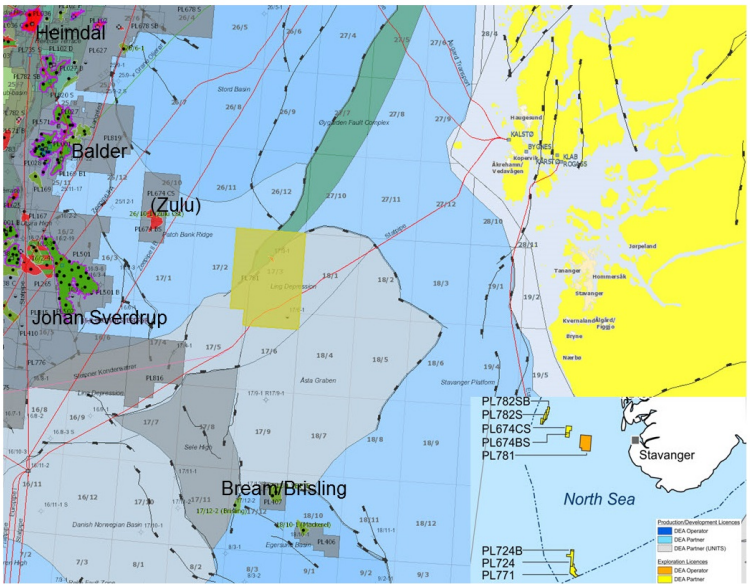
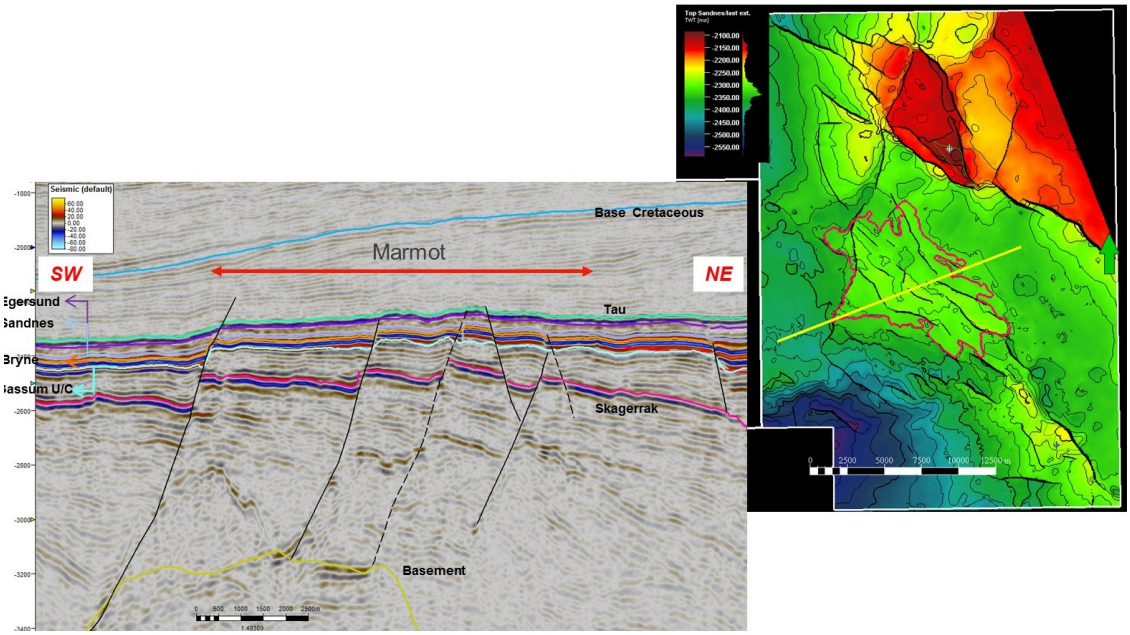
PL781 Relinquishment Report





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1 Key Licence History

License PL781 is located 70km east of Johan Sverdrup and 60-70 km North of the Bream/ Brisling and 18/10-1. The southern part of the license is in the Ling Depression while the northern part covers parts of the Øygarden Fault Complex and Patch Bank Ridge (Fig. 1.1). The license was awarded in February 2015 (APA 2014) to E.ON E&P Norge AS, now DEA Norge AS. DEA is the operator with 40% equity along with Petrolia NOCO AS (former Petrolia Norway AS) and Fortis Petroleum Norway AS who have 30% equity each. The partnership's equity distribution remained unchanged from the award to the Drill or Drop decision. DEA and Petrolia applied for the acreage in an AMI, while Fortis applied on their own, in the APA 2014. All three companies applied for the acreage based on the Middle-Upper Jurassic prospectivity, though Fortis' prospect outlines were different from those of the AMI group. Fortis had also identified prospectivity in the Cretaceous and Paleogene. The main focus has been to evaluate the Jurassic prospectivity.

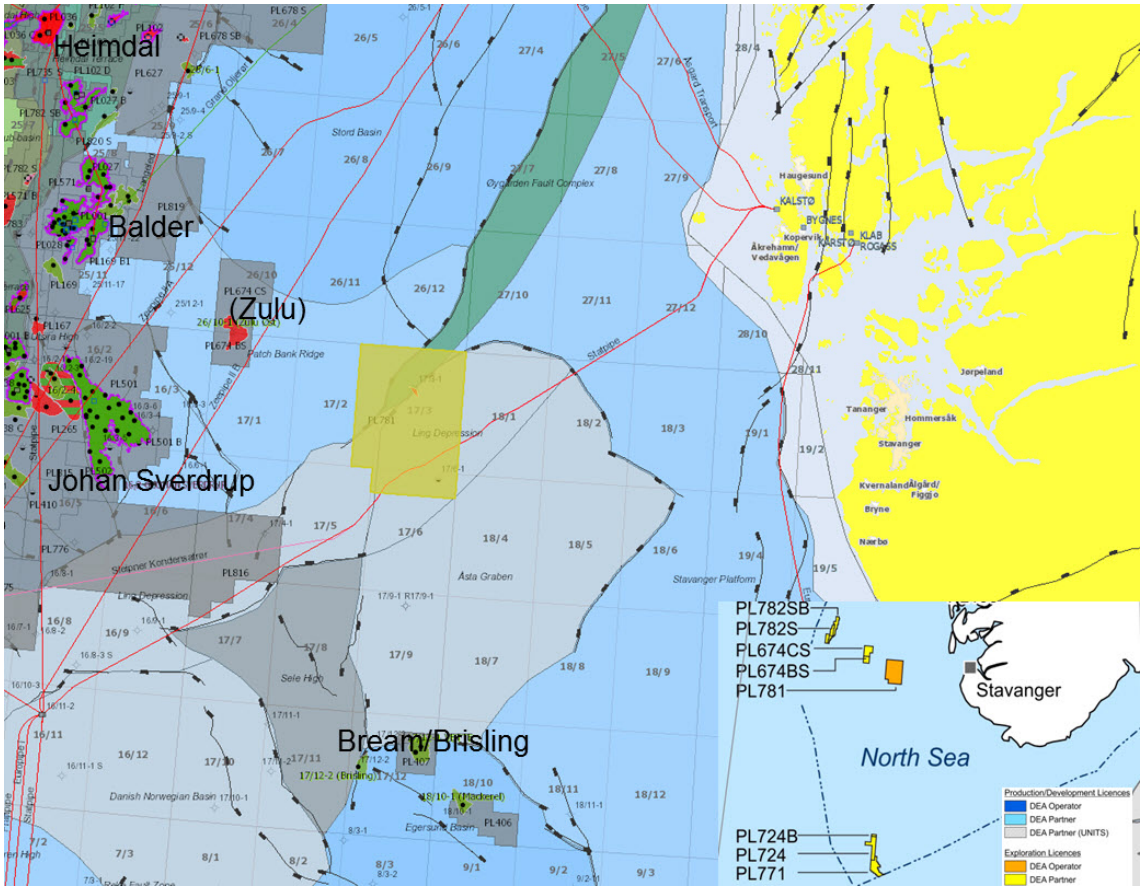


Fig. 1.1 Regional location of PL781

The voting rules are:

- Decisions require a minimum of 2 companies and at least 50% equity.
- Relinquishment of part of whole of the license requires unanimity.

DEA Norge, as operator of PL781, and the partners have decided to relinquish the license before the DoD deadline 06.02.2017.

Initial work obligations and work periods
Within two years from the award (by 06.02.2017):

- Obtain 3D seismic data over the prospective area.
- Drill or Drop.

Within four years from the award (by 06.02.2019)

- Drill exploration well.
- BoK or drop.

Within six years from the award (06.02.2021)

- Conceptual studies.
- BoV or drop.

Within eight years from the award (06.02.2023)

- Prepare development plan.
- PDO or drop.

Overview of meetings held
The table below contains the list of meetings held during the license period:

Table 1.1 Overview of held meetings

Combined EC/MC #1	Established the licence, built the common database, shared the views on prospectivity, budget and work program for 2015.
11/02/2015	
Combined EC/MC #2	Interpretation status and prospect evaluation of the main prospectivity, pressure analysis of the 17/6-1 well, and evaluation of remaining prospectivity.
09/11/2015	
Combined EC/MC #3	Presented volumes and final risking, upside potential and discussed budget and work program, the operator proposed to relinquish the license.
15/11/2016	

Reasons for relinquishment
The main prospect in the license is the Marmot prospect (oil with associated gas). It has been thoroughly evaluated and it has been concluded that the partnership deems the prospect medium risk (34%) but very low reward (2,88 Mean mmSm3oe recoverable resources). The partnership considers the Play risks to be 1. The reservoir sands in the Jurassic Vestland Gp, and the source and seal of the Late Jurassic Tau Fm shales are considered well established and no risk.

At a prospect level the main risks are:

- Prospect trap validity/retention of charge (0,8): The flat nature of the 4-way dip closure is very sensitive to depth conversion.
- Access to charge (0,6): Small and possibly immature kitchen a fair distance away.
- Reservoir quality (0,7): Possible cemented Sandnes Fm.

Reservoir presence and preservation is not considered a risk due to penetrations of these reservoir level sands, Sandnes Fm and Bryne Fm, in nearby wells and good well ties.

Overall Possibility of Finding Hydrocarbons (POFH): 34%.

The operator's Minimum Economic Field Size (MEFS) for this area is estimated to be 9,7 Mean mmSm3oe with a leased FPSO. The Marmot prospect's Mean recoverable resources is estimated to be 2,88 Mean mmSm3oe. This yields a Chance of Commercial Success (COCS) of 1,8%. This is considered by the partnership to be too low to be a drilling candidate.

The partnership has agreed to drop the license.

2 Database

2.1 Well Database

The common well database contain wells that have penetrated the Middle Jurassic reservoir sections and the Upper Jurassic source/seal sections. Most of the wells have been drilled far west of the PL781 license. Hence the wells in the common well database are primarily to the south (Fig. 2.1 and). There are no proximal analogous wells to the north. The 17/6-1 discovery well has been used for fluid substitution and the 17/3-1 well has been key in understanding the access to charge.

