PL1015

Relinquishment Report

April 2020

Contents

1. License History 4
2. Database 5
3. Results of the Geological and Geophysical Studies 8
3.1 Amplitude analysis 9
3.2 Reservoir quality and producibility study 9
3.3 Petrophysical study 10
4. Prospect Update 11
4.1 Summary and conclusion after new evaluations 14
5 Technical Evaluation 17
6 Conclusions 18
7. References 19

Figure list

Figure 1: Location of license PL1015 with the main prospect Aragorn. 4
Figure 2: 2D and 3D seismic data included in the common database 6
Figure 3: 2D seismic lines showing the Aragorn trap configuration. 9
Figure 4: 2D SL-SLRE01-119 line with the isothermal gradients superimposed. 11
Figure 5 Top Aragorn reservoir depth map.. 12
Figure 6: W-E Seismic section and geological interpretation... 13
Figure 7: NW-SE Seismic section and geological interpretation... 13
Figure 8: Side-seal risk against the hydrothermal vent around 6607/12-1 (Træna). 14
Figure 9: Development Concept for Aragorn 18

Table list

Table 1: License meetings and communication..5
Table 2: Well database 6
Table 3: 2D and 3D seismic Database 7
Table 4: Purchased 2D seismic data (as part of work obligation for the license) 8
Table 5: List of key studies completed during the evaluation (described in this section)..................8
Table 6: Additional studies completed during the evaluation 8
Table 7: INEOS risking scheme with included risk adjustments...15
Table 8: Final prospect data for Aragorn, February 2020...16

1. License History

License PL1015 is located in the Træna Basin in the Norwegian Sea, and comprises blocks 6607/8, 6607/9 (part) and 6607/11 (part) (Figure1).

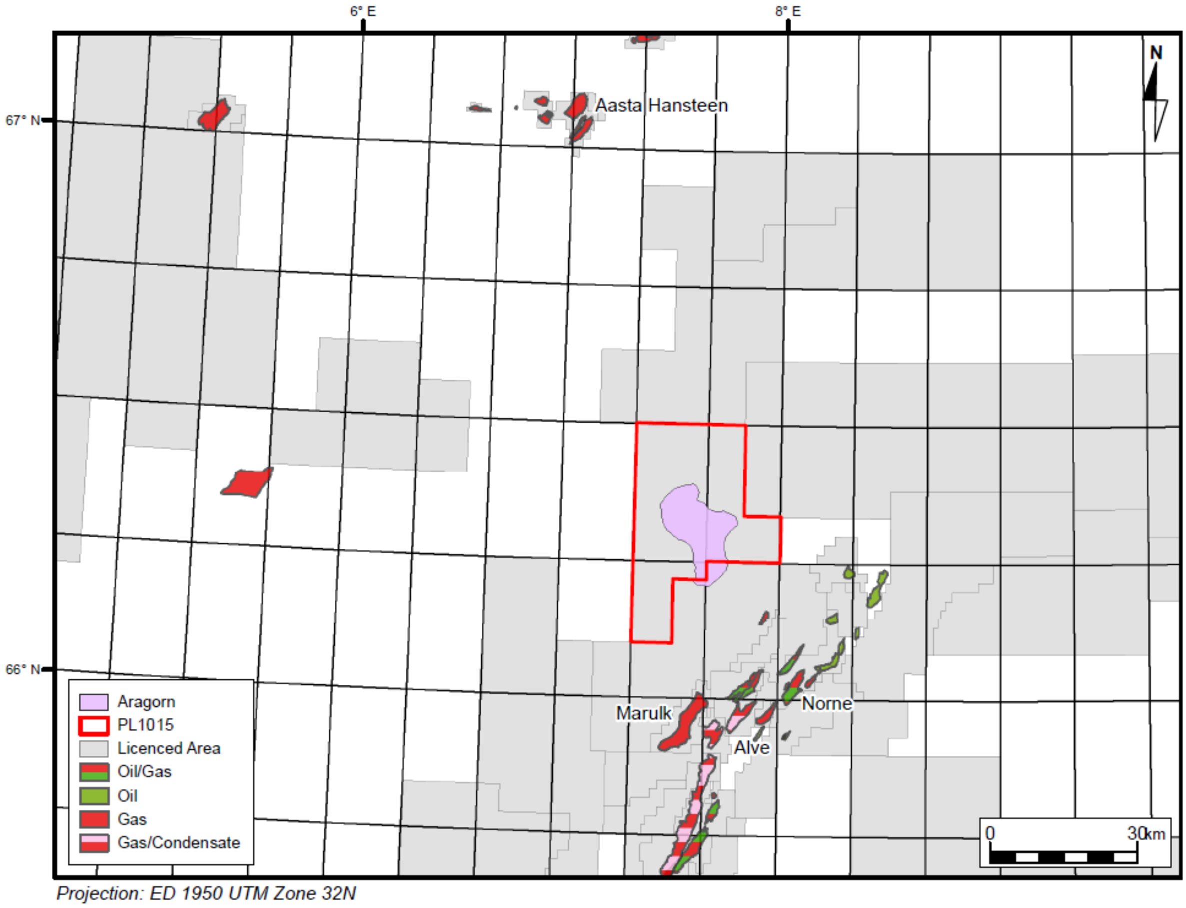

Figure 1: Location of license PL1015 with the main prospect Aragorn.

The license was awarded 1st March 2019 as a result of the APA 2018 Round application. INEOS E&P Norge AS was assigned as Operator with 70% share and DNO Norge AS as partner with 30% share.

Work commitments in PL1015 were the following:

- Acquire 2D seismic data.
- Decision to Acquire 3D or drop within 1 year from award.
- Decision to Drill or drop within 4 years from award.
- Decision to Concretize (BoK) or drop within 6 years from award.
- Decision to Continue (BoV) or drop within 8 years from award.
- Decision to Submit PDO or drop within 9 years from award.

An extensive evaluation of the license was performed, and the results shared through several meetings (Table 1) between INEOS E&P Norge AS and DNO Norge AS.

Table 1: License meetings and communication

Meetings	Date
ECMC#1 – License Establishment	09.04.2019
EC Work meeting – Prospect update	12.11.2019
ECMC#2 – Technical evaluation 3D or Drop	27.11.2019
Conclusion of technical and economic analysis (L2S) Recommendation for 3D or drop (L2S)	06.02.2020

The conclusions from the PL1015 technical and economic evaluations and recommendation for acquiring 3D or drop were agreed between the parties to be shared on L2S.

The Operator has identified the Aragorn prospect as the main opportunity within the license. The Aragorn prospect is characterized as a large amplitude-supported prospect with a reservoir composed of siliceous diatomaceous ooze within the Tare Formation. This represents a novel play on the Norwegian Continental Shelf. The prospect is situated in a favorable position to receive gas charge from the underlying Spekk Formation and potentially also from the Cretaceous Lange Formation.

As the PL1015 evaluation progressed in 2019 it became clear that there were several additional technical challenges associated with the Aragorn prospect, which were not identified during the APA2018 evaluation.

