PL 973 & 973 B Status Report

License Surrender

Harbour Energy

Table of Contents

1. History of the production licence

Award date, licensees, and operator

The PL 973 license is located within Norway block 15/12 in the South Viking Graben, south of the Sleipner fields. The license was awarded to a partnership consisting of Chrysaor Norge AS 50%, OKEA ASA 30% and Petoro AS 20% the 1st of March 2019 (APA 2018). The initial operatorship of the license was granted to OKEA and upon pre-qualification as an operator on the Norwegian Continental Shelf, the operatorship was transferred to Chrysaor Norge the 4th of September 2019. PL 973 was supplemented with PL 973 B the 14th of February 2020 (APA 2019).

Work obligations with deadlines

The work obligations for the license have been fulfilled, comprising of 3D seismic purchase and reprocessing. In addition, two exploration wells, 15/12-25 and 15/12-26 have been drilled in 2021.

Applications for and decisions to extend deadlines

No extension application for PL 973 or PL 973 B have been filed for.

Overview of meetings held

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

- 09.04.2019 ECMC meeting
- 27.09.2019 ECMC meeting
- 13.11.2019 EC workshop
- 27.11.2019 ECMC meeting
- 05.03.2020 ECMC workshop
- 25.03.2020 MC meeting
- 28.05.2020 ECMC meeting
- 12.11.2020 EC workshop
- 24.11.2020 ECMC meeting
- 12.01.2021 EC workshop
- 15.02.2021 EC 15/12-25 drilling
- 09.03.2021 EC 15/12-26 drilling
- 23.03.2021 EC 15/12-25 debrief
- 20.05.2021 EC 15/12-26 debrief
- 04.11.2021 EC workshop
- 30.11.2021 ECMC meeting
- 25.05.2022 ECMC meeting
- 03.11.2022 ECMC work meeting

Brief substantiation for surrender/lapse/expiration

The main prospects identified in the original license application, the Paleocene Ty Formation Jerv and the Upper Jurassic Ula Formation Ilder, have been tested with the 15/12-25 and 15/12-26 exploration wells respectively. The remaining exploration potential within PL 973 and PL 973 B has been subsequently re-evaluated. The interpretation of reprocessed 3D seismic and post-well studies has resulted in a decreased chance of success for follow-up potential within the licensed area. E.g. 15/12-26 result has raised concerns regarding charge availability and migration in the eastern parts of the block. Moreover, the recoverable volumes of the Blondie prospect have been significantly reduced after interpretation of reprocessed seismic and obtained results from the biostratigraphic update of wells 15/12-8 and -8 A. In combination, the results have led the operator to re-evaluate the main reservoir for the prospect, changing it from Hugin to Skagerrak Formation. The focus of 2022 exploration efforts have been on the Upper Jurassic downfaulted, pinch-out trap named Molina, identified below the tested Paleocene Ty Formation interval at Jerv (**Figure 1**).

