PL939 Licence status report - relinquishment

2023-019951

Summary

PL939 is situated in the Grinda Graben in the Norwegian Sea central Halten Terrace. The license was awarded following TFO 2017 with the Late Cretaceous Egyptian Vulture prospect being the single opportunity. The prospectivity was re-evaluated using good quality reprocessed seismic data, and one exploration well, 6407/1-9, was drilled to test the Upper Cretaceous Egyptian Vulture prospect. The well proved laterally extensive oil filled Turonian reservoir sands with marginal reservoir quality/net thickness. After extensive post well studies and licence work meetings, the estimated oil-filled reservoir parameters and geometries pointed to a sub-economical discovery and no further appraisal of the discovery was recommended by the licence.

A downfaulted Jurassic trap in the Garn Formation was identified and evaluated. The volume potential here was estimated to be sub-economical due to low likelihood for a substantial column.

A drop decision for PL939 was agreed in the license as no new drilling candidate were identified in the licence.

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1 Licence history

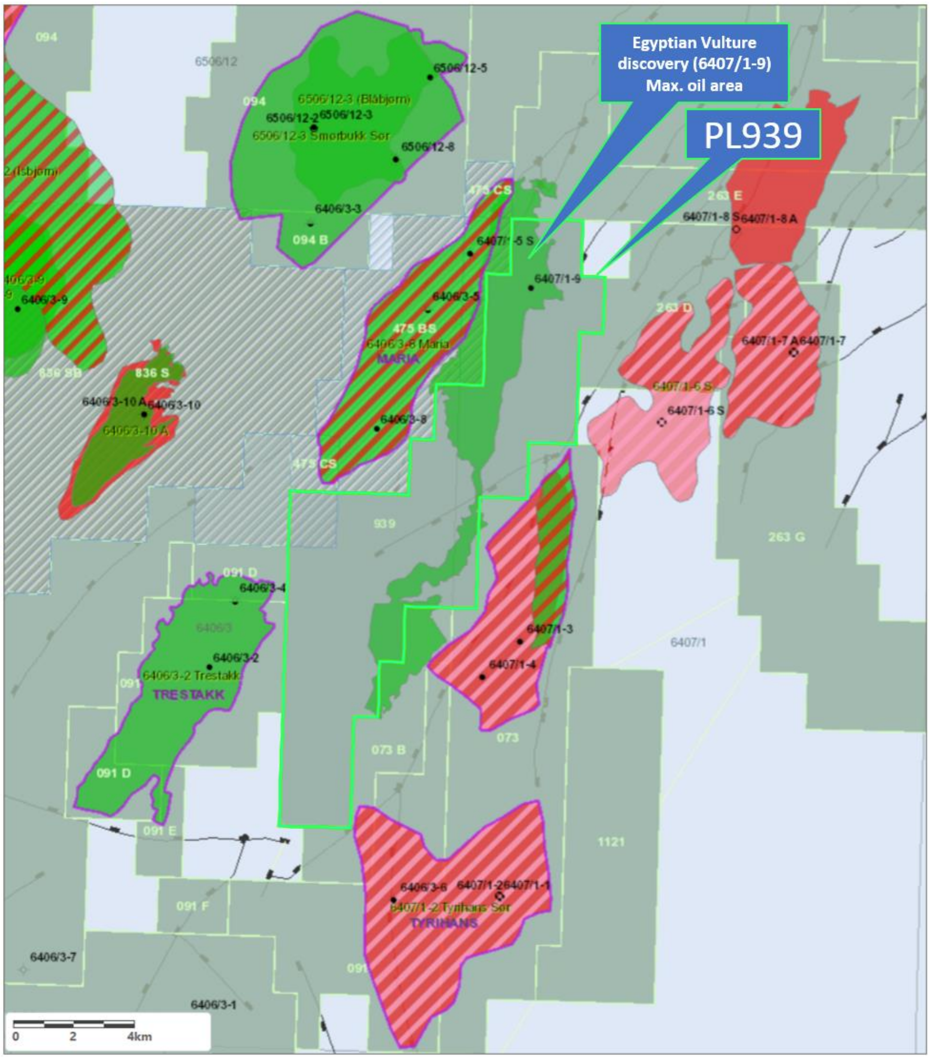

Figure 1.1: PL939 Licence area situated in the Grinda Graben adjacent to Tyrihans Nord, Trestakk, Maria Fields. 6407/1-9 well location and Egyptian Vulture oil discovery outline shown.

