PL 333B License Surrender Report

Parts of block 2/4

Table of Contents

License surrender report PL 333B

Reference is made to the email sent to MPE dated 23.06.2017 (our reference AU-EXP NUKE ANS-00027) regarding the withdrawal of license extension application and surrender of production license 333B (PL 333B). This report outlines the key license history, database, and prospect evaluations of PL 333B, and fulfills the requirement by the NPD for a license status report.

1 KEY LICENSE HISTORY

Production license 333B is located south of the King Lear and Julius discoveries in block 2/4 in the Central Graben (Figure 1.1), and was as awarded 7th of February 2014 as a license extension as a part of the 2014 APA award. Statoil Petroleum AS was awarded the operatorship with 77.8 % and with Total E&P Norge AS as a partner with 22.8%. Work obligations were G&G work and decide on a Drill or Drop within 7th of February 2017. The partnership has made a unanimous drop decision for PL 333B.

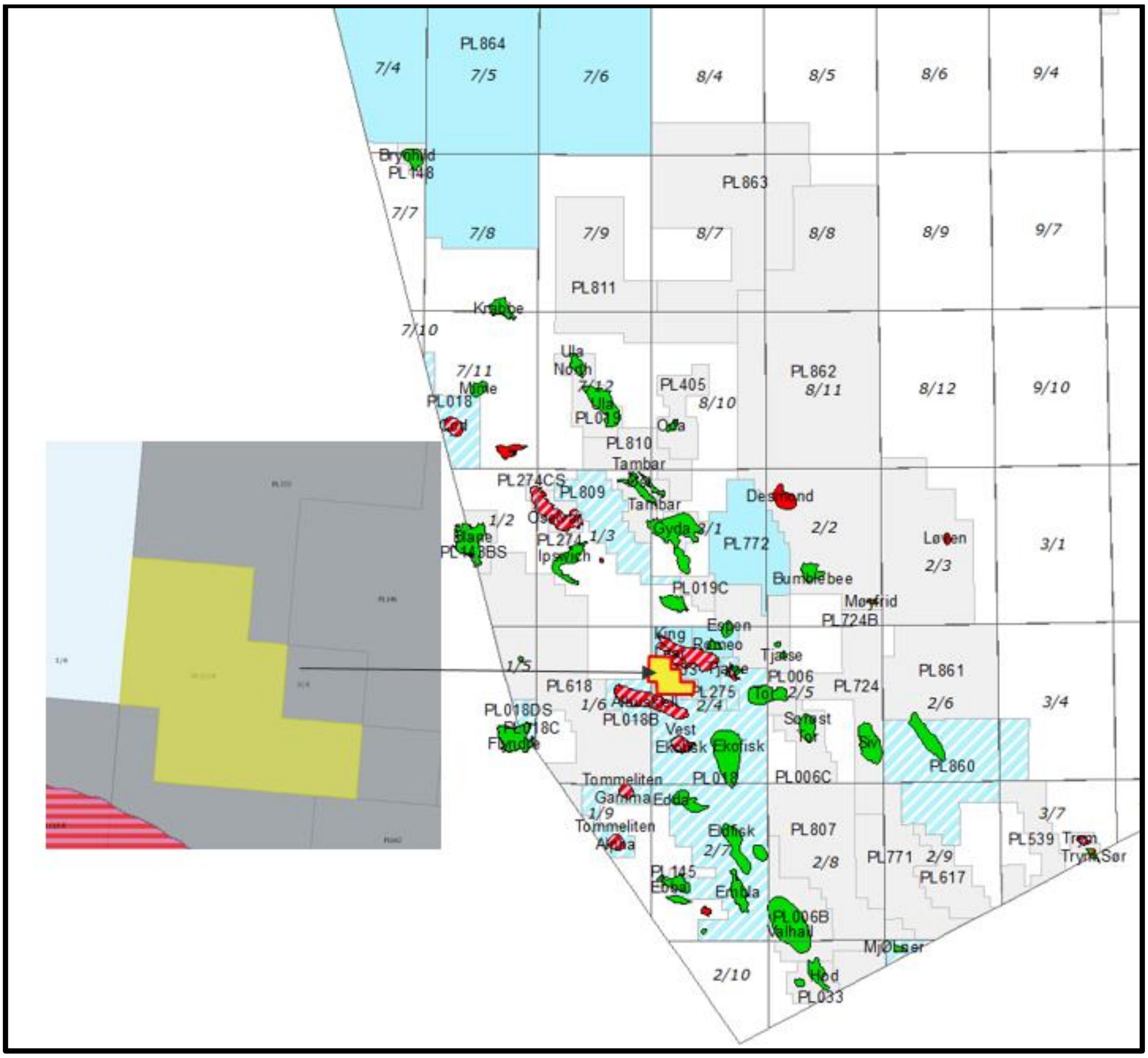

Figure 1.1 – Location map for PL 333B in the Central Graben.

