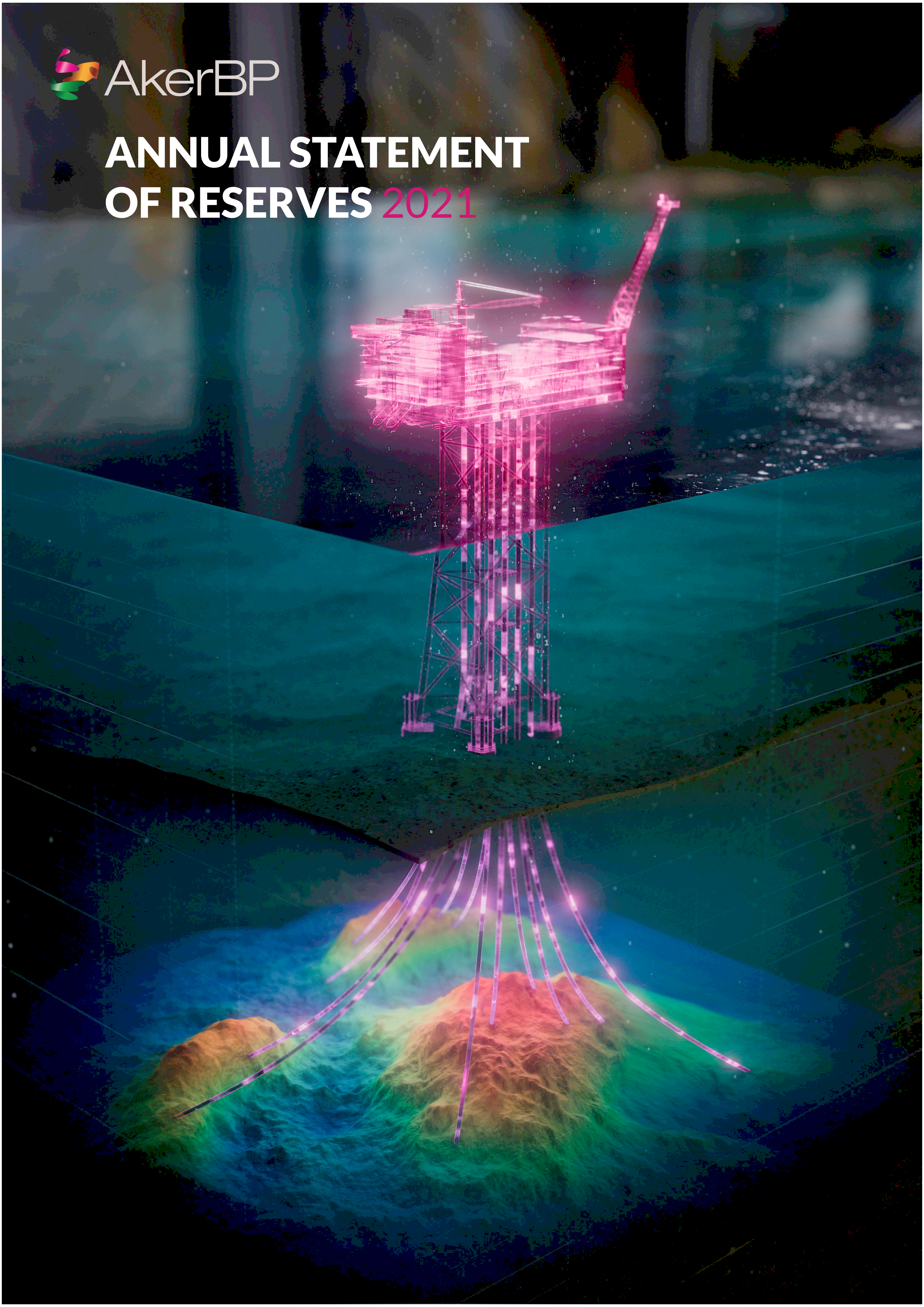
ANNUAL STATEMENT OF RESERVES 2021



CONTENTS

LIST OF FIGURES

LIST OF TABLES

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.

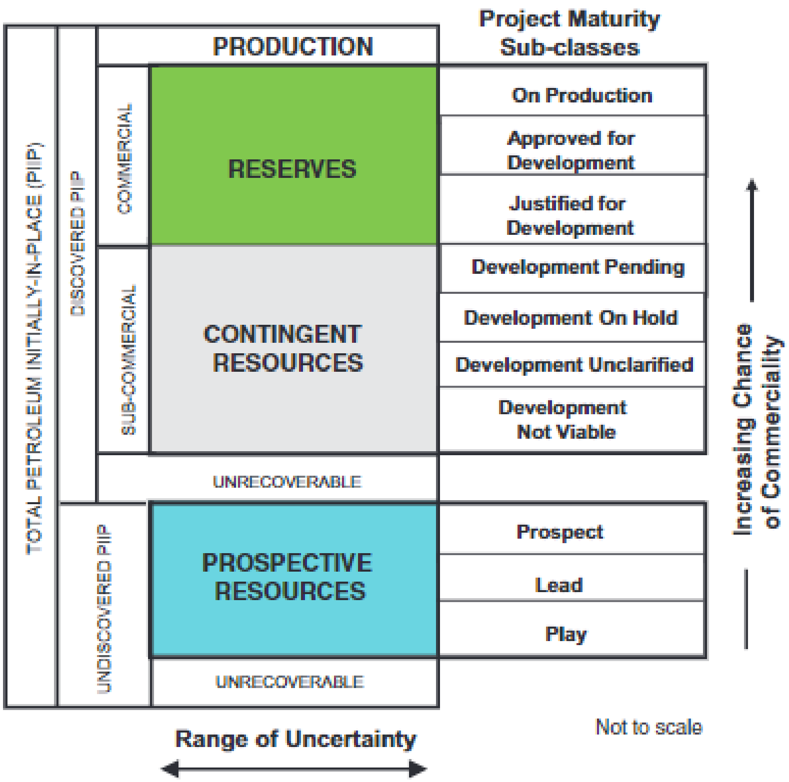


FIG. 1.1 SPE reserves and recourses classification system

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 36 fields/projects containing reserves, see Table 2.1. Out of these fields/projects, 25 are in the sub-class "On Production"/Developed, 10 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 and projects containing reserverves

Field/Project	Interest (%)	Operator	Resource Class	Comment
Developed Reserves				
Alvheim Kam/Knel Base	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	
Skogul Base	65%	Aker BP	On Production	
Vilje Base	47%	Aker BP	On Production	
Volund Base	65%	Aker BP	On Production	
Volund P5 Sidetrack	65%	Aker BP	On Production	
Ivar Aasen Base	35%	Aker BP	On Production	
Johan Sverdup Phase 1	12%	Equinor	On Production	
Oda	15%	Spirit Energy	On Production	
Skarv Base	24%	Aker BP	On Production	
Skarv Gråsel	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	
Ærfugl Nord Development	30%	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 A-10 Recompletion	80%	Aker BP	On Production	
Hod Base	90%	Aker BP	On Production	
Valhall Base	90%	Aker BP	On Production	
Atla Base	10%	Total Energies	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	
Kameleon Infill West	65%	Aker BP	Approved for Development	
Kobra East/Gekko	65%	Aker BP	Approved for Development	
Hanz	35%	Aker BP	Approved for Development	
Johan Sverdup Phase 2 (incl WAG)	12%	Equinor	Approved for Development	Phase 2 PDO based on WAG approved 2019
Skarv LPP	24%	Aker BP	Approved for Development	
Ærfugl LPP	30%	Aker BP	Approved for Development	Name formally changed to Ærfugl Nord 21.01.2021
Hod Field Development	90%	Aker BP	Approved for Development	
Valhall Flank West V-11 Infill	90%	Aker BP	Approved for Development	
Valhall New Central Platform	90%	Aker BP	Approved for Development	
Frosk	65%	Aker BP	Justified for Development	

Total net proven reserves (P90/1P) as of 31.12.2021 to Aker BP are estimated at 599 million barrels of oil equivalents. Total net proven plus probable reserves (P50/2P) are estimated at 802 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 31.12.2021 per projects and reserve class

As of 31.12.2021	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%	34	0	5	39	26	41	0	8	49	32
Boa Base	58%	7	0	1	8	5	11	0	2	12	7
Bøyla Base	65%	2	0	0	2	1	2	0	0	2	2
Frosk Test Production	65%	0	0	0	0	0	7	0	0	7	5
Skogul Base	65%	3	0	0	3	2	4	0	0	5	3
Vilje Base	47%	9	0	0	9	4	13	0	0	13	6
Volund Base	65%	3	0	0	4	2	6	0	1	7	4
Volund P5 Sidetrack	65%	1	0	0	1	0	1	0	0	1	1
Ivar Aasen Base	35%	45	3	10	58	20	59	4	12	75	26
Johan Sverdup Phase 1	12%	1 349	32	40	1 421	164	1 607	43	46	1 696	196
Oda	15%	8	0	1	9	1	12	0	1	14	2
Skarv Base	24%	12	15	68	95	23	13	17	81	111	27
Skarv Gråsel	24%	6	0	2	8	2	8	1	4	12	3
Ærfugl A-1H	24%	3	5	23	31	7	6	7	35	48	11
Ærfugl Phase 1	24%	8	9	42	58	14	12	13	60	84	20
Ærfugl Phase 2	24%	1	1	6	8	2	1	2	10	14	3
Ærfugl Nord Development	30%	1	1	7	9	3	1	3	14	18	5
Tambar Base	55%	3	0	1	4	2	5	0	1	7	4
Tambar East Base	46%	0	0	0	0	0	0	0	0	0	0
Ula Base	80%	12	1	0	13	10	21	2	0	22	18
Ula A-10 Recompletion	80%	2	0	0	2	2	4	0	0	4	3
Hod Base	90%	2	0	0	2	2	2	0	0	3	3
Vahall Base	90%	158	7	28	194	174	200	9	35	245	221
Atla Base	10%	0	0	0	0	0.0	0	0	0	0	0
Enoch Base	2%	0	0	0	0	0.0	0	0	0	0	0
Total		**1 669**	**75**	**232**	**1 977**	**467**	**2 037**	**103**	**310**	**2 450**	**601**

