PL1034 Status Report

License Surrender

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1. History of the production licence

Award date, licensees and operator

The PL 1034 license is located within Norway block 15/12 in the South Viking Graben, it covers the de-commissioned Varg field and 15/12-8 Rev Øst discovery. The license was awarded to a partnership consisting of Chrysaor Norge AS (Op.) 60% and OKEA ASA 40% the 14th February 2020 (APA 2019). The APA 2019 application of PL 1034 and PL 973 B was driven by activity on Chrysaor operated PL 973, awarded within the same block a year earlier. Operational efficiency and capitalizing on synergies between the three licenses has been a priority for the partnership.

Work obligations with deadlines

The work obligations for the initial phase have been fulfilled, comprising of 3D seismic purchase and reprocessing supplemented with geological and geophysical studies. The work program was coordinated to assess Chrysaor operated licenses PL 1034, PL 973 and PL 973 B jointly.

Applications for and decisions to extend deadlines

PL 1034 decision to drill was dependent on the outcome of the two exploration wells drilled by Chrysaor in the neighbouring PL 973 in Q1-Q2 2021; i.e. 15/12-25 and 15/12-26. To align the operator's subsurface assessment in block 15/12, the original decision to drill deadline (DoD) for PL 1034 was extended from 14.02.2022 to 14.02.2023, coinciding with the decision to concretize (BoK) date for PL 973 and PL 973 B.

Overview of meetings held

The MC and EC meetings held during the licence period are listed below.

- 28.05.2020 ECMC meeting
- 12.11.2020 EC workshop
- 24.11.2020 ECMC meeting
- 30.11.2021 ECMC meeting
- 25.05.2022 ECMC meeting
- 03.11.2022 ECMC work meeting

Brief substantiation for surrender/lapse/expiration

The main prospect identified in the original license application; the Paleocene Ty Formation Fleming East, was applied for as deemed follow-up for the Jerv prospect. Unfortunately, evaluation of reprocessed seismic and the encountered Ty Formation reservoir pressure in the Jerv exploration well, 15/12-25, excludes Fleming East from being considered a viable drilling target. Consequently, the exploration potential within PL 1034 had to be re-evaluated. The interpretation of reprocessed 3D seismic integrated with a biostratigraphic review, a fluid inclusion study and in-house formation evaluation shifted focus to the undeveloped 15/12-8 Rev Øst discovery. Oil migration through south-east Varg field was evaluated as an enabler to resume exploration in the area. However, results from Varg producers targeting the easternmost segments; i.e. 15/12-A-8 and 15/12-A-1-A hampered optimism. Even if 15/12-A-8 determined an oil down to 2947m TVDSS or 27m deeper than the oil-water contact proven at 15/12-5, it also encountered a thicker Heather Formation than expected and a notably deeper, thinner, and poorer quality Ula Formation reservoir than prognosed. The 15/12-A-1-A well penetrated the Ula Formation near the 15/12-5 bottom-hole location, but the well measured ~75 bar depletion when drilled in 2011 and was plugged back and side-tracked. The combination of a challenged top Ula Formation reservoir depth interpretation, proven depletion and ultimately limited recoverable volume potential led the license to stop pursuing the area further (**Figure 1**).

