ANNUAL STATEMENT OF RESERVES

2020

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1 CLASSIFICATION OF RESERVES AND CONTINGENT RESOURCES

Aker BP ASA's reserve and contingent resource volumes have been classified in accordance with the Society of Petroleum Engineer's (SPE's) "Petroleum Resources Management System". This classification system is consistent with Oslo Stock Exchange's requirements for the disclosure of hydrocarbon reserves and contingent resources. The framework of the classification system is illustrated in Fig. 1.1.

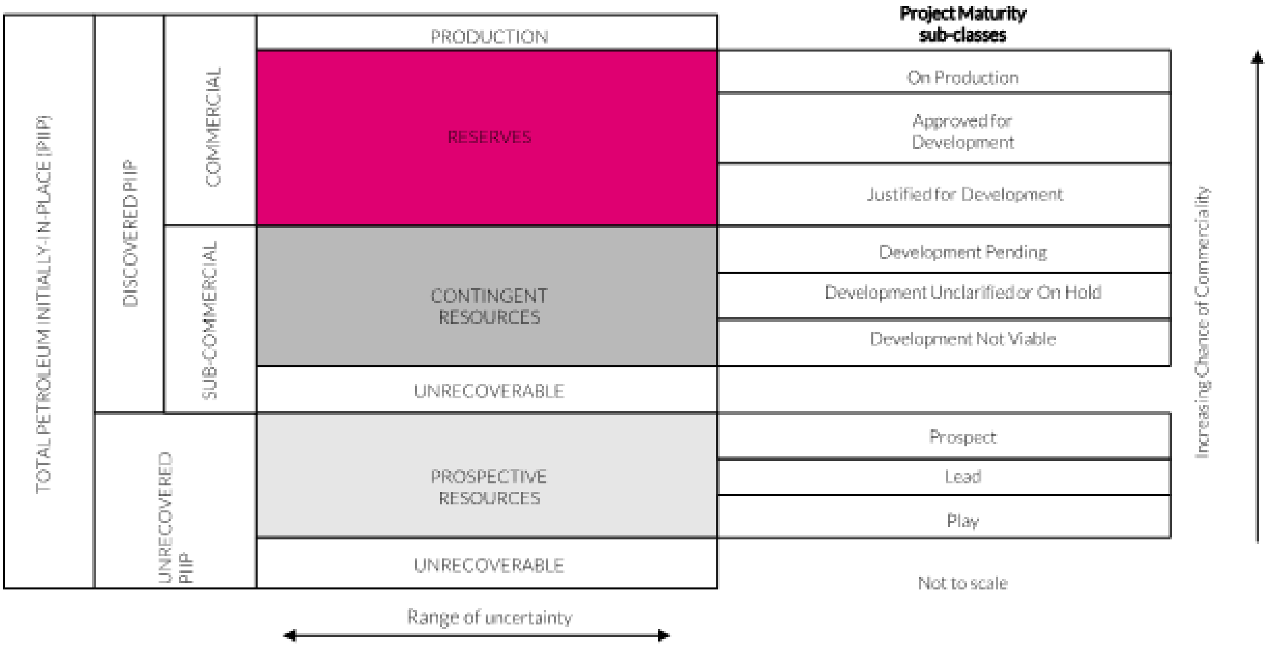


FIG. 1.1 SPE reserves and recourses classification system

2 RESERVES, DEVELOPED AND NON-DEVELOPED

All reserve estimates are based on all available data including seismic, well logs, core data, drill stem tests and production history. Industry standards are used to establish 1P and 2P. This includes decline analysis for mature fields in which reliable trends are established. For undeveloped fields and less mature producing fields reservoir simulation models or simulation models in combination with decline analysis have been used for profile generation.

Note that an independent third party, AGR Petroleum Services, has certified all reserves except for the minor assets Atla and Enoch, representing approximately 0.004 % of total 2P reserves.

Aker BP ASA has a working interest in 39 fields/projects containing reserves, see Table 2.1. Out of these fields/projects, 23 are in the sub-class "On Production"/Developed, 15 are in the sub-class "Approved for Development"/Undeveloped and one is in the sub-class "Justified for Development"/Undeveloped. Note that several fields have reserves in more than one reserve sub-class.

Table 2.1 Aker BP Fields containing reserves

Field/Project	Interest (%)	Operator	Resource Class	Comment
		Developed Reserves		
Alvheim	65 %	Aker BP	On Production	Incl Kameleon/Kneler Base
Boa Base	58 %	Aker BP	On Production	
Bøyla Base	65 %	Aker BP	On Production	
Frosk Test Production	65 %	Aker BP	On Production	
Kameleon Infill Mid	65%	Aker BP	On Production	
Skogul	65 %	Aker BP	On Production	
Vilje Base	47 %	Aker BP	On Production	
Volund Base	65 %	Aker BP	On Production	
Ivar Aasen Base	35 %	Aker BP	On Production	
Johan Sverdrup Phase 1	11.573 %	Equinor	On Production	Production commenced 5.10.2019
Oda	15 %	Spirit Energy	On Production	
Skarv Base	24 %	Aker BP	On Production	
Ærfugl A-1H	24 %	Aker BP	On Production	
Ærfugl Phase 1	24 %	Aker BP	On Production	
Ærfugl Phase 2	24 %	Aker BP	On Production	
Tambar Base	55 %	Aker BP	On Production	
Tambar East Base	46 %	Aker BP	On Production	
Ula Base	80 %	Aker BP	On Production	
Ula Drilling phase 1	80 %	Aker BP	On Production	
Hod Base	90 %	Aker BP	On Production	
Valhall Base	90 %	Aker BP	On Production	
Atla Base	10 %	Total E&P Norge	On Production	
Enoch Base	2 %	Repsol Sinopec	On Production	

Table 2.1 Continued

Field/Project	Interest (%)	Operator	Resource Class	Comment
Undeveloped Reserves				
Alvheim Kameleon Gas Cap Blow Down	65 %	Aker BP	Approved for Development	
Boa Attic South	58 %	Aker BP	Approved for Development	
Hanz	35 %	Aker BP	Approved for Development	
Ivar Aasen OP-E-SK2 (D-20)	35 %	Aker BP	Approved for Development	
Ivar Aasen OP-W (D-17)	35 %	Aker BP	Approved for Development	
Johan Sverdrup Phase 2 (incl WAG)	12 %	Equinor	Approved for Development	Phase 2 PDO based on WAG approved 2019
Snadd Outer	30 %	Aker BP	Approved for Development	Name formally changed to Ærfugl Nord 21.01.21
Tambar K2 Side-track	55 %	Aker BP	Approved for Development	
Ula A-10 Recompletion	80 %	Aker BP	Approved for Development	
Ula Unit F Producer 1	80 %	Aker BP	Approved for Development	
Hod Field Development	90 %	Aker BP	Approved for Development	
Valhall Flank North Infill N1	90 %	Aker BP	Approved for Development	
Valhall Flank North Infill Phase 2	90 %	Aker BP	Approved for Development	
Valhall Flank North Water Injection	90 %	Aker BP	Approved for Development	
Valhall WP Lifetime Extension	90 %	Aker BP	Approved for Development	
Skarv Gråsel	24 %	Aker BP	Justified for Development	

Total net proven reserves (P90/1P) as of 31.12.2020 to Aker BP are estimated at 641 million barrels of oil equivalents. Total net proven plus probable reserves (P50/2P) are estimated at 842 million barrels of oil equivalents. The split between liquid and gas and between the different subcategories for all fields/projects are given in Table 2.2.

Table 2.2 Aker BP 1P and 2P reserves as of 31.12.2020 per projects and reserve class

As of 31.12.2020	Interest	1P/P90 (low estimate)					2P/P50 (Base estimate)				
		Gross Oil	Gross NGL	Gross Gas	Gross oe	Net oe	Gross Oil	Gross NGL	Gross Gas	Gross oe	Net oe
	%	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)
ON PRODUCTION											
Alvheim Kam/Knel Base	65 %	27	0	2	29	19	39	0	7	46	30
Boa Base	58 %	7	0	1	8	5	10	0	2	12	7
Bøyla Base	65 %	2	0	0	2	2	3	0	0	3	2
Frosk Test Production	65 %	1	0	0	1	1	1	0	0	1	1
Kameleon Infill Mid	65 %	2	0	0	2	1	4	0	0	4	2
Skogul Base	65 %	2	0	0	2	1	5	0	0	6	4
Vilje Base	47 %	9	0	0	9	4	14	0	0	14	7
Volund Base	65 %	4	0	1	5	3	6	0	2	9	6
Ivar Aasen Base	35 %	42	2	7	52	18	75	4	12	91	32
Johan Sverdrup Phase 1	12 %	1538	38	46	1622	188	1797	49	52	1898	220
Oda	15 %	16	1	1	17	3	22	1	1	24	4
Skarv Base	24 %	15	15	67	97	23	19	19	88	126	30
Ærfugl A-1H	24 %	5	7	34	47	11	8	12	55	74	18
Ærfugl Phase 1	24 %	9	11	53	73	17	10	13	61	84	20
Ærfugl Phase 2	24 %	7	9	41	57	14	9	12	56	76	18
Tambar Base	55 %	3	0	1	4	2	6	0	1	7	4
Tambar East Base	46 %	0	0	0	0	0	0	0	0	0	0
Ula Base	80 %	7	0	0	7	6	10	0	0	11	9
Ula Drilling phase 1	80 %	13	0	0	13	10	17	1	0	18	14
Hod Base	90 %	2	0	0	3	2	3	0	0	3	3
Valhall Base	90 %	162	8	30	200	180	197	9	36	242	218
Atla Base	10 %	0	0	0	0	0	0	0	0	0	0
Enoch Base	2 %	0	0	0	0	0	1	0	0	1	0
Total		**1875**	**91**	**286**	**2252**	**511**	**2256**	**120**	**375**	**2751**	**647**

An oil price of 45 USD/bbl (2021), 55USD/bbl (2022) and 65 USD/bbl (following years) has been used for reserves estimation. Low- and high case sensitivities with oil prices of 35 and 90 USD/bbl, respectively, have been performed by AGR. This had only moderate effect on the reserves estimates. The low price resulted in a reduction in total net proven (1P/P90) reserves of 10 % and net proven plus probable (2P/P50) reserves of 12 %. The high oil price scenario did not result in any change to the proven (1P/P90)- or proven plus probable (2P/P50)-estimates.

Changes from the 2019 reserve report are summarized in Table 2.4. The main reason for increased net reserve estimate (i.e. disregarding the produced volumes) is initiatives to increase recovery from existing or already decided projects, e.g. use of multilateral wells instead of single wellbore wells in Alvheim and Valhall, production from unit F in Ula, etc.

Table 2.2 Continued

As of 31.12.2020	Interest	1P/P90 (low estimate)					2P/P50 (Base estimate)				
		Gross Oil	Gross NGL	Gross Gas	Gross oe	Net oe	Gross Oil	Gross NGL	Gross Gas	Gross oe	Net oe
	%	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)
APPROVED FOR DEVELOPMENT											
Alvheim Kameleon Gas Cap Blow Down	65 %	0	0	10	10	6	0	0	15	15	10
Boa Attic South	58 %	4	0	1	4	3	5	0	1	6	4
Hanz	35 %	9	1	2	11	4	14	1	3	18	6
Ivar Aasen OP-E-SK2 (D-20)	35 %	3	0	0	3	1	5	0	1	6	2
Ivar Aasen OP-W (D-17)	35 %	1	0	0	2	1	2	0	0	3	1
Johan Sverdrup Phase 2 (incl WAG)	12 %	379	1	1	381	44	601	4	5	610	71
Snadd Outer	30 %	1	4	17	22	7	2	4	21	27	8
Tambar K2 Side-track	55 %	2	0	1	3	2	5	0	1	6	3
Ula A-10 Recompletion	80 %	3	0	0	3	3	4	0	0	4	4
Ula Unit F Producer 1	80 %	2	0	0	2	1	3	0	0	3	3
Hod Field Development	90 %	25	1	4	30	27	33	1	5	40	36
Valhall Flank North Infill N1	90 %	2	0	0	1	1	2	0	0	2	2
Valhall Flank North Infill Phase 2	90 %	4	0	1	5	5	7	0	1	8	7
Valhall Flank North Water Injection	90 %	6	0	0	6	6	7	0	0	8	7
Valhall WP Lifetime Extension	90 %	16	1	4	21	19	25	2	6	33	30
Total		**456**	**8**	**41**	**505**	**128**	**715**	**14**	**60**	**789**	**192**
JUSTIFIED FOR DEVELOPMENT											
Skarv Gråsel	24 %	4	1	2	7	2	9	1	3	13	3
Total		**4**	**1**	**2**	**7**	**2**	**9**	**1**	**3**	**13**	**3**
Total Reserves		**2336**	**100**	**329**	**2764**	**641**	**2980**	**135**	**437**	**3553**	**842**