Table 2.2 Continued

As of 31.12.2021	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	4	4	3	0	0	13	13	8
Kameleon Infill West	65%	2	0	1	3	2	3	0	0	4	3
Kobra East/Gekko	65%	16	0	24	40	26	22	0	29	51	33
Hanz	35%	9	1	2	12	4	15	1	3	20	7
Johan Sverdup Phase 2 (incl WAG)	12%	377	1	1	379	44	600	4	5	609	71
Skarv LPP	24%	1	1	5	7	2	1	2	10	14	3
Ærfugl LPP	24%	0	0	2	3	1	1	1	5	7	2
Hod Field Development	90%	24	1	4	29	26	32	1	5	39	35
Valhall Flank West V-11 Infill	90%	1	0	0	2	1	3	0	0	3	3
Valhall New Central Platform	90%	16	1	4	21	19	25	2	6	33	30
Total		**448**	**5**	**47**	**500**	**128**	**703**	**12**	**78**	**793**	**194**
JUSTIFIED FOR DEVELOPMENT											
Frosk	65%	6	0	0	6	4	9	0	1	10	6
Total		**6**	**0**	**0**	**6**	**4**	**9**	**0**	**1**	**10**	**6**
Total Reserves		**2 123**	**80**	**280**	**2 483**	**599**	**2 749**	**115**	**389**	**3 253**	**802**

Table 2.3 Aker BP net 1P and 2P reserves as of 31.12.2021 per field and area

As of 31.12.2021	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	43	0	11	55	35	55	0	23	78	50
Bøyla	2	0	0	2	1	2	0	0	2	2
Frosk + Test Production	6	0	0	6	4	16	0	1	17	11
Skogul	3	0	0	3	2	4	0	0	5	3
Vilje	9	0	0	9	4	13	0	0	13	6
Volund	4	0	0	4	3	7	0	1	8	5
Kobra East/Gekko	16	0	24	40	26	22	0	29	51	33
Alvheim Area	83	0	36	119	75	120	0	54	174	110
Tambar	3	0	1	4	2	5	0	1	7	4
Tambar East	0	0	0	0	0	0	0	0	0	0
Ula	13	1	0	15	12	25	2	0	26	21
Ula Area	17	1	1	19	14	30	2	1	34	25
Hod	26	1	4	31	28	34	2	6	42	38
Valhall	176	9	32	216	195	228	11	42	281	253
Valhall Area	202	10	36	248	223	262	13	48	323	291
Hanz	9	1	2	12	4	15	1	3	20	7
Ivar Aasen	45	3	10	58	20	59	4	12	75	26
Ivar Aasen Area	54	4	12	70	24	74	5	15	94	33
Skarv	18	16	75	110	26	22	20	95	137	33
Ærfugl (Incl. Ærfugl Nord)	13	17	79	109	26	21	26	124	171	42
Skarv Arera	31	33	154	218	53	43	47	219	308	75
Johan Sverdrup	1 726	32	41	1 799	208	2 207	48	51	2 305	267
Oda	8	0	1	9	1	12	0	1	14	2
Atla	0	0	0	0	0	0	0	0	0	0
Enoch	0	0	0	0	0	0	0	0	0	0
Other	8	0	1	9	1	13	0	1	14	2
Total	**2 123**	**80**	**280**	**2 483**	**599**	**2 749**	**115**	**389**	**3 253**	**802**

An oil price of 70 USD/bbl (2021), 67 USD/bbl (2022) and 65 USD/bbl (following years) has been used for reserves estimation. Low- and high case sensitivities with oil prices of 35 USD/bbl and 90 USD/bbl, respectively, have been performed by AGR. This had a moderate effect on the reserves estimates. The low price resulted in a reduction in total net proven (1P/P90) reserves of 25% and net proven plus probable (2P/P50) reserves of 17%. The high oil price scenario resulted in a marginal increase in reserves of less than 2% to the proven (1P/P90)- or proven plus probable (2P/P50)-estimates.

Changes from the 2020 reserve report are summarized in Table 2.4. The main reasons for increased net reserve estimate (i.e. disregarding the produced volumes) are the KEG- and Frosk-developements, drilling of more wells in Valhall and initiatives to increase recovery from existing or already decided projects, primarily in the Alvheim-area. On the negative side, reserves were reduced in both Ærfugl and Ivar Aasen due to poorer than expected reservoir performance.

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 31.12.2020	511	647	128	192	2	3	641	842
Production	-76	-76					-76	-76
Transfer	30	43	-28	-40	-2	-3	0	0
Revisions	2	-14	-4	-2	0	0	-3	-15
IOR	0	1	6	10	0	0	6	11
Dicovery and Extensions	0	0	26	33	4	6	30	40
Acquisition and sale	0	0	0	0	0	0	0	0
Balance as of 31.12.2021	**467**	**601**	**128**	**194**	**4**	**6**	**599**	**802**
Delta 21-20	**-44**	**-45**	**0**	**2**	**2**	**3**	**-42**	**-40**

Three projects (Ærfugl Nord, Skarv, Gråsel and Volund P5-sidetrack) and several new Valhall wells started production in 2021, and were transferred to resource category “On production”.

Johan Sverdrup and Valhall are the two most important field contributing approximately 65% of the company’s 2P reserves.

Total net production to Aker BP averaged 209 mboepd (total ~76 mmboe) in 2021. This is slightly below the forecast from 2020 (~215 mboep).

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 2021. 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 2021 to 31 October 2021 and forecast for the period 1 November 2021 to 31 December 2021. These volumes are used for assessment of remaining reserves as of 31.12.2021.

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.

The Alvheim field comprises licences covered by PL203, PL088 and PL036C. The main Alvheim reservoirs are Kneler, East Kameleon and Kameleon (PL203), and the Boa reservoir (PL088, 11.65% on UK side). Sales gas from the Vilje (PL036D) field is sold by PL203 through a commercial agreement. The Viper-Kobra reservoirs fall into PL203.

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 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.

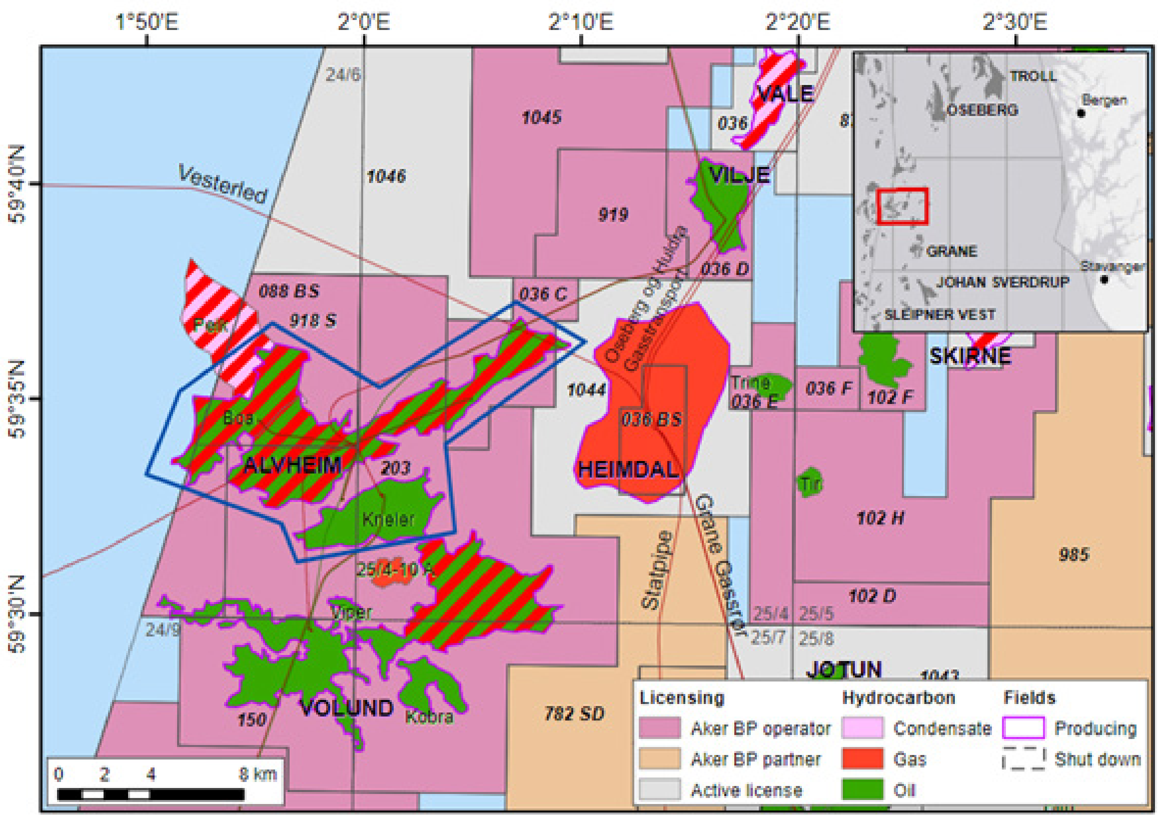


Figure 3.1 Alvheim and Viper/Kobra location map

Alvheim

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 2021 despite the Since last assessment, the two infill wells Kameleon Infill Mid (KA6) and Boa Attic South (B6) have gone from incremental profiles to part of base production.

A capacity debottlenecking of topside total gas and water handling is being finalized in late 2021 / early 2022. This will increase the total gas capacity from 3.84 MSm3/d to 4.4 MSm3/d and water handling from 32 ksm3/d to 36 ksm3/d.

