Relinquishment Report
PL569, PL072C and PL046C
Parts of Blocks 15/9, 16/4 and 16/7

1 INTRODUCTION AND LICENSE HISTORY

The PL569, PL072C, PL046C and PL303B licenses are located within parts of blocks 15/6, 15/9, 16/4 and 16/7 on the southeastern flank of the South Viking Graben. The 4 licenses cover 49,629 km^2. The licenses went through a carve-out and harmonization process in 2011 with the aim to harmonize the ownership equity and license expiry dates for the Theta NE prospect and H-Discovery. The intension was a joint development if commercial volumes are proven in the Theta NE prospect. The 4 licences have since then been administered by PL569.

Statoil Petroleum AS is the Operator of all of the licenses with a 59.6% share, whereas ExxonMobil Exploration & Production Norway AS and Total E&P Norge AS hold 30.4% and 10%, respectively (similar equity as in the Sleipner East field). PL303B already expired on the 12th of December 2013. The remaining license details are listed below and shown in Figure 1.

PL569:
License award / expire: 04.02.2011 / 04.02.2015
All work obligations are fulfilled.
BoV decision: 04.08.2014
(applied for extension until 30.09.2014)

PL072C:
License award / expire: 21.12.2011 / 31.12.2028
All work obligations are fulfilled.

PL046C:
License award / expire: 21.12.2011 / 31.12.2028
All work obligations are fulfilled.

PL303B:
License award / expire: 27.05.2011 / 12.12.2013
All work obligations are fulfilled.

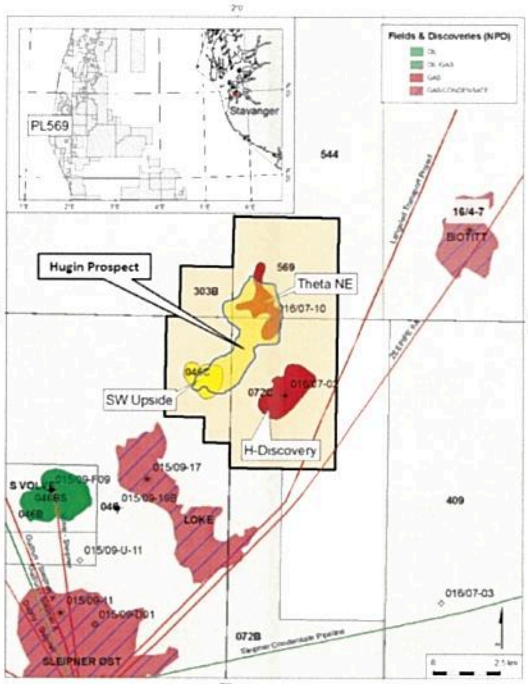

Figure 1. License overview map with discoveries, wells and prospects.

PL569 was granted for a four year initial period. The initial phase work obligations were to drill one exploration well and to decide if a BoK should be taken within the first two years. The partnership then had one year to decide if a BoV should be prepared before filing a PDO within the licence expiry on 04.08.2015.

The business concept was to explore the Theta NE prospect, the sister structure to the existing H-Discovery drilled by Esso Exploration and Production Norway A/S in1982, and to develop both gas accumulations by means of a tieback solution to the Loke / Sleipner Øst field (Figure 1). The 16/7-2 well (H-Discovery, 1982) encountered gas within the Ty Formation and also explored a deeper Jurassic Hugin Formation reservoir target, which was found to be dry. The 16/7-10 'Theta NE' well intended to prove the presence of an economic gas / condensate column within the Ty Formation, but not to explore any deeper intervals.

The PL569 drill commitment was fulfilled by the Theta NE well 16/7-10 and 16/7-10 T2, which was completed on the 13th of September 2011. Unfortunately, the well encountered only a thin non-commercial gas / condensate column (<2m) in the prospective Ty Formation which resulted in a significant downgrading of resource estimates within the licences.

Consequently, the main rationale for the relinquishment of PL072C and PL046C and the negative BoV decision for the PL569 license is the combination of the disappointing and non-commercial gas / condensate volumes discovered in the Paleocene Ty Formation by wells 16/7-2 (H-Discovery, 1982) and 16/7-10 / 16/7-10 T2 (Theta NE, 2011). There is one small Paleocene prospect with a DHI called SW Upside (Figure 1). The underlying Hugin prospect is a large 4-way dip-closed trap but has high risk on hydrocarbon migration since the neighboring trap is drilled dry.

