Aker BP

ANNUAL STATEMENT OF RESERVES 2018

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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.

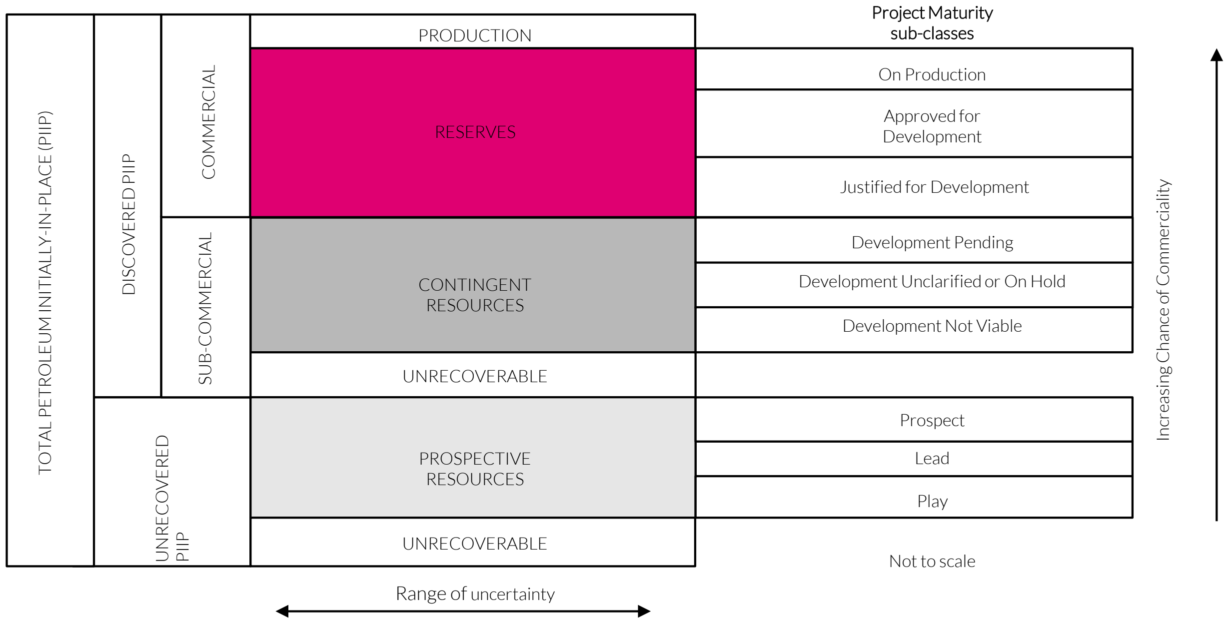

Fig. 1.1 SPE reserves and recourses classification systen

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 40 fields/projects containing reserves, see Table 2.1 . Out of these fields/projects, 17 are in the sub-class «On Production»/Developed, 19 are in the sub-class «Approved for Development»/Undeveloped and four are 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 Base	65 %	Aker BP	On Production	Including Kameleon and Kneler
Boa Base	57.6 %	Aker BP	On Production	Norwegian part
Vilje Base	46.9 %	Aker BP	On Production	
Volund Base	65 %	Aker BP	On Production	
Bøyla Base	65 %	Aker BP	On Production	
Atla Base	10 %	Total	On Production	
Ula Base	80 %	Aker BP	On Production	
Ula Phase 3 drilling	80 %	Aker BP	On Production	
Tambar Base	55 %	Aker BP	On Production	
Tambar East Base	46 %	Aker BP	On Production	
Valhall Base	90 %	Aker BP	On Production	
Hod Base	90 %	Aker BP	On Production	
Skarv Base	23.8 %	Aker BP	On Production	
Ærfugl A-1H	23.8 %	Aker BP	On Production	
Ivar Aasen Base	34.8 %	Aker BP	On Production	
Gina Krog Base	3.3 %	Equinor	On Production	Production start 2017. Moved from Approved for Development
Enoch Base	2 %	Repsol Sinopec	On Production	No reserves reported in 2018 due to well integrity uncertainties