Lifetime extension (LTE) has been sanctioned for the Alvheim FPSO, increasing the technical lifetime from 01.2034 to 01.2041. This has allowed a later economic cut-off (Cessation of Production, CoP) for most fields in the asset. The 2P CoP is calculated to 01.2039 for Alvheim Base and Kameleon Gas Blowdown, 2035 for Boa Base and 2034 for Kamelon Infill West.

The future Kameleon Gas Cap Blowdown project has been deferred from 2028 to 2034, due to the sanctioning of LTE.

The actual production in 2021 is ~3% above the oil 2P estimate for 2021 in Aker BP Reserves Certification 31.12.2020.

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

The recoverable volumes from Kameleon Infill West (infill well) are classified as «Reserves; Approved for Development» (SPE's classification system).

The recoverable volumes from Kobra East-Gekko (field development) are classified as «Reserves; Approved for Development» (SPE's classification system). Kobra East-Gekko (KEG) is described in more detail in section 3.2.

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 holding a 15 percent interest.

The Boa reservoir straddles the Norway-UK median line. The Boa reservoir is unitized 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

Production from Vilje started in 2008 and the plateau oil production rate was 5 000 - 6 000 Sm3/d until mid-2012. Water breakthrough occurred in mid-2011. VI1 is the main producer at the Vilje Field. It experienced water breakthrough in 2011 and since the middle of 2017 the well has been produced at maximum gas lift rates. VI1 produced less then expected in 2021 due to the watercut development. Well VI2 is being produced from the lower branch only, with stable oil rate and watercut. The upper branch of the well is watered out and was last produced in May 2018. This was also confirmed with 4D seismic from 2017, showing response of water replacing oil for this part of the reservoir. VI2 was shut in for a large part of 2021 due to challenges with slugging in the common flowline to the Alvheim FPSO. An upgrade of compressor (R100) has enabled production from VI2 as it is now better suited to handle the slugging. The well came back on production in October 2021, with lower water cut than seen on last production test. VI3 is connected to a limited reservoir volume and is only produced intermittently when production system constraints allow for it. Production and pressure behaviour indicate good aquifer support.

Lifetime extension (LTE) has been sanctioned for the Alvheim FPSO, increasing the technical lifetime from 2034 to 2041. The 2P Vilje CoP is calculated to 2039.

The actual production in 2021 is expected to be at the oil 2P estimate for 2021 in Aker BP Reserves Certification 31.12.2020. The recoverable volumes of Vilje are classified as “Reserves; On Production” (SPE’s classification system).

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.

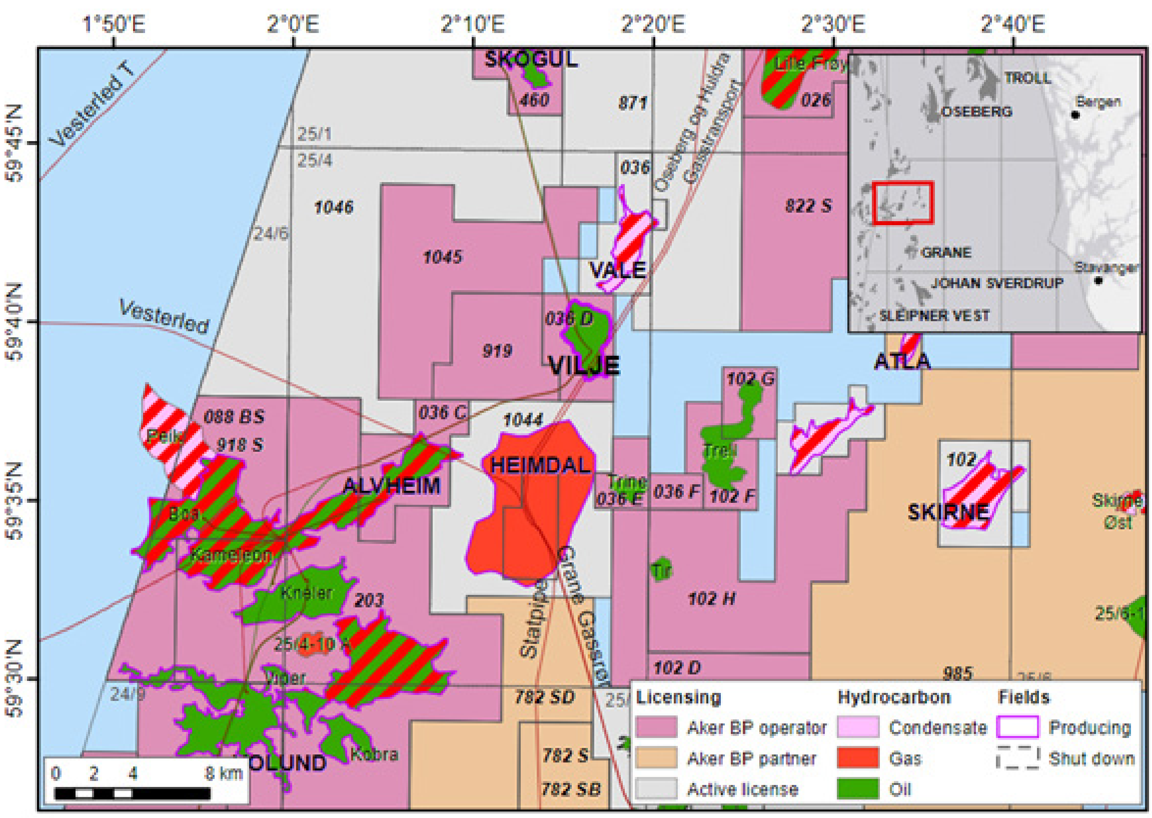


Fig. 3.2 Vilje location map

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. 4.3. 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 1 995 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. Two of the original producers has been side-tracked, one in 2019 and one in 2021.

Status

The Volund Field is on decline with an average field watercut of 80%, up from 65% as of 31.12.2020. Production in 2021 was from four producers; P9H, P10BH (tri-lateral well), P3BH and P5BHT4. P6 is an intermittent producer, but the well has not been active in 2021. P5BHT4 was drilled in September 2021 and targets remaining oil in eastern dyke above P5AH (shut in since 2016). After three unsuccessful sidetracks, T4 penetraded the reservoir primarily as expected after entering the injectite wing (i.e. good match of sand to seismic amplitudes). The well encountered an oil column in the heel close to prognosed high side estimate, but there are uncertainties (and associated risks) with regards to the distance to water, especially in the toe of the well. Production from P5BHT4 started in November 2021 and as expected the well has high productivity, however the GOR is significantly higher than expected (completed in gas zone in toe, and placed close to gas-oil contact). The water injector P4AH is active and has been injecting approximately 2 500 Sm3/d at 92 bar wellhead pressure for a long time.

Lifetime extension (LTE) has been sanctioned for the Alvheim FPSO, increasing the technical lifetime from 2034 to 2041. The 2P Volund base CoP is calculated to 2039 and 2034 for infill well P5BHT4.

The actual production in 2021 is expected to be 12% above the oil 2P estimate for 2021 in Aker BP Reserves Certification 31.12.2020. This is mainly due to better performance of P3BH than expected. The recoverable volumes of Volund are classified as "Reserves; On Production" (SPE's classification system).

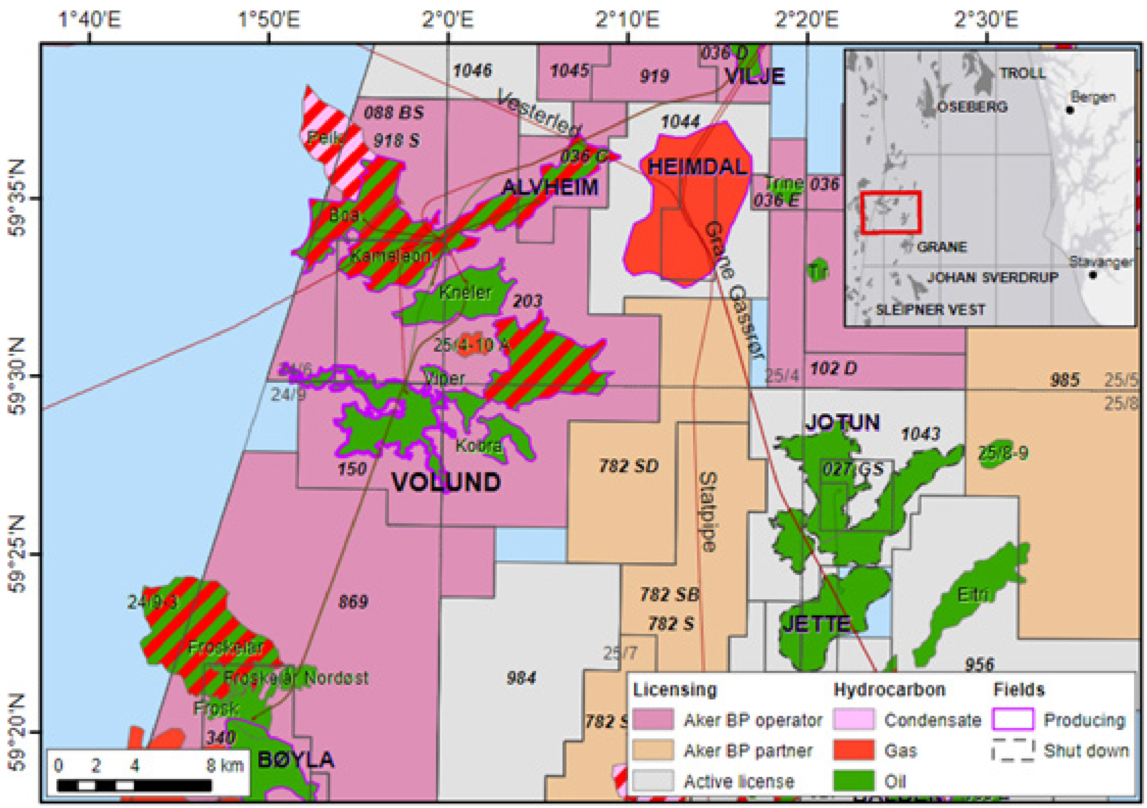


Fig. 3.3 Volund location map

Aker BP is the operator and holds a 65 percent interest in Volund, while Lundin Energy 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 had a longer shut-in period starting from 21 August 2019 to enable test production from the Frosk Test Producer. Testing activities from the Frosk reservoir, located in the same production license, had been sanctioned by the license partnership and approved by the MPE until response of submitted PDO of the Frosk development. Bøyla produced large parts of 2021 while Frosk Test Producer was shut-in awaiting an intervention job that took place in November 2021. The Bøyla and Frosk wells are produced to achieve maximum short and long term value within the booking capacity and commercial agreement the license falls under. This means poorer wells will be intermittently taken off stream.