The license was awarded on 02.03.2018 following a TFO2017 application with seismic reprocessing and G&G studies commitments, and a drill or drop (DoD) decision to be taken within 02.03.2021. The partners were Equinor (70%, Op), PGNiG Upstream Norway AS (30%) at the point of application and Longboat Energy Norge AS farmed in later (15% share transferred from Equinor).

Licence:	PL939	
Awarded:	02.03.2018	
License period:	Expires 02.03.2023 Initial period: 5 years	
License group:	Equinor Energy AS	55% (Operator)
	PGNiG Upstream Norway AS	30%
	Longboat Energy Norge AS	15%
License area:	79 km^2	
Work programme:	Seismic 3D reprocessing (data available for licence 05.11.2019) (approved) Drill Well (positive DoD decision by 02.03.2021) (approved) Concept studies (dropped by unanimous negative BoK decision 02.03.2023) Perform PDO (dropped by unanimous negative BoK decision 02.03.2023)	

Meetings held:

04.04.2018	EC/MC startup meeting
05.11.2018	EC/MC meeting
27.06.2019	EC/MC work meeting
25.11.2018	EC/MC meeting
15.01.2020	EC/MC work meeting
20.01.2020	EC/MC work meeting
24.06.2020	EC/MC work meeting
11.11.2020	EC/MC meeting
19.01.2021	EC/MC work meeting
29.11.2021	EC/MC meeting
18.02.2022	EC/MC work meeting
01.03.2022	EC/MC work meeting
04.05.2022	EC/MC work meeting
02.06.2022	EC/MC work meeting
30.06.2022	EC/MC meeting
01.12.2022	EC/MC meeting
17.02.2023	EC/MC meeting

Work performed:

Focus of the application was Cretaceous Lange Fm. prospectivity. The strategy was to license open acreage around a pronounced seismic anomaly in the main Cenomanian-Turonian untested depocenter of the Grinda Graben, the Egyptian Vulture prospect. Then perform reprocessing on the seismic 3D dataset HVG2013 with focus on the Cretaceous section and evaluate a drill decision.

The seismic reprocessing commitment was approved by using a sub-cube of the Equinor 2018 DUG reprocessed MC3D-HVG2013 data with focus on Cretaceous (HVG2013EQZ18). The data was reprocessed by the DUG to improve imaging of Cretaceous layers with focus on denoising, multiple removal, and improved velocity model, incorporating anisotropy parameters. The data went through broadband anisotropic Kirchhoff prestack depth migration. A post migration sequence consisting of a comprehensive noise and multiple attenuation was applied to push the signal/noise ratio without compromising the AVO response. Final statics were applied to the data. To improve imaging of the Cretaceous layers, a new anisotropic velocity model was applied. For improving gather flatness on far and ultrafar offsets, an epsilon scan was run after iteration 5 tomography resulting in a laterally varying epsilon field. The reprocessing result was good quality seismic data sufficient for improved structural interpretation and geophysical analysis in the Cretaceous sequence.

Redefinition of the Egyptian Vulture prospect was based on the new data. Structural mapping, sedimentological modelling, AVO-work, trap seal work was performed and lead the way to the drill decision.

One well was drilled on the Egyptian Vulture prospect. The 6407/1-9 well position tested the prospect in a geophysical/sedimentological “sweet-spot” and clarified the volume potential for the proven reservoir and oil fill.

Comprehensive post well studies were run on PVT, geochemistry, petrophysics, Image log, petrography, sedimentology. Together with Seismic re-interpretation, AVO and tuning analysis, updated depth conversion and reservoir technical analysis, this formed basis for the final valuation and drop decision.

Reason for surrender:

The prospectivity update in PL939, based on good quality reprocessed PSDM seismic data, led to an uplift of the business case for the Egyptian Vulture prospect and the decision to drill well 6407/1-9. Post well volume update was however conclusive on a sub-economical oil discovery. Further appraisal was discussed thoroughly and eventually not recommended in the partnership.

Evaluation of secondary prospectivity in the Jurassic concluded on only sub-economical value for a Garn hanging-wall prospect model in the Grinda Graben. No further drillable prospects have been identified in the licence.

