Relinquishment Report for PL 558

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(See also margin identification throughout document)

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GM Exploration & Geosciences (Norway)	Stavanger	[redacted]
Exploration Manager (Norway)	Stavanger	[redacted]
Team Lead Norwegian Sea	Stavanger	[redacted]
Geologist	Stavanger	[redacted]

Table: DOCUMENT APPROVAL

Prepared by:	Date:	[redacted]
Kristian Tellefsen	15/12-14	
Reviewed by:	Date:	
Adrian White	15.12.14	
Reviewed by:	Date:	
Kate Langaker	15/12-14	
Approved by:	Date:	
Svend Erik Petterson	16.12.14	

Relinquishment Report for PL 558

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1 Key Licence History

Introduction
E.ON Exploration and Production, as operator for PL558, have together with the license partners decided to relinquish the license after the results of the 6507/5-7 well (Rig takeover from Tullow at 04:25 on June 4th 2014 and Rig off E.ON hire at 22:30 on June 24th 2014). The partnership considers the remaining prospectivity in the license to not be of commercial interest due to limited prospect volumes and relatively high geological risk.

Key Licence History

Summary of award and participants
PL558 was originally applied for in the APA 2009. It was awarded on February 19th 2010. E.ON was awarded the operatorship with 30% along with its partners PGNiG Norway AS (15%), Nexen Exploration and Production Norge AS (15%), Petoro (20%), Det Norske (20%). PGNiG took over Nexen's interest in January 2012. Det Norske farmed down with 10% to Petrolia in June 2014. When the well penetrated the reservoir the ownership in the license was E.ON (30%), PGNiG (30%), Petoro (20%), Det Norske (10%), and Petrolia (10%).

Initial work obligations and work periods

Within 2 years of the award (by February 19th 2010)

- G&G Studies
- Seismic reprocessing
- Drill or Drop decision

Within 4 years of the award (February 19th 2014)

- Drill or drop decision
- Decision to prepare a plan for development (BoV)

Within 6 years of the award (February 19th 2016)

- Hand in plan for development

Any applications and grants for extension of deadlines
Due to difficulties in securing a drilling unit within the required timeframe, an application for an extension of the BoV date was sent to Olje og Energidepartementet on June 20th 2013. The extension was approved on September 10th 2013 and the new deadline was extended to February 19th 2015.

Overview of meetings held

- EC/MC Meeting - April 8th 2010
- EC and Work Meeting - April 28th 2011
- EC Meeting - Reprocessing Status - May 19th 2011
- EC Meeting - Migration velocity QC Meeting - June 30th 2011
- EC Meeting - Stacking velocity review meeting - July 22nd 2011
- EC/MC Meeting - November 11th 2011
- EC Work Meeting - December 16th 2011
- EC Meeting - Petrophysics - January 10th 2012
- EC/MC and Work Meeting - January 26th 2012
- EC Meeting - Migration work meeting - February 6th 2012

- MC Meeting - Drill or Drop - February 14th 2012
- EC Meeting - Seismic Inversion Study Kick-off meeting - March 26th 2012
- EC Meeting - Seismic Inversion Status - May 4th 2012
- EC Meeting - Inversion Study and Formation Evaluation Results - June 12th 2012
- EC and Work Meeting - April 20th 2012
- EC Meeting - Seismic Inversion Summary Meeting - August 24th 2012
- EC/MC Meeting - November 21st 2012
- EC Meeting - Terne Well Concept Selection - May 3rd 2013
- MC Meeting - Audit of the Terne Well Project - October 23rd 2013
- EC/MC Meeting - November 28th 2013
- EC Meeting - Terne Status - March 31st 2014
- EC/MC Meeting - November 5th 2014

Reason for relinquishment
The partnership has evaluated the prospectivity of PL558 and identified the Terne prospect as being the main target. Well 6507/5-7 has tested this structure and proved that it is not hydrocarbon bearing. The reason for the failure is believed to be lack of charge. Several additional leads were identified and evaluated, however none of them have sufficient volume potential to support any further drill decisions. The decision to relinquish is unanimously supported by the license.

2 Database

Work on the license data base
The most recent mapping of the license is done on the ANO9403-EO-T11 (3D) but also on BPN0501 (3D), ANO9403 (3D), ANO9602 (3D), ST9717 (3D), SG9605 (3D), and MC3D Haltenbanken MegaMerge (3D). See Table 2.2 and Fig. 2.1 for an overview.

Any new seismic data acquired and interpreted
There were no new seismic surveys shot for PL558 specifically, however the ANO9403 3D was reprocessed by Western Geco in Stavanger from March to August 2011. The new reprocessed 3D is called ANO9403-EO-T11. It covers 475km2 in the blocks 6507/5&6.

The original survey was acquired by GecoPrakla during 1994, 1995, 1996. The 98 sequences were shot by three boats in 5 different boat configurations. The aim of the reprocessing was to preserve amplitude variations around 1500ms over the entire survey area.

Seismic acquisition specifications:
Rho - 2 Cables
Searcher - 4 Cables
Searcher - 6 Cables
Searcher (Shooting) & Beta - 4+3 Cables
Beta (Shooting) & Searcher - 6 Cables

Navseis merged data for all 98 sequences, along with Observers logs, boat configuration documentation, final field reports and far field signatures were recieved by the license and used as input to the reprocessing.

Other wells in the license
There are no other wells in PL558.

Any other new/released well results included in evaluation
There were no wells included in the evaluation other than the ones listed in Table 2.1.

2.1 Well Database

The wells are listed in Table 2.1 and were considered the most applicable wells for further exploration in PL558.

Table 2.1 PL558 Well database

WELL	Wellbore Completion Date	License	Total depth (mRKB)	Oldest Penetration age, Fm.	Status	Field Discovery
6506/6-1	07/12/2000	PL211	5491	Early Jurassic, Åre Fm.	Gas	
6506/12-4	13/08/1985	PL094	4457	Early Jurassic, Åre Fm.	Shows	
6507/3-2	27/4/1997	PL159	2032	Triassic Red Beds	Biogenic gas in Fangst Gp.	
6507/3-3	25/3/1999	PL159	3830	Early Jurassic, Åre Fm.	Gas, Jurassic sst.	
6507/5-1	05/03/1998	PL212	4224	Early Jurassic, Åre Fm.	Oil/Gas/Cond	Skarv
6507/5-2	23/9/1999	PL212	3897	Early Jurassic, Åre Fm.	Gas/Cond	Skarv
6507/5-3	23/6/2000	PL212	3000	Early Cretaceous, Lange Fm.	Gas	Skarv
6507/5-4	15/4/2001	PL212	3812	Early Jurassic, Åre Fm.	Oil/Gas	Skarv
6507/5-5	14/2/2002	PL212	3948	Early Jurassic, Åre Fm.	Oil	Skarv
6507/6-1	23/8/1986	PL123	4040	Early Triassic	Biogenic gas, Åre Fm.	
6507/6-2	16/7/1991	PL123	4354	Late Triassic, Åre Fm.	Oil shows, Lange Fm.	
6507/7-1	01/12/1984	PL095	4825	Early Jurassic, Tilje Fm.	Gas shows	
6507/7-12	12/08/1999	PL095	3976	Late Jurassic, Spekk Fm.	Oil shows, Early Cret.	
6507/8-3	20/9/1988	PL124	2075	Late Triassic, Åre Fm.	Biogenic gas, Garn Fm.	
6507/8-6	09/10/1993	PL124	2850	Late Triassic, Red Beds	Dry	

2.2 Seismic Database

The following seismic database was utilized. See the list in Table 2.2 and the map overview in Fig. 2.1.

Table 2.2 Seismic database

Survey name	Owner
BPN0501	BP
ANO9403	BP
ANO9403-EO-T11	E.ON Reproc
ANO9602	BP
ST9717	Statoil
SG9605	BP
MC3D Haltenbanken MegaMerge	PGS

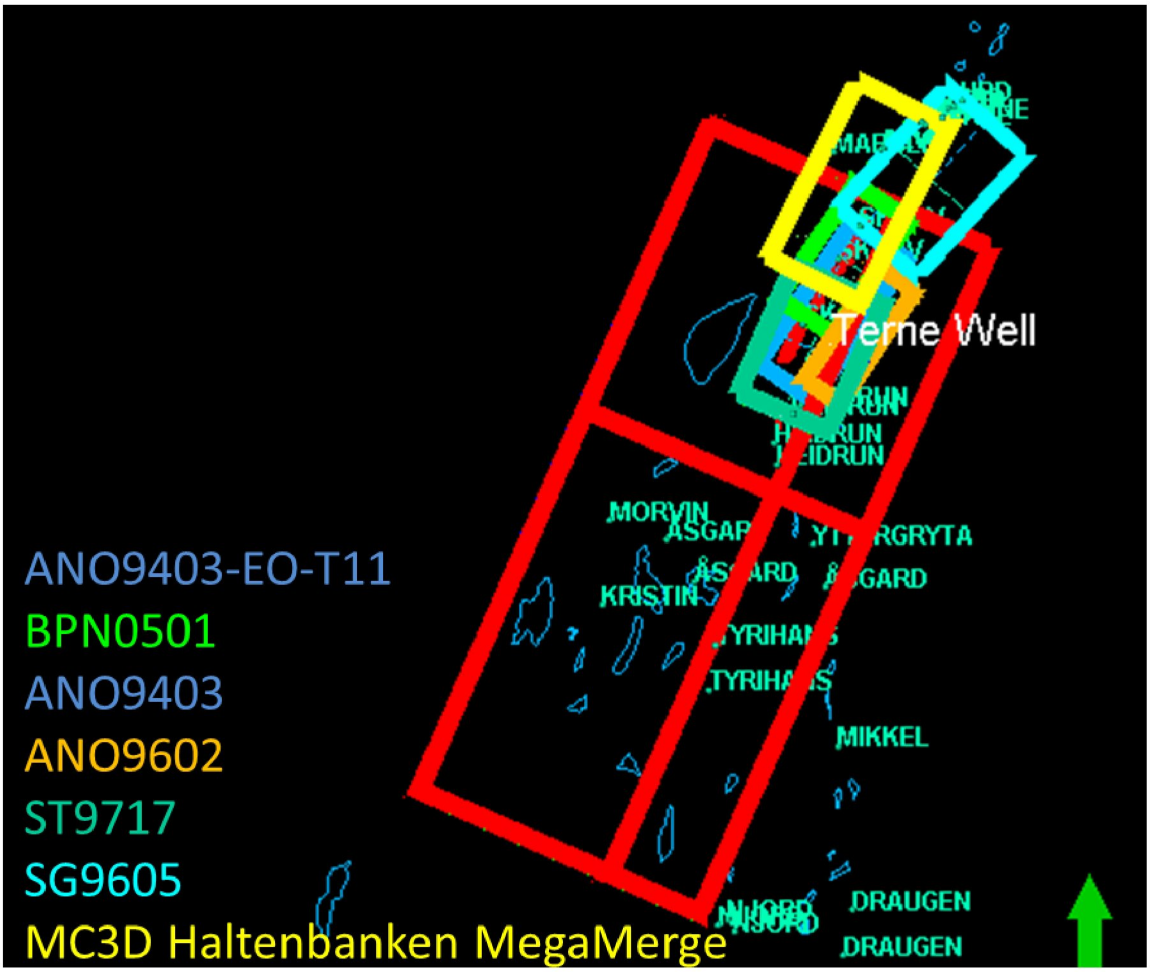


Fig. 2.1 Seismic database map overview

3 Review of Geological and Geophysical Framework

The subsurface evaluation of the PL558 license was primarily focused on the Middle to Lower Jurassic Fangst Group and Båt Group. There were primarily two rotated fault blocks that were studied. The larger of the two was the Terne prospect (See Fig. 3.1 and Fig. 3.2) which was also the main target for the 6507/5-7 well. The other one was called Lead A (See Fig. 3.3 and Fig. 3.4).

Secondary prospectivity was also evaluated in the Tertiary and Triassic. This comprises mainly of the Tunfisk lead and the Skrei channels in the Tertiary (See Fig. 3.5 and Fig. 3.6) and Lead North (Fig. 3.7), Lead Central (Fig. 3.8) and Lead South (Fig. 3.9) in the Triassic (See Fig. 3.10). See Fig. 3.11 for an overview of the prospect and leads evaluated in PL558.