Reservoirs composed of siliceous oozes are characterized by very high porosities (dominated by micro-porosity) and low permeabilities in the Opal-A phase which results in high in-place volumes. In the APA 2018 application document the presence of thin sand layers within the diatomite were included to enhance fluid/gas flow within the reservoir.

New detailed geological and petrophysical work in 2019 suggests that the siliceous ooze in the reservoir has transformed from Opal-A to Opal-CT (Porcelenite) resulting in a major decrease in the Aragorn in-place volumes. In addition, there is little evidence for sand interbeds to enhance flow within this low permeability reservoir. An additional concern to the validity of the Aragorn prospect is the integrity of the top seal due to the identification of a high content of ooze in the overlying Brygge Formation. In a production scenario a high number of wells will be required to produce the resources which gives a strongly negative business case for the low (P90) and base cases (P50).

By February 2020 the license partnership has unanimously taken a decision to drop the license by the end of the current period.

2. Database

The agreed Common Database (CDB) for the license consists of released wells from the Træna and Rås Basins, Vigrid and Någrind Synclines, Utgard and Nyk Highs as well as the Ormen Lange Field. Key wells and seismic data in the Common Database (CDB) as well as INEOS entitled seismic data have been used in the evaluation of the license prospectivity (Figure 2, Tables 2 and 3). The Aragorn prospect is only covered by 3D seismic data in the most up-dip eastern part of the license and the remaining part has been evaluated based on 2D seismic data of various vintages and quality.

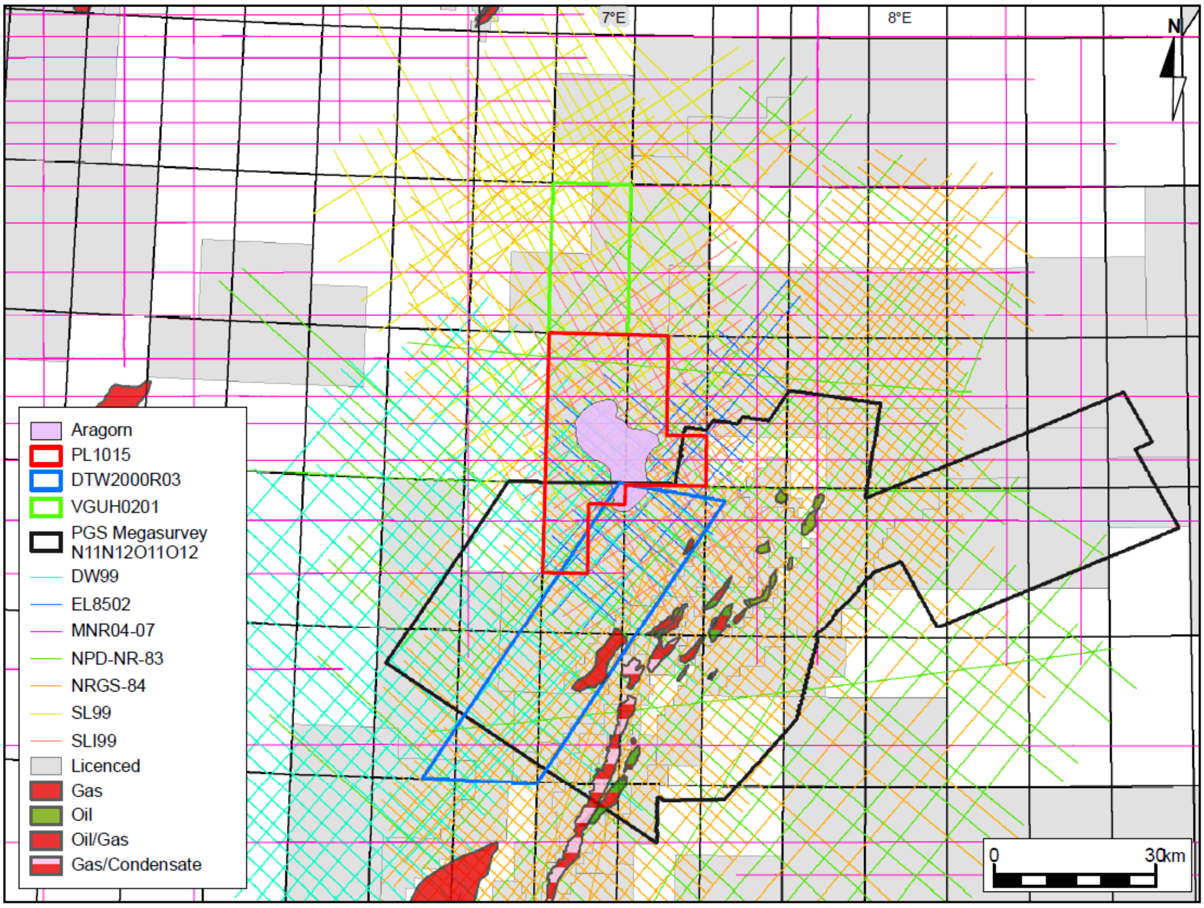

Figure 2: 2D and 3D seismic data included in the common database

Table 2: Well database

Well (NPDID)	Status	Operator	Completion Date	Formation TD (m TVDSS)	Formation at TD	Content (NPD)
6605/8-1 (4984)	Released	Norsk Hydro	22.10.2005	4508	Lange Fm.	Gas
6605/8-2 (5812)	Released	StatoilHydro	10.07.2008	4196	Lange Fm.	Dry
6506/3-1 (4344)	Released	Norsk Chevron	19.08.2001	3662	Lange Fm.	Dry
6607/12-1 (925)	Released	Elf Petroleum	01.10.1986	3516	Springar Fm.	Dry
6607/5-1 (1064)	Released	Esso Exploration	11,09.1987	3805	Lange Fm.	Dry
6607/5-2 (1789)	Released	Esso Exploration	17.11.1991	4666	Kvitnos Fm.	Dry

6607/2-1 (5471)	Released	Eni Norge	26.03.2007	3526	Springar Fm.	Dry
6707/10-1 (3075)	Released	BP Norway	23.07.1997	5026.5	Kvitnos Fm.	Gas
6706/11-1 (3202)	Released	Den norske stats oljeselskap	22.03.1998	4306	Lange Fm.	Dry
6305/4-1 (4441)	Released	Norsk Hydro	03.06.2002	2974	Springar Fm.	Gas

Table 3: 2D and 3D seismic Database

Survey (NPDID)	Type	Year	Company	Status
DW99 (3972)	2D	1999	Fugro-Geoteam A/S	Released
MC2D-NH0509 (4292)	2D	2005	PGS Geophysical AS	Released
SH8808_RAWMIG (3165)	2D	1988	A/S Norske Shell	Released
SL99-2D.MIG-FIN (4011)	2D	1999	Fugro Multi Client Services AS	Released
SLI99 (4012)	2D	1999	Fugro Multi Client services AS	Released
MNR04 (4252)	2D	2004	Spectrum ASA	Some released, some entitled to INEOS
MNR05 (4298)	2D	2005	Spectrum ASA	Some released, some entitled to INEOS
MNR06 (4364)	2D	2006	Spectrum ASA	Some released, some entitled to INEOS
MNR07 (4450)	2D	2007	Spectrum ASA	Some released, some entitled to INEOS
EL8502 (2710)	2D	1985	Total E&P, Norge	Released
NRGS-84 (2654)	2D	1984	Equinor	Released
NPD-NR-83.2D.MIG_FIN (2571)	2D	1983	NPD	Released
DTW2000R03 (4034)	3D	2000	ConocoPhillips Scandinavia	Entitled to INEOS
VGUH201 (4239)	3D	2003	CGG Service Norway	Released
PGS Megasurvey N11_N12_O11_O12_P12_final Mig_8bit	3D	2010	PGS Geophysical AS	Entitled to INEOS

Several additional 2D lines were acquired as part of the work commitment of the license (Table 4). Furthermore, angle stacks and gathers were acquired for the additional lines to evaluate the amplitude anomaly defining the Aragorn prospect.

