	4166.3	4178.6	12.3	12.0	0.974	0.233	~~0.941~~	0.388	7.0
	Hugin	4035.8	4178.6	142.8	133.6	0.936	0.207	~~0.953~~	0.183	529.0

Table 9.a Average values for Volve

Loke Well	Formation	Interval		Gross	Net	Average values				
		Top	Base			N/G	PHIF	SW	VSH	KLOGH
		m md rkb		m	m					md
15/9-17	Hugin 4	2715.3	2717.5	2.2	2.2	1.000	0.255	0.145	0.189	1414.3
	Skagerrak 13	2717.5	2725.8	8.3	8.3	1.000	0.188	0.332	0.257	4.2
	Skagerrak 12	2725.8	2732.4	6.6	6.6	1.000	0.215	0.281	0.219	11.1
	Skagerrak 11	2732.4	2741.4	9.0	8.7	0.966	0.196	0.330	0.214	8.1
	Skagerrak 10	2741.4	2749.9	8.5	7.1	0.839	0.179	0.321	0.372	5.3
	Skagerrak 9	2749.9	2755.2	5.3	5.3	1.000	0.199	0.268	0.299	4.8
	Skagerrak 8	2755.2	2763.1	7.9	6.1	0.768	0.178	0.364	0.520	2.2
	Skagerrak 7	2763.1	2773.1	10.0	6.3	0.634	0.172	0.424	0.552	2.7
	Skagerrak 6	2773.1	2779.7	6.6	1.1	0.169	0.137	0.616	0.618	0.7
	Skagerrak 5	2779.7	2786.2	6.5	6.1	0.942	0.168	0.382	0.465	2.9
	Skagerrak 4	2786.2	2791.2	5.0	1.9	0.374	0.153	0.605	0.704	0.4
	Skagerrak 3	2791.2	2797.6	6.4	4.1	0.643	0.178	0.384	0.506	2.5
	Skagerrak 2	2797.6	2808.4	10.8	6.8	0.633	0.198	0.348	0.367	8.2
	Skagerrak 1	2808.4	2814.2	5.8	5.8	1.000	0.203	0.354	0.393	3.8
	Skagerrak	2717.5	2814.2	96.7	73.5	0.760	0.189	0.349	0.378	5.1
	Transition Zone 4	2814.2	2832.1	17.9	3.1	0.174	0.147	0.566	0.421	0.7
	Transition Zone 3	2832.1	2846.5	14.4	4.6	0.323	0.155	0.507	0.272	2.2
	Transition Zone 2	2846.5	2859.1	12.6	1.9	0.153	0.144	0.636	0.274	2.3
	Transition Zone 1	2859.1	2870.8	11.7	3.7	0.314	0.162	0.586	0.423	1.7
	Transition Zone	2814.2	2870.8	56.6	13.4	0.236	0.154	0.560	0.348	1.7
15/9-C-2 AH	**Draupne**	3184.0	3239.7	55.7	23.0	0.413	0.209	0.231	0.311	541.6
	Hugin 7	3239.7	3249.8	10.1	8.3	0.819	0.187	0.395	0.153	292.8
	Hugin 6	3249.8	3257.2	7.4	7.4	1.000	0.209	0.263	0.115	652.0
	Hugin 5	3257.2	3260.4	3.2	3.2	1.000	0.245	0.056	0.001	6368.0
	Hugin 4	3260.4	3265.0	4.6	4.5	0.976	0.242	0.101	0.135	1054.4
	Hugin	3239.7	3265.0	25.3	23.4	0.923	0.212	0.236	0.117	1380.2
	Skagerrak 11	3265.0	3276.8	11.7	2.1	0.181	0.127	0.661	0.262	2.0
	Skagerrak 10	3276.8	3285.1	8.4	0.0	0.000	-	-	-	-
	Skagerrak 9	3285.1	3297.3	12.2	3.5	0.286	0.209	~~0.783~~	0.333	13.3
	Skagerrak 8	3297.3	3306.2	8.9	3.2	0.360	0.203	~~0.917~~	0.283	14.6
	Skagerrak 7	3306.2	3311.3	5.1	1.0	0.206	0.193	~~0.848~~	0.391	6.3
	Skagerrak 6	3311.3	3317.2	5.9	0.2	0.033	0.247	~~0.604~~	0.504	8.8
	Skagerrak 5	3317.2	3331.4	14.2	12.1	0.856	0.214	~~0.811~~	0.300	20.5
	Skagerrak 4	3331.4	3338.5	7.1	3.1	0.432	0.192	~~0.804~~	0.311	7.3
	Skagerrak 3	3338.5	3345.2	6.7	0.1	0.017	0.150	~~1.000~~	0.328	0.6
	Skagerrak 2	3345.2	3352.7	7.6	0.2	0.020	0.182	~~0.826~~	0.204	5.0
	Skagerrak 1	3352.7	3357.5	4.7	2.7	0.579	0.198	~~0.809~~	0.288	6.8
	Skagerrak	3265.0	3357.5	92.5	28.3	0.306	0.201	~~0.812~~	0.304	14.0
	Transition Zone 4	3357.5	3370.6	13.1	0.1	0.004	0.158	~~0.812~~	0.289	1.1
	Transition Zone 3	3370.6	3382.3	11.7	4.0	0.345	0.175	~~0.849~~	0.306	2.8
	Transition Zone 2	3382.3	3395.4	13.1	0.0	0.000	-	-	-	-
	Transition Zone 1	3395.4	3401.4	6.0	2.4	0.405	0.193	~~0.841~~	0.324	4.4
	Transition Zone	3357.5	3401.4	43.9	6.5	0.149	0.182	~~0.846~~	0.313	3.4

Table 9.b Average values for Loke

SLE Hugin Well	Formation	Interval Top	Base	Gross	Net	N/G	PHIF	SW	VSH	KLOGH
		m md rkb		m	m	Average values				md
15/9-11	Hugin 8	2789.5	2791.2	1.7	1.4	0.818	0.134	0.356	0.096	22.4
	Hugin 7	2791.2	2795.0	3.8	0.1	0.025	0.113	0.675	0.304	5.4
	Hugin 6	2795.0	2803.1	8.1	8.1	1.000	0.207	0.119	0.029	956.6
	Hugin 5	2803.1	2807.6	4.5	4.5	1.000	0.204	0.122	0.060	403.2
	Hugin 4	2807.6	2815.0	7.4	7.4	1.000	0.201	0.079	0.016	689.1
	Hugin 3	2815.0	2818.6	3.6	3.6	1.000	0.193	0.101	0.017	426.7
	Hugin 2	2818.6	2823.8	5.3	5.3	1.000	0.180	0.146	0.021	280.6
	Hugin 1	2823.8	2830.5	6.7	6.7	1.000	0.174	~~0.664~~	0.162	74.5
	Hugin	2789.5	2830.5	41.0	37.0	0.903	0.191	0.209	0.055	491.4
15/9-A-15	Hugin 8	4116.5	4124.3	7.8	6.5	0.837	0.218	0.219	0.152	659.3
	Hugin 7	4124.3	4133.3	9.0	1.2	0.137	0.143	0.445	0.284	45.9
	Hugin 6	4133.3	4142.1	8.8	8.7	0.992	0.246	0.096	0.061	2872.2
	Hugin 4	4142.1	4154.6	12.6	10.6	0.848	0.233	0.071	0.064	1716.6
	Hugin 3	4154.6	4158.9	4.3	3.8	0.892	0.203	0.231	0.224	367.8
	Hugin 1	4158.9	4165.0	6.0	5.7	0.947	0.216	0.201	0.205	279.4
	Hugin	4116.5	4165.0	48.5	36.6	0.754	0.225	0.146	0.125	1384.8
15/9-A-25	**Draupne**	4879.2	4911.0	31.8	22.3	0.700	?	?	?	?
	Hugin	4911.0	4937.5	26.5	24.5	0.925	0.223	0.212	0.201	858.0
15/9-A-12	Hugin 8	3075.5	3079.7	4.2	3.6	0.850	0.179	0.219	0.124	125.5
	Hugin 7	3079.7	3081.7	2.0	2.0	1.000	0.154	0.305	0.206	32.8
	Hugin 6	3081.7	3085.2	3.5	2.1	0.606	0.181	0.242	0.200	458.5
	Hugin 4	3085.2	3092.2	7.0	7.0	1.000	0.241	0.086	0.069	5706.2
	Hugin 1	3092.2	3097.3	5.2	1.3	0.248	0.192	0.484	0.426	4.3
	Hugin	3075.5	3097.3	21.8	16.0	0.731	0.204	0.181	0.144	2599.2
15/9-13	Hugin 8	2764.5	2768.7	4.2	4.2	1.000	0.216	0.163	0.170	252.6
	Hugin 7	2768.7	2770.9	2.2	0.2	0.100	0.235	0.360	0.204	232.9
	Hugin 6	2770.9	2774.7	3.8	0.0	0.000	-	-	-	-
	Hugin 4	2774.7	2781.4	6.7	5.9	0.885	0.190	0.245	0.284	57.0
	Hugin 1	2781.4	2785.0	3.6	2.8	0.788	0.157	0.418	0.437	2.6
	Hugin	2764.5	2785.0	20.5	13.2	0.643	0.192	0.250	0.281	109.6
15/9-A-8	Hugin 8	3487.0	3488.7	1.7	0.5	0.281	0.175	~~0.887~~	0.154	57.5
	Hugin 7	3488.7	3492.5	3.8	0.7	0.191	0.128	~~0.951~~	0.353	2.3
	Hugin 6	3492.5	3494.4	1.9	1.9	1.000	0.210	~~0.895~~	0.054	1409.4
	Hugin 4	3494.4	3506.0	11.6	10.5	0.908	0.246	~~0.923~~	0.156	1506.4
	Hugin 3	3506.0	3510.0	4.0	3.7	0.923	0.237	~~0.927~~	0.244	633.1
	Hugin 1	3510.0	3513.8	3.9	1.6	0.413	0.177	~~0.939~~	0.317	11.3
	Hugin	3487.0	3513.8	26.8	18.9	0.705	0.228	~~0.922~~	0.184	1106.8

Table 9.c Average values for SLE Hugin

Gamma and My2 Well	Formation	Interval Top	Base	Gross	Net	N/G	PHIF	SW	VSH	KLOGH
		m md rkb		m	m	Average values				md
15/9-A-22	Hugin 6	3249.0	3251.1	2.1	2.1	1.000	0.092	~~0.921~~	0.140	0.2
	Hugin 4	3251.1	3254.6	3.4	1.5	0.424	0.102	~~0.807~~	0.167	0.3
	Hugin 2	3254.6	3258.5	3.9	0.1	0.029	0.203	~~0.528~~	0.368	3.8
	Hugin	3249.0	3258.5	9.5	3.7	0.390	0.099	~~0.851~~	0.158	0.4
	Skagerrak	3258.5	3503.0	244.5	226.7	0.927	0.190	~~0.632~~	0.175	20.8
15/9-9	Hugin 6	2627.0	2634.8	7.8	0.0	0.000	-	-	-	-
	Hugin 4	2634.8	2637.7	2.9	0.0	0.000	-	-	-	-
	Hugin 1	2637.7	2642.0	4.3	0.0	0.000	-	-	-	-
	Hugin	2627.0	2642.0	15.0	0.0	0.000	-	-	-	-
	Skagerrak	2642.0	2775.0	133.0	123.3	0.927	0.165	~~0.867~~	0.163	15.1
15/9-A-23	Hugin 8	4940.3	4945.3	5.0	1.5	0.304	0.197	0.281	0.567	0.8
	Hugin 6	4945.3	4953.4	8.1	3.7	0.456	0.124	0.419	0.231	14.5
	Hugin 4	4953.4	4958.4	5.0	2.7	0.540	0.163	0.335	0.218	20.6
	Hugin 1	4958.4	4966.3	7.9	5.2	0.659	0.159	0.315	0.115	59.6
	Hugin	4940.3	4966.3	26.0	13.1	0.504	0.155	0.338	0.222	32.0
15/9-A-23 A	**Hugin**	5362.5	5375.2	12.7	6.8	0.539	0.236	0.107	0.135	2735.3
	Skagerrak	5375.2	5571.1	195.9	168.6	0.860	0.186	~~0.832~~	0.213	45.8