Undeveloped Reserves				
Johan Sverdup	11.573 %	Equinor	Approved for Development	Phase 2 PDO based on WAG submitted 2018
Hanz	35 %	Aker BP	Approved for Development	
Alvheim Kameleon Gas Cap Blowdown	65 %	Aker BP	Approved for Development	
Alvheim Kameleon infill S	65 %	Aker BP	Approved for Development	
Frosk Test Production	65 %	Aker BP	Approved for Development	Six months test production approved
Skogul	65 %	Aker BP	Approved for Development	
Volund Sidetrack North	65 %	Aker BP	Approved for Development	
Valhall Flank North Infill drilling	90 %	Aker BP	Approved for Development	
Valhall Flank North Water Injection	90 %	Aker BP	Approved for Development	
Valhall Flank South Infill drilling	90 %	Aker BP	Approved for Development	
Valhall Flank West Project	90 %	Aker BP	Approved for Development	
Valhall IP drilling programme	90 %	Aker BP	Approved for Development	
Ula drilling phase 1	80 %	Aker BP	Approved for Development	
Tambar K2 Workover	55 %	Aker BP	Approved for Development	
Tambar Artificial Lift	55 %	Aker BP	Approved for Development	
Ærfugl Phase 1	23.8 %	Aker BP	Approved for Development	
Ærfugl Phase 2	23.8 %	Aker BP	Approved for Development	
Ærfugl Outer	30.0 %	Aker BP	Approved for Development	
Oda	15.0 %	Spirit Energy	Approved for Development	
Ivar Aasen Skagerak Infill Well	34.8 %	Aker BP	Justified for Development	
Ivar Aasen Alluvial Fan Infill Well	34.8 %	Aker BP	Justified for Development	
Frosk test production Part 2	65 %	Aker BP	Justified for Development	Remaining 18 months of test production application
Valhall WP Production recovery	90 %	Aker BP	Justified for Development	Lower Hod developement, expected decision early 2019

Total net proven reserves (P90/1P) as of 31.12.2018 to Aker BP are estimated at 683 million barrels of oil equivalents. Total net proven plus probable reserves (P50/2P) are estimated at 917 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 31.12.2018 per projects and reserve class.

As of 31.12.2018	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)	(mmbbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)
On Production											
Alvheim Kameleon / Kneler	65.0 %	37	0	4	40	26	50	0	7	57	37
Boa Base	57.6 %	7	0	2	9	5	16	0	4	20	12
Vilje Base	46.9 %	10	0	0	10	5	15	0	0	15	7
Volund Base	65.0 %	10	0	2	12	8	15	0	3	18	12
Bøyla Base	65.0 %	3	0	0	3	2	5	0	0	5	3
Atla Base	10.0 %	0	0	0	0	0	0	0	0	0	0
Enoch Base	2.0 %	0	0	0	0	0	1	0	0	1	0
Ula Base	80.0 %	9	0	0	9	7	13	0	0	13	11
Ula Drilling Ph3	80.0 %	4	0	0	4	3	5	0	0	5	4
Tambar Development	55.0 %	2	0	0	2	1	4	0	1	5	3
Tambar East Base	46.2 %	0	0	0	0	0	0	0	0	0	0
Valhall Base	90.0 %	113	5	17	135	121	145	6	22	174	156
Hod Base	90.0 %	3	0	0	3	3	3	0	0	4	4
Skarv Base	23.8 %	25	22	101	148	35	37	22	104	163	39
Ærfugl A-1H	23.8 %	3	3	15	21	5	4	4	21	29	7
Ivar Aasen Base	34.8 %	67	3	12	82	28	104	5	16	125	44
Gina Krog Base	3.3 %	49	23	52	124	4	67	25	79	171	6
Total		**341**	**56**	**205**	**602**	**255**	**486**	**63**	**258**	**807**	**344**
Approved for Development											
Johan Sverdup	11.6 %	2063	43	55	2160	250	2559	54	68	2681	310
Hanz	35.0 %	11	0	2	13	4	14	1	2	17	6
Alvheim Kameleon Gas Cap Blow Down	65.0 %	0	0	12	12	8	0	0	21	21	14
Alvheim Kameleon infill S	65.0 %	3	0	0	3	2	4	0	0	4	3
Frosk Test Production	65.0 %	1	0	0	1	1	2	0	0	2	1
Skogul	65.0 %	5	0	1	6	4	9	0	1	10	6
Volund Sidetrack North	65.0 %	1	0	0	1	1	1	0	0	1	1
Valhall Flank North Infill drilling	90.0 %	1	0	0	2	2	3	0	0	3	3
Valhall Flank North Water Injection	90.0 %	6	0	0	6	5	7	0	0	7	7
Valhall Flank South Infill drilling	90.0 %	5	0	1	6	6	8	0	1	10	9