2 Database overviews

2.1 Seismic data

MC3D-HVG2013EQZ18:
348 km2 of reprocessed MC3D-HVG2013 (Cretaceous focus). Full and angle stacks covering PL939 with tie to relevant nearby wells (Figure 2.1)

2.2 Well data

- 6407/1-7 & 7A Solberg
- 6407/1-6S Rodriguez
- 6407/1-3 Tyrihans
- 6407/1-4 Tyrihans appraisal well
- 6407/1-2 Tyrihans sør
- 6407/1-5S Maria
- 6406/3-8 & T2 Maria
- 6406/3-5 Maria
- 6406/3-2 Trestakk
- 6406/3-4 Trestakk
- 6406/3-3 Smørbukk S
- 6506/12-5 Smørbukk S
- 6506/12-8 Smørbukk S

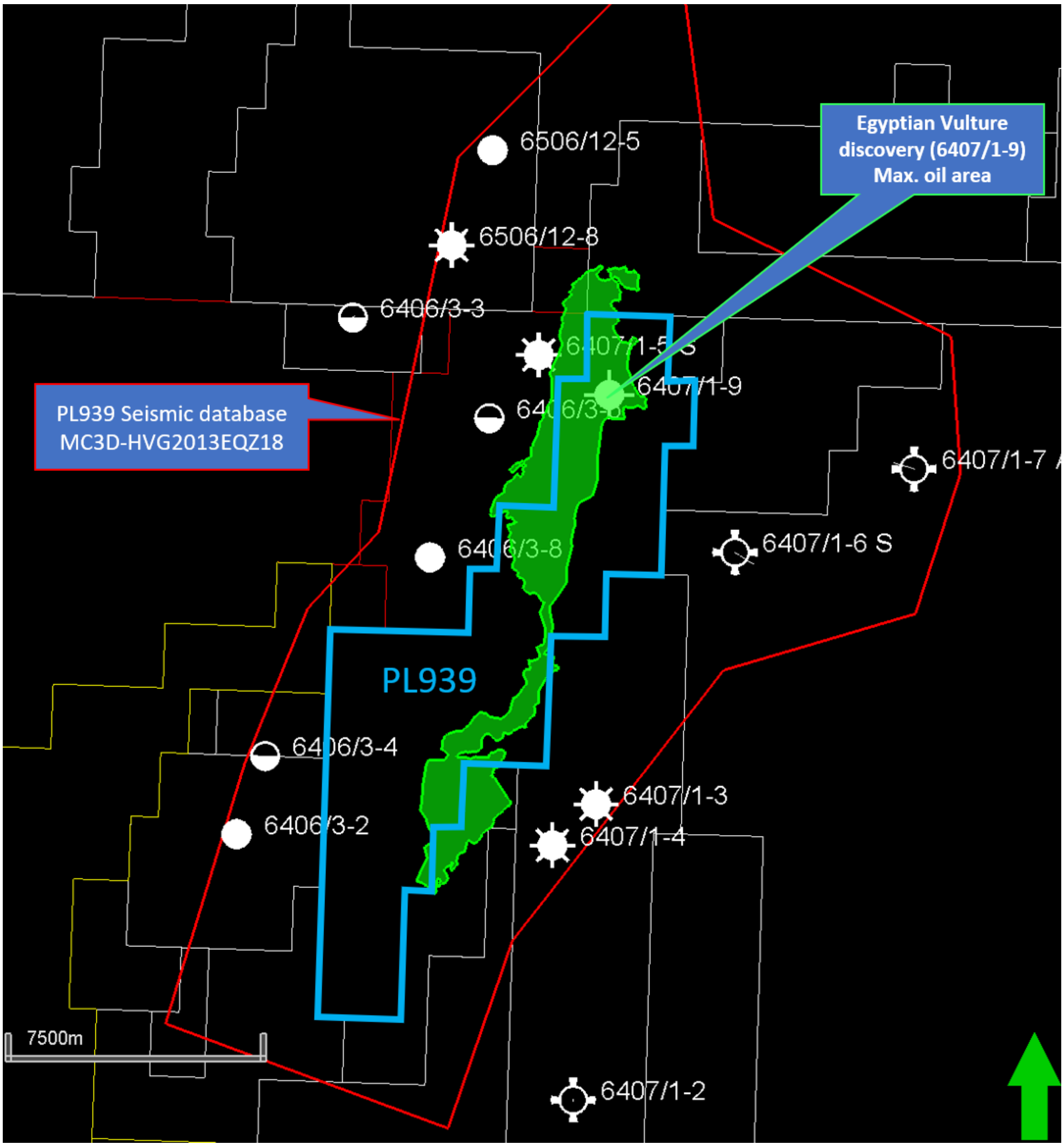

Figure 2.1: PL939 Licence common database. Reprocessed MC3D-HVG2013 within the red polygon and exploration wells. Egyptian Vulture oil discovery outline shown.