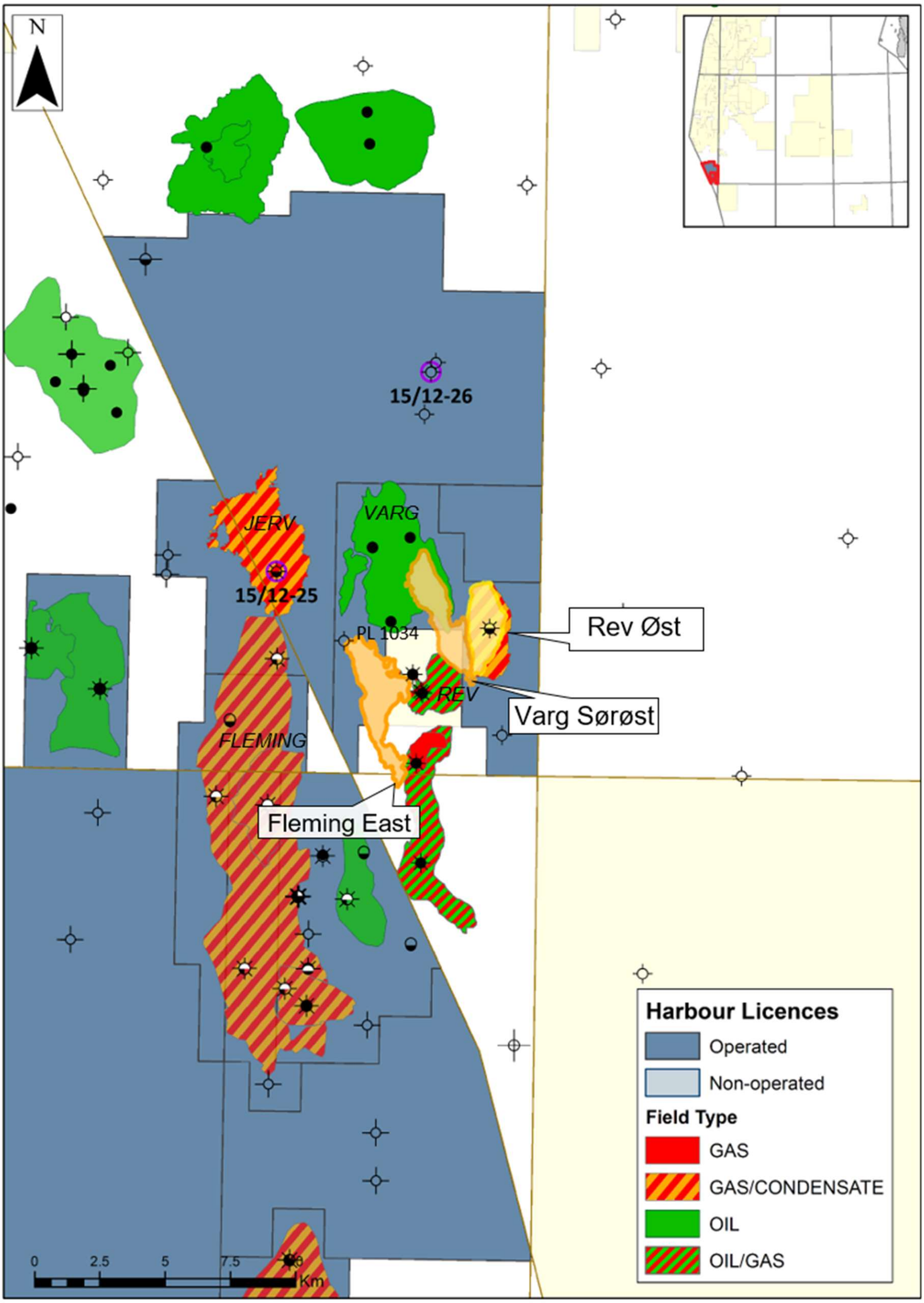

Figure 1 Location map. Location Map with prospects, leads and discoveries in PL1034. The Chrysaor operated 15/12-25 and 15/12-26 wells have been highlighted and labelled for reference.

2. Database overview

2.1 Seismic data

The PL 1034 common seismic database consists of sub-selections of both PGS Geostreamer and CGG Cornerstone Tomo ML multiclient 3D surveys (**Table 1**). The license operator contracted DownUnder GeoSolutions (DUG) to perform a merger and reprocessing of the data. The resulting proprietary PSDM dataset, CHR20M01 3D, covers a combined full-fold area of approximately 725 km^2 (**Figure 2**). Subsequently, Chrysaor performed a 2022 inhouse seismic CRAM reprocessing of the CHR20M01 3D in its entirety. Regularised CMP gathers from the reprocessed survey (CHR20M01) was used as input for the CRAM reimaging project.

Survey	NPD ID	Type 2D/3D	Area (km^2) *	Year acquired/ reprocessed	Availability	Quality	Comments
CGG Q22P105	n/a (UK)	3D	250	2005	Commercial	Variable	Common database. PSTM and PSDM, full stack, angle stacks, gathers and velocities.
MC3D-GRV2010	7342	3D	320	2010	Commercial	Variable	Common database. PSTM, full stack, angle stacks, gathers and velocities.
MC3D-LIN2012	7653	3D	155	2012	Commercial	Variable	Common database. PSTM, full stack, angle stacks, gathers and velocities.
TE14200R15	7992	3D	32	2015	Publicly Available	Variable	PSTM and PSDM, full stack.
CHR20M01	n/a	3D	725	2020	Proprietary	Good	K-PSDM, full stack and angle stacks and velocities.
CHR20M01R22	n/a	3D	725	2022	Proprietary	Good	CRAM-PSDM, full stack and angle stacks.

Table 1 Seismic database. *Area included in common database and reprocessing. The publicly available TE14200R15 3D OBS was used to infill the reprocessed survey over the Varg field data gap in the underlying PGS and CGG acquisitions.

2.2 Well data

In addition to the exploration wells listed in (**Table 2**) numerous production wells from the Varg field were included in the formation evaluation work done by Chrysaor. Particularly pressure measurements and water salinity of the added wells raised awareness of depletion and reservoir connectivity. E.g. Varg production wells 15/12-A-1-A and 15/12-A-8 can be mentioned as particularly value adding for the exploration effort within PL1034 during 2022.

Well Name	NPDID	Year	Biostrat.	CPI	Pressure	Fluid Incl.	Core Descr.
15/12-1	94	1975	Y	Y	Y	Y	Y
15/12-2	331	1976	Y	Y	-	Y	Y
15/12-3	199	1980	Y	-	-	-	-
15/12-4	438	1984	-	Y	Y	-	-
15/12-5	113	1986	Y	Y	Y	-	Y
15/12-6 S	1524	1990	-	Y	Y	-	-
15/12-7 S	1680	1990	Y	Y	Y	-	-
15/12-8	1778	1991	Y	Y	Y	Y	-
15/12-8 A	1835	1991	Y	Y	Y	Y	-
15/12-9 S	1978	1992	-	Y	Y	-	-
15/12-10 S	2285	1996	Y	Y	Y	-	-
15/12-11 S	3074	1997	Y	Y	Y	Y	-
15/12-15	5017	2004	-	Y	-	-	-
15/12-17 S	5442	2007	Y	-	Y	-	-
15/12-17 A	5484	2007	Y	-	Y	-	-
15/12-18 S	5607	2007	Y	Y	Y	Y	-
15/12-18 A	5608	2007	Y	-	Y	-	-
15/12-20 S	5824	2008	-	Y	Y	-	-
15/12-21	6047	2009	Y	Y	Y	Y	Y
15/12-21 A	6139	2009	Y	-	Y	-	-
15/12-22	6326	2010	Y	-	Y	Y	-
15/12-23	6327	2010	Y	Y	Y	-	-
15/12-23 A	6404	2010	Y	-	Y	-	-
15/12-24 S	7661	2015	Y	Y	Y	Y	-
15/12-25	9203	2021	Y	Y	Y	-	-
15/12-26	9204	2021	Y	Y	Y	Y	-
16/10-1	901	1986	Y	Y	-	-	-
16/10-2	1767	1991	Y	Y	Y	-	-
16/10-3	2703	1996	-	Y	Y	-	-
16/10-4	3531	1998	Y	-	Y	-	-
6/3-1	450	1984	Y	-	-	-	-

Table 2 PL 1034 data table showing analytical techniques performed on Norwegian exploration wells, (Y = Yes, - = No). Biostratigraphy, log-derived reservoir properties and available pressure data has been reviewed for indicated wells. A supplementing fluid inclusion study and proprietary core descriptions have also been performed.