2 TECHNICAL WORK AND MEETINGS

The main body of technical work within the licensed area is associated with PL569 and concerns the pre-drill planning, execution and post well analysis performed for 16/7-10 and 16/7-10 T2. Two seismic surveys, the ST04M02 and ST98M3, form the basis of the geological and geophysical work and evaluations, along with data from key offset well 16/7-2 and supporting knowledge of the Sleipner East area data, see Figure 2.

<u>Post 16/7-10 T2, technical re-evaluation:</u>

- Remapped top reservoir based on a revised interpretation strategy (greater attention to AVO responses).
- Detailed mapping of high velocity Grid Formation channels in the overburden.
  - Construction of new depth conversion model to account for velocity pull-up observed beneath channels.
- Revision of resource calculation across former Theta NE (now Theta NE discovery and Theta NE SW upside) and H-Discovery.
- Re-evaluation of the Theta NE Hugin Formation reservoir segment prospect based on revised depth conversion model.
- Revised risk and technical economical evaluation.

<u>Management and Exploration Committee license meetings:</u>

- MC Meeting 29.04.2011
- EC Meeting 25.05.2011
- EC Work Meeting 26.09.2011
- MC Meeting 01.12.2011
- EC Work Meeting 17.09.2012
- MC Meeting 19.11.2012
- EC/MC Meeting 14.11.2013
- EC Work Meeting 23.05.2014
- MC Meeting 26.06.2014

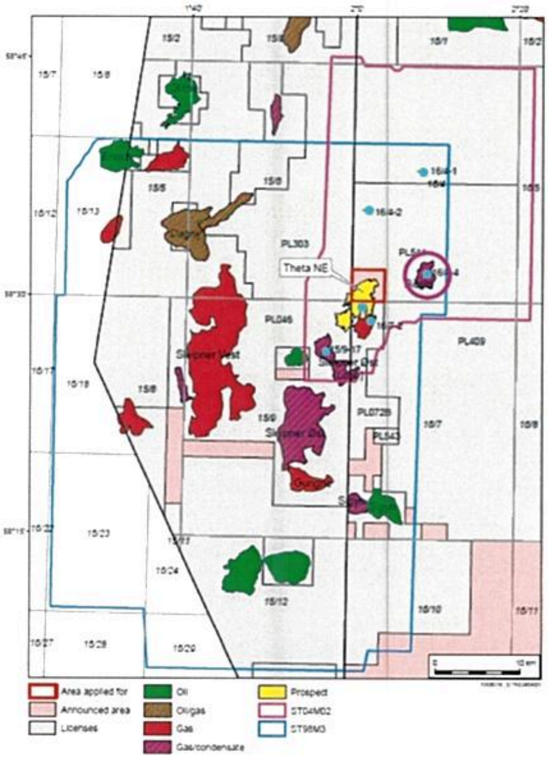

Figure 2. Overview of seismic surveys coverage and key wells.

3 PROSPECT EVALUATION

Following the award of PL569, the Theta NE prospect Ty Formation reservoir segment was matured to drilling candidate status. The prospect was a structural look-alike to the H-Discovery and carried as such a high probability of discovery (68%).

The pre-drill probability of reservoir was 0.95 since it is proven in the H-Discovery well (16/7-2, 1982) with further support from the offset wells and regional depositional model.

Pre-drill probability of trap was distributed between trap seal (0.9) and trap geometry (0.8). The risk on trap seal was included as the overlying Lista Formation could potentially contain sand stringers or thief zones; although this not observed in offset wells. Trap geometry was identified as the main risk for the Theta NE prospect, given the low relief nature of the structure, and the fixed GWC (-2327m TVD MSL established by H-Discovery). An AVO anomaly within the structure was viewed as supportive, but not considered definitive at the time.

Presence of source rocks was proven (1.0) by the discoveries at H-Discovery (16/7-2), Loke (15/9-17) and Biotitt (16/4-4) (Figure 3). Geochemical studies show that the source rock is early-mature and in line with an expected Upper Jurassic age source.

Top reservoir was encountered 35.5m deeper than prognosed in the 16/7-10 T2 Theta NE well. The GWC was encountered only 1m deeper than prognosis based on pre-drill estimates from the H-Discovery sister structure. Given the low relief nature of Theta NE, this resulted in greatly reduced bulk rock volume within the expected reservoir.