3 Results of geological and geophysical studies

The following main pre well G&G studies were carried out in the license evaluation:

- Seismic reprocessing
- Seismic interpretation and mapping
- Geophysical observations and AVO assessment

3.1 Seismic reprocessing

The licence database was established with 348 km2 of the reprocessed 3D seismic data HVG2013EQZ18 (Figure 2.1). The area was defined as sufficient for updating the Egyptian Vulture prospect within the frame of the Grinda Graben and including seal/closure elements and relevant offset tie to exploration wells. The data was part of a full HVG2013 reprocessing project initiated by Equinor in the central/western Halten Terrace. The reprocessing enhanced seismic data quality sufficiently for updated interpretation and geophysical analysis in the Cretaceous interval. Stacking velocities from the data formed the basis for depth conversion of the updated maps.

3.2 Seismic interpretation and mapping

Seismic interpretation of key horizons using the reprocessed data was the basis for the pre well volume/risk assessment and preparation for the well placement. Special attention was made to the fault definitions and pinch out zones identified as major risk elements. This resulted in a new set of time and depth structure maps. Top and base reservoir depth maps were used for input to volume calculation.

The architectural composition of the depositional system was modelled based on amplitude maps, offset well logs/cores and the regional understanding of the slope gravity flow systems in the Cenomanian/Turonian Lange Formation on the Halten Terrace. This sedimentological model was important input for the fault seal analysis in the entry point of the sands into the graben, as well as for spatial prediction of sand facies distribution.

3.3 Geophysical observations and AVO assessment

The new maps and the reprocessed seismic were used as input to “net pay from seismic tuning analysis” and other amplitude analyses to aid the interpretation of reservoir geometries and hydrocarbon presence. AVO classes varying from II to III reservoir sand were observed in Egyptian Vulture. In comparison, a class III AVO anomaly in the Solberg reservoir (6407/1-7 & 1-7A) is seen for the interpreted reservoir there. The Egyptian Vulture reservoir holds poorer quality and larger burial compared to the Solberg reservoir and the phase is oil instead of gas as in Solberg. This may explain the difference in AVO class.
Egyptian Vulture had a slight DFI uplift applied, based on a partially depth conformant amplitude anomaly in the south.

4 Well result and post well update report

Well 6407/1-9 targeted the Egyptian Vulture prospect. The vertical well was planned to test a reservoir amplitude/thickness “sweet spot” in an elevated trap position and clarifying both reservoir upside and a contact with positive business case.

The seismic signature and pond-like depositional setting within the graben suggested reservoir to be thicker than the nearby hydrocarbon bearing and roughly time equivalent reservoirs previously penetrated by the wells 6407/1-7, 6407/1-7 A and 6407/1-6 S. This model was proven by the well.

Light oil in an over-pressured reservoir was proven in the Lange Fm. sst. I target of upper Cretaceous Early Turonian age with an oil down to 3751mTVDSS (Figure 4.1). The well was drilled to 3914m MD in the Lange Fm. All other reservoirs encountered in the well were water wet. The petrophysical evaluation of the target zone was based on core, log, fluid, and pressure data acquired in the well.

One core was cut covering part of the Intra Lange sst. I reservoir (Figure 4.1). Overall, reservoir deposits in the core support the prognosed depositional model and show a good example of a prograding channel-lobe complex.

A study on Image logs from well 6407/1-9 has documented details in the complexity of the Intra Lange sandstone depositional system in the well area. In addition to the overall N-S trending depositional system witnessed by seismic amplitude, a local reconstructed environment derived from image logs in the well area point to active slumping/faulting during deposition in Turonian times. The Intra-Lange sandstone interval in the well area has been influenced by m-scale slide blocks, slumps and sandy debris flows (witnessed by structural dips, depositional dip angles and “image log facies”). This indicates a very dynamic system that includes channel scours and instabilities within the channel lobe system containing sandy gravity flows as well as debris flows, as witnessed by core description. A local easterly sediment source in addition to the main north-westerly source area is inferred. It may be questioned if the well area is a negative reservoir outlier dominated by local slumping; however, the well was drilled in a seismic "sweetspot" and post well calibrated sub-regional tuning analysis concludes on the well likely being a relative reservoir "sweetspot" testing mostly the upside.

The petrographic core analyses documented the existence of high amounts of intergranular clay matrix in the sandstone in an area defined as a reservoir “sweet-spot”. This significantly degraded the average permeability range and recoverable volume for the discovery.