Work commitment

Work obligations were to:

- G&G work: 07.02.2017
- Drill or Drop Decision: 07.02.2017
- BoK: 07.02.2019
- BoV: 07.02.2020
- PDO: 07.02.2021

Reasons for license surrender

The Timon prospect is the only prospect identified in the license. It consists of a northern and a southern segment. The potential HC volumes are relatively small with a comparatively low chance of success. The reservoirs are deeply buried (4900-5300m) and the prospect is within the high temperature - high pressure domain (HTHP). Partners in PL 333B do not see enough value in the Timon prospect to continue with a drill decision in 2017.

2 DATABASE

2.1 Seismic data

The key seismic dataset used for the mapping of the Timon prospect is the 3D survey VGCNS05Z12 full offset depth cube. A prestack depth migration (PSDM) of the VGCNS05STT11 (reprocessing of VGCNS05 in 2011) was carried out in in 2012 to improve the imaging of the prospects King Lear, Julius and Romeo. The aim was to improve the structural image of the target reflections and to give the correct depths. The resulting cube shows a significant uplift in image quality compared to the previous PSTM imaging; it has less multiples and a better imaging of the faults due to the detailed work on the velocity model. Even though the target reflection cannot be interpreted with high certainty and the faults are unclear in the most complex areas, the data quality of the VGCNS05Z12 dataset is considered to be good. The VGCNS05Z12 survey covers the entire area applied for except two small areas (Figure 2.1) where seismic data is missing due to installations.
VGCNS04_PSDM_Final_stack_depth (3Dfisk) has been used to cover these missing data areas (Figure 2.1). Reprocessing and the prestack depth migration of this cube was carried out by PL018, operated by ConocoPhillips, in 2009/2010, resulting in multiple attenuation and a significant improvement in imaging of pre-Cretaceous structures. The data quality is generally good. Table 2.1 list the seismic surveys in the common database.