Depth conversion for the leads were done by calibrating seismic velocities from the ANO9403-EO-T11 3D. Velocity model consisted of calibrated seismic velocities from Seabed to BCU, V0 (kriged surface) and k (constant) for Jurassic layers and calibrated seismic velocities below Triassic anhydrite. Well misties at the BCU are in the order +/- 30m. V0 were kriged using the BCU as external trend due to the large variation in depth at the Skarv wells and up on the ridge. See Fig. 3.12 and Fig. 3.13 for a quick summary of the velocity modelling.

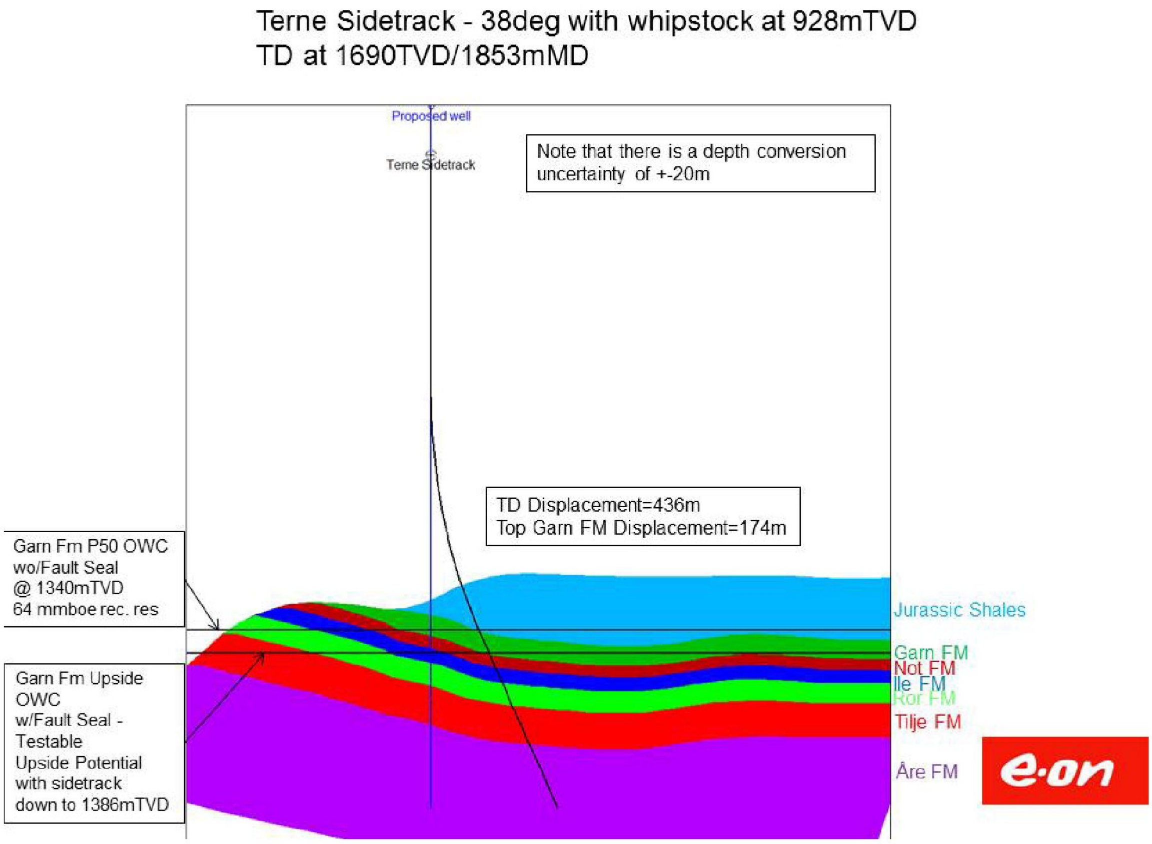


Fig. 3.1 Terne geosection

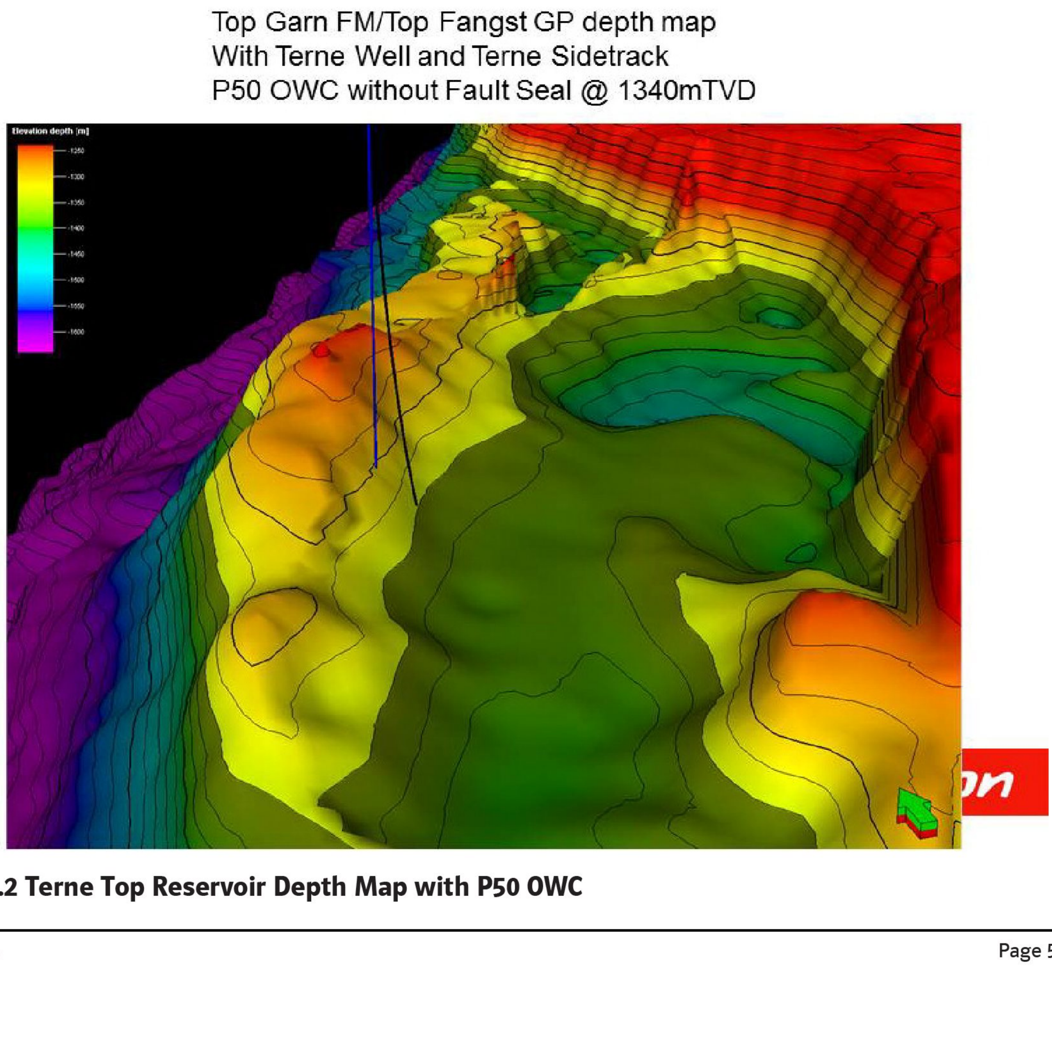


Fig. 3.2 Terne Top Reservoir Depth Map with P50 OWC

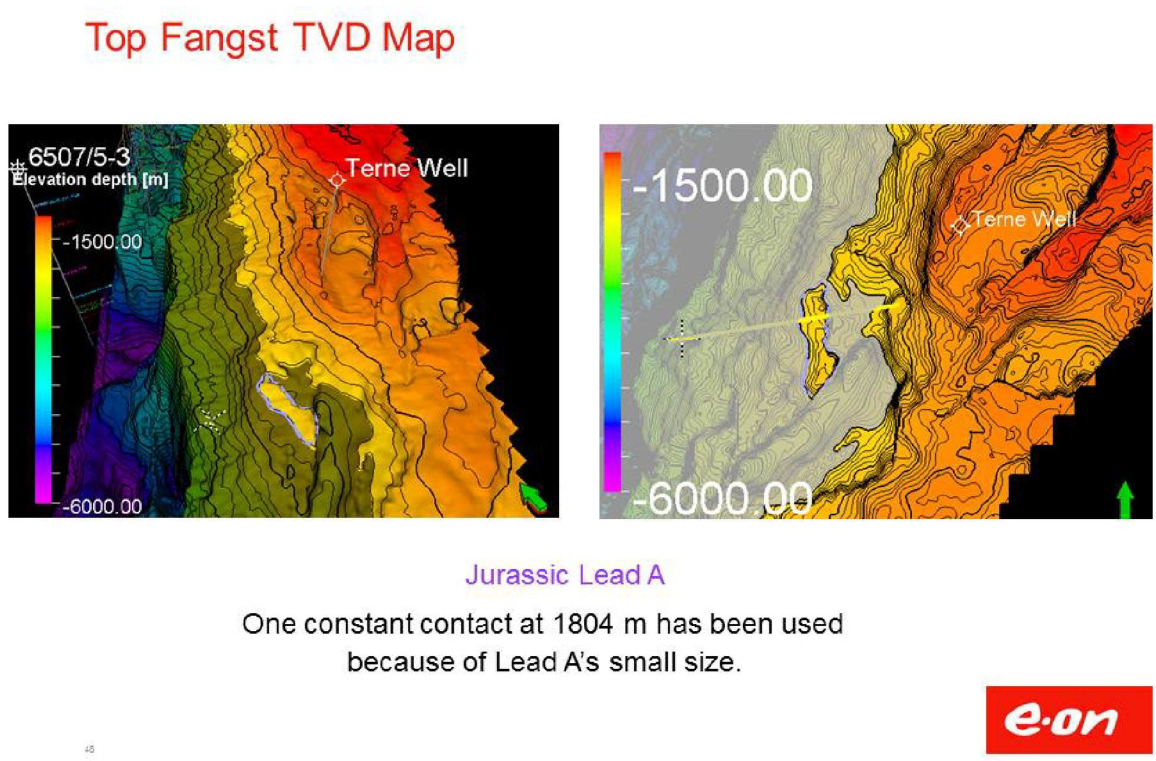


Fig. 3.3 Lead A Top Reservoir Map with OWC

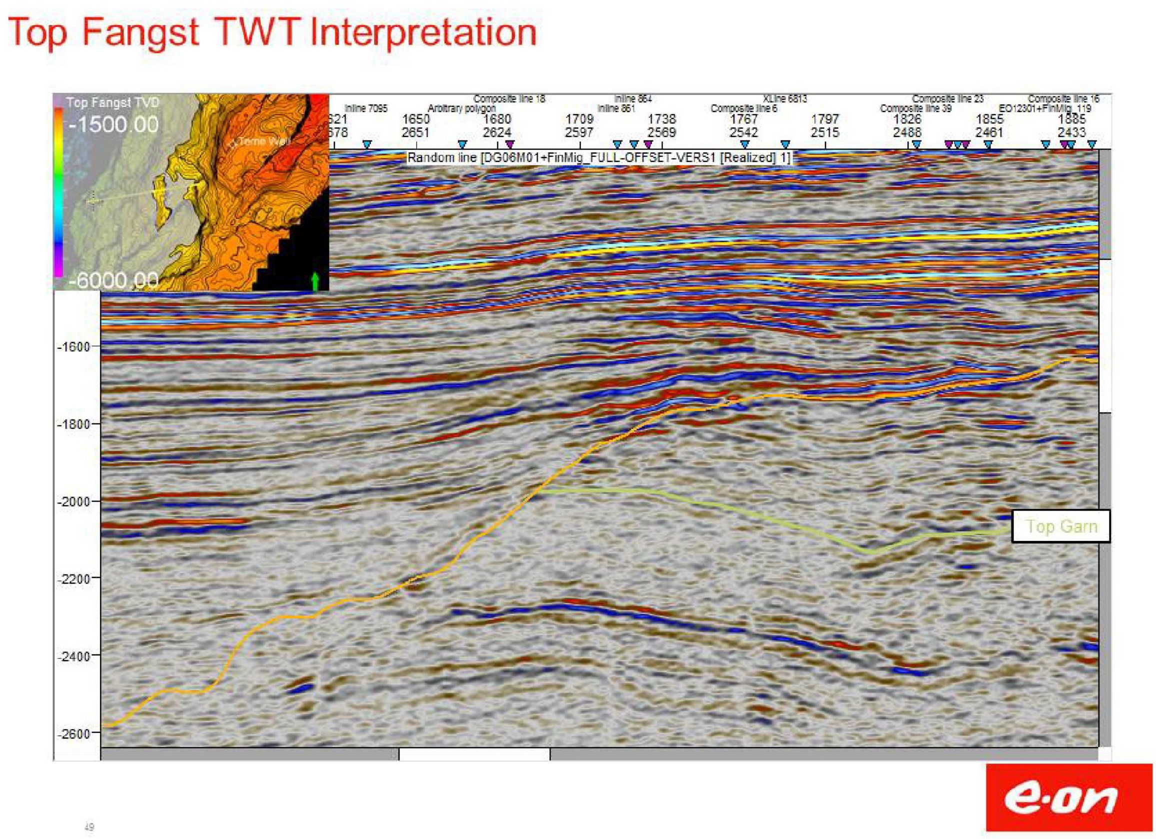


Fig. 3.4 Lead A - Seismic section

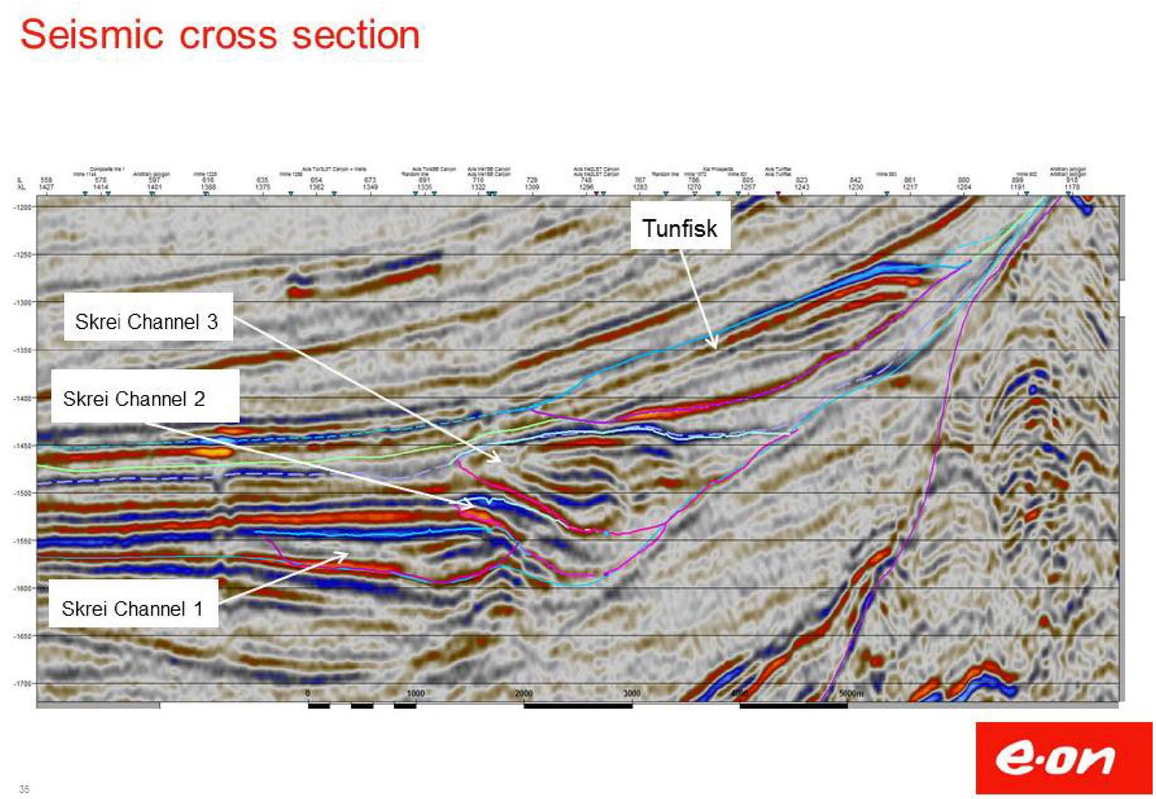


Fig. 3.5 Seismic line showing the Tertiary leads

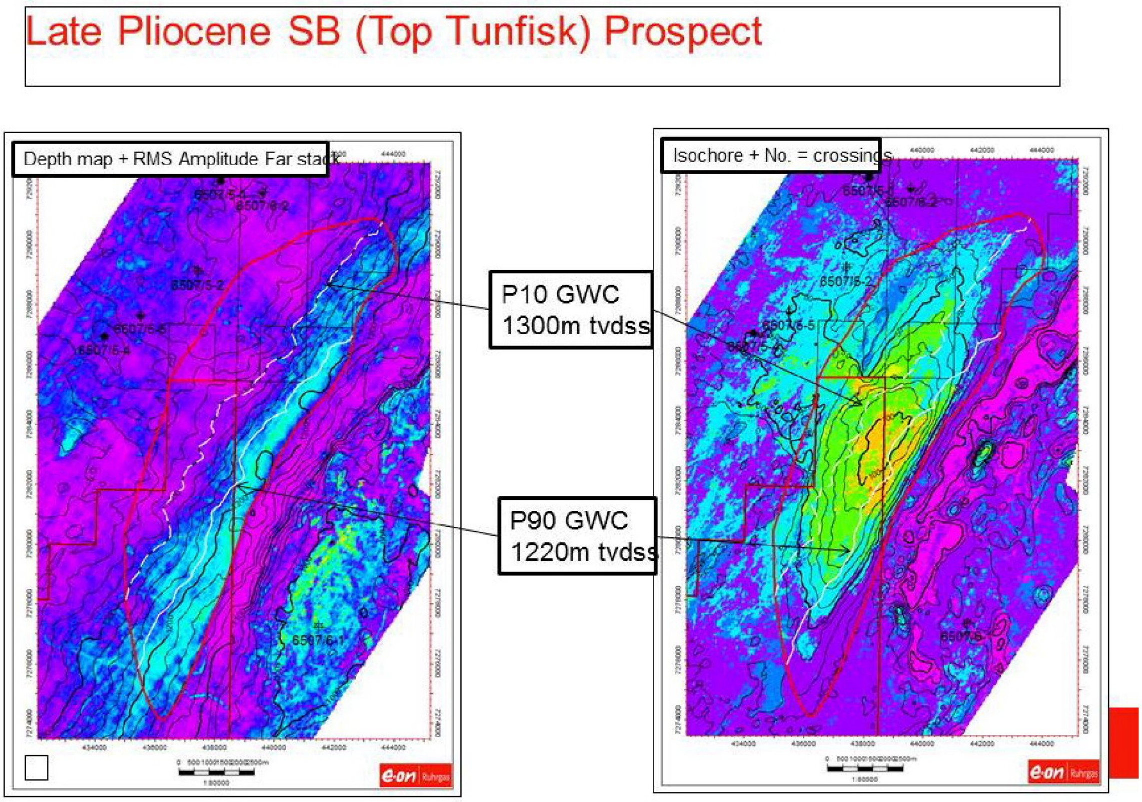


Fig. 3.6 Top Tunfisk Amplitude map (Far Stack)