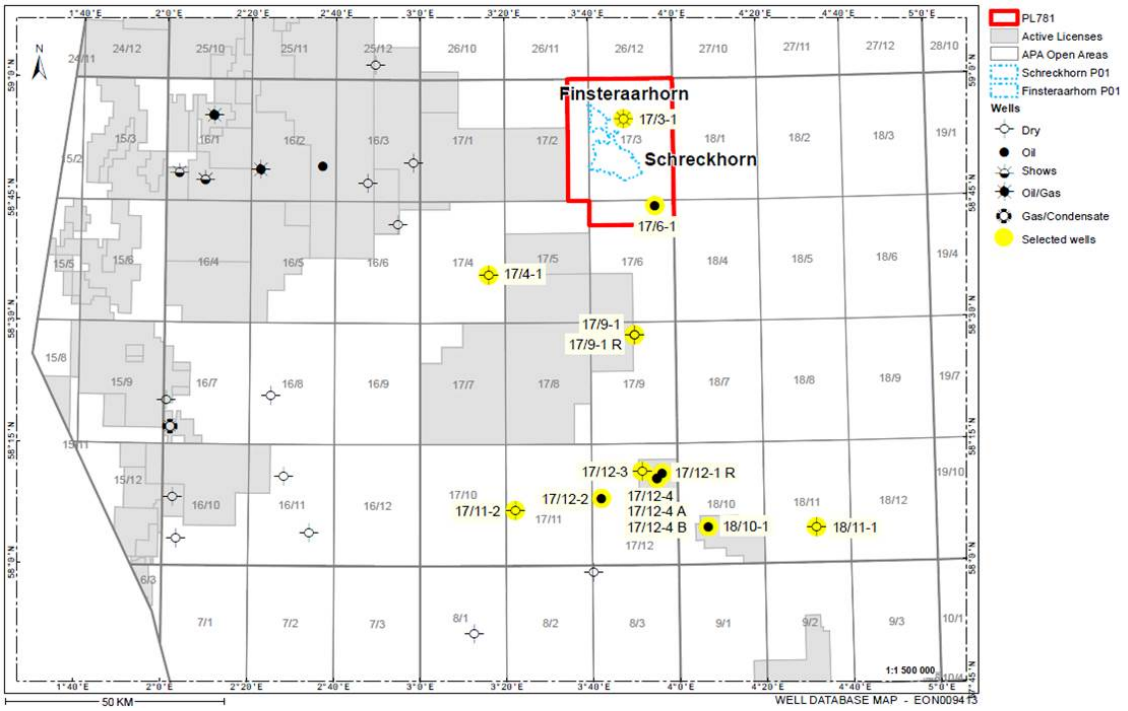


Fig. 2.1 Well overview map

Table 2.1 Well overview table

Well name	Result	Wellbore completion date	Licence	TD (MD) (m RKB)	TVD m RKB	Age at TD	Fm. at TD	Discovery/Field
17/3-1	Gas in Sandnes Fm.	20.08.1995	PL188	2852	2852	Pre-Devonian	Basement	17/3-1 discovery
17/4-1	Dry	26.08.1968	PL007	3997	3997	Early Permian	Rotliegend Gp.	
17/6-1	Oil in Sandnes Fm.	07.02.2011	PL545	3065	3064	Late Triassic	Skagerrak Fm.	Svaneøgle discovery
17/9-1	Dry	23.10.1973	PL002	2816	2816	Middle Jurassic	Vestland Gp.	
17/9-1R	Dry	11.06.1974	PL002	3161	3161	Late Triassic	Skagerrak Fm.	
17/11-2	Dry	17.05.1976	PL010	2644	2644	Late Triassic	Smith Bank Fm.	
17/12-1R	Oil in Sandnes Fm.	21.06.1972	PL016	4298	4298	Late Permian	Zechstein Gp.	Bream discovery
17/12-2	Oil in Sandnes Fm.	09.10.1973	PL016	2334	2334	Devonian	No group defined	Brisling discovery
17/12-3	Dry	03.02.1980	PL016	2730	2730	Late Triassic	Skagerrak Fm.	
17/12-4	Oil in Bryne Fm.	10.07.2009	PL407	2470	2470	Triassic	Skagerrak Fm.	Bream appraisal
17/12-4A	Oil in Bryne Fm.	15.08.2009	PL407	3338	2319	Middle Jurassic	Bryne Fm.	Bream appraisal
17/12-4B	Oil in Bryne Fm.	26.08.2009	PL407	3253	2312	Middle Jurassic	Bryne Fm.	Bream appraisal
18/10-1	Oil in Sandnes and Bryne Fms.	01.01.1980	PL008	2800	2800	Late Triassic	Skagerrak Fm.	18/10 discovery
18/11-1	Dry	31.03.1974	PL008	2086	2086	Pre-Devonian	Basement	

2.2 Seismic Database

Mapping of the prospects in PL781 was based on the DOLPH13033D and TA0701 data sets. Well tie for 17/6-1 was made on the TA0701 dataset, while the well tie for 17/3-1 was made on the DOLPH-13033D dataset. Numerous 2D surveys were also utilized for regional interpretation and understanding. See Fig. 2.2, Fig. 2.3, and Table 2.2 for overview.

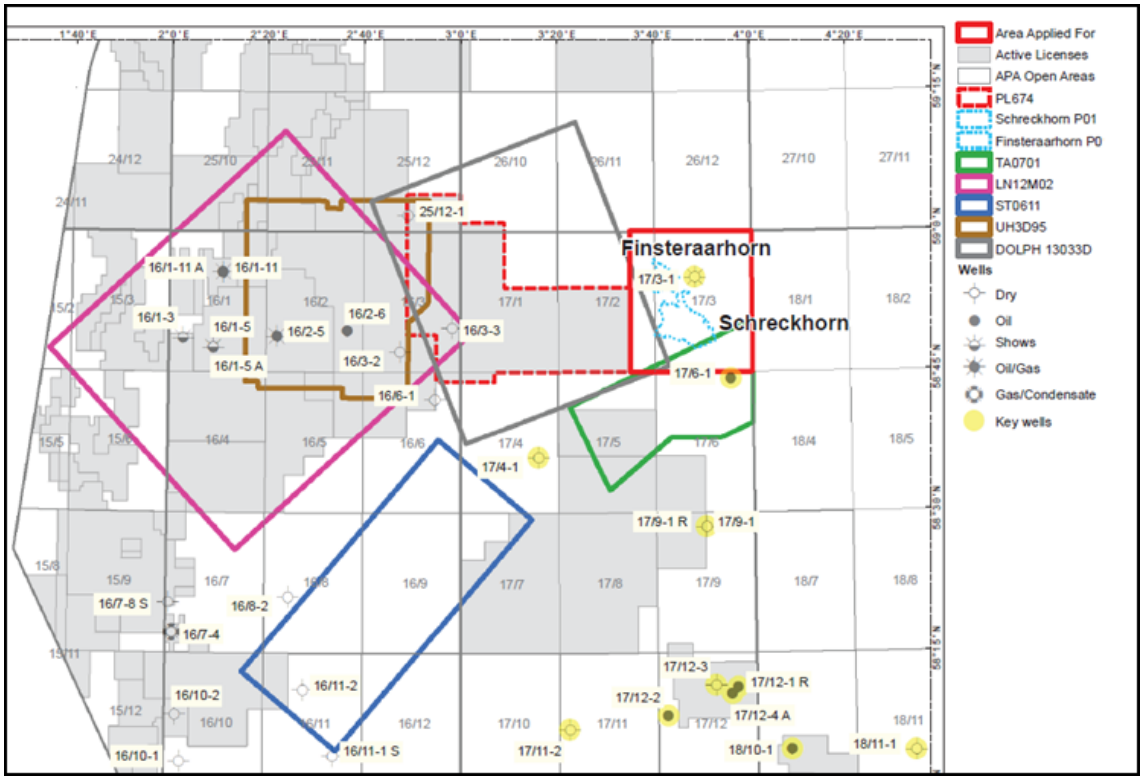


Fig. 2.2 Overview of 3D seismic

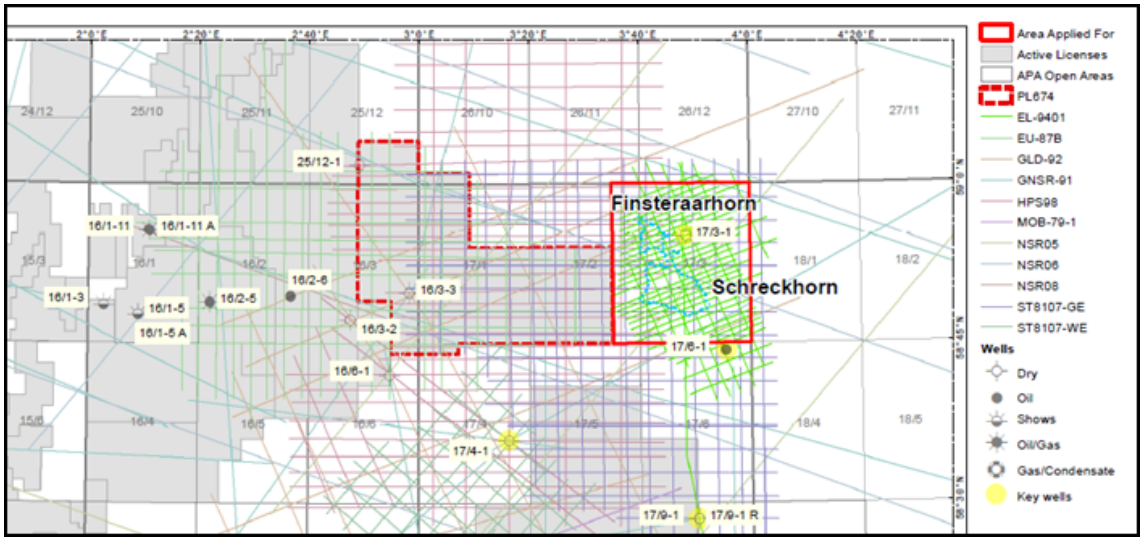


Fig. 2.3 Overview of 2D seismic

Table 2.2 Seismic overview

Survey name	Survey	Quality	Comments
DOLPH-13033D Fasttrack	3D	Good	PL674 licence work & well ties
DOLPH-13033D	3D	Good	PL674 licence work & well ties
TA0701	3D	Good	PL674 licence work, well tie & southern part block 17/3
ST0611(Broadseis, fasttrack cube)	3D	Good	PL674 licence work & well tie
UH3D95	3D	Fair-good	PL674 licence work & well tie
LN12M02 (Broadseis)	3D	Fair-good	PL674 licence work & well tie
NSR05	2D	Good	PL674 and regional work
NSR06	2D	Good	PL674 and regional work
NSR08	2D	Good	PL674 and regional work
EL9401	2D	Good	Block 17/2 & 3 interpretation
ST8107	2D	Fair	Blocks 17/2 & 3 and semiregional mapping
EU87B	2D	Fair	PL674 licence work
MOB-79	2D	Fair	Semiregional (1 line)
GLD-92	2D	Fair-good	PL674 semiregional & well ties
HPS98	2D	Fair-good	Blocks 17/2 & 3 and PL674 work
GNSR-91	2D	Good	PL674 semiregional & well ties

3 Review of Geological and Geophysical Framework

Studies performed

The following geological and geophysical studies have been undertaken in connection with the license work and the preparation of the drill or drop decision.

Table 3.1 Special studies performed for the PL781 prospectivity evaluation

Year	Study name	Author
2015	Well ties	DEA
2015	Velocity model	DEA
2015/2016	Depth conversion uncertainty	DEA
2016	Basin modelling	DEA
2016	Fluid substitution and AVO modelling	DEA

Results of block evaluation and major changes compared to original licence application

Finsteraarhorn and Schreckhorn were the names of the two original prospects that were applied for in the APA 2014 in the AMI between Petrolia and E.ON (now DEA) (Fig. 3.1). The play model for these two prospects has remained the same throughout the license period however, the names have changed to Chamois and Marmot, respectively. The Marmot prospect became the main prospect. It is the evaluation of this prospect that has had the biggest impact of the DoD decision for PL781.

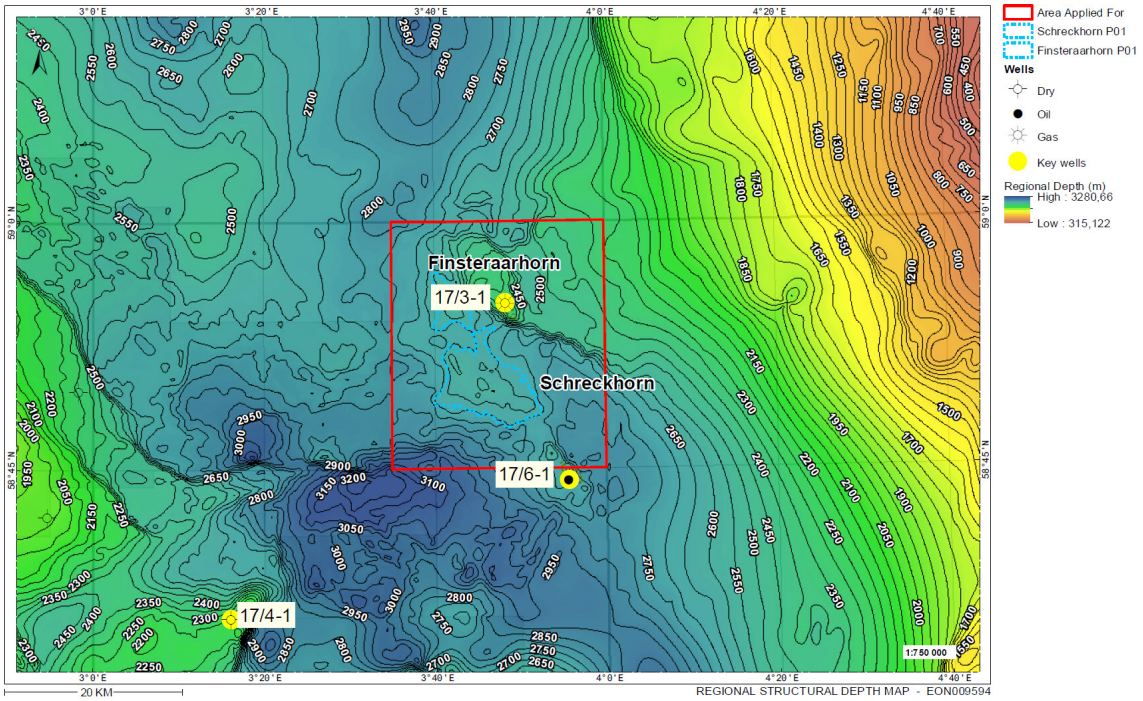


Fig. 3.1 Top Vestland Fm depth map

Several leads were also identified by DEA and Petrolia (Fig. 3.2) and Fortis (Fig. 3.3).