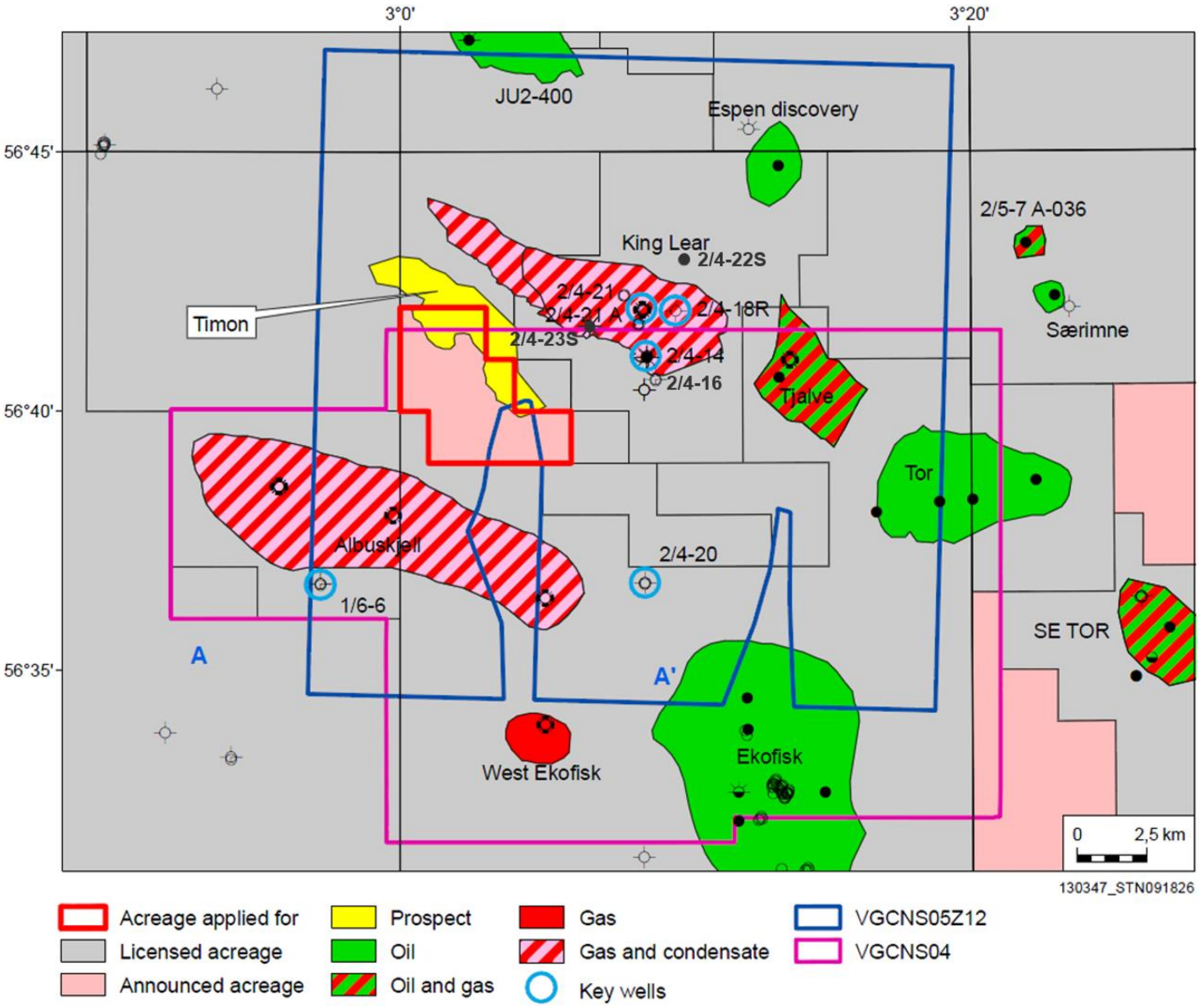

Figure 2.1 – Seismic survey database and key wells. VGCNS05Z12 PSDM in blue and VGCNS04 in pink.

Table 2.1: List of seismic surveys in the common database.

Survey/Dataset	**Type**	**Data owner**	**Year**	**NPDID**	**Market available**
VGCNS05Z12	Reprocessed	License	2005	4334/4335	NO
VGCNS04	Reprocessed	License	2004	4281/4282	NO

2.2 Well data

The well database used in the evaluation of PL333B is given in Table 2.2

Table 2.2- Well database for PL 333B

Well	Oldest penetration	Drilling operator	Content	Completion year	NPDID
2/4-23S	Triassic	Statoil	Gas/Condensate	2015	7657
2/4-22S	Permian	Statoil	Oil	2015	7535
2/4-21	Late Jurassic	Statoil	Gas/Condensate	2012	6736
2/4-21A	Late Jurassic	Statoil	Gas/Condensate	2012	6933
2/4-18 R	Late Jurassic	Saga petroleum	Shows	1994	2253
2/4-14	Late Jurassic	Saga petroleum	Gas/Condensate	1988	1343
2/4-20	Permian	ConocoPhillips	Dry	2007	5556
1/6-6	Triassic	A/S Norske Shell	Shows	1992	1839

3 REVIEW OF GEOLOGICAL AND GEOPHYSICAL STUDIES

In the APA 2014 application, the prospective interval was believed to be only Farsund Formation sandstones with the same age as the King Lear discovery. In the work after the APA award the shallow marine Ula Formation is included in the Timon prospect, as oil was discovered in the Ula Formation in the Romeo well (2/4-22S) and gas/condensate was discovered in the Julius well (2/4-23S).

The Timon prospect is downfaulted from the King Lear – Julius structure and consists of a northern segment (Timon North) and a further downfaulted southern segment (Timon South) (Figure 3.1). As the Timon prospect is downfaulted from the King Lear/Julius structure the key risk is trap as the two reservoirs are juxtaposed to the water bearing (2/4-23S) sandy Skagerrak Formation (Figure 3.2).

The Julius well (2/4-23S) (HPHT) appraised the Farsund Formation turbiditic sandstone that were discovered in the King Lear wells (HPHT) in 2012 (2/4-21 – 2/4-21A). However, only 2 thin sandstones (each 3 m thick) were encountered in the well and consequently reduced the potential in the Timon prospect, which is interpreted to be located further away (south) from the sand source.