Prognosis failure was attributed to velocity anomalies in the overburden (channelized Grid Formation sands) that were not built into the initial depth conversion model, and a flawed seismic interpretation strategy that was applied too broadly to the prospect.

In order to estimate the resources within the Theta NE discovery, a thorough re-evaluation of the licence was conducted. Issues with seismic data quality forced a remapping on near stack data only with greater attention paid to AVO response to indicate distribution of hydrocarbon accumulations within the overall structure. A new depth model required detailed mapping of overlying Grid Formation channels so that these high velocity features and their resultant pull-up effect on deeper horizons could be better resolved (Figure 4&5).

A revised Top Ty Formation interpretation resulted in three small hydrocarbon accumulations above the GWC within the Theta NE area. Both H-Discovery and Theta NE were greatly reduced in size. The evaluation of the third, untested prospect, Theta NE SW Upside (Figure 4), resulted in a total discovery probability of 90% and mean recoverable volumes of 0,436 MSm^3 oe (Table 2&3).

The new depth model impacted all interpreted horizons below the Grid Fm. necessitating a re-evaluation of the Hugin prospectivity. The main risks for the Theta NE Hugin prospect are migration (0.2) trap geometry (0.7), and reservoir presence (0.9), giving a total discovery probability of 12.6% and mean recoverable volumes of 3.41 MSm^3 oe (Table 4&5). Expected phase is gas due to the vicinity and possible spill from the Loke discovery.

The key barrier to hydrocarbon migration within the Jurassic interval is the presence of a large, regional fault (Tornquist Trend) which separates Theta NE (as well as H-Discovery and Biotitt) from the highly prospective Sleipner East terrace (Figure 6). No wells so far have proven migration to the east of this fault trend below the Shetland Group.

The Hugin formation itself is overall very thin, averaging only a few 10s of metres (from Sleipner) and comprises progradational marine wedges within an overall retrogradational system.

4 RESOURCES

Currently, the licenses portfolio comprises of two minor discoveries and two prospects, ref. Table 1.

The mean recoverable volumes for the Theta NE discovery are 0,253 MSm^3 oe with P90 to P10 range of 0,138 to 0,392 MSm^3 oe, respectively. The remapping and re-evaluation process also resulted in a downgrade of the reported mean recoverable volumes within H-Discovery from 1,44 MSm3 oe (pre-drill) to 0,583 MSm3 oe with P90 to P10 range of 0,449 to 0,727 MSm^3 oe, respectively.

Theta NE SW Upside is now regarded as the main remaining prospect within the licence (PL046C). This Ty Formation target carries a 90% probability of discovery with estimated mean recoverable volumes of 0,426 MSm^3 oe with P90 to P10 range of 0,269 to 0,613 MSm^3 oe, respectively. The deeper Theta NE Hugin prospect of the Hugin Formation has a 12.6% probability of discovery with mean recoverable volumes of 3.41 MSm^3 oe with P90 to P10 range of 0.51 to 7.37 MSm^3 oe, respectively. The range is high because the top reservoir is difficult to map seismically so spill points are very uncertain.

Table 1: In-place and recoverable volumes for the identified prospects within the licensed area.

Well:		**Prospect/discovery name:**	H-Discovery, Theta NE					
UNDISCOVERED	Prospect segments	In-place res. (MSm^3oe) 100%, Total Structure			Recoverable res. (MSm^3oe) 100%, Total Structure			Pg %
		P90	Mean	P10	P90	Mean	P10	
Pre drill segment	Theta NE Hugin	0,8	5,2	11,0	0,5	3,4	7,4	12,6
Pre drill segment	Theta SW Upside	0,7	1,1	1,5	0,3	0,4	0,6	90
DISCOVERED	Discovery/prospect segments	In-place res. (MSm^3oe) 100%, Total Structure			Recoverable res. (MSm^3oe) 100%, Total Structure			Pg %
		P90	Mean	P10	P90	Mean	P10	
Proven by well	H-Discovery	1,1	1,5	1,8	0,4	0,6	0,7	
Proven by well	Theta NE discovery	0,3	0,6	1,0	0,1	0,3	0,4	

5 TECHNICAL / ECONOMICAL EVALUATIONS

The pre-drill development solution for Theta NE was a joint subsea satellite development with the 16/7-2 discovery (H-discovery) tied back to Sleipner A for processing and export. The 16/7-10 / 16/7-10 T2 discovery is sub-economic and the well result has significantly reduced the hydrocarbon potential in Theta NE and H-Discovery.