- Chamois Prospect
  - 3-way closure with lateral fault seal dependency for volumes above P90 case.
  - P50 Smaller volumes than Marmot
- Leads: Ibex and Mouflon
  - Recognized 4-way dip closures with unproven source and reservoir play risks in this area.
  - Key surrounding wells do not exhibit reservoir presence and there are no Cretaceous or Paleocene accumulations in the Ling Graben or Stord Basin
  - Hard reflections on seismic

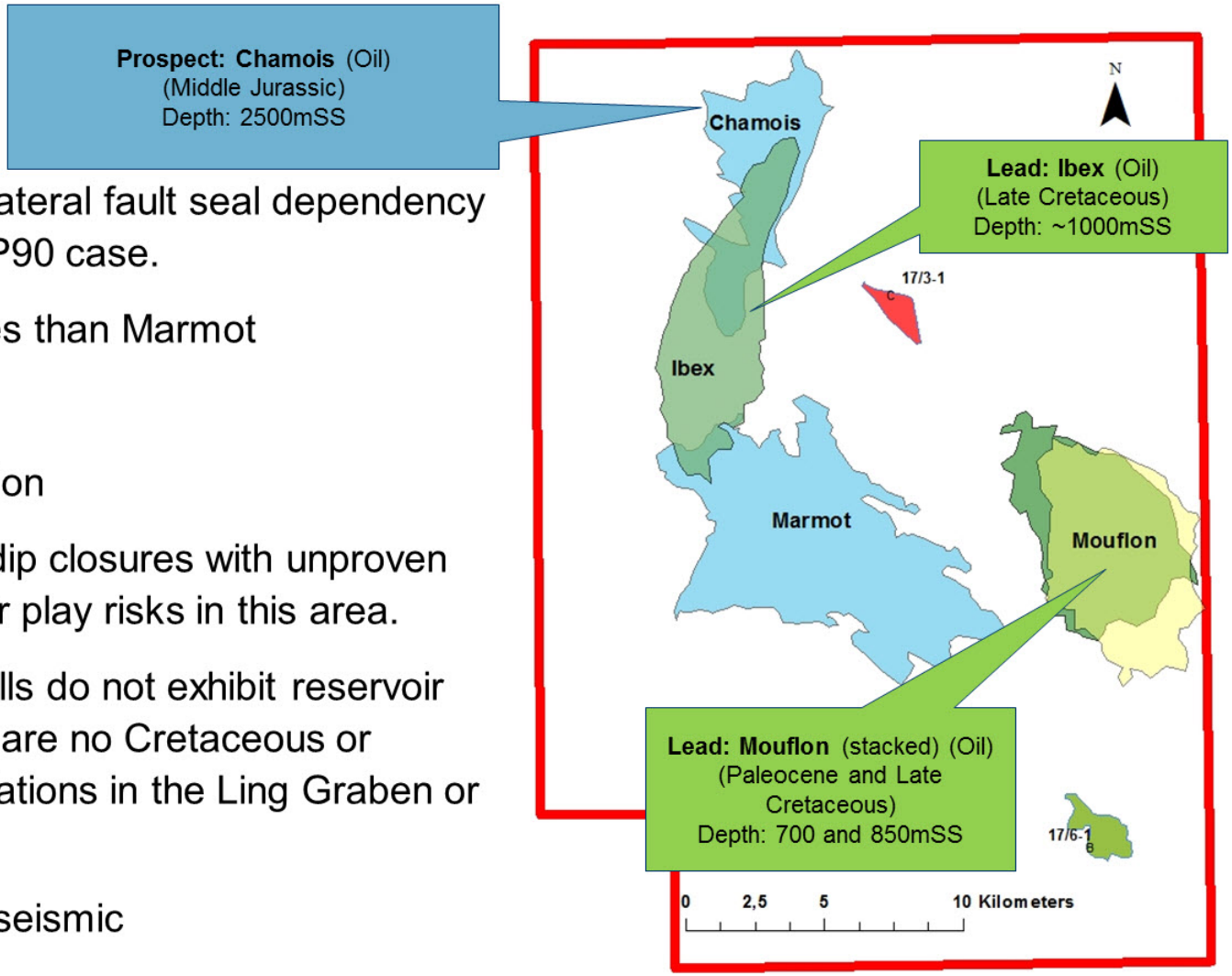


Fig. 3.2 Prospectivity overview

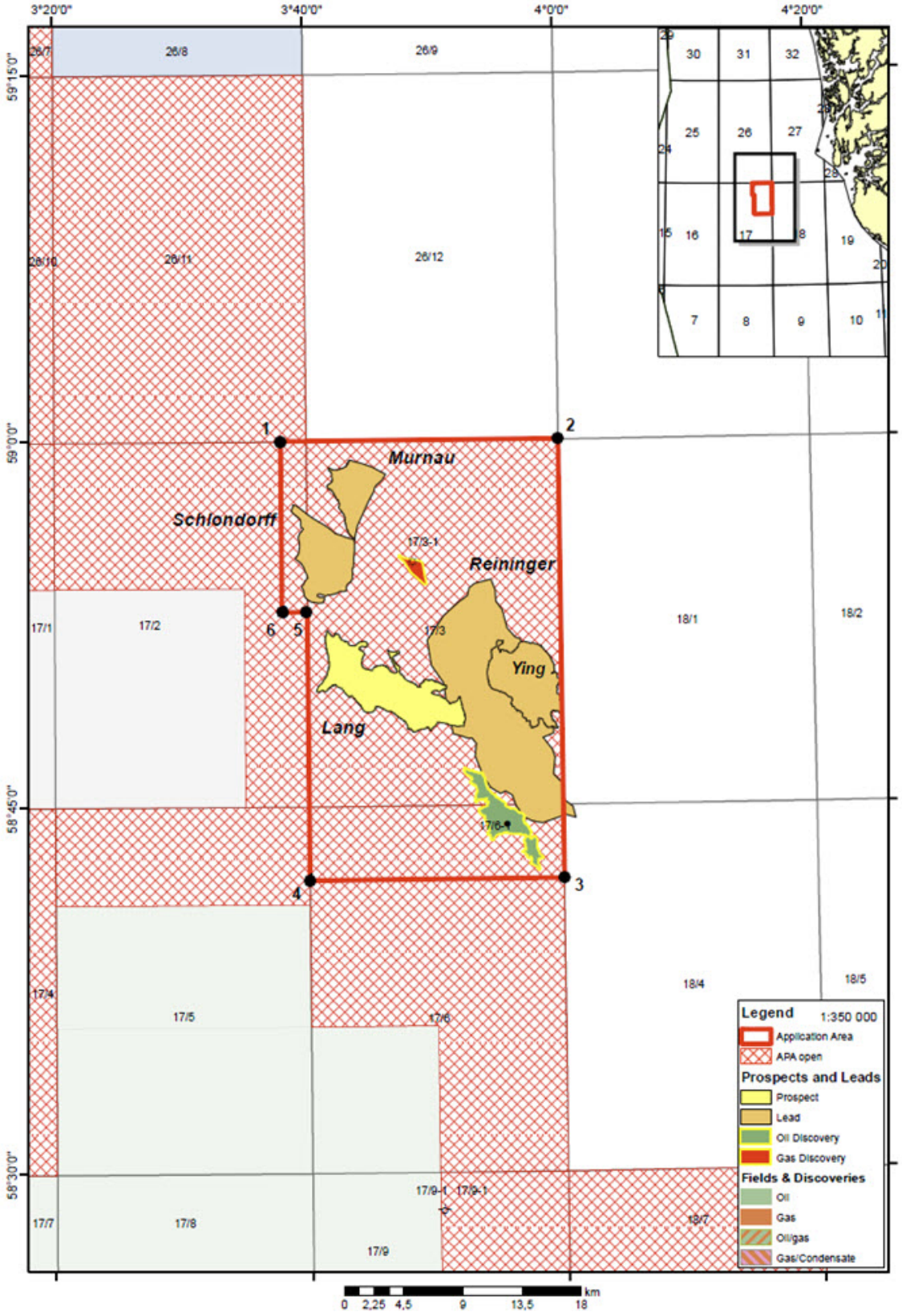


Fig. 3.3 Fortis prospectivity overview

The Marmot prospect is situated in the transition zone between the Ling Depression, the southern extension of the Øygarden Fault complex and the Patch Bank Ridge. It is located approximately 70km East of the proven Johan Sverdrup trend of the Utsira High and 60-70 km North of the Bream/Brisling and 18/10-1 Middle Jurassic Vestland Gp. Discoveries. The prospects and leads lie immediately updip from the deepest part of the Ling Depression (Fig.

1.1). The Marmot prospect is a downthrown, segmented, structural trap situated in the hanging-wall of the bounding fault to the 17/3-1 high and located in a similar structural position as the 17/6-1 Svaneøgle structure (Fig. 3.4 and Fig. 3.5). The Chamois prospect is in a similar structural position, however, displaying a compressional element probably due to influence by the Øygarden Fault Complex and can be described by a pop-up structure/compression of hanging wall (Fig. 3.6 and Fig. 3.7).

Fairly flat structure with basement-rooted faulting which were not active or re-activated in the Cretaceous.