Table 9.d Average values for Gamma

Gungne Well	Formation	Interval Top	Interval Base	Gross	Net	N/G	PHIF	SW	VSH	KLOGH
		m md rkb		m	m					md
15/9-A-19 A	**Hugin**	6824.3	6836.8	12.6	6.7	0.531	0.162	0.303	0.151	237.7
	Skagerrak	6836.8	6984.2	147.4	54.4	0.369	0.142	~~0.663~~	0.249	2.2
15/9-15	Bathonian sst	2821.0	2859.9	38.9	35.7	0.918	0.163	0.496	0.088	4.2
	Skagerrak 5_1	2859.9	2905.3	45.4	20.4	0.449	0.151	0.605	0.313	1.3
	Skagerrak 4_1	2905.3	2945.8	40.5	13.4	0.331	0.221	~~0.758~~	0.218	73.4
	Skagerrak 3_1	2945.8	2976.2	30.4	28.3	0.929	0.243	~~0.850~~	0.219	152.8
	Skagerrak 2	2976.2	3018.0	41.8	21.4	0.513	0.221	~~0.841~~	0.348	25.4
	Skagerrak 1	3018.0	3091.0	73.0	59.7	0.818	0.210	~~0.915~~	0.213	32.6
	Skagerrak	2859.9	3091.0	231.1	143.2	0.620	0.210	~~0.842~~	0.249	54.6
15/9-A-2 T2	Bathonian sst	8329.0	8504.8	175.8	174.3	0.991	0.202	0.236	0.059	677.059
	Skagerrak 5_1	7238.0	7322.7	84.7	66.3	0.783	0.205	0.166	0.212	54.6
	Skagerrak 4_1	7322.7	7510.1	187.4	154.7	0.826	0.224	0.188	0.322	25.3
	Skagerrak 5_2	8061.2	8329.0	267.8	91.0	0.340	0.171	0.396	0.328	2.2
	Skagerrak 3_1	7510.1	7689.9	179.8	171.9	0.956	0.219	0.183	0.250	34.9
	Skagerrak 4_2	7943.4	8061.2	117.8	57.4	0.487	0.221	0.218	0.317	30.8
	Skagerrak 2	7689.9	7830.5	140.6	112.9	0.803	0.230	0.274	0.484	15.5
	Skagerrak 3_2	7830.5	7943.4	112.9	105.2	0.931	0.234	0.229	0.334	48.1
	Skagerrak	7238.0	8329.0	1091.0	759.4	0.696	0.217	0.227	0.322	29.4
15/9-A-3 T2	Skagerrak 5_1	7198.8	7270.5	71.7	27.1	0.379	0.195	0.153	0.189	20.4
	Skagerrak 4_1	7270.5	7362.5	92.0	62.8	0.682	0.210	0.202	0.260	90.3
	Skagerrak 3_1	7362.5	7404.0	41.5	36.7	0.886	0.216	0.198	0.232	56.6
	Skagerrak 2	7404.0	7484.0	80.0	64.4	0.806	0.189	0.245	0.116	46.4
	Skagerrak 1	7484.0	7623.8	139.8	123.9	0.887	0.195	0.404	0.144	63.4
	Skagerrak	7198.8	7623.8	425.0	315.1	0.741	0.199	0.283	0.175	60.8

Table 9.e Average values for Gungne

The results for the Hugin Formation show that the reservoir thickness is best in the north at Volve and Loke, with N/G close to 1. In SLE Hugin it drops to value ranges of 0.65 – 0.9, around 0.5 at My2 while almost absent in Gamma and Gungne. The average porosity lies around 0.2 v/v in all the areas while it drops down to around 0.16 v/v in 15/9-A-23 and 15/9-A-19 AT2 which both are wells on the flank. The Hugin Formation is relatively clean with low average shale volume and the permeability is high, with average values above 100 mD.

The Skagerrak Formation is best represented in the south with the highest N/G values on Gamma and My2 of around 0.9 and around 0.6 in Gungne and Loke. The best reservoir quality is found on Gungne with average porosity above 0.2 v/v, a little less in the other areas. The shale volume is higher for this formation and in the order of 20 – 30 %, making the permeability lower, the average values lies below 100 mD.

The strikethrough on the average water saturation values means that they contain more or less amounts of data below the water contact, and therefore not valid. The valid values of water saturation show consistently low values between 0.1 – 0.2 v/v for Hugin Formation while it is higher, around 0.3 v/v for Skagerrak Formation.

5 Fluid contacts

A new study has been done to update the fluid contacts for Volve, Loke, Hugin, Gamma, My2 and Gungne. The evaluation is based on logs, pressure data, strontium measurements on cores and segmentation/barrier studies.

Data from the two new wells 15/9-A-23 A and 15/9-A-19 A are included. All the formation pressure data have been consistently corrected and checked against the original field prints. Strontium measurements have been done for all the cored wells on SLE and a new segmentation/barriers study has been done.

Table 10 summarizes the observations in each well and the estimation of the free water level, *FWL*, for the different areas, and in Figure 15 all the formation pressure data is plotted. This plot show 5 different water gradients; Gamma&My&Gungne, Sigyn, local 15/9-11, Volve&16/7-5 and 16/7-2&16/7-3. These different water systems are drawn in Figure 16.

A discussion of the areas is given below. All depths in this section are in m TVDMSL.

Area	Well	Contact		Pressure	FWL	Formation	Comments
		Logs	Type	Data			
Volve	**15/9-19 SR**	2879	ODT	N/A	3120	Hugin	From logs
	15/9-19 A	3101.5	ODT	N/A	3120	Hugin	If in contact with Sleipner Fm
		3120	OWC	N/A	**3120**	Sleipner	
	15/9-19 BT2	3147.5	WUT	Water	3120	Hugin	Water filled
Loke	**15/9-17**	2836	GDT	Gas	<2930	Skagerrak	Water grad 16/7-2, 16/7-3
	15/9-C-2 AT2	2801	GDT	N/A	-	Hugin	
	15/9-C-2 AH	2830	GWC	Gas/Water	<2930	Hug/Skag	Water grad 16/7-2, 16/7-3
SLE Hugin	**15/9-11**	**2793**	GOC	Gas/Oil	**2796**	Hugin	FWL
		2801	OWC	Oil/Water	**2801**	Hugin	FWL
	15/9-A-15	2699	GDT	Gas	2801*		
	15/9-A-25	2796	GWC	N/A	2801*		Depleted
	15/9-A-12	2651	GDT	Gas	2801*		
	15/9-13	2759.5	GDT	Gas	2801*		
	15/9-A-8	2758.5	WUT	Water	-		
Gamma	**15/9-A-22**	**2527**	GWC	Gas/Water	**2527**	Skagerrak	FWL
	15/9-9	2616	WUT	Water	2527	Skagerrak	
My2	**15/9-A-23**	2707(?)	GDT	Gas	2757.5	Hugin	
	15/9-A-23 A	**2757.5**	GWC	Gas/Water	**2757.5**	Hug-Skag	FWL
Gungne	**15/9-15**	**2895**	GWC	Gas/Water	**2895**	Bath/Skag	FWL
	15/9-A-2 T2	2808	GDT	N/A	2895	Skagerrak	
	15/9-A-3 T2	2876	GDT	N/A	2895	Skagerrak	
	15/9-A-19 AT2	2855	GDT	Gas	2895	Skagerrak	