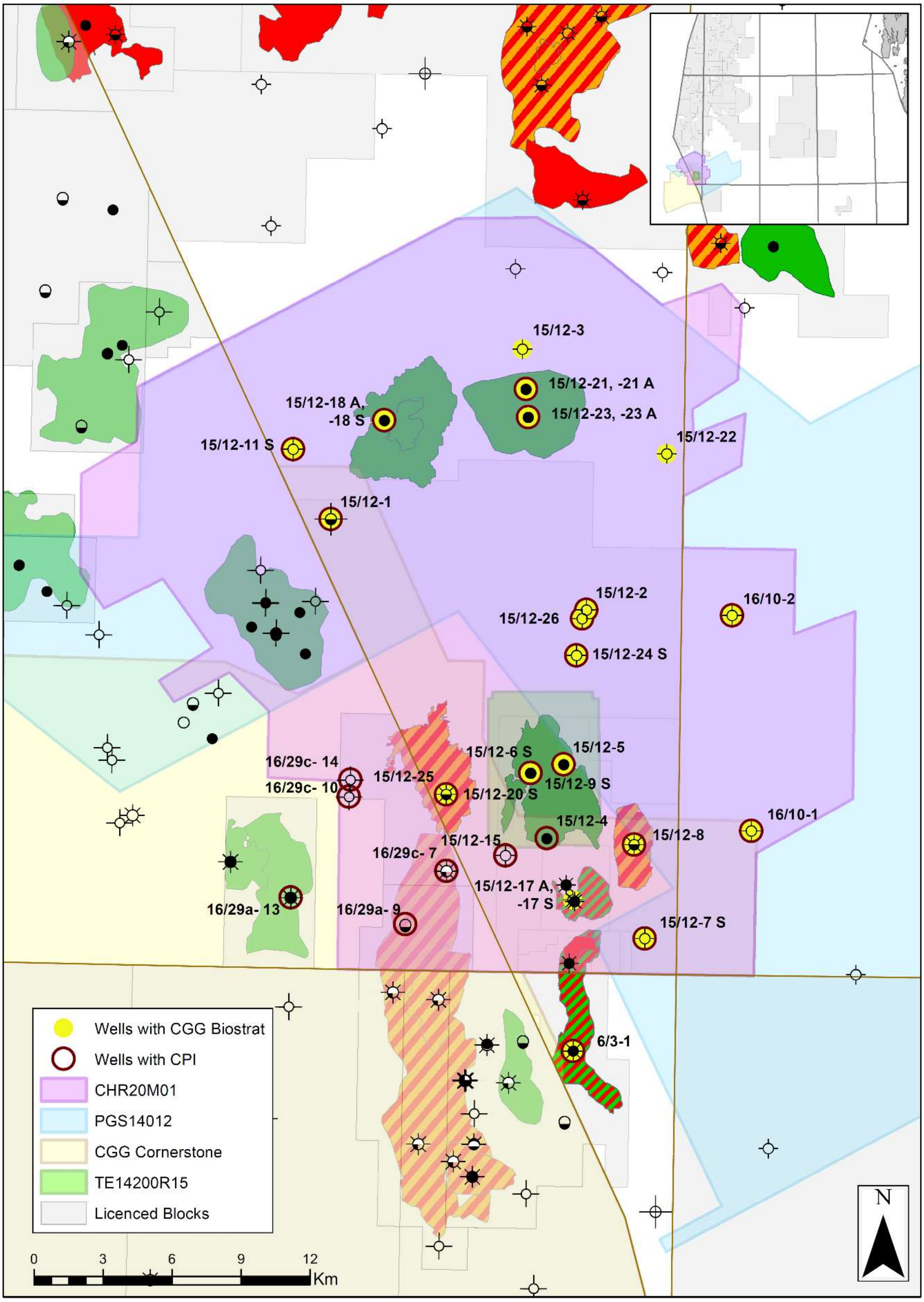

Figure 2 Seismic database for PL1034.

3. Results of geological and geophysical studies

Several proprietary studies have been undertaken as part of the license work to evaluate the prospectivity in PL 1034. All study results were integrated to reach a conclusion. The study results are summarized below

Biostratigraphic and Sedimentological Review - CGG Robertson

A biostratigraphic and sedimentological review was carried out on 23 selected wells drilled in blocks 15/12, 16/10 and 6/3. A stratigraphic framework was established through the review of existing reports, charts and .dex file data, combined with new palynological analysis. An initial review of existing data allowed gaps to be identified and subsequently addressed by a palynological study of 45 infill samples. The key lithostratigraphic units of the study were the main reservoir intervals of the Late - Middle Jurassic; Ula, Hugin, and Sleipner Formations and the Paleocene: Ty and Heimdal Formations. A more accurate definition of the Hugin and Ula Formation shoreface development within block 15/12 was achieved by re-dating and standardizing the naming convention. In accordance with regional observations, the results show a general shoreline retreat towards the east-southeast initiating in the Callovian to Oxfordian and continuing into the Kimmeridgian. Applying a biostratigraphically constrained depositional sequence framework to the Ula Formation enabled further sub-division of the reservoir into seven informal members. This added detail to the understanding of the Upper Jurassic reservoir sandstone distribution and observed quality variation.

The biostratigraphic study was supplemented with updated sedimentological core descriptions for four selected wells: 15/12-1, 15/12-2, 15/12-5 and 15/12-21. This resulted in a comprehensive understanding of the sedimentological facies of the available cored sections, spanning all key reservoir units and the relevant depositional processes involved. To complement the CGG Robertson study, the cored Skagerrak Formation section of 15/12-8 A was described by Chrysaor for PL 1034.

Formation Evaluation - Chrysaor

Petrophysical analysis was carried out on all the key wells in the area to evaluate reservoir quality in detail. In addition, water resistivity and pressure data were examined and integrated with the updated stratigraphy to better understand the petroleum system connectivity. Reservoir quality of the identified main sandstone units is generally good to very good, with local change induced by either facies variation or burial depth. As a general conclusion, understanding the regional effect of Varg Field production and the resulting depletion, was deemed crucial for the evaluation of remaining exploration potential in the southern part of block 15/12 and PL 1034.