Table 2.3 Aker BP net 1P and 2P reserves as of 31.12.2020 per field and area

As of 31.12.2020	1P/P90 (low estimate)					2P/P50 (Base estimate)				
	Gross Oil	Gross NGL	Gross Gas	Gross oe	Net oe	Gross Oil	Gross NGL	Gross Gas	Gross oe	Net oe
	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)
Alvheim	40	0	14	54	34	57	0	26	83	53
Bøyla	2	0	0	2	2	3	0	0	3	2
Frosk Test Production	1	0	0	1	1	1	0	0	1	1
Skogul	2	0	0	2	1	5	0	0	6	4
Vilje	9	0	0	9	4	14	0	0	14	7
Volund	4	0	1	5	3	6	0	2	9	6
Alvheim Area	**58**	**0**	**16**	**74**	**45**	**87**	**0**	**29**	**116**	**71**
Ula	24	1	0	25	20	35	1	0	36	29
Tambar	6	0	2	7	4	10	0	2	13	7
Tambar East	0	0	0	0	0	0	0	0	0	0
Ula Area	**30**	**1**	**2**	**33**	**24**	**46**	**2**	**2**	**50**	**36**
Valhall	190	9	34	233	210	238	11	43	292	263
Hod	27	1	4	33	29	36	1	6	43	39
Valhall Area	**217**	**10**	**39**	**266**	**240**	**274**	**13**	**49**	**336**	**302**
Ivar Aasen	47	3	8	57	20	82	4	13	100	35
Hanz	9	1	2	11	4	14	1	3	18	6
Ivar Aasen Area	**55**	**3**	**10**	**68**	**24**	**97**	**5**	**16**	**118**	**41**
Skarv	20	15	70	104	25	28	20	92	139	33
Ærfugl (Incl. Ærfugl Nord)	22	31	146	199	49	29	41	192	262	64
Skarv Area	**42**	**46**	**216**	**303**	**74**	**57**	**60**	**283**	**401**	**97**
Johan Sverdrup	**1917**	**39**	**47**	**2003**	**232**	**2397**	**54**	**57**	**2508**	**290**
Atla	0	0	0	0	0	0	0	0	0	0
Enoch	0	0	0	0	0	1	0	0	1	0
Oda	16	1	1	17	3	22	1	1	24	4
Other	**16**	**1**	**1**	**17**	**3**	**23**	**1**	**1**	**25**	**4**
Total	**2336**	**100**	**329**	**2764**	**641**	**2980**	**135**	**437**	**3553**	**842**

Table 2.4 Aggregated reserves, production, developments, acquisitions, IOR, extensions and revisions

Net attibuted million barrels of oil equivalents (mmboe)	On Production		Approved for Development		Justified for Development		Total	
	1P/P90	2P/P50	1P/P90	2P/P50	1P/P90	2P/P50	1P/P90	2P/P50
Balance as of 31.12.2019	**449**	**580**	**192**	**288**	**25**	**38**	**666**	**906**
Production	-77	-77					-77	-77
Transfer	93	142	-68	-104	-25	-38	0	0
Revisions	50	7	-9	-8			41	0
IOR			14	16	2	3	15	19
Discovery and Extensions							0	0
Acquisition and sale	**-4**	**-5**					**-4**	**-5**
Balance as of 31.12.2020	**511**	**647**	**128**	**192**	**2**	**3**	**641**	**842**
Delta 20-19	**62**	**67**	**-64**	**-95**	**-23**	**-35**	**-24**	**-63**

Three projects (Ærfugl, both Phase 1 and Phase 2, Skogul and Kameleon infill Mid started production in 2020, and were transferred to resource category "On production". Johan Sverdrup and Valhall are the two most important field contributing approximately 70% of the company's 2P reserves. Total net production to Aker BP averaged 211 mboepd (total ~77 mmboe) in 2020. This is in line with the forecast from 2019.

Note that the production numbers are approximate, based on actual production for the first 10 months and a prognosis for the last two months of 2020. Final actuals may differ slightly.

3 DESCRIPTION OF RESERVES

3.1 Producing Assets

The following chapter describes the reserve assessment from all producing fields. Please note that the produced volumes reported herein may differ slightly from volumes reported as sales volumes in quarterly reports etc. The reason is that the volumes in this report are based on actual production from 1 January 2020 to 31 October 2020 and forecast for the period 1 November 2020 to 31 December 2020. These volumes are used for assessment of remaining reserves as of 31.12.2020.

3.1.1 Alvheim (PL036, PL088BS, PL203)

Alvheim is an oil and gas field in the central part of the North Sea, west of Heimdal and near the border with the British sector. The field includes three discoveries: 24/6-2 (Kameleon reservoir), 24/6-4 (Boa reservoir) and 25/4-7 (Kneler reservoir). The Boa discovery lies partly in the British sector. Included in this chapter are also the Viper (25/4-10S) and Kobra (25/7-5) discoveries, located to the south of Alvheim just north-east of the Volund Field, Fig. 3.1. The water depth in the area is 120 – 130 m.

Discovery

The Alvheim Field was discovered in 1998 with well 24/6-2 that encountered oil and gas in sandstones in the Heimdal Formation. The gross gas and oil columns were 52 m and 17 m, respectively. The reservoir quality is generally excellent although local variations do occur. The Kobra discovery was made in 1997 with well 25/7-5 proving oil in the Hermod Formation, and the Viper discovery was made in 2009 with well 25/4-10S proving oil in Hermod Formation injection sands.

Reservoir

The Alvheim Field consists of high porosity, high permeability sandstones in the Heimdal Formation of Palaeocene age. The sand was deposited as sub-marine fan deposits and lies at a depth of approximately 2,200 m. A number of production wells have penetrated the reservoirs and confirmed the static models.

The Viper and Kobra structures are comprised of remobilized Palaeocene Hermod sands with enhanced reservoir properties. Viper is an injection

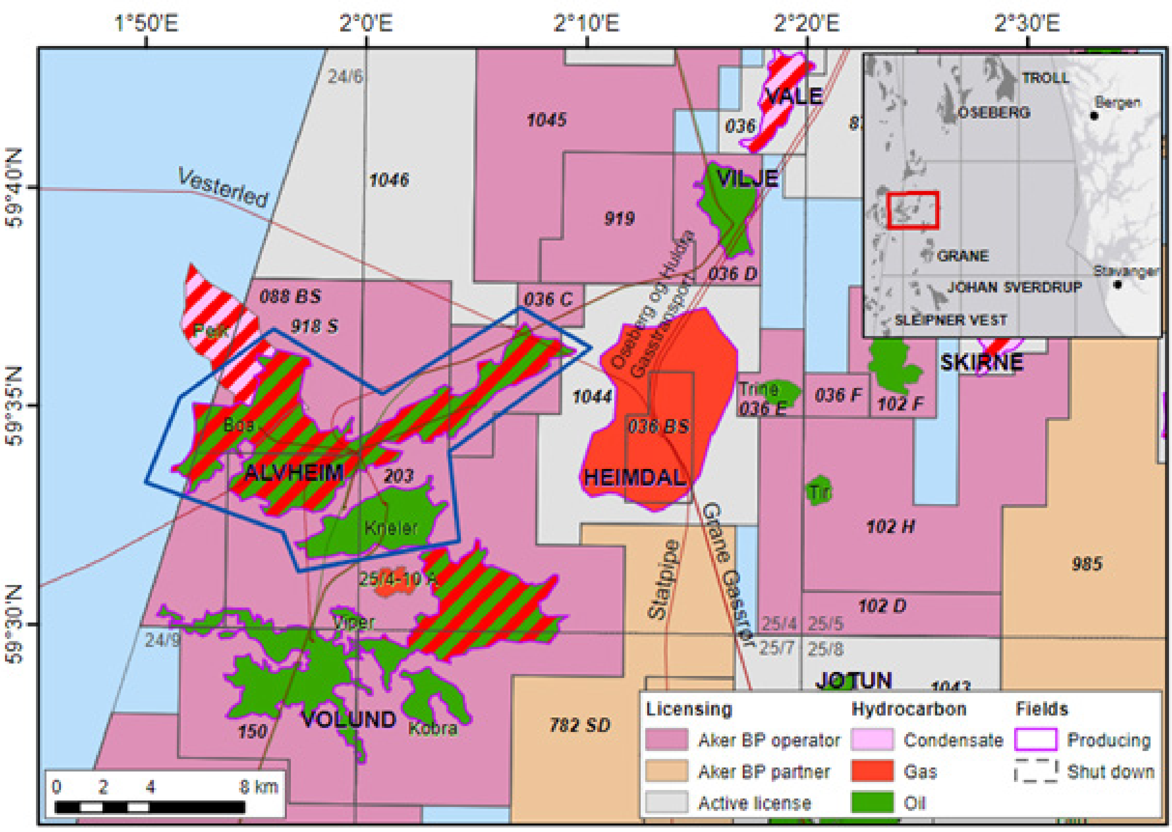


Figure 3.1 Alvheim and Viper/Kobra location map


Alvheim

feature cutting through the overlying stratigraphy whilst Kobra sands are mainly in-situ with some volumes in injection features above. The development drilling campaign confirmed a common oil water contact in both structures, and it is therefore likely that Viper and Kobra communicate both in the oil leg and the aquifer.

Development

The Alvheim Field is developed with a production vessel (the Alvheim FPSO) and subsea wells. The oil is stabilized and stored on the production vessel before being exported by tanker. Processed rich gas is transported by pipeline from Alvheim to the Scottish Area Gas Evacuation (SAGE) pipeline system on the British continental shelf. Alvheim is produced through long horizontal wells completed with ICDs/AICDs nozzles, and several of the wells are multilateral. The recovery method is natural water drive from an active underlying aquifer.

Viper and Kobra was developed in 2016 with one horizontal well in Viper and a bilateral MLT in Kobra with the main bore in the main sill and a lateral shallower in injection dykes (Kobra shallow). The wells are tied back to a new manifold connected to the main Volund manifold.

Status

Alvheim has produced above expectations through 2020 despite the governmentally imposed production curtailment and a downstream facility shutdown in August 2020. This is partly explained by a planned extensive period of production downtime due to repairs of the subsea infrastructure related to the East Mid Water Arch failure in 2019 that has been cancelled. In addition, the base well performance has been higher than expected with the Kobra and Kameleon Infill South decline being lower than forecasted.

The main topside constraint for 2020 has been the gas compressor capacity. This constraint will remain one of the main constraints in the coming years despite a planned debottlenecking activity in 2021. Water handling is expected to become another constraint in a near future. An expansion of the installed water treatment is planned for 2021.

The Estimated Ultimate Recovery (EUR) of the base wells (pre-2020) has increased since the reserves certification 31.12.2019, primarily due to the latest well drilled on the Kameleon structure (Kameleon Infill South) which started production in November 2018 as well as the Kobra well that keeps demonstrating strong performance with a low water cut. In addition, the KA6 well, previously called Kameleon Infill Mid (KIM), was drilled and completed as a trilateral well in August 2020. The well was brought online on 31.10.2020 and is included in the Alvheim base. Finally, the Boa Attic South (BAS – formerly Boa Side-track South) well was spudded on 6.11.2020. This well is planned as a tri-lateral well and is targeting an area with no 4D anomalies as well as attic oil above the main branch of the A-1 well. The area with no 4D anomalies was confirmed by the 24/6-A-6 H pilot well in 2017.

The recoverable volumes for Alvheim, Viper and Kobra are classified as «Reserves; On Production» (SPE's classification system), with the exception of BAS, which will be completed in 2021, and therefore currently booked in reserves category 2 («Approved»).

Production from the Alvheim Field is expected to cease in 2033, with subsequent abandonment scheduled to take place between 2033 and 2035.

Aker BP is the operator of the Alvheim Area Fields with a 65 percent working interest in the Norwegian parts. The other partners are ConocoPhillips Skandinavia AS holding a 20 percent interest and Lundin Energy Norway AS holding a 15 percent interest.

The Boa reservoir straddles the Norway-UK median line. The Boa reservoir is unitised with NEO Energy, who are the owners on the UK side. Aker BP's interest in the Boa unit is 57.62 percent.

3.1.2 Vilje (PL036D)

The Vilje Field is an oil field located 5 km north-east of the Heimdal production facility in block 25/4 licensed under PL 036D in the North Sea, see. Fig. 3.2. Production started in 2008. The reservoir depth is about 2,200 m TVD MSL and the water depth in the area is approximately 120 m.

Discovery

The Vilje Field was discovered in 2003 by well 25/4-9 S. The Heimdal Formation reservoir was encountered at 2,135 m TVD MSL with 61 m gross sand (56 m net). The sand had very good reservoir properties and was oil bearing with undersaturated oil. Production from the nearby Heimdal Field and Frigg Field had caused depletion of the regional aquifer by approximately 18 bars. Based on the well results the OWC has been determined at various levels between 2,195 and 2,198 m TVD MSL, and the current OWC is expected to be influenced locally by depletion and production.

Reservoir

The Vilje Field is a flat low-relief fan of Heimdal depositional system. The field has two separate structures, namely Vilje Main and Vilje South. The reservoir is a turbidite deposit, in the Heimdal Formation of Palaeocene age at about 2,150 m TVD MSL. The reservoir interval is divided into three reservoir zones – R1, R2 and R3 – where R1 and R3 are clean sands while R2 is a fine-grained muddy layer which is acting as a baffle to fluid flow.

Development

The Vilje Field is a subsea development with three subsea horizontal producers tied back to the Alvheim FPSO. Vilje Main is drained by one single lateral well (VI1) and one bilateral well (VI2) with one branch above and one below the R2 shale. There is one single lateral well on Vilje South (VI3). The water depth in the area is approximately 120 m. The recovery mechanism is natural water drive from the regional underlying Heimdal aquifer.

Status

The reservoir management for Vilje consists of effectively draining the remaining resources for the field by continuously optimising the production from the three available wells.

Vilje 1 is the main oil production well on Vilje, and currently the only well on stream. The Vilje 3 well connects to a limited reservoir volume to the south and is only produced intermittently for short periods, as the water cut increases rapidly and producing the well reduces the total field production. The upper branch of Vilje 2 has watered out and has been shut in since May 2018. Vilje 2 lower branch behaves well and has potential for further production. However, after Skogul came on stream in March 2020, Vilje 2 has been shut in due to slugging issues in the common flowline to the Alvheim FPSO. There is a commercial agreement between the Skogul and Vilje licenses, where Skogul compensates for deferred Vilje production.