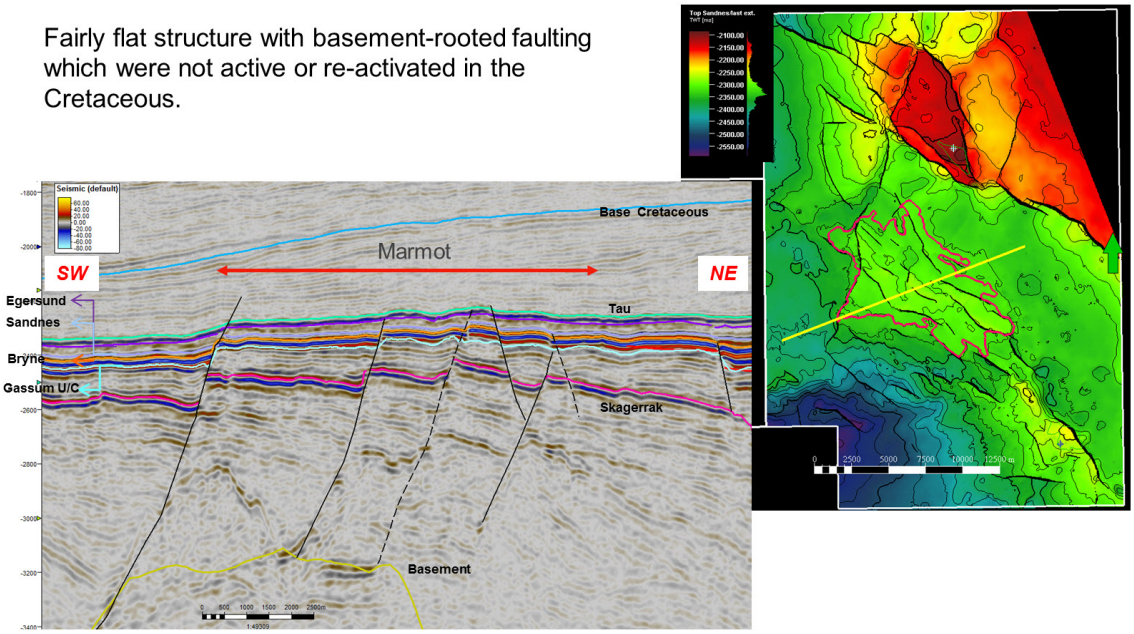


Fig. 3.4 Key seismic section 1

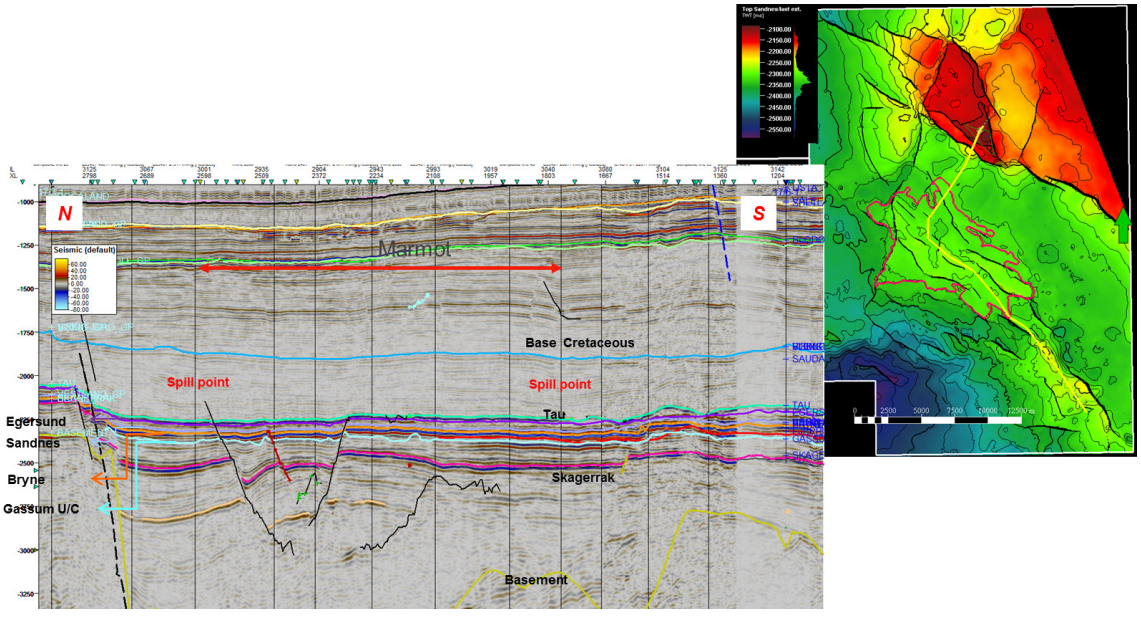


Fig. 3.5 Key seismic section 2

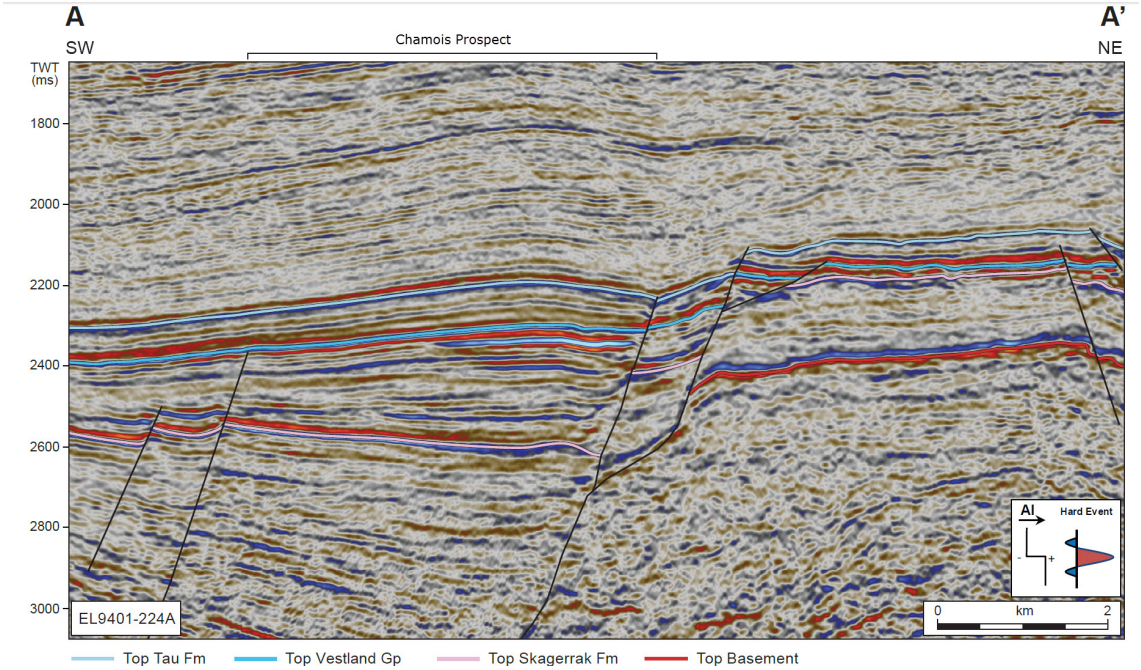


Fig. 3.6 SW-NE seismic line through the Chamois Prospect

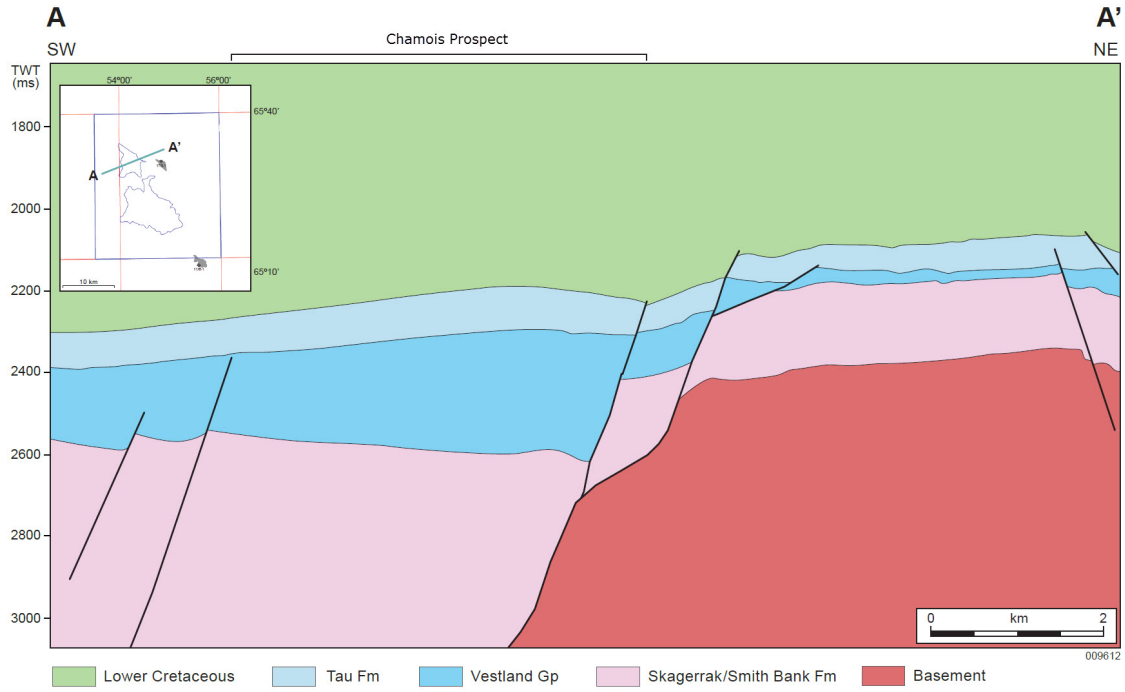


Fig. 3.7 SW-NE geosection line through the Chamois Prospect

The additional prospectivity in the Cretaceous and Paleogene identified by Fortis were the Ekofisk Fm Ying oil lead. And the Balder Fm Reininger oil lead. See Fig. 3.3 and Fig. 3.8 for overview map and geosection.

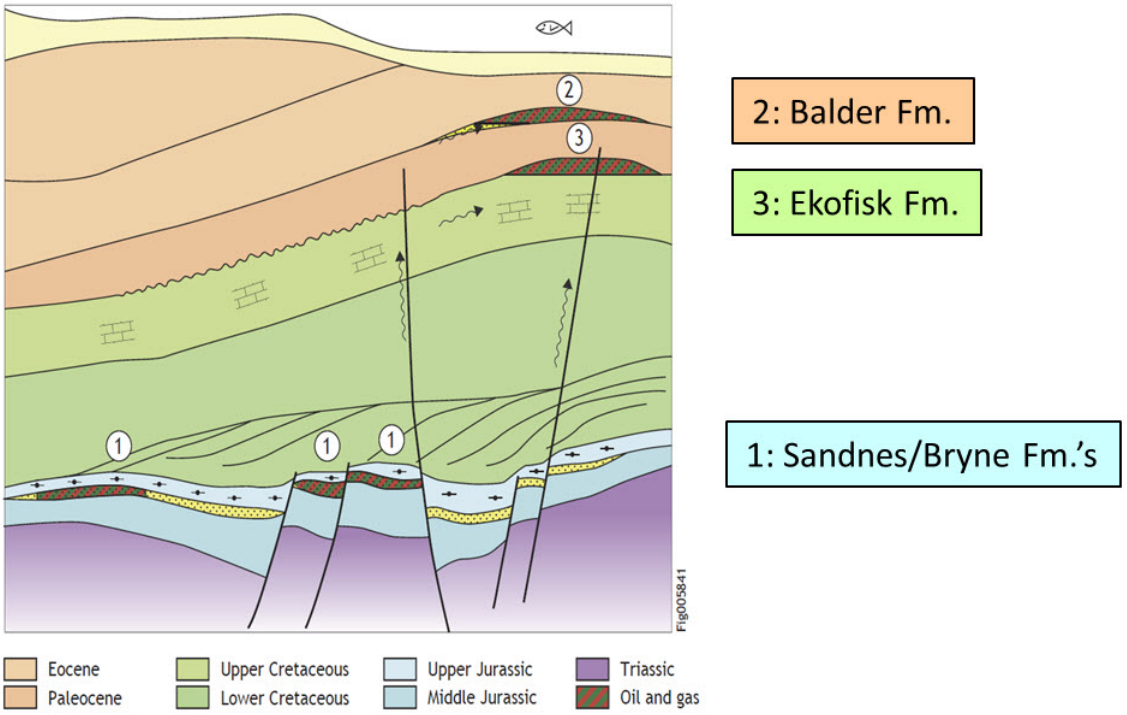


Fig. 3.8 Fortis prospectivity geosection

The Marmot prospect is the only prospect that has gone through the whole technical and economic evaluation. The main difference in the evaluation of Marmot between the APA application and the present is that it is now expected to have a thinner reservoir, lower porosity, lower N/G, smaller HC column and a lower GRV (the latter is primarily due to the fact that the prospect was interpreted on 2D data in the APA while it has been re-interpreted on 3D data in the license period). See overview below:

Table 3.2 Main differences between the current Marmot prospect and the Marmot prospect in the APA 2014

	APA 2014 (Overall POFH 18%)	Current (Overall POFH: 34%)
Reservoir presence and preservation	0,7	1
Charge	0,4	0,6
Reservoir thickness (m) P90-P50-P10	80-110-140	50-75-100
Porosity (fraction)	0,15-0,20-0,25	0,14-0,17-0,2
N/G (fraction)	0,40-0,55-0,70	0,3-0,45-0,6
HC column height (m)	38-70-102	30-44-64
GRV mmSm3	2044-2267-2498	1411-1739-1988
Volumes P90-P50-Mean-P10 mmSm3oe rec res	0,9-10-17-43	0,26-1,45-2,9-7

4 Prospects Update

Prospects originally presented in the license application
The AMI group applied in the APA 2014 based on the Schreckhorn (now Marmot) and Finsteraarhorn (now Chamois) prospects, and the Ibex and Mouflon Leads (Fig. 3.2). Fortis applied in the APA 2014 based on an evaluation of the Svanøgle discovery, one prospect named Lang, and four leads named Schløndorff, Murnau, Reiniger, and Ying (Fig. 3.3 and Fig. 3.8).

Marmot prospect

The changes outlined in the previous section have been applied to the Marmot prospect which has yielded the following final prospect evaluation volumetric results.

- The Vestland Gp thickness ranges are based on the two closest wells (Fig. 4.1) on either side of prospect (50 and 100m thickness) Seismic mapping suggests 80m thickness. See Fig. 4.2 for ranges.
- The Vestland Gp porosity ranges are also based on the two wells (Fig. 4.1) on either side of the prospect. These wells have around 16,5% porosity. See Fig. 4.3 for ranges.
- The Vestland Gp N/G ranges are based on the same two wells (Fig. 4.1) on either side of the prospect which yields a range between 25% and 60% N/G. See Fig. 4.4 for ranges.
- The contact range is based on the underfilling of the two (Fig. 4.1) closest structures penetrated by wells. The contact distribution is skewed such that the Mean is close to the 17/6-1 well (Fig. 4.5). This leaves a 30m column updip of the well location. The pressure analysis indicates an OWC at 2634mTVDss. The HC column in 17/6-1 is therefore assumed to be 47m which is represented by the Mean case in the volumetric input for Marmot. Pmax is defined as the spillpoint. The Area/depth curves have a -20/+10 uncertainty range. See Fig. 4.6 for the geometrical input overview and Fig. 4.7 for the map overview.
- These final prospect evaluation inputs yield the following in-place and recoverable resources outlined in Fig. 4.8 and Fig. 4.9, respectively.