Table 10 Summary fluid contacts * the contact can be deeper

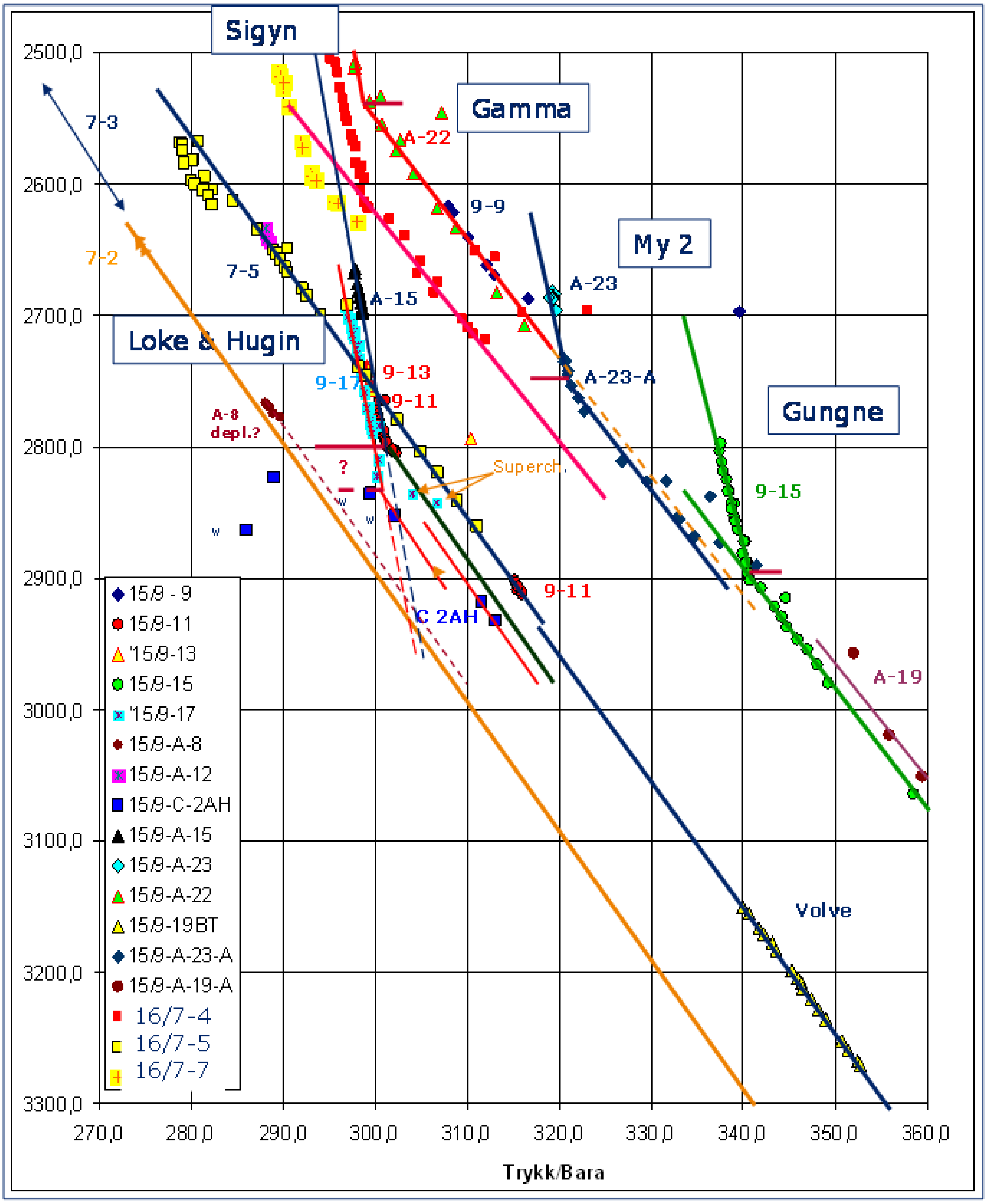


Figure 15 Formation pressure

Pressure – Water Gradients

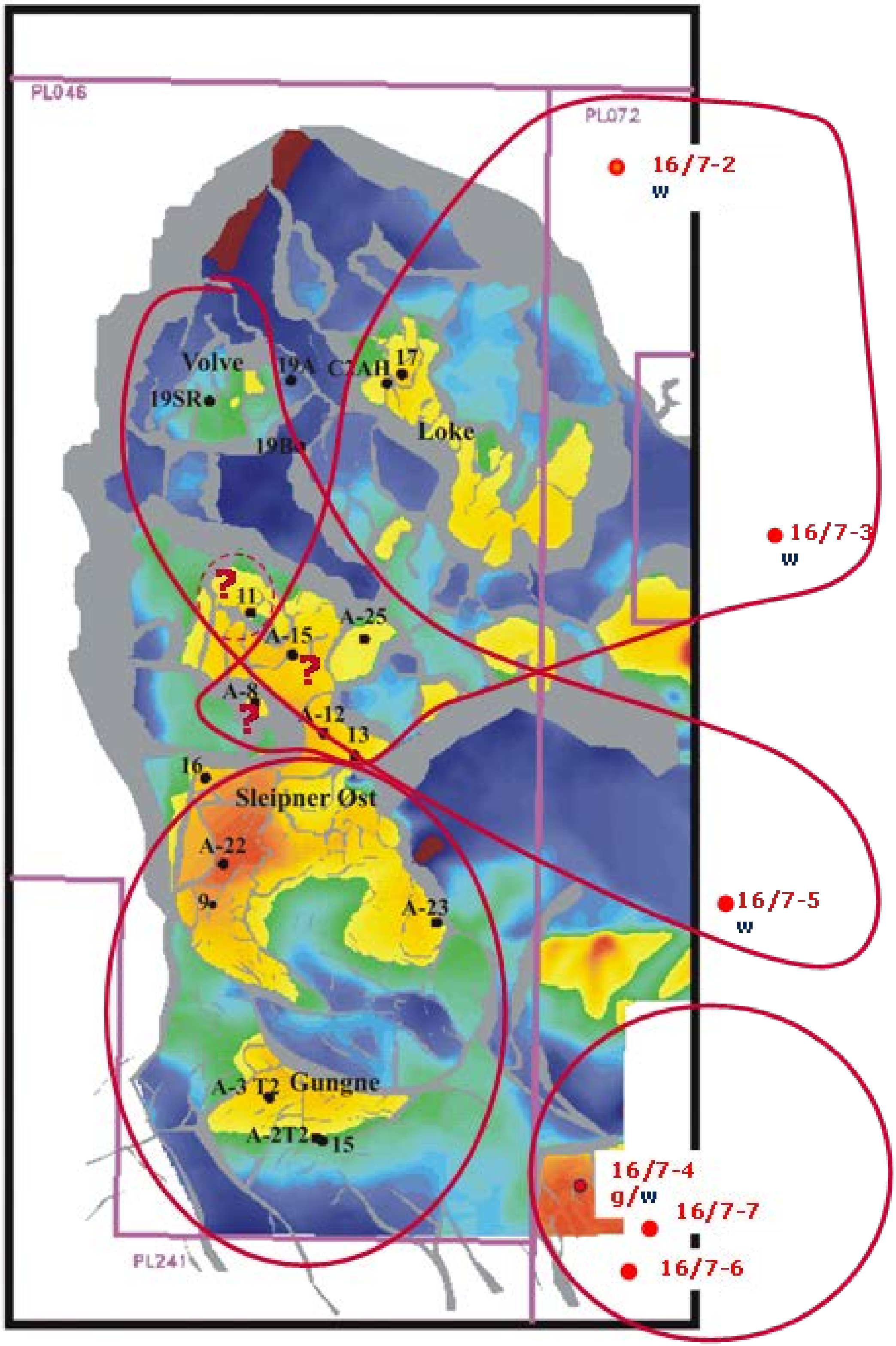


Figure 16 Water systems

Volve area

No certain contacts have been observed in any of the evaluated wells from the logs. Pressure data is only available in well 15/9-19 BT2 giving the water gradient. In the lowermost few meters of the Hugin Formation in well 15/9-19 A a slight increase in water saturation is observed. This may be related to a capillary transition zone. Capillary pressure (or J-function) modelling indicates that the corresponding

FWL should be 3120 m +/- 15m

Loke area

Logs, pressure data and strontium measurements show a gas water contact, *GWC*, for the well 15/9-C-2 AH at 2830 m. This *GWC* is situated in the shaly and tight Skagerrak Transition zone and may therefore be isolated. The logs and pressure data from 15/9-17 show a deeper contact than 2836 m.

The production data show that there is good communication between the Loke and SLE Hugin area. There is a deep spill point between Hugin and Skagerrak of 2900 – 2930m, and the gas volume seen by 15/9-C-2 AH indicates a deeper contact than 2830 m. Using the water gradient from 16/7-2 and 16/7-3 area, Figure 15 and 16, the *GWC* is at 2930 m. The strontium data, Figure 17 shows *GWC* from 2830 – 2880 m, but this is uncertain.

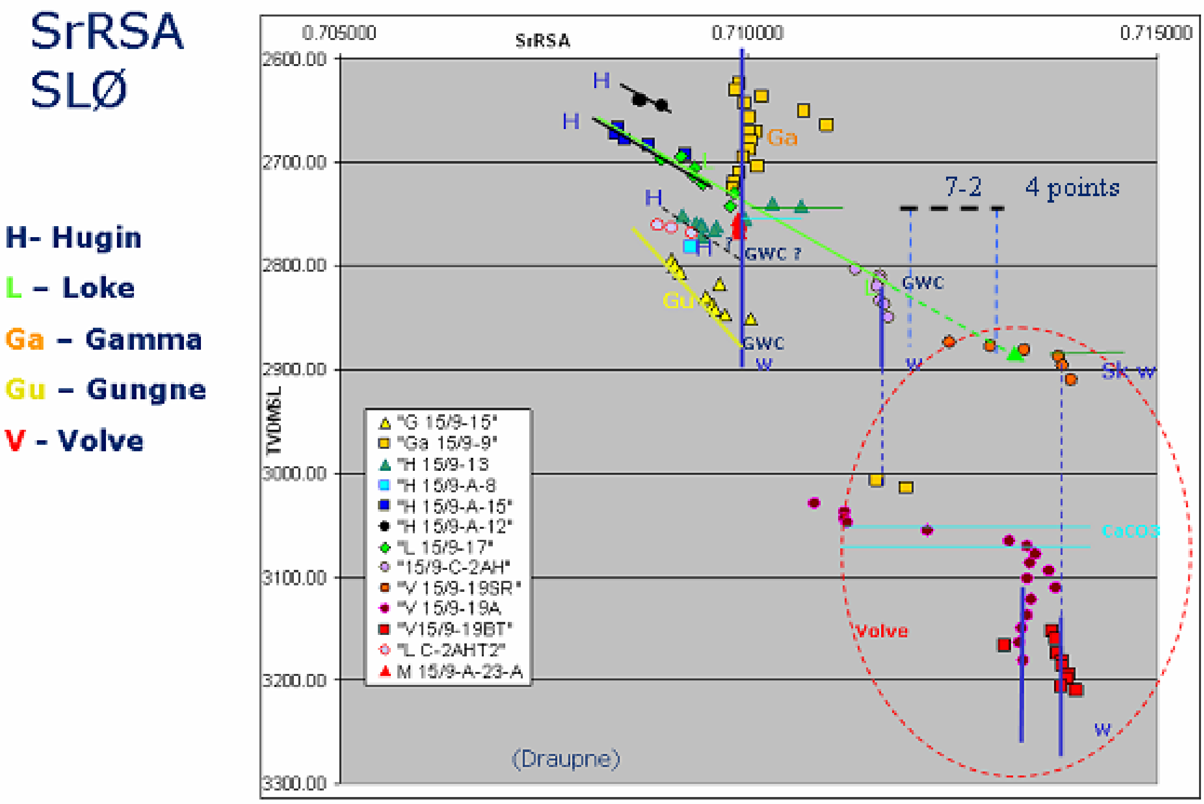


Figure 17 Strontium

The FWL = 2900 – 2930 m on Loke, by assuming the *GWC* in 15/9-C-2 AH is a local contact for the tight transition Skagerrak Fm, as illustrated in Figure 18.

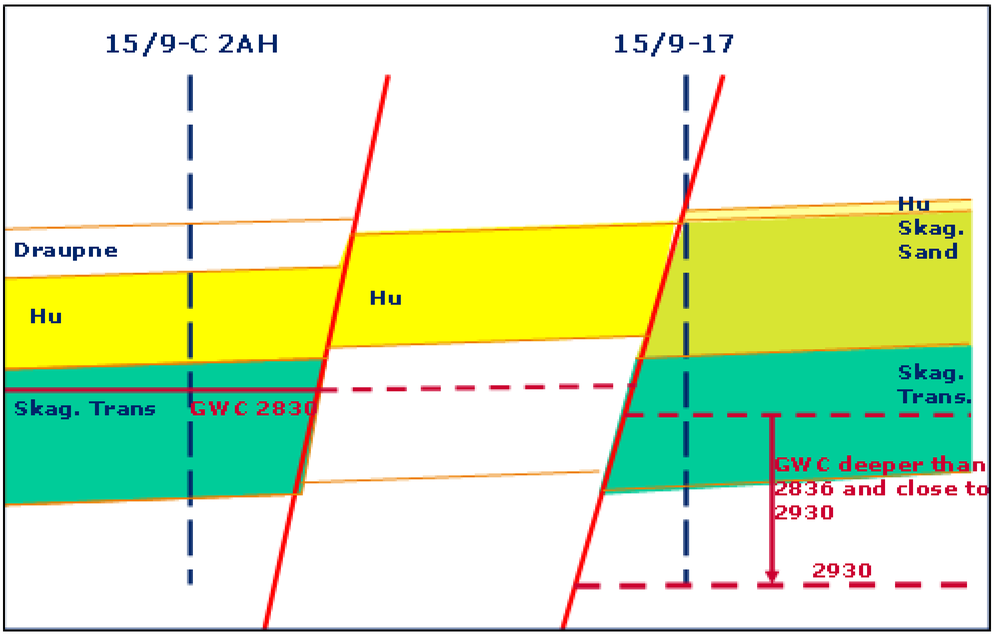


Figure 18 Schematic illustration of contacts on Loke

SLE Hugin area

The free water level, *FWL*, for the SLE Hugin area is mainly based on the well 15/9-11, where an oil water contact, *OWC*, at 2801 is seen both from the logs and pressure data. The data also show a gas oil contact, *GOC*, at 2793 m. The well 15/9-A-25 shows a GWC close to 2800 m but this well is depleted.

The FWL (OW) **= 2801 m on SLE Hugin**, but can be deeper if the 15/9-11 segment is isolated in the water zone.