Table 4: Purchased 2D seismic data (as part of work obligation for the license)

Line name (NPDID)	Type	Year	Company	Status
MNR05-7300	2D	2005	Spectrum	Incl. Angle stacks, gathers and velocities
MNR05-7353	2D	2005	Spectrum	Incl. Angle stacks, gathers and velocities
MNR06-7360	2D	2006	Spectrum	Incl. Angle stacks, gathers and velocities
MNR06-7412	2D	2006	Spectrum	Incl. Angle stacks, gathers and velocities
MNR10-444	2D	2010	Spectrum	Incl. Angle stacks, gathers and velocities
MNR11-80475	2D	2011	Spectrum	Incl. Angle stacks, gathers and velocities
MNR08-434	2D	2008	Spectrum	Incl. Angle stacks, gathers and velocities
SL-SLIRE01-119 (4129)	2D	2001	Spectrum	Incl. Angle stacks, gathers and velocities

All MNR lines are purchased as CFI reprocessed lines

3. Results of the Geological and Geophysical Studies

Very few wells have been drilled close to the PL1015 license. Wells 6506/3-1, 6607/2-1 and the 6607/12-1 well drilled just up-dip of the Aragorn prospect are the most relevant to the play (Table 2). The area surrounding and including the PL1015 license is covered by 2D seismic lines of variable vintages and of moderate to poor quality and by 3D seismic surveys of adequate quality. The Aragorn prospect itself is covered largely by 2D seismic data and only a small portion over the easternmost part of Aragorn is covered by the 3D PGS Mega-survey and the DTW2000R03 (Figure 2). Several studies have been performed to shed light on the uncertainties flagged in the APA 2018 application document and proposed in the initial work program (Tables 5 and 6).

Table 5: List of key studies completed during the evaluation (described in this section)

Study	Duration of study
Amplitude analysis (Gradient analysis)	September-October 2019
Reservoir quality and producibility study	September-November. 2019
Petrophysical study (done by Lloyds Register)	June-November 2019
Literature study (Monterey Fm. analogue and Svensen *et al*. 2003)	August-November 2019
Additional prospectivity	November-December 2019

All studies presented at EC/MC #2 (27.11.2019)

Table 6: Additional studies completed during the evaluation

Study	Duration of study
Rock property analysis and fluid substitution	September 2019
Velocity model	September 2019
Chronostratigraphic correlation	October 2019

All studies presented at EC/MC #2 (27.11.2019)

3.1 Amplitude analysis

In the PL1015 license the Aragorn prospect is defined by a soft amplitude anomaly which has a maximum areal extent of 187 km^2 (Figure 3). For the license work it was important to evaluate this geophysical response during the first phase of the work program as neither seismic gathers nor angle stacks were available to INEOS during the writing of the APA 2018 application. Selected 2D seismic lines with angle stacks and gathers were therefore purchased for amplitude analysis as part of the work program.

Gradient analysis of the gathers was performed to investigate a possible AVO response. Areas were evaluated both inside and outside the amplitude anomaly area, on each of the 2D lines with gathers.

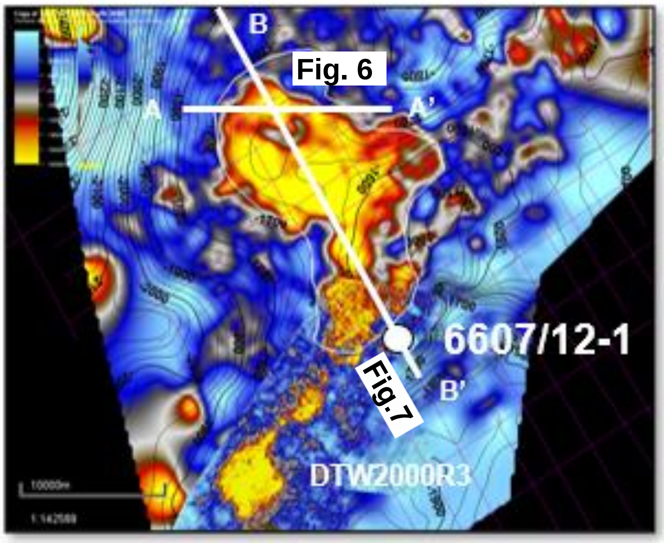

Figure 3: The map is an amplitude map (Chi 20 cube) combining the 2D and 3D DTW2000R3 data across the area. Note the amplitude conformance with structure in the northwestern part of the prospect

The analysis yielded what could be loosely interpreted as a class IV response, although some of the points outside the anomaly gave the same response. It is unclear whether the AVO response is due to gas, residual gas, or the presence of opal-CT in the reservoir, as opal-CT is also known to produce a class IV response. Consequently, the results of the study were inconclusive.

In addition, similar amplitude anomalies have been observed at several levels both above and below the amplitude which defines the Aragorn prospect. These could potentially be due to the presence of shallow gas anomalies in the area, which are causing amplitude shut-off beneath the gas clouds.

In conclusion, what was initially believed to be an anomalous amplitude brightening defining the Aragorn prospect now appears to be relatively similar to the amplitudes of the overlying reflectors in the area (e.g. Opal-CT and Brygge Fm. horizons on Figure 4).

3.2 Reservoir quality and producibility study

The Aragorn reservoir is composed of a siliceous diatomite ooze of Early Eocene age assigned to the Tare Formation. It is a novel play on the Norwegian Continental Shelf. However, siliceous ooze is a well-established onshore play in California (US) where numerous oil fields are producing from the prospective ooze intervals of the Monterey Formation (Bowersox, 1990; Bhat and Kovscek, 1998; Allan et al., 2010). The Monterey Formation ooze is dominated by opal-A characterized by very high porosities but very low permeabilities leading to low producibility. Consequently, the onshore light oil Belridge Field in California has a very high well density and a total of more than 6000 wells have been drilled during its long production history which started in 1905 (Allan and Lalicata, 2011). In places the well spacing is only 11,5 meters.