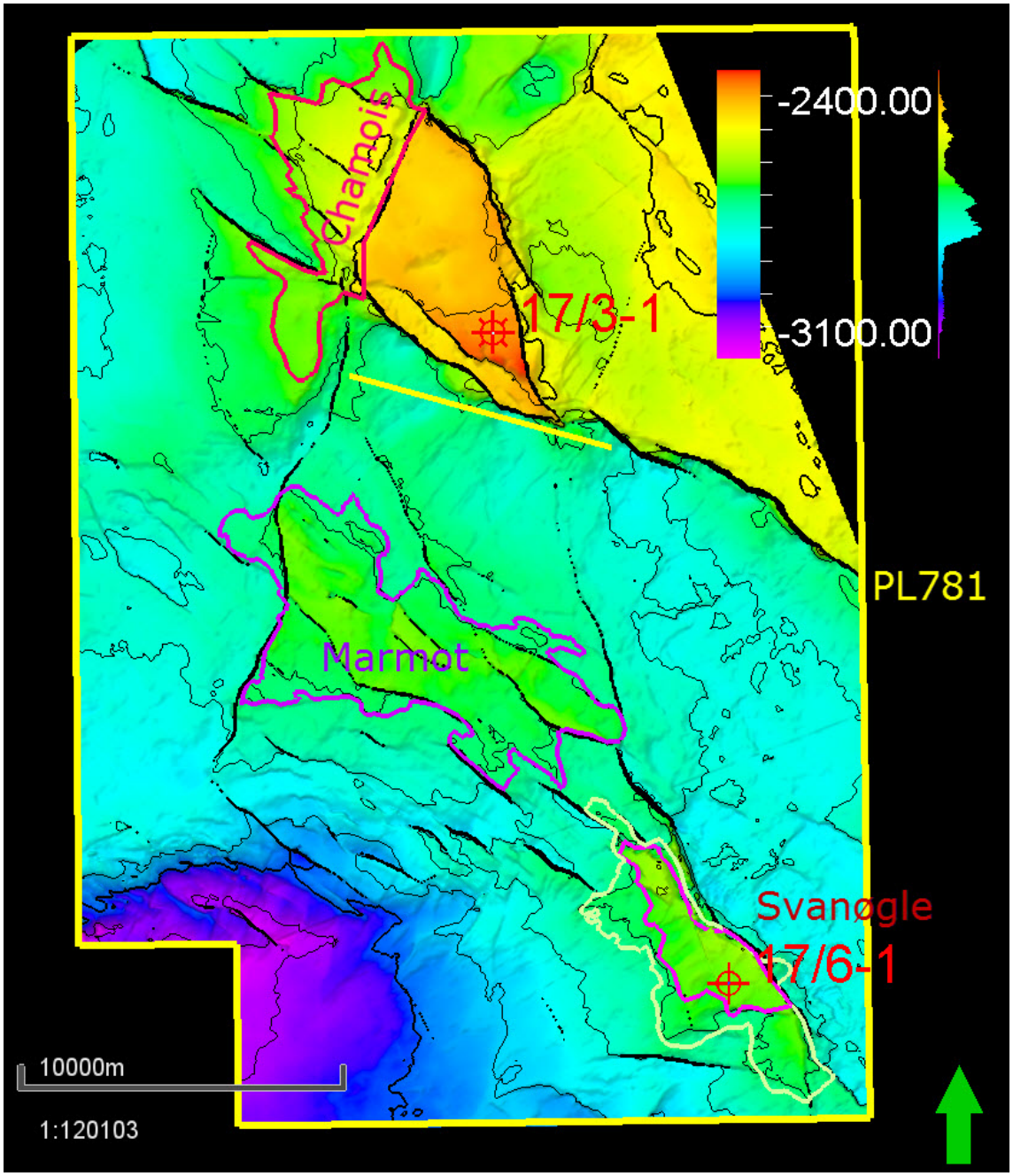


Fig. 4.1 2 key nearby wells

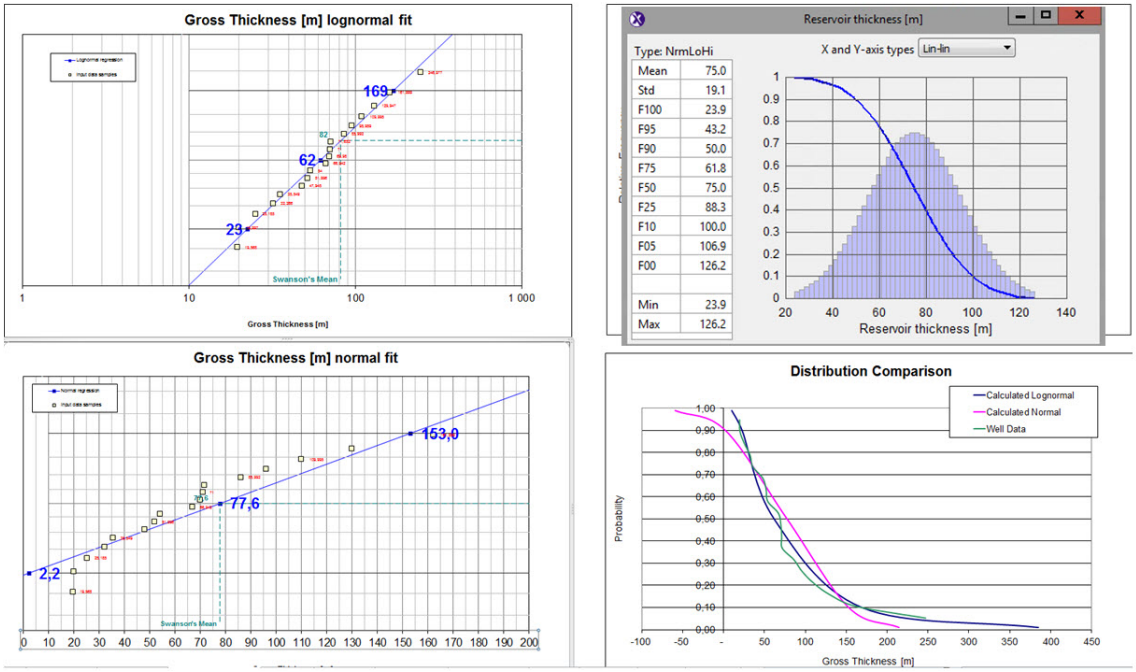


Fig. 4.2 Marmot thickness ranges

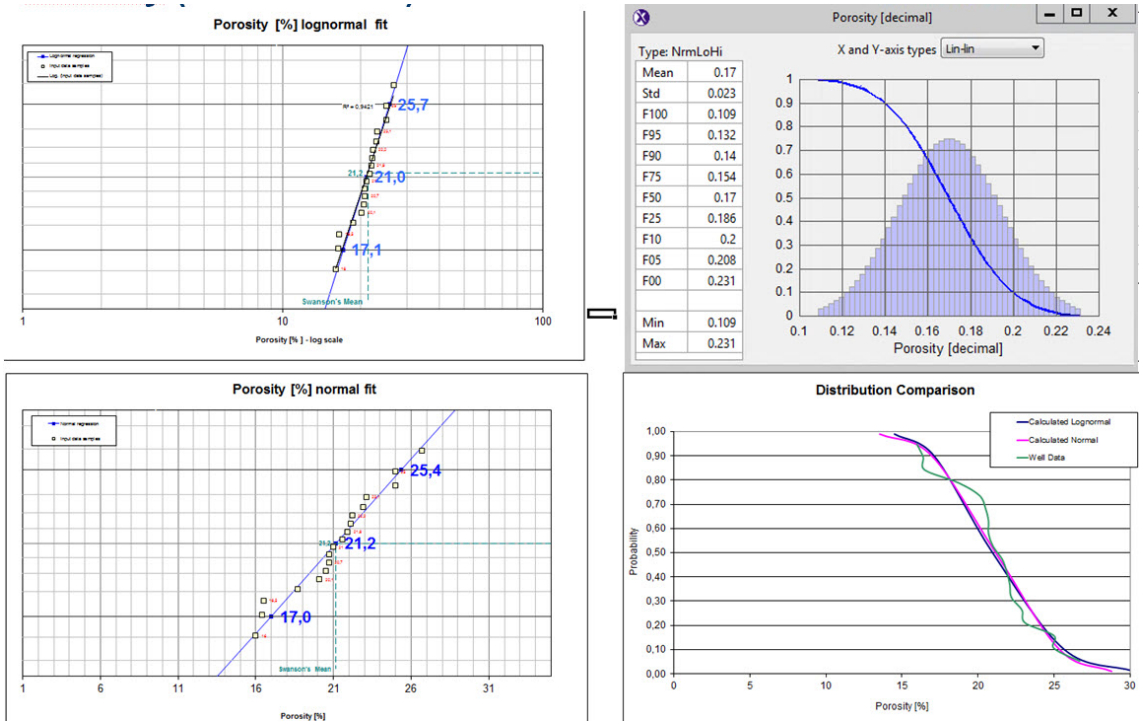


Fig. 4.3 Marmot porosity ranges

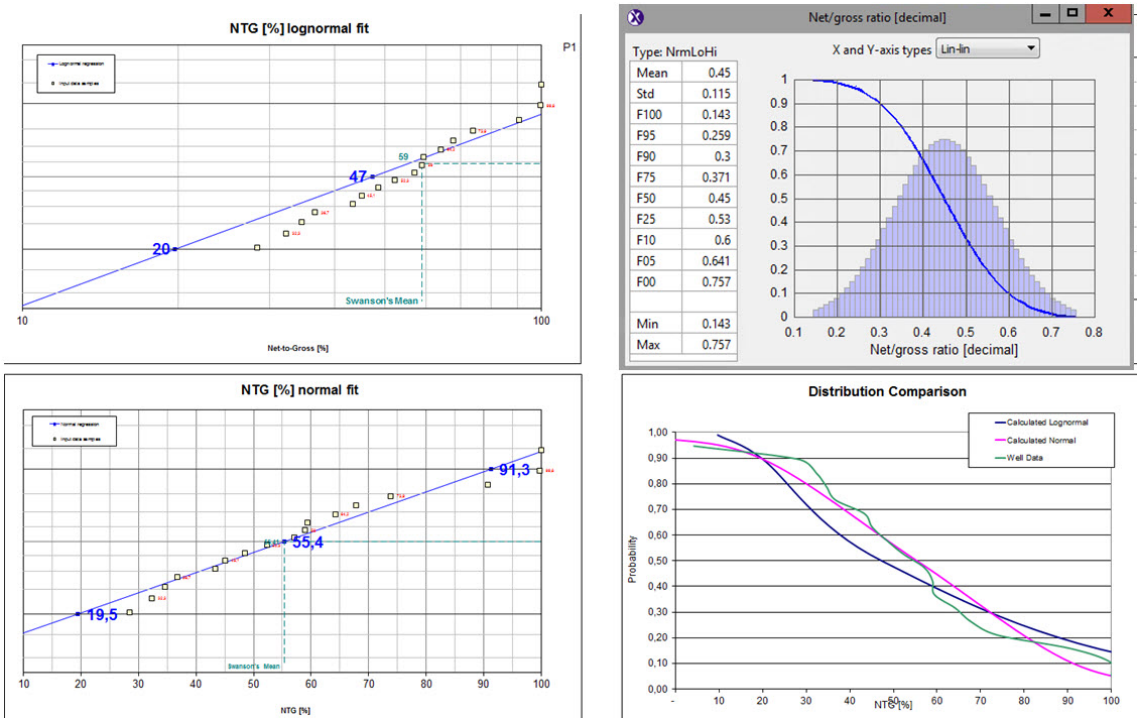


Fig. 4.4 Chamois N/G ranges

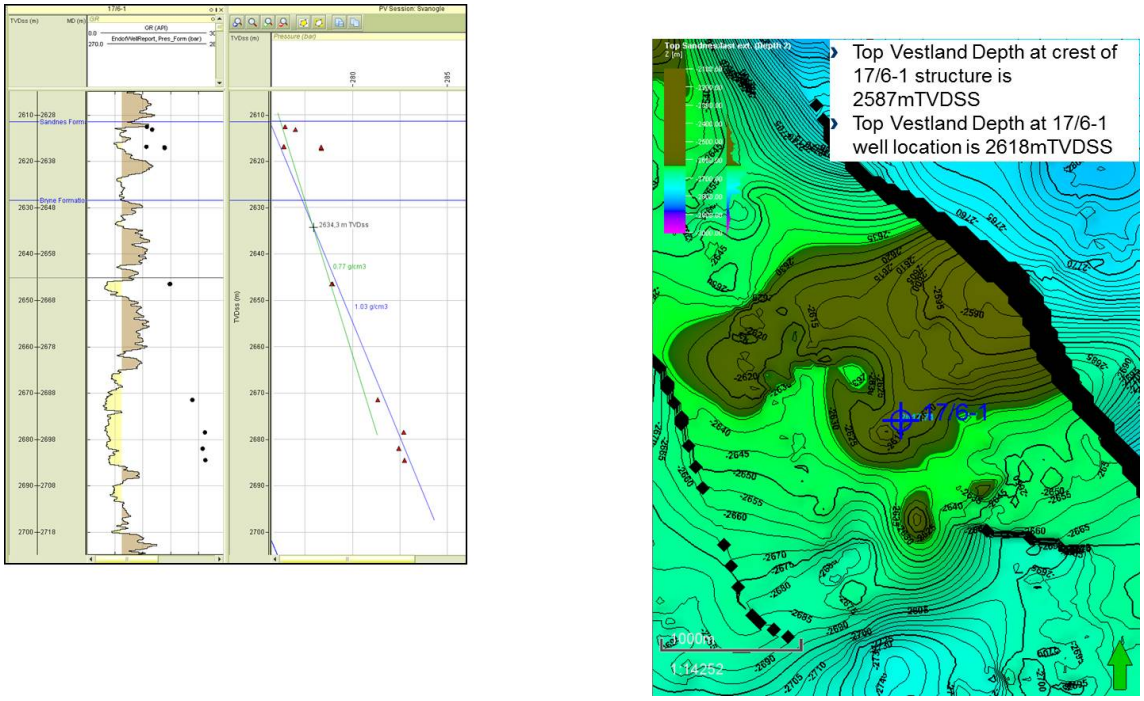
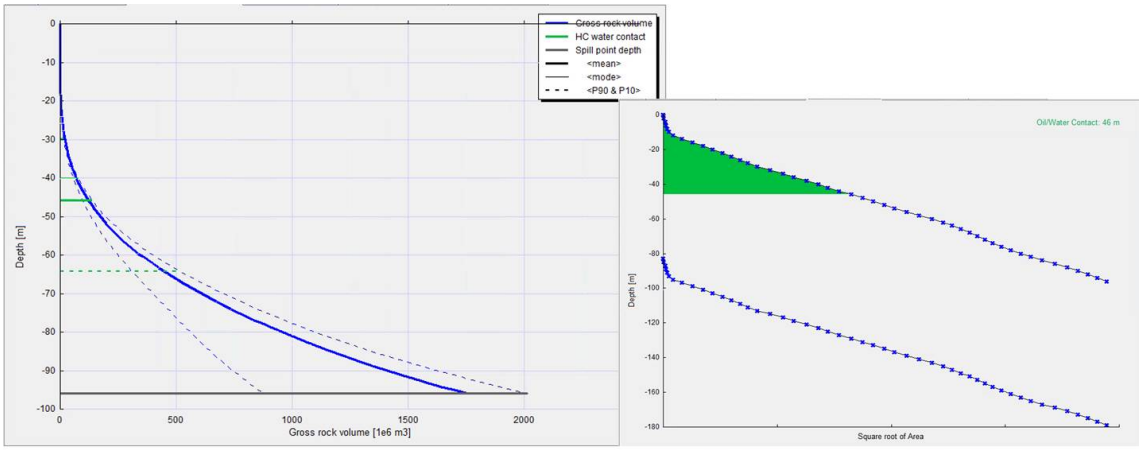


Fig. 4.5 17/6-1 underfilling



Resource Type [Units]	Dist. type	Mode	Mean	Std. dev.	F99	F90	F50	F10	F1
Overall									
Gross rock volume - result [1e6 ...	MC(10000)	1791.5	1716.0	225.4	1103.4	1410.5	1739.0	1987.6	2136.6
Productive area [km2]	MC(10000)	3.47	12.3	10.0	1.14	2.72	9.34	26.3	47.6
Average gross pay [m]	MC(10000)	7.0	11.4	4.53	4.33	6.99	10.6	17.4	25.5
Net rock volume - result [1e6 m3]	MC(10000)	8.77	83.2	113.6	1.9	7.81	42.8	205.7	578.7
Average net pay [m]	MC(10000)	3.73	5.16	2.51	1.42	2.53	4.61	8.44	13.5
HC pore volume [1e6 m3]	MC(10000)	1.0	10.1	14.4	0.214	0.889	5.02	25.1	71.5
HC bearing gross rock volume [1...	MC(10000)	18.5	184.2	239.0	5.0	18.7	99.1	455.9	1203.9
HC water contact - result [m]	MC(10000)	41.3	45.7	13.7	22.7	30.0	43.8	64.3	85.4
Oil									
Oil gross rock volume [1e6 m3]	MC(10000)	18.5	184.2	239.0	5.0	18.7	99.1	455.9	1203.9
Oil pore volume [1e6 m3]	MC(10000)	1.0	10.1	14.4	0.214	0.889	5.02	25.1	71.5

Fig. 4.6 Contact ranges and Area/Depth curves

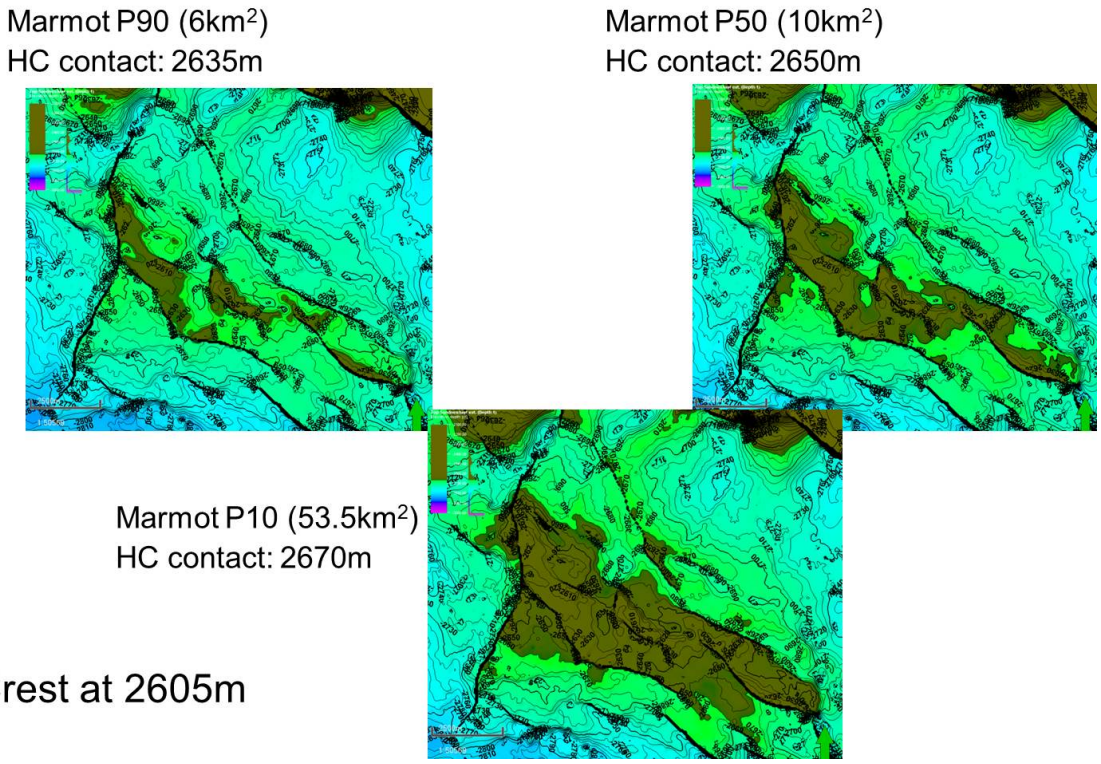


Fig. 4.7 Map overview of contacts

Resource Type [Units]	Dist. type	Mode	Mean	Std. dev.	F99	F90	F50	F10	F1
Oil [1e6 Sm3]									
Accumulation size	MC(10000)	0.779	7.74	10.8	0.181	0.705	3.96	19.1	53.9
Uncond. prospect potential	MC(10000)-r		2.64	7.28	0.0	0.0	0.0	7.9	36.1
Assoc. Gas [1e9 Sm3]									
Accumulation size	MC(10000)	0.053	0.485	0.679	0.0118	0.0444	0.248	1.2	3.46
Uncond. prospect potential	MC(10000)-r		0.166	0.459	0.0	0.0	0.0	0.489	2.29
Non Assoc. Gas [1e9 Sm3]									
Accumulation size	MC(0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Uncond. prospect potential	MC(0)-r	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Condensate [1e6 Sm3]									
Accumulation size	MC(0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Uncond. prospect potential	MC(0)-r	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Resources [1e6 Sm3 OE]									