Bøyla production was consistent with production before the long shut-in during Frosk Test production with a minor flush-out effect over a few days.

Lifetime extension (LTE) has been sanctioned for the Alvheim FPSO, increasing the technical lifetime from 2034 to 2041. The 2P Bøyla CoP is calculated to 2039.

The actual production in 2021 is expected to be 40% above the 2P oil estimate for 2021 in Aker BP Reserves Certification 31.12.2020 due to longer than planned shut-in of the Frosk test producer, enabling more production from Bøyla. The recoverable volumes of Bøyla are classified as “Reserves; On Production” (SPE’s classification system).

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

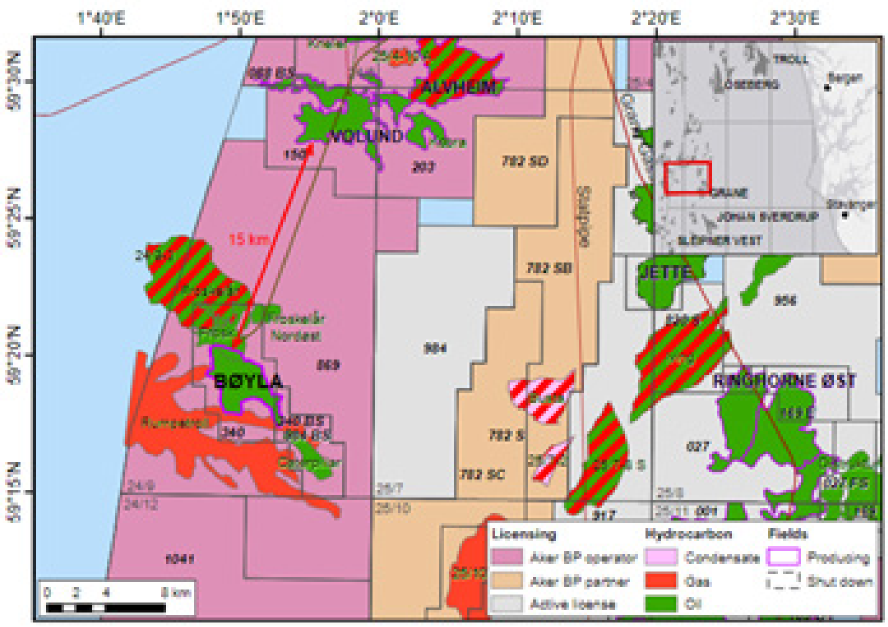


Fig. 3.4 Bøyla location map

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. 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

The Frosk Test Producer did not produce large parts of 2021 due to failure to pass a routine well integrity test. Large amounts of sand was also observed topside during this time. A successful intervention job was performed in November 2021, restoring the integrity of the well by replacing a leaking gas-lift valve. Well surveillance was also performed to identify the most likely source for the sand production. The sand production is most likely from the main bore, damage believed to have occurred on the main bore completion during drilling of the Frosk test lateral. The Frosk Test main bore will most likely remain closed. The impact of reserves is expected to be small and a significant part captured by one of the Frosk Development wells.

Lifetime extension (LTE) has been sanctioned for the Alvheim FPSO, increasing the technical lifetime from 2034 to 2041. The 2P Frosk CoP is calculated to 2039.

The actual production from Frosk Test in 2021 is expected to be 55% below the 2P oil estimate for 2021 in Aker BP Reserves Certification 31.12.2020 due to shorter production period than expected.

The Frosk Development project passed DG3 in September 2021 and and the PDO was submitted the same month. Planned production start is Q1 2023.

The recoverable volumes of Frosk Test are classified as "Reserves; On Production" (SPE's classification system). The recoverable volumes of Frosk Development are classified as "Reserves; Justified for Development" (SPE's classification system).

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

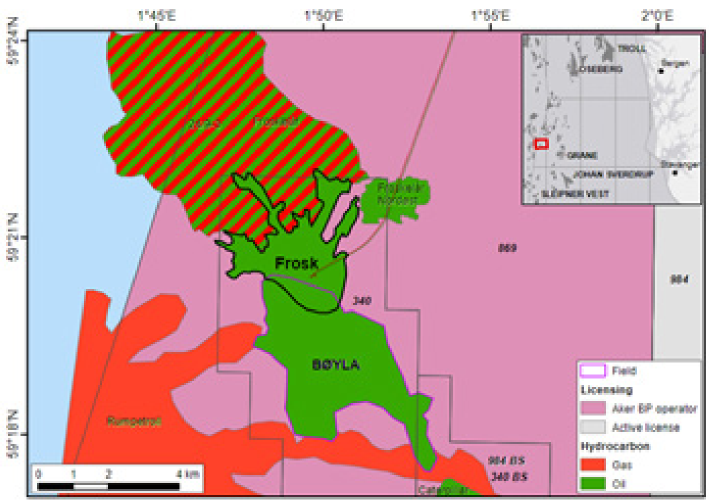


Fig. 3.5 Frosk Field location map

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, and production started in March 2020.

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

The bilateral producer (25/1-S-1 AY1H T3 & AY3H) started production in March 2020 and the well had higher decline in 4Q 2020 than forecasted due to watercut development. However, due to available capacity on the flowline (with 2 out of 3 wells at Vilje shut in during the most part of 2021) and higher performance, Skogul is ahead of the production permit for 2021. Production has been optimized based on the combined Vilje/ Skogul production permit, limited on liquid rate and gas lift. The actual production in 2021 is expected to be 3% above the oil 2P estimate for 2021 in Aker BP Reserves Certification 31.12.2020.

Lifetime extension (LTE) has been sanctioned for the Alvheim FPSO, increasing the technical lifetime from 2034 to 2041. The 2P Skogul CoP is calculated to 2039.

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 (PI001B, 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 is produced by natural depletion where the major driving force is aquifer drive. In total eleven producers (ten 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 mechanical sand control and ICD completions while the injectors have cemented perforated liners, except two 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. Hanz development is discussed in Chapter 3.2.1.

The Ivar Aasen 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 December 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.

Ivar Aasen

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. In 2018, two new water injection wells were drilled in 2018, named D-6 and D-7. In 2019, two new producers were drilled; D-18 in the underlying Alluvial Fan formation and one branched Skagerrak 2 producer in the East (D-15). In Q1 2021, two new producers started production; D-17 in Alluvial Fan and D-20 in Skagerrak 2. Well D-13 was also drilled, targeting the Braid Plane reservoir zone. This well was considered dry as the permeability, hence productivity, was too low. One injector supporting drainage in Skagerak 2 (D-4A) commenced injection in Q3 2021.

In place volumes and reserves, including new structural interpretation post D-13, D-17 and D-20, was updated June 2021 based on model history match and uncertainty study. The reserves estimate on Ivar Aasen was reduced about 16% from Q4 2020 to Q4 2021.

Main causes for change in reserves;

- Lower in place volumes in SK2 and Sleipner
- Higher complexity of SK2 formation, lower recovery factor

Net production at Ivar Aasen averaged 16.7 mboepd in 2021. This was about 6% lower than expected mainly because of power failure and no injection for approximately two months (9 Sep -10 Nov 2021). Cessation of production (CoP) from the Ivar Assen field is expected EOY 2035.

The recoverable volumes of Ivar Aasen 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).

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 Energy (1.3850 percent) and OKEA (Norge) AS (0.5540 percent).

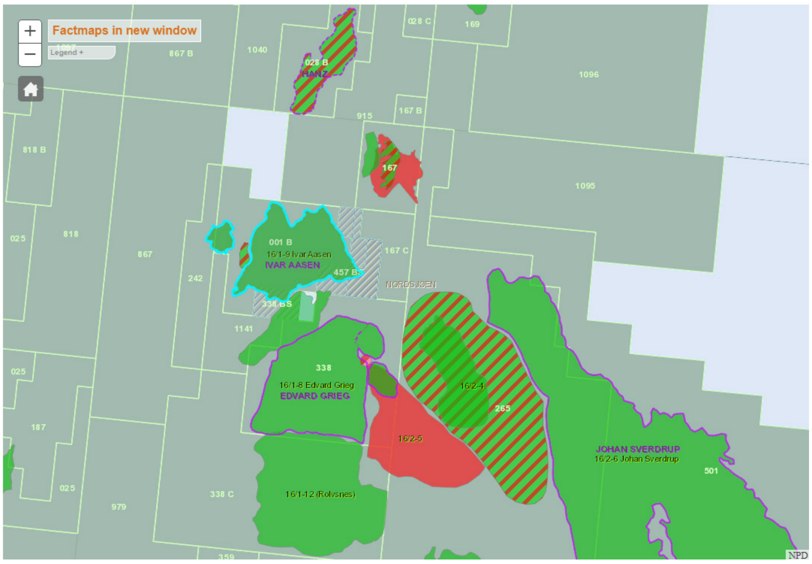


Fig. 3.6 Ivar Aasen Unit and Hanz location map

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 located 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 and 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) were 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 taken into use. 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 finished P&A work in 2021.