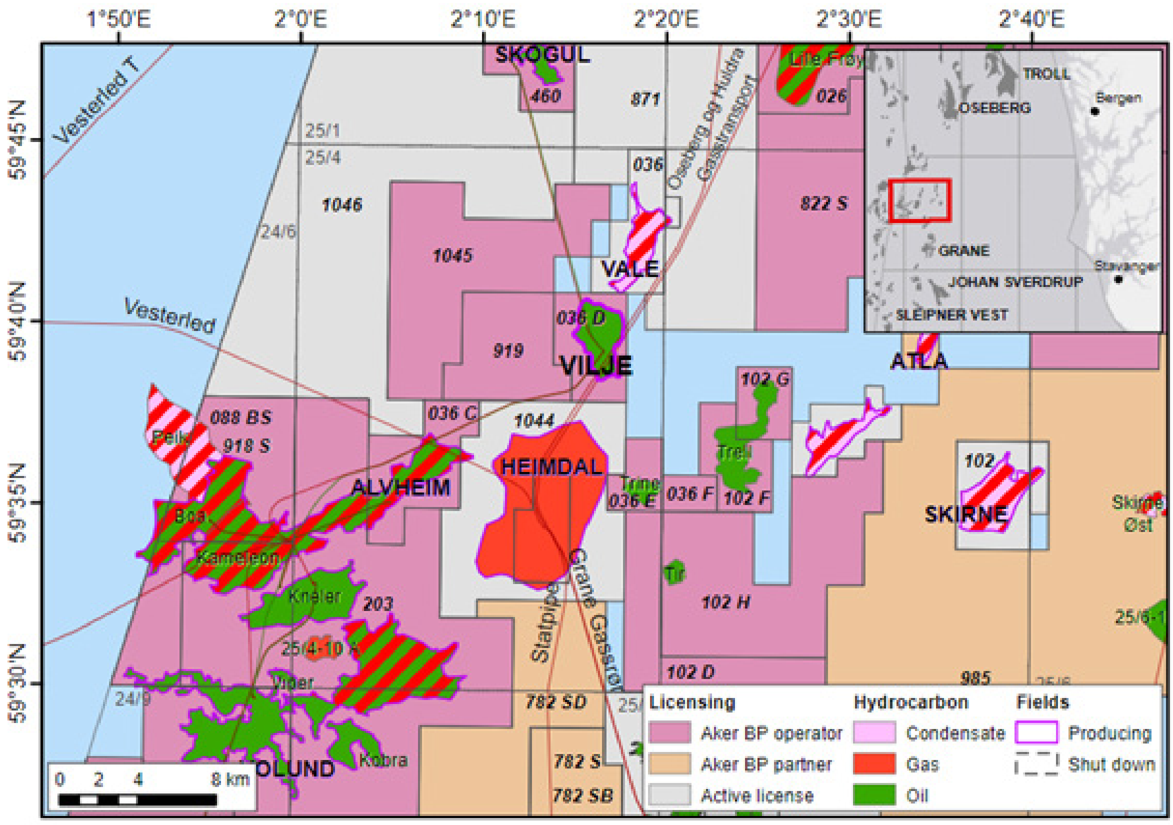


Fig. 3.2 Vilje location map

The Estimated Ultimate Recovery (EUR) has increased slightly since the reserves certification 31.12.2019. This is mainly due to the fact that the 2020 production has allowed to rule out some of the down-side scenario.

The recoverable volumes for Vilje are classified as «Reserves; On Production» (SPE's classification system).

Production from the Vilje field is expected to cease in 2033, with subsequent abandonment scheduled to take place between 2033 and 2035, which coincides with the expected cessation of production from the Alvheim area.

Aker BP holds a 46.904 percent interest in the license and serves as operator. The other license partners are DNO Norge, holding a 28.853 percent interest, and PGNiG Upstream Norway with a 24.243 percent interest.

3.1.3 Volund (PL150)

The Volund Field is an oil field located 8 km south of the Alvheim Field and in block 24/9 licensed under PL150 in the North Sea, see Fig. 3.3.

The reservoir depth is about 1,900 m TVD MSL and the water depth in the area is about 120-130 m. Production started in April 2010. Fig. 3.3 shows the location of the asset.

Discovery

The Volund Field was discovered in 1994 by well 24/9-5. The Intra Balder Formation sandstones were encountered with oil in the interval 2,011 m to 2,018 m TVD MSL (oil down to). The discovery was appraised by wells 24/9-6 and 24/9-7, confirming a field wide OWC of 1995 m TVD MSL and a GOC of 1,891 m TVD MSL.

Reservoir

Volund is a massive injectite complex consisting of high quality, Darcy quality sands which have been injected from early Eocene Hermod Formation into overlying shales of the Sele, Balder and Hordaland formations. Dykes, termed "wings", rise in three directions from a central lower sill which is mainly situated below the OWC. This results in a "bathtub" shape open to the west. Volund is unique in the sense that the entire hydrocarbon accumulation is contained in injected sands and with the majority within cross-cutting dykes.

Development

The field is developed with six production wells and one injection well as a subsea tie-back to the nearby production vessel, Alvheim FPSO. Initial development included three producing wells targeting the ~100 m oil column in the wings supported by one water injector in the sill in addition to natural water drive. The first infill well started production in 2013. Another two infill wells started production in 2017, and one of the original producers was side-tracked in 2019.

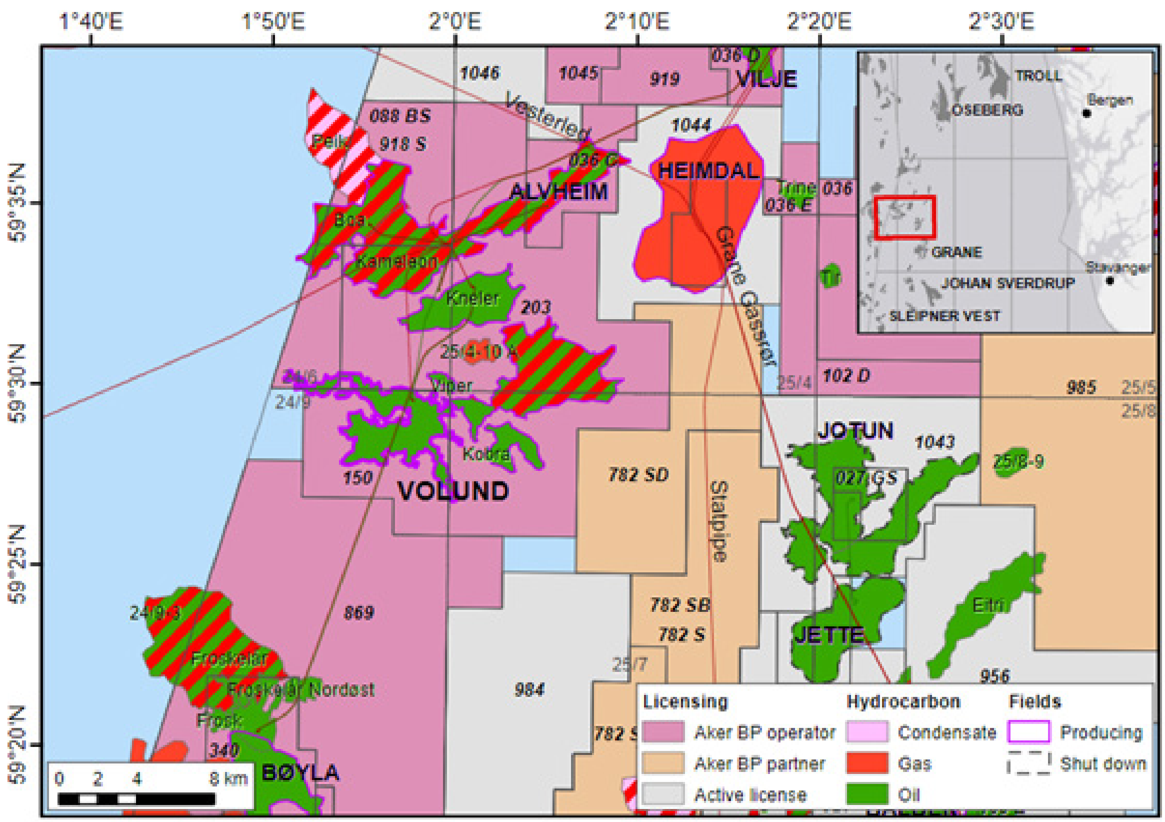


Fig. 3.3 Volund location map

Status

Production comes currently from four producers: infill wells P9 & P10, new infill P3BH and intermittent producer P6. Well P3BH is a side-track of P3 AH and came on stream in May 2019. The wells share a manifold and flowline with the Viper/Kobra wells. Water injection helps support the active aquifer to maintain reservoir pressure. Oil production continues to decline while water cut increases. The infill well P3BH has outperformed predictions and significantly contributed to better performance from the field during 2020.

The Estimated Ultimate Recovery (EUR) has increased since the reserves certification 31.12.2019, primarily due to the performance of the latest well drilled on the field (P3BH). The recoverable volumes of Volund are classified as «Reserves; On Production» (SPE's classification system), Cessation of production from the Volund field is expected in 2033.

Aker BP is the operator and holds a 65 percent interest in Volund, while Lundin Energy AS holds the remaining 35 percent interest.

3.1.4 Bøyla (PL340)

The Bøyla Field is an oil field located in PL 340, block 24/9 in the central part of the North Sea 15 km south-west of the Volund Field. Water depth is 120 m and depth of reservoir is 2,000 m TVD MSL. Well M-01 BH, on the north western flank, started to produce 19 January 2015 and has been the main contributor. The location of the Bøyla Field is shown in Fig. 3.4

Discovery

The Bøyla Field was discovered in 2009 by well 24/9-9 S. The initial discovery name was "Marihøne A". The well proved undersaturated oil at normal pressure with an OWC at 2,071 m TVD MSL. Subsequent pilot and development wells have confirmed the OWC across the field. Bøyla started to produce in January 2015.

Reservoir

The Bøyla structure is a flat low-relief Eocene turbidite fan deposit. The reservoir is within the Palaeocene/Eocene Hermod Sandstone Member, completely encased within Sele Formation shales. The Hermod Sandstone Member is interpreted as sediment gravity flows sourced from the East Shetland Platform, depositing in a basin floor setting. Hermod sandstones are assumed to have filled bathymetric lows created by the underlying Heimdal member.

Two major depocenters have been recognized in the field, one in the west, and one in the east. Questions have been raised as to connectivity between these two parts of the reservoir. The pre-drilled wells confirmed a consistent OWC. Injection testing of the single water injector has proved enough injectivity and interference between the injector (M3) and the western producer (M1). Production experience shows that communication between the injector and the eastern producer (M2) is not present on a production time scale.

Development

The field is a subsea development with two long horizontal producers (about 2,300 m) and one deviated water injector tied back to the Alvheim Field some 28 km to the North via the Kneler A manifold. Gas lift is required in the production wells.

Status

Production from the Bøyla reservoir has been shut-in from the 21 August 2019 to enable test production from the Frosk Test Producer. Testing activities from the Frosk reservoir, located in the same production license, have been sanctioned by the license partnership and approved by the MPE for a two year period until 27 August 2021 where the Bøyla subsea facilities will be prioritized for production of Frosk through a tied-in separate dedicated well. Bøyla production and reserves have been deferred accordingly and are consistent with end year 2019.

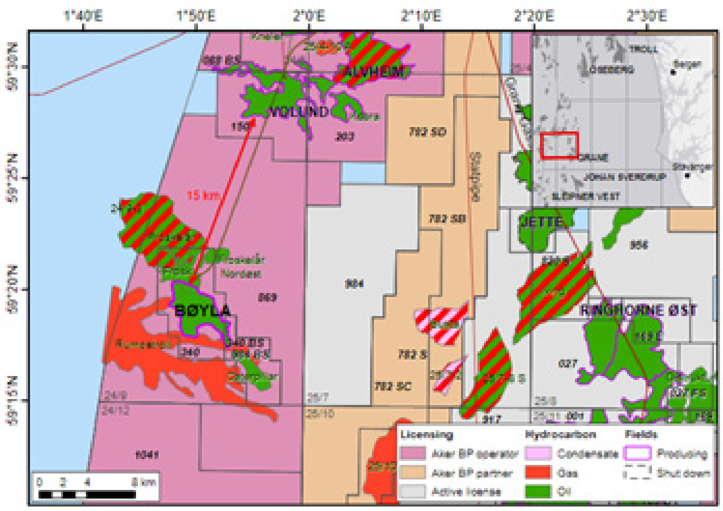


Fig. 3.4 Bøyla location map

Limited production from the M-1 production well in the Bøyla Field has occurred in 2020. These short production intervals occurred during PBU (pressure build-up) activities for Frosk Test. Production behaviour was according to expectations, exhibiting some minor flush production and as expected pressure response.

The recoverable volumes of Bøyla are classified as "Reserves; On Production" (SPE's classification system).

Net production at Bøyla averaged 0.1 mboepd in 2020 due to the prioritization of production from Frosk Test. Cessation of production from the Bøyla field is expected in 2033 together with abandonment activities relating to the other Alvheim Area fields.

Aker BP is operator and holds a 65 percent interest in Bøyla. Vår Energi AS holds a 20 percent interest and Lundin Energy Norway AS holds the remaining 15 percent.

3.1.5 Frosk (PL340)

The Frosk prospect was originally identified as a seismic anomaly interpreted to be a sand injectite and is discussed in the Bøyla PDO (PL340) as an area upside opportunity. The Frosk discovery was made on 12 January 2018, drilled by wells 24/9-12 S, 24/9-12 ST2, and 24/9-12 AT2.

The Frosk field lies within Production License 340 and is located in block 24/9 of the Norwegian sector of the North Sea, see Fig.3.5. Forty meters of oil bearing injectite sand was penetrated within the Eocene Hordaland Group located just above the Balder Formation. An OWC was penetrated, cored, and aligned with pressure data at 1,861.5 m TVDSS. The GOC was calculated to be 1,786 m TVDSS based on pressure data and supported by the measured PVT bubble point pressure. A gas bearing thinner injectite was penetrated in the side-track which constrained the depth of the GOC. The water depth at the discovery well is 119 m.