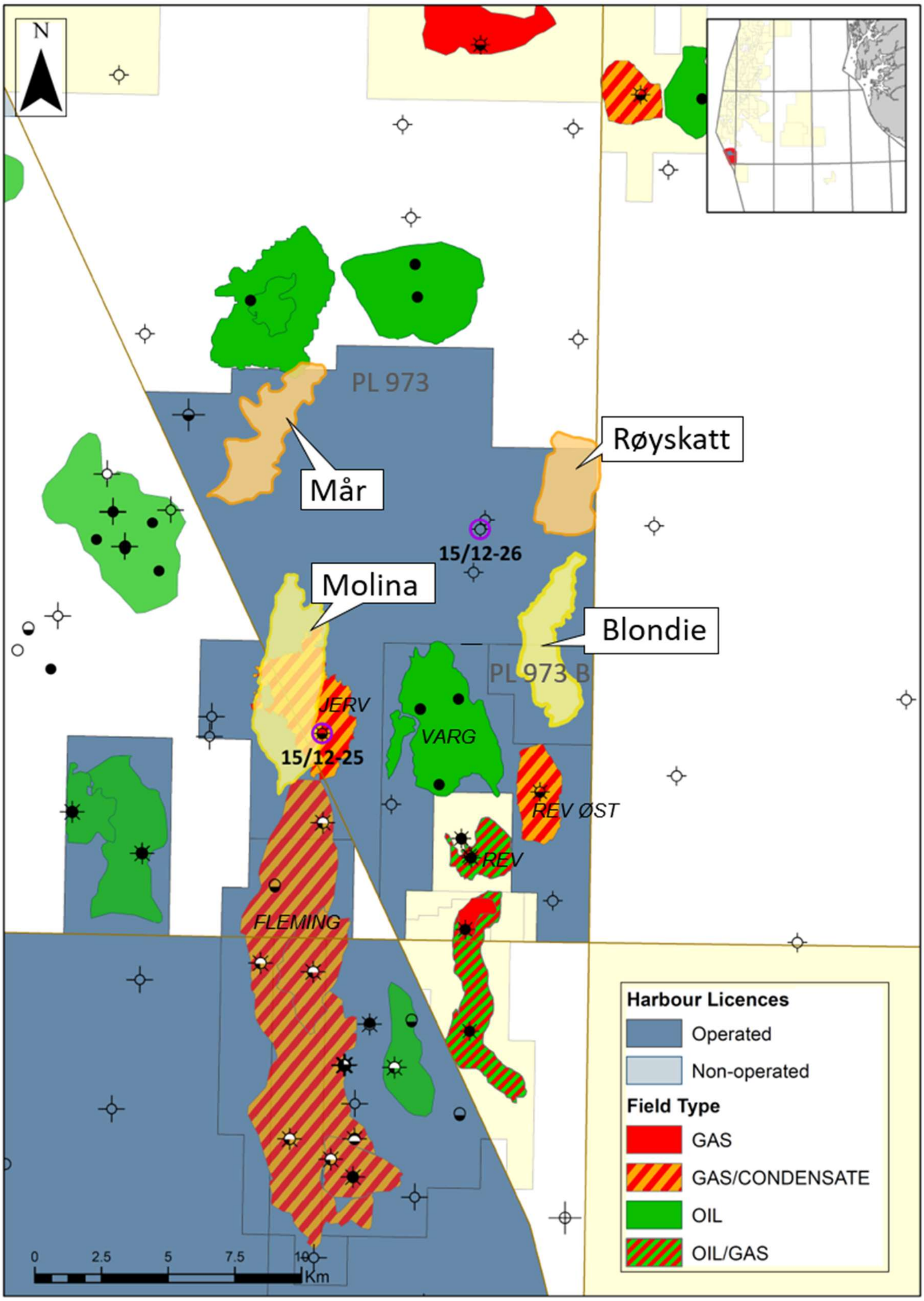

Figure 1 Location map. Location Map with prospects, leads and discoveries in PL 973 and PL 973B. The Chrysaor operated 15/12-25 and 15/12-26 wells have been highlighted and labelled for reference.

2. Database overview

2.1 Seismic data

The PL 973 common seismic database consists of sub-selections of both PGS Geostreamer and CGG Cornerstone Tomo ML multiclient 3D surveys, namely CGG Q22P105, MC3D-GRV2010 and MC3D-LIN2012 (**Table 1**). The license operator contracted DownUnder GeoSolutions (DUG) to perform a merger and reprocessing of the above mentioned multiclient surveys from SEGY and SEGD field tapes through a broadband TTI anisotropic depth migration processing sequence. 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 survey 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.
CHR20M01	n/a	3D	725	2020	Proprietary	Good	K-PSDM, full stack and angle stacks and velocities.
CHR20M01 R22	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.

2.2 Well data

In addition to the exploration wells listed in (**Table 2**) numerous production wells from the Varg field and relevant UK wells were included in the formation evaluation work done by Chrysaor (**Figure 2**). Particularly original pressure 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 and UK exploration wells 16/29c-14 and 16/29c-7 can be mentioned as particularly value adding for the exploration efforts within PL 973 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 973 and 973 B 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.