An updated technical & economical evaluation of the Theta NE Hugin prospect was performed. This included a joint subsea development solution with the H-Discovery; a subsea template tie-in to Sleipner A (~15.5km) with 2 gas producers (1 to H-Discovery and 1 to Theta NE Hugin) with a gas production plateau of ~1MSm^3/d. [redacted] Other development scenarios have also been looked into, but the technical economical evaluation shows no obvious positive solutions for these, not alone or in combination.

6 SUMMARY AND CONCLUSIONS

The work programme for the initial period of PL569 has been fulfilled. Results from the Theta NE 16/7-10 /16/7-2 T2 commitment well were disappointing and subsequent post well studies have shown the area to be poor in terms of upside prospectivity.

A reassessment of the deeper Hugin Formation target was undertaken which gave appreciable volumes in a relatively large structure. However, when placed in a regional context, the probability of migrating hydrocarbons into this structure is extremely low. Large scale, regional faults separate the prospect, along with similar dry structures tested by the 16/7-2 (H-Discovery) and 16/4-7 (Biotitt 2013) wells, from the proven Sleipner East terrace (Figure 6).

The failure of Theta NE prospect (Ty Formation) to prove commercial volumes, coupled with the downgrading of the existing H-Discovery and lack of viable alternative prospectivity within the PL569 licence group does not justify further exploration at this time. The partnership has therefore elected to relinquish the licences (PL569, PL046C and PL072C) ahead of the next licence commitment (submission of a BoV, PDO).

All communication in the partnership can be found on LicenseWeb; all relevant datasets are available in Petrobank.

7 REFERENCES

1. Statoil, 2012. Final Well Report, 16/7-10 and 16/7-10 T2 Theta NE, License: PL 569.
2. StatoilHydro, 2009. HFunn and ThetaNE Subsurface DG1 Evaluation Report, Statoil Internal report.