Gamma / My2 area

The fluid contact on the Gamma high is based on log data, capillary pressure measurements and formation pressure data. Figure 19 shows a closer view of the formation pressure data in this area indicating a free water level of 2527 m in well 15/9-A-22. The logs in this well, however, indicate that the *GWC* could be between 2527 m and 2534 m. The water saturation has been evaluated both from logs and capillary pressure and the capillary pressure shows a deeper *GWC* than 2534 m.

For the My2 area both log and pressure data in well 15/9-A-23 A show that

The FWL is 2757.5 m on My2

The FWL is 2527 m on Gamma high

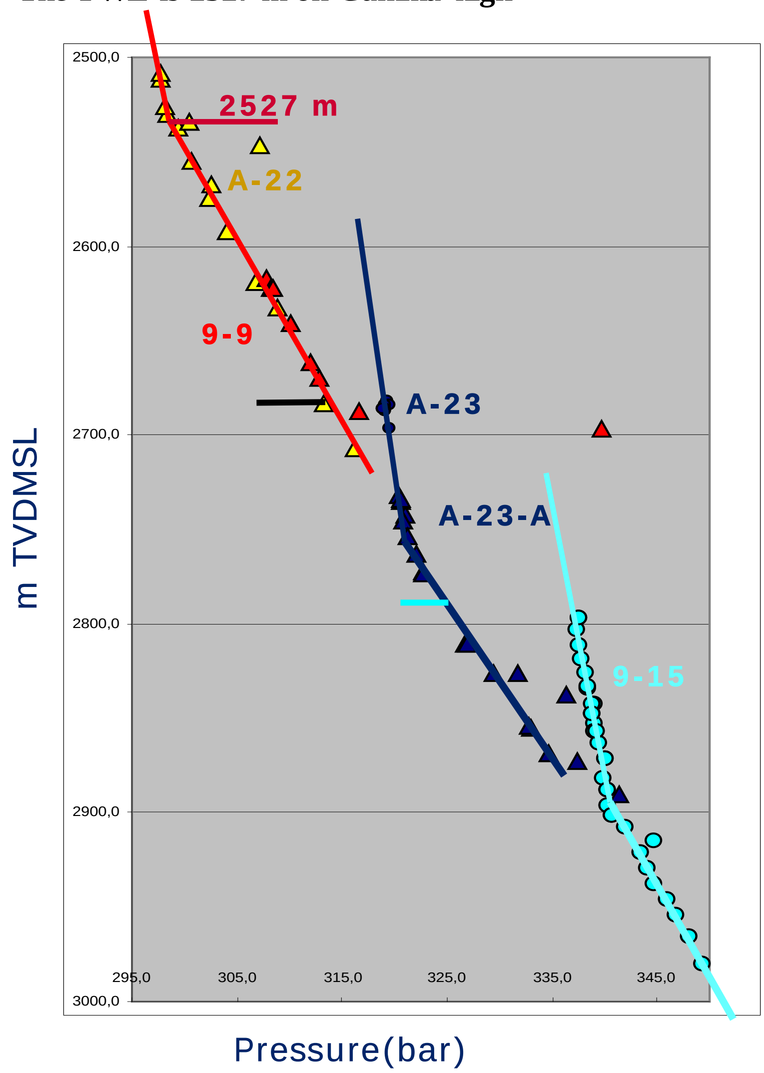


Figure 19 Pressure plot Gamma High, My 2 and Gungne

Gungne area

Both logs and pressure data from the well 15/9-15 show a *GWC* close to 2895 m. The pressure data, Figure 19, indicates that the contact is between 2893 m to 2897 m. This is consistent with the well log interpretation of gas down to 2894 m and water up to 2895 m. No contact is reached in the three other wells so therefore

The FWL = 2895 m on Gungne

6 Water Saturation Modelling

The water saturation in the reservoir can be written as a function of the normalised water saturation.

$$Sw = Swn(1 - Sw_{irra}) + Sw_{irra} \tag{20}$$

$$Sw_{irra} = c_1 \cdot \log k + c_2 \tag{21}$$

An expression for the water saturation as a function of capillary forces was found in Section 3.5. Generally, the capillary pressure, *Pc*, can be written as a function of the height above free water level if equilibrium is assumed between the capillary forces and the gravity forces, as given below.

$$Pc = \Delta\rho \cdot g \cdot H \tag{22}$$

$\Delta\rho$	Difference is density between the fluids (g/cc)
g	Gravity constant (=9.81 g/cc)
H	Height above free water level, H=D-FWL, where D is the actual depth (m tvdss)

The J-function for reservoir conditions can therefore be written as

$$J = \left(\frac{\Delta\rho \cdot g \cdot H}{\sigma \cdot \frac{\cos\theta}{3.141} \cdot 10^5} \right)_{res} \cdot \left(\sqrt{\frac{k}{\phi}} \right)_{res} \tag{23}$$

The fluid density is taken from DST analysis and the following values are used:

Gas **275 kg/m³** Oil **720 kg/m³** Water **1065 kg/m³**

Thus the fluid density difference is, $\Delta\rho$ = 790 kg/m^3 for gas and 345 kg/m^3 for oil.

The resulting parameters used for modelled water saturation comes from an iteration process, based on choosing the two parameters *Swirra* and $\sigma\cos\cdot\theta$ to obtain the best possible fit between the modelled water saturation and the one from the logs.

The fraction of irreducible water saturation (*Swirra*) for the Hugin Formation is based on cross plotting the water saturation from both log (Archie) against the log permeability, see Figure 20.a for Sleipner Øst and 20.b for Volve. Here also the Swirr from the SCAL data measurements is plotted. The parameters used is summarised in Table 11.

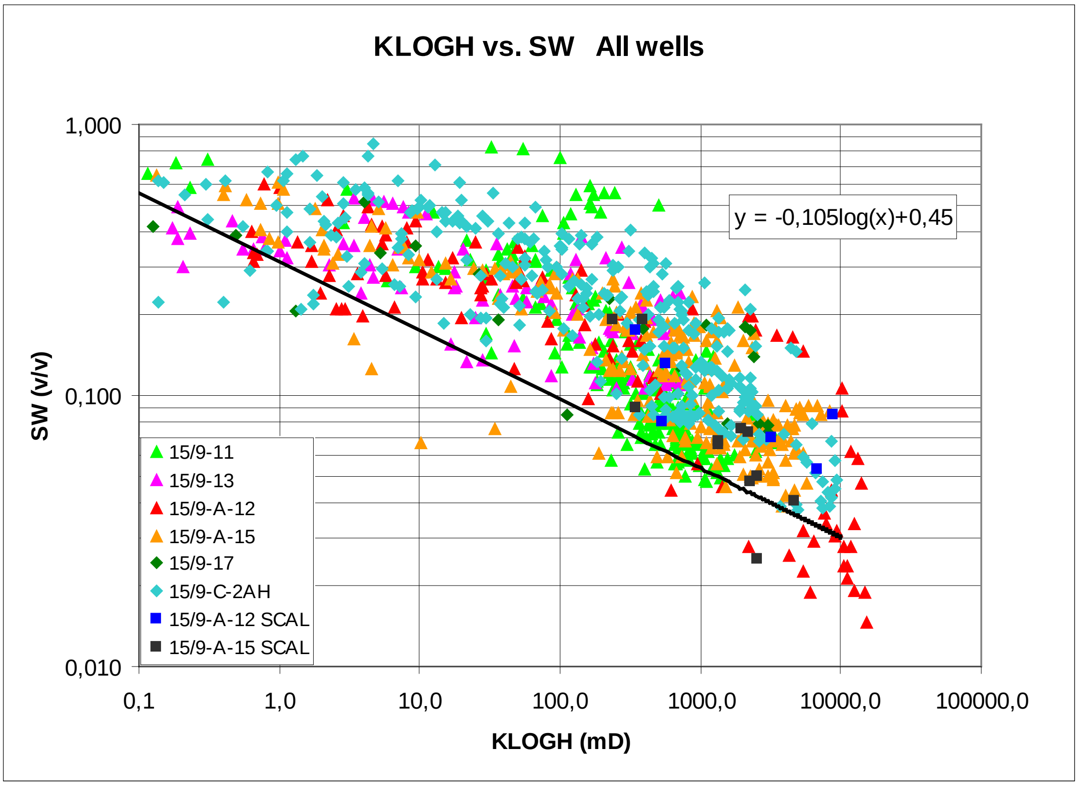


Figure 20.a Water saturation vs. permeability, Hugin Formation, Sleipner Øst

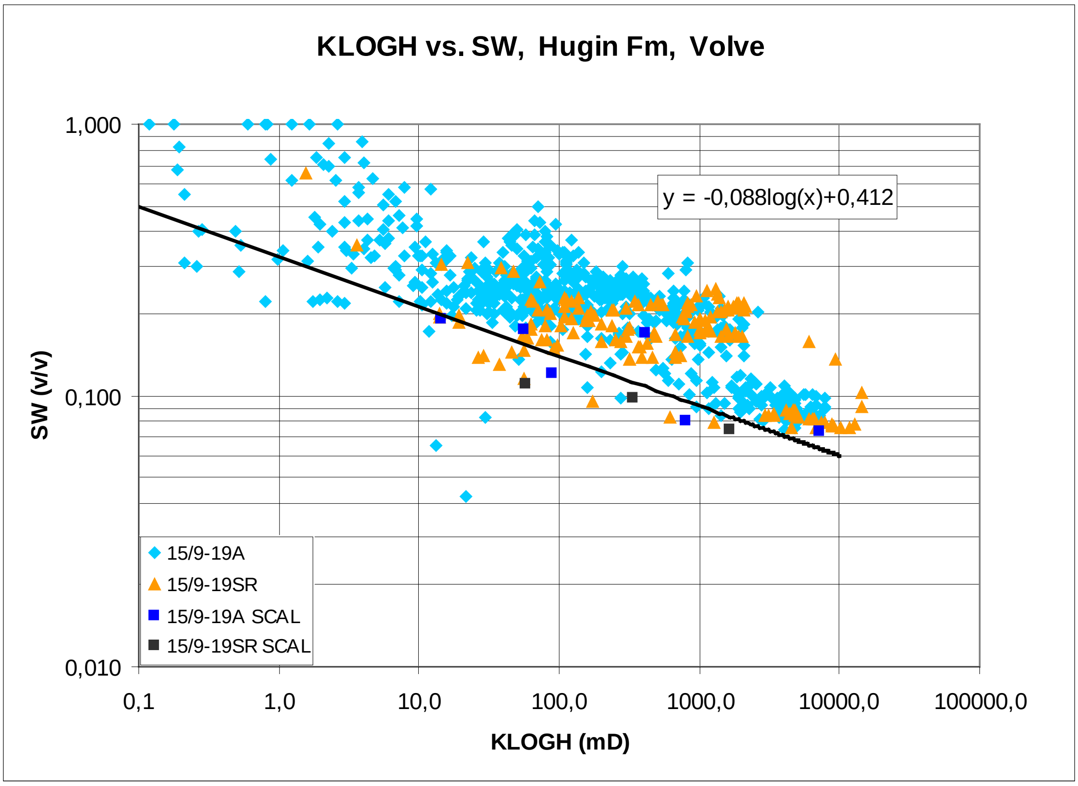


Figure 20.b Water saturation vs. permeability, Hugin Formaiton, Volve

For the Skagerrak formation the fraction of irreducible water saturation (*Swirra*) is based on two methods:

1. *Swirra* from Sw log (Archie) vs. log permeability, Figure 20.c
2. *Swirra* from Sw core (Sw at 12 bars) vs. core permeability, Figure 20.d

Figure 20.c shows one correlation 1) for the well 15/9-17 and a more optimistic correlation 2) for the wells 15/9-A-2 T2 and 15/9-A-3 T2. *Swirra* from core measurements, Figure 20.d show the same correlation for the well 15/9-17, 1) but the average correlation from core data 3) shows a more pessimistic *Swirra*.