Reservoir

The Frosk injectite sands are believed to have been injected into the Sele, Balder and Hordaland formations from the underlying Gamma structure. Gamma is a 70 m thick sand body in the Balder formation (24/9-3). Frosk consists of a dyke coming from the crest of Gamma and levels out as a thick sill in the Hordaland formation. Around the main Frosk injectite are several small dykes and sills, acting as "fingers". The injection process has enhanced the reservoir properties, with average porosity of 32 percent and permeabilities up to 10 Darcy. The main sill is very homogeneous, with a net to gross close to 100 percent. The behaviour of the Frosk reservoir outside the main seismic amplitude is uncertain, but likely the sands bifurcate into smaller sills and dykes as seen in Bøyla development pilot wells.

Development

The early phase of development of the Frosk reservoir has commenced with an extended production test. The Frosk reserves are consequently associated with the Frosk Test Production well only. The well has been drilled as a horizontal bi-lateral production well that targets two segments of the Frosk injectite sands (Main Injectite and Frosk Y3H area). Production commenced in late August 2019, exhibiting good performance in line with the P50 prognosis. The Frosk Test subsea well head is tied into the Bøyla 'M' production manifold. The Bøyla production manifold is tied back to the Alvheim FPSO.

Dynamic performance from the Frosk Test producer has highlighted that the aquifer in the Gamma sand is sufficiently strong to support the Frosk Development. Based on this, water injection is currently only planned as a contingent part of the Frosk Development Project. Thus, depletion with aquifer support is assumed as the main drive mechanism for the test production.

Status

In 2018, Aker BP applied for a production test period of two years and permission to produce for the full two years has been granted by the MPE (27 August 2019 to 26 August 2021).

In 2019 early oil production rates of 2,000 sm3/d were observed with negligible water cut nor build in GOR. In 2020 oil production has declined associated with increasing water cut which has gradually built through

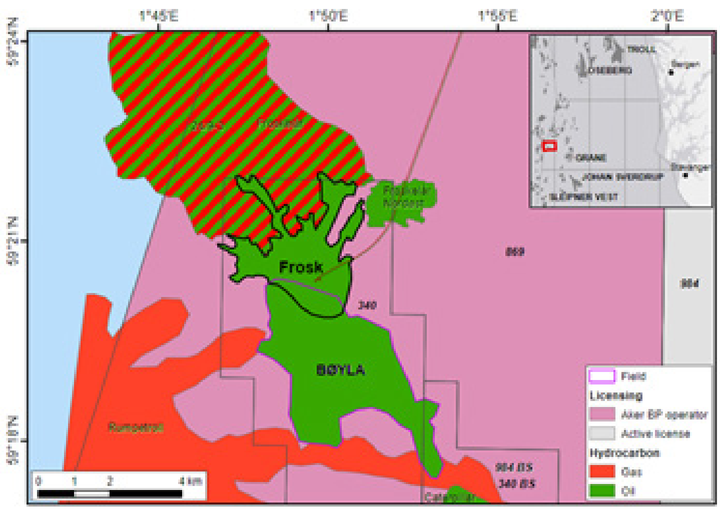


Fig. 3.5 Frosk Field location map

end year (approx. 40%). Tracer evaluations and production tests on the Frosk Test Producer suggest that the Y3H northern branch is the main contributor to water production. GOR has shown some variations but these are possibly associated with allocation uncertainty and thus is not interpreted to have signs of gas-cap gas breakthrough. Pressure decline has been much less than modelled expectation at the time of sanction. Forecasted production profiles have been derived as a part of the Frosk Development project, yielding incremental volumes produced through the Bøyla manifold.

Reserves have been booked for the test production well, and for the two years period only. Volumes for the two-year period are classified as «Reserves, On Production».

Net production at Frosk averaged 5.7 mboepd in 2020. Cessation of test production from the Frosk field is expected in 2021 at the end of the approved MPE production permit for testing activities.

Aker BP is the operator and holds a 65 percent share. Partners are Vår Energi AS (20 percent) and Lundin Petroleum (15 percent).

3.1.6 Skogul

The Skogul oil field is located approximately 40 km north of Alvheim in block 25/1 under PL 460 in the Central Viking Graben in the Norwegian North Sea and consists of Eocene Balder and Frigg Formation deep marine deposited sandstones. Fig. 3.2 shows the location of the discovery. The water depth is about 107 m in the area, and the crest of the structure is estimated to be at 2,097 m TVD MSL. The PDO was submitted in December 2017.

Discovery

The discovery well 25/1-11 R and the side-track well 25/1-11A were drilled in 2010 proved a thin gas cap overlying a 20 m oil column within excellent reservoir quality Upper Balder-Frigg Formation sandstones. Vertical well 25/1-11 R was drilled on a structural high with a strong amplitude anomaly, encountering a 13 m oil column and an oil water contact (OWC) was proven at 2,126 mTVDSS. A deviated (29°) side-track well, 25/1-11 A, was subsequently drilled higher on the structure, but in an area with a dimmer amplitude anomaly. This well encountered a small gas cap with a gas oil contact (GOC) at 2,106 m TVDSS and a 12 m oil column.

Reservoir

The reservoir consists of the Lower Eocene Upper Balder-Frigg Formation sandstones with good quality properties. Upper Balder and Frigg Formation sandstones were derived from the East Shetland Platform to the west and deposited from deep marine turbidity currents as part of the Frigg submarine fan. In well 25/1-11 R the Skogul reservoir interval of 21.7 m TVD MSL contains 20.1 m MD of reservoir sand with a porosity of 31 percent, giving a net-to-gross ratio of 92.4 percent. In Well 25/1-11 A the Skogul reservoir interval of 14.1 m MD contains 12.6 m MD of reservoir sand with a porosity of 32 percent, giving a net-to-gross ratio of 89.2 percent.

Development

The Skogul field is developed with a subsea template with one dual-lateral oil production well. The template has one available spare slot. The Skogul production flow line is daisy chained with the Vilje flow line, which is further tied back to Alvheim FPSO.

In the Skogul PDO, one of the branches of the production well was planned to be extended into the deeper Heimdal formation for pressure support into Skogul (Assisted Aquifer Pressure Support - AAPS). Due to drilling challenges, the planned AAPS had to be abandoned. Pressure support is now supplied by the regional aquifer only.

Status

Production started on 11 March 2020. Clean-up tracer analysis indicate good clean-up from all zones. Early production data indicates that the pressure support from the aquifer could be strong enough to offset the loss of the AAPS. Consequently, the Estimated Ultimate Recovery (EUR) has been kept unchanged from the previous annual statement of reserves.

Skogul field recoverable volumes are classified as "Reserves; Approved " (SPE's classification system).

Aker BP is operator and holds a 65 percent interest in the Skogul Field. The remaining 35 percent shares are held by PGNiG Upstream Norway AS

3.1.7 Ivar Aasen Unit and Hanz (Pl001B, PL028B, PL242, PL338BS, PL457)

The Ivar Aasen Field is located in the North Sea, 8 km north of the Edvard Grieg Field and around 30 km south of Grane and Balder. The field contains both oil and free gas. The Ivar Aasen Field includes two accumulations: Ivar Aasen and West Cable, Fig. 3.6. The accumulations cover several licenses and have been unitized into the Ivar Aasen Unit. Ivar Aasen commenced production 24.12.2016. The water depth in the area is approximately 110 m and the main reservoir at Ivar Aasen is found at about 2,400 m TVD MSL reservoir depth.

Discovery

Ivar Aasen was discovered with well 16/1-9 in 2008, proving oil and gas in Jurassic and Triassic sandstones. An earlier exploration well 16/1-2 in 1976 within the structural closure was initially classified as dry but was after a re-examination reclassified as an oil discovery. West Cable was discovered with well 16/1-7 in 2004, proving oil in Jurassic sandstones.

Reservoir

The two accumulations are located at the Gudrun Terrace between the Southern Viking Graben and the Utsira High. The reservoir sands are fluvial and shallow marine deposits of late Triassic to late Jurassic age. The reservoir sands in the Ivar Aasen structure are complex and heterogeneous while the reservoir at West Cable is more homogeneous. The Ivar Aasen structure contains saturated oil and two gas caps while the West Cable structure contains undersaturated oil.

Development

The drainage strategy for the Ivar Aasen structure assume water injection for pressure maintenance. West Cable will be produced by natural depletion where the major driving force is aquifer drive. In total nine producers (eight targeting the Ivar Aasen structure and one in West Cable) and eight water injectors (in the Ivar Aasen structure) have been drilled in the Ivar Aasen Field. The production wells are completed with

Ivar Aasen

mechanical sand control and ICD completions while the injectors have cemented perforated liners, except one horizontal injector with screens. In Phase 2 of the development, the Hanz discovery will be developed with two subsea wells tied-back to the Ivar Aasen platform. Current plan is production start-up from Hanz in 2024.

The field is developed with a steel jacket including living quarters and process facilities located at a water depth of 110 m with dry well heads on the platform. The wells are drilled from a jack-up rig. The well stream is partly processed on the platform before transportation through pipelines to the Edvard Grieg installation for final stabilization and export. Edvard Grieg also supplies Ivar Aasen with power until a joint solution for power from shore is established October 2022.

Status

The PDO of Ivar Aasen area was approved early 2013. The field development went according to plan and the field came on production 24.12.2016.

All initially planned wells have been drilled in the Ivar Aasen and West Cable structures. The development wells on Ivar Aasen Main Field came in roughly as expected. Two new water injection wells were drilled in 2018, named D-6 and D-7. Two new producers were drilled in 2019, one in the underlying Alluvial Fan formation (D-18) and one branched Skagerrak 2 producer in the East (D-15). Two new producers where drilled late 2020 (D-17 in Alluvial Fan and D-20 in Skagerrak 2) and is ready for production start late 2020/early 2021. The total in-place volumes are unchanged in the current model but will be updated after the drilling of D-17 and D-20. A history match will be done Q1 2021 and an uncertainty study in Q2 2021.

The production of Ivar Aasen was as expected in 2020, except for rapid water cut increase in the D-12 producer in Vestland in the East. The field is producing with high uptime.

The recoverable volumes of Ivar Assen are classified as «Reserves; On Production» (SPE's classification system).

The recoverable volumes of Hanz are classified as «Reserves; Approved for Development» (SPE's classification system).

Net production at Ivar Aasen averaged 20.1 mboepd in 2020. Cessation of production from the Ivar Assen field is expected in 2035.

Aker BP holds a 34.7862 interest in the Ivar Aasen Unit. The other licensees are Equinor (41.4730), Spirit Energy (12.3173 percent), Wintershall Norge AS (6.4615 percent), Neptune Energy Norge AS (3.0230 percent), Lundin Norway AS (1.3850 percent) and OKEA (Norge) AS (0.5540 percent).

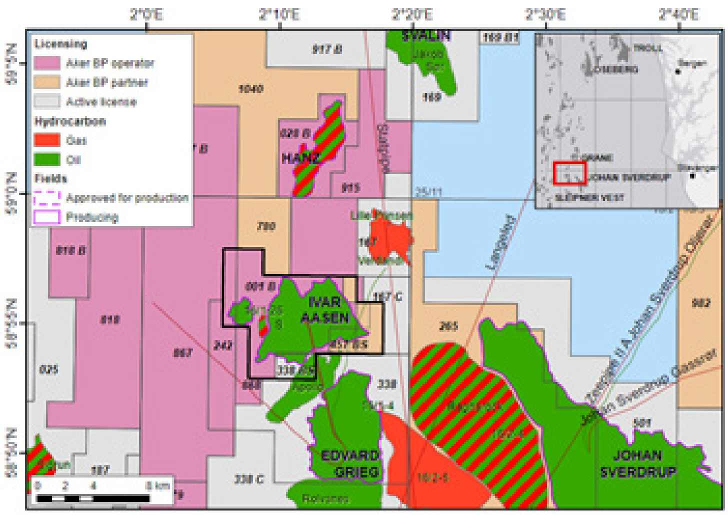


Fig. 3.6 Ivar Aasen Unit and Hanz location map

3.1.8 Valhall (PL006B, PL033B)

Valhall is an oil field in the southern part of the Norwegian sector of the North Sea in PL 006B and PL 033B (unitized into the Valhall Unit) in blocks 2/8 and 2/11, Fig. 3.7. The water depth is about 70 m.

Discovery

The Valhall Field was discovered in 1975 by exploration well 2/8-6. Production started in 1982.

Reservoir

The reservoir consists of chalk in the Upper Cretaceous Tor and Hod Formations. Reservoir depth is approximately 2,400 metres. The Tor Formation chalk is fine-grained and soft; with high porosity (up to 50 percent). Matrix permeability is in the 1-10 mD range. There are areas with natural fractures with high permeability conduits. The Hod Formation porosity is 30 percent-38 percent with permeability 0.1-1mD.

The Valhall Field is subdivided into eight reservoir units: (a) North Flank, (b) Northern Basin, (c) East Flank, (d) West Flank, (e) South Flank, (f) Central Crest, (g) Southern Crest, (h) Lower Hod Formation. Seven of the units are areally distributed within the Tor formation. The eighth unit is in the underlying Lower Hod formation.

The field has produced with pressure depletion and a very effective compaction drive since 1982. As a result of the pressure depletion the chalk has compacted, and the seabed subsided. Water injection in the centre of the field started in 2004. This has reduced pressure depletion and hence subsidence. Gas lift is used to optimize production in most of the producers as a remedy to avoid oscillating production and premature dying of wells.