Accumulation size	MC(10000)	0.835	8.22	11.4	0.193	0.75	4.21	20.3	57.0
Uncond. prospect potential	MC(10000)-r		2.81	7.73	0.0	0.0	0.0	8.4	38.4
HC liquid [1e6 Sm3]									
Accumulation size	MC(10000)	0.779	7.74	10.8	0.181	0.705	3.96	19.1	53.9
Uncond. segment potential	MC(10000)-r		2.64	7.28	0.0	0.0	0.0	7.9	36.1
Gas [1e9 Sm3]									
Accumulation size	MC(10000)	0.053	0.485	0.679	0.0118	0.0444	0.248	1.2	3.46
Uncond. prospect potential	MC(10000)-r		0.166	0.459	0.0	0.0	0.0	0.489	2.29

Fig. 4.8 Marmot in-place resources

Resource Type [Units]	Dist. type	Mode	Mean	Std. dev.	F99	F90	F50	F10	F1
Oil [1e6 Sm3]									
Accumulation size	MC(10000)	0.156	2.71	3.86	0.0604	0.241	1.36	6.68	19.1
Uncond. prospect potential	MC(10000)-r		0.927	2.6	0.0	0.0	0.0	2.76	12.8
Assoc. Gas [1e9 Sm3]									
Accumulation size	MC(10000)	0.021	0.17	0.244	0.00385	0.0151	0.0852	0.417	1.24
Uncond. prospect potential	MC(10000)-r		0.058	0.164	0.0	0.0	0.0	0.169	0.802
Non Assoc. Gas [1e9 Sm3]									
Accumulation size	MC(0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Uncond. prospect potential	MC(0)-r	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Condensate [1e6 Sm3]									
Accumulation size	MC(0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Uncond. prospect potential	MC(0)-r	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Resources [1e6 Sm3 OE]									
Accumulation size	MC(10000)	0.247	2.88	4.09	0.0652	0.257	1.45	7.11	20.3
Uncond. prospect potential	MC(10000)-r		0.985	2.75	0.0	0.0	0.0	2.94	13.5
HC liquid [1e6 Sm3]									
Accumulation size	MC(10000)	0.156	2.71	3.86	0.0604	0.241	1.36	6.68	19.1
Uncond. segment potential	MC(10000)-r		0.927	2.6	0.0	0.0	0.0	2.76	12.8
Gas [1e9 Sm3]									
Accumulation size	MC(10000)	0.021	0.17	0.244	0.00385	0.0151	0.0852	0.417	1.24
Uncond. prospect potential	MC(10000)-r		0.058	0.164	0.0	0.0	0.0	0.169	0.802

Fig. 4.9 Marmot recoverable resources

Play risks

The risking of the Marmot prospect yields an overall play risk of 1. This is because the Vestland Gp sands have been encountered in the wells surrounding the prospect. The Upper Jurassic shales is also a well established regional top seal. The Upper Jurassic Tau Fm is in the oil generation window in the area. In addition the 17/6-1 well has proven a mature petroleum system. Both lateral and vertical migration is possible.