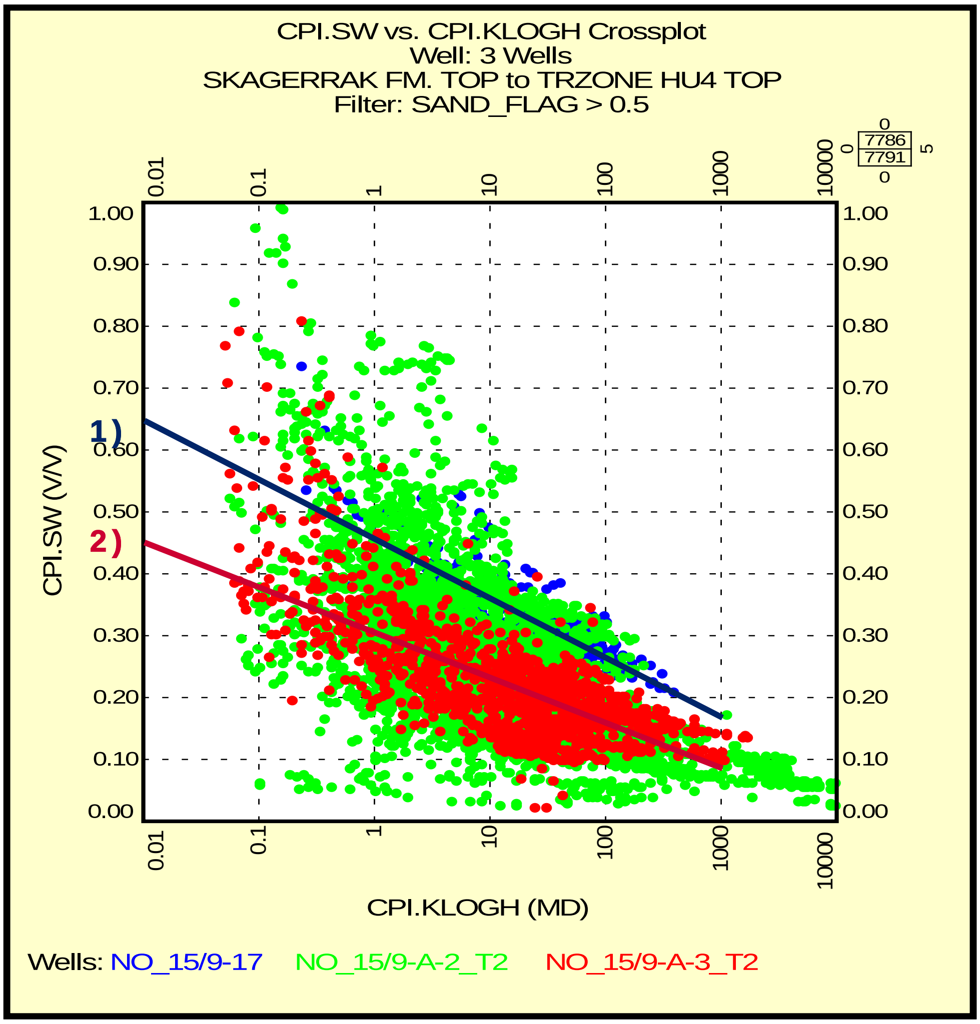


Figure 20.c Swirra from Sw log vs. permeability

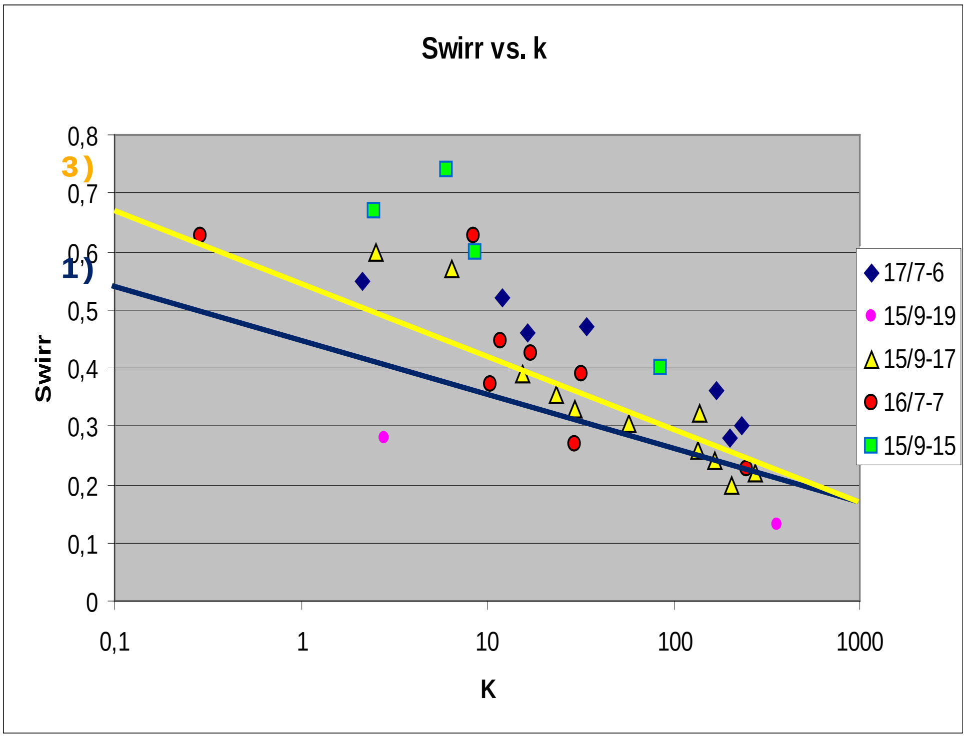


Figure 20.d Swirra from core Sw vs. core permeability

All the Skagerrak wells are based on the same correlation between SwN and J, see Table 11. By calculation of Sw from J function , SwJ = SwN (1-Swirra)+Swirra, and compare the SwJ with Sw log (Archie) the best fit is obtained by using Swirra correlation 1) for the Gamma and Loke area, correlation 2) for the Gungne and My area and correlation 3), the average from core data, for the well 15/9-A-19 AT2.

This evaluation shows 3 different saturation models for the Skagerrak Formation, which is illustrated in the Figure 21.

1) Gungne/My2 with good reservoir quality, low Sw
2) Gamma/Loke with normal reservoir quality, moderate Sw
3) 15/9-A-19 AT2 area with low reservoir quality, high Sw

Model	Area	Formation	Swn = $a \cdot J^{-b}$		$\sigma \cos\theta$	Swirra = $-c_1 \cdot \log k + c_2$		Reservoir Quality
			a	*b*		c_1	c_2	
	Volve	Hugin	2.222	1.111	2	0.105	0.45	Good
	Sleipner Øst	Hugin	0.526	1.087	2	0.088	0.412	Good
1)	Gamma/Loke	Skagerrak	0.158	0.847		0.094	0.452	Normal
2)	Gungne/My2	Skagerrak	0.158	0.847		0.07	0.33	Good (Low Sw)
3)	15/9-19 AT2	Skagerrak	0.158	0.847		0.14	0.56	Bad (High Sw)

Table 11 Water saturation model parameters

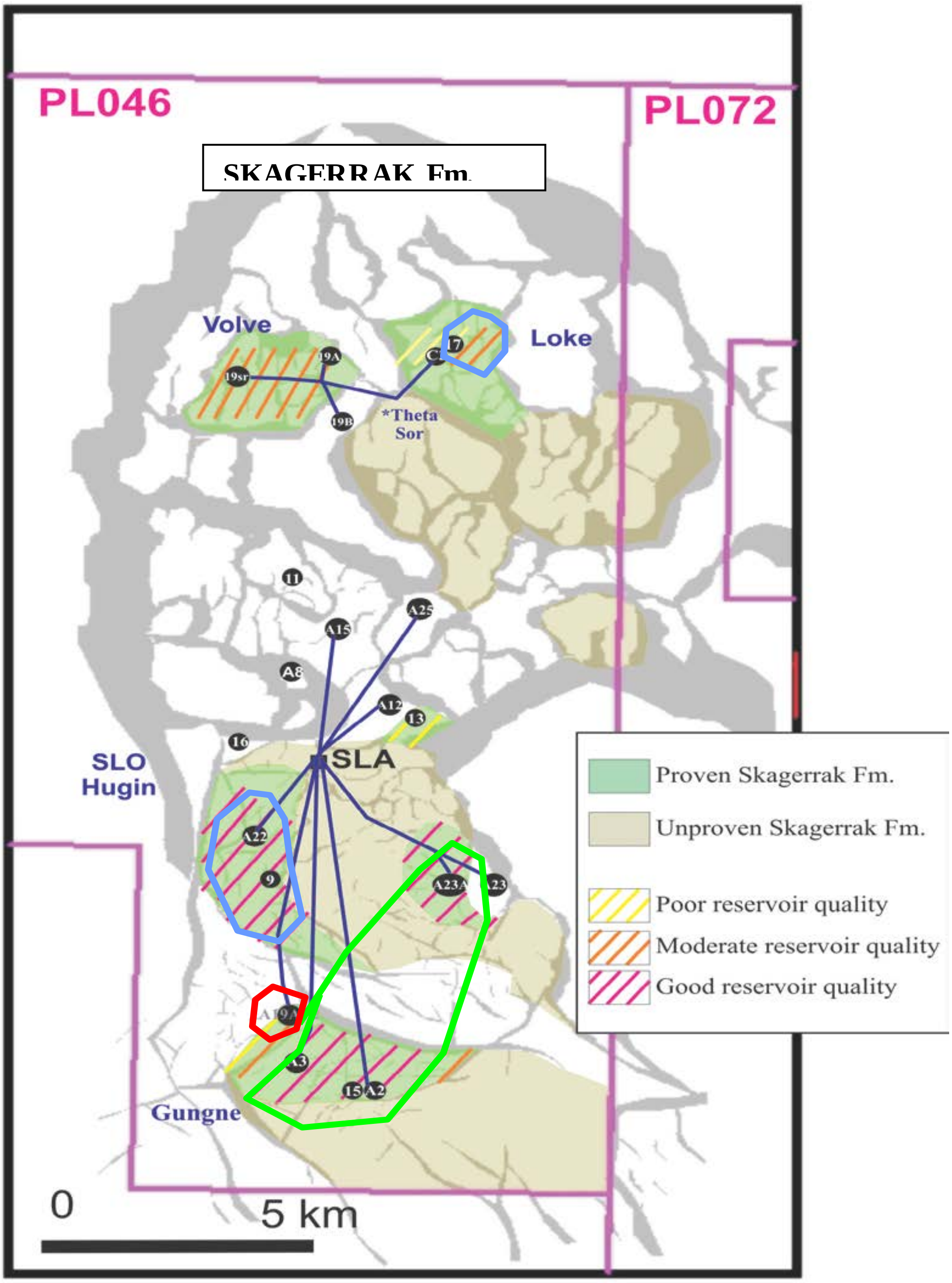


Figure 21 Reservoir quality Skagerrak Formation

Figure 22 illustrates the variation of the quality of the Hugin Formation in the various areas around Sleipner Øst. The occurrence and quality is best in the north and as moving to the south more shale and coal is introduced, reducing the net/gross ratio, but also the quality of the reservoir is more variable as shown on the cross section below the chart. In spite of this variation only one Sw model for Hugin Formation was needed.