Development

The plan for development and operation (PDO) for Valhall was approved in 1977. The field was originally developed with three platforms: accommodation, drilling and processing (QP, DP & PCP). The PDO for a Valhall wellhead platform was approved in 1995, and the platform (WP) was installed in 1996. A PDO for a water injection project was approved in 2000, and an injection platform (IP) was installed in 2003 next to WP. Two satellite wellhead platforms (SF & NF) where installed in 2003 with 16 slots each, drilling targets to the South and North Flanks of the field. In 2013 a new integrated Production and Hotel Platform (PH), bridge linked to the IP Platform was installed. A satellite wellhead platform (WF) with 12 well slots was sanctioned in 2017, drilling targets to the West Flank. The original platforms PCP and QP have been decommissioned and DP is currently doing P&A work on the last wells.

Oil and NGL are routed via pipeline to Ekofisk and further to Teesside in the UK. Gas is sent via Norpipe to Emden in Germany.

Status

Valhall currently has 54 active producers and seven active injectors. During 2020 Valhall drilled four new wells. Two of these were put on production during 2020.

Two WP wells (F-18B and F-11A), part of the WP Production Recovery project (WPPR), were drilled with the IP rig in 2019 and have been put on production/injection in 2020. The remaining five wells in the WPPR project and two remaining Tor Infill wells (RA11 and PSCN) have been lumped into a new project called "Valhall WP Life Time Extension" and delayed. The drilling of these targets is now scheduled for 2023 – 2024.

Four Valhall Flank West wells (V-7, V-2, V-12 & V-4) were drilled in 2020. In total seven West Flank wells are on production by Year End 2020 (V-9, V-6, V-8, V-5, V-3, V-7 & V-4). All West Flank production is reported in base reserves.

Two Valhall Flank South Infill wells (S-16B and S-6A) were drilled in 2019. S-16B was put on production in 2019 while S-6A was put on production in 2020.

One Valhall Flank North Infill Drilling well (N-8) was completed and put on production in 2019. It produced for one week and when attempting to

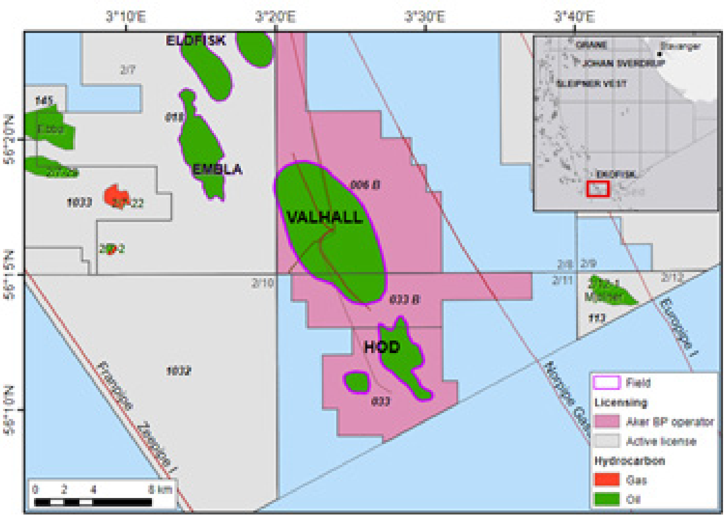


Fig. 3.7 Valhall and Hod location map


Valhall

do additional stimulation, a fish was left in the well and currently unable to produce. There is a high chance that the well will have to be re-drilled. This well is moved out of base production for year-end 2020 reserve reporting and put into the new Valhall Flank North drilling campaign in 2021 – 2022. Two new targets have during 2020 been sanctioned to the same drilling campaign (N-2 / RN3 producer and N-1C / IF16 injector). This project consisting of three wells and called "Valhall Flank North Infill Drilling Phase 2".

The North Flank Water Injection project (NFWI) was approved in 2018. The water injector (N-4) was drilled in 2018 and water injection pipeline to the Flank North is completed. First injection is expected in the second half of 2021.

The recoverable volumes for Valhall Base are classified as «Reserves; On Production».

Valhall WP Life Time Extension, Valhall Flank North Water Injection and Valhall Flank North Infill Drilling Phase 2 have all been classified as «Reserves; Approved for Development».

The 2P/P50 production profile indicates an economic cut-off in 2049. Net production to Aker BP averaged 50 mboepd in 2020.

Aker BP holds 90 percent interest in the Valhall field, with Pandion holding the remaining 10 percent.

3.1.9 Hod (PL033)

Hod is an oil field 13 km south of the Valhall Field in the southern part of the Norwegian sector in the North Sea (PL 033 in block 2/11), Fig. 3.7. The water depth is approximately 70 m and the reservoir depth is about 2,700 m TVD MSL. Location of Hod is shown in Fig. 3.7.

Discovery

The Hod Field was discovered in 1974 by exploration well 2/11-2. Production started in 1990.

Reservoir

The reservoir lies in chalk in the lower Palaeocene Ekofisk Formation, and the Upper Cretaceous Tor and Hod formations. The field consists of three structures: Hod West, Hod East and Hod Saddle.

The field has been produced by pressure depletion. Gas lift has been used in some wells to increase production and lift performance.

Development

The field was initially developed with an unmanned production wellhead platform which was remotely controlled from Valhall. There has, however been no production from the Hod facility since 2012. The Hod Saddle, which connects the Hod and Valhall reservoirs, is currently produced through four wells drilled from Valhall Flank South. The Hod facility awaits decommissioning and disposal.

Transport of oil and NGL from Valhall is routed via pipeline to Ekofisk and further to Teesside in the UK. Gas from Valhall is sent via Norpipe to Emden in Germany.

Status

There has been no production from the Hod facility since 2012. The only production from the Hod license is from the four wells drilled from the Valhall South Flank platform and part of these wells extend into the Hod license. The equity split between the Valhall and Hod licenses is based on 'length of well' in respective licenses. The wells on the current Hod facility are awaiting final P&A.

A Hod Field Development project has been sanctioned. The project consists of building a copy of the Flank West Platform with 12 well slots, and an initial drilling phase consisting of five production wells. First production is assumed to be 1Q 2022.

Net production to Aker BP averaged 0.7 mboepd in 2020.

The recoverable volumes for Hod Base are classified as «Reserves; On Production».

The Hod Field Development project has been classified as «Reserves; Approved for Development».

Aker BP has a 90 percent interest in the Hod field, with Pandion holding the remaining 10 percent.

Ula

3.1.10 Ula (PL019)

Ula is an oil field in the southern part of the Norwegian sector of the North Sea in block 7/12 in PL 019, Fig. 3.8. The water depth in the area is about 70 m and the reservoir depth is about 3,500 m TVD MSL.

Discovery

Ula was discovered by well 7/12-2 in 1976. The well penetrated a major Late Jurassic reservoir (Ula Formation) and was terminated within a Triassic hydrocarbon bearing sequence of poor quality sands and interbedded shales. Core analysis and log interpretation indicate an Ula Formation sandstone reservoir, of 128 m net thickness with porosities ranging from 14 percent to 28 percent, permeabilities from a few mD to over 2 D and water saturations from 5 percent to over 50 percent. The Ula Formation was oil bearing from top to base at 3,532 m in an oil down-to setting.

Development

The Ula development consists of three conventional steel facilities for production, drilling and accommodation, which are connected by bridges. The gas capacity at Ula was upgraded in 2008 with a new gas processing and gas injection module (UGU) that doubled the capacity. Ula is the processing facility for Oda, Tambar and Blane. The oil is transported by pipeline via Ekofisk to Teesside in the UK. All gas is reinjected into the reservoir to increase oil recovery.

Reservoir

The main reservoir is at a depth of 3,345 metres in the Upper Jurassic Ula Formation. The Jurassic reservoir consists of two production intervals with water and gas injection in the deeper layer. A separate Triassic reservoir underlies the main reservoir. Oil was initially recovered by pressure depletion, but after some years, water injection was implemented to improve recovery. Water alternating gas (WAG) injection started in 1998. The WAG program has been extended with gas from Tambar (2001), Blane (2007), Oda (2019) and Oselvar (2012, now ceased). Gas lift is used in the shallowest reservoir interval.

Status

45 wells have been drilled on Ula since start-up of which eight wells are currently producing and four are injecting.

Based on the positive experiences with WAG effect on oil recovery, gradually more WAG wells are planned. In 2016, the partnership in

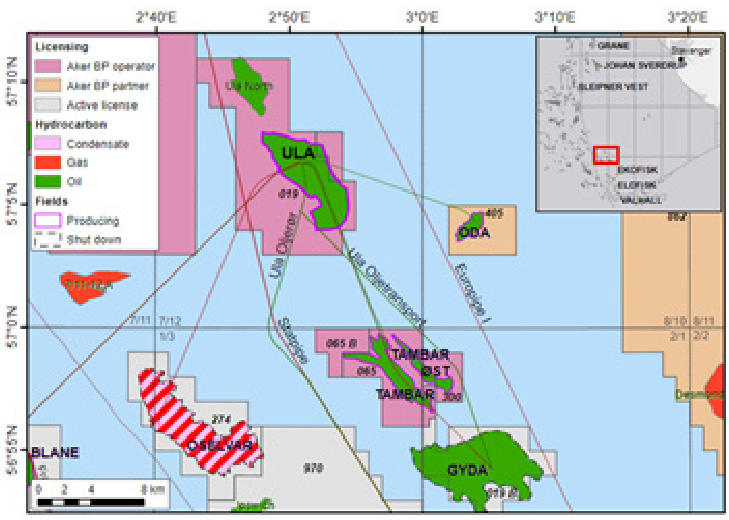


Fig. 3.8 Ula, Tambar and Tambar East location map

production license 405 decided to develop the 8/10-4 S discovery (Oda) as a tie-in to Ula and a PDO was issued November 2016. Production from Oda commenced in 2019. Gas from Oda is injected into the Ula reservoir to increase recovery.

Injection of additional import gas is being evaluated, which could increase reserves. In addition, some non-sanctioned planned infill wells will probably increase production from Ula. The volumes from these future projects are classified as contingent resources.

The 2P/P50 production profile indicates an economic cut-off in 2032.

Net production to Aker BP averaged approximately 5.1 mboepd in 2020. The recoverable volumes for Ula Base are classified as "Reserves; On Production".

Aker BP is the operator and holds an 80 percent interest in the Ula Field. The remaining 20 percent shares are held by DNO Norge AS.

3.1.11 Tambar (PL065)

Tambar is an oil field about 16 kilometres south-east of the Ula Field in the southern part of the Norwegian sector of the North Sea, Fig. 3.9. The water depth in the area is 68 metres.

Discovery

Tambar was discovered in 1983 by well 1/3-3.

Reservoir

The reservoir consists of Upper Jurassic sandstones in the Ula Formation, deposited in a shallow marine environment. The reservoir lies at a depth of 4,100-4,200 m and the reservoir characteristics are generally very good. The field is produced by pressure depletion, with natural gas expansion combined with aquifer support as the main reservoir drive mechanisms.

Development

The field has been developed with a remotely controlled wellhead facility without processing equipment. The oil is transported to Ula through a pipeline. After processing at Ula, the oil is exported in the existing pipeline system via Ekofisk to Teesside in the UK, while the gas is injected into the Ula reservoir to improve oil recovery.

Status

A total of five producers have been drilled on Tambar since start-up of which two wells are currently producing.

Major challenges restricting production are the wells' ability to lift with ever decreasing reservoir pressure combined with increased water cut. Infill producer K-2B will be drilled in 2021 in the northern area of the field. This well replaces existing producer K-2A, which has struggled with lack of sufficient reservoir pressure since start-up in 2018. The Tambar team continues to evaluate potential infill drilling targets.

The recoverable volumes of Tambar are classified as "Reserves; On Production" (SPE's classification system). Net 2020 production to Aker BP from Tambar averaged approximately 2.9 mboepd.

Aker BP is operator and holds a 55 percent interest in the Tambar Field. The remaining 45 percent shares are held by DNO Norge AS.

3.1.12 Tambar East (PL065, PL300, PL019B)

Tambar East is a minor oil field located east of Tambar, see Fig. 3.8.

Discovery

Tambar East was discovered in 2007 by well 1/3-K-5.

Reservoir

The reservoir consists of sandstones of Late Jurassic age, deposited in a shallow marine environment. The reservoir lies at a depth of 4,050-4,200 metres and the quality varies, but is generally poorer than the Tambar main field. The field is produced by pressure depletion, and the reservoir is believed to be compartmentalized.

Development

Tambar East is an oil field in the North Sea developed with one production well drilled from the Tambar facility. The field location is shown in Fig. 3.9. The oil is transported to Ula via Tambar. After processing at Ula, the oil is exported in the existing pipeline system via Ekofisk to Teesside in the UK. The gas is used for gas injection in the Ula reservoir to improve oil recovery.

Status

In RNB submissions, cessation of production was assumed in 2017. The well was temporarily shut down in November 2017. The base assumption is that well K-5A will be restarted in 2024 when back pressure has declined and local reservoir pressure has increased.

There was no production from Tambar East in 2020.

The recoverable volumes of Tambar are classified as "Reserves; On Production" (SPE's classification system).

Aker BP is the operator and holds a 46.2 percent interest in the Tambar East Unit. The remaining shares are held by DNO Norge AS (37.8 percent), Repsol Norge AS (9.76 percent), INEOS (5.44 percent) and KUFPEC Norway AS (0.80 percent).