The post well seismic tie showed all permeable sands to be largely restricted to a one-cycle soft envelope (on a -90^{O} rotated far offset cube). The Lange sst. I was confirmed as a soft event between top and base on the far angle stack (24-36 degrees). Updated reservoir maps showed a decrease in overall reservoir thickness and well-calibrated net pay from seismic tuning analysis suggested a decreased reservoir Net/Gross. The reservoir corresponds to a 35.5m gross interval with 7.5m net sand (Figures 4.1, 4.2, 4.3).

AVO modelling using LFP substituted logs shows that the Intra Lange sst. I corresponds to a soft seismic response between top and base reservoir for both brine, oil and gas substitutions in the well (Figure 4.4). Increased softening with increasing offsets points to AVO class III. In the brine substitution case, it could be associated with an AVO class II. As shown on Figure 4.4, oil and gas substitutions at well 6407/1-9 are impossible to differentiate on angle gathers even at large angle stack (> to 30 degrees).

The well was drilled in an area classified as a turbidite channel lobe transition zone in a stepped slope/partially active graben. An explanation for the excessive amount of detrital clay in the reservoir samples from the well may lie in the syntectonic nature of the Grinda Graben. The graben may have acted as an effective trap for the dominating supply of hemipelagic slope sediments to be incorporated heavily in the gravity flows during deposition.

The pre-well main risk element (trap) was related to sand pinch out and membrane fault seal in the north and northeast. The well has proven that a downfaulted trap with self-juxtaposed reservoir may work for the Lange play and that the up-dip lateral reservoir pinch-out also worked as a trapping mechanism in the Grinda Graben. The poor permeability of the reservoir itself may be an integrated part of the working trapping mechanisms.

The updated post well reservoir and fluid parameters are listed in tables 4.1 and 4.2. Final volume simulation results are listed in table 4.3.

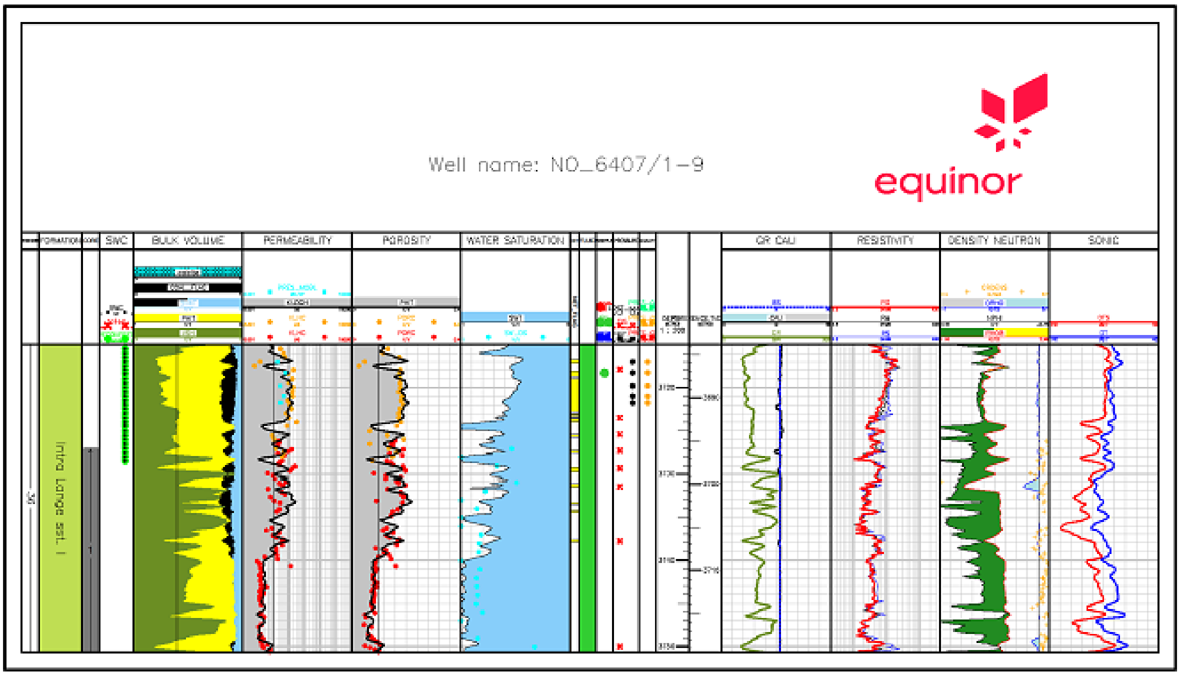

Figure 4.1: CPI plot Intra Lange sst. I. 35.5m Gross sand was proven by the well.