Prospect risks

The Sandnes Fm and the Bryne Fm sands are proven in nearby wells and it is considered unlikely that no sands exists in the prospect. Hence, reservoir presence and preservation is given a geological chance factor of 1. The reservoir quality has a higher risk as the nearby wells indicate an onset of cementation in the Sandnes Fm, but better poro/perm in the Bryne Fm. The access to charge is based on a confident mapping of the source rock on recent 3D data. However, the drainage area is small and there is only the underfilled 17/6-1 discovery that proves this source. Hence, the charge risk is set to 0,6. The trap validity risk is low because of good confidence mapping of the structure. It spills towards the 17/3-1 well in the north and the 17/6-1 well to the south. Marmot's flat structure and the spill point's sensitivity to depth conversion plays a relatively important part in the overall size of the prospect. The overall Potential Of Finding Hydrocarbons (POFH) for Marmot is 34% (Table 4.1).

Table 4.1 Overall Geological POFH - Marmot prospect

RISK PARAMETER	P	COMMENT
Play Reservoir Presence	1	Proven Play
Play Source Presence, Maturity and Communication	1	Proven Play
Play Top Seal Presence	1	Proven Play
Prospect Reservoir Presence / Preservation (local)	1	Sandnes and Bryne Fm found in adjacent wells
Prospect Reservoir Quality	0,7	Possible cementation in Sandnes Fm
Prospect Access to Charge	0,6	Small kitchen, fair distance, possible immaturity
Prospect Trap Validity / Retention of Charge	0,8	Fairly flat 4-way dip closure
TOTAL	**34%**	

Chamois prospect

Chamois is a Middle Jurassic oil prospect. It is a 3-way closure with a lateral faul seal dependent trap in the P90 case (Fig. 4.10 and Fig. 4.11). The sealing capacilities of this fault is important as it is down dip from the 17/3-1 discovery. This uncertainty has a big impact on column heights and the retention and access to charge risks (Fig. 4.12). 17/3-1 is an underfilled gas/condensate discovery which proves HC in the area but also suggests that Chamois is in a migration shadow and/or is leaking in to the 17/3-1 high (Fig. 4.13 and Fig. 4.14).

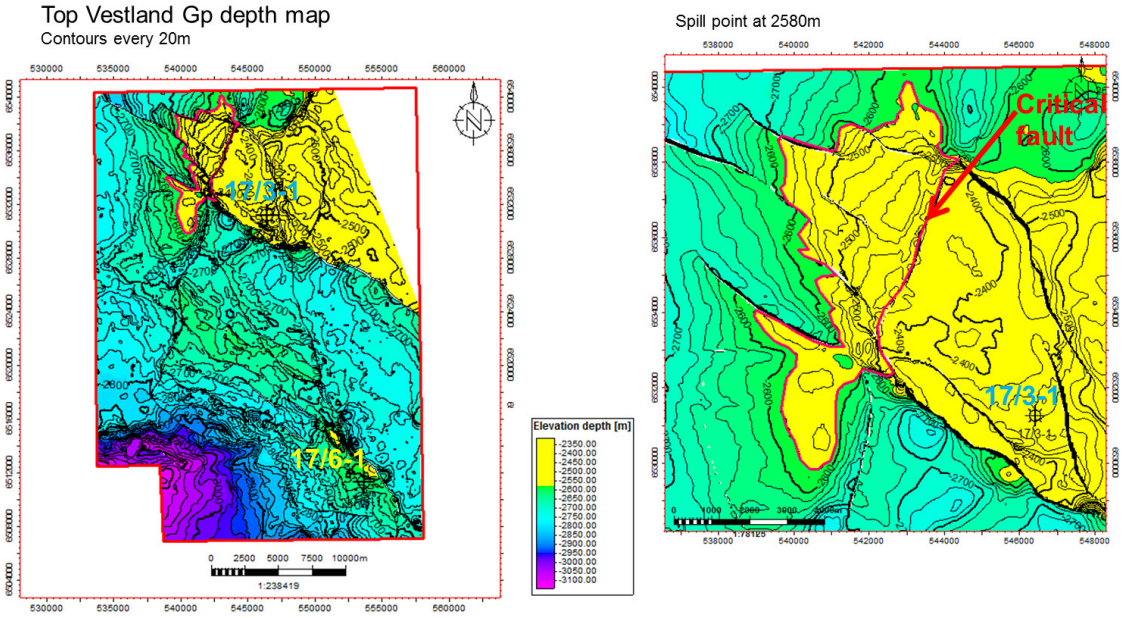


Fig. 4.10 Chamois top reservoir map

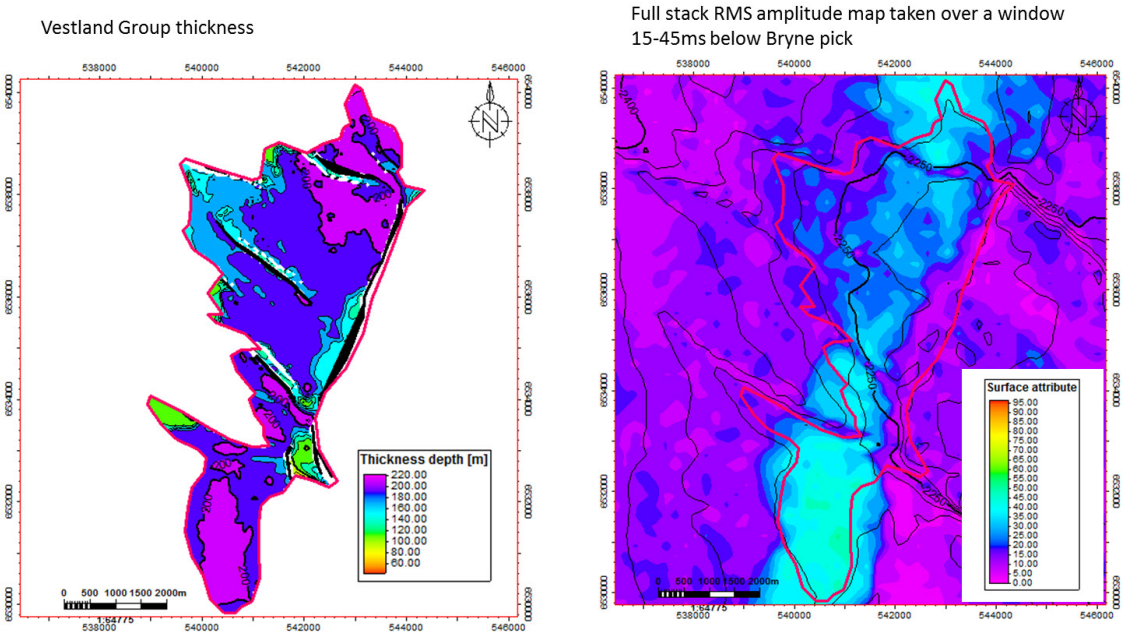


Fig. 4.11 Chamois reservoir thickness map and RMS map

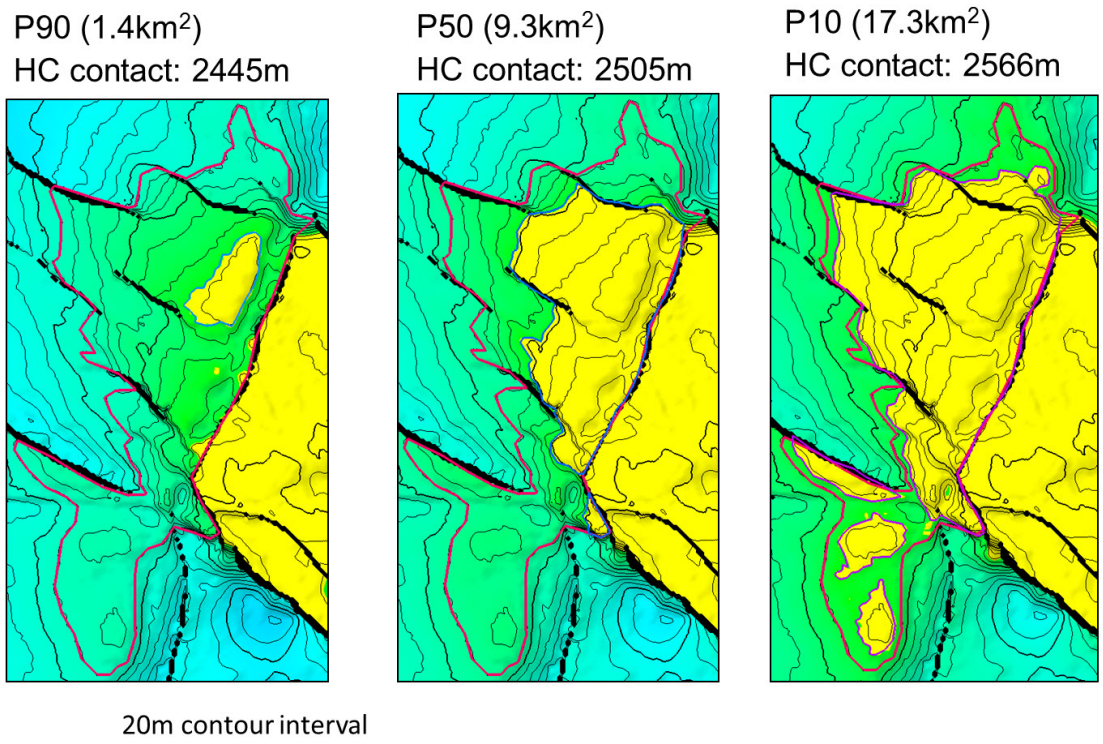


Fig. 4.12 Chamois contact ranges

Basin modeling fails to fill accumulation at Chamois. Possible migration shadow.

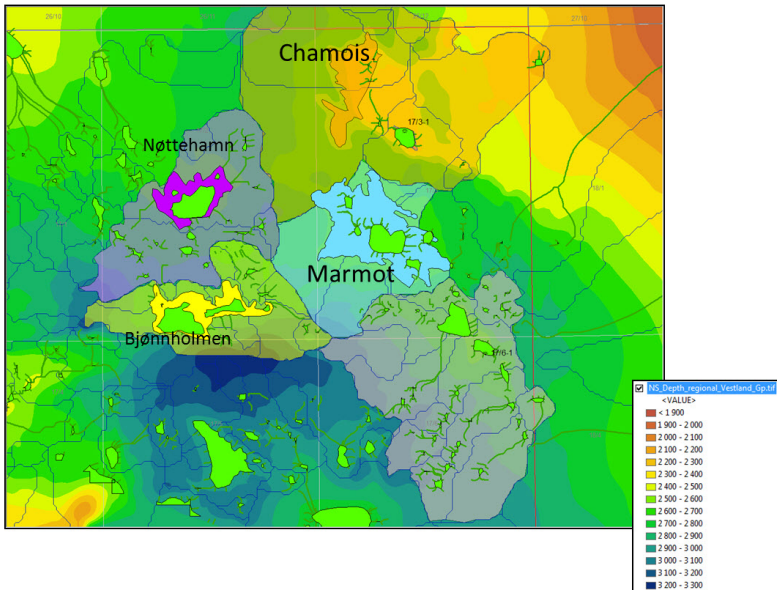


Fig. 4.13 Chamois Top Vestland drainage area

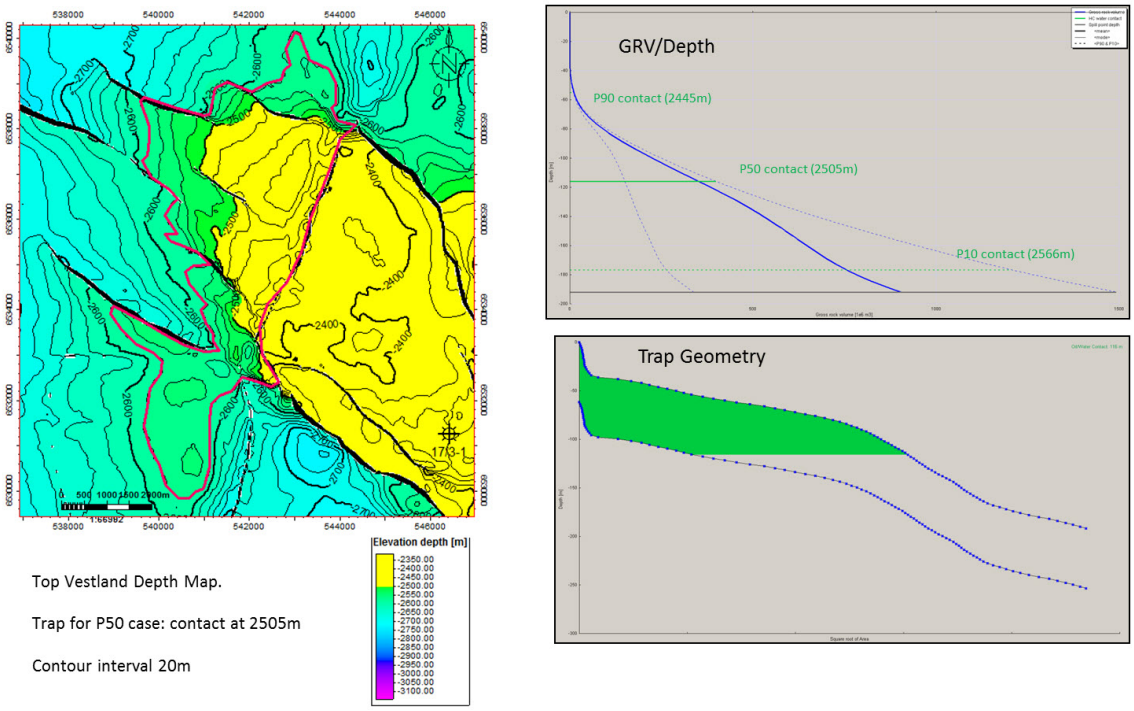


Fig. 4.14 Chamois prospect summary

Ibex and Mouflon leads

The Ibex and Mouflon leads are 4-way dip closures with unproven source and reservoir play risks in this area. See Fig. 3.2 for location overview. The key surrounding wells do not exhibit reservoir presence and there are no Cretaceous or Paleocene accumulation in the Ling Graben or Stord Basin. They are both oil leads in the Late Cretaceous, but the Mouflon lead also has a Paleocene component.