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 56 active producers and nine active injectors. During 2021 Valhall drilled three new wells on North Flank that are now on production/injection. A fish in N-8 liner was successfully retrieved, and the well was put on production in 2021. A redrill of N-8 was consequently not needed, and instead a new production target was sanctioned, drilled and put on production in 2021 (N-3B). N-4 was put on injection in 2021 and volumes moved to "On Production". The Valhall Sulphate Removal Unit (SRU) project was sanctioned in 2021 and will protect base production for the long term water injection scheme. A new infill well from West Flank platform was sanctioned in 2021 planned to be drilled in 2022.

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

Valhall WP Life Time Extension (Part of the NCP-project) and Valhall Flank West V-11 have been classified as «Reserves; Approved for Development».

The 2P/P50 production profile indicates an economic cut-off (CoP) in 2049. Net production to Aker BP averaged 46 mboepd in 2021.
Aker BP holds 90 percent interest in the Valhall field, with Pandion holding the remaining 10 percent.


Valhall

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. Since 2012 there has, however, been no production from the Hod facility. 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 was sanctioned in 2020. The project consists of building a copy of the Flank West Platform with 12 well slots, and an initial drilling phase consisting of six production wells. Topside platform was installed in 2021 and as of 31.12.2021 three of the six development wells have been drilled. First production is assumed to be 1Q 2022.

Hod field CoP is estimated to be 2049, as for the Valhall field.
Net production to Aker BP averaged 0.5 mboepd in 2021.
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.

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.

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

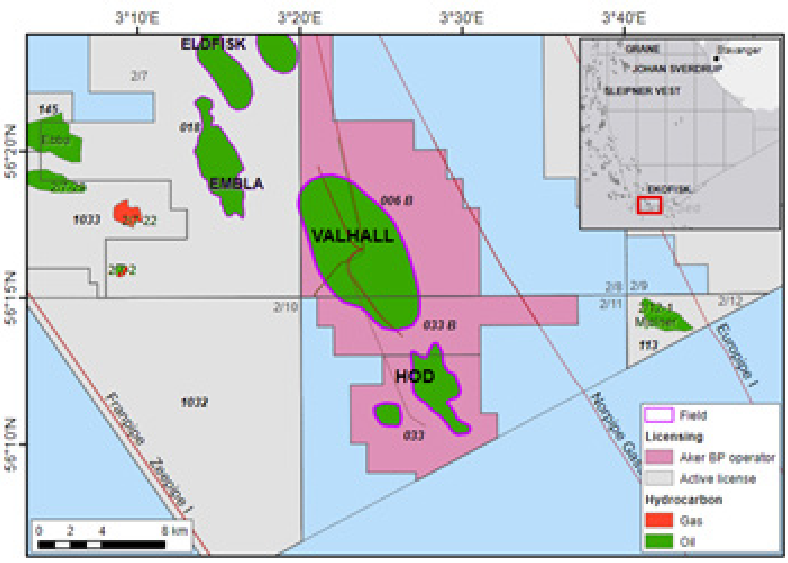


Fig. 3.7 Valhall and Hod location map

Ula

with water and gas injection in the deeper layer. A separate Triassic reservoir underlies the main reservoir.

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.

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

49 wells have been drilled on Ula since start-up of which nine 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.

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 4.5 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.

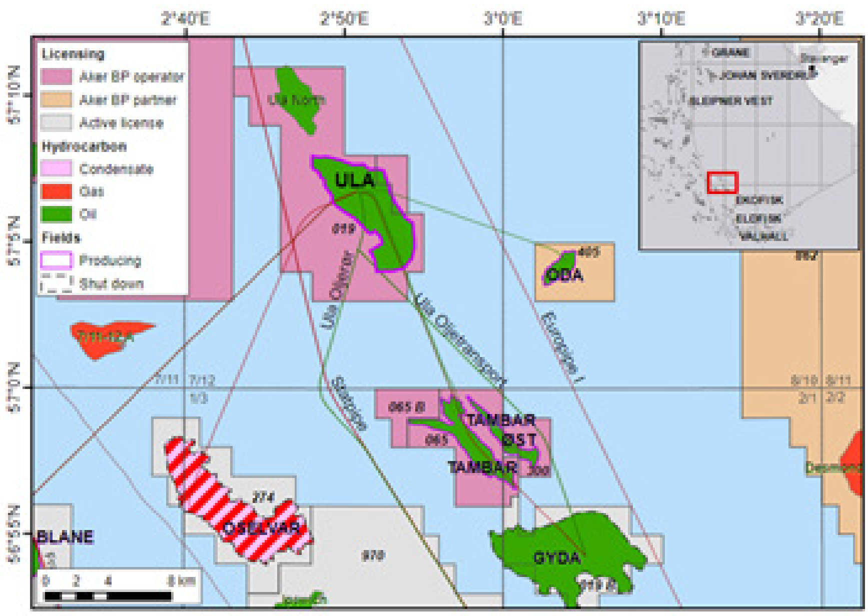


Fig. 3.8 Ula, Tambar and Tambar East location map

3.1.11 Tambar (PL065)

Tambar is an oil field about 16 kilometers 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 meters.

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 six producers have been drilled on Tambar since start-up of which three 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 was drilled in 2021 to replace K-2A in the northern area of the field. However, this well has struggled with lack of sufficient reservoir pressure, similarly to the previous K-2A. The Tambar team continues to evaluate potential infill drilling targets.
Tambar field CoP is estimated to be 2028.

The recoverable volumes of Tambar are classified as "Reserves; On Production" (SPE's classification system). Net 2021 production to Aker BP from Tambar averaged approximately 2.4 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 meters 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. However, the team is also looking into alternatives, like a deep sidetrack to the existing producer. This work has recently been kicked off and is still at an early stage.

There was no production from Tambar East in 2021.

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), PGNiG Upstream Norway AS (5.44 percent) and KUFPEC Norway AS (0.80 percent).

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. 3.10. The Skarv unit is a joint development of the Skarv and Idun, Gråsel 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. 3.10, but is described here together with Ærfugl.

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 twentytwo

Skarv FPSO

wells. Distribution between the well types are: Six oil producers, four gas producers, four gas injectors in Skarv/Idun, in addition one oil producer and a commingled injector in Gråsel and seven Ærfugl gas producers). Gråsel and Ærfugl are described in separate sections in this chapter.

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 faults. However, production experience indicates that the fault between B and C segment may 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. Two gas wells are currently producing in Garn A. The two Idun wells are shut in due to back pressure from Ærfugl wells and are planned to restart production when moving Ærfugl production over to the low pressure separator, currently assumed in 2026. All gas wells are on decline.

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 2021.

The western Idun well, D02, is the only well that has had significant 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.

Net production from Skarv averaged 22.1 mboepd in 2021. In total, Skarv, Gråsel, Ærfugl and Ærfugl Nord produced 29.4 mboepd. Economic cut-off (CoP) for the Skarv-area is estimated to be 2034 for the 2P-case.

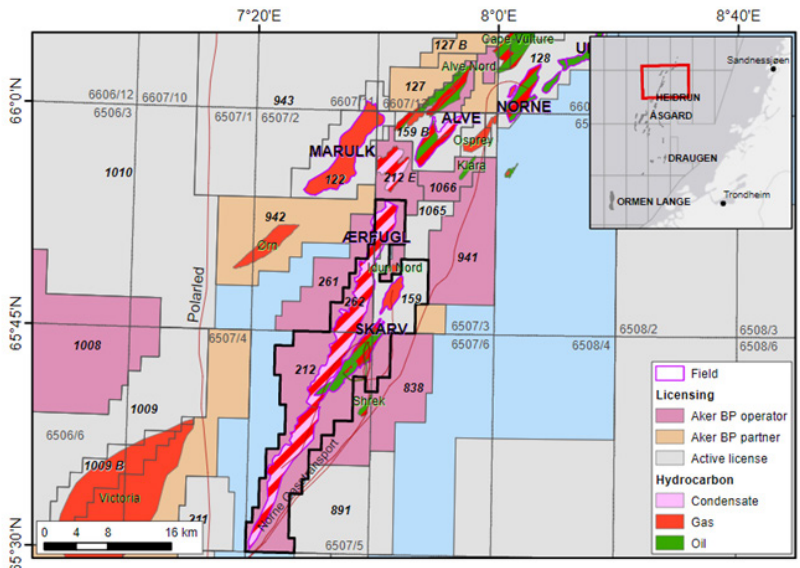


Fig. 3.9 Skarv and Ærfugl location map

The recoverable volumes of Skarv and Idun, including Gråsel, Ærfugl and Ærfugl Nord, 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 Norway AS (11.9175 percent).

3.1.14 Gråsel

Discovery

Skarv well 6507/5-1 also found oil in Cretaceous sandstones of Cromer Knoll Group in Lange Formation which is the Gråsel discovery.

Reservoir

The Gråsel discovery is situated stratigraphically above the Skarv Field. Shallow marine sandstones of Late Cretaceous age, Lange formation, forms the main reservoir. The field exhibits high reservoir porosity and permeability (ca. 1-5 D). The Gråsel field has been defined by combined structural and stratigraphic trap, pinching out to North East and dip-closure in all other directions. The reservoir is tecturally complex sansdstonewith thin argillaceous layer, crossbedding and bioturbation.

Development

The Gråsel reservoir is developed with one oil producer (B-7 AH) and one gas injector commingled with Skarv Tilje (J-3 H), tied back to the FPSO.

Status

B-7 AH started producing 14 June 2021 with oil rates around 2000 Sm3/d. First injection in J-3H in Gråsel was 21 September 2021 and producer-injector communication was confirmed after 3 months.