Table 2.2 (continued)

Valhall IP drilling programme	90.0 %	20	1	3	25	22	26	1	4	31	28
Ula drilling phase 1	80.0 %	18	1	0	18	15	29	1	0	30	24
Tambar K2 Workover	55.0 %	2	0	0	2	1	3	0	1	4	2
Tambar Artificial Lift	55.0 %	2	0	0	2	1	3	0	1	4	2
Ærfugl Phase 1	23.8 %	12	12	55	79	19	18	18	82	118	28
Ærfugl Phase 2	23.8 %	5	6	30	42	10	8	11	50	69	17
Snadd Outer	30.0 %	4	6	28	38	11	6	8	38	52	15
Oda	15.0 %	28	0	1	30	4	45	0	2	47	7
Total		**2226**	**72**	**198**	**2495**	**410**	**2798**	**97**	**284**	**3179**	**543**
Justified for Development											
Frosk test production Pt 2	65.0 %	1	0	0	1	1	3	0	0	3	2
Ivar Aasen Skagerak	34.8 %	4	0	1	5	2	8	0	1	10	3
Ivar Aasen Alluvial Fan	34.8 %	2	0	0	2	1	4	0	1	5	2
Valhall WP Production recovery	90.0 %	12	1	3	16	14	19	1	5	26	23
Total		**19**	**1**	**4**	**25**	**18**	**34**	**2**	**7**	**44**	**30**
Total Reserves		**2586**	**129**	**407**	**3122**	**683**	**3318**	**161**	**549**	**4029**	**917**

Table 2.3 Aker BP net 1P and 2P reserves as of 31.12.2018 per field and area.

As of 31.12.2018	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)	(mmbbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)
Alvheim	47	0	18	65	41	70	0	33	102	65
Volund	11	0	2	13	8	16	0	3	20	13
Vilje	10	0	0	10	5	15	0	0	15	7
Bøyla	3	0	0	3	2	5	0	0	5	3
Skogul	5	0	1	6	4	9	0	1	10	6
Frosk Test Production	3	0	0	3	2	5	0	0	5	4
Alvheim Area	**79**	**0**	**21**	**100**	**62**	**120**	**0**	**37**	**157**	**98**
Ula	30	1	0	31	25	47	2	0	49	39
Tambar	5	0	1	6	4	10	0	3	14	7
Tambar East	0	0	0	0	0	0	0	0	0	0
Ula Area	**35**	**1**	**1**	**38**	**28**	**58**	**2**	**3**	**63**	**47**
Valhall	197	9	33	239	215	261	12	44	316	285
Hod	3	0	0	3	3	3	0	0	4	4
Valhall Area	**200**	**9**	**34**	**242**	**218**	**264**	**12**	**45**	**320**	**288**
Ivar Aasen	73	4	13	89	31	116	6	18	140	49
Hanz	11	0	2	13	4	14	1	2	17	6
Ivar Aasen Area	**83**	**4**	**14**	**101**	**35**	**130**	**6**	**21**	**157**	**55**
Ærfugl	24	27	128	180	45	37	41	191	268	67
Skarv	25	22	101	148	35	37	22	104	163	39
Skarv Area	**49**	**49**	**229**	**328**	**80**	**74**	**63**	**294**	**431**	**106**
Johan Sverdrup	**2063**	**43**	**55**	**2160**	**250**	**2559**	**54**	**68**	**2681**	**310**
Atla	0	0	0	0	0	0	0	0	0	0
Enoch	0	0	0	0	0	1	0	0	1	0
Gina Krog	49	23	52	124	4	67	25	79	171	6
Oda	28	0	1	30	4	45	0	2	47	7
Other	**77**	**23**	**53**	**154**	**9**	**114**	**25**	**81**	**219**	**13**
Total	**2586**	**129**	**407**	**3122**	**683**	**3318**	**161**	**549**	**4029**	**917**