Fluid Inclusion Study - FIT Schlumberger

8 wells were included in the fluid inclusion study conducted to supplement basin modelling in block 15/12. The well selection included four reportedly dry wells; 15/12-2, 15/12-11 S, 15/12-22, and 15/12-24 S. One well with reported shows: 15/12-1 and three discovery wells; 15/12-8 and -8A, 15/12-18 S, and 15/12-21. The study was complemented later with an additional well, 15/12-26, also reported dry. To summarise the study conclusions, a low abundance of rare inclusion amounts was seen in both Paleocene and Jurassic reservoir intervals supporting past migration events. Particularly relevant to PL 1034, the inclusion abundance within the 15/12-8 (and -8A) gas bearing Skagerrak Formation was studied with the aim to get proof of eastward oil migration from the Varg field.

Petroleum System Analysis - Chrysaor

The license is located on the western edge of the Ling Depression, where north-northeast – south-southwest trending, downfaulted terraces of the South Viking Graben overprint the roughly east-west trending Permo-Carboniferous graben feature. The thickness of Draupne Formation source rock increases drastically in the mature, syn-rift grabens in the western parts of block 15/12. In addition, Heather Formation shale and Sleipner Formation coals are known to contribute to hydrocarbon generation in the area. Regional basin models covering PL 1034 were constructed for both APA2018 and APA2019 applications. During the evaluation of remaining prospectivity in block 15/12, a 2022 basin model was created to assess the amount of generated hydrocarbons in the local fetch area expected to charge the Varg Field.

Seismic Merge and Reprocessing - DownUnder Geosolutions

The license operator contracted DownUnder GeoSolutions (DUG) to perform a reprocessing and seamless merger of the multiclient surveys introduced in **2.1 Seismic data**. The objectives of the reprocessing was to get a continuous high resolution broadband volume showing improved structural imaging while preserving relative amplitudes that can reliably be used for input to AVO analysis and pre-stack inversion. A summary of the key processing steps applied during the PSDM reprocessing of CHR20M01 are listed in **Table 3a**.

The input seismic data quality was deemed variable. Noted challenges included strong swell noise, seismic interference noise and surface related multiples. In addition, the heavily faulted overburden and complex structure at deeper target levels limited the aggressiveness of many noise attenuation processes and as expected with conventional cable acquisition, source and receiver ghost notches limited the bandwidth of the raw data.

The resulting proprietary PSDM dataset, CHR20M01 3D, covers a combined full-fold area of approximately 725 km^2.

CRAM Reimaging & Rock Physics - Chrysaor

In 2022 Chrysaor undertook an inhouse seismic CRAM depth imaging project of the CHR20M01 3D survey in its entirety. The input seismic data consisted of CHR20M01 regularised CMP gathers from the original CGG and PGS surveys. The project aim was to obtain an improved seismic image of the pre-Cretaceous stratigraphy, with emphasis on interpretability of the Upper Jurassic Ula Formation. The project was performed using Common Reflection Angle Migration (CRAM) which is part of the Paradigm software suite. A summary of the CRAM processing steps for the proprietary PSDM dataset, CHR20M01R22 3D, are listed in **Table 3b**

The Rock Physics properties of the Ula reservoir was investigated on the CHR20M01R22 3D survey. Shear reflectivity was used to try to determine sand presence within PL 1034. The results were ambiguous due to poor logs in nearby wells, introducing uncertainty to the interpretation of the observed response. As expected, no clear fluid effect was observed on seismic.

a) Key processing steps applied during initial phase of reprocessing	
1	Extensive swell noise attenuation and seismic interference noise removal
2	Source and receiver deghosting - for robust and stable deghosting (DUG Broad)
3	3D SW SRME / muted SRME & 2D DUG SWaMP demultiple applications
4	4D interpolation and regularisation (DUG Reg)
5	6 passes of tomography, incorporating TTI anisotropy
6	3D Kirchhoff Pre-Stack Depth migrations
b) Key processing steps applied during CRAM reprocessing	
1	Build Q-model
2	Common Reflection Angle Migration with Q compensation
3	Residual Multiple attenuation

Table 3 Summary of processing steps for **a)** CHR20M01 and **b)** CHR20M01R22.

4. Prospect update report

PL 1034 was applied for in APA 2019 as a direct consequence of the portfolio maturation efforts in PL 973, awarded in March of the same year (**Figure 3a**). The PL 973 subsurface update led to the application and awards of both PL 1034 (**Figure 3b**) and the extension license PL 973 B, covering opportunities around the decommissioned Varg field and the undeveloped Rev Øst gas/condensate discovery. In conjunction, the operator was preparing for a drill decision on PL 973 prospects Jerv and Ilder, both viewed as crucial to move the potential development of Grevling discovery forward and to open up for further exploration in block 15/12. 15/12-25 (Jerv) resulted in a gas/condensate discovery with no realistic development scenarios, while 15/12-26 (Ilder) turned out dry. The wells were drilled back-to-back in Q1-Q2 2021 respectively.

Fleming East, considered as potential Jerv upside, is no longer viewed as a viable concept following the encountered Ty Formation reservoir pressure at 15/12-25. The focus of exploration efforts was subsequently redirected to evaluate the oil potential surrounding the 15/12-8 Rev Øst gas/condensate discovery. If the observed south-eastern segment of Varg could be verified as the field's true spill point, oil migration past Rev Øst would become likely. Unfortunately, learnings from the technical work program and seismic reprocessing have been unsuccessful to sufficiently alter the operator's view and the subsurface risk remains relatively high for any remaining exploration potential.

The Varg Sørøst lead is an Upper Jurassic Ula Formation opportunity that has been matured and evaluated post license award. The prospect evaluates the Ula Formation potential above known oil-water contacts on Varg field, enabling follow-up potential caused by further eastward migration of oil from Varg.