Gråsel production averaged at 1.3 mboed (net average start up June 2021).

3.1.15 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. 3.10.

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

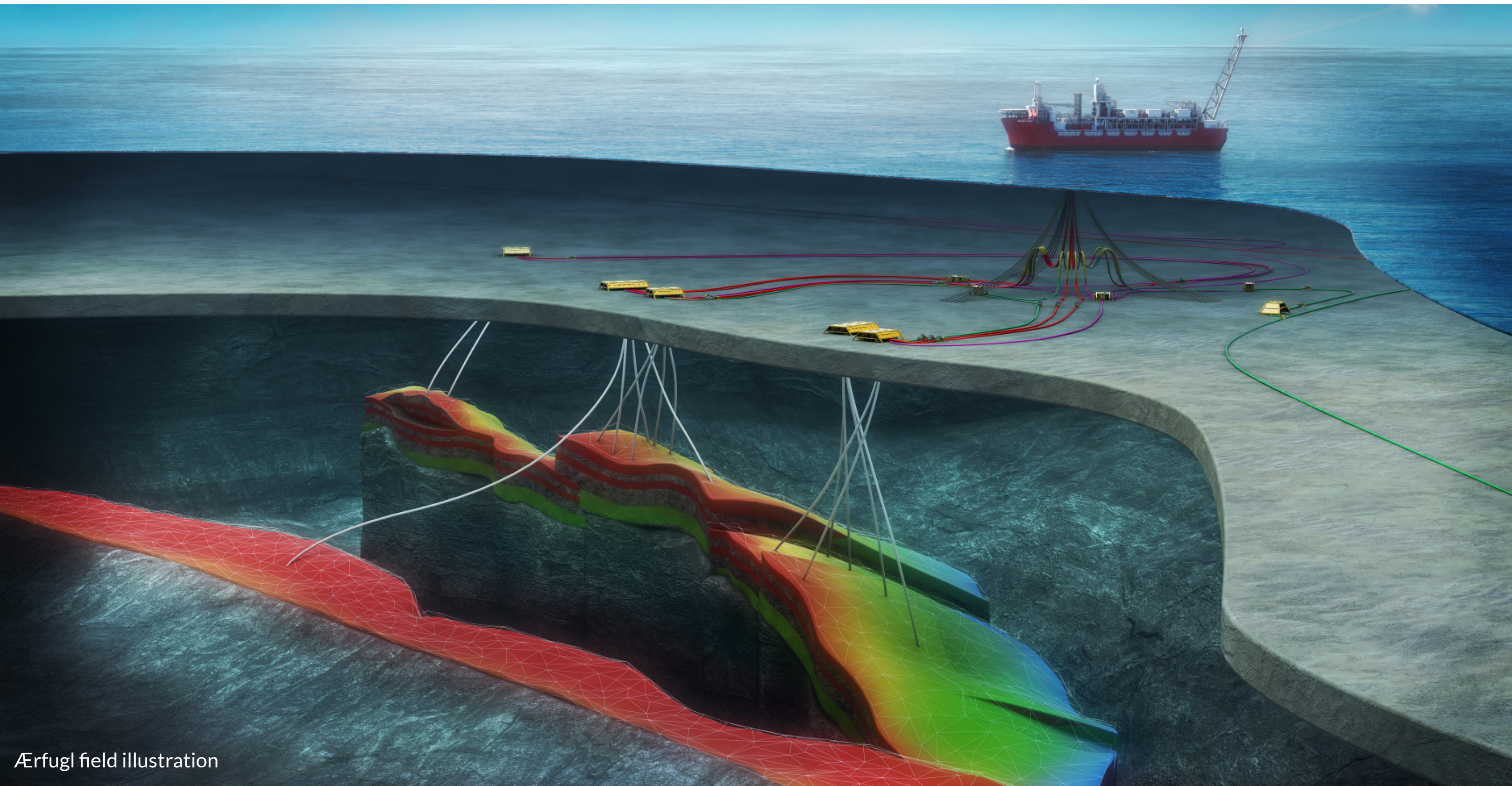
The Ærfugl Field was discovered in 2000 with well 6507/5-3. It was appraised in 2010/2011 by wells 6507/5-6 S, 6507/5 A-1 H, 6507/5 B-5, and in 2012 by well 6507/3-9 S for Ærfugl Nord (previously called Snadd Outer.

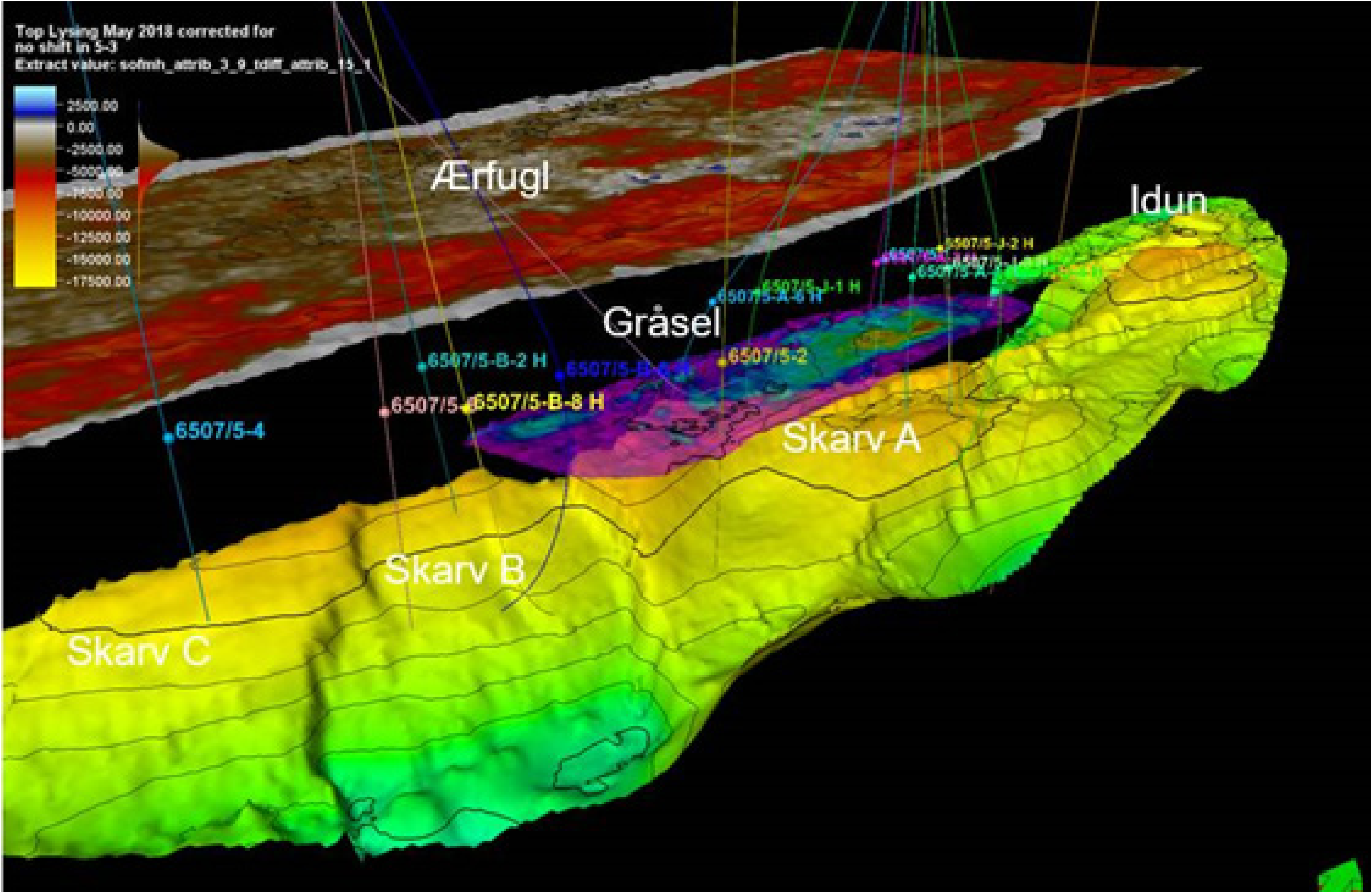
Reservoir

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 and developed with six highly deviated subsea wells tied into the Skarv FPSO with heated flowlines. Phase I came on production in November 2020 and includes three wells on Ærfugl South. Phase II includes three wells towards the north , with first well already on production in 2020, and the two remaining wells online end of 2021. One of the Phase 2 wells, G-1H, lays in the Ærfugl Nord license.


Ærfugl field illustration



Status

The A-1 H test producer in Ærfugl started gas production February 2013, and has produced stable 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. Phase1 wells were drilled and put on production in November 2020, two of these wells, L01 H and M01 H, have also experienced water breakthrough. The two last wells of Phase 2, including Ærfugl Nord (G-1H) has not seen water yet.

The D04 and L01H wells were worked over in 3Q 2021 in an attempt to shut off water producing zones. Success in L01H has been confirmed. The intervention has not, however, been successful in D04. The well has been a challenge to start after shut-ins and incremental reserves from this well have been risked accordingly.

Latest model update on Ærfugl includes the most important new data from drilling the two recent wells in the north. The updated model ensemble has on average 15% less GIIP overall and 25% less GIIP in Ærfugl Nord with new structural realizations being the largest contributor. Pressure mapping is also showing more complexi connectivity. Based on this, the overall Ærfugl reserves have been reduced by 18% .

Net production in 2021 from the Ærfugl was approximately 5.2 mboepd. Ærfulg Nord production was approximately 0.6 mboepd.

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

3.1.16 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.3.11. 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 generally 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 - 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 center with four platforms: a processing platform, a drilling platform, a riser and export platform and a living quarters and utilities platform, see Fig. 3.12. 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 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 center, 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.