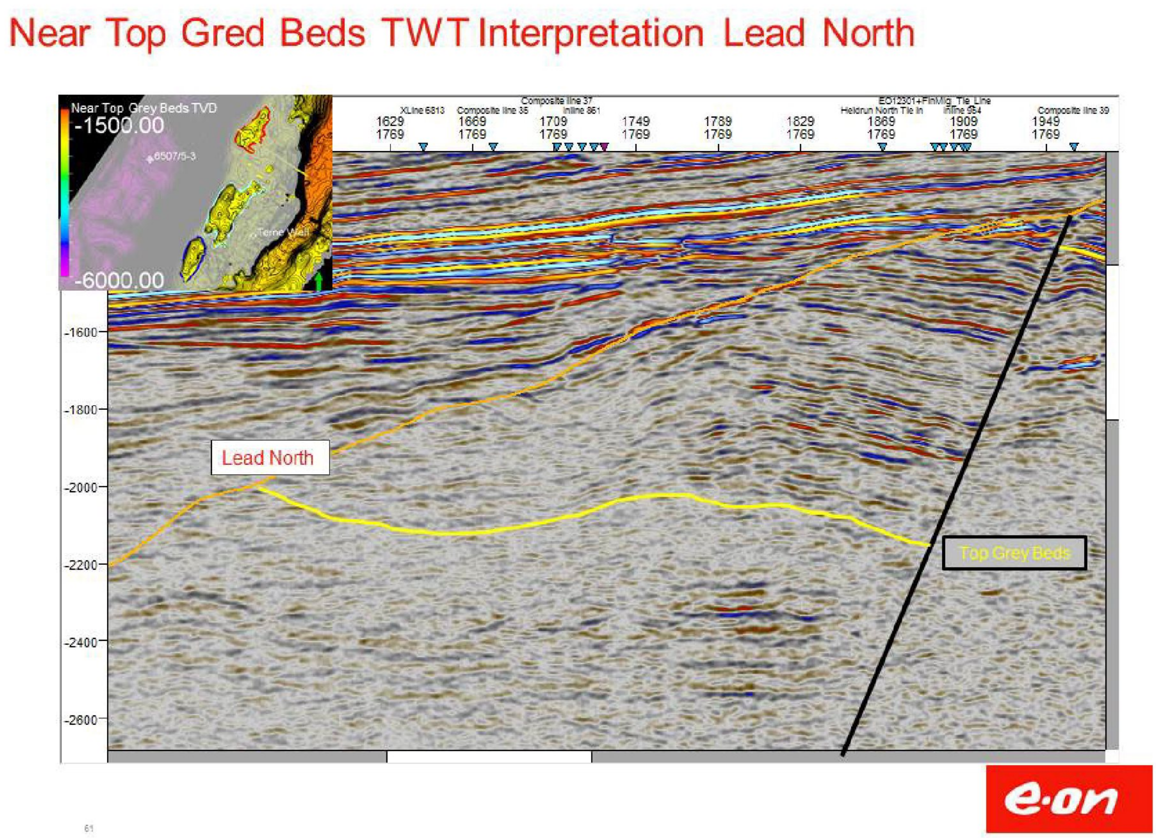


Fig. 3.7 Lead North - Seismic Section

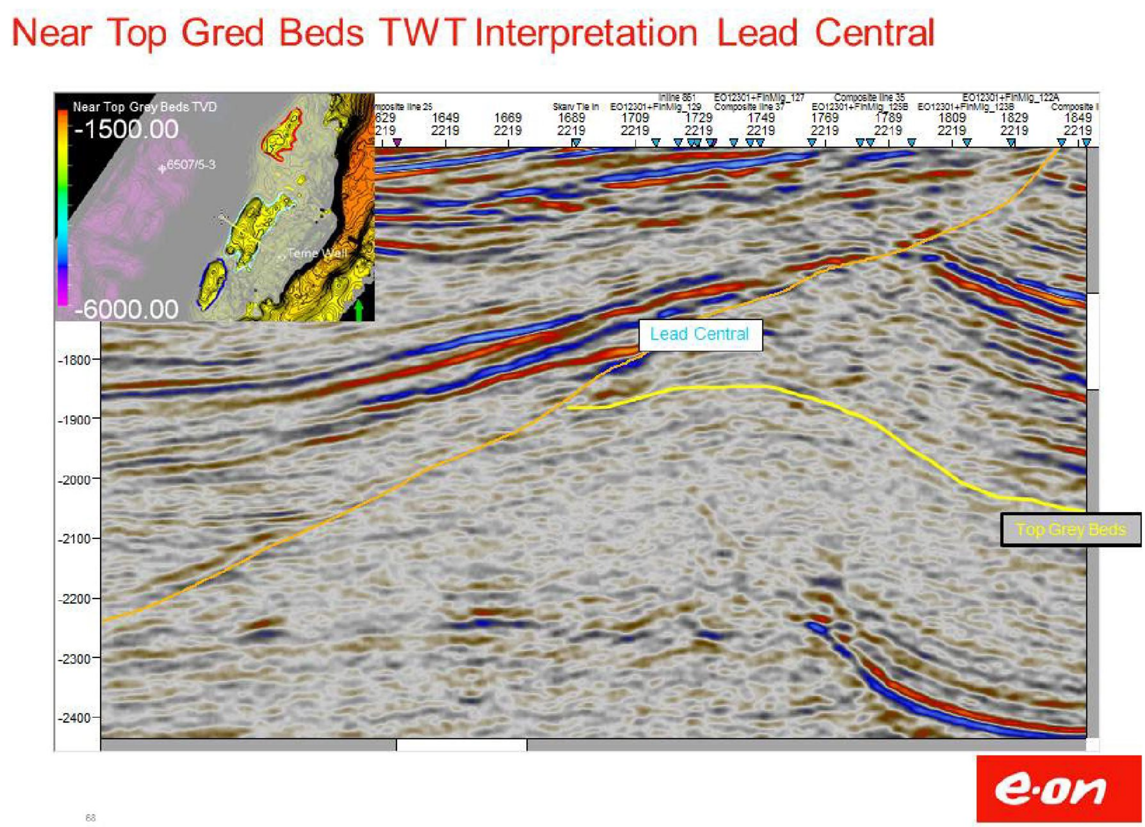


Fig. 3.8 Lead Central - Seismic Section

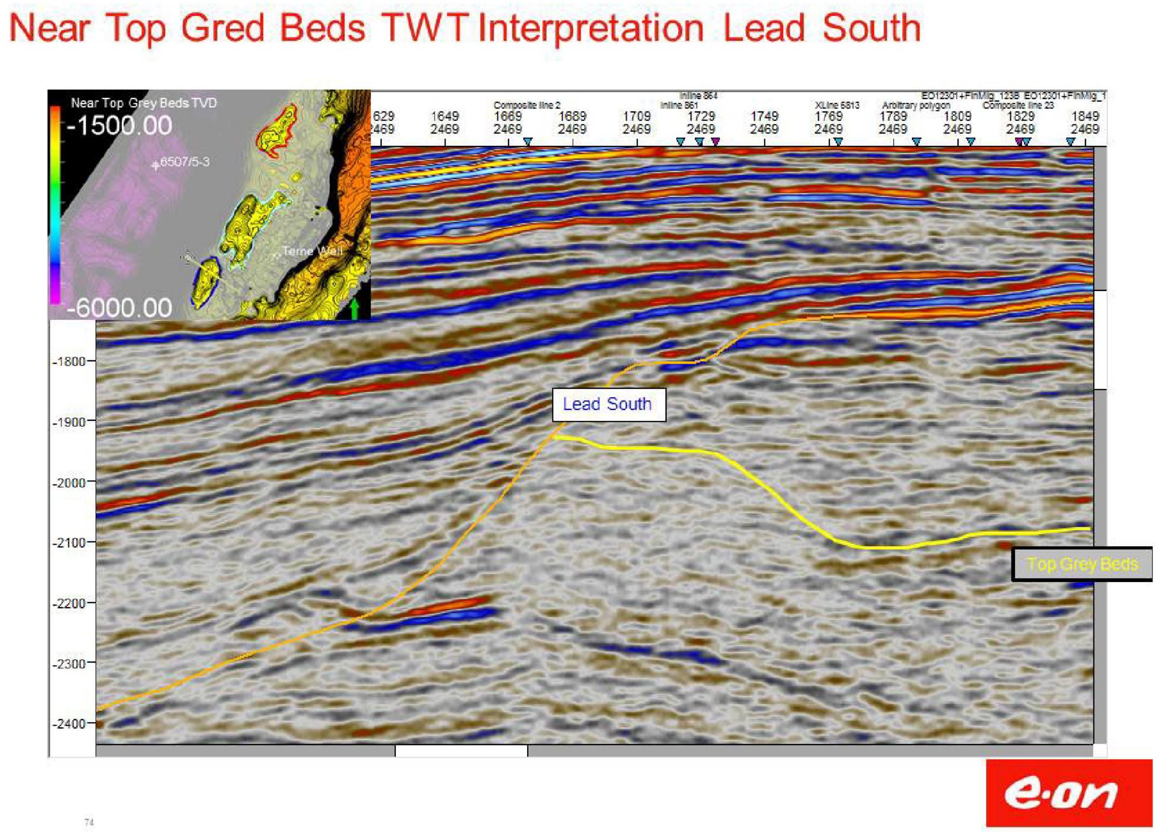


Fig. 3.9 Lead South - Seismic section

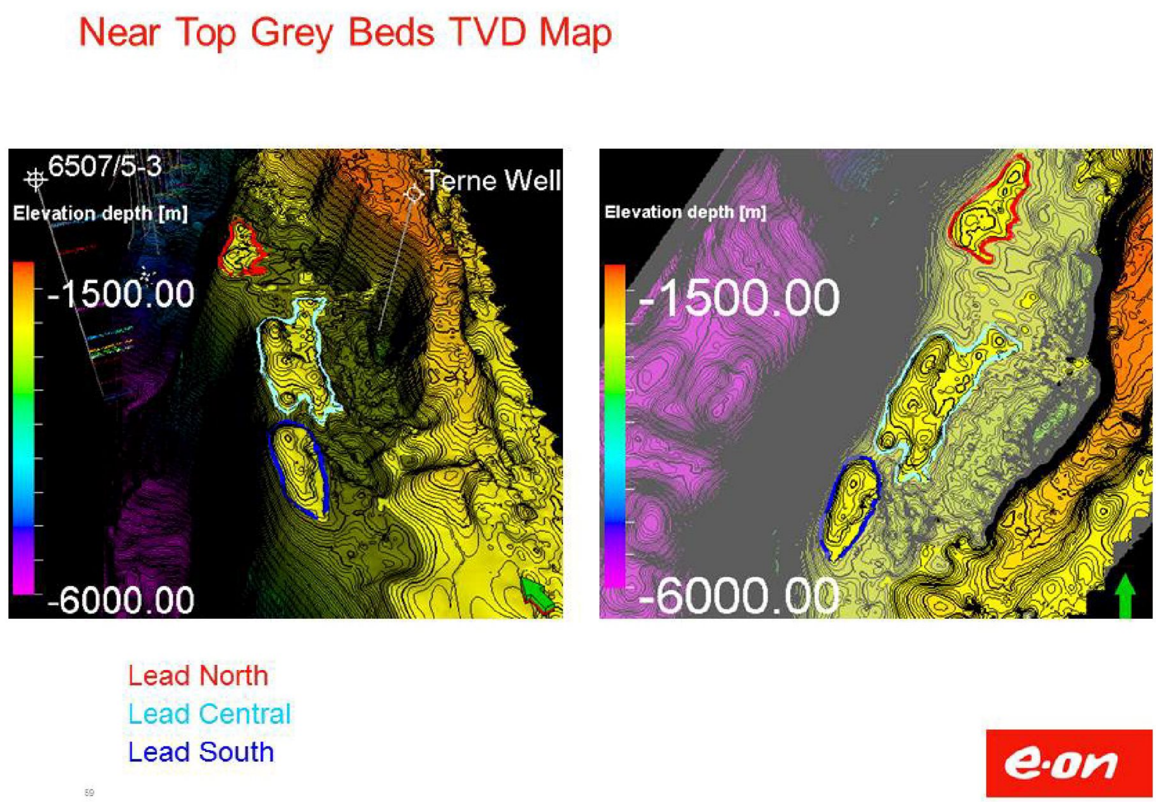


Fig. 3.10 Near Top Grey Beds Depth Map Showing Triassic Grey Beds Leads

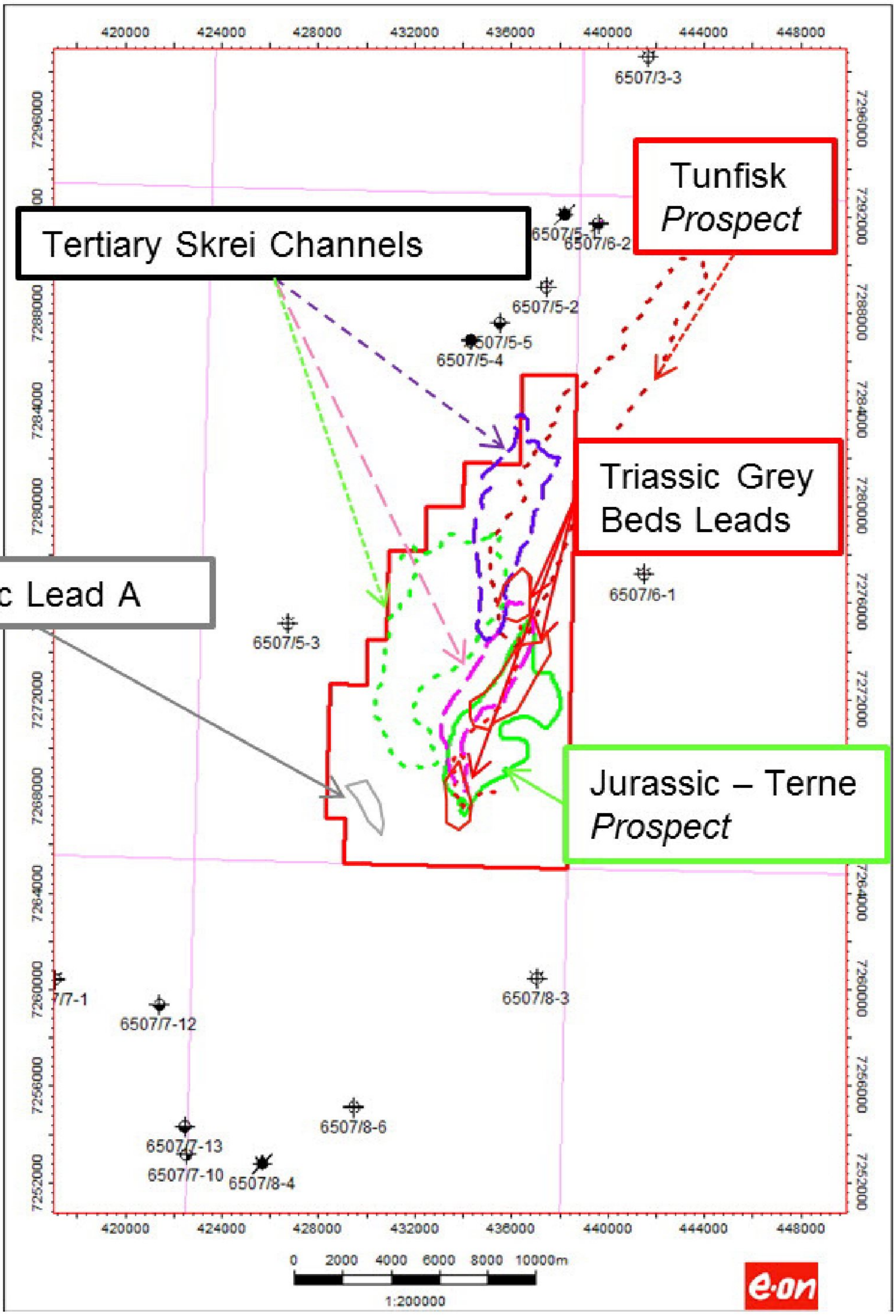


Fig. 3.11 PL558 prospect and leads overview

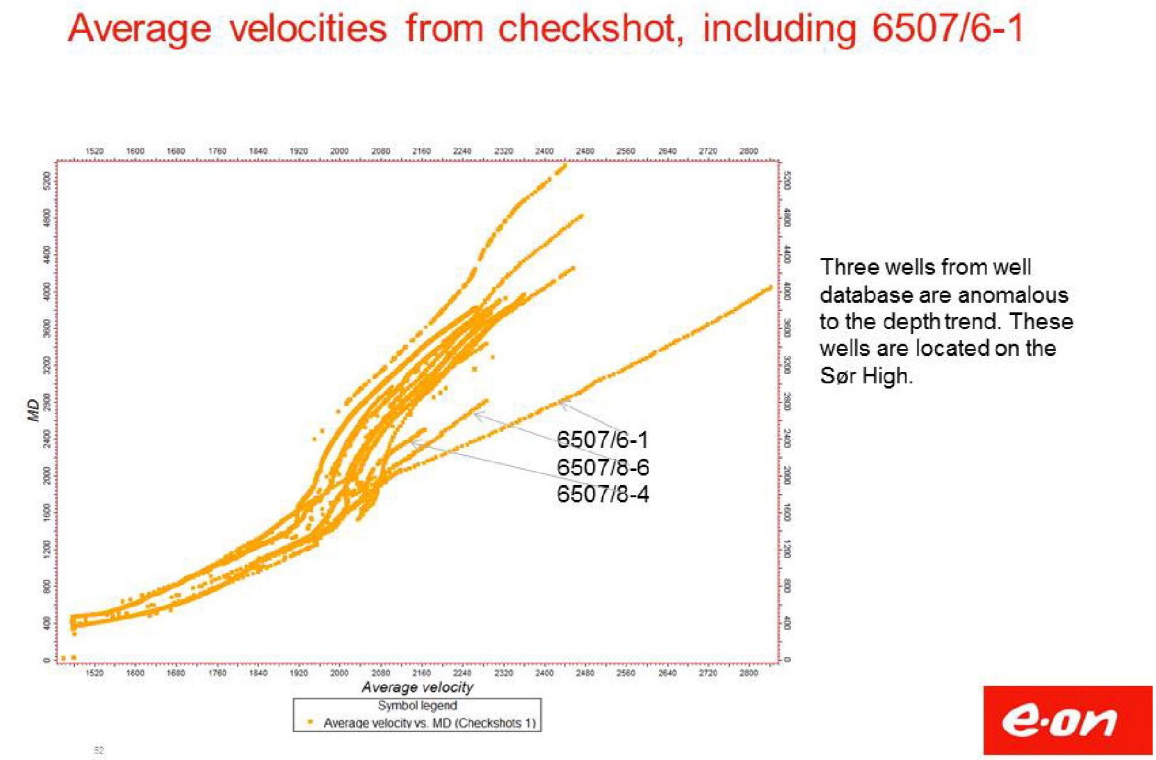


Fig. 3.12 Avergae velocities from checkshots from applicable wells

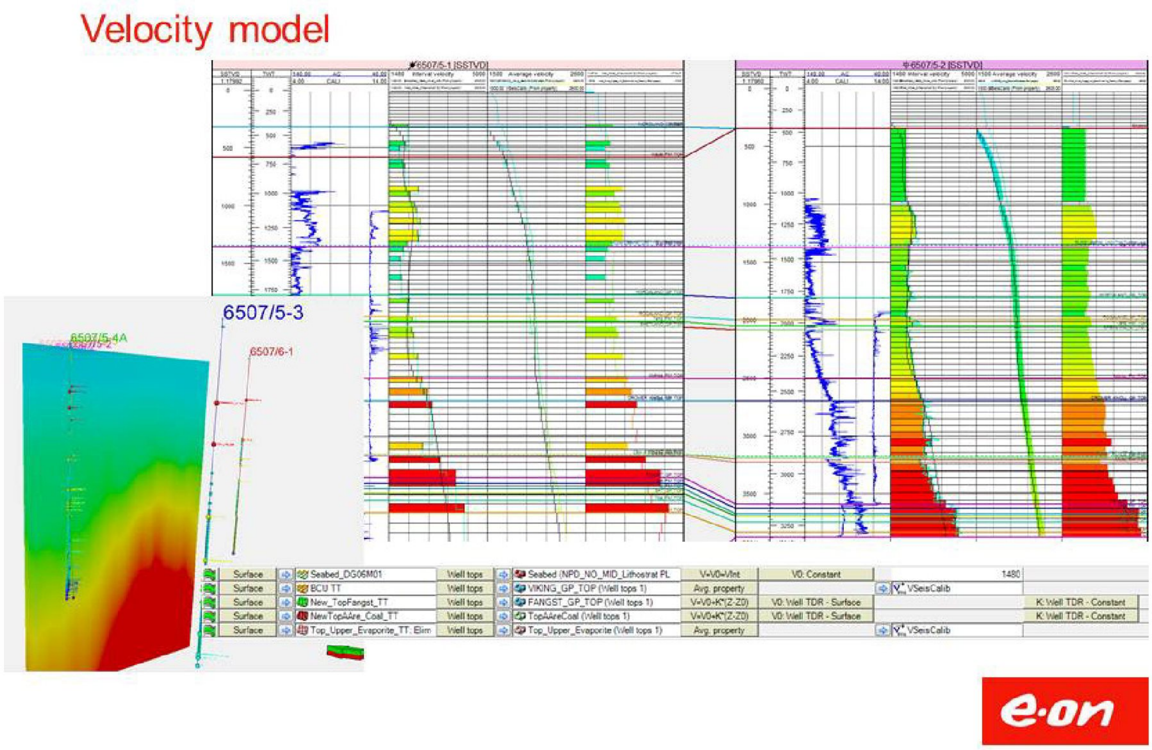


Fig. 3.13 Velocity model input

3.1 Reservoir

The Middle to Early Jurassic sandstones of the Fangst and Båt Groups were evaluated as the main reservoir levels in the Terne prospect. The Fangst Group's Garn Formation and Ile Formation reservoir properties were: Porosity: 0,32 and 0,32; and N/G: 0,9 and 0,4 respectively and the Båt Group's Tilje Formation: Porosity: 0,32; and N/G: 0,4 respectively.

3.2 Trap

The Terne prospect is well defined on seismic. The top reservoir, Garn Formation was assumed to be present based on seismic character, tectonic reconstruction of the nearby faults, and sediment thickness above what was interpreted as the Åre Coal. The reservoir formation thicknesses were estimated by looking at nearby wells. Hence the top reservoir, Garn Formation, was mapped out, and then isopachs were used to estimate the thickness of the Ile Formation and Tilje Formation. Tieing in offset wells was challenging because the prospect is located in the Revfallet Fault Complex. The offset wells used were on the Nordland Ridge and on the Dønna Terrace. Subsequently, there are no wells that can be tied in to the prospect without interpreting through fault zones (See Fig. 3.14).