A detailed study on the reservoir quality of the Aragorn reservoir was undertaken**.** This study focused on the possible diagenetic transformation of the diatomite ooze from opal-A to an opal-CT (Porcelenite) dominated phase. The opal-CT transformation occurs due to mineral instability driven by a combination of temperature and pressure. Porosity is adversely affected as the biogenic opal-A is transformed to the diagenetic opal-CT. The critical temperature is thought to be in window from 40 to 55^{o}C (Ireland, 2011).

It was assumed in the APA 2018 application that opal-A was the dominant mineral phase of the diatomite oozes in the Tare Formation as this were encountered by other wells in the Vøring Basin. However, detailed studies on the adjacent 6607/12-1 (Træna) by Svensen *et al.* (2003) have demonstrated that the major transformation from opal-A to opal-CT has occurred in the Tare Formation encountered in the well. Moreover, INEOS evaluations indicate that the Aragorn reservoir is presently located at a depth and temperature where the opal-A to opal-CT transformation has most likely occurred (see Figure 5). These two new observations have increased the risk of a poorer reservoir quality than previously estimated, and the reservoir parameters have been adjusted accordingly in the volumetric calculations (Table 8).

3.3 Petrophysical study

A new petrophysical study was undertaken to investigate the character and properties of the ooze reservoir.

The producibility of the Aragorn prospect was evaluated as part of the APA 2018 work. A dry gas phase in combination of interbedded sandstones with diatomite ooze was essential to achieve reasonable recovery factors in the Reservoir Engineering model. However, the new petrophysical evaluation has indicated that sandstones do not constitute a significant lithology within the Tare Formation. Consequently, it is concluded that the previously envisaged scenario of diatomite oozes interbedded with sandstones is unlikely.

The main target of the 6607/12-1 well located 2 kilometers from Aragorn was the Brygge Formation which represents the top seal for the prospect. Petrophysical evaluations and cuttings descriptions outlined in the APA 2018 work suggested that the Tare Formation was mud-prone in the well. Consequently, it was concluded that the Aragorn amplitude and ooze reservoir had not been tested by the 6607/12-1 well.

The new petrophysical evaluation in 2019 revealed that diatomite ooze was present in the 6607/12-1 well in both the Tare and Brygge formations. This is confirmed by the work done by Svensen *et al.* (2003). Moreover, diatomite ooze was also identified in a cored section of the overlying Brygge Formation raising concerns regarding the sealing lithologies of the Aragorn prospect.

In addition to wells close to the Aragorn prospect, the 6305/4-1 from the Ormen Lange field was included in the study which contain siliceous ooze deposits. The well was chosen as analogues to the depositional setting, even though the ooze is of Miocene age rather than Early Eocene. The 6305/4-1 well has a core in the ooze section which was a valuable calibration point to the logs.

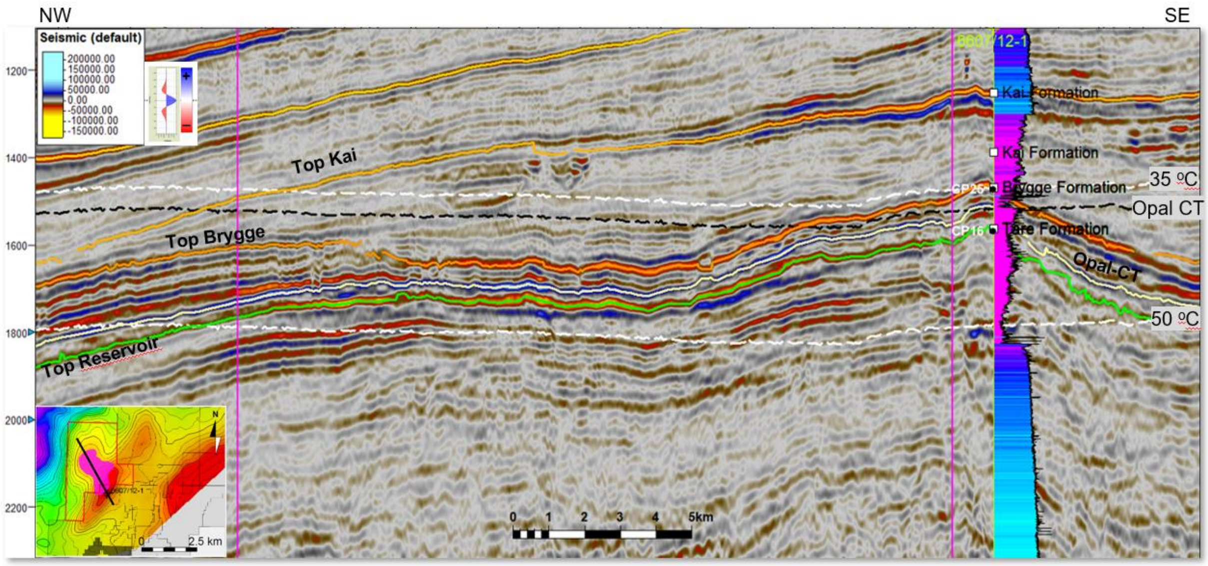

Figure 4: 2D SL-SLRE01-119 line with the isothermal gradients superimposed. Based on this study it became clear that the Aragorn is at present located at the depth and temperature where Opal-A to Opal-CT transformation might occur. Note the similarity in amplitude of the Top Reservoir horizon compared to the overlying Opal-CT and Top Brygge horizons. By comparison the Top Reservoir is not a unique seismic event.

4. Prospect Update

The APA 2018 application submitted by INEOS E&P Norge AS was based on the Aragorn prospect comprising an Early Eocene diatomite ooze reservoir within the Tare Formation. The Spekk Formation provided the source rock and the seal was provided by marine shales of the lower Brygge Formation. Additional prospectivity within the area had not been identified at the time of application.

The Aragorn prospect was at time of the APA 2018 application defined as a soft amplitude anomaly. Although located only 2 kilometers from well 6607/12-1, the initial technical evaluation concluded that the amplitude anomaly was not penetrated and tested by the well. To gain enough confidence in the observed amplitude response, first pass AVO analysis was undertaken using the data available to INEOS. However, due to the lack of angle stacks and gathers for the 2D seismic lines, any detailed amplitude analysis was not possible at the time. Consequently, acquiring additional 2D seismic data for an in-depth geophysical evaluation of the amplitude response was a key part of the work program

The trap of the Aragorn prospect was defined as a combined structural closure to the northwest and an up-dip stratigraphic closure to the east, sealed against a hydrothermal vent. The center of the hydrothermal vent was drilled and tested by the 6607/12-1 while the interval corresponding to the Aragorn reservoir, was interpreted to be a mudstone-dominated interval with side-sealing potential.

The ooze reservoir interval for the Aragorn prospect has been encountered in the Vøring Basin in the nearby wells 6607/2-1 and 6506/3-1. Petrophysical evaluations and well studies suggested the ooze reservoir to be characterized by very high estimated porosities but very low permeabilities. These findings are in accordance with published data from the producing onshore analogue fields of the Monterey Formation in California (US) but also the Ormen Lange well 6305/4-1 where diatomite ooze intervals have been encountered, cored and later studied in detail by Farrow (2003).