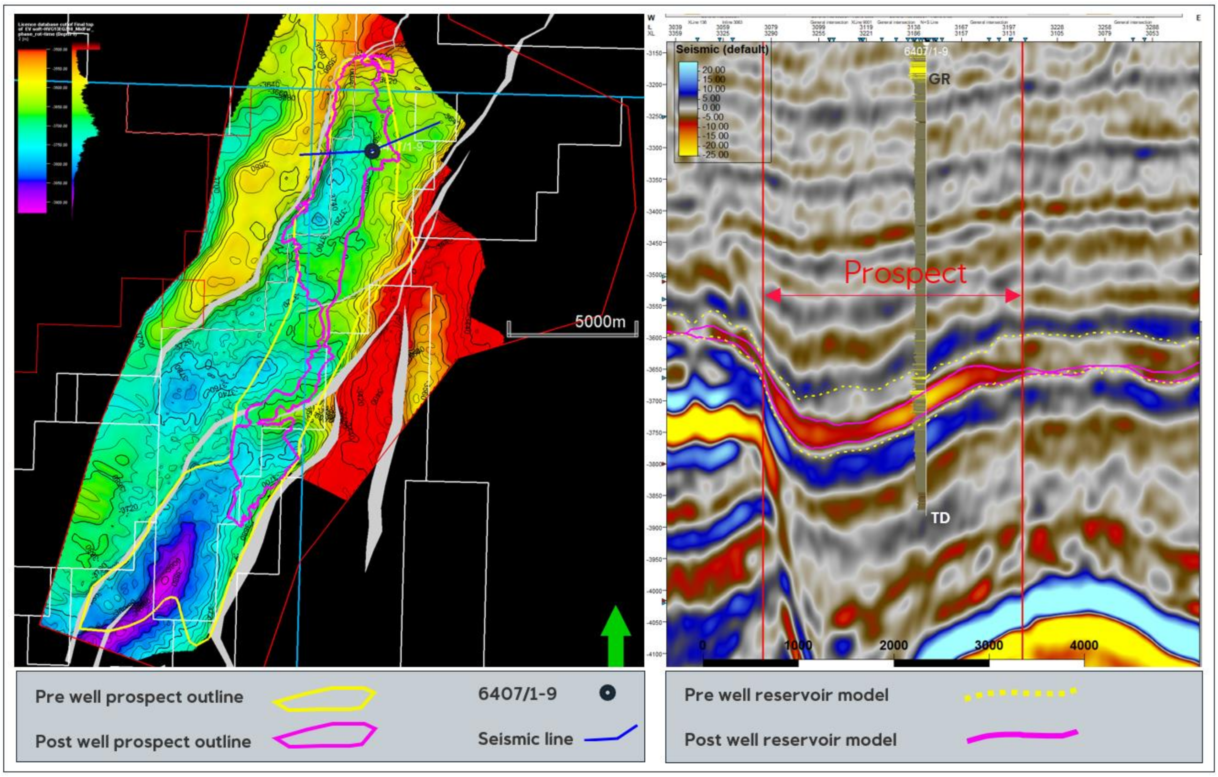

Figure 4.2: Left: Top reservoir depth structure map updated post well. Well 6407/1-9 tested the northern part of the prospect. Post well discovery outline is smaller than pre well definition (27km2 vs. 49km2). Right: Depth seismic line tying well 6407/1-9 (MC3D-HVG2013EQZ). Post well reservoir thinning was implemented by the well tie.