An oil price of 70 USD/bbl (2019) and 65 USD/bbl (following years) has been used for reserves estimation. Low- and high case sensitivities with oil prices of 45 and 81.3 USD/bbl, respectively, have been performed by AGR. This had only minor effect on the reserve estimates. The low price resulted in a reduction in total net proven (1P/P90) reserves of 4% and net proven plus probable (2P/P50) reserves of 2.5%. The high oil price resulted in an increase of 0.9% and 0.1% for proven (1P/P90) and proven plus probable (2P/P50), respectively.

Changes from the 2017 reserve report are summarised in Table 2.4. The main reason for increased net reserve estimate are the continued development of the Valhall field (34.5 mmboe) and Phase 2 PDO decision on Johan Sverdrup (10 mmboe).

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

Net attibute million barrels of oil equivavalents (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 31.12.2017	**271**	**363**	**324**	**415**	**97**	**136**	**692**	**914**
Production	-56	-56	-	-	-	-	-58	-58
Transfer	5	9	91	126	-97	-136	0	0
Revisions	35	27	-30	-39	0	0	4	-12
IOR	0	0	0	0	0	0	0	0
Discovery and Extensions	0	0	25	40	18	30	43	71
Aqcusition and sale	0	0	0	0	0	0	0	0
Balance as of 31.12.2018	**255**	**344**	**410**	**543**	**18**	**30**	**683**	**917**
Delta 18-17	**-16**	**-20**	**86**	**129**	**-79**	**-105**	**-9**	**3**

Johan Sverdrup is still the most important contributor to Aker BP reserves, contributing approximately a third of the company's 2P-reserves, but the Valhall reserves are almost equally important.

Total net production to Aker BP averaged 154 mboepd (total ~56 mmboe) in 2018. This is approximately 0.9 % lower than the forecast from 2017.

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 2018. 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 01.01.2018 to 31.10.2018 and forecast for the period 01.11.2018 to 31.12.2018. These volumes are used for assessment of remaining reserves as of 31.12.2018.

3.1.1 Alvheim (PL036, PI088BS, 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.

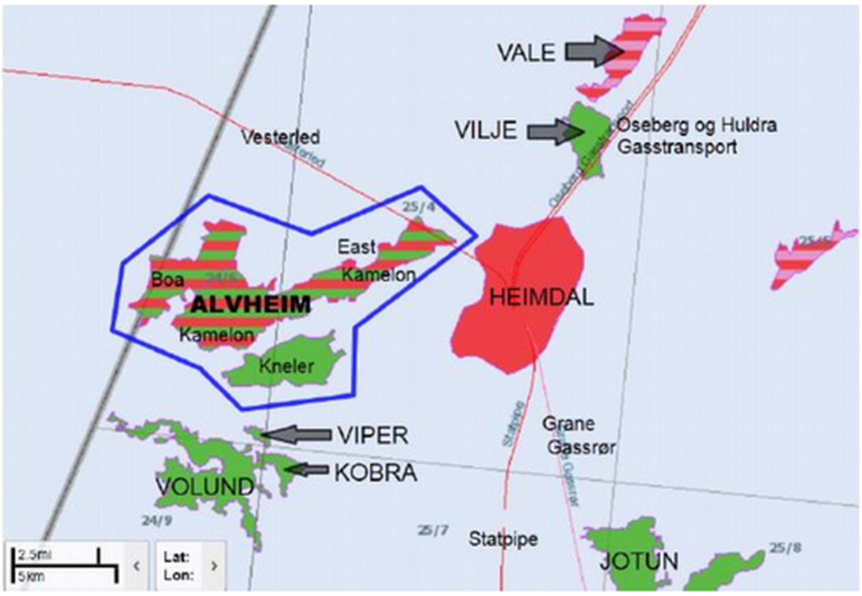

Fig. 3.1 Alvheim and Viper/Kobra Location Map

The Alvheim Field is divided into the Boa (partly on UK side), Kameleon and Kneler structures.