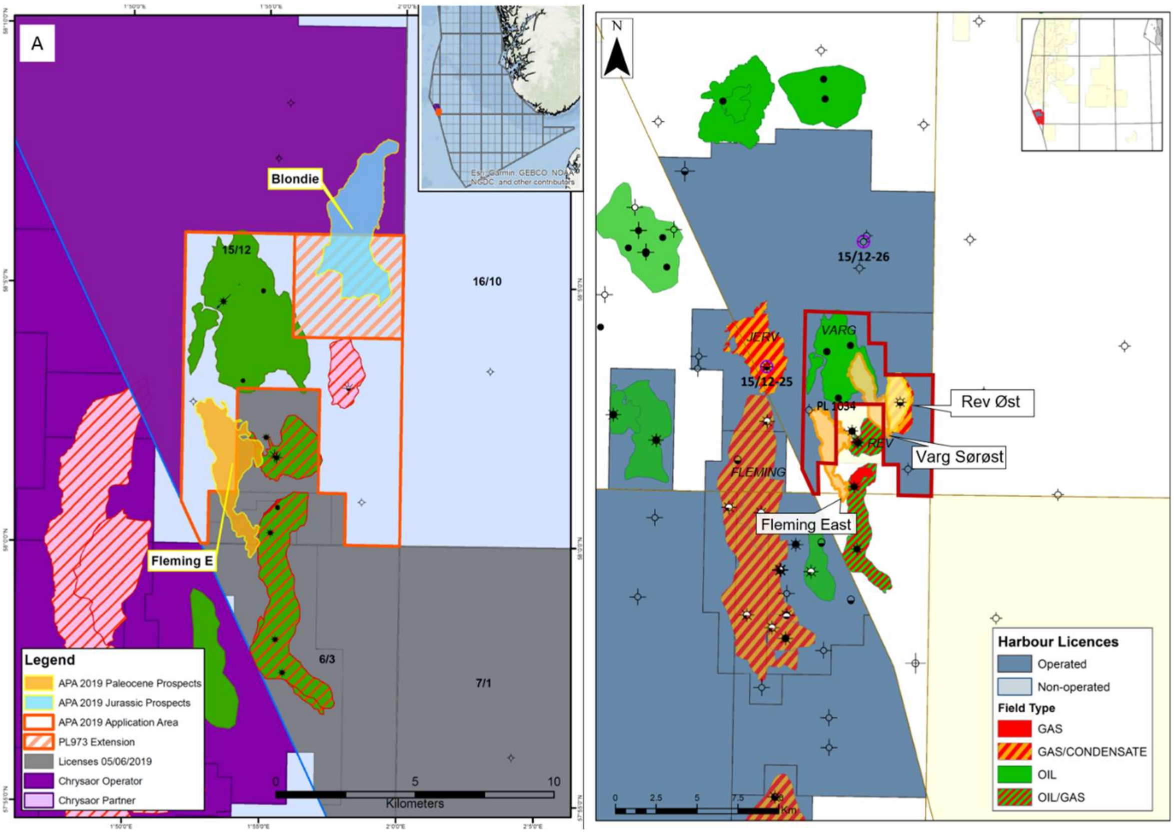

Figure 3 a) Original APA 2019 prospectivity, **b)** PL 1034 updated current prospectivity.

Discovery/ Prospect/ Lead name [1]	D/ P/ L [2]	Case (Oil/ Gas/ Oil&Gas) [3]	Unrisked recoverable resources [4]						Probability of discovery [5] (0.00 - 1.00)	Resources in acreage applied for [%] [6] (0.0 - 100.0)	Reservoir		Nearest relevant infrastructure [8]	
			Oil [10^6Sm^3] (>0.00)			Gas [10^9Sm^3] (>0.00)					Litho-/ Chrono-stratigraphic level [7]	Reservoir depth [m MSL] (>0)	Name	Km (>0)
			Low (P90)	Base (Mean)	High (P10)	Low (P90)	Base (Mean)	High (P10)						
15/12 Fleming East	P	Gas	0.21	0.33	0.47	1.24	1.88	2.63	0.16	55.0	Ty Fm/ Paleocene	2485	Armada (UK)	8
15/12 Rev Øst	D	Gas	0.15	0.18	0.23	0.88	1.05	1.23	1.00	100.0	Hugin and Skagerrak Fms/ Middle Jurassic and Late Triassic	2838	Armada (UK)	12

Figure 4 - Resource Table (NPD Table 2) from APA 2019.

Fleming East

Fleming East is a Paleocene stratigraphic trap on the western flank of the Rev salt dome. One of the main objectives of the 15/12-25 well, testing the adjacent Jerv prospect was to prolong the field life of the existing Armada infrastructure. But unfortunately, the negative outcome of the well had significant consequences for continued efforts to prove up reserves for the platform. Seismic imaging of thin Ty Formation sands deposited immediately above the hard Shetland Gp chalk is known to be challenging. Also, the reprocessed seismic over the area does not support the original interpretation defining the Fleming East wedge as Ty Formation reservoir. Instead, the current assessment is more inclined towards interpreting it as Paleocene reworking and slumping of chalk on the western flank of the growing Rev salt feature. The increased reservoir presence risk at Fleming East, combined with a limited resource potential has resulted in a downgrading of the APA 2019 prospect to a lead. The current Fleming East chance of success is defined as 0.10.

Varg Sørøst

The Varg Sørøst lead, not included in the APA 2019 application, was initially mapped on the reprocessed seismic CHR20M01 (**Figure 5**), which in turn was supplemented with the publicly available TE14200R15 3D ocean bottom seismic survey covering the Varg Field. Understanding segmentation and the extent of reservoir depletion in the area has been crucial for the maturation of the untested south-eastern segment of the field. A conducted pressure study of Varg Field producers found the wells targeting the eastern segments of the field, i.e., 15/12-A-1-A and 15/12-A-8 discouraging with regards to further exploration. 15/12-A-8 encountered a thicker than prognosed Heather Formation and subsequently a notably deeper and thinner Ula Formation reservoir. Surprisingly, the well determined an oil down to at 2947m TVDSS, 27m deeper than the oil-water contact at the exploration well 15/12-5. The 15/12-A-1-A drilled in 2011 penetrated the Ula Formation near the 15/12-5 bottom-hole location, but the well measured ~75 bar depletion and was plugged back and side-tracked to the central segment of the field. A challenging top Ula Formation reservoir depth interpretation, an uncertain oil-water contact, a high risk of pressure depletion as seen in 15/12-A-1-A and Rev field combined with a limited recoverable volume potential led the license to stop pursuing the area.