Tambar

Skarv FPSO

3.1.13 Skarv Unit (PL262, PL159, PL212B, PL212)

Skarv/Idun is an oil and gas field located about 35 km south-west of the Norne Field in the northern part of the Norwegian Sea in the Skarv Unit in blocks 6507/2, 6507/3, 6507/5 and 6507/6. The water depth in the area is 350-450 m, Fig. 3.9. The Skarv unit is a joint development of the Skarv, Idun and Ærfugl fields (formerly known as Snadd). Note that the northern part of the Ærfugl discovery (Ærfugl Nord, formerly known as Snadd Outer) is not a part of the Skarv Unit, Fig. 3.9

Discovery

Gas in the segment Skarv A was discovered by 6507/5-1 in 1998. Later the field was appraised and gas with an oil column was found in the Skarv B and C segments. Dry gas in Idun north of Skarv was discovered by well 6507/3-3 in 1999.

Development

The development concept is a production, storage and offloading vessel (FPSO) above the Skarv Field tied to five subsea templates with nineteen wells. Distribution between the well types are: Six oil producers, four gas producers, four gas injectors in Skarv/Idun and five Ærfugl gas producers (Ærfugl A-1H, which was previously used as a test well, D04, which is first well in Phase 2, and three phase one wells K-1H, L-1H and M-1H). Ærfugl is discussed in Chapter 3.2.1.

The oil is exported by a shuttle tanker. The gas is exported in an 80 km pipeline connected to the Åsgard Transport System. Capacity in Gassled is secured through the Gassco booking system.

Reservoir

The Skarv structure is defined by three segments - the A, B and C segments, separated by sealing faults. However, production experience indicates that the fault between B and C segment can be leaking. Idun (East and West) is a separate, gas filled structure with no communication to the three Skarv segments. The segments are close to hydrostatic pressure. Each segment constitutes of Jurassic Garn, Ile and Tilje formations. The Garn Formation is a high quality reservoir and the deeper Ile and Tilje formations are more heterogeneous with poorer reservoir quality.

Skarv/Idun Field contains both oil and gas. The production strategy is oil production in combination with gas injection, keeping the pressure constant, followed by gas blowdown. The gas filled segments are produced by depletion.

Status

Skarv/Idun production started 31.12.2012. To date, approximately two thirds of the estimated ultimate recovery has been produced. Four gas wells are currently producing, two in Garn A and two in Idun. All gas wells are on decline.

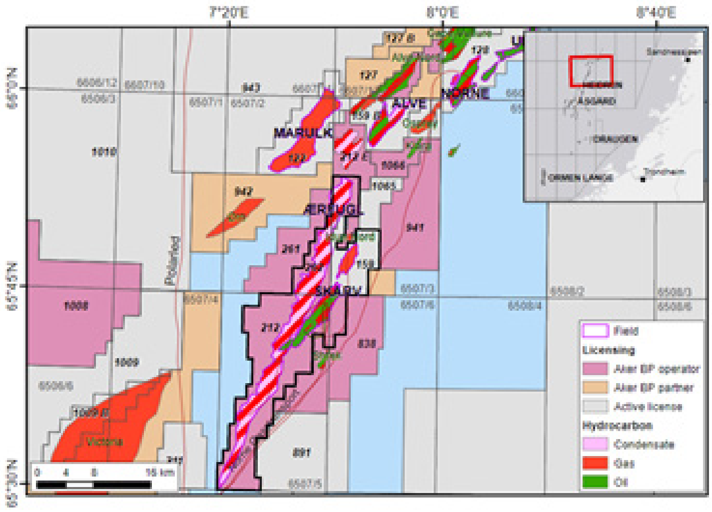


Fig. 3.9 Skarv and Ærfugl location map

The oil wells in the B and C segments are on a slight in-year decline, and all have increasing GOR after gas breakthrough from supporting gas injectors. The two oil wells in Tilje Formation in the A segment have been producing with a stable rate throughout 2020.

The western Idun well, D02, is the only well that has had water production. The water production rate stabilized and the well has seen no lifting issues and little impact on gas production since. It is assumed that the water was coming from an underlying sand rather than from the main production targets. Both Idun producers are currently shut in due to back pressure from Ærfugl well D04. D04 came online in April 2020. The plan is to restart the Idun wells as soon as D04 and Ærfugl Phase 2 goes to low pressure production in 2028-2029.

Net production from Skarv averaged 9.3 mboepd in 2020. Production from the Ærfugl was approximately 11.7 mboepd. In total, Skarv and Ærfugl A-1H, D04 and Phase 1 produced 21.0 mboepd.

The recoverable volumes of Skarv and Idun, including volumes from Ærfugl, are classified as «Reserves; On Production» (SPE's classification system).

Aker BP is the operator and holds a 23.835 percent interest in the Skarv Unit. The remaining shares are held by Equinor (36.165 percent), Wintershall DEA Norge AS (28.0825 percent) and PGNiG Upstream International AS (11.9175 percent).

3.1.14 Ærfugl

Ærfugl is a gas condensate field located about 35 km south-west of the Norne Field in the northern part of the Norwegian Sea in the Skarv Unit in blocks in 6507/2, 6507/3, 6507/5 and 6507/6, see Fig. 3.9. The water depth in the area is 350-450 m and the reservoir depth is about 2,800 m TVD MSL. The field was tested through one producer tied into the Skarv facilities for four years prior to the field development decision. The PDO was submitted in December 2017.

Discovery

The Ærfugl Field was discovered in 2000 with well 6507/5-3. It was appraised in 2010/2011 by wells 6507/5-6 S, 6507/5 A-1 H, 6507/5 B-5, and in 2012 by well 6507/3-9 S for Snadd Outer.

Reservoir

The reservoir is almost 60 km long and only 2 to 3 km wide. The thickness varies from 5 to 60 m in the hydrocarbon bearing area. The reservoir in Ærfugl is the Cretaceous Lysing Sandstone Formation with good reservoir properties (average porosity 21.4 percent, permeability 234 mD and net/gross of 0.85).

Development

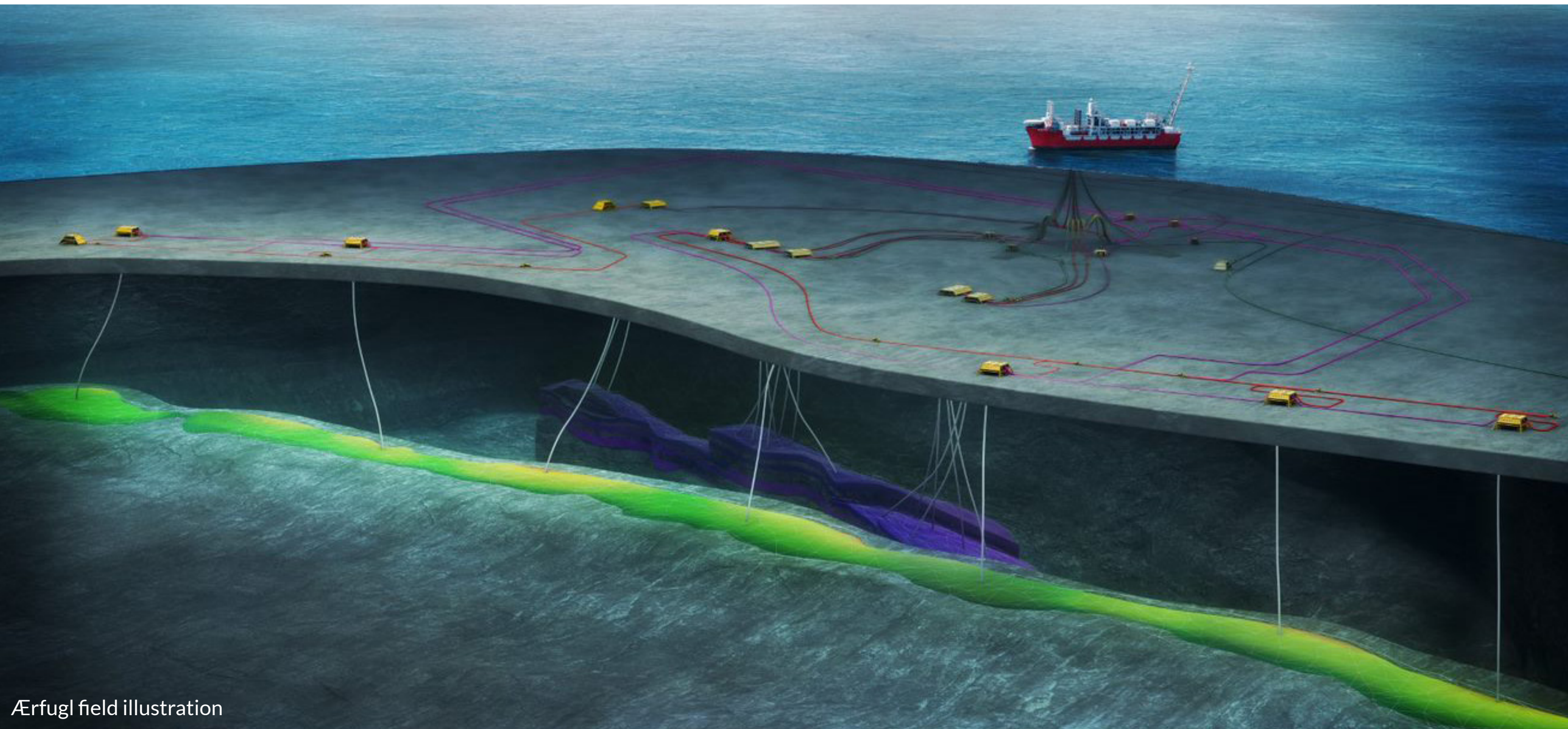
The Ærfugl Field is produced through the existing facilities on Skarv. The depletion plan includes six new highly deviated subsea wells plus the existing test well A-1 H tied into the Skarv FPSO with heated flowlines. Phase I is already drilled and on production as of November 2020 and includes three wells on Ærfugl South. Phase II includes three wells towards the north of Ærfugl North and Snadd Outer, with first well already on production in 2020, and the two remaining wells in Q4 2021.

Status

The A-1 H test producer in Ærfugl started gas production February 2013, and has successfully produced since. Producing this well has provided excellent data which has helped to significantly de-risk the Ærfugl development. D04 was drilled from Idun template and put on production in April 2020. D04 experienced water break through earlier than expected, however, water rates seem to have stabilized. Studies are ongoing to evaluate where water is coming from. Phase 1 wells were drilled and put on production in November 2020, as per plan. Future volumes predicted from these wells are considered as "Reserves / On Production" (SPE's classification system).

The other recoverable volumes of Ærfugl; Snadd Outer, are classified as "Reserves; Approved " (SPE's classification system).

The Ærfugl Field is located in the Skarv Unit. Aker BP holds a 23.835 percent share in the Unit. The northern extension, Snadd Outer, is located in license PL212E in which Aker BP holds a share of 30 percent.



Ærfugl field illustration

Fig. 3.11 Johan Sverdrup field centre

3.1.15 Johan Sverdrup (PL265, PL501, PL502, PL501B)

Johan Sverdrup is a major oil field extending over three licenses (PL 028, PL 501 and PL 502), for which the plan for development and operation (PDO) was approved in 2015. The field is located in a half-graben on the Utsira High in the North Sea, approximately 160 km west of Stavanger in blocks 16/2, 16/3, 16/5 and 16/6; see Fig.3.10. The water depth in the area is 110 - 120 m and the reservoir depth is about 1,900 m TVD MSL.

Discovery

The discovery well 16/2-6 was drilled in 2010 on the Avaldsnes High. The well proved oil in Jurassic and pre-Jurassic sandstones in the Karmsund Graben. A large number of wells have been drilled since then to appraise the discovery.

Reservoir

The reservoir consists of late to middle-early Jurassic sediments in the Draupne sandstone and in the older Statfjord Fm/Vestland Groups. The reservoirs are characterized by excellent reservoir properties. The apex of the field is located at approximately 1,800 m TVD MSL and the free water levels (FWL) encountered are in the range of 1,922 – 1,934 m TVD MSL. Top reservoir is flat whereas the base is irregular. Gross reservoir thickness varies from up to ~90 m in the central/western parts of the field to less than 10 m in the fringes, with several parts of the field having thin reservoir below seismic resolution.

The reservoir fluid is highly undersaturated oil with a low GOR ranging between 40 and 80 Sm3/Sm3 and with a viscosity of approximately 2 cP.

Phase 1 field development is in general based on producers located in the central/western thicker parts of the field with water injection located down dip in the water zone in the eastern and southern parts of the field.

Development

The PDO for Phase 1 was approved by the authorities in August 2015. The Phase 1 development plan includes a field centre with four platforms: a processing platform, a drilling platform, a riser and export platform and a living quarters and utilities platform, see Fig. 3.11. The platforms are installed on steel jackets linked by bridges. Phase 1 also includes 18 oil production and 16 water injection wells and three subsea water injection templates. Production from Phase 1 commenced on the 5 October 2019.

The Phase 2 (the full field development) will develop the reserves in the fringe areas of the field as well as enable acceleration of the production from the Phase 1 area. The PDO for Phase 2 was submitted in August 2018 and approved by the authorities in the spring of 2019. Production start is planned in 2022. The Phase 2 development includes an additional processing platform (P2) located next to the riser platform at the field centre, Fig.3.12. The fringe areas will be developed with subsea templates tied back to the riser platform (RP). The wells will be a mixture of subsea wells and additional wells drilled from the central drilling platform DP.