8 SUPPORTING FIGURES

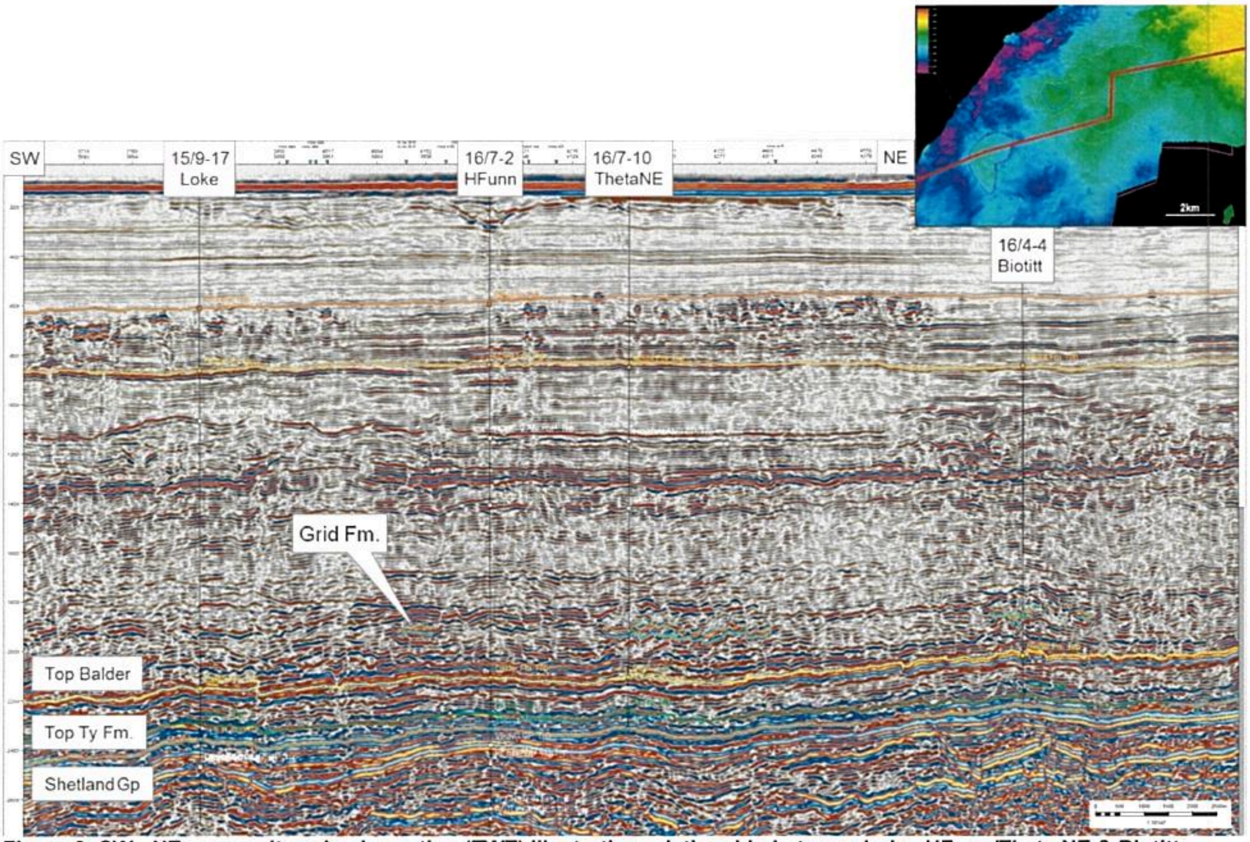

Figure 3: SW - NE composite seismic section (TWT) illustrating relationship between Loke, HFunn/Theta NE & Biotitt.

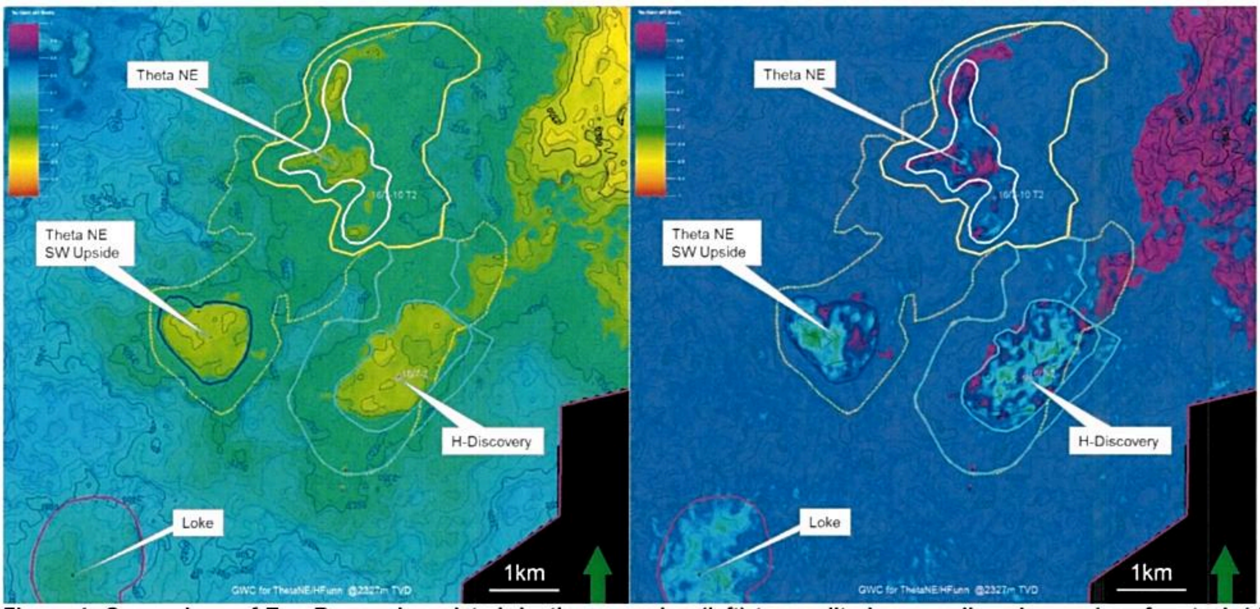

Figure 4: Comparison of Top Reservoir updated depth conversion (left) to amplitude anomalies observed on far stack (right). 10m contour interval. The yellow dotted line shows the pre-drill Theta NE outline. Spill points of the structures in cyan and yellow. The white, blue and inner cyan polygons are marking the area with AVO response and represent the GWC.