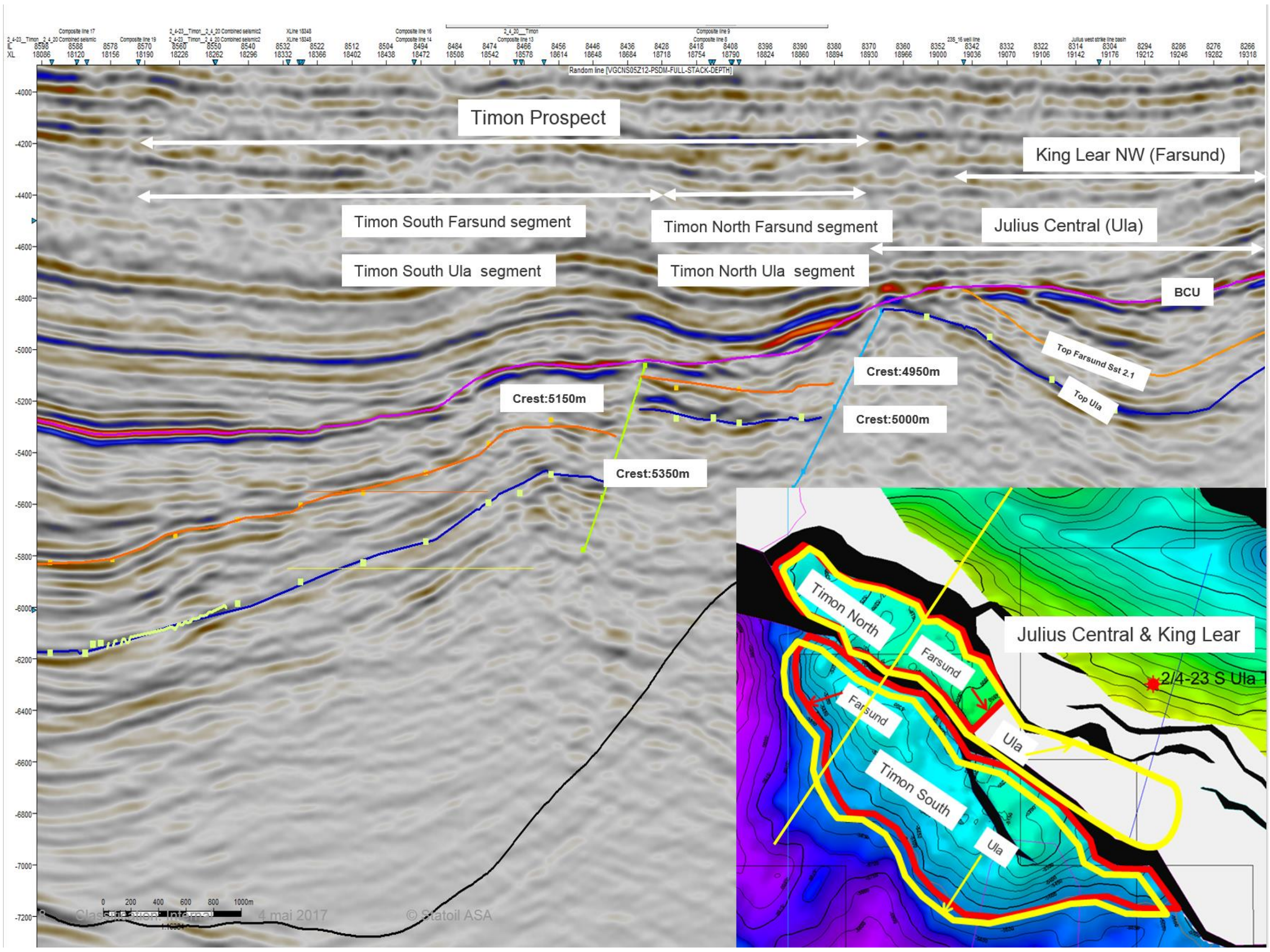

Figure 3.1 – Seismic random line (VGCNS05Z12 PSDM) showing the Timon Prospect downfaulted from the King Lear – Julius structure.

4 PROSPECT UPDATE

The "simple" Timon Prospect from the APA 2014 has been subdivided into a southern and a northern segment. The southern segment has the largest potential, and will be the best location for an exploration well. Both segments are within the high temperature – high pressure (HTHP) burial zone.