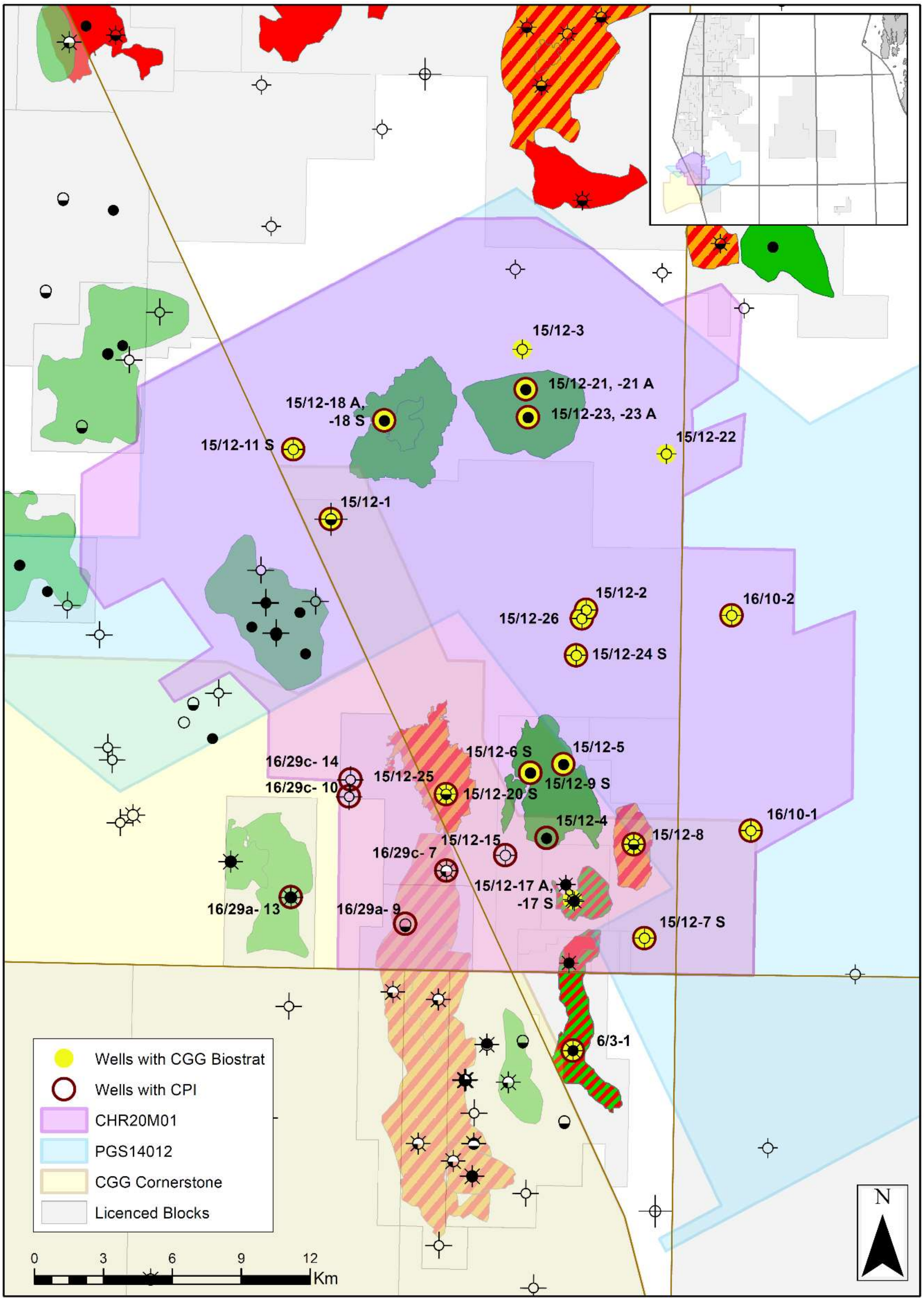

Figure 2 Seismic and well database for PL 973 and PL 973B.

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 973 and 973 B. 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.

Formation Evaluation - Chrysaor

To evaluate reservoir quality in detail, petrophysical analysis was carried out on all the key wells in the area. 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. In order to evaluate the remaining exploration potential in the southern part of Block 15/12, it was vital to understand the regional effect of Varg Field production and the resulting reservoir pressure depletion.

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 -8 A, 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. The 8 wells included in the FIT Schlumberger study are available for purchase in their Norwegian multi-client well database.

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 the license. In addition, Heather Formation shales and Sleipner Formation coals are known to contribute to hydrocarbon generation in the area. Regional basin models were constructed for both APA2018 and APA2019 applications. During the evaluation of remaining prospectivity in block 15/12, a 2022 prospect specific basin model was created to assess the sufficiency of generated hydrocarbons in the local fetch area expected to charge both the Molina prospect and the up-dip 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 3D 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 the Molina prospect. 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 at Ula Formation depth 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

Upon license award, a prospect maturation and ranking of opportunities was conducted during Phase 1 of the work obligation (**Figure 3a**). The PL 973 subsurface update led to the extension application of PL 973 B Blondie prospect in 2019 (**Figure 3b**) and PL 1034 covering decommissioned Varg Field and the undeveloped Rev Øst discovery. It also became evident that the identified main prospects in the original APA 2018 license application, Jerv and Ilder, were the most mature and robust drilling candidates. A positive drill decision was taken for both wells in Q4 2019 and the 15/12-25 and 15/12-26 wells were drilled back-to-back in Q1 and Q2 2021 respectively. The Jerv well (15/12-25) resulted in a minor gas/condensate discovery with no realistic development scenarios, while the Ilder well (15/12-26) turned out dry.