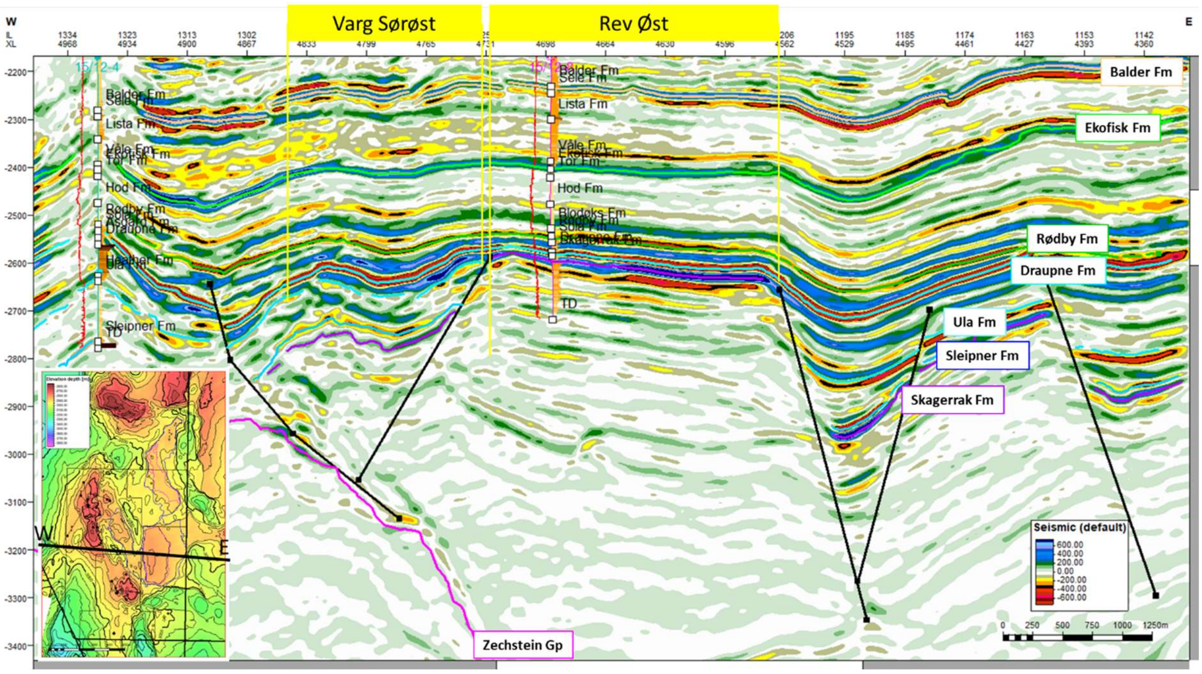

Figure 5 Rev Øst and Varg Sørøst seismic line.

Rev Øst

The Rev Øst gas/condensate discovery was presented in the APA 2019 application as an undeveloped recoverable resource of approximately 5 Mmboe, encountered in Hugin and Skagerrak Formation reservoir. The biostratigraphic update conducted during the initial phase of exploration redetermined the Rev Øst hydrocarbon bearing reservoir sands in wells 15/12-8 and -8 A to be entirely within Skagerrak Formation. The shift in reservoir age has raised potential concerns of lateral continuity of the Rev Øst reservoir, but it has also opened for alternative prospective concepts in the area (**Figure 5**).

In contrast to the APA 2019 application, the current assessment of Rev Øst evaluates the oil potential down-dip of the proven gas/condensate discovery and effectively reclassifies the discovery as a prospect. The performed work addressed the potential oil migration within Ula Formation through the south-eastern segments of the Varg field to Rev Øst and onwards to both Blondie (discussed in more detail in PL 973 & PL 973 B Status Report) and Block 16/10.

Well 15/12-8 (and -8 A) Final Well Report estimated the Rev Øst gas-water contact (GWC) to be at 2854m TVDSS, confirmed by FMT pressure gradients and wire line logs. Interestingly the defined GWC is placed at the base of a ~11 m thick shale sequence that separates the gas bearing, marine influenced sands at the top of the Skagerrak Formation from water bearing thin fluvial sands below. In addition, pressure depletion was seen in some of the repeated depths in 15/12-8 A. This was attributed to depletion of sand bodies in the lower section of the gas column after a drill stem test (DST) was performed in the main wellbore, 15/12-8. Low vertical permeability between the sand bodies was concluded as the most likely reason for the observed depletion.

If the well results are viewed objectively, 15/12-8 (and -8 A) has likely encountered a gas bearing, relatively high net/gross Skagerrak Formation reservoir that is separated from water wet, poorer quality fluvial sands by a low permeability zone. The defined water gradient at Rev Øst is ~5 bar higher than the regional Ula Formation aquifer pressure, as defined by 15/12-5 and 16/10-2 exploration wells located in the vicinity of the Rev Øst structure. This supports the notion that the Skagerrak Formation fluvial section encountered at 15/12-8 is isolated from the regional aquifer and consequentially also hydrocarbon migration (**Figure 6**).