Top seal of the Farsund Fm. reservoir is the shales of the Farsund Fm. and Mandal Fm., however at crest, the ultimate top seal would be the Cretaceous Cromer Knoll Group in areas of local erosion. Top seal of the Ula Fm. is the shales of the Haugesund Fm. (Mandal Fm.) proven in the area. Fault seal represents a main prospect / segment risk and fault seal studies are performed for the Ula Fm. reservoir. The Farsund reservoir with a relatively thick shaly part below the Farsund reservoir indicate high sealing potential based on the conclusion from the Ula Fm. study.

Another risk is also related to presence of an efficient Farsund Fm. reservoir. The 20m thick reservoir (6m net sandstone) with 28% N/G and 20% porosity observed in the nearby 2/4-23S (Julius) well is considered to be a reservoir failure in the Timon prospect. The sand source area for the Farsund Fm. turbidites is the Hidra High, where severe erosion is observed. The deep-water sediments were deposited south of the Hidra High and locally subject to later uplift and erosion at crest of the King Lear – Julius structure. Seismic imaging does not allow for detailed interpretation of these depositional systems, hence the reservoir distribution is conceptual, and guided by nearby wells. The King Lear wells 2/4 21A and 21 show well developed turbiditic sandstones in Farsund Fm. with gross thickness of 51 m, N/G of 44% and a porosity of 21%. The 2/4-18 and 2/4-23S wells show a poorer reservoir development.

The gas-condensate discovery of the Ula Formation in the Julius well (2/4-23S) demonstrates the reservoir potential at these burial depths, and the Ula Formation has therefore been included in the Timon prospect. The Ula Formation in the 2/4-23S consists of a 41 m thick gross reservoir (N/G = 0.5) with a relatively good reservoir at the base and at the top, and with a relative poor silty middle part. The Ula Formation classifies as quartz arenite /subarkose and consists of very fine to fine-grained, well to moderately well sorted sandstones. The average porosity is 17 % and permeabilities are ranging from 0.1mD up to 240 mD with an average of 10 mD. Pressure tests conclude that the upper part of the Ula Fm. is not in pressure communication with the lower part of the Ula Fm., pointing out the lateral reservoir extent uncertainty.

Updated volumes and risks are presented in Table 4.1 and 4.2 respectively.