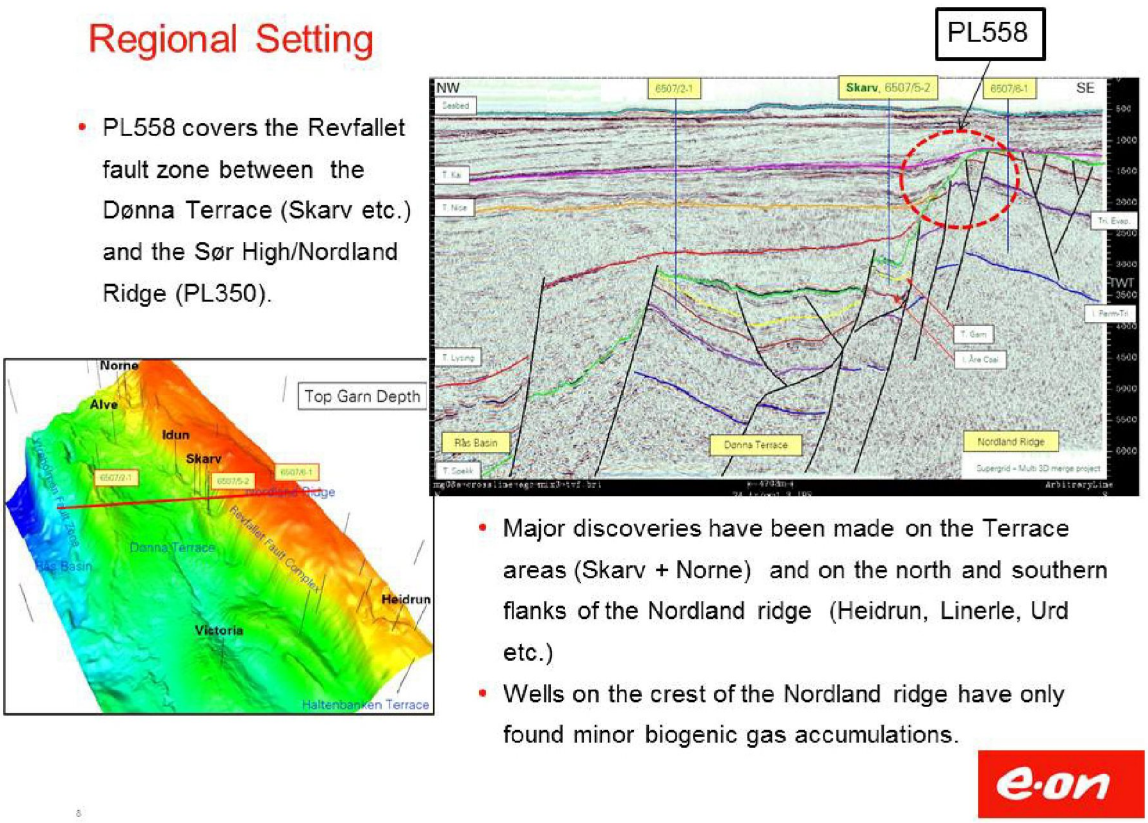


Fig. 3.14 Regional seismic line showing the Rås Basin to the West and the Nordland Ridge to the East

The apex top seal was interpreted to be the Intra Kai Formation. This posed a risk as the young top seal required HC migration within the last 3 million years. Sandy channels are also fairly common in the Kai Formation. Potential thief sands above the Terne prospect was therefore a retention risk. The well found a Kai Formation silty-sandy sequence overlaying the Terne prospect but with no shows. The top seal on the East side of the prospect is interpreted to be Melke shales and is therefore considered to be sealing (See Fig. 3.15).

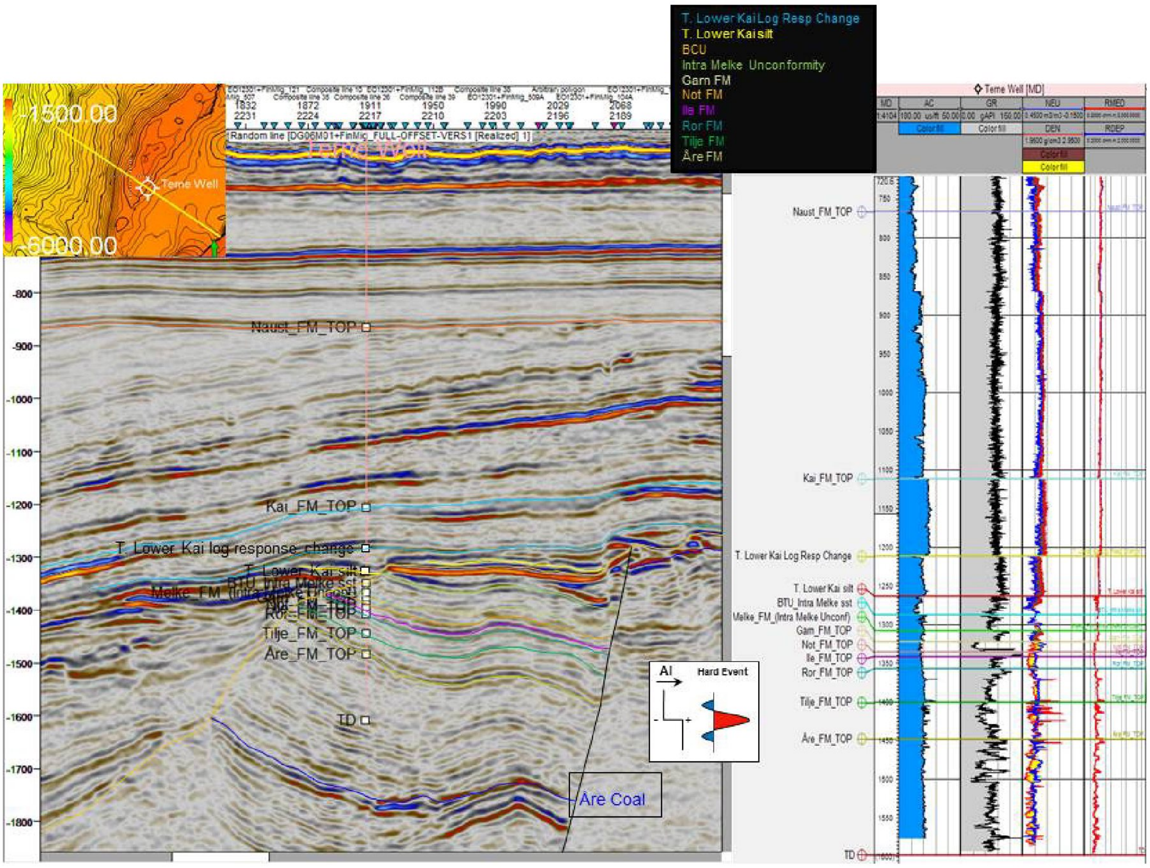


Fig. 3.15 Seismic line across the Terne prospect

3.3 Source and Migration

The Terne prospect was modelled to have been charged via spill from the Heidrun field to the South. This migration route is fairly complicated compared to the direct migration route from Skarv field to the West. An AVO study including a fluid substitution study was done and concluded that the lack of clear AVO response observed in the Terne prospect could be consistent with a fill of heavy oil similar to that found at in Heidrun (<29 API). A lighter oil, more similar to that found in Skarv, should be expected to result in a clear AVO response in a reservoir at Terne prospect depth (See Fig. 3.16).