Jerv Nord, a potential upside to Jerv, is no longer considered a viable concept following the encountered reservoir pressure in Ty Formation in well 15/12-25. The Mår and Røyskatt opportunities have also been re-evaluated following the Jerv and Ilder well campaign. The negative impact of 15/12-26 on Røyskatt is inevitable and a further reduction of chance of success has been necessary due to the leads' direct charge reliance on spill from the tested Ilder structure. Learnings from the technical work program and seismic reprocessing have resulted in an increased Upper Jurassic reservoir presence risk and the downgrading of Mår from a prospect to a lead in the current assessment (**Figure 3c**).

Blondie is a Skagerrak Formation prospect dependent on hydrocarbon migration from the Varg Field to the west and Rev Øst discovery to the south.

The Molina prospect is an Upper Jurassic Ula Formation opportunity that has been matured and evaluated post license award. The prospect is located approximately 4 km West of the Varg Field, stratigraphically beneath the Paleocene Jerv gas/condensate discovery. The current prospect assessment is based on the CHR20M01R22 CRAM 3D seismic dataset.

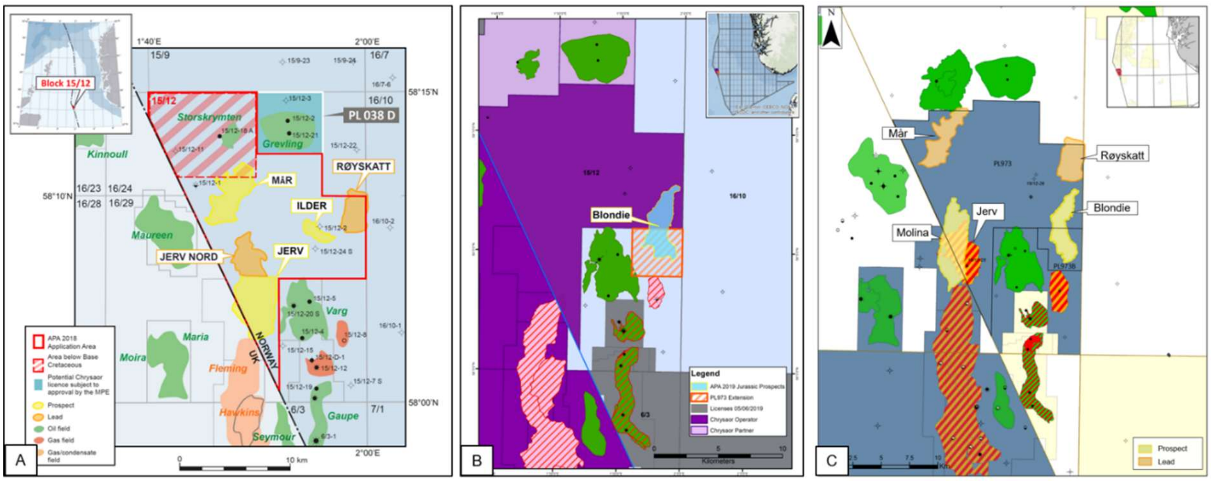

Figure 3 a) Original APA 2018 prospectivity, **b)** PL 973 Extension application from 2019, and **(c)** updated current prospectivity.

A Discovery/ Prospect/ Lead name [1]	D/ P/ L [2]	Case (Oil/ Gas/ Oil&Gas) [3]	Unrisked recoverable resources [4] Oil [10^6Sm^3] (>0.00) Low (P90)	Oil Base (Mean)	Oil High (P10)	Gas [10^9Sm^3] (>0.00) Low (P90)	Gas Base (Mean)	Gas High (P10)	Probability of discovery [5] (0.00 - 1.00)	Resources in acreage applied for [%] [6] (0.0 - 100.0)	Reservoir: Litho-/ Chrono-stratigraphic level [7]	Reservoir depth [m MSL] (>0)	Nearest relevant infrastructure [8] Name	Km (>0)
15/12 Jerv	P	Gas	0,72	1,25	1,83	4,71	8,35	12,17	0,57	97,0	Ty Formation/ Paleocene	2630	Armada (UK)	15
15/12 Ilder	P	Oil	3,30	5,82	8,52	0,19	0,40	0,64	0,34	100,0	Ula Fm - Hugin Fm/ Late Jurassic - Middle Jurassic	2615	Armada (UK)	21
15/12 Mår	P	Oil	4,30	10,10	16,60	0,30	1,10	2,00	0,18	100,0	Ula Fm - Hugin Fm/ Late Jurassic - Middle Jurassic	3100	Armada (UK)	25
15/12 Røyskatt	L	Oil	1,00	3,50	6,60	0,00	0,20	0,50	0,13	95,0	Skagerrak Fm/ Triassic	2620	Armada (UK)	25
15/12 Jerv Nord	L	Gas		0,32			2,07		0,13	100,0	Ty Formation/ Paleocene	2700	Armada (UK)	17