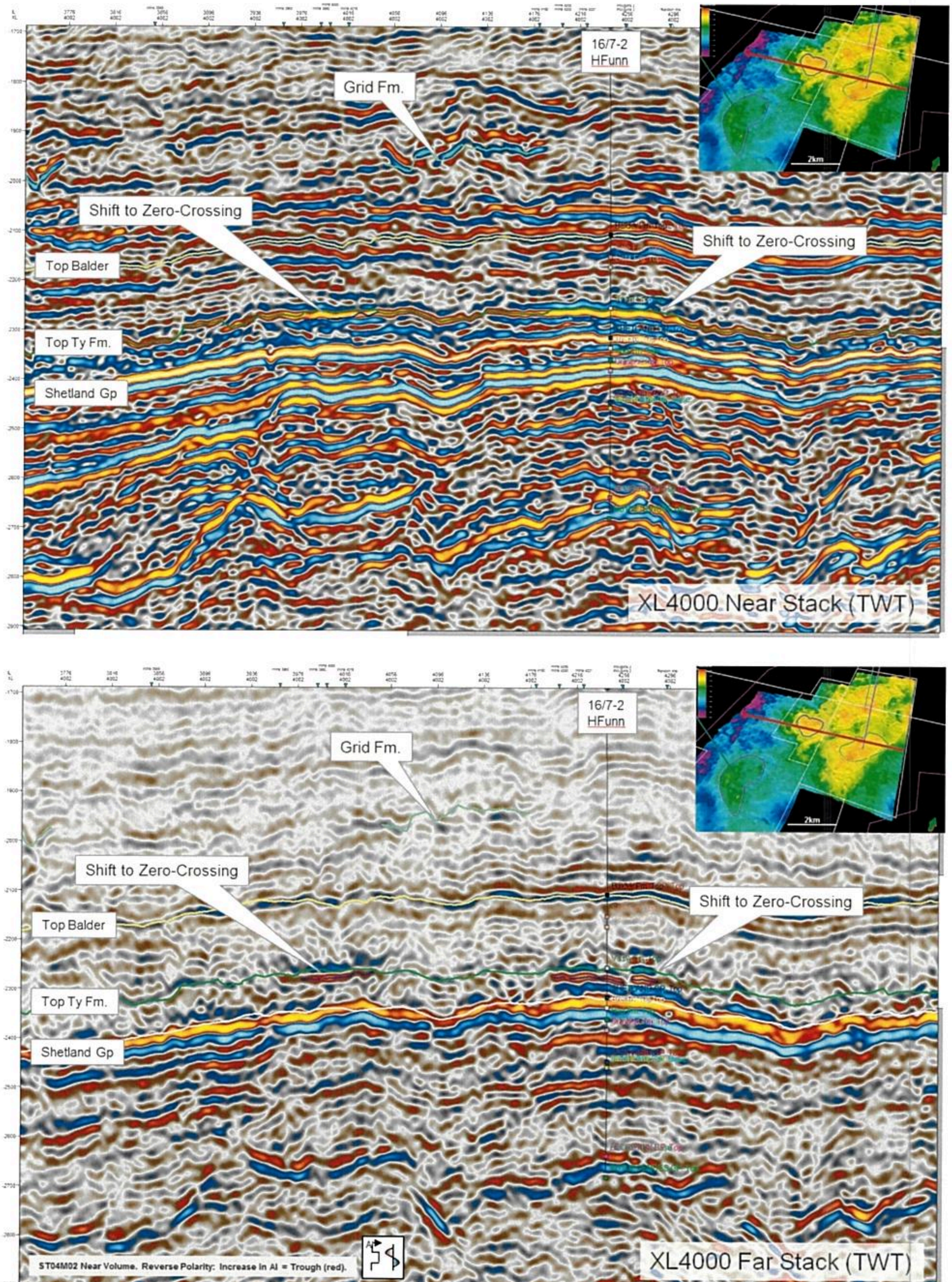

Figure 5: Comparison of seismic AVO response as an indicator of hydrocarbon presence at Top Ty. Channelised Grid Fm sands overlying the prospect with higher than anticipated interval velocities resulted in pull up over the prospect and neighbouring H Discovery (16/7-2). Compounding the pull-up effect, interpretation strategy relied on input from previous AVO study which concluded that mapping of gas filled Top Ty reservoir should be moved up to the Zero-crossing above top reservoir pick. Adjusting the top reservoir pick over the entire structure also included brine filled regions affected by velocity pull-up.

Table 2: Final resource estimates for revised Palaeocene prospectivity within the licensed area.