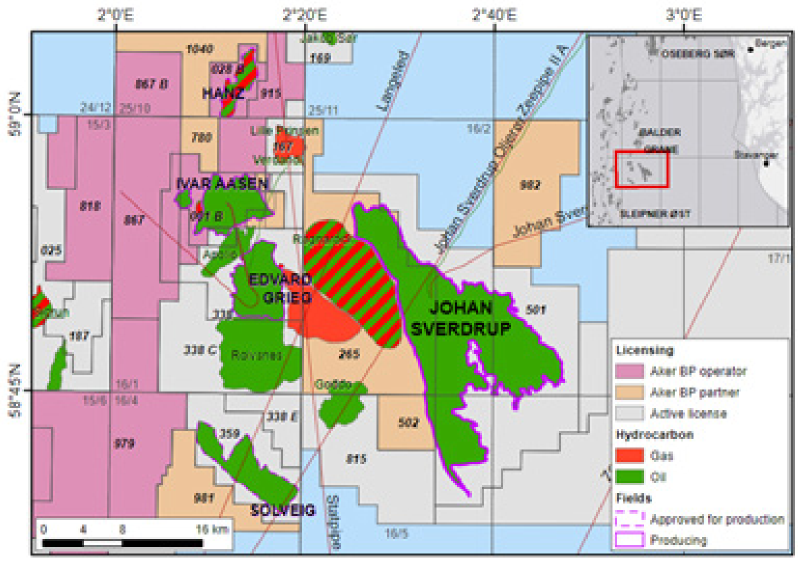


Fig. 3.10 Johan Sverdrup location map

Fully developed, 62 oil production and water injection wells are planned to be drilled on Johan Sverdrup. Currently, the field is producing at a plateau of 500 000 bbl/d, and it is expected that this will increase to 535 000 bbl/d before the summer 2021. After phase 2 start-up, the oil production plateau production is expected to be at least 720 000 bbl/d.

Oil and gas is transported to shore via dedicated pipelines. The oil is transported to the Mongstad terminal and the gas is transported via the Statpipe system to Kårstø for processing and onward transportation.

Status

The production from Phase 1 started 05.10.2019. After a very successful ramp-up, the field by year-end 2020 reached a production of more than 500,000 bbl/d (approximately 60,000 boe/d net to Aker BP) from twelve producers supported by twelve water injection wells.

PDO for Phase 2 was submitted in August 2018, and approved early 2019. Production start for Phase 2 is planned in 2022. Aker BP has included reserves assuming a full field development of the field in the reserve base (both Phase 1 and Phase 2), including volumes from the WAG-project (which has been approved by the license).

The volumes related to the Phase 1 development are classified as «Reserves; On Production», whereas the volumes related to Phase 2 and WAG are classified as «Reserves; Approved» (SPE's classification system).

Several IOR/EOR techniques are identified which may increase the reserves on Johan Sverdrup. The most promising is infill drilling.

The unit agreement gives Aker BP an 11.5733 percent share of the field. The remaining shares are held by Equinor (42,6267 percent), Lundin (20.000 percent), Petoro (17.3600 percent) and Total (8.4400 percent).

3.1.16 Oda (PL405)

The Oda Field is located ~14 km east of the Ula Field in Block 8/10, PL405, on the eastern side of the Central Graben in the Norwegian North Sea (Fig. 3.11). Water depth is about 66 m. The crest of the structure is estimated to ca. 2,300 m TVD MSL. The PDO was approved by the authorities, May 2017. Production commenced in March 2019.

Discovery

The discovery well 8/10-4 S was drilled in 2011 in the north-western part of a salt-induced structure. The well proved an oil-down-to situation in the Ula Fm. A water gradient in a downflank side-track suggests FWL at 2,985 m TVD MSL. The east and south-west segments of the structure were drilled dry in 2014.

Reservoir

The Oda reservoir consists of the Upper Jurassic Ula Formation; a sandstone reservoir with high quality properties, on the western flank of the steeply dipping salt diapir. The oil column is about 685 m of high quality, light crude oil.

Development

The development concept is a subsea tie-in to the Aker BP operated Ula Platform with re-usage of Oselvar facility and separator at Ula. The Oda reservoir is drained by two producers supported by one water injection well. All the wells have been drilled from an integrated subsea template.

Status

Oda production started in March 2019, five months earlier than planned. The field was produced without pressure support during the first ~7 months due to damages in the water injection pipeline, and technical problems during water injection start up, October 2019.

Oda net production 2020 averaged approximately 3.5 mboepd. The field production performance was negatively impacted by repeated blockages in the asphaltene inhibitor injection lines and water break through (August 2020).

Oda recoverable volumes are classified as «Reserves; On Production» (SPE's classification system). Not included here is a side-track well option currently under evaluation for decision 1Q 2021. The intent of the side-track option is to increase the productivity of the field attic oil and by that increase the value of the remaining production after watering out the down dip production well.

Aker BP holds a 15 percent interest in Oda. The remaining shares are held by Spirit Energy (40 percent, operator), Suncor Energy Norge AS (30 percent) and DNO ASA (15 percent).

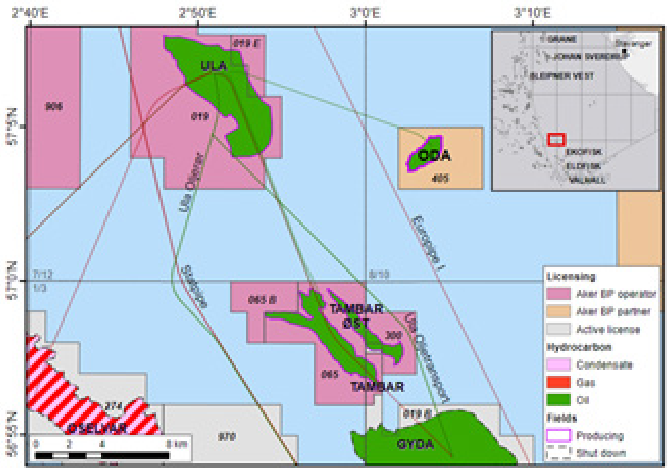


Fig. 3.12 Oda location map

3.1.17 Atla (PL102C)

Atla is a small gas/condensate field in the central part of the North Sea in a water depth of 119 metres.

Discovery

The Atla Field was discovered in 2010 by well 25/5-7.

Reservoir

The reservoir contains gas/condensate in sandstones in the Brent Group of Middle Jurassic age at a depth of about 2,700 metres.

Development

The field produces with a subsea installation tied back to the existing pipeline between the Heimdal and Skirne fields. Production started two years after the discovery in October 2010.

Status

Atla physical production has ceased, and P&A is planned in 2022. The reserve estimates reflect reallocation at Heimdal,

Atla was shut-in during year 2020 and therefore, net production was 0 mboepd. The recoverable volumes are classified as «Reserves; On Production» (SPE's classification system).

Aker BP holds a 10 percent interest in the license. Total E&P Norge AS is the operator holding a 40 percent interest while Petoro AS holds a 30 percent interest and Lotos Exploration and Production Norge AS holds the remaining 20 percent interest.

3.1.18 Gina Krog (PL029B)

Late 2019 Aker BP sold all its interests in the Gina Krog oil and gas field. The transaction was finalized during the spring of 2020.

3.2 Development Projects

3.2.1 Gråsel

2Gråsel is an oil and gas accumulation discovered by well 6507/5-1 well in 1998 by BP Amoco. Gråsel consists of Lange formation sandstones located directly above Skarv A segment.

Discovery

The Gråsel reservoir was made by the Skarv discovery well 6507/5-1 in 1998 by BP Amoco. The discovery has been penetrated by five Skarv wells.

Reservoir

The Gråsel field is situated stratigraphically above the Skarv Field. Shallow marine sandstones of Late Cretaceous age, Lange formation, forms the main reservoir at approximately 3,000 m depth, directly above Skarv A block. The reservoir consists of sandstone with thin mud layers and shales which potentially separate the sands. The logs show highly porous permeable sandstone, but poorer vertical permeability. The reservoir is overpressured and not all Gråsel sands are in communication indicating stratigraphic and/or structural barriers.

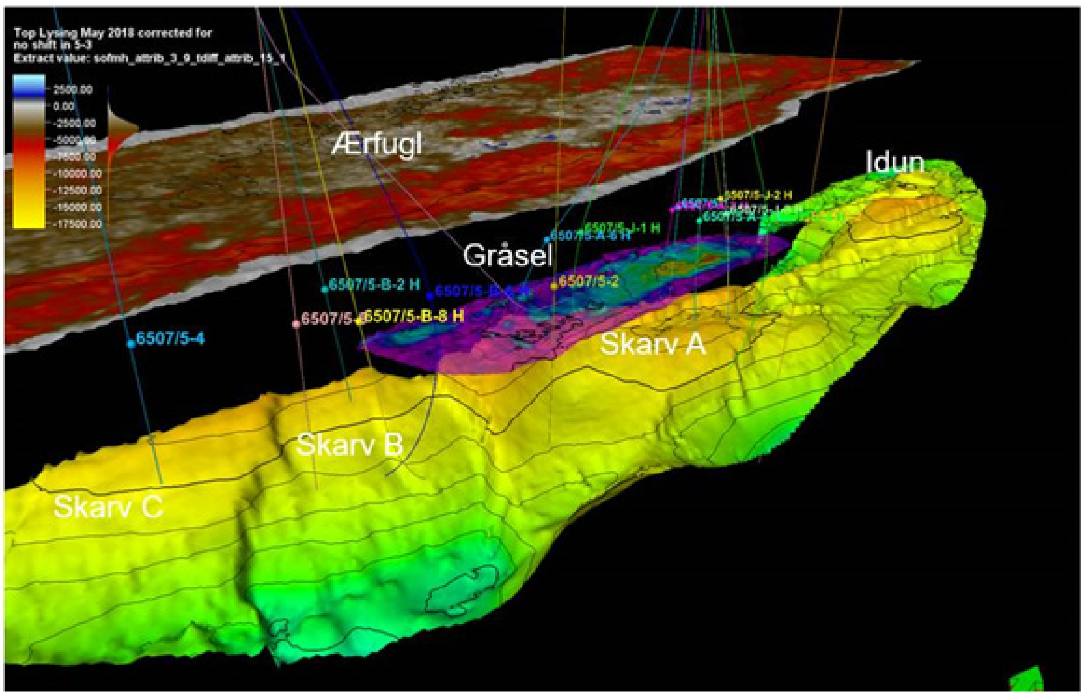
Development

Gråsel will be produced through the existing facilities on Skarv. The drainage strategy is pressure support by gas injection and production through a slanted oil producer. The planned wells are recompletion of current Skarv Tilje injector J-03 to a dual-zone injector with Gråsel and a new producer from existing spare slot on Skarv BC East template. The wells will be drilled/recompleted in 2021 and is planned online 3Q 2021.

Status

The Gråsel development was sanctioned by the license in December 2020. The recoverable volumes of Gråsel are classified as "Reserves; Approved " (SPE's classification system).

Aker BP holds 23.835 percent in Gråsel. The remaining shares are held by Equinor (36.1650 percent), Wintershall Dea Norge AS (28.0825 percent) and PGNiG Upstream Norway AS (11.9175 percent).



4 Contingent Resources

Aker BP has contingent resources in a wide range of assets and at different stages of maturation. The total net contingent resources estimates reported here include volumes in resource categories "Development Pending" and "Development not clarified or on hold", see Fig. 1.1. Discoveries that need more data acquisition to define the way forward, such as Rondeslottet and Liatårnet, are not included.

The contingent resources range from 459 mmboe to 1,526 mmboe, with a 2C volume of 895 mmboe. Approximately 50 percent of this is associated with further development of the fields containing reserves described in 3 Description of Reserves

The most important contributors to the contingent resources are the discoveries in the NOAKA area (North of Alvheim and Askja/Krafla), the King Lear volumes and volumes in the Valhall area.

The following is a short description of the most important discoveries within the company's core areas containing contingent resources.

4.1 Contingent Resources by area

4.1.1 The NOAKA Area (North of Alvheim Krafla Askja)

The area includes ten discoveries over a 60 km long trend, south of Oseberg and North-east of Alvheim, See Fig. 4.1. A concept with a PdQ platform located centrally (Aker BP operated), an Unmanned Processing Platform (Equinor operated) on the Krafla and 3 wellhead platforms and subsea templates were approved by all licenses in June 2020. Key commercial terms between the licensees were approved at the same time.

The discoveries include:

The Frøy Field (PL364) was in production from 1995 to 2001 with Elf as the operator. The field was shut down in 2001 due to several reasons, including technical challenges, recovery rates falling below expectations and low oil price. The licensees have worked on getting the field redeveloped. In 2008, a PDO was submitted, but was postponed due to the financial crisis. Through 2010 the Frøy group matured alternative concepts to establish a more robust concept featuring a leased field centre (FPSO/JUDPSO) combined with a WHP. The goal was to deliver an updated PDO. During spring 2011 the work on preparing an updated Frøy PDO was put aside.

Aker BP holds 90.26 percent interest in Frøy.

Frigg Gamma Delta (PL442) discoveries in the North Sea, about 20 kilometres east of the Frigg. Water depth in the area is approximately 120 meters. The discovery was proven by well 25/2-10S in Frigg Gamma structure in 1986. The reservoir contains oil and gas in sandstone of Eocene age in the Frigg formation, at approximately 1,900 meters depth. The resources also include the Frigg Delta structure, where well 25 /2-17 proved oil in the same reservoir level in 2009.

Aker BP holds 90.26 percent interest in the Frigg Gamma Delta discovery.

Langfjellet (PL442) was discovered with well 25/2-18 and appraised in 2016 and contains oil in the Middle Jurassic Hugin- and Sleipner Formations. Several side-tracks were drilled and two successful formation tests (DST) were conducted in well 25 /2-18A. The maximum oil production rate was 3,800 bbl/d through a 40/64 inch choke in the lower oil zone.

Aker BP holds 90.26 percent interest in the Langfjellet discovery.

Rind (PL442, 25/2-5) was discovered in 2010. Aker BP holds 92.13 percent interest in the Rind discovery.

Fulla (PL873) was discovered in 2009 with wells 30/11-7 and -7A. It is a gas condensate discovery in the Brent formation. Aker BP holds 40 percent interest in the Fulla discovery.

Krafla Area (PL272, PL035, PL035C)

The Krafla discoveries are located in the northern part of the North Sea, between the Oseberg and Frigg fields. The area includes clusters of segments grouped into Krafla, Central and Askja areas. The water depth is 108 metres.