B Discovery/ Prospect/ Lead name [1]	D/ P/ L [2]	Case (Oil/ Gas/ Oil&Gas) [3]	Unrisked recoverable resources [4] Oil [10^6Sm^3] (>0.00) Low (P90)	Oil Base (Mean)	Oil High (P10)	Gas [10^9Sm^3] (>0.00) Low (P90)	Gas Base (Mean)	Gas High (P10)	Probability of discovery [5] (0.00 - 1.00)	Resources in acreage applied for [%] [6] (0.0 - 100.0)	Reservoir: Litho-/ Chrono-stratigraphic level [7]	Reservoir depth [m MSL] (>0)	Nearest relevant infrastructure [8] Name	Km (>0)
15/12 Blondie	P	Oil	4.37	7.17	10.10	0.24	0.45	0.70	0.28	46.0	Hugin, Skagerrak/ Middle Jurassic, Late Triassic	2800	Armada (UK)	17

Figure 4 - Resource Table (NPD Table 2) from (A) APA 2018 and (B) Extension application 2019.

Røyskatt & Mår

Røyskatt is a Skagerrak Formation lead within a well-defined tilted fault block structure. Following the 15/12-26 (Ilder) well, the already critical charge risk has further increased. Combined with an uncertain expected recovery factor from the variable quality Skagerrak Formation reservoir the Røyskatt chance of success has been degraded down to 0.05 in the current risk assessment.

Mår has been downgraded from a secondary prospect in the APA 2018 application to a lead in the current assessment. The biostratigraphic update conducted in block 15/12 anticipates that the Hugin Formation transitions into the Ula Formation as continuous transgression shifts the shoreface eastward. Seismic imaging of the Ula Formation is admittedly a challenge, but in contrast to the tested Ula shoreface at e.g. 15/12-22, the Late Oxfordian to Kimmeridgian wedge forming the Mår lead does not show any indications of Ula sand presence within the Heather shale sequence. Consequently, the current assessment increases the Mår reservoir presence and quality risk, resulting in an overall chance of success of 0.14.

Blondie

Blondie was added to the PL 973 portfolio in APA 2019. Prospect maturation post application is highly dependent on the subsurface evaluation of the Rev Øst discovery and the potential oil migration from the south-eastern segments of the Varg Field, this work is covered in more detail in the PL 1034 Status Report. Summarized here, the biostratigraphic update redetermined the Rev Øst hydrocarbon bearing reservoirs in wells 15/12-8 and -8 A to be Skagerrak Formation, which led to the same change for the expected reservoir at Blondie prospect. This shift has had a substantial negative effect on the expected recovery factor and ultimately prospective volumes at Blondie. So even if the current estimate is slightly more optimistic regarding oil migration further east from the Varg Field, resulting in an overall chance of success of 0.30 for Blondie, the recoverable hydrocarbon volume potential is regarded too low to consider it a viable drilling target.