Final QC volume numbers (oil equivalents)				
	Recoverable Mean Volume (10e6 Sm3)	P90 volume	P50 volume	P10 volume
Theta NE discovery	**0.253**	**0.138**	**0.236**	**0.392**
Theta NE upside SW*	**0.426***	**0.269**	**0.400**	**0.613**
Theta NE (total)	**0.635**	**0.369**	**0.634**	**0.890**

*Theta NE upside has 90% chance of discovery

The H-discovery has been revaluated with the following volumes:

Final QC volume numbers (oil equivalents)				
	Recoverable Mean Volume (10e6 Sm3)	P90 volume	P50 volume	P10 volume
H-Discovery	**0.583**	**0.449**	**0.574**	**0.727**

Table 3: Risk summary for Theta NE SW Upside prospect.

Risk factor	P(play)	P(segment I ...	Overall risk
Trap Geometry [decimal]		0.900	0.900
Trap Seal [decimal]	1.000 [High]	1.000 [Medium]	1.000
Reservoir Presence [decimal]	1.000 [High]	1.000 [High]	1.000
Producibility [decimal]		1.000	1.000
Source Presence [decimal]	1.000 [High]	1.000 [High]	1.000
Source Migration [decimal]		1.000	1.000
HC-Phase Success [decimal]		1.000	1.000
> Marginal play probability [decimal]	1.000		
> Conditional segment probability [decimal]		0.900	
> Unconditional probability [decimal]		0.900	
> Dry hole risk [decimal]		0.100	