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 535 000 bbl/d. oil 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 has produced with high regularity. The oil production

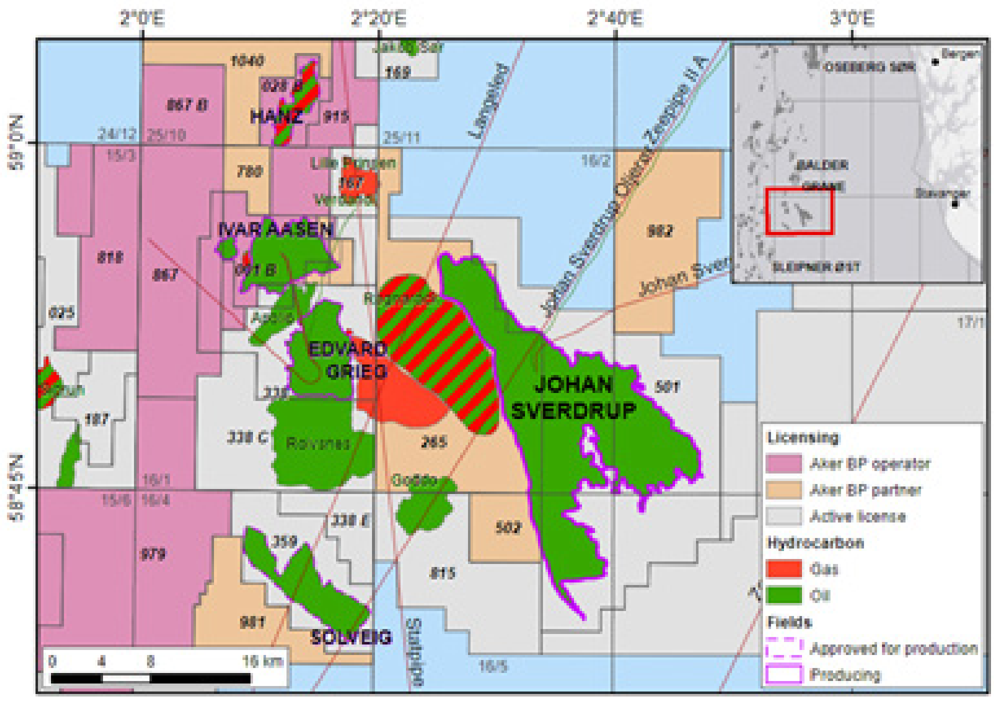


Fig. 3.10 Johan Sverdrup location map

Fig. 3.11 Johan Sverdrup field centre

capacity has been increased to production level of 535 000 bbl/d (approximately 65 000 boe/d net to Aker BP) from 14 producers supported by 14 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 have been identified which may increase the reserves on Johan Sverdrup. The most promising is infill drilling.

Estimated economic cut-off (CoP) for the Johan Sverdrup field is in the 2P-case year-end 2058.

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 Energy (20 percent), Petoro (17.36 percent) and Total (8.44 percent).

Johan Sverdrup

3.1.17 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. 3.13). 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 485 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 ahead of plan. 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. With pressure support the wells delivered the planned 35 mboepd with B-1 H as the main producer. B-3 AH did not deliver as expected, likely a consequence of position in fault, reduced reservoir thickness and damage area in the fault block.

In 2021, Oda net production was 1.3 mboepd reflecting well B-1 AH production decline and associated increase in water cut. September onwards, B-3 AH produced at higher draw down and near doubled production following positive field trials on asphaltene onset pressure (AoP).

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

Not included here is a side-track well option (from B-1 H) currently under evaluation for decision in 2022. 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.

Estimated economic cut-off (CoP) for the Oda field is in the 2P-case year-end 2032.

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).

3.1.18 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 2024. The reserve estimates reflect reallocation at Heimdal. Net production in 2021 was 0.08 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.

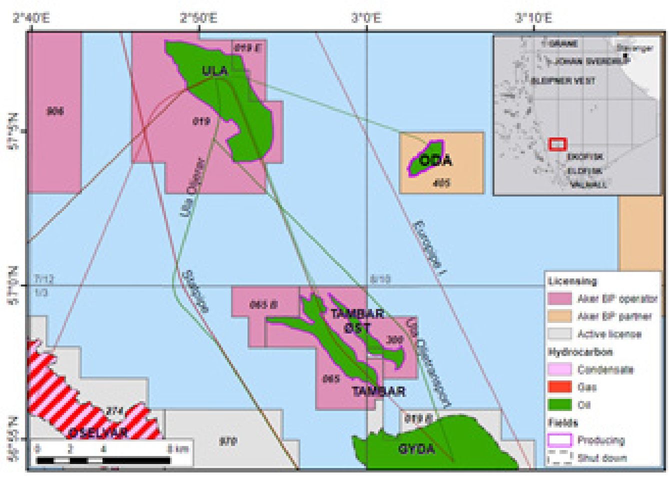


Fig. 3.12 Oda location map

3.2 Development Projects

3.2.1 Hanz

Hanz is an oil and gas accumulation discovered by well 25/10-8 in 1997, 12 km north of the Ivar Aasen PDQ. Hanz consists of Draupne formation sandstones, see Fig.3.6.

Discovery

The Hanz discovery was made by the exploration well 25/10-8 in 1997 by Exxon. A production test (DST) was performed on the discovery well. The Hanz reservoir was further apprised by wells 25/10-16 S, 25/10-16 A and 25/10-16 C by Aker BP in the 2018 appraisal campaign.

Reservoir

The Hanz discovery consists of Upper Jurassic Draupne sandstones at about 2 400 m depth. The depositional environment is gravity flow turbidites originating from the Utsira High to the east. The reservoir has several overlying thin sands each with a thickness of 1-7 meters, separated by thin shale layers. Both DST, core samples and logs show excellent reservoir quality with highly porous multi-Darcy sandstone. The reservoir pressure is slightly below hydrostatic. Vertical communication between sand bodies is believed to be poor. Lateral communication is in general good, but barriers might exist.

The Hanz Heimdal aquifer reservoir is about 350 m above the Hanz Draupne reservoir. The Heimdal reservoir is a highly porous multi-Darcy homogeneous sand package of about 60 m thickness and extends in a very large area of the North Sea. The reservoir pressure is slightly below hydrostatic.

Development

Hanz will be produced through a 14 km pipeline to Ivar Aasen. The drainage strategy is pressure support by a cross flow water injector taking water from the Heimdal aquifer reservoir located about 350 m above the Hanz Draupne reservoir. Both the producer and the cross flow water injector will have about 2 000 m horizontal well reservoir section in the Draupne reservoir. The wells will be about 700 m apart and aim to penetrate all mayor hydrocarbon sands on the Draupne Horst structure. The wells will be drilled as satellites in July 2023 and are planned online 1Q 2024.

Status

The Hanz development was sanctioned by the license in December 2021. The recoverable volumes of Hanz are classified as "Reserves; Approved" (SPE's classification system).

Aker BP holds 35 percent in Hanz. The remaining shares are held by Equinor (50 percent) and Spirit Energy (15 percent).

3.2.2 Kobra East and Gekko (KEG)

The KEG discoveries are located approximately 10 km south-east of the Alvheim FPSO. Figure 3.16 Alvheim and Viper/Kobra location map.

Discovery

The Gekko oil and gas discovery was made in 1974 by well 25/4-3 in the Heimdal Formation. Kobra East was discovered in 2016 through drilling an extension of the Kobra well 24/9-P-8 AY1H.

Reservoir

The Gekko reservoir consists of Heimdal Fm sands, in a submarine fan system south of and analogous to the Alvheim reservoir. Gekko is defined by two subtle four-way closures, Gekko South with blocky stacked sandy turbidites and high net/gross and Gekko North with channel sands interbedded with more fine grained deposits. The reservoir is all-over in pressure communication within Heimdal and to the large aquifer. The Kobra East reservoir is analogous to Viper and Kobra and is consisting of a main injection sill overlain by dykes and wings. The reservoir properties are excellent.

Development

The KEG field development is planned as a subsea tie-back via the Kneler B manifold to the Alvheim FPSO. Gekko is planned to have a four-slot manifold in the south and a two-slot manifold in the north. The drainage strategy is to produce oil from three tri-lateral wells (two into Gekko South and one into Gekko North), followed by a gas blowdown phase produced through two sidetracks. The main drainage mechanism for the oil phase is natural pressure depletion, with a strong aquifer drive and some gas cap expansion. To achieve good drainage of the 6-7 m oil column, each of the nine laterals is planned to have a completion length of about 4000 m (with AICDs) and will be placed about 2 m below the gas-oil contact. Kobra East is to be developed by a tri-lateral well drilled from the same four-slot template as Gekko South. Pressure support is provided by the large Heimdal aquifer. The Kobra East well will be able to continue production during Gekko gas blowdown.

Status

The KEG field development passed DG3 and submitted the PDO in June 2021. KEG phase 1 (first oil) is scheduled to January 2024, while KEG phase 2 (first gas) is scheduled to Q4 2030 - Q1 2031. The recoverable volumes of KEG are classified as "Reserves; Approved " (SPE's classification system).

Aker BP holds 65 percent in KEG. The remaining shares are held by ConocoPhillips Skandinavia AS (20 percent) and Lundin Energy (15 percent).