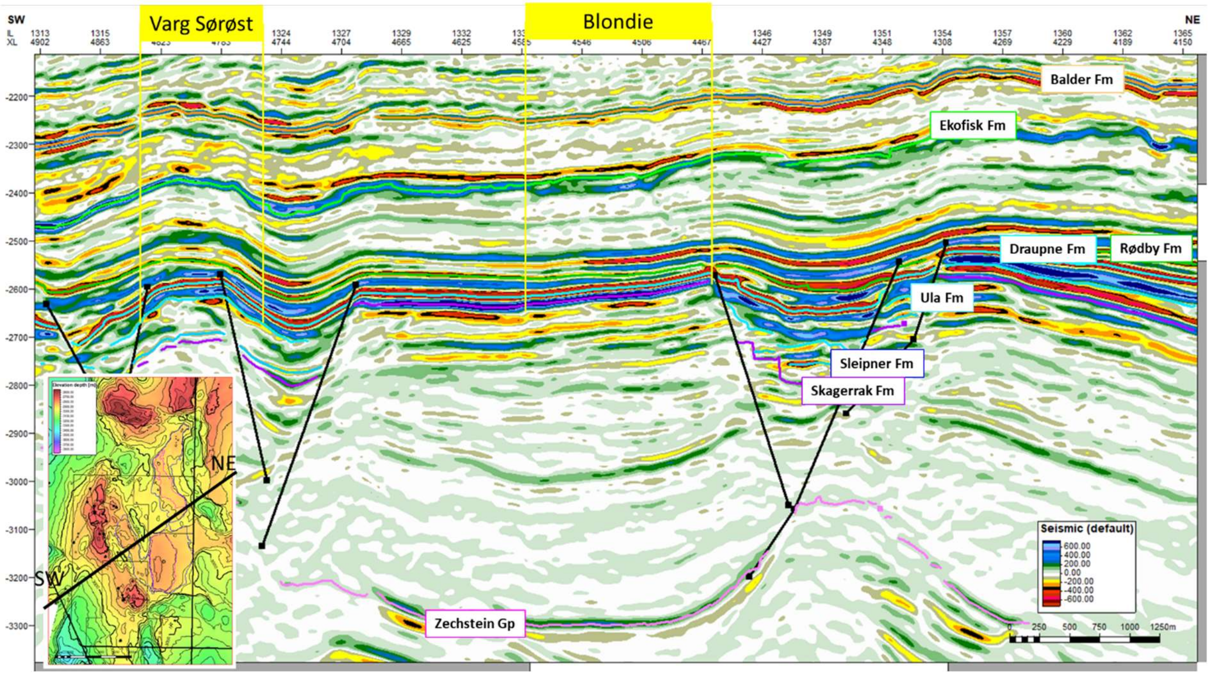

Figure 5 Blondie prospect Southwest – Northeast seismic line. The reservoir has been changed to Skagerrak Formation in the current assessment.

Molina

The Molina prospect, not included in the APA 2018 application, was initially mapped on the reprocessed seismic, CHR20M01 and later reassessed on CHR20M01R22. The prospect is defined by anticipating Ula Formation reservoir presence within a downfaulted/stratigraphic combination trap on the western flank of the Varg dome. Shales of the Heather and Draupne Formations act as top seal for the prospect, while base seal is provided by regionally present coal layers pertaining to the Sleipner Formation. The structure is constrained to the south by pinching-out of the Ula Formation, proven by UK well 16/29c-7 where only thin Draupne/Heather Formation shales drape heterogeneous sections of Sleipner and Skagerrak Formation. A structural component is added to the closure by faults in the eastern and northern parts of the prospect.

The seismic interpretation of the Upper Jurassic shallow-marine depositional system, forming the main hydrocarbon-bearing reservoirs in both Varg and Rev fields, was complemented by the biostratigraphic update of relevant wells and a subsequent revision of the operator’s Upper Jurassic post-well analysis including penetrations within block 15/12 and the adjacent UK block 16/29. The conclusions from the studies demonstrate Ula Formation presence in the southwestern half of block

15/12, showing generally good to very good reservoir quality at well penetrations. In UK block 16/29, the presence of Ula equivalent Fulmar Formation sands has been proven at the Maria field and its vicinity, but with a significantly diminished reservoir quality compared to Norway. The seen degradation in reservoir quality is largely caused by an approximately 1000m deeper burial depth on the UK side of the maritime border. Ula Formation post-well failures in the area are attributed to a range of prospect specific risk elements, either charge, trap or seal while reservoir failure is less common.

Seismic data analysis indicates the potential of Ula Formation sandstones within the well-defined Upper Jurassic wedge at the Molina prospect but performed rock physics work was unable to verify good reservoir quality within the interpreted sequence. The fact that the prospect is approximately 500m deeper than the penetrated Ula Formation sands in block 15/12 and that clearly poorer quality Ula equivalent Fulmar Formation sands have been penetrated in nearby UK wells, e.g. 16/29c-14, introduces uncertainty into the expected reservoir quality at the Molina prospect.

The complex trap requires a combination of lateral seal elements to work, stalling migration up towards the Varg field. Faulting juxtaposes the expected Ula Formation reservoir against the Sleipner and Skagerrak Formations, both regionally relatively heterogeneous and shale-prone but worryingly the nearby up-dip wells 15/12-20 S and 16/29c-7 have good quality Sleipner Formation reservoir present. The uncertainty surrounding the lithologies juxtaposed along the critical faults and an increased requirement on lateral seal capacity caused by the high maximum potential hydrocarbon column of the Molina prospect, add up to an increased risk of breaching the fault seal. Only a minor accumulation size at Molina is possible in a seal failure scenario and the majority of available hydrocarbon will migrate up-dip towards 15/12-20 S, worryingly containing oil in the Sleipner Formation.

Lateral fault seal is therefore considered the main risk to the integrity of the prospect, while also expected reservoir quality and its direct correlation to recovery factor is a valid concern (**Figure 6**).