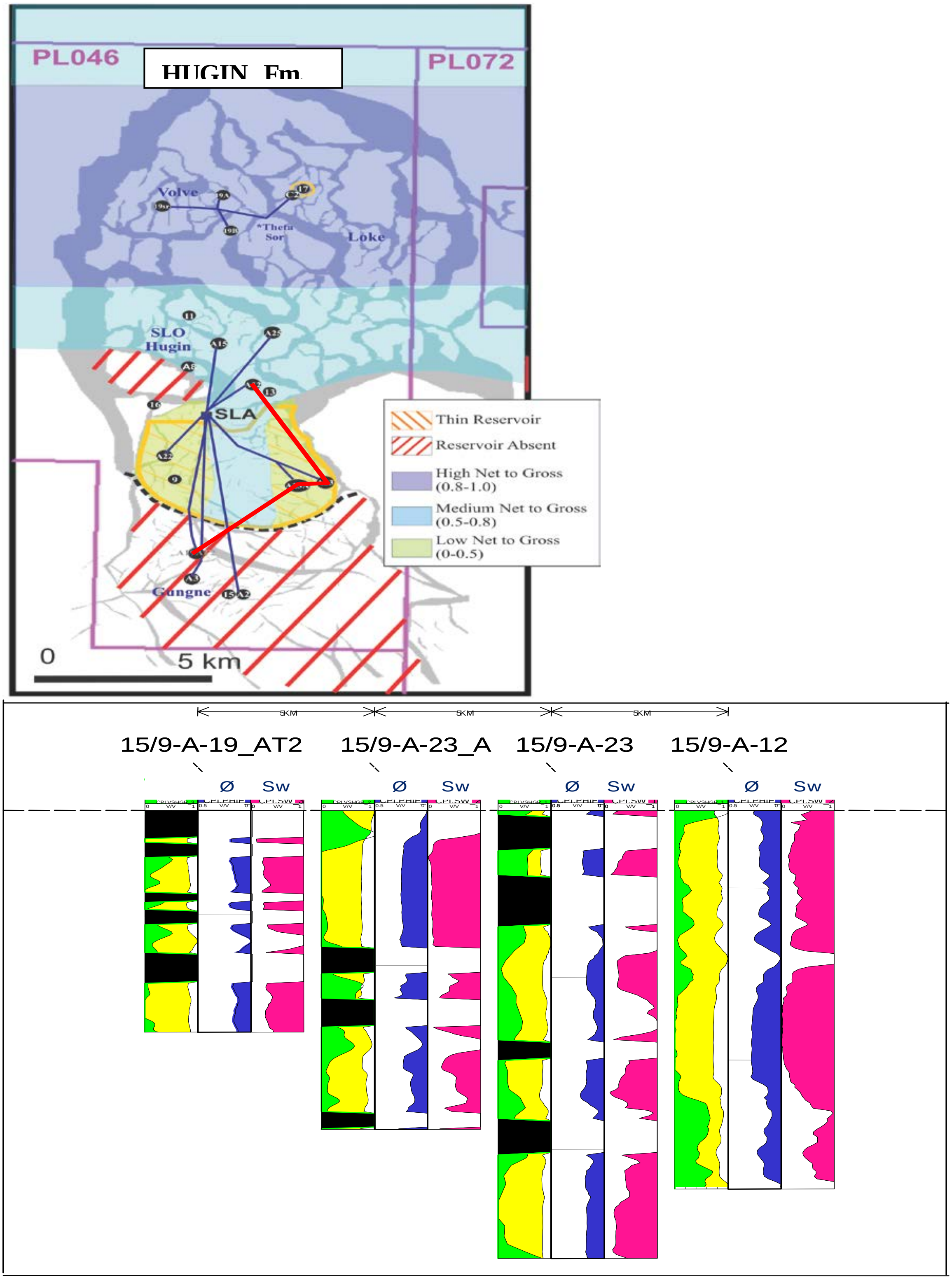

PL046
HUGIN Fm.
PL072
Volve
Loke
SLO
Hugin
SLA
Gungne
Thin Reservoir
Reservoir Absent
High Net to Gross
(0.8-1.0)
Medium Net to Gross
(0.5-0.8)
Low Net to Gross
(0-0.5)
0
5 km
15/9-A-19_AT2
15/9-A-23_A
15/9-A-23
15/9-A-12
Ø
Sw

Figure 22 Reservoir quality Hugin Formation with cross section

7 Uncertainty evaluation

7.1 Introduction

A study of the uncertainty of the petrophysical evaluation has been performed and the results are given as the uncertainty in hydrocarbon pore fraction (*HCPF*) per zone interval or facies.

The equation is:

$$HCPF = \frac{N}{G} \cdot \Phi \cdot (1 - Sw) \qquad (24)$$

N/G: Net/Gross (fraction)
Φ: Porosity (fraction)
Sw: Water Saturation (fraction)

The evaluation is done through a Monte Carlo type simulation by using the @Risk programme where the properties are drawn from specified distributions and combined. The resulting uncertainty is expressed as the distribution of the simulated *HCPF* normalised to the base case *HCPF* for each zone/facies on an average basis. The averaging process eliminates any random measured uncertainty.

The uncertainty in *HCPF* is estimated based of the uncertainty in the input parameters, *N/G*, *Φ* and *Sw*. The dependency between *N/G*, *Φ* and *Sw* are applied by the correlation matrix below.

Correlation matrix			
Parameter	***N/G***	***PHIF***	***Sg***
N/G	1	-0,7	-0,7
PHIF	-0,7	1	0,7
Sg	-0,7	0,7	1

The wells 15/9-A-25 and 15/9-A-19 T2 has been left out of the study due to no zonation information available. An average value for Sw has only been used when the whole zone is above the gas water contact and hence no Sw data from 15/9-9, 15/9-19 BT2 and 15/9-A-8 have been used.

The study area has been divided into four groups.

1. **Hugin Formation Volve**, per facies, see Table 12.a below. The numbers in grey indicate values excluded from the average value.
2. **Hugin Formation Sleipner Øst**, SLE Hugin wells, geological zonation used

3. **Skagerrak Formation Sleipner Øst**, Loke and Gamma wells. Own zonation made for uncertainty study purpose, see Table 12.b below. The value from Skag 5 has been used for Skag 4 and from Skag 2 for Skag 3.
4. **Bantonian and Skagerrak Formation Gungne**, geological zonation used

Well	Formation	Interval Top	Base	Gross	Weighted Average values Net	N/G	PHIF	SW	VSH	KLOGH	Description
		m md rkb		*m*	*m*					*md*	
15/9-19 A	Tidal Channel	3821.5	3919.6	15.6	15.6	1.000	0.194	0.221	0.126	472.7	Homogeneous, very good properties
15/9-19 BT2	Tidal Channel	4035.8	4179.0	29.8	29.3	0.983	0.195	0.914	0.135	419.9	
15/9-19 SR	Tidal Channel	4316.5	4339.9	2.4	2.4	1.000	0.209	0.185	0.068	1214.7	
Average				**47.8**	**47.3**	**0.990**	**0.195**	**0.216**	**0.128**	478.3	
15/9-19 A	Tidal Flat Sandy	3821.5	3919.6	44.3	41.0	0.927	0.194	0.228	0.186	229.0	More heterogeneous, little more VSH
15/9-19 BT2	Tidal Flat Sandy	4035.8	4179.0	38.9	34.9	0.897	0.208	0.956	0.281	94.4	
15/9-19 SR	Tidal Flat Sandy	4316.5	4339.9	6.1	6.1	1.000	0.219	0.183	0.171	165.0	
Average				**89.2**	**82.0**	**0.919**	**0.202**	**0.222**	**0.225**	167.0	
15/9-19 A	Middle Shoreface	3821.5	3919.6	23.3	21.4	0.919	0.195	0.240	0.213	143.6	Most heterogeneous, higher VSH, still high N/G
15/9-19 BT2	Middle Shoreface	4035.8	4179.0	25.5	23.1	0.907	0.212	0.955	0.304	63.1	
15/9-19 SR	Middle Shoreface	4316.5	4339.9	4.8	3.7	0.762	0.213	0.172	0.146	308.9	
Average				**53.6**	**48.2**	**0.899**	**0.204**	**0.230**	**0.252**	117.5	
15/9-19 A	Bay Sandstones	3821.5	3919.6	14.9	14.9	1.000	0.227	0.089	0.039	3540.4	Homogeneous, very good properties
15/9-19 BT2	Bay Sandstones	4035.8	4179.0	48.6	47.1	0.970	0.203	0.972	0.072	1140.1	
15/9-19 SR	Bay Sandstones	4316.5	4339.9	10.1	10.1	1.000	0.224	0.144	0.024	3634.3	
Average				**73.5**	**72.1**	**0.980**	**0.211**	**0.111**	**0.058**	1983.8	

Table 12.a Parameters for uncertainty in Hugin facies on Volve Field

Well	Zone	Interval Top	Base	Gross	Weighted Average values Net	N/G	PHIF	SW	VSH	KLOGH	Description
		m md rkb		*m*	*m*					*md*	
15/9-A-23 A	Skag 5	5379.5	5443.0	63.5	58.3	0.918	0.178	0.794	0.136	77.9	Mixed quality and shale content
15/9-A-22	Skag 5	3258.5	3333.0	74.5	72.1	0.967	0.173	0.455	0.177	19.3	
15/9-17	Skag 5	2717.5	2755.2	37.7	33.7	0.895	0.198	0.300	0.245	7.1	
Average				**175.7**	**164.1**	**0.934**	**0.180**	**0.300**	**0.176**	**37.6**	
15/9-A-23 A	Skag 4	5443.0	5529.0	86.0	84.6	0.984	0.198	0.855	0.147	30.3	Homogeneous zone with good properties and high N/G
15/9-A-22	Skag 4	3333.0	3473.6	140.6	138.5	0.985	0.199	0.671	0.174	23.3	
15/9-9	Skag 4	2642.0	2702.6	60.6	58.6	0.967	0.196	0.879	0.193	25.4	
Average				**287.2**	**281.7**	**0.981**	**0.198**	**0.300**	**0.170**	**25.8**	
15/9-A-23 A	Skag 3	5529.0	5570.0	41.0	24.0	0.584	0.176	0.891	0.255	6.9	Very variable quality of sands, mixed with shales
15/9-A-22	Skag 3	3473.6	3503.0	29.4	25.1	0.855	0.176	0.750	0.267	4.3	
15/9-9	Skag 3	2702.6	2775.0	72.4	60.2	0.832	0.146	0.828	0.152	6.6	
Average				**142.8**	**109.3**	**0.765**	**0.159**	**0.350**	**0.201**	**6.1**	
15/9-17	Skag 2	2755.2	2814.2	59.0	25.4	0.431	0.189	0.350	0.370	5.1	Low N/G, sands have variable quality
15/9-C-2 AH	Skag 2	3265.0	3357.5	92.5	31.5	0.340	0.199	0.812	0.326	12.7	
Average				**151.5**	**56.9**	**0.375**	**0.194**	**0.350**	**0.345**	**9.3**	
15/9-17	Skag 1	2814.2	2870.8	56.6	11.7	0.207	0.153	0.557	0.300	1.9	Low N/G, good quality sands
15/9-C-2 AH	Skag 1	3357.5	3401.4	43.9	8.1	0.184	0.184	0.842	0.338	3.2	
Average				**100.5**	**19.8**	**0.197**	**0.165**	**0.557**	**0.315**	**2.4**	

Table 12.b Zones and parameters for uncertainty in Skagerrak on Loke and Gamma area

In the simulation model limitations are set such that N/G does not exceed the interval 0 to 1 and Sw is not less than 0.034 v/v. This is based on irreducible water saturation from SCAL analysis. The color codes yellow – blue indicates a subdivision of the zones from good (yellow) to poor properties (blue) and this has been used throughout this section.