The failure of the modelled migration route from Heidrun field is believed to be the key cause of the failure for Terne prospect.

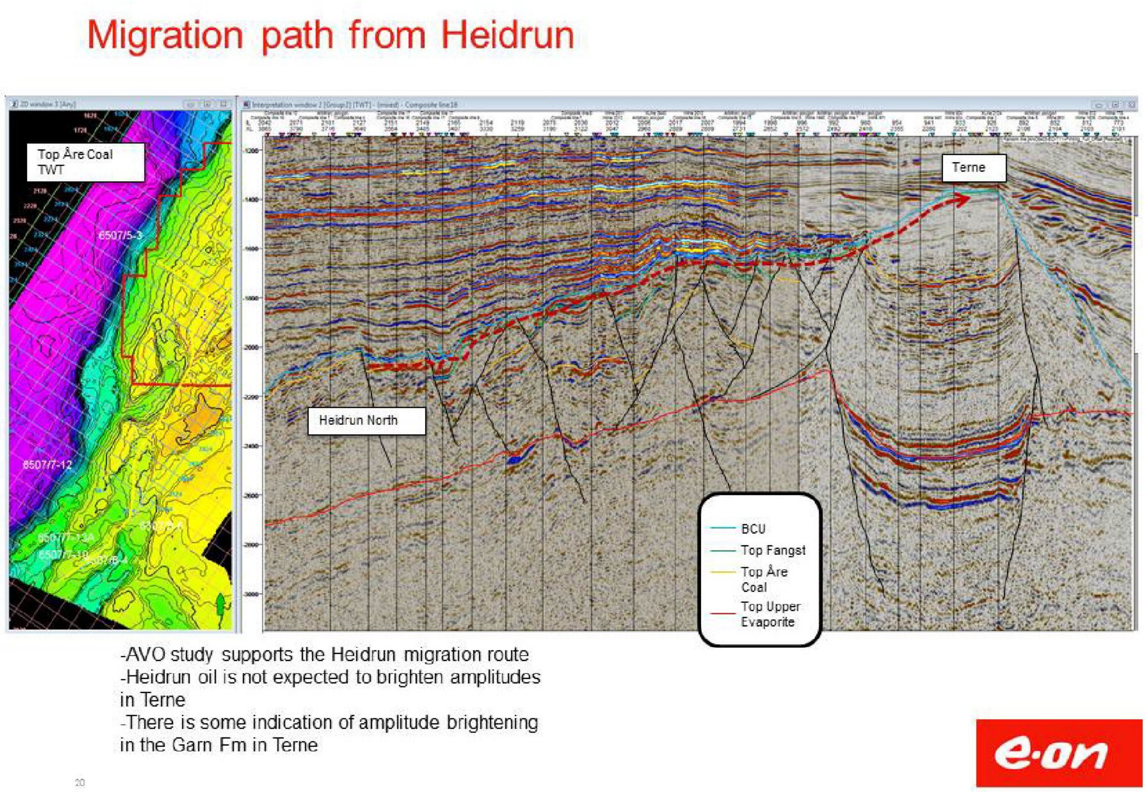


Fig. 3.16 Terne migration route from Heidrun

4 Prospect Update

Results of post-well block evaluation

Terne - Main prospect

The top reservoir, Garn Formation, came in 23m shallower than expected. The interpretation was not re-interpreted as the difference from prognosis is within one seismic cycle. Instead the map was adjusted 23m to conform with the well top. The underlying formations: Not, Ile, Ror, Tilje, and Åre came in shallower than prognosed and have been updated (See Fig. 4.1 and Fig. 4.2).

The reservoir parameters came in close to prognosis (see oil case table below):

6507/5-7 Terne	APA 2009 Porosity*	Pre-drill Porosity	Post-drill Porosity	APA 2009 N/G*	Pre-drill N/G	Post-drill N/G
Garn Formation	0,25	0,32	0,32	0,76	0,9	1
Ile Formation	0,25	0,32	0,37	0,76	0,4	1
Tilje Formation	0,25	0,32	0,34	0,76	0,4	0,72

**Values are averages for all reservoir sections.*

The overall chance of geological success was 31% with P50 at 12,4 mmSm³ OE Recoverable Reserves.

Tunfisk and Skrei - Additional Tertiary leads

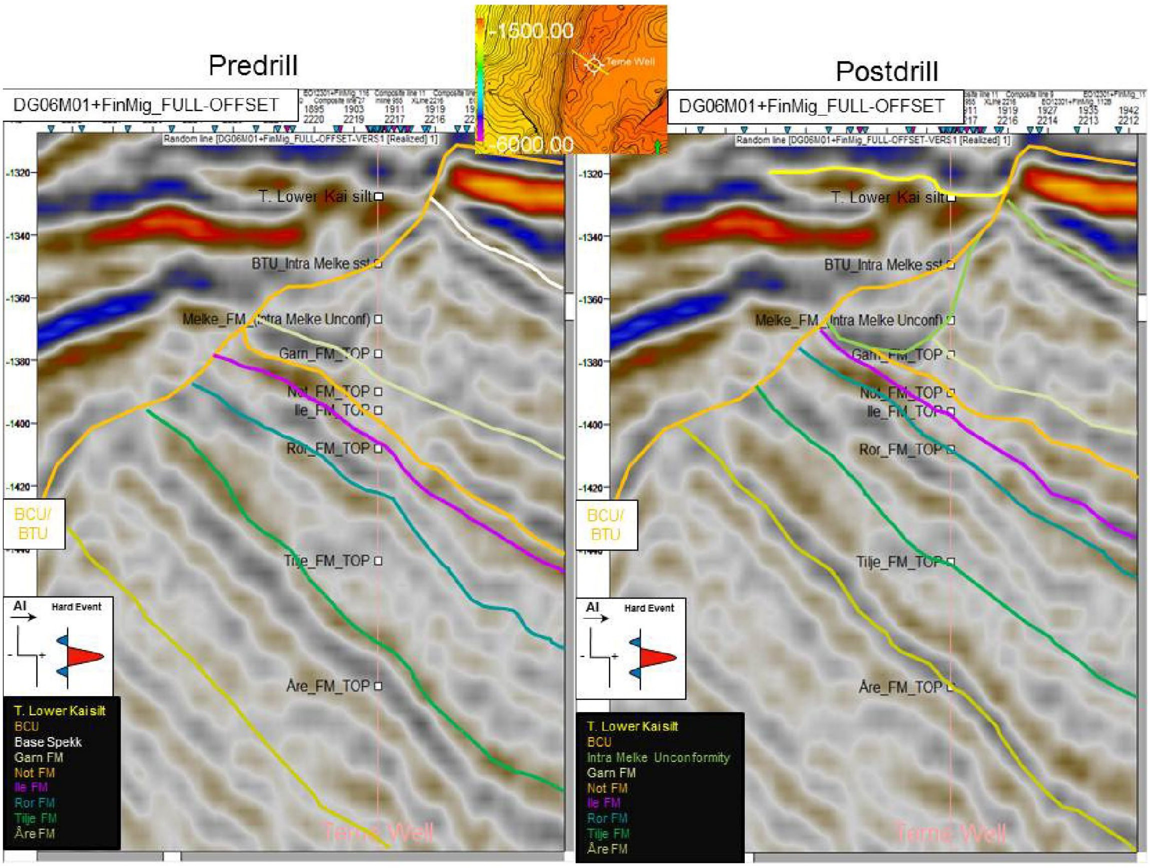


Fig. 4.1 Pre-, and Post drill interpretation

6507/5-7 Terne Top Prognosis v Actual 27-Oct-14															
Age	Group	Formation	Layer	Prognosis				Actual			Difference		Hole Depth	Casing & Casing shoe depth	Pick Criteria
				Depth	Depth	Depth	Uncert +/-	Depth	Depth	Depth	TVDSS	MD			
				m MDbrt	m TVD	m TVDss	m	m MDbrt	m TVD	m TVDss	m	m			
RT				0	0			0	0						
MSL				31	31	0	5	31	31	0,0	0	0			
Quaternary	Nordland	Unit 1 / Seabed		435	435	404	5	435	435	404	0	0	36in to 508	30in @ 502	
		Unit 2		480	480	449	5	480	480	449	0	0	36in to 508	30in @ 502	Res
		Unit 3		606	606	575	10	610	610	579	4	4	17 1/2in & 9-7/8in to 720	13-3/8in @ 716	Res
		Unit 4		667	667	636	10	668	668	637	1	1	17 1/2in & 9-7/8in to 720	13-3/8in @ 716	Res
Tertiary		Naust		744	744	713	10	766	766	735	22	22	12 1/4in to 1296	9 5/8 liner @ 1295	Seismic
		Kai		1113	1113	1082	20	1111	1111	1080	-2	-2	12 1/4in to 1296	9 5/8 liner @ 1295	LWD Data
Jurassic	Viking	Melke	Intra Melke Sst	Not prognosed	Not prognosed	Not prognosed	N/A	1287	1287	1256	N/A	N/A	12 1/4in to 1296	9 5/8 liner @ 1295	LWD data
				1314	1314	1283	20	1307	1307	1276	-7	-7	8 1/2in to TD @ 1598	Open hole	LWD data
	Fangst	Garn		1345	1345	1314	20	1322	1322	1291	-23	-23	8 1/2in to TD @ 1598	Open hole	LWD data
		Not		1388	1388	1357	20	1335	1335	1304	-53	-53	8 1/2in to TD @ 1598	Open hole	LWD data
		Ile		1413	1413	1382	30	1341	1341	1310	-72	-72	8 1/2in to TD @ 1598	Open hole	LWD data
	Båt	Ror		1444	1444	1413	30	1356	1356	1325	-88	-88	8 1/2in to TD @ 1598	Open hole	LWD data
		Tilje		1489	1489	1458	30	1400	1400	1369	-89	-89	8 1/2in to TD @ 1598	Open hole	LWD data
		Åre		1569	1569	1538	30	1447	1447	1416	-122	-122	8 1/2in to TD @ 1598	Open hole	LWD data
		TD		1619	1619	1588	30	1598	1598	1567	-21	-21	8 1/2in to TD @ 1598	Open hole	LWD data

* All prognosed tops have been shifted 3m deeper to tally with revised water depth of 404m. Some planning documents used 401m water depth.

Fig. 4.2 6507/5-7 - Terne Top Prognosis versus Actual

The main additional prospectivity in the license was the Tertiary Tunfisk and Skrei leads.

Tunfisk is interpreted as a Tertiary slope apron attached to Sør High where significant erosion of Jurassic sediments occurred in the Cretaceous and early Tertiary. It is up-dip from silty shales with abundant gas readings (See Fig. 4.3). Sealed by the Kai Formation shale, which is the same as for the biogenic gas column in 6-1 well, and by a lateral pinchout of the reservoir. Tunfisk has a structurally conformable brightening of amplitudes in the thickest part of package, but with a less clear picture on the flanks. AVO response is inconclusive but geophysics suggest that the lithology is different from the downdip wells, but without indicating a massive sand. The polarity of the top reflector is favourable for a hydrocarbon response. Tunfisk was risked with two different scenarios; one with a "coarse sand" where a best case scenario was utilised, and one with the most expected reservoir properties were used. The reason the two scenarios were made was because the high uncertainty in reservoir properties due to the lack of proven sand within the Kai Formation. As a result there was a need to evaluate the potential upside with a "coarse sand" model where the properties were better than expected than in the base scenario. Both scenarios result in uncommercial volumes of gas.