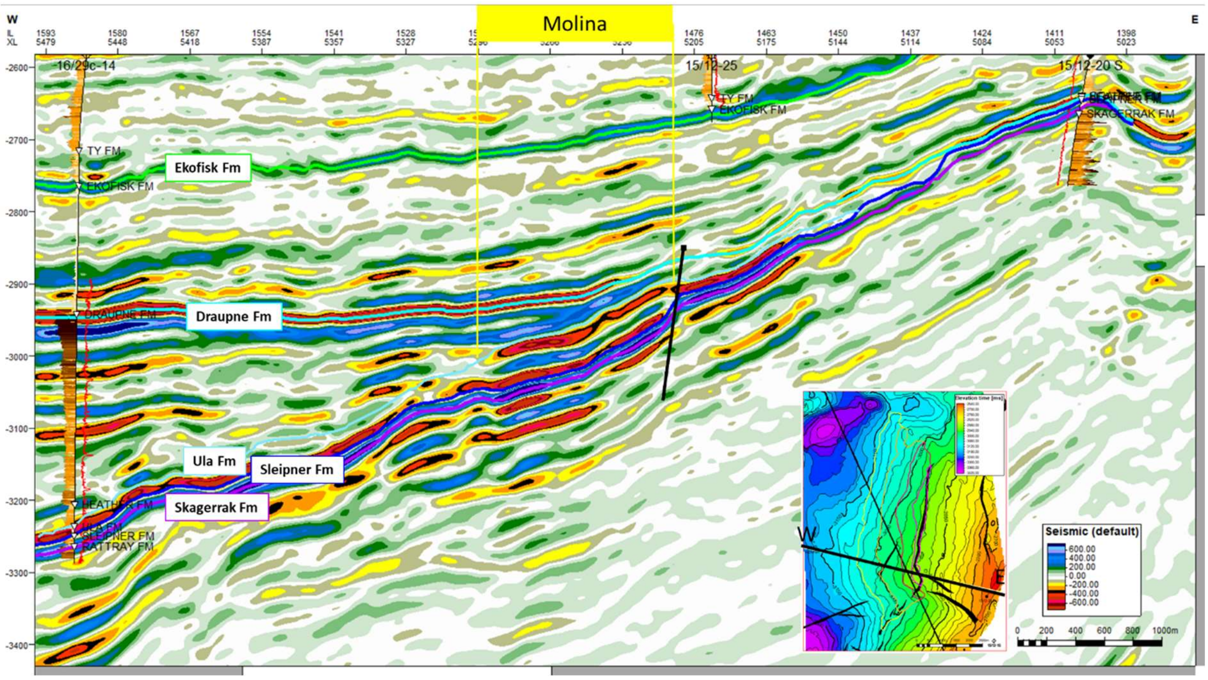

Figure 6 Molina prospect Southeast – Northwest seismic line. The prospect is defined by anticipating Ula Formation presence within the Upper Jurassic wedge thickening drastically West of the black fault displacing the Sleipner and underlying Skagerrak Formations.

The pressure history from wells shows regional Ula Formation aquifer depletion caused by Varg field production. The Varg field itself shows evidence of significant segmentation and existing pressure barriers but the regional effect caused by depletion drive has been recorded at e.g. the Rev field, approximately 6km south of the by now decommissioned Varg FPSO location and at the 15/12-24 S and 15/12-26 well locations, approximately 6 and 7 km northwest respectively. It is evident that lateral pressure communication within the Ula Formation is more efficient than vertical communication between e.g. Ula and the underlying Skagerrak Formation. The nearby UK Fulmar Formation penetrations at both Maria and 16/29c-14 are within a higher-pressure regime when compared to original pressure measurements from Varg.

In conclusion, all prospect risk parameters and recoverable volumes have been reassessed to evaluate the remaining exploration potential within PL 973 and 973 B. The implemented changes to risk elements are prospect/lead specific, while e.g. the Blondie prospect has had a significant negative revision of recoverable volumes due to the uncertainty of Skagerrak Formation reservoir efficiency. An overview of the updated volumes and risks 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**	
Molina	Oil	2.1	11.8	25.1	0.09	0.69	1.55	16%
Blondie	Oil	0.4	1.48	2.92	0.03	0.11	0.21	30%
Mår	Oil	4.3	10.1	16.6	0.3	1.1	2.0	14%
Røyskatt	Oil	1.0	3.5	6.6	0.0	0.2	0.5	5%

Table 4 Recoverable resources and risk for the defined prospects and leads within the PL 973 and 973 B licenses.

	Reservoir	Trap	Charge	Retention	Total
Røyskatt	0.7	0.75	0.25 → 0.1	1.0	0.13 → 0.05
Mår	0.4 → 0.3	0.65	0.7	1.0	0.18 → 0.14
Blondie	0.7	0.9	0.5 → 0.6	0.9 → 0.8	0.28 → 0.30
Molina	0.55	0.65	0.9	0.5	0.16

Table 5 Summary of changes to risk parameters in PL 973 and 973 B prospect portfolio, comparing application and current assessment. Red = negative change, white = no change, green = positive change.