The confidence intervals for the input parameters are listed in Table 13 below. A discussion of these parameters is followed.

Code	N/G90	N/G	N/G10	PHI90	PHI	PHI10	SG90	SG	SG10
		fraction			*p.u.*			*s.u.*	
Yellow	0,02	1	0,02	0,01	1	0,01	0,03	1	0,03
Orange	0,05	1	0,05	0,015	1	0,015	0,05	1	0,05
Green	0,1	1	0,1	0,02	1	0,02	0,1	1	0,1
Blue	0,15	1	0,15	0,025	1	0,025	0,1	1	0,1

Table 13 80% Confidence interval of the input parameters

7.1.1 Net to gross

N/G is determined by applying cut off values to the porosity, permeability and shale volume. The base case cut off values is 0.05/0.5 mD (gas/oil) and 0.5 v/v. The P90 and P10 cut off values of the permeability and corresponding porosity is visualised in Figure 13.a and b, and together with a variation of the cut off value for shale the cases could be summarised as this:

	P90	BASE	P10	Formation	Area
KLOGH	2	0,5	0,2		
PHIF	0,13	0,1	0,08	Hugin	Volve
VSH	0,4	0,5	0,6		
KLOGH	0,2	0,05	0,02		
PHIF	0,12	0,1	0,08	Hugin	SLE Hugin
VSH	0,4	0,5	0,6		
KLOGH	0,2	0,05	0,02		
PHIF	0,14	0,12	0,11	Bathonian	Gungne
VSH	0,4	0,5	0,6		
KLOGH	0,2	0,05	0,02		
PHIF	0,125	0,1	0,08	Skagerrak	Gamma and Gungne
VSH	0,4	0,5	0,6		
VSH	0,6	0,7	0,8	Skag 2	Well 15/9-A-2T2

Table 14 Cut off values variation

The confidence interval for the N/G is determined by comparing the P90 and P10 value against the base case values and visualised in the Figures 23.a – d below. Table 13 (with color codes) shows the confidence intervals used in the analysis for N/G.

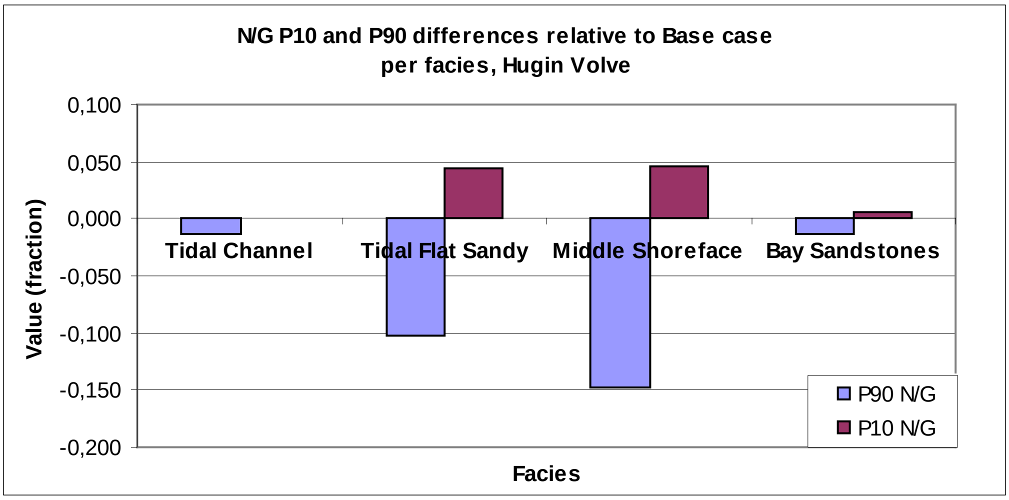


Figure 23.a N/G P10 and P90 relative to base case N/G per facies, Volve

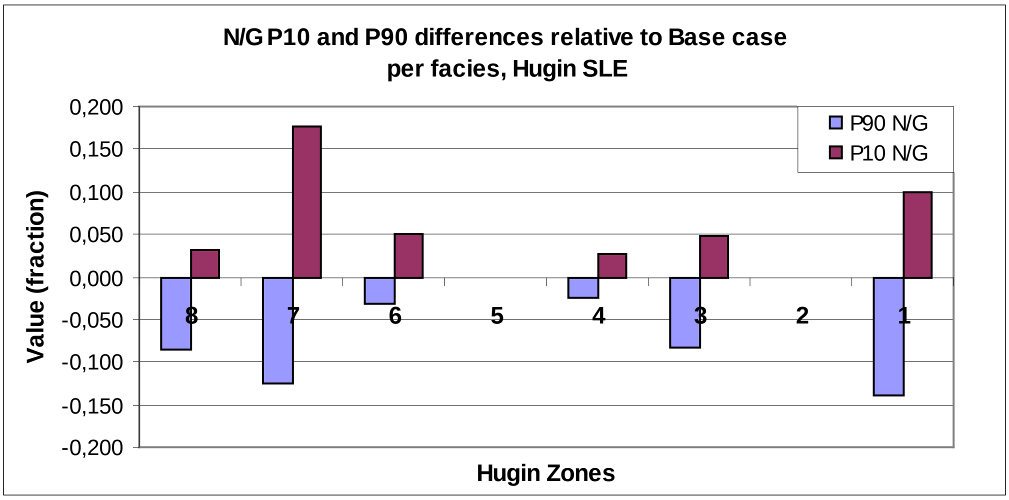


Figure 23.b N/G P10 and P90 relative to base case N/G per Hugin zone, SLE Hugin

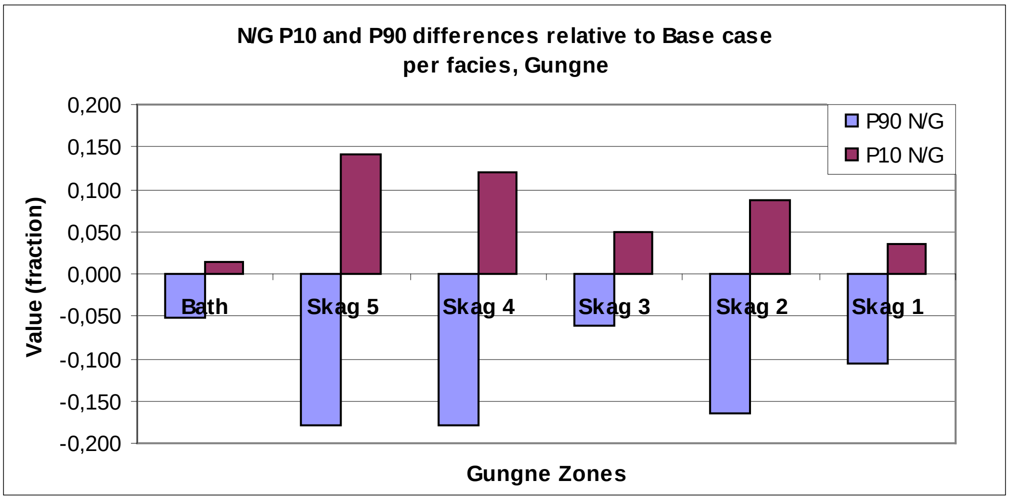


Figure 23.c N/G P10 and P90 relative to base case N/G per zone, Gungne

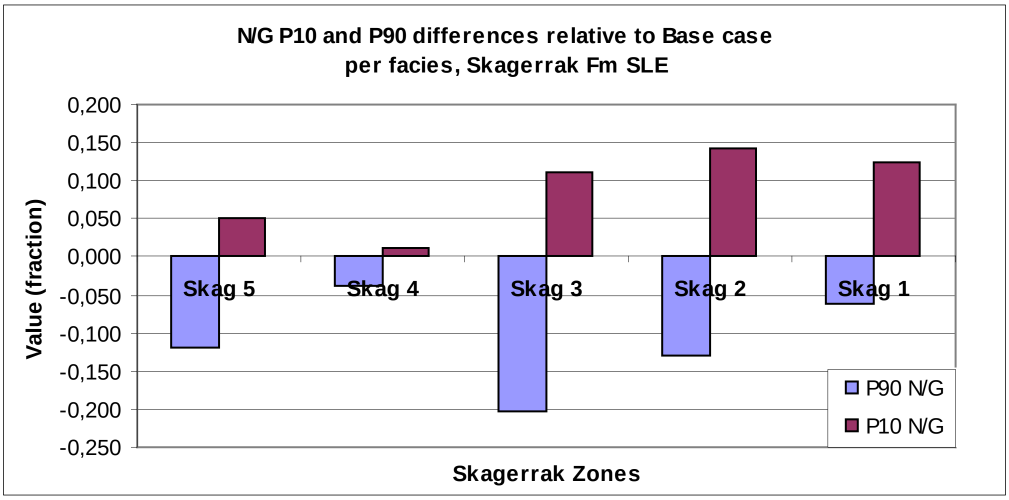


Figure 23.d N/G P10 and P90 relative to base case N/G per Skagerrak zone, Loke and Gamma

These figures show that the variation in N/G increases as the shale content increases. The confidence interval used in the analysis can be found in Table 13.

7.1.2 Porosity

The uncertainty in the calculated porosity mainly depends on various errors in the core data; i.e. overburden correction, measurement errors, depth shifting errors, the representativity of core vs. log and the quality of the correlation against log data. Based on this the confidence interval for porosity is set quite narrow, see Table 13.

7.1.3 Water Saturation

The modelled water saturation used in the geological model, described in Section 6 is calibrated to the log water saturation, see Section 4.3. The uncertainty therefore mainly depends on the parameters of the Archie equation; a, m, n, Rw and Rt, and the quality of the correlation between the average water saturation from logs vs. from the model.

Systematic errors in Rt is assumed attached to incomplete environmental and invasion corrections together with shoulder bed effects. The Hugin Formation mostly consists of homogeneous formation of good properties. The Skagerrak Formation also has large homogeneous sections with slightly poorer properties but is also is associated with more shale and increasingly shoulder effects problems with poorer facies. This is reflected in the confidence interval for *Sw*.

The resistivity of the formation water is based on several representative samples from DST, MDT and FMT, showing similar values, thus the uncertainty is considered to be relatively low for this parameter.

The uncertainty in the electrical core measurements, *m* and *n*, is based on uncertainty in the actual measurements and in the estimation of the average values for a zone. This could origin from the treatment and preparation of the core material during drilling an in the laboratory, which can cause permanent changes in the character of the core material. Errors can also be introduced during the measurements, either method or equipment, and also if the core material is not representative. There is a relatively good coverage of *FF* measurements for determining the *m* value, and this has also been confirmed by log data. For the *n* exponent the data shows more variation, but the quality is believed to be good.

The confidence interval for water saturation is set somewhat wider than for porosity, see Table 13.