At the time of the APA 2018 application several thin sand layers interbedded in the ooze had been interpreted in the 6607/2-1 well. Based on this an ooze reservoir with thin interbedded sandstone was introduced into the reservoir engineering model. Owing to the sand interbeds, enhanced permeabilities and an overall increased producibility was envisaged for the Aragorn reservoir.

Hydrocarbon charge was considered a minor risk as Cretaceous shows and discoveries are observed in all wells in the Træna Basin. INEOS in-house 3D basin modelling had suggested dry gas as the hydrocarbon phase with the prospect being charge through the underlying Cretaceous and into the overlying Tare Formation oozes.

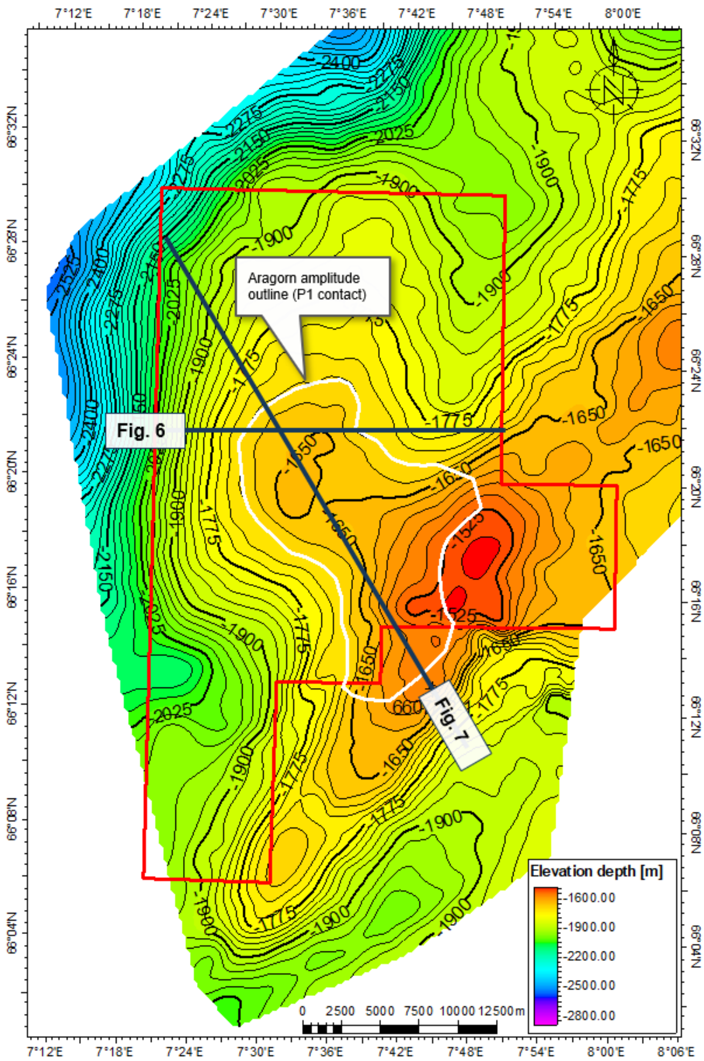

Figure 5 Top Aragorn reservoir depth map

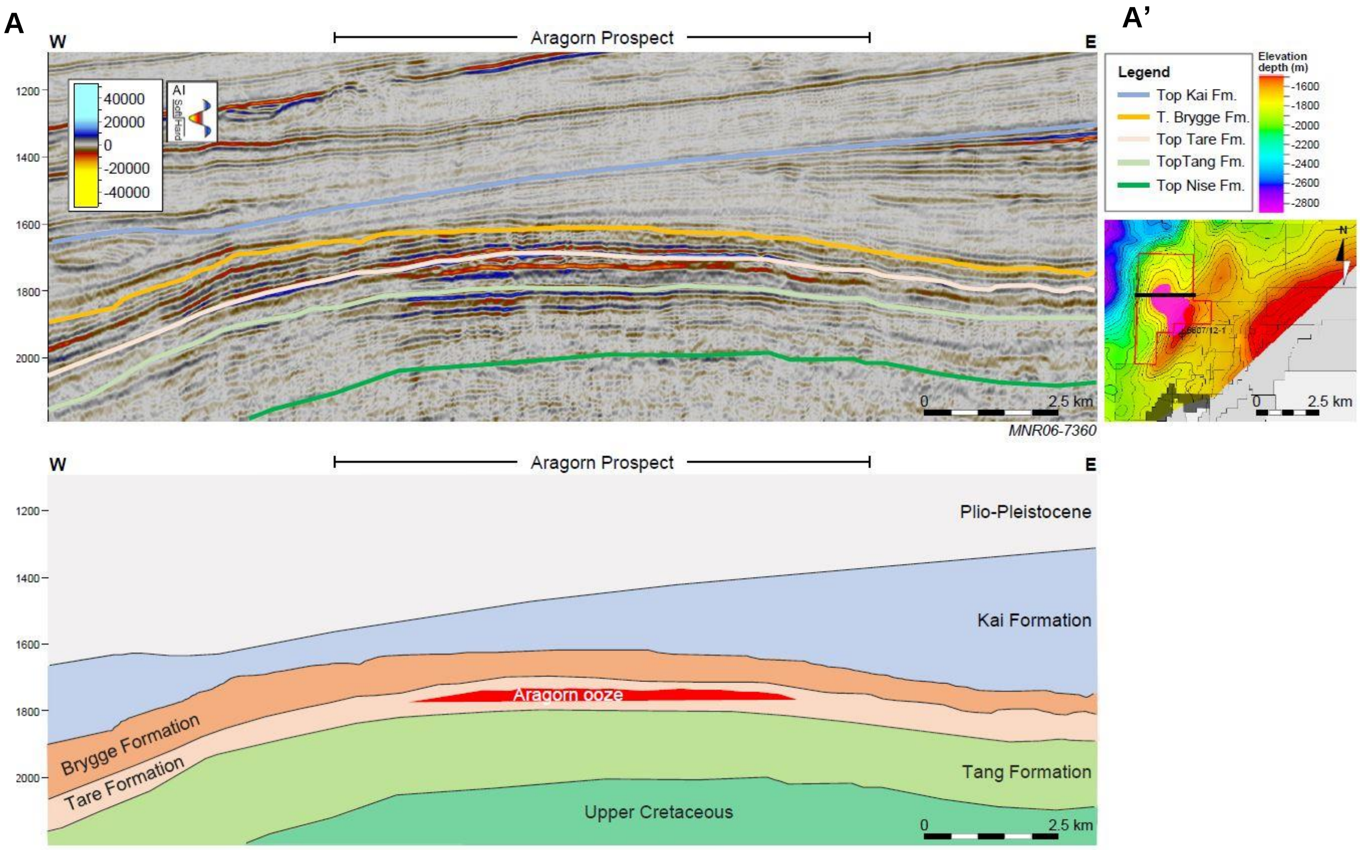

Figure 6: W-E Seismic section and geological interpretation

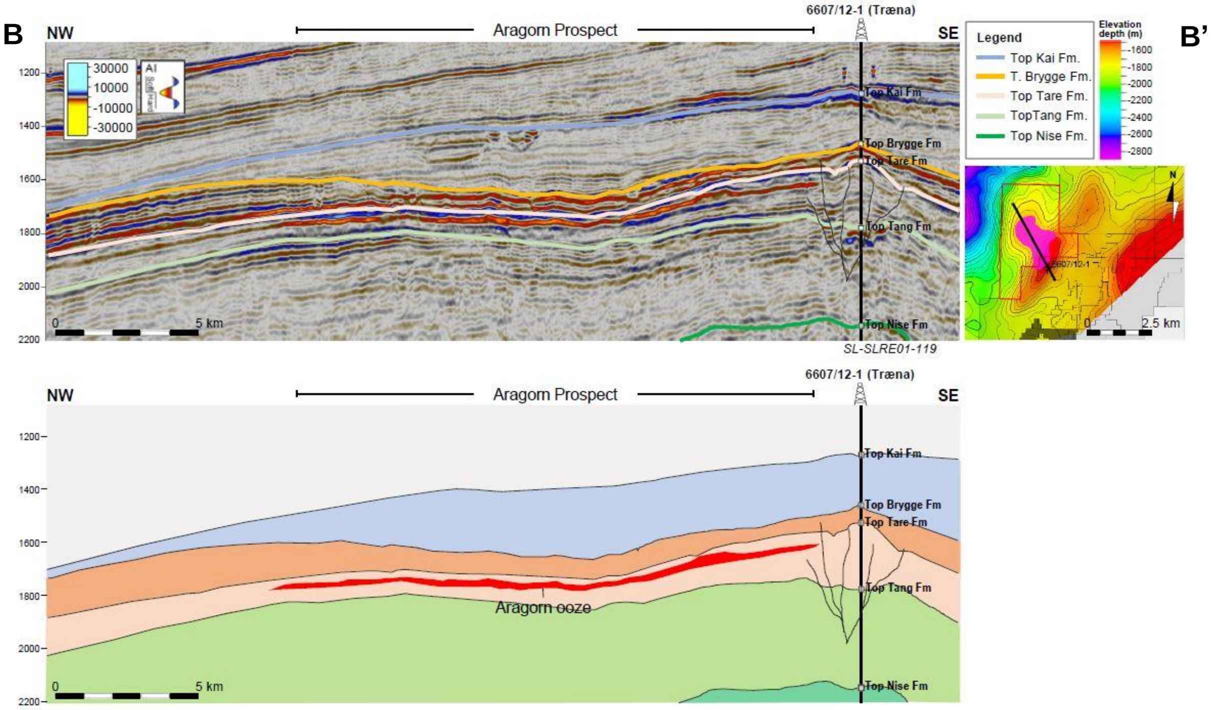

Figure 7: NW-SE Seismic section and geological interpretation

The sealing rocks were the transgressive mudstones of the overlying Brygge Formation which had been encountered by the 6607/12-1 well and mapped on 2D seismic across the prospect. No detailed petrophysical evaluation of the Brygge Formation had been done at time of the APA 2018 application and the cored section in upper Brygge Formation of the 6607/12-1) had not been assessed.

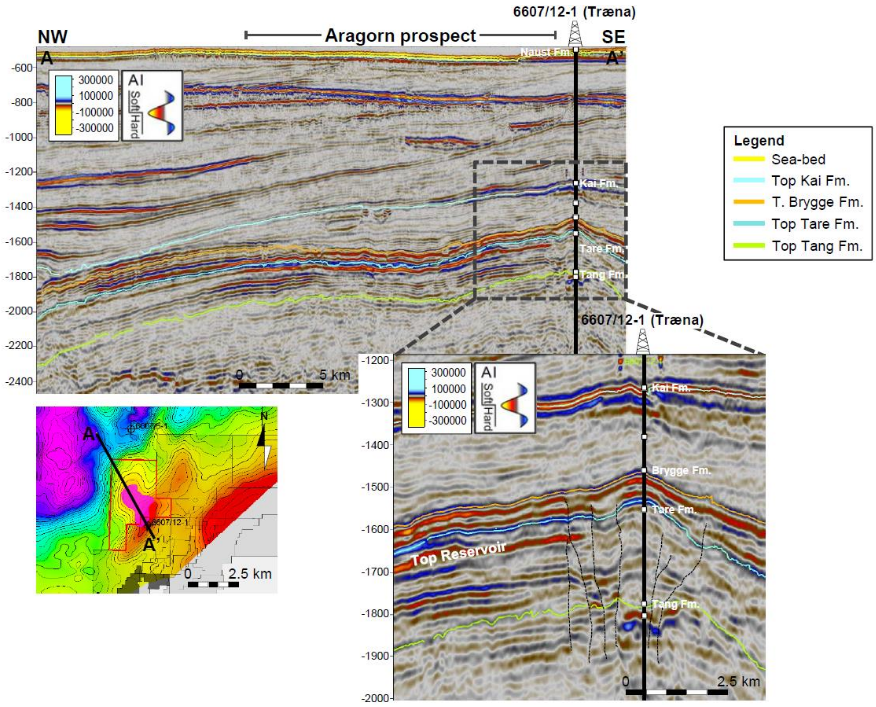