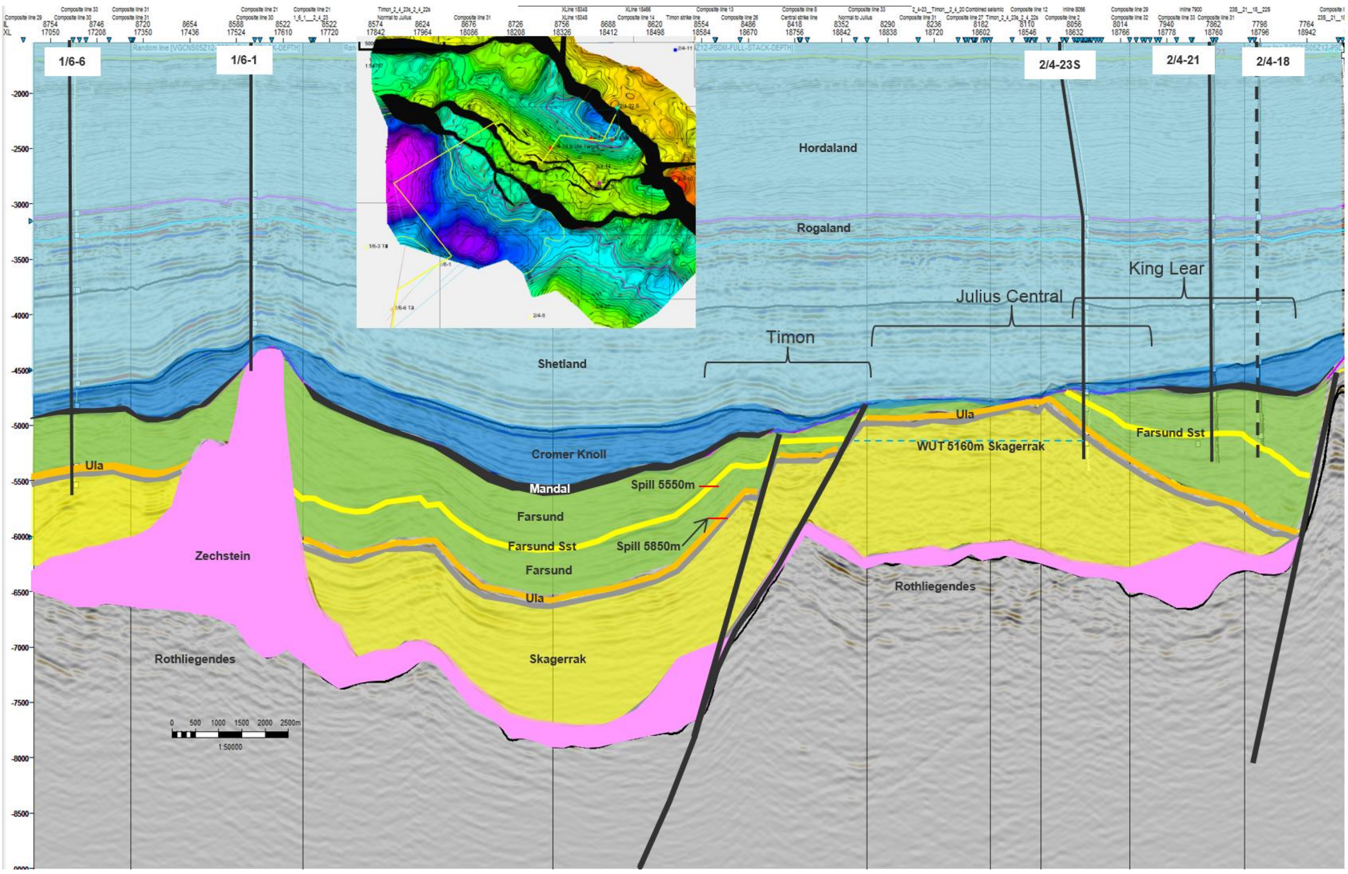

Figure 3.2 – Seismic random line (VGCNS05Z12 PSDM) from Albuskjell to Timon, Julius and King Lear structures.

Well:		***Prospect/discovery name:***						
UNDISCOVERED	Prospect segments	In-place res. (MSm^3) main phase 100%, Total Structure			Recoverable res. (MSm^3oe) 100%, Total Structure			Pg
		P90	Mean	P10	P90	Mean	P10	%
Pre drill segment	Timon South Farsund	2.59	7.32	14.1	1.03	2.92	5.63	18
Pre drill segment	Timon South Ula	3.2	7.62	13.7	1.15	2.75	4.94	23
Pre drill segment	Timon North Ula	1.98	4.54	7.52	0.19	0.46	0.79	34
Pre drill segment	Timon North Farsund	1.77	3.21	4.99	0.48	0.88	1.37	16

Table 4.1 Volume distribution for the Timon segments.

Prospect segments	**P-Play**			**P-Prospect/Segment**							**Discovery**	
	Reserv.	Source	Seal	Reservoir		Source			Trap			
				pre-sence	produc-ability	pre-sence	migra-tion	hc-phase	geo-metry	seal	**Pg**	**Pg (DFI)**
Timon South Farsund	1.00	1.00	1.00	0.50	0.90	1.00	1.00	1.00	0.80	0.50	0.18	
Timon South Ula	1.00	1.00	1.00	0.70	1.00	1.00	0.90	1.00	0.80	0.45	0.23	
Timon North Ula	1.00	1.00	1.00	0.80	1.00	1.00	1.00	1.00	0.95	0.45	0.34	
Timon North Farsund	1.00	1.00	1.00	0.50	0.90	1.00	1.00	1.00	0.70	0.50	0.16	

Table 4.2 Risk distribution for the individual Timon segments

5 TECHNICAL EVALUATIONS

Since Timon South has the largest volume potential valuation is focused on this part. Assuming a dedicated Timon UWP tied back to the King Lear UWP and to the Ekofisk Complex. The reservoir parameters applied in the evaluation are summarized in Table 5.1. Furthermore, assuming commingled production from Ula and Farsund from 2 deviated producers. The only commercial outcome is the combined discoveries in both Ula Formation and Farsund Formation (Figure 5.1). ENPV after tax (8%disc. MUSD16) was negative (-9.4 MUSD16). (Table 5.2).