7.1.4 Results

The resulting uncertainty is expressed as the distribution of the simulated HCPC normalised to the base case HCPC, which has been set to 100%. This is listed in Table 15.a – d for the four areas by the colour codes used in Table 13, and displayed graphically in Figures 24.a – d, specified by the base case and the P90 and P10 values in percent. The values for further use have been slightly rounded.

Volve Facies	P90	Base Case	P10	P90	Base Percent	P10	P90	Base Percent	P10	Ave VSH
Tidal Channel	0,922	1	1,065	**-7,8**	1	**6,5**	**-8**	1	**6**	0,128
Tidal Flat Sandy	0,826	1	1,115	**-17,5**	1	**11,5**	**-17**	1	**12**	0,225
Middle Shoreface	0,744	1	1,098	**-25,6**	1	**9,8**	**-26**	1	**10**	0,252
Bay Sandstones	0,935	1	1,056	**-6,5**	1	**5,6**	**-7**	1	**6**	0,058

Table 15.a Uncertatinty analysis results for *HCPC*, Volve Field

Hugin Zones	P90	Base Case	P10	P90	Base Percent	P10	P90	Base Percent	P10	Ave VSH
Hugin 8	0,852	1	1,124	**-14,8**	1	**12,4**	**-15**	1	**12**	0,145
Hugin 7	0,727	1	1,219	**-27,3**	1	**21,9**	**-27**	1	**22**	0,218
Hugin 6	0,914	1	1,084	**-8,6**	1	**8,4**	**-9**	1	**8**	0,091
Hugin 5	0,924	1	1,038	**-7,6**	1	**3,8**	**-8**	1	**4**	0,036
Hugin 4	0,917	1	1,052	**-8,3**	1	**5,2**	**-8**	1	**5**	0,110
Hugin 3	0,835	1	1,072	**-16,6**	1	**7,2**	**-17**	1	**7**	0,157
Hugin 2	0,915	1	1,062	**-8,5**	1	**6,2**	**-9**	1	**6**	0,021
Hugin 1	0,726	1	1,226	**-27,4**	1	**22,6**	**-27**	1	**23**	0,233

Table 15.b Uncertatinty analysis results for *HCPC*, SLE Hugin area

Skagerrak Zones	P90	Base Case	P10	P90	Base *Percent*	P10	P90	Base *Percent*	P10	Ave VSH
Skag 5	0,797	1	1,139	**-20,3**	1	**13,9**	**-20**	1	**14**	0,176
Skag 4	0,872	1	1,088	**-12,8**	1	**8,8**	**-13**	1	**9**	0,170
Skag 3	0,743	1	1,219	**-25,7**	1	**21,9**	**-26**	1	**22**	0,201
Skag 2	0,692	1	1,228	**-30,8**	1	**22,8**	**-31**	1	**23**	0,345
Skag 1	0,587	1	1,275	**-41,3**	1	**27,5**	**-41**	1	**28**	0,315

Table 15.c Uncertatinty analysis results for *HCPC*, Loke and Gamma area

Gungne Zones	P90	Base Case	P10	P90	Base *Percent*	P10	P90	Base *Percent*	P10	Ave VSH
Bathonian	0,876	1	1,086	**-12,5**	1	**8,6**	**-12**	1	**9**	0,068
Skag 5	0,758	1	1,193	**-24,2**	1	**19,3**	**-24**	1	**19**	0,297
Skag 4	0,791	1	1,113	**-21,0**	1	**11,3**	**-21**	1	**11**	0,292
Skag 3	0,912	1	1,082	**-8,8**	1	**8,2**	**-9**	1	**8**	0,269
Skag 2	0,785	1	1,155	**-21,6**	1	**15,5**	**-22**	1	**15**	0,353
Skag 1	0,781	1	1,163	**-21,9**	1	**16,3**	**-22**	1	**16**	0,186

Table 15.d Uncertatinty analysis results for *HCPC*, Gungne Field

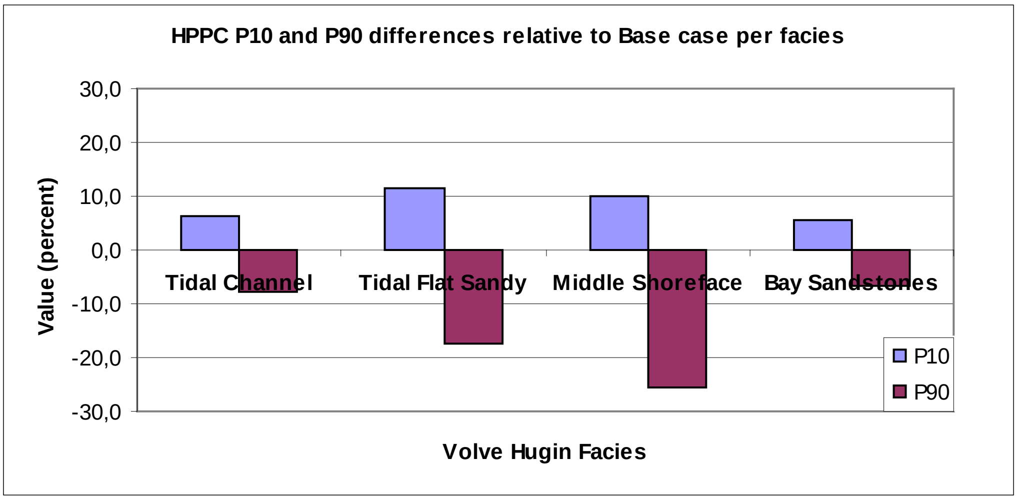


Figure 24.a Resulting uncertainty by Hugin facies, Volve

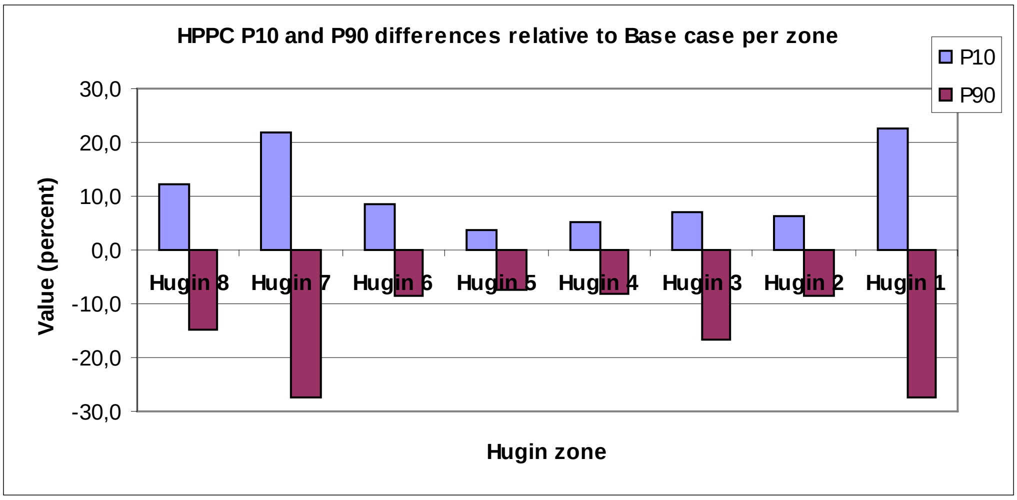


Figure 24.b Resulting uncertainty by Hugin zone, SLE Hugin

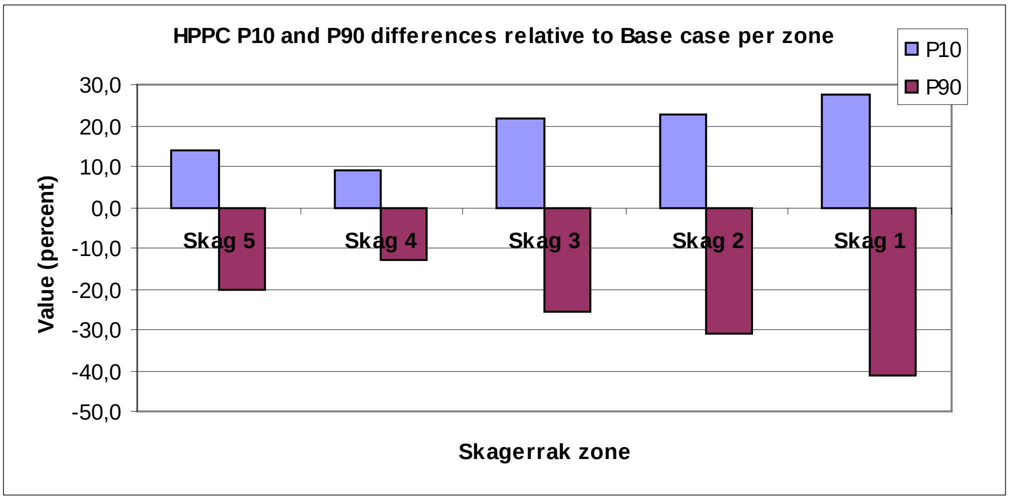


Figure 24.c Resulting uncertainty by Skagerrak zone, Loke and Gamma

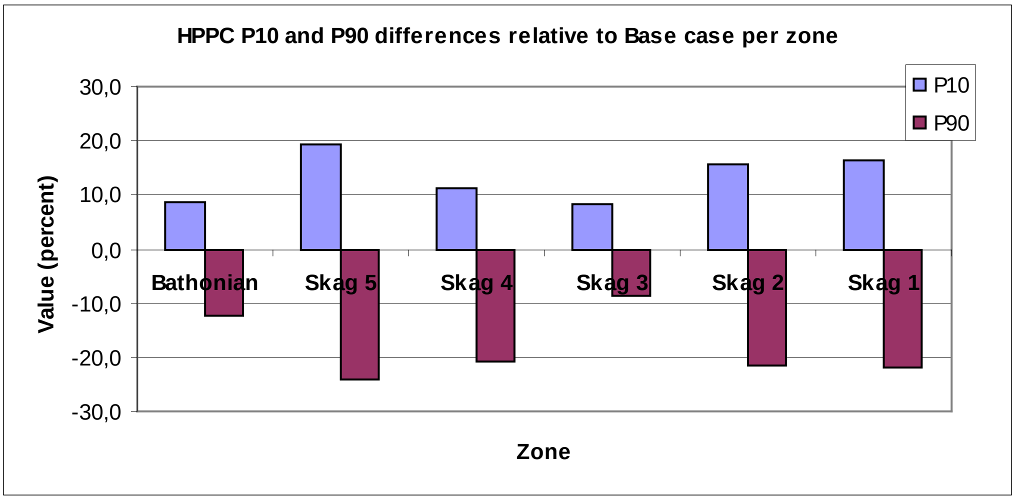


Figure 24.d Resulting uncertainty by zones, Gungne

The results show that the uncertainty is relatively low for the best zones, marked yellow and orange, and show results in the range variating from ± 5 – 13%. As the formation becomes more and more heterogeneous the uncertainty increases, which is expected. For the green zones the uncertainty is in the average of ± 15 – 20% (except for Skag 1 on Loke) and for the blue zones the average is ± 20 – 30%.

The value for Skag 1 for P90 of – 41% may seem very high, but this is the average for the Transition zone on Loke, with a very low N/G of 0.2, which is the main reason for this high value. Also there seem to be a lower P10 than P90 (higher downside potential) and this is due to that the base case cut off value is set relatively low.

From the results of the study it can also be seen that for the good quality zones with low uncertainty the porosity contributes most to the uncertainty. N/G becomes more and more important as more shale is introduced into the formation. The water saturation seems mostly to be medium important.

8 References

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