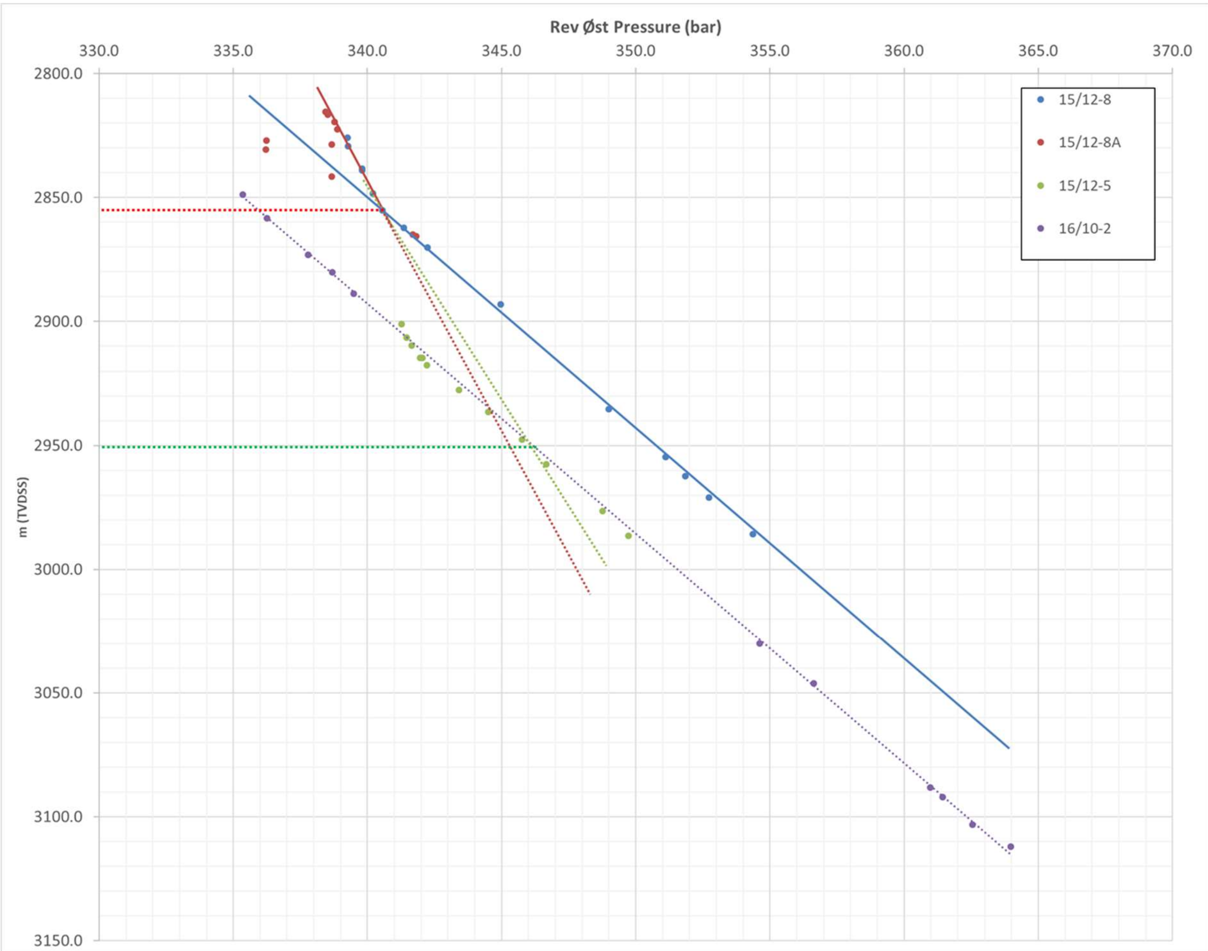

Figure 6 Rev Øst 15/12-8 and -8A Skagerrak Formation pressure data compared to nearby 15/2-5 and 16/10-2 Ula Formation pressure. Red stippled line is the estimated gas-water contact at 2877 m RKB (2854 m TVDSS). The green stippled line is a possible oil-water contact of Rev Øst if the gas bearing, marine influenced sands

found at the top of Skagerrak Formation communicates with regional Ula Formation aquifer. Lower part of the gas column gets depleted during 15/12-8 DST, seen in 15/12-8A pressure points with ~3 bar depletion.
The possible deeper hydrocarbon-water contact at Rev Øst is ~2950m TVDSS if instead of vertically, the encountered gas column communicates laterally with the regional Ula Formation aquifer. Not only is ~2950m TVDSS in better alignment with encountered contacts on Varg e.g. the oil down to in the nearest well 15/12-A-8 at 2947m TVDSS, but also charge and migration of a mixed oil and gas phase comparable to the encountered accumulation at Rev would be easier to ratify by basin modelling than the reported underfilled gas/condensate discovery proven by 15/12-8.

The Rev Øst gas/condensate accumulation has proven the efficiency of Draupne Formation shale as top seal. The structure is a relatively simple tilted fault block with potential Ula Formation presence and upside on the flanks. Skagerrak Formation reservoir quality has been proven by 15/12-8 and -8A but uncertainty surrounding the lateral continuity of the reservoir and its effect on recovery factor is concerning. Oil charge is still considered the main risk to the integrity of the prospect.

The pressure history of the area shows evidence of regional Ula Formation aquifer depletion caused by Varg field production. The regional effect has been evident at e.g. Rev field, approximately 6 km south of the by now decommissioned Varg FPSO location. Comparably, the Rev Øst structure is close to both fields, ~5km to the southeast of Varg. Drilled wells show lateral pressure communication within the Ula Formation to be more efficient than vertical communication between e.g. Ula and the underlying Skagerrak Formation. Therefore, depletion must be considered when assessing Rev Øst oil potential.

The resulting estimated overall chance of success of Rev Øst (oil prospect) is estimated at 0.38, but the risk of depletion and a recoverable PMean hydrocarbon volume of ~20 MMboe do not meet requirements for a standalone development.

In conclusion, demotion of Fleming East as a direct consequence of the encountered depletion in 15/12-25 resulted in a reassessment of the PL 1034 license. The exploration potential of the Rev Øst area has been re-evaluated giving updated recoverable volumes and newly established prospect risk profiles. An overview of the updated volumes and risking is given in **Table 4** and **Table 5** below.