Tables with Discovery and Prospect data (NPD Table 4)

Table 4: Discovery and Prospect data (Enclose map)									
Block	15/12	Prospect name	Blondie	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	Reported by company	Harbour Energy	Reference document	APA 2019 - PL973 Extension Application			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)	1.40	2.62	3.93	6.94				
	Gas [10^9 Sm^3] (>0.00)					0.08	0.21	0.25	0.44
Recoverable resources	Oil [10^6 Sm^3] (>0.00)	0.40	0.52	1.48	2.92				
	Gas [10^9 Sm^3] (>0.00)					0.03	0.05	0.11	0.21
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)	0.30	Oil case (0.00-1.00)	1.00	Gas case (0.00-1.00)	0.00	Oil & Gas case (0.00-1.00)	0.00		
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)	0.80		
Parametres:	Low (P90)	Base	High (P10)	*Comments*					
Depth to top of prospect [m MSL] (> 0)		2864							
Area of closure [km^2] (> 0.0)	2.1	4.1	5.8						
Reservoir thickness [m] (> 0)	17	21	25						
HC column in prospect [m] (> 0)	23	35	46						
Gross rock vol. [10^9 m^3] (> 0.000)	0.043	0.073	0.093						
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)									
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 6: Blondie prospect.

Table 4: Discovery and Prospect data (Enclose map)									
Block	15/12	Prospect name	Molina	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	Reported by company	Harbour Energy	Reference document				Assessment year	2022
This is case no.:	1 of 1	Structural element	Ling Depression	Type of trap	Structural	Water depth [m MSL] (>0)	86	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)	4.98	9.23	25.10	48.70				
	Gas [10^9 Sm^3] (>0.00)					0.24	0.33	1.46	3.09
Recoverable resources	Oil [10^6 Sm^3] (>0.00)	2.10	2.60	11.80	25.10				
	Gas [10^9 Sm^3] (>0.00)					0.09	0.22	0.69	1.55
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)	0.16	Oil case (0.00-1.00)	1.00	Gas case (0.00-1.00)	0.00	Oil & Gas case (0.00-1.00)	0.00		
Reservoir (P1) (0.00-1.00)	0.55	Trap (P2) (0.00-1.00)	0.65	Charge (P3) (0.00-1.00)	0.90	Retention (P4) (0.00-1.00)	0.50		
Parametres:	Low (P90)	Base	High (P10)	*Comments*					
Depth to top of prospect [m MSL] (> 0)		3345							
Area of closure [km^2] (> 0.0)	1.2	4.3	9.3						
Reservoir thickness [m] (> 0)									
HC column in prospect [m] (> 0)	78	155	232						
Gross rock vol. [10^9 m^3] (> 0.000)	0.075	0.320	0.617						
Net / Gross [fraction] (0.00-1.00)	0.55	0.65	0.75						
Porosity [fraction] (0.00-1.00)	0.18	0.20	0.21						
Permeability [mD] (> 0.0)									
Water Saturation [fraction] (0.00-1.00)	0.21	0.25	0.31						
Bg [Rm3/Sm3] (< 1.0000)									
1/Bo [Sm3/Rm3] (< 1.00)	0.6930	0.7860	0.8740						
GOR, free gas [Sm^3/Sm^3] (> 0)									
GOR, oil [Sm^3/Sm^3] (> 0)	27	60	92						
Recov. factor, oil main phase [fraction] (0.00-1.00)	0.31	0.45	0.59						
Recov. factor, gas ass. phase [fraction] (0.00-1.00)	0.31	0.45	0.59						
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)	410			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

Figure 7 Molina prospect.

5. Technical assessment

A scoping exercise was performed of adjacent Chrysaor operated host platforms on the UK continental shelf. This study was aimed at assessing possible tie-back solutions for the remaining resources within PL 973. The nearest installation, Armada, is located approximately 10 km South of the license but unfortunately it is likely to be decommissioned in too short a timeframe to serve as tie-in host for PL 973 resources.

Two other potential host platforms were considered on the UK side; Everest located approximately 35 km South and Britannia located approximately 45 km West. These producing hubs are working towards extending field life until 2040 and beyond with the main elements being to consider OPEX reductions and new exploration opportunities. Most hydrocarbons being produced at these hubs are gas condensate, however oil field tie-ins are also present.

Everest and Britannia could both be considered as hosts for potential discoveries in PL 973, however significant top side scope would need to be included to address water injection capacity.

The high geological risk associated with the determined recoverable volumes for prospects and leads within PL 973 and 973 B did not justify a detailed technical-economic evaluation for the remaining prospectivity.

6. Conclusion

The prospectivity within licenses PL 973 and PL 973 B 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 both PL 973 and PL 973 B in their entirety.