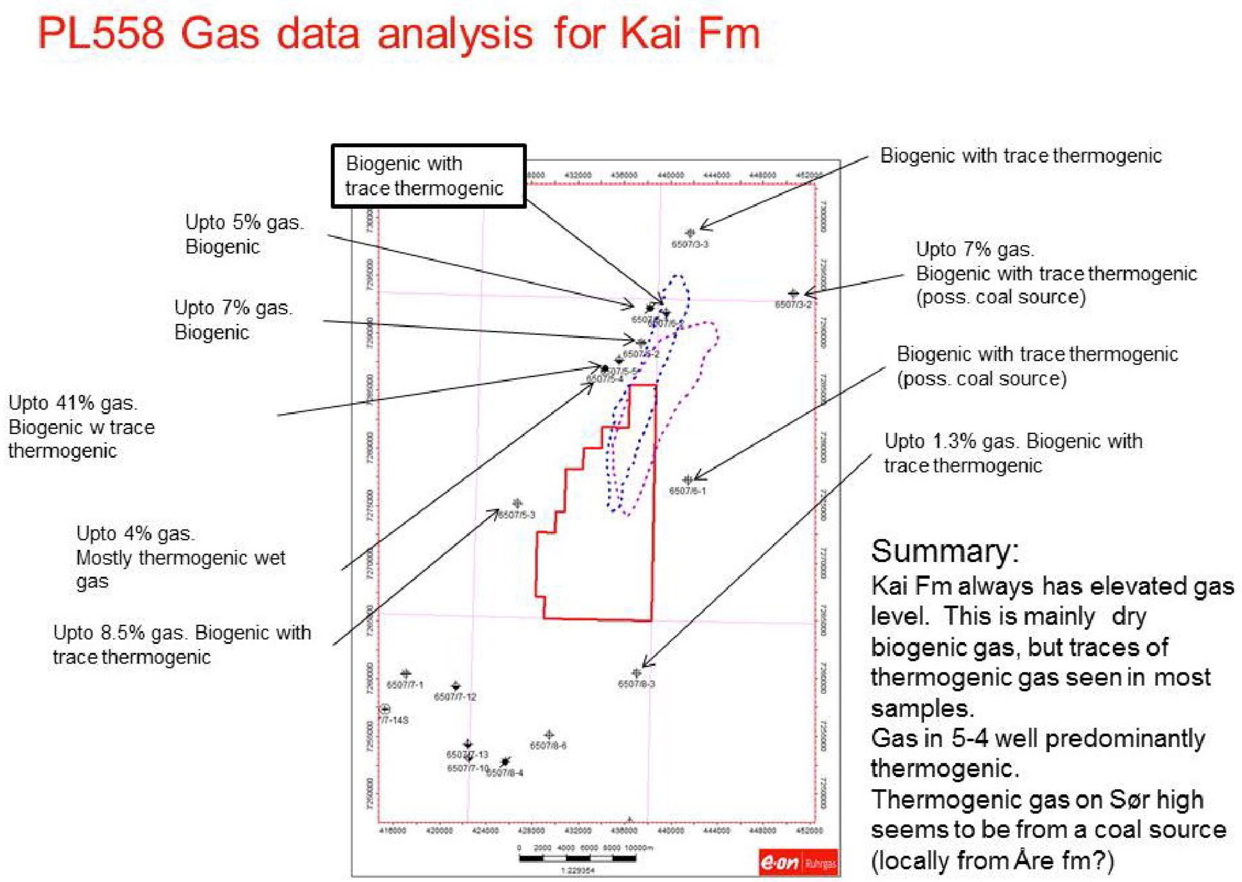


Fig. 4.3 Gas data analysis for the Kai Formation

The Skrei channels have been mapped as separate leads from the Tunfisk lead and lie stratigraphically deeper within the Kai Formation. The Skrei channels are assumed to be Messinian to Tortonian in age and are related to a possible bypass system around the Sør High. The three channels are Skrei Channel 1 and Skrei Channel 2 (Messinian age), and Skrei Channel 3 (Toronian age).

	Reservoir	**Charge**	**Seal**	**Geometry**	**Total GCF**	**Rec. res (mmSm³) OE**
Tunfisk	0,56	0,7	0,8	1	0,31	1,11
Tunfisk Coarse Sand model	0,48	0,7	0,8	1	0,27	2,38
Tunfisk - Post 6507/5-7	0,56	0,7	0,8	1	0,31	0,96
Skrei Channel 1 - Messinian	0,42	0,9	0,6	1	0,23	0,75
Skrei Channel 2 - Messinian	0,42	0,9	0,6	1	0,23	0,95
Skrei Channel 3 - Toronian	0,42	0,9	0,6	1	0,23	2,56

The main reasons for the Tertiary leads being deemed uncommercial is the small volume combined with an estimated low recovery factor, due to the shallow depth with low pressure and low gas expansion factor. In addition, the reservoir is fairly thin and stretched out over a long area and therefore would require several producers for a development, leading to a relatively high development cost in relation to the volume. There is also in the near term a constraint in the available gas export capacity route from the area, which implies any discovered gas would not be produced until existing fields and discoveries (Such as Skarv and Snadd) are in decline.

Lead A - Additional Jurassic lead

Lead A is another rotated Jurassic fault block South of the 6507/5-7 well. It is much smaller than the Terne prospect and this is the main reason the partnership decided to not work this lead any further. It has been split in to three segments (Garn Fm, Ile Fm, and Tilje Fm). It is risked as an oil case with associated gas (no NGL or Dry gas). The seismic in the area is of good quality although the interpretation is challenging and reservoir presence relies on wellties to the 6507/5-7 well. The porosities and the N/G have been taken from the 6507/5-7 but the Bo, GOR and Rf have been adjusted to correspond to Lead A being 400m deeper than the main Jurassic target in 6507/5-7. The source and migration was the main risk in the Terne prospect and is considered the main reason why it was dry. The only way to increase the charge history is if the Northern fault in Lead A is sealing completely; leaving no HC migration in to the Terne prospect. This model is considered to have low confidence as it is expected that there would be at least some shows in the Terne prospect if Lead A was HC filled. The chance of the Garn Formation being filled to spill, allowing the Ile Formation and the Tilje Formation to be filled as well, is considered even less likely than one accumulation in the Garn Formation. Hence the risking for the three formations is similar except for the Charge where the chance of HC presence decreases as the formations are deeper. Subsequently, the following risking was applied to Lead A:

	Reservoir	**Seal**	**Charge**	**Geometry**	**GCF**	**Rec. res (mmSm³) OE**
Garn Fm	1	0,6	0,3	0,8	0,14	
Ile Fm	1	0,6	0,2	0,8	0,10	
Tilje Fm	1	0,6	0,2	0,8	0,10	
Total Lead A					0,17*	1,56

**Charge and Seal depencies applied*

Lead A is too small to be evaluated on its own, but it was considered as an opportunity in a 6507/5-7 success case.

North-, Central-, and South leads - Additional Triassic leads

Three leads have been identified in the Triassic Grey Beds in PL558. They are all oil cases with associated gas (no NGL or Dry gas). These leads have a very low chance of success. This is because the presence of a structure is based on very poor quality seismic data. The Upper Jurassic migration route, that failed, from Heidrun and in to the Terne prospect this considered to be even less likely when it also incorporates a Triassic migration route. Reservoir presence as a play model is also difficult as it has not proven very successful in the area in the past. Additionally, reservoir presence as a segment risk is low as the Triassic reservoirs penetrated in the area have a very wide range of properties. The lowest risk for these leads is the seal as it is overlain by Cretaceous shales to the West and Åre Formation to the East.

	Reservoir	Seal	Charge	Geometry	GCF	Rec. res (mmSm^3) OE
Lead North	0,49	0,6	0,4	0,5	0,06	0,87
Lead Central	0,49	0,6	0,4	0,5	0,06	2,23
Lead South	0,49	0,6	0,4	0,5	0,06	1,33

The partnership has agreed to relinquish the license based on the following:

- License obligations and work commitments completed. Ÿ
- Main prospect proven to be dry (Terne).
- Remaining Tertiary prospectivity is not economically attractive (with current gas prices and lack of short term gas export route). Ÿ
- Remaining Jurassic and Triassic leads are not attractive due to small resource volumes and low chance of success.

Changes in resource volumes and probability estimates
Attached is the revised NPD table "Well Prognosis and Results" for the Terne Prospect (oil case).

5 Technical Evaluation

Technical evaluations performed and concluded regarding possible development of remaining prospectivity.

E.ON has performed a full technical and economical evaluation on the Tertiary Tunfisk and Skrei leads. As well as a complete technical evaluation of the Jurassic Lead A and the three Triassic Grey Beds leads; Lead North, Lead Central, and Lead South. It was decided through an E.ON peer process to relinquish the license. This proposal was presented to the partnership in an EC/MC meeting on November 5th 2014. The partners agreed to relinquish the license.

6 Conclusions

Comments on the remaining petroleum potential in the area and reason for relinquishment.

During the license period operated by E.ON E & P Norge, extending from February 19th 2010 to February 19th 2015, the partnership of PL558 has evaluated the prospectivity in the license. The only well in the license, 6507/5-7, targeting the Terne prospect was dry. The best candidate for a second well was the Tunfisk/Skrei leads. However, the potential complexity in developing these were too high relative to the volume potential and they are therefore considered uneconomic. The remaining Lead A in the Jurassic and the three Triassic Grey Beds leads; Lead North, Lead Central, Lead South were all too high risk and too little reward. The remaining prospects would have been more interesting in a 6507/5-7 discovery case. The opportunities for tie-backs to Terne would have lowered the threshold for drilling the other leads.

The license is relinquished primarily because the 6507/5-7 Terne well was dry and hence it provided no tie-back solutions for the other smaller leads in the license.

7 Well prognosis and results

	A	B	D	G	H	I	J	K	L
1	**Only white cells in column I and J should be filled in by the operator.** Notice: There should be **one or more prognosis** per prospect (target) & **one result** per prospect (target). Each well may have one or more prospects (targets). The completed form to be submitted to: **postboks@npd.no** within 6 months after the well completion date.								
2				Example		If there is more than one prognosis per prospect, please duplicate the prognosis column (column " i ")			
3	Section: "Well data"	Comments	Comments	Dummy Prognosis	Dummy Result	Prognosis	Result		
4	Well Name	Always fill in	NPD approved name	**6203/4-5**	**6203/4-5**	**6507/5-7**	**6507/5-7**		
5	Production Licence Number	NPD input	NPD approved name	328					
6		NPD input	NPD approved name	B					
7	Operator			XX		E.ON			
8	Well type: required/committed as a part of the licence award?		Yes/No	YES		NO			
9	Well classification		Wildcat / appraisal	Wildcat		Wildcat			
10	License round	NPD input		12					
11		NPD input		A					
12	Seismic database (2D/3D)		2D/3D	3D		3D			
13	Frontier area?	NPD input	Yes/No	NO					
14	Structural element/Province			MARULK BASIN		Revfallet Fault complex			
15	Spud date	NPD input			10/7/1997				
16	Completion date	NPD input			11/10/1997				
17	Water depth		meter		351		404		
18	Stratigraphic age at TD				Upper Triassic		Lower Jurassic		
19	Paragraph: prospect								
20	Prospect name	Always fill in	Operators name	B	B	Terne	Terne		
21	Prospect ID	NPD input	NPD code	456					
22	Distance to nearest relevant well		km	2,3		9.6			
23	Nearest well Name		NPD approved name	34/2-1		6507/8-3			
24	Prospect Priority if several in well		number 1,2,...	1		1			
25	SubParagraph: prognosis // result								
26	Prognosis ID (if several)		Operators name	Oil Case		Oil Case			
27	Prognosis priority in prospect	(1/2/3...)	number 1,2,...	1		1			
28	Reference(s) to mapping & evaluation		Report name etc.	EC-handout no,20 (PL130), drilling program	Final well report 33/4-1, Discovery report 33/4-1	MC meeting 5 presentations with intention of making a drill decision	6507/5-7 End of Well Report		
29	Evaluation year			1996	1997	2014	2014		
30	Reference(s) to NPD evaluation	NPD input		Geologisk evaluering av utlyste blokkker	Sluttrapport Brønn A				
31	NPD evaluation year	NPD input		1995	1997				
32		Date (DD.MM.YY)		10/1/1996	10/1/1997	4/20/2012	11/28/2014		
33	Data compilation	Department, Institution		Exploration dept.	Exploration dept.	G&G department	G&G department		
34		Name		Ole Olsen	Ole Olsen	[redacted]			
35		Date (DD.MM.YY)		10/6/1996	10/6/1998	4/27/2012	11/28/2014		
36	Data Quality control	Department, Institution		Exploration dept.	Exploration dept.	G&G department	G&G department		
37		Name		Kari Normann	Kari Normann	[redacted]			