PL 973 & 973 B Recoverable Resources and Risk								
Prospect/Lead	**Fluid Type**	**Oil (10^6 Sm^3)**			**Ass. Gas (10^9 Sm^3)**			**P_g %**
		P90	**Mean**	**P10**	**P90**	**Mean**	**P10**	
Rev Øst	Oil and Gas	0.92	2.59	4.76	0.38	0.78	1.26	38%
Varg Sørøst	Oil	1.5	4.6	8.4	0.12	0.36	0.66	N/A
Fleming East	Gas/Cond.	0.21	0.33	0.47	1.24	1.88	2.63	10%

Table 4 Recoverable resources and risk for the defined prospects and leads within the PL 1034 license. Reported Rev Øst volumes and risk is evaluating the oil potential underneath the proven gas in 15/12-8 and -8A.

	Reservoir	**Trap**	**Charge**	**Retention**	**Total**
Rev Øst	0.7	0.9	0.6	1.0	0.38
Varg Sørøst	Varg SE risk has not been assessed, depletion is a main concern.				
Fleming East	0.4 → 0.25	0.9	0.5	0.9	0.16 → 0.10

Table 5 Summary of changes to risk parameters in PL 1034 prospect portfolio, comparing application and current assessment. Red = negative change, white = no change, green = positive change. Rev Øst has been changed from a proven discovery to an oil and gas prospect.

Tables with Discovery and Prospect data (NPD Table 4)

Table 4: Discovery and Prospect data (Enclose map)									
Block	15/12	Prospect name	Rev Øst	Discovery/Prosp/Lead	Prospect	Prosp ID (or New!)	NPD will insert value	NPD approved (Y/N)	
Play name	NPD will insert value	New Play (Y/N)		Outside play (Y/N)					
Oil, Gas or O&G case:	Oil&Gas	Reported by company	Harbour Energy	Reference document	APA2019 Block 15/12			Assessment year	2022
This is case no.:	1 of 1	Structural element	Ling Depression	Type of trap	Structural	Water depth [m MSL] (>0)	85	Seismic database (2D/3D)	3D
Resources IN PLACE and RECOVERABLE		**Main phase**				**Associated phase**			
Volumes, this case		Low (P90)	Base, Mode	Base, Mean	High (P10)	Low (P90)	Base, Mode	Base, Mean	High (P10)
In place resources	Oil [10^6 Sm^3] (>0.00)	3.15	5.47	6.64	11.12				
	Gas [10^9 Sm^3] (>0.00)					0.69	1.53	1.28	1.95
Recoverable resources	Oil [10^6 Sm^3] (>0.00)	0.92	1.40	2.59	4.76				
	Gas [10^9 Sm^3] (>0.00)					0.38	0.61	0.78	1.26
Reservoir Chrono (from)	Late Triassic	Reservoir litho (from)	Skagerrak Fm	Source Rock, chrono primary	Late Jurassic	Source Rock, litho primary	Draupne Fm	Seal, Chrono	Late Jurassic, E. Cret
Reservoir Chrono (to)	Middle Triassic	Reservoir litho (to)	Skagerrak Fm	Source Rock, chrono secondary	Late Jurassic	Source Rock, litho secondary	Heather Fm	Seal, Litho	Draupne, Cromer Knoll
Probability [fraction]									
Total (oil + gas + oil & gas case) (0.00-1.00)	0.38	Oil case (0.00-1.00)	0.00	Gas case (0.00-1.00)	0.00	Oil & Gas case (0.00-1.00)	1.00		
Reservoir (P1) (0.00-1.00)	0.70	Trap (P2) (0.00-1.00)	0.90	Charge (P3) (0.00-1.00)	0.60	Retention (P4) (0.00-1.00)	1.00		
Parametres:	Low (P90)	Base	High (P10)	*Comments:*					
Depth to top of prospect [m MSL] (> 0)		2786							
Area of closure [km^2] (> 0.0)	3.1	3.5	3.9						
Reservoir thickness [m] (> 0)	17	21	25						
HC column in prospect [m] (> 0)	78	95	112						
Gross rock vol. [10^9 m^3] (> 0.000)	0.099	0.119	0.141						
Net / Gross [fraction] (0.00-1.00)	0.30	0.50	0.70						
Porosity [fraction] (0.00-1.00)	0.17	0.19	0.21						
Permeability [mD] (> 0.0)		55.0							
Water Saturation [fraction] (0.00-1.00)	0.25	0.30	0.35						
Bg [Rm3/Sm3] (< 1.0000)									
1/Bo [Sm3/Rm3] (< 1.00)	0.7500	0.7800	0.8300						
GOR, free gas [Sm^3/Sm^3] (> 0)									
GOR, oil [Sm^3/Sm^3] (> 0)	48	63	78						
Recov. factor, oil main phase [fraction] (0.00-1.00)	0.28	0.35	0.42						
Recov. factor, gas ass. phase [fraction] (0.00-1.00)	0.33	0.40	0.47						
Recov. factor, gas main phase [fraction] (0.00-1.00)									
Recov. factor, liquid ass. phase [fraction] (0.00-1.00)				For NPD use:					
Temperature, top res [°C] (>0)	130			Innrapp. av geolog-init:	NPD will insert value	Registrert - init:	NPD will insert value	Kart oppdatert	NPD will insert value
Pressure, top res [bar] (>0)	340			Dato:	NPD will insert value	Registrert Dato:	NPD will insert value	Kart dato	NPD will insert value
Cut off criteria for N/G calculation	1	2	3.					Kart nr	NPD will insert value

Table 3 Rev Øst prospect.

5. Technical assessment

The high geological risk associated to determined recoverable prospective volumes within PL 1034 did not justify a detailed technical-economic evaluation for the remaining prospectivity.

6. Conclusion

The prospectivity within license PL 1034 has been thoroughly evaluated and all the license commitments have been fulfilled. As a result of the license work the partnership concludes that the geological risk (Pg) is too high, and the recoverable hydrocarbon volumes potential is too low to make a viable business case to warrant further work and development. The partnership has unanimously decided to relinquish PL 1034 in its entirety.