Figure 8: Side-seal risk against the hydrothermal vent around well 6607/12-1 (Træna). During the APA 2018 evaluation it was believed that the 6607/12-1 had encountered mudstones in the Tare Formation but new information strongly suggest the interval to be dominated by Opal-CT. Therefore, only potential sealing faults associated to the formation of the vent might prevent a leak of the Aragorn reservoir towards the 6607/12-1. Hence, the side-seal carries a high risk.

4.1 Summary and conclusion after new evaluations

Based on the new technical evaluations and the studies described above (Section 3), both the recoverable volumes and the chance of success for Aragorn prospect has decreased (Tables 7, 8).

The Aragorn prospect remains a combined structural closure to the northwest and a stratigraphic closure in the up-dip eastern part. However, due to the new insights into the lithology of the Tare Formation in the 6607/12-1 well, the side-seal potential against the hydrothermal vent now carries an increased risk. Based on the new information the opal-CT transition was encountered in the Tare Formation in the well which contained siliceous ooze and not mudstones as previously stated. Consequently, only fractures associated with the formation of the hydrothermal vent might act as a potential side-seal, and only if they are cemented (see Figure 5).

The top seal of Aragorn was previously represented by mudstones of the overlying Brygge Formation. However, the new data from 6607/12-1 clearly demonstrate that the Brygge Formation is composed of shales and intervals of pure diatomite ooze. This observation has reduced the confidence in the top seal potential and is now seen as a key challenge for the prospect.

Due to these factors, the trap validity risk (Retention + Trap risk, using the INEOS risking scheme) has been decreased from 0.5 to 0.4 (Table 7).