	A	B	D	G	H	I	J	K	L
38	Comments	Variation from standard methodology		No variation from standard methodology	No variation from standard methodology	No variation from standard methodology	No variation from standard methodology		
39	*Geo*								
40	Trap type		Defined numeric code	2.2 Subcrop traps	2.2 Subcrop traps	2.2 Truncated tilted fault block	2.2 Truncated tilted fault block		
41	Reservoir stratigraphic level(s)	Chronostratigraphic		LOWER JURASSIC	LOWER JURASSIC	UPPER, MIDDLE, LOWER JURASSIC	UPPER, MIDDLE, LOWER JURASSIC		
42	Reservoir stratigraphic level(s)	Lithostratigraphic		STATFJORD FM	STATFJORD FM	GARN FM, ILE FM, TILJE FM	GARN FM, ILE FM, TILJE FM		
43	NPD play	NPD input		NRU,JM-1	NRU,JM-1				
44	New play	NPD input		NO	NO				
45	Inferred source rock 1	Chronostratigraphic		UPPER JURASSIC	UPPER JURASSIC	UPPER JURASSIC	UPPER JURASSIC		
46	Inferred source rock 1	Lithostratigraphic		DRAUPNE FM	DRAUPNE FM	SPEKK FM	SPEKK FM		
47	Inferred source rock 2	Chronostratigraphic		LOWER JURASSIC	LOWER JURASSIC	UPPER JURASSIC	UPPER JURASSIC		
48	Inferred source rock 2	Lithostratigraphic		DUNLIN GR	DUNLIN GR	MELKE FM	MELKE FM		
49	Seal	Chronostratigraphic		LOWER CRETACEOUS	LOWER CRETACEOUS	MIOCENE	MIOCENE		
50	Seal	Lithostratigraphic		CROMER KNOLL GR	CROMER KNOLL GR	KAI FM	KAI FM		
51	*Probability*								
52	Probability of discovery, technical	Total		0.36		0.30			
53	Probability of discovery, technical	Charge	Fraction	0.50		0.43			
54	Probability of discovery, technical	Trap		0.80		0.60			
55	Probability of discovery, technical	Reservoir		0.90		1.00			
56	Comments	Comments relevant to risking (DHI, AVO analysis, etc.)		No DHI indicator observed		Primary risks were a complicated migration route from Heidrun (the AVO study indicated viscous/heavy oil from Heidrun, as opposed to lighter oil from the Skarv area); and top seal because of the potential presence of sandy thief channels in the Kai FM.			
57	*Resources*								
58	Main hydrocarbon phase		OIL, OIL/GAS, GAS	OIL	OIL/GAS	OIL	WATER WET		
59	Fractiles, resource parameter ranges	Low/Minimum	Fraction	0.80	0.80	0.9	0.9		
60	Fractiles, resource parameter ranges	Preferably Mean (or Most likely or Median)	Mean/ML/Med	Mean	Mean	Mean	Mean		
61	Fractiles, resource parameter ranges	High/Maximum	Fraction	0.20	0.20	0.1	0.1		
62	Gas in place (as main phase)	Low/Minimum			1.20	N/A	N/A		
63	Gas in place (as main phase)	Central/Most likely	10^9Sm3		2.00	N/A	N/A		

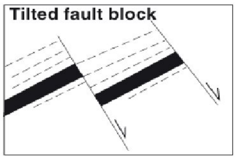
	A	B	D	G	H	I	J	K	L
64	Gas in place (as main phase)	High/Maximum			2.85	N/A	N/A		
65	Oil as associated phase in place	Low/Minimum				N/A	N/A		
66	Oil as associated phase in place	Central/Most likely	10^6Sm3		0.01	N/A	N/A		
67	Oil as associated phase in place	High/Maximum				N/A	N/A		
68	Oil in place (as main phase)	Low/Minimum		5.90	2.20	6.59	0.00		
69	Oil in place (as main phase)	Central/Most likely	10^6Sm3	8.80	3.45	35.70	0.00		
70	Oil in place (as main phase)	High/Maximum		12.50	5.70	63.70	0.00		
71	Gas as associated phase in place	Low/Minimum		2.00	0.35	0.33	0.00		
72	Gas as associated phase in place	Central/Most likely	10^9Sm3	3.00	0.70	1.78	0.00		
73	Gas as associated phase in place	High/Maximum		4.10	1.25	3.26	0.00		
74	Gas recoverable (as main phase)	Low/Minimum				N/A	N/A		
75	Gas recoverable (as main phase)	Central/Most likely	10^9Sm^3		1.10	N/A	N/A		
76	Gas recoverable (as main phase)	High/Maximum				N/A	N/A		
77	Oil as associated phase recoverable	Low/Minimum				N/A	N/A		
78	Oil as associated phase recoverable	Central/Most likely	10^6Sm3		0.00	N/A	N/A		
79	Oil as associated phase recoverable	High/Maximum				N/A	N/A		
80	Oil recoverable (as main phase)	Low/Minimum				2.31	0.00		
81	Oil recoverable (as main phase)	Central/Most likely	10^6Sm3	4.20	1.35	12.50	0.00		
82	Oil recoverable (as main phase)	High/Maximum				22.60	0.00		
83	Gas as associated phase recoverable	Low/Minimum				0.11	0.00		
84	Gas as associated phase recoverable	Central/Most likely	10^9Sm3	1.50	0.30	0.62	0.00		
85	Gas as associated phase recoverable	High/Maximum				1.15	0.00		
86	Part of prospect in Production Licence		Fraction	1.00	1.00	1.00	1.00		
87	*Reservoir parameters*								
88	Pressure, top reservoir		bar	510	524	130			
89	Temperature, top reservoir		degrees C	125	121	37			
90	Fractiles, reservoir parameter ranges	Low/Minimum	Fraction	0.80	0.80	0.90	0.90		
91	Fractiles, reservoir parameter ranges	Preferably Mean (or Most likely or Median)	Mean/ML/Med	Mean	Mean	Mean	Mean		
92	Fractiles, reservoir parameter ranges	High/Maximum	Fraction	0.20	0.20	0.10	0.10		
93	Depth to top of prospect	Low/Minimum		3935	3942	1294			
94	Depth to top of prospect	Central/Most likely	meters, MSL	3965	3952	1314	1322		
95	Depth to top of prospect	High/Maximum		3995	3962	1334			
96	Depth to top reservoir in well	Low/Minimum		3997		1294			
97	Depth to top reservoir in well	Central/Most likely	meters, MSL, TVD	4012	4001	1314	1322		
98	Depth to top reservoir in well	High/Maximum		4027		1334			
99	Gross rock volume	Low/Minimum		0.57	0.72	31.78			
100	Gross rock volume	Central/Most likely	10^9m^3	0.78	0.80	347.90			
101	Gross rock volume	High/Maximum		1.02	0.97	861.40			
102	Hydrocarbon column height in prospect/ segment	Low/Minimum		40	45	95	0		
103	Hydrocarbon column height in prospect/ segment	Central/Most likely	meters	70	50	108	0		
104	Hydrocarbon column height in prospect/ segment	High/Maximum		110	55	197	0		
105	Hydrocarbon column height in well	Low/Minimum		35		95	0		
106	Hydrocarbon column height in well	Central/Most likely	meters	40	20	108	0		
107	Hydrocarbon column height in well	High/Maximum		45		197	0		
108	Area of prospect/segment	Low/Minimum		0.45		2.01	N/A		
109	Area of prospect/segment	Central/Most likely	Km^2	0.80	0.23	4.98	N/A		
110	Area of prospect/segment	High/Maximum		1.95		21.46	N/A		

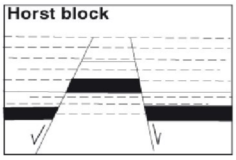
	A	B	D	G	H	I	J	K	L
111	Reservoir thickness	Low/Minimum	meters vertical at well position	210		74	N/A		
112	Reservoir thickness	Central/Most likely		250	120	154	75		
113	Reservoir thickness	High/Maximum		290		234	N/A		
114	Net/gross	Low/Minimum		0.40		0.42			
115	Net/gross	Central/Most likely	Fraction	0.50	0.60	0.54	0.82		
116	Net/gross	High/Maximum		0.60		0.75			
117	Porosity	Low/Minimum		0.15		0.31			
118	Porosity	Central/Most likely	Fraction	0.20	0.15	0.32	0.34		
119	Porosity	High/Maximum		0.25		0.34			
120	Water saturation	Low/Minimum		0.10		0.38	1.00		
121	Water saturation	Central/Most likely	Fraction	0.30	0.35	0.30	1.00		
122	Water saturation	High/Maximum		0.50		0.28	1.00		
123	Bg	Low/Minimum				N/A	N/A		
124	Bg	Central/Most likely	decimal number		0.0025	N/A	N/A		
125	Bg	High/Maximum				N/A	N/A		
126	1/Bo	Low/Minimum		0.51		0.83	N/A		
127	1/Bo	Central/Most likely	decimal number	0.67	0.80	0.87	N/A		
128	1/Bo	High/Maximum		0.91		91.00	N/A		
129	GOR, free Gas	Low/Minimum		1400		N/A	N/A		
130	GOR, free Gas	Central/Most likely	Sm3/Sm3	1900	1200	N/A	N/A		
131	GOR, free Gas	High/Maximum		2500		N/A	N/A		
132	GOR, Oil	Low/Minimum		100		35.3	N/A		
133	GOR, Oil	Central/Most likely	Sm3/Sm3	200	280	50	N/A		
134	GOR, Oil	High/Maximum		500		64.6	N/A		
135	*Evaluation - discovery*								
136	Discovery?		Yes/No		YES		NO		
137	Surprise discovery ?		Yes/No		NO		NO		
138	Resource class	NPD input	NPD codes		6				
139	*Evaluation - dry well*								
140	If Dry, Oil shows?		Yes/No				NO		
141	If Dry, Gas shows?		Yes/No				NO		
142	CHARGE	Charge			OK		FAIL		
143		Presence of source	OK / Fail / Not relevant				OK		
144		Maturity of source					OK		
145		Migration of HC					FAIL		
146	TRAP	Trap			OK		OK		
147		Presence of closure	OK / Fail / Not relevant				OK		
148		Presence of top seal					FAIL		
149		Presence of lateral seal					OK		
150	RESERVOIR	Reservoir			OK		OK		
151		Presence of reservoir	OK / Fail / Not relevant				OK		
152		Quality of reservoir					OK		
153	COMMENT	Dry well comments							
154	:::END:::								

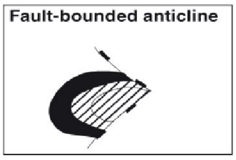
1. STRUCTURAL TRAPS

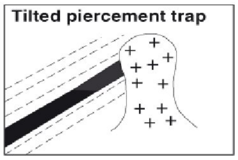
1.1 Fault dependant traps

1.1.1 Upthrown traps

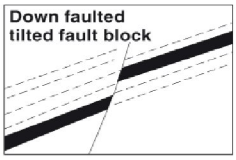


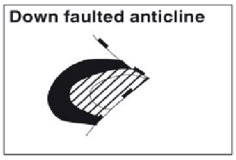




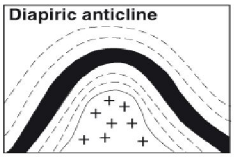


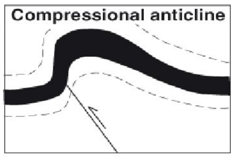
1.1.2 Downthrown traps



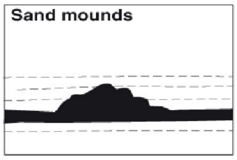


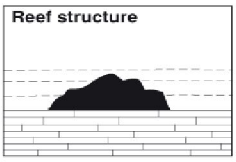
1.2 Anticlinal traps

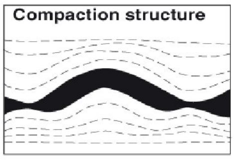




1.3 Drape traps

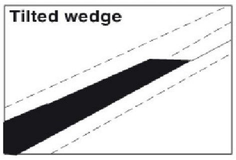


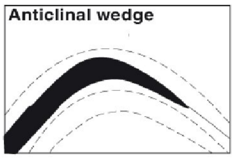




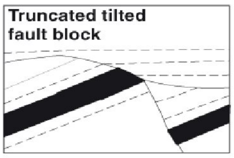
2. STRATIGRAPHIC TRAPS

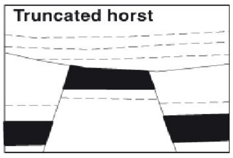
2.1 Pinch out traps

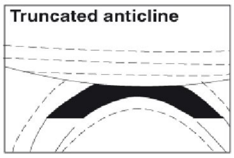




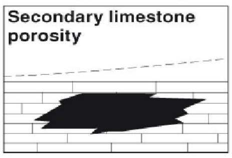
2.2 Subcrop traps

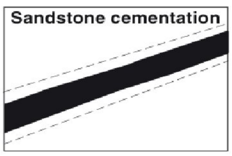






2.3 Diagenetic traps





OD 0506004