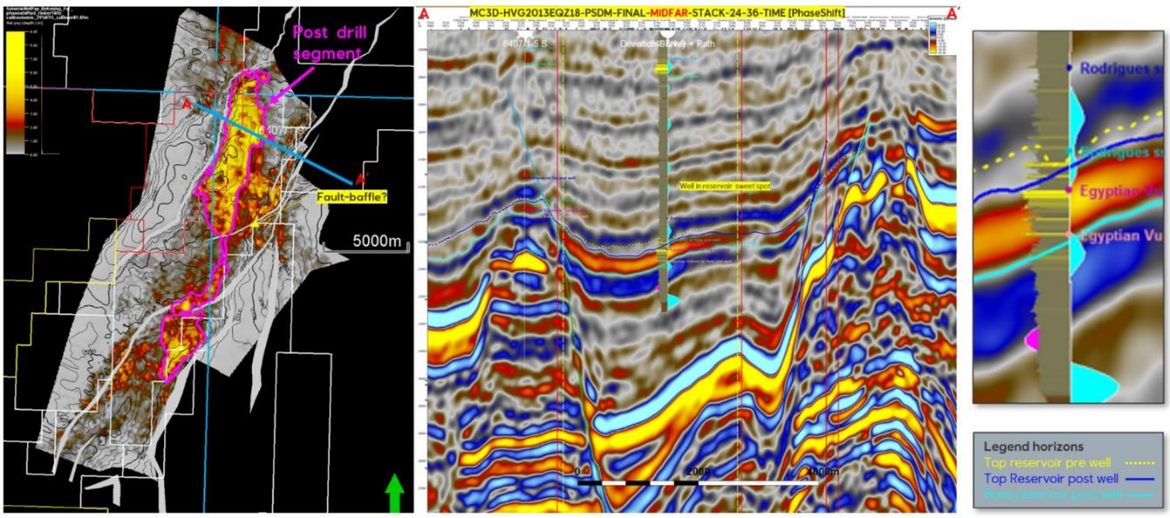

Figure 4.3: Updated well tie and interpretation on far angle stack (24-36 degrees) MC3D-HVG2013EQZ18 PSDM dataset. Detuned amplitude map to the left.

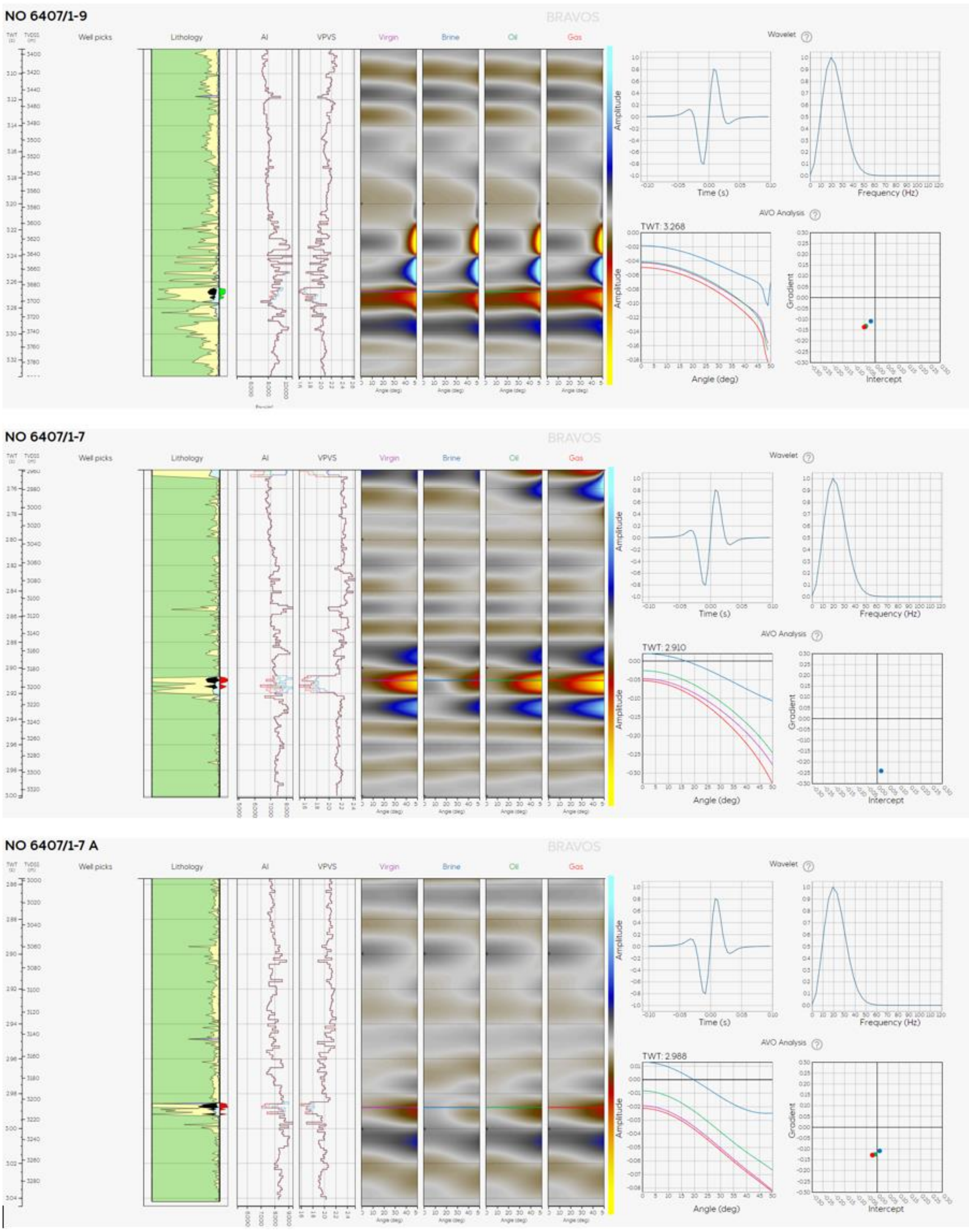

Figure 4.4: LFP modelling at wells 6407/1-9 (top), 6407/1-7 (middle) and 6407/1-7A (bottom). The seismic wavelet is a -90 degrees phase rotated Ricker with a peak frequency of 20 Hz. The purple line, blue line, green line, and the red line represent top reservoir picks for respective substituted fluids.