Svanøgle discovery

The Svanøgle discovery well hit the main target, Sandnes and Bryne formations at 2630 m. The formations had a total gross reservoir thickness of 96 m containing sandstones interbedded with claystones and thin coal beds. Reservoir properties were poorer than expected in the Sandnes Formation, and only minor amounts of hydrocarbons (oil) were encountered in the

uppermost part. The Bryne Formation had a better reservoir sand development, but was found to be water bearing. The secondary target Sauda Formation had no sand/reservoir development. The Gassum/Skagerrak Formation showed minor amounts of sandstones, but contained no hydrocarbons. The Balder Formation showed no reservoir development and had no indications of hydrocarbon shows. Two cuttings samples from the Sandnes Formation showed weak cut fluorescence (no core samples were taken); otherwise no oil shows were recorded in the well.

Lang prospect

The reservoir in the Lang prospect is a Sandnes Fm and Bryne Fm located in a horst block. The play model is similar to the other Middle Jurassic prospects and leads in the license.

Schløndorff and Murnau prospects

The Schløndorff and Murnau prospects constitutes more or less what the AMI group refers to as the Chamois prospect. Both Schløndorff and Murnau are tilted fault blocks with medium sized volumes but low chance of success.

Reiniger and Ying leads

The Reiniger lead is a Balder Fm stratigraphic trap while the Ying lead is an Ekofisk Fm structural trap. No volumes have been calculated for these two leads.

5 Technical Evaluation

DEA has performed a full evaluation regarding a possible development in case of discovery for Marmot. The development option for Marmot is a leased FPSO due to the distance to existing infrastructure (Fig. 5.1). DEA has also performed a full technical evaluation on the remaining potential prospectivity in the license. It was decided through internal DEA peer processes to relinquish the license. The partners agreed.

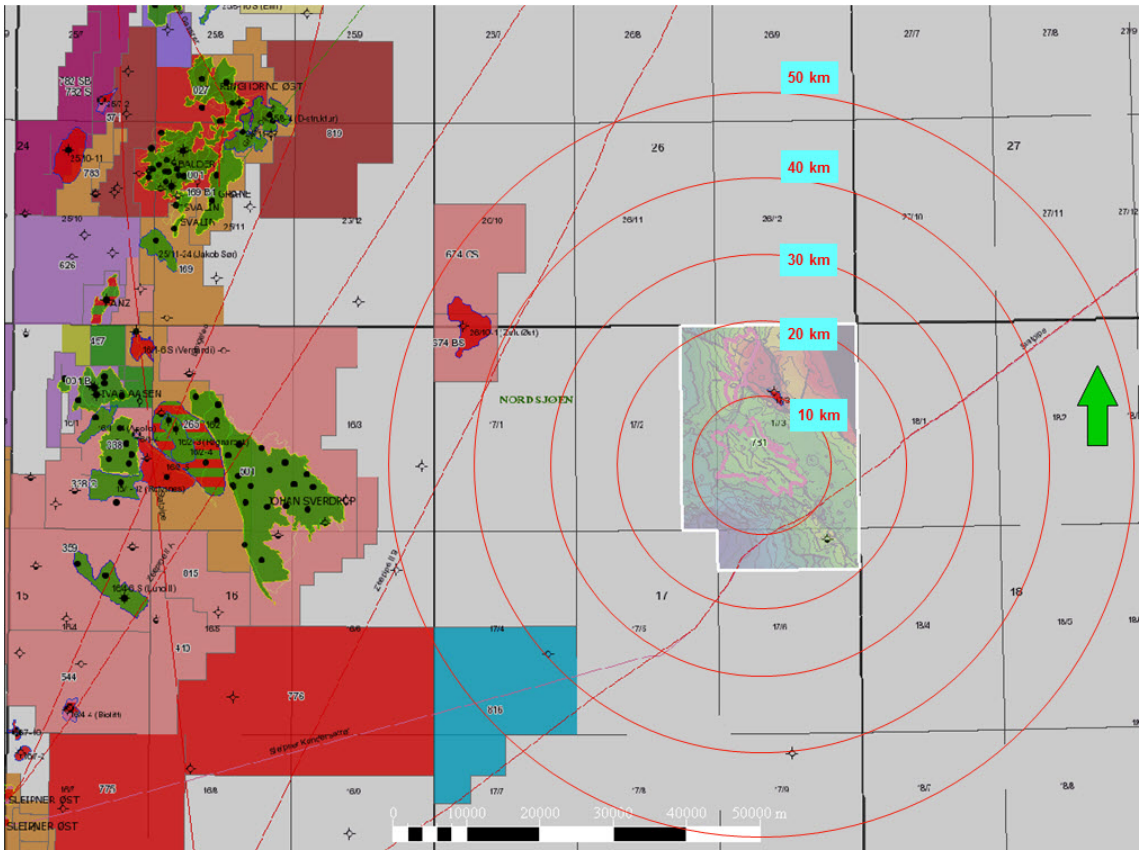
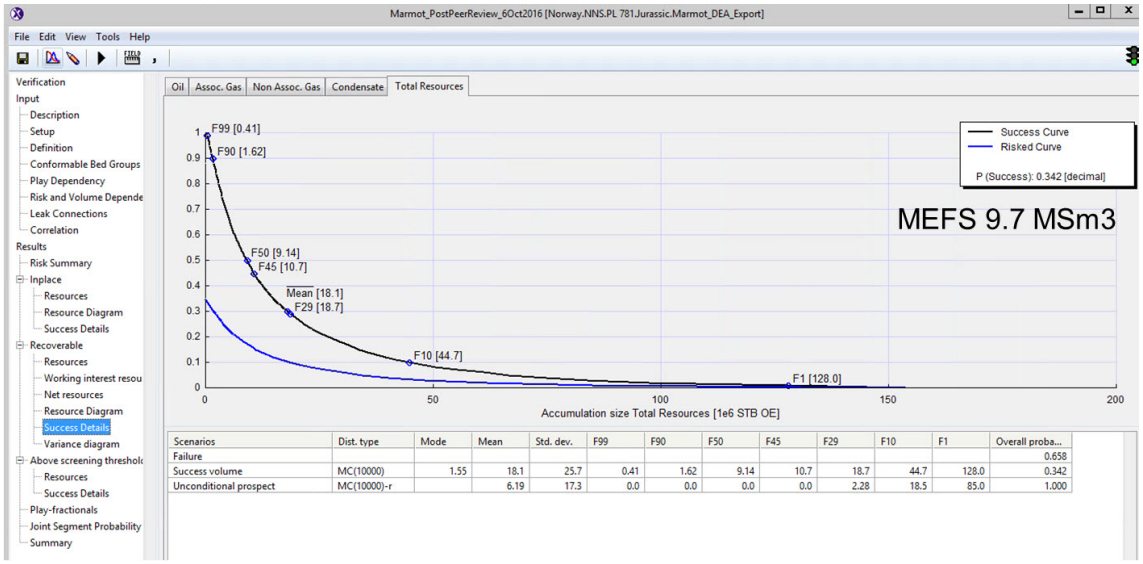


Fig. 5.1 Distance to infrastructure

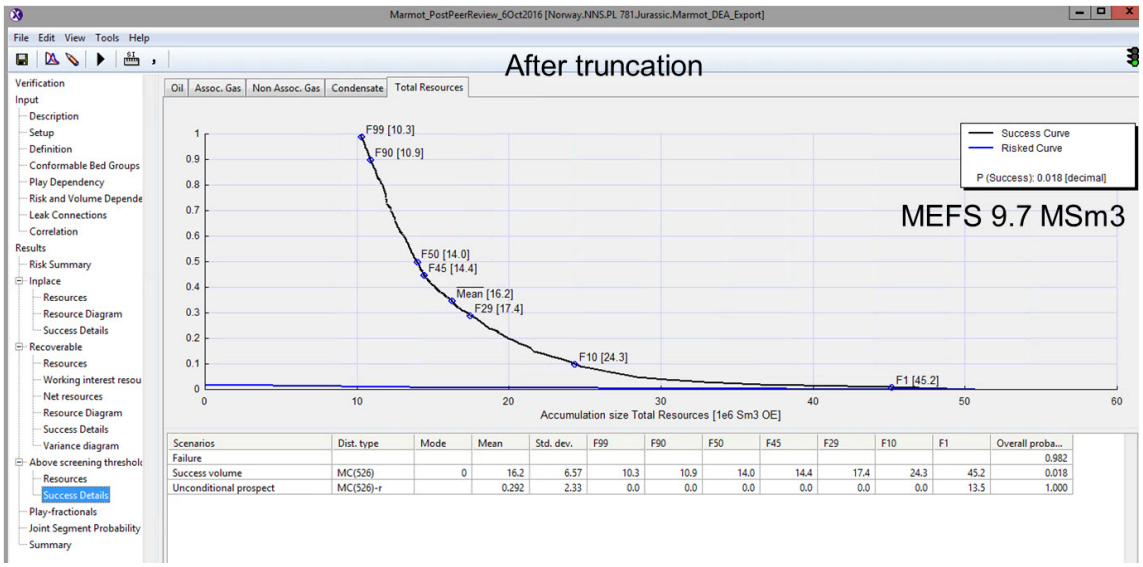
6 Conclusions

A full prospect evaluation of the Marmot prospect with volumetrics, risking, reservoir profiles, field development studies and economic studies were performed and presented to the partnership in November 2016. The partnership agreed that Marmot was the best candidate to be drilled in order to possibly de-risk prospects and leads in the license. Marmot was run as an oil with associated gas case yielding Mean recoverable resources of 2,88 mmSm3oe/18,1 mmSTBoe and a POFH of 34% (Fig. 6.1). The main risks associated with Marmot is reservoir presence/preservation and charge (Table 3.2). The operator's Minimum Economic Field Size (MEFS) for this area is estimated to be 9,7 Mean mmSm3oe with a leased FPSO. This gives a low Chance Of Commercial Success (COCS) of 1,8% (Fig. 6.2).



Scenarios	Dist. type	Mode	Mean	Std. dev.	F99	F90	F50	F45	F29	F10	F1	Overall proba...
Failure												0.658
Success volume	MC(10000)	1.55	18.1	25.7	0.41	1.62	9.14	10.7	18.7	44.7	128.0	0.342
Unconditional prospect	MC(10000)-r		6.19	17.3	0.0	0.0	0.0	0.0	2.28	18.5	85.0	1.000

Fig. 6.1 Marmot resource curve



Scenarios	Dist. type	Mode	Mean	Std. dev.	F99	F90	F50	F45	F29	F10	F1	Overall proba...
Failure												0.982
Success volume	MC(526)	0	16.2	6.57	10.3	10.9	14.0	14.4	17.4	24.3	45.2	0.018
Unconditional prospect	MC(526)-r		0.292	2.33	0.0	0.0	0.0	0.0	0.0	0.0	13.5	1.000

Fig. 6.2 Marmot resource curve with truncation

Based on this technical evaluation the licence does not see the basis for a positive drill decision and has agreed to a relinquishment.