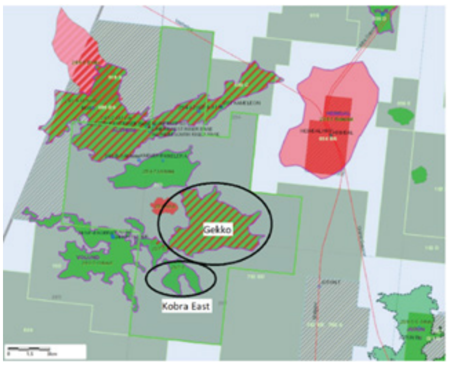


Figure 3.13 Kobra East and Gekko location map

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 567 mmboe to 1 329 mmboe, with a 2C volume of 1 022 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 NOAKA Area (North of Alvheim Krafla Askja) includes ten discoveries over a 60 km long trend, south of Oseberg and North-east of Alvheim, See Fig. 4.1. DG2 was passed for the NOA and Fulla discoveries in September 2021 and for the Krafla area in November 2021 based on a concept with a PdQ platform located centrally (Aker BP operated), an Unmanned Processing Platform (Equinor operated) on the Krafla and one wellhead (NUI) platform on Frøy and a total of nine subsea templates were approved.

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 87.7 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 87.7 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 87.7 percent interest in the Langfjellet discovery.

Rind (PL442, 25/2-5) was discovered in 2010. Aker BP holds 87.7 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 47.7 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.

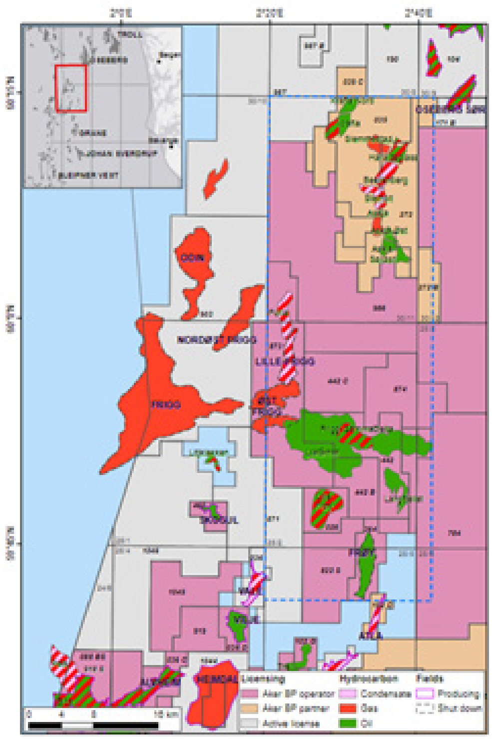
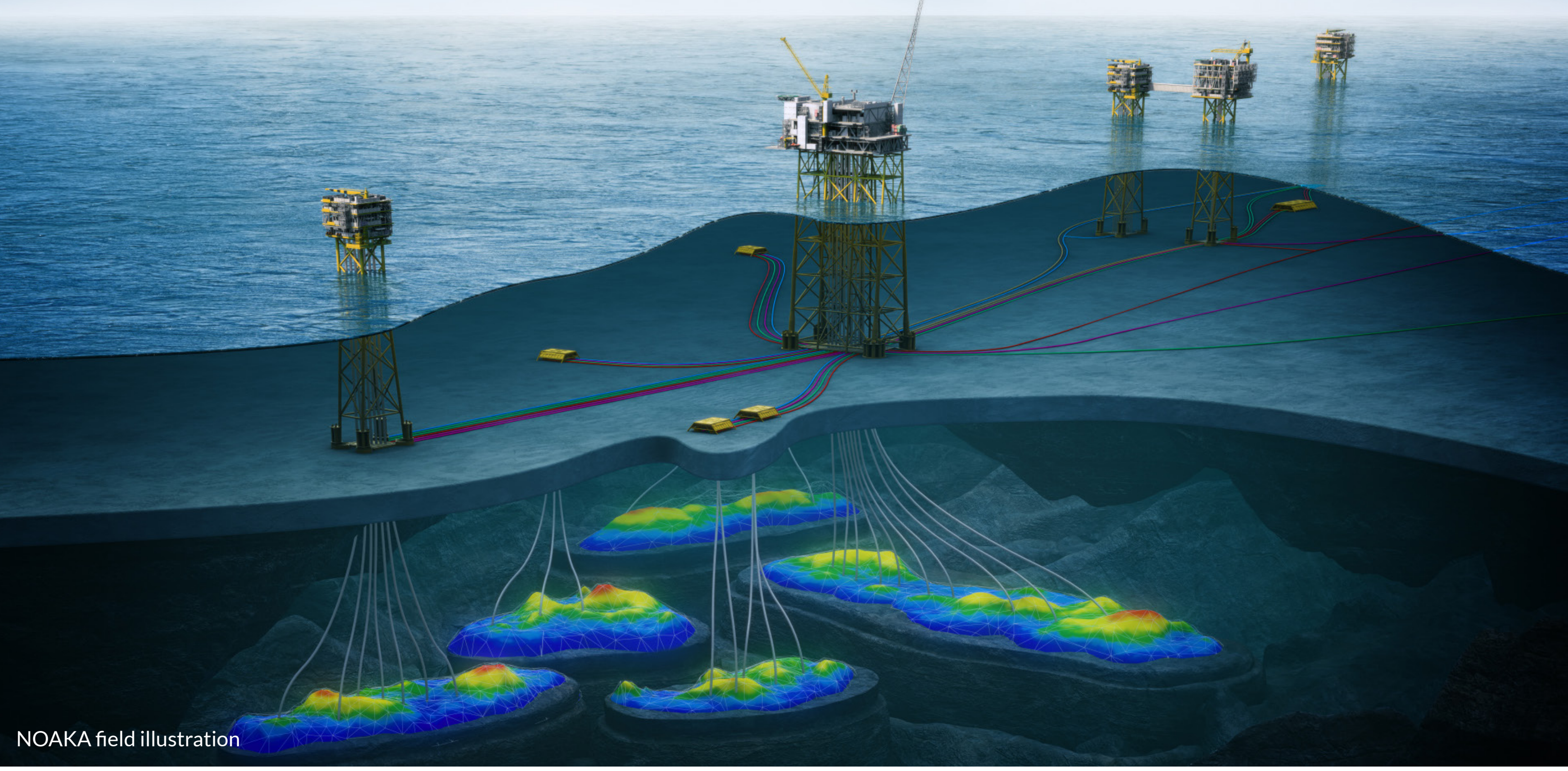


Fig. 4.1 The NOAKA area (North of Alvheim Krafla Askja)



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 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 estimated to around 600 mmboe. The net resource potential for Aker BP for the NOAKA area ranges from 280 to 590 mmboe.

4.1.2 Alvheim Area

The contingent resources in resource category 4 and 5 («Development Pending» and «Development not Clarified or on Hold») in the Alvheim area are:

- Trell and Trine project – plan to pass DG3 in June 2022
- Froskelår development
- Froskelår North East

Several rsource category 7 projects exist as well, among them Caterpillar, Rumpetroll and Kneler NE. The combined net contingent resource potential for the Alvheim Area ranges from 17 to 78 mmboe.

The Alvheim Area is actively being worked to add additional infill and development opportunities from resource category 7 and have a focused Exploration strategy for potential prospect opportunities.

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 4 and 5 («Development Pending» and «Development not Clarified or on Hold»), Fig. 1.1:

- King Lear
- Valhall Flank Additional infill drilling
- Valhall Flank West Water Flooding
- Valhall New Central Platform
- Valhall New Central Platform Technology Upside
- Valhall redrills and Late Side-tracks
- Hod Field development expansion
- Valhall Extended production
- Part of Valhall and Hod Diatomite developments

Some of these projects are expected to be sanctioned within 2022, while other will need further maturing prior to sanction.

Several projects in resource category 7 have alse been identified, including further development of the diatomite, infill driolling and extended waterflood, EOR, etc. Pending further maturation, these projects are at present not included in the Valhall area contingent resources estimate below.

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 170 to 435 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, 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.

Infill wells in Tilje C, B/C and Ærfugl are also being considered.

The combined net resource potential for the Skarv Area ranges from 32 to 106 mmboe.

4.1.5 Ula Area

The Ula areas is very mature. Even so, the Ula field has identified and is currently evaluating several projects, including import of external gas to improve WAG efficiency, extended field life, gas blowdown, Ula Triassic infil drilling and an additional unit F producer.

On Tambar, projects related to possible additional drilling and to injection have been identified.

The combined net resource potential for Aker BP for the Ula Area ranges from 6 to 76 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 3 600 m TVD MSL in the northern North Sea. The reservoir is high pressure (630 bar) with somewhat challenging fluid characteristics (high pour point temperature, unstable asphaltene and H2S contend).

Garantiana was discovered by 34/6-2S and 2A in 2012 (central area) and appraised 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 12 to 25 mmboe to Aker BP. The discovery will most likely be developed as a subsea tie-back to Snorre B. Current plans indicate production start in 2029.

An exploration well was drilled in Q2 2021 in the Garantiana West segment. This is an oil discovery in the Cook formation with good reservoir quality. There is an improved fluid type observed at Garantiana West. Volume estimates indicate a net resource potential ranging from 2 to 4 mmboe to Aker BP. Garantiana West will most likely be developed as a satellite structure tie-in to Garantiana.

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

4.1.7 Other

Other resources classified in the resource classes “Development Pending” and “Development not clarified or on hold” includes infill wells on Ivar Aasen and the Lille Prinsen discovery.

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 2.0 percent, a long-term exchange rate of 8.0 NOK/USD (8.56 and 8.5 in 2021 and 2022, respectively), and a long-term oil price of 65 USD/bbl (real 2021 terms), down from a 2021 oil price estimate of 70 USD/bbl and 2022 estimate of 67 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.

Karl Johnny Hersvik
CEO, Aker BP

Photo credits:

Headspin, Woldcam, Equinor, IKM
Anne Lise Norheim, Øyvind Gravås, Jan Arne Wold, Even Kleppa, Stuart Conway

Aker BP ASA

Fornebuporten, Building B
Oksenøyveien 10
1366 Lysaker

Postal address:
P.O. Box 65
1324 Lysaker, Norway

Telephone: +47 51 35 30 00
E-mail: post@akerbp.com

www.akerbp.com