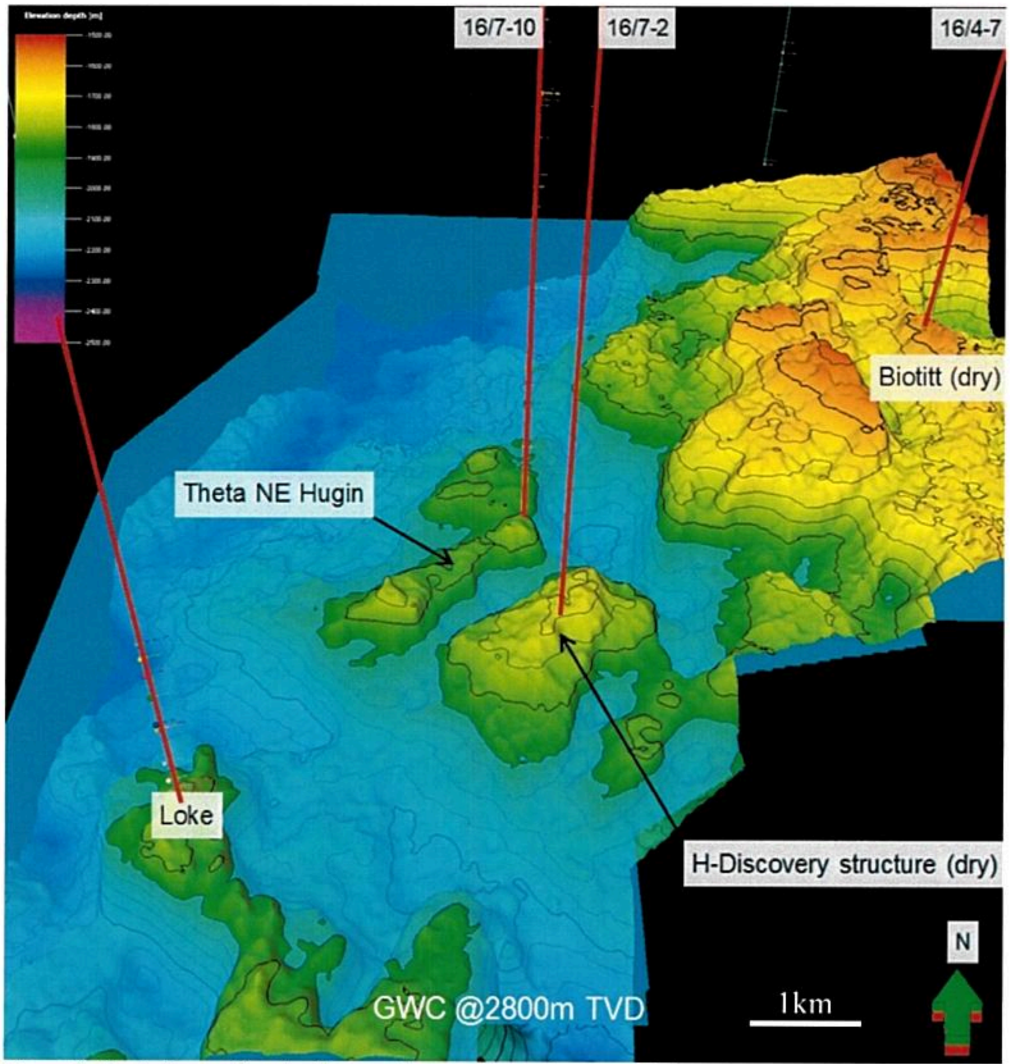

Figure 6: Hugin Formation depth map, discoveries and prospectivity. 50m contour interval with pseudo GWC to visualise the Theta NE Hugin prospect.

Table 4: Risk summary for the Theta NE Hugin prospect (2014).

Risk factor	P(play)	P(segment | play)	Overall risk
Trap Geometry [decimal]		0.700	0.700
Trap Seal [decimal]	1.000	1.000	1.000
Reservoir Presence [decimal]	1.000	0.900	0.900
Producibility [decimal]		1.000	1.000
Source Presence [decimal]	1.000	1.000	1.000
Source Migration [decimal]		0.200	0.200
HC-Phase Success [decimal]		1.000	1.000
> Marginal play probability [decimal]	1.000		
> Conditional segment probability [deci...		0.126	
> Unconditional probability [decimal]		0.126	
> Dry hole risk [decimal]		0.874	

Table 5: In-place and recoverable resources for the Theta NE Hugin prospect (2014).

Resource type	Dist.type	Mean	Std ...	P90	P50	P10
Oil [1e6 Sm3]						
Accumulation size above Minimu...	Const	0.0	0.0	0.0	0.0	0.0
Cond. segment potential	Const	0.0	0.0	0.0	0.0	0.0
Uncond. segment potential	Const	0.0	0.0	0.0	0.0	0.0
Non Assoc. Gas [1e9 Sm3]						
Accumulation size above Minimu...	MC(10000)	2.84	2.52	0.43	2.23	6.13
Cond. segment potential	MC(1000...	0.358	1.3	0.0	0.0	0.676
Uncond. segment potential	MC(1000...	0.358	1.3	0.0	0.0	0.676
Assoc. Gas [1e9 Sm3]						
Accumulation size above Minimu...	Const	0.0	0.0	0.0	0.0	0.0
Cond. segment potential	Const	0.0	0.0	0.0	0.0	0.0
Uncond. segment potential	Const	0.0	0.0	0.0	0.0	0.0
Condensate [1e6 Sm3]						
Accumulation size above Minimu...	MC(10000)	2.36	2.11	0.35	1.84	5.13
Cond. segment potential	MC(1000...	0.298	1.084	0.0	0.0	0.561
Uncond. segment potential	MC(1000...	0.298	1.084	0.0	0.0	0.561

Resource type	Dist.type	Mean	Std ...	P90	P50	P10
Oil [1e6 Sm3]						
Accumulation size above Minimu...	Const	0.0	0.0	0.0	0.0	0.0
Cond. segment potential	Const	0.0	0.0	0.0	0.0	0.0
Uncond. segment potential	Const	0.0	0.0	0.0	0.0	0.0
Non Assoc. Gas [1e9 Sm3]						
Accumulation size above Minimu...	MC(10000)	1.99	1.77	0.3	1.55	4.31
Cond. segment potential	MC(1000...	0.251	0.913	0.0	0.0	0.47
Uncond. segment potential	MC(1000...	0.251	0.913	0.0	0.0	0.47
Assoc. Gas [1e9 Sm3]						
Accumulation size above Minimu...	Const	0.0	0.0	0.0	0.0	0.0
Cond. segment potential	Const	0.0	0.0	0.0	0.0	0.0
Uncond. segment potential	Const	0.0	0.0	0.0	0.0	0.0
Condensate [1e6 Sm3]						
Accumulation size above Minimu...	MC(10000)	1.42	1.27	0.21	1.1	3.08
Cond. segment potential	MC(1000...	0.179	0.651	0.0	0.0	0.335
Uncond. segment potential	MC(1000...	0.179	0.651	0.0	0.0	0.335
Total Resources [1e6 Sm3 OE]	MC(10000)	3.41	3.03	0.51	2.66	7.37