Table 5.1 Reservoir parameters applied in the technical evaluation

	Timon South Farsund	Timon South Ula
Stratigraphy, Fm	**Jurassic, Farsund Fm.**	**Jurassic, Ula Fm.**
Litology, deposition system	**Turbidites**	**Middle- upper shoreface**
Gross res. thickness / area	**42.7 m / apprx 6.9 km2**	**48 m / apprx 6 km2**
Res prop	**NTG 0.4, por 17% Perm 30 mD**	**NTG 0.47, por 17%, Perm 20 mD**
Pressure and temp	**1000 bars 185 deg C**	**1080 bars 190 deg C**
IGIP (GSm^3) / CIIP (MSm^3)	**3.95 / 3.37**	**4.22 / 3.4**
Rec gas (GSm^3) / cond (MSm^3)	**1.78 / 1.11**	**1.69 / 1.02**
RF gas / cond (%)	**45 / 33**	**40 / 30**
# wells	**2 drainage points (commingled prod)**	**2 drainage points (commingled prod)**
Max well rate, MSm3/d	**0.7 MSm3/d**	**0.4 MSm3/d**
Area/producer, km2	**3,5**	**3**
Regularity	0,85	0,85
Cum gas pr well	0.88 GSm3	0.83 GSm3

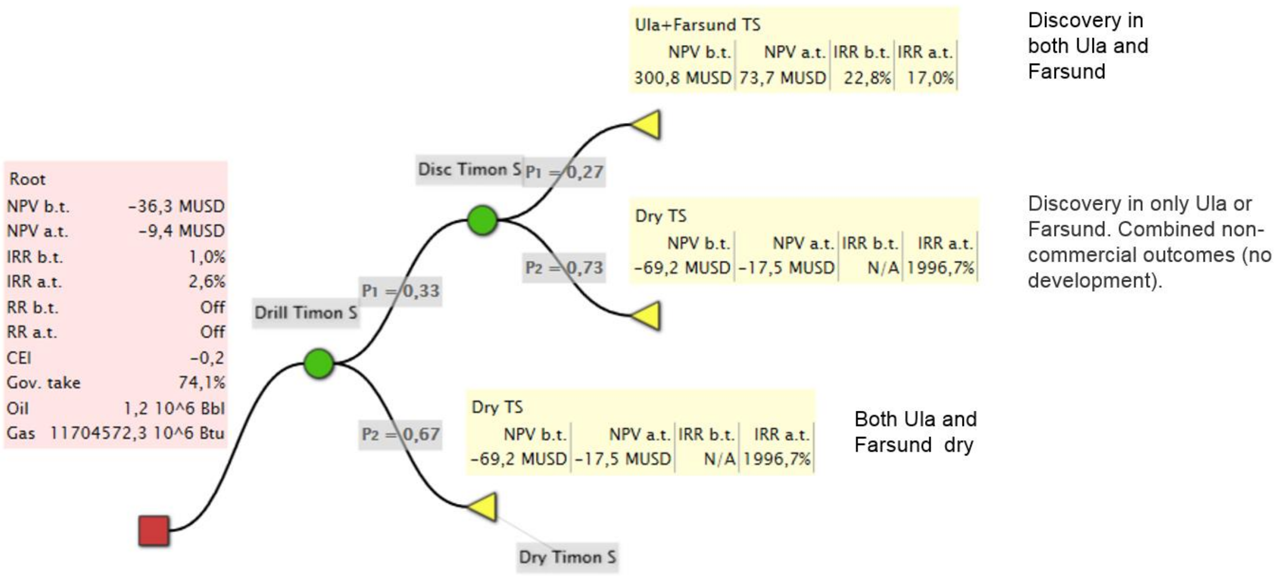

Figure 5.1 Decision tree for possible development of Timon prospect. The probabilities in the decision tree has been derived from an aggregated case with Ula Fm. and Farsund Fm. combined.

Key valuation metrics 100%		
KPI	**Timon partner**	**Ula+Farsund TS partner**
NPV after tax (8% disc., MUSD16)	-9,4	73,7
Capital efficiency index (CEI)	-0,15	0,29
IRR (after tax, %)	3 %	17 %
Breakeven gas price (USD16/mbtu)	13,9	5,5
Breakeven oil price (USD16/boe)	139	55
Finding cost (USD16/boe)*	35,2	3,3

Given discovery

Table 5.2 KPI Timon South

6 CONCLUSIONS

The potential HC volumes are relatively small with a comparatively low chance of success. Partners in PL 333B does not see enough value in the Timon prospect to continue with a drill decision in 2017, and the license is consequently dropped.