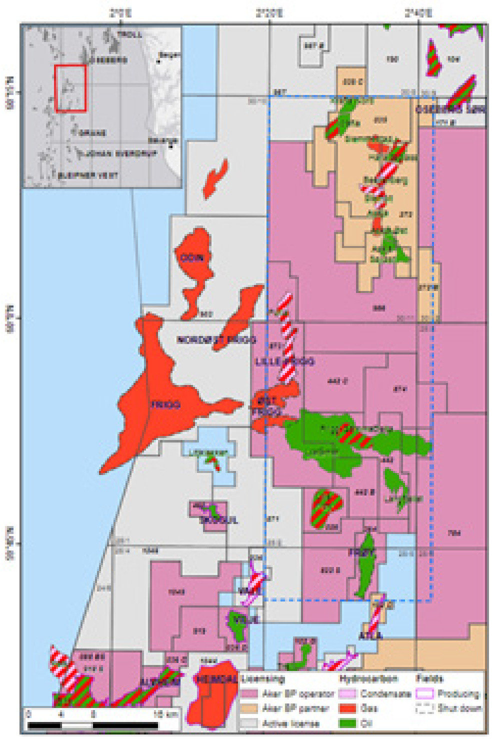
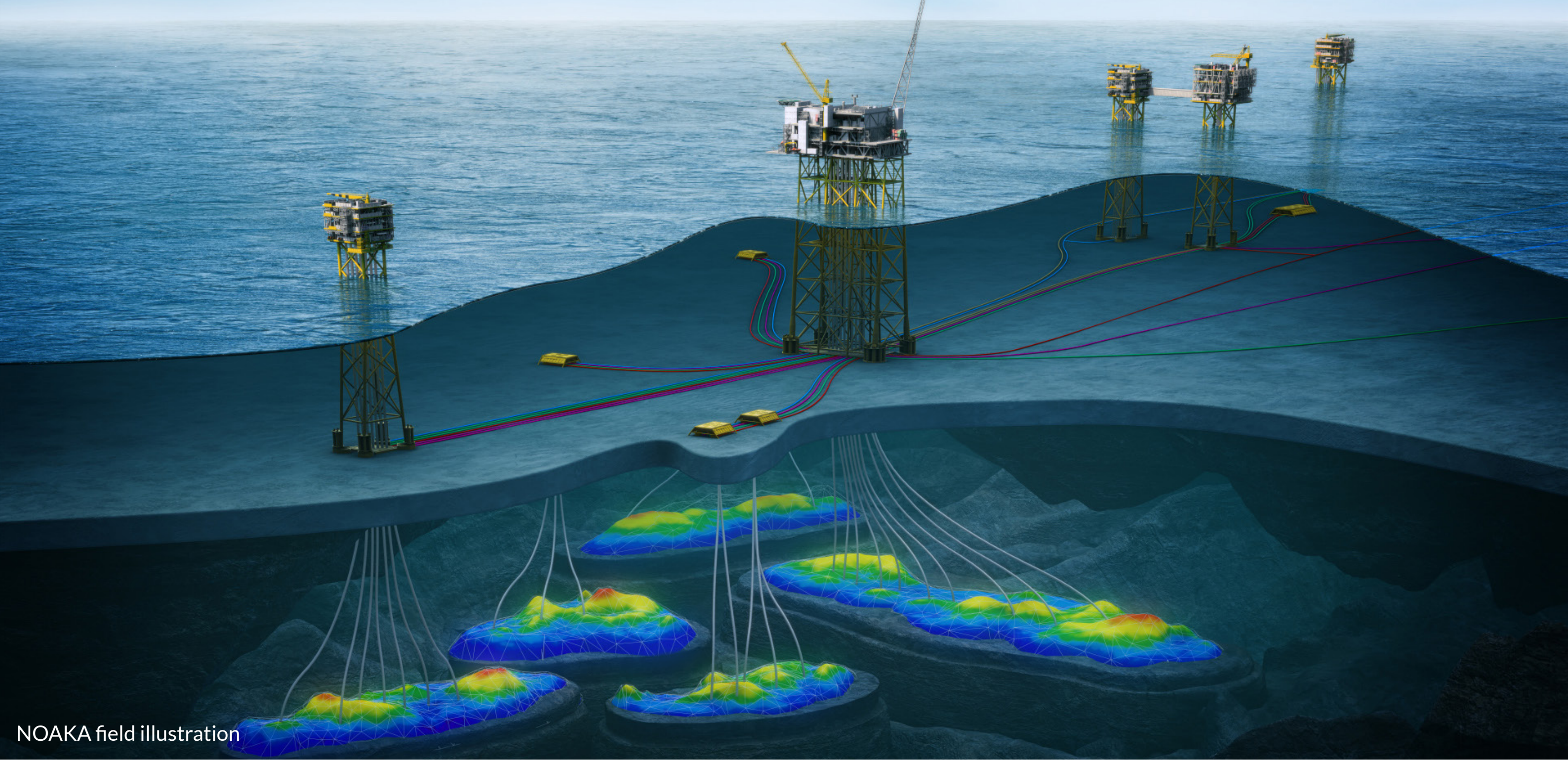


Fig. 4.1 The NOAKA area (North of Alvheim Krafla Askja)


NOAKA field illustration

The reservoir section in all the discoveries are the Middle Jurassic Tarbert and Ness Formations with fair to good reservoir quality. Reservoir depths vary from approximately 2,900 mTVD to approximately 3,800 mTVD.

Aker BP interest in licenses PL035/PL035C and PL272 is 50 percent. Equinor is operator for the licenses and holds the remaining 50 percent.

Krafla
- Krafla Main & Krafla West (wells 30/11-8S and 30/11-8A drilled in 2011) – oil discovery
- 30/11-10A, Krafla Main appraisal 2014/2015
- 30/11-10S, Krafla North in 2014 – oil discovery

Central
- 30/11-11S, Madame Felle 2016 – oil discovery
- 30/11-13 Beerenberg 2016 – gas discovery
- 30/11-14 Slemmestad 2016 – gas discovery
- 30/11-14B Haraldsplass 2016 – gas discovery

Askja
- 30/11-8S, Askja East in 2013 - oil discovery
- 30/11-9ST2, Askja West 2013/2014 - gas discovery
- 30/11-12S, Askja South East 2016 - oil discovery
- 30/11-12A Askja SE downflank 2016 - oil discovery
- 30/11-11A, Viti prospect in 2016 – dry

A DG2 decision is planned for September 2021 and DG3 is planned end 2022. First oil is expected in Q1 2027. The schedule is agreed in all licenses.

The gross 2C resource potential in the NOAKA area is above 500 mmboe. The net resource potential for Aker BP for the NOAKA area ranges from 200 to 430 mmboe.

4.1.2 Alvheim Area

There are several promising discoveries in the Alvheim area. The Gekko (PL203) discovery is located approximately ten km south-east of Alvheim, see Fig.3.2, and was discovered in 1974 and further appraised in 2018. A thin (6.5 m) oil column underlies a large gas cap. The reservoir sandstones are within the Palaeocene Heimdal Formation. Current plan is to develop the field with three tri-lateral oil producers from two subsea templates towards Alvheim FPSO. Possible production start is 2024 and is planned to be combined with the development of the Kobra East development through an additional tri-lateral well. Aker BP is the operator and holds a 65 percent share in the KEG (Kobra East Gekko) project.

Other promising discoveries in the Alvheim area are Trine, Trell, Froskelår and the volumes of the Frosk development beyond the two years of test production. The combined net resource potential in resource categories 4 and 5 for Aker BP for the Alvheim Area ranges from 29 to 75 mmboe.

4.1.3 Valhall Area

Several projects which may increase the reserves from the Valhall and Hod fields significantly are identified. The following is a list of projects included in the resource classes «Development Pending» and «Development not Clarified or on Hold», Fig. 1.1.

- Valhall Extended production
- Valhall Flank Additional infill drilling
- Valhall Flank West Water Flooding
- Valhall WP Production recovery waterflooding
- Valhall New Central Platform
- Valhall redrills and Late Side-tracks
- Hod Field development expansion
- Part of Valhall and Hod Diatomite developments

Some of these projects are expected to be sanctioned within 2020, while other will need further maturing prior to sanction. Aker BP holds 90 percent interest in all these projects.

The combined net resource potential in resource categories 4 and 5 for Aker BP for the Valhall Area ranges from 78 to 196 mmboe.

4.1.4 Skarv Area

The largest undeveloped discovery in the Skarv area is Alve Nord. Alve Nord was acquired from Total during 2018 and is expected to be tied into the Norne FPSO. The resources are primarily located in mid/lower Jurassic sands in the Fangst- and Båtgruppen and in the Cretaceous Lange Formation. Aker BP holds 88.08 percent in Alve Nord.

Other undeveloped discoveries planned to be tied back to Skarv FPSO are Idun North (Aker BP share 23.835 percent), Shrek (Aker BP share 35 percent), and Ørn (Aker BP share 30 percent, non-operator).

Potentially undrained resources in Idun Tunge, located in the saddle area between Skarv A and Idun, is also included in resource category 5, with the current plan to drill a keeper well in 2023.

The combined net resource potential in resource categories 4 and 5 for Aker BP for the Skarv Area ranges from 27 to 99 mmboe.

4.1.5 Ula Area

In 2018, Aker BP acquired the King Lear discovery from Equinor. King Lear is expected to have total resources ranging from 46 to 119 mmboe. Aker BP holds 78 percent of King Lear.

In addition, initiatives to increase the recovery efficiency in the Ula field is expected to generate another up to 68 mmboe net volumes (based on an Aker BP share of 80 percent in the Ula field).

Included in the potential resources in the Ula area are Ula Triassic development and further development of the WAG-process.

The combined net resource potential in resource categories 4 and 5 for Aker BP for the Ula Area ranges from 63 to 209 mmboe.

4.1.6 Garantiana (PL554)

The Garantiana discovery is an elongated structure with a gross ~100 m thick Early Jurassic / Cook formation / medium quality reservoir (200-400 mD) located at a depth of approximately 3,700 m TVD MSL in the northern North Sea. The reservoir is high pressure (630 bar) with somewhat challenging fluid characteristics (high content of CO_2, H_2S, high Pour point pressure and risk of asphaltene precipitation).

Garantiana has been appraised by 34/6-2S and 2A in 2012 (central area) and by 24/6-3S in 2014 (south area). The southern area has proven good reservoir properties through drill stem tests, the middle area has poorer characteristics, and the northern area is not appraised.

Updated volume estimates indicate a net resource potential ranging from 14 to 24 mmboe to Aker BP. The discovery will most likely be developed as a subsea tie-back to existing infra structure. Thus, a development will be dependent on available process capacity in the area. Current plans indicate production start in 2025.

Equinor is the operator, and Aker BP holds a 30 percent share in PL554.

4.1.7 Gohta (PL492)

The Gohta discovery, located on the southern part of the Loppa High in the south west Barents Sea was discovered in 2013 by well 7120/1-3. The well proved oil with an overlaying gas cap in Permian porous karstified carbonates of the Tempelfjorden Group. An appraisal well was drilled in 2014, 7120/1-4. Both wells were tested. Well 7120/1-3 tested the oil zone. Well 7120/1-4 produced gas from the gas zone but failed to produce from the oil zone. It is uncertain if this is related to reservoir performance or to a poor cement job before the DST.

A possible development will most likely be a common development with the Alta discovery. This will most likely be a tie-back to Johan Castberg in the future (approximately 2030). An application has been sent to the MPE to extend the DG2 and DG3 dates for the Gohta area. Current net recourse potential to Aker BP ranges from 0 to 56 mmboe.

Lundin is operator for the license and Aker BP holds a 60 percent share in PL492.

Other

Other resources classified in the resource classes “Development Pending” and “Development not clarified or on hold” includes infill wells on Skarv and Ivar Aasen and several IOR projects on the Ula and Tambar fields.

5 Management's Discussion and Analysis

The assessment of reserves and resources is carried out by experienced professionals in Aker BP based on input from operators, partners, and in-house evaluations. The responsibility to carry out the evaluation lies with the business projects. The reserves and resource accounting is coordinated and quality controlled by a small group of professionals, headed by a reservoir engineer with more than 30 years of experience in such assessments.

Additionally, all volumes within the reserve category (except for the minor Enoch and Atla) have been certified by an independent third-party consultancy (AGR Petroleum Services AS). All production- and cost profiles are included in AGR certification report for completeness and assessment of economic cut-off with Aker BP SPE PRMS price assumptions.

The reported 2P/P50 reserves include volumes which are believed to be recoverable based on reasonable assumptions about future economical, fiscal and financial conditions. Discounted future cash flows after tax are calculated for the various fields based on expected production profiles and estimated proven and probable reserves. Cut-off time for the reserves in a field or project is set at the time when the maximum cumulative net cashflow for each project occurs. The company has used a long-term inflation assumption of 2.5 percent, a long-term exchange rate of 8.0 NOK/USD (9.0 and 8.5 in 2021 and 2022, respectively), and a long-term oil price of 65 USD/bbl (real 2020 terms), rising from a 2021 oil price estimate of 45 USD/bbl and 2022 estimate of 55 USD/bbl.

The calculations of recoverable volumes are, however, associated with significant uncertainties. The 2P/P50 estimate represents our best estimate of reserves/resources while the 1P/P90 estimate reflects our high confidence volumes. The methods used for subsurface mapping do not fully clarify all essential parameters for either the actual hydrocarbons in place or the producibility of the hydrocarbons. Therefore, there is a remaining risk that actual results may be lower than the 1P/P90. A significant change in oil prices may also impact the reserves. Low oil prices may force the licensees to shut down producing fields early and lead to lower production. Higher oil prices may extend the life of the fields beyond what is currently assumed.

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