The new petrophysical evaluation has also raised concerns regarding the reservoir quality and producibility of the diatomite reservoir as discussed in Section 3. The transformation of the reservoir from opal-A to opal-CT has likely reduced the porosity from around 55-60% (opal-A) to 20-55% (opal-CT) (Allen and Lalicata, 2011). Based on these inputs and adjustments to the new volume calculation, the in-place volumes have decreased by approximately 50% compared to the APA 2018 in-place estimates (Table 8).

In addition to the reservoir quality, the producibility is also considered a challenge. Driven by the low chance of having interbedded sand layers within the Aragorn ooze reservoir, the well count to attain an adequate recovery factor has doubled compared to the APA 2018 application. As a result, the well cost has significantly increased and combined with smaller volumes the resulting business case for Aragorn is negative for the low (P90) and base cases (P50).

Finally, the geophysical analysis of the Aragorn amplitude remains challenging. The amplitude analysis has demonstrated class IV AVO anomalies both inside and outside the Aragorn defining anomaly. It is unclear whether the amplitude response is due to gas, residual gas, or the presence of opal-CT, as opal-CT is also known to produce a class IV response. Consequently, the geophysical analysis on the Aragorn defining seismic amplitude has been inconclusive.

The chance of the Aragorn prospect receiving a gas charge is still considered to be good and charge is not seen to be a major concern for the Aragorn prospect.

Table 7 INEOS risking scheme with included risk adjustments

Chance element	Probability of Success (Play)	Probability of Success (Prospect)	Probability after 2019 evaluation.
Reservoir Presence	100%		100%
Top Seal Presence	70%		70%
Source Presence, maturity and communication	80%		80%
Local preservation of reservoir		80%	80%
Reservoir Quality		70%	70%
Trap Validity		50%	**40%**
Access to Charge		80%	80%
	Total COS*	**13%**	**10%**

* COS: Chance of Success

Based on the key challenges and uncertainties presented above, acquiring a 3D seismic dataset over the PL1015 area will not resolve the key risk elements such as reservoir quality and producibility or the top seal integrity issue for the Aragorn prospect. A justification for such an investment is hence not in place.

Table 8 Final prospect data for Aragorn, February 2020. Prospect data updates since APA 2018 application are annotated in red.

Block	6607/8, 6607/9 (part) and 6607/11 (part)	Prospect name	Aragorn	Discovery/Prosp/Lead	Prospect	Prosp ID (or New!)	NPD will insert value	NPD approved (Y/N)	
Play name	Eocene (Tare)	New Play (Y/N)	Y	Outside play (Y/N)	No				
Oil, Gas or O&G case:	Gas	Reported by company	INEOS E&P Norway	Reference document				Assessment year	2018
This is case no.:	1 of 1	Structural element	Træna Basin	Type of trap	4-way dip closure + stratigraphic trap	Water depth [m MSL] (>0)	350	Seismic database (2D/3D)	2D and 3D
Resources IN PLACE and RECOVERABLE Volumes, this case		Main phase				Associated phase			
		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)					0,99	3.4		20,7
	Gas [10^9 Sm^3] (>0.00)	292	28.4	35.6	71.8				
Recoverable resources	Oil [10^6 Sm^3] (>0.00)					0.06	1.01		10.1
	Gas [10^9 Sm^3] (>0.00)	3.1	15.6		54.5				
Reservoir Chrono (from)	Early Eocene	Reservoir litho (from)	Tare Fm, Siliceous ooze and sand	Source Rock, chrono primary	Spekk Formation	Source Rock, litho primary	Shale	Seal, Chrono	Brygge Formation
Reservoir Chrono (to)	Eocene	Reservoir litho (to)	Tare Fm. Siliceous ooze and sand	Source Rock, chrono secondary	Lange Formation	Source Rock, litho secondary	Shale	Seal, Litho	Shale
Probability [fraction]									
Technical (oil + gas + oil & gas case) (0.00-1.00)	0.10	Oil case (0.00-1.00)	0	Gas case (0.00-1.00)	1.0	Oil & Gas case (0.00-1.00)	0		
Reservoir (P1) (0.00-1.00)	0.56	Trap (P2) (0.00-1.00)	0.50	Charge (P3) (0.00-1.00)	0.64	Retention (P4) (0.00-1.00)	0.6		
Parametres:	Low (P90)	Base	High (P10)	Base, Mode (P50) Base for parameters: mean value Top and Base reservoir used for computing GRV Prospect data updates post application award, is highlighted in red					
Depth to top of prospect [m TVDSS] (> 0)	1500	1500	1500						
Area of closure [km^2] (> 0.0)	58	83	107						
Reservoir thickness [m] (> 0)	23	25	26						
HC column in prospect [m] (> 0)	94	158	200						
Gross rock vol. [10^9 m^3] (> 0.000)	5,389	5,677	5,969						
Net / Gross [fraction] (0.00-1.00)	0.30	0.53	0.76						
Porosity [fraction] (0.00-1.00)	0.18	0.30	0.42						
Permeability [mD] (> 0) Ooze	0.1	0.5	10						
Water Saturation [fraction] (0.00-1.00) Ooze	0.70	0.61	54						
Bgi [Rm3/Sm3] (< 1.0000)	0.00230	0.00241	0.00252						
1/Boi [Sm3/Rm3] (< 1.00)									
GOR, free gas [Sm^3/Sm^3] (> 0)	27775	8385	3460						
GOR, oil [Sm^3/Sm^3] (> 0)									
Recov. factor, oil main phase [fraction] (0.00-1.00)									
Recov. factor, gas ass. phase [fraction] (0.00-1.00)									
Recov. factor, gas main phase [fraction] (0.00-1.00)	0.37	0.55	0.76						
Recov. factor, liquid ass. phase [fraction] (0.00-1.00)	0.06	0.30	0.49	For NPD use:					
Temperature, top res [°C] (>0)	50			Innrapp. av geolog-init:	NPD will insert value	Registrert - init:	NPD will insert value	Kart oppdatert	NPD will insert value
Pressure, top res [bara] (>0)	234			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

4.2 Additional prospectivity in the license

To evaluate the upside potential within the PL1015 license, a semi-regional evaluation was completed with a focus on the deeper Cretaceous Nise and Springar plays and the Pliocene-Pleistocene Naust play above the Aragorn prospect interval. Unfortunately, the interpretation is complicated by poor seismic resolution of the Cretaceous intervals on both 2D and 3D seismic dataset within the license.

Inspired by the Aasta Hansteen gas field to the northwest, potential Nise and Springar sand fairways entering into the PL1015 area was investigated using well data, seismic mapping and studying literature. However, while the main Nise sand systems are widely distributed in the Outer Vøring Basin, it remains less likely that Nise sands reached as far southeast as the PL1015 area. A clear thinning of the Nise sand interval from the Aasta Hansteen area towards the southeast is observed on seismic datasets while this interval appears to be absent or below seismic resolution in PL1015. This observation is supported by well data and literature published from the area.