Table 4.1: Oil case reservoir parameters, pre versus post well 6407/1-9.

Egyptian Vulture - Applied oil reservoir parametres for simulation - Pre versus Post 6407/1-9					
Simulation	**Average gross reservoir (m) (mapped isopach)**	**N/G (fraction) (P90-Mean-P10)**	**Porosity (fraction) (P90-Mean-P10)**	**Permeability (mD) (mean)**	**Saturation (oil) (fraction) (P90-Mean-P10)**
Pre well prospect	49,00	0,21-**0,28**-0,35	0,16-**0,18**-0,20	16,00	0,65-**0,73**-0,81
Post well discovery	29,70	0,07-**0,11**-0,15	0,17-**0,18**-0,19	0,91	0,41-**0,44**-0,48

Table 4.2: Fluid parameters and recovery factors applied to the post well resource update.

Egyptian Vulture - fluid parametres applied for simulation - Post 6407/1-9				
Simulation	**Gas oil ratio (Sm3/Sm3) (P90-Mean-P10)**	**Formation volume factor (Bo)(m3/Sm3) (P90-Mean-P10)**	**Recovery factor oil (P90-Mean-P10)**	**Recovery factor ass. gas (P90-Mean-P10)**
Post well discovery	327-**345**-363	1,92-**1,95**-1,98	**0,01 - 0,08- 0,21**	**0,02 - 0,14 - 0,33**

5 Reservoir technical analysis and volumes

Measured permeability values in well 6407/1-9 were very low and therefore there is a degree of uncertainty as to whether any form of well productivity for oil is achievable and, if so, whether it would be sufficient to attain economic volumes using conventional methods. Therefore MBAL, together with Prosper, was used to analyze the oil reservoir, for different assumed average permeability values to ascertain a range of recovery factors for oil and its associated gas that may be possible for such methods using production from one well.

For this analysis a sand box was assumed, as is the case with MBAL, with Egyptian Vulture rock and fluid properties together with in-place volumes. Prosper was used to derive in-flow calculations for a 1000m horizontal well and was also used to calculate VLP curves. Tests were carried out for different average permeability values and associated aquifer volumes. It was found that, as expected, recovery was very low for both oil and associated gas (no greater than 3%) for average permeability values less than 3 mD. However, beyond that, recovery seemed to edge up a bit more to more reasonable limits and could be increased by assuming greater pressure support from the aquifer (twice the reservoir volume). To reflect this a recovery factor distribution was created in GeoX in which the majority of recovery factor values (for both oil and associated gas) were less than 3% but for which the higher values of average permeablity and aquifer support (in which the chances of occurrence were very low) the recoveries were much higher. In the final analysis a highly skewed distribution for oil recovery factor of Min = 0%, Mean = 3% and Max = 30% was arrived at together with an associated gas recovery factor of Min = 0%, Mean = 3% and Max = 65% in which the majority of values were less than 3%. This tended to push up the mean of the recovery distributions, in each case, to 8 and 14% respectively but where the P50 was lower (Table 5.1).

Table 5.1: Recoverable oil volumes post well 6407/1-9.

	Case	Phase	P100	P90	Mean	P10	P00	Recovery factor (P90-Mean-P10)
Post well discovery Recoverable	Oil	Oil (MSm3)	0,00	0,01	0,11	0,29	0,64	0,01 - 0,08- 0,21
		Ass. Gas (GSm3)	0,00	0,01	0,07	0,17	0,41	0,02 - 0,14 - 0,33
	Total resources (MSm3 OE)		0,01	0,04	0,18	0,39	0,84	

6 Conclusion

Prospectivity update in PL939 after well 6407/1-9 was conclusive on a sub-economical oil discovery for the Egyptian Vulture and an appraisal well in the discovery was considered of very marginal value. No positive business cases were identified in the Middle Jurassic play or elsewhere within the Licence boarder. On this basis the partnership relinquished PL939 by 3rd of March 2023.