The Late Cretaceous Springar Play was also evaluated. However, as no Springar sands of significance has been encountered in the nearby wells around PL1015 it was concluded as of minor significance.

Similarly, the Naust Play was evaluated for upside prospectivity. In the PL1015 area several potential shallow gas amplitude anomalies have been observed in the Naust Formation. While appearing promising on seismic amplitude maps, the anomalies lack robust trap definitions. In addition, the shallow nature of the Naust Formation induces generic challenges with integrity of the top seal as the overburden section mainly consists of uncompacted shales.

In summary, the technical evaluation of Pliocene-Pleistocene and Cretaceous intervals in PL1015 license has not identified any valid prospects or leads that can justify a 3D seismic acquisition over the license.

5 Technical Evaluation

The development scenario for Aragorn comprise of 3 x 4-slots subsea production templates for the P50 (base) and P10 (high) cases (Figure 6). The P90 (low) case is based on 2 x 4-slots subsea production templates, like the P50/P10 cases but the most northern template is not installed in this scenario. The templates will be located approximately 6 km from each other along a northwest bound axis, starting ca. 39 km northwest of the Norne FPSO. The production from the subsea templates will be tied back to the Norne FPSO via a new 39 km 12-inch pipe-in-pipe flowline from the South template and 6 km infield flowlines between the templates which will daisy-chain these. A new production riser, riser base and SSIV for Aragorn service would be needed at the Norne FPSO. At the Norne FPSO the produced fluids will be processed and exported along with Norne fluids.

Required chemicals and subsea controls will be provided by a new umbilical from Norne FPSO to the Aragorn templates. The templates are to be controlled from Norne Topside.

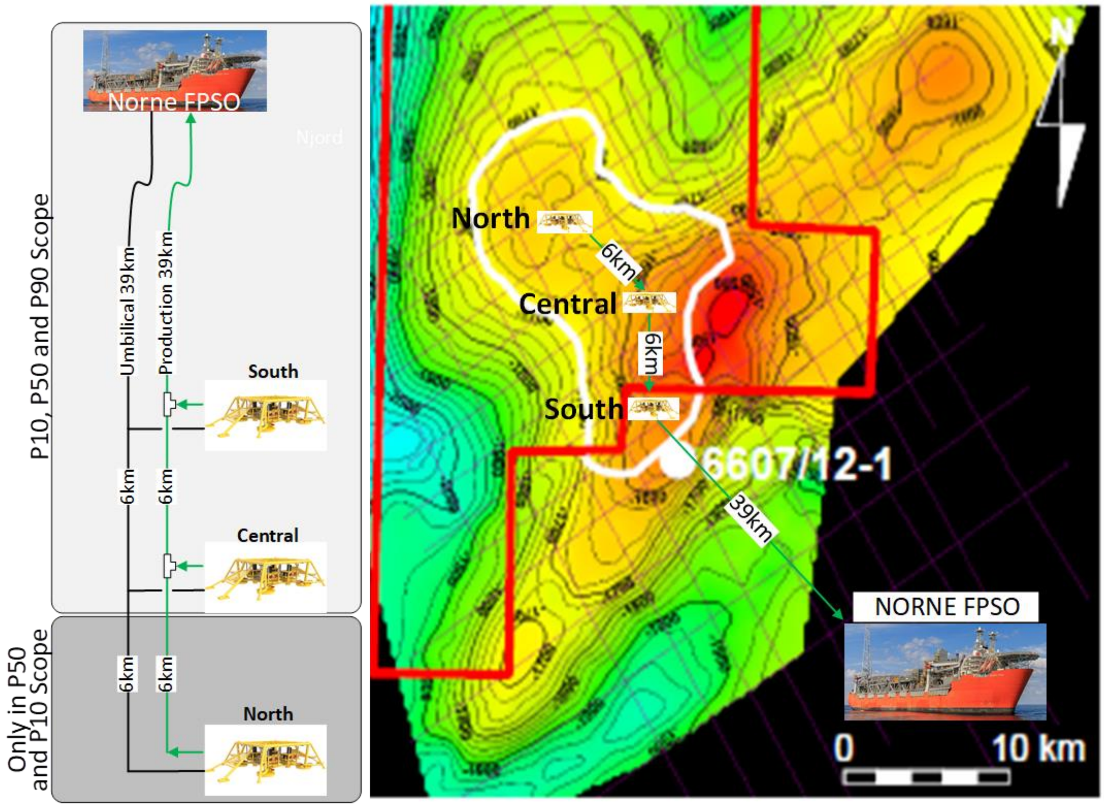

Figure 9: Development Concept for Aragorn

6 Conclusions

Based on a comprehensive technical and economical evaluation of the Aragorn prospect in PL1015, the licensees conclude that there is no commercial potential for the low and base case recoverable volumes in the Aragorn prospect. Substantial amounts of hydrocarbons (gas) could potentially be contained within the Aragorn prospect, however, due to the low permeability of the diatomite ooze reservoir a high number of wells would be required to produce the resources. Economic production levels could only be obtained for the P10 resource estimate. The Aragorn prospect carries substantial technical risk related to its reservoir quality, producibility and top seal integrity and a 3D seismic survey will not contribute to reduce this risk to an acceptable level.

Available 2D and 3D seismic datasets has been screened for additional prospectivity in the license with a negative outcome.

In conclusion, technical and economic evaluations of PL1015 does not warrant the acquisition of a new 3D seismic survey over the license. On this ground the license partnership has unanimously taken a decision to relinquish the license by the end of the current period.

The Operator would like to thank the PL1015 Partner for good co-operation and sharing of knowledge and experience from the area.

7. References

Allan, M.E., Gold, D.K and Reese, D.W., 2010. Development of the Belridge Fields's Diatomite Reservoirs with Hydraulically Fractured Horizontal Wells: From First Attempts to Current Ultra-Tight Spacing. SPE 133511

Allan, M.E. and Lalicata, J.J, 2011. The Belridge Giant Oil Field - 100 Years of History and a Look to a Bright Future. Search and Discovery article #20110.

Bhat, S.K. and Kovscek, A.R., 1998. Modelling permeability alteration in diatomite reservoirs during steam drive. SUPRI TR 113 Report**.** Work Performed Under Contract No. DE-FG22-96BC14994. Prepared for U.S. Department of Energy, Assistant Secretary for Fossil Energy.

Bowersox, J.R., 1990. Geology of the Belridge Diatomite, Northern South Belridge Field, Kern County, California. © AAPG Pacific Section, 2009 - Structure, Stratigraphy and Hydrocarbon Occurrences of the San Joaquin Basin, California (1990), pp 215-223

Farrow, G., 2003. Ooze Prospectivity: Ormen Lange Field. Report

Ireland, M.T., 2011. 3-D seismic investigation of the diagenesis and deformation of Cenozoic siliceous sediments on the Eastern Atlantic Margin. Durham theses, Durham University. Available at Durham E-Theses Online: http://etheses.dur.ac.uk/712/

Svensen, H. and Planke, S. 2003. Well 6607/12-1: Final Report. Volcanic Basin Petroleum Research.