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 Paleocene age. The sand was deposited as sub-marine fan deposits and lies at a depth of approximately 2200 m. A number of production wells have penetrated the reservoirs and confirmed the static models.

The Viper and Kobra structures are comprised of remobilised Paleocene 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.

Development

The Alvheim Field is developed with a production vessel, «Alvheim FPSO», and subsea wells. The oil is stabilised 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 one lateral in the main sill and one lateral shallower in injection dykes (Kobra shallow). The wells are tied back to a new manifold connected to the Volund riser.

Status

Alvheim has produced close to and in some periods above expectations through 2018, but the field is constrained on gas even though the gas compressor capacity was increased in 2016. The Estimated Ultimate Recovery (EUR) has increased since the reserves certification 31.12.2017, primarily due to better than expected performance in wells KA1 and KA4.

Two infill wells have been completed in Boa in 2018. Boa reserves will be reevaluated in light of performance of these wells in 2019.

Production from Viper and Kobra started in November 2016. The production from both wells has consistently exceeded expectations, leading to reserves additions every year of assessment.

The East Kameleon L-4 well production is improving with a stabilised GOR, reducing the number of shut-ins due to production optimization and management strategy.

The recoverable volumes for Alvheim, Viper and Kobra are classified as «Reserves; On Production» (SPE's classification system), with the exception of Kameleon Infill South (KIS), which was completed in 2018, but is, due to cut-off date for the reserves evaluation, currently booked in reserves category 2 («Approved»).

Net production from Alvheim, including Viper/Kobra and the Norwegian part of Boa, averaged ~41 mboepd in 2018 which is approximately 20% above forcasted volumes.

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% working interest in the Norwegian parts. The other partners are ConocoPhillips Skandinavia AS holding a 20% interest and Lundin Norway AS holding a 15% interest.

The Boa reservoir straddles the Norway-UK median line. The Boa reservoir is unitised with Maersk Oil & Gas and Verus Petroleum, who are the owners on the UK side. Aker BP’s interest in the Boa unit is 57.62%.

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 PL036D in the North Sea, see. Fig. 3.2. Production started in 2008. The reservoir depth is about 2200 m TVD MSL and the water depth in the area is approximately 120 m.

Fig. 3.2 Vilje location map

Discovery

The Vilje Field was discovered in 2003 by well 25/4-9 S. The Heimdal Formation reservoir was encountered at 2135 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 2195 and 2198 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 Paleocene age at about 2150 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

Plateau oil production was 5000-6000 Sm3/d until July 2012. Water breakthrough occurred in July 2011 and currently the oil rate is around 2000 Sm3/d. The lower branch in well VI2 was shut-in in 2011 and was reopened in April 2016, increasing the production rate. However, it should be noted that the production is again declining since the reopening, due to an increased water-cut. The upper branch of VI2 was shut-in from July 2016. The upper branch was reopened briefly during 2018, but did not increase production. Currently, the well is producing from the lower branch, only, at a stable oil rate and water cut. Producing with a low draw down seems to be the key factor to stabilise water cut development in the lower branch.

VI3 produced from time to time in 2018. The water cut development in this well is very sensitive to gas lift/draw-down development. Going forward it is assumed that the well will be produced on a cyclic basis.

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

Net production from Vilje averaged 4.0 mboepd in 2018 which is approximately 13% above prognosed volume. The reason for this is improved performance from existing wells and production optimization.

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% interest in the licence and serves as operator. The other licence partners are Equinor, holding a 28.853% interest, and Total E&P Norge AS with a 24.243% 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. 4.3. The reservoir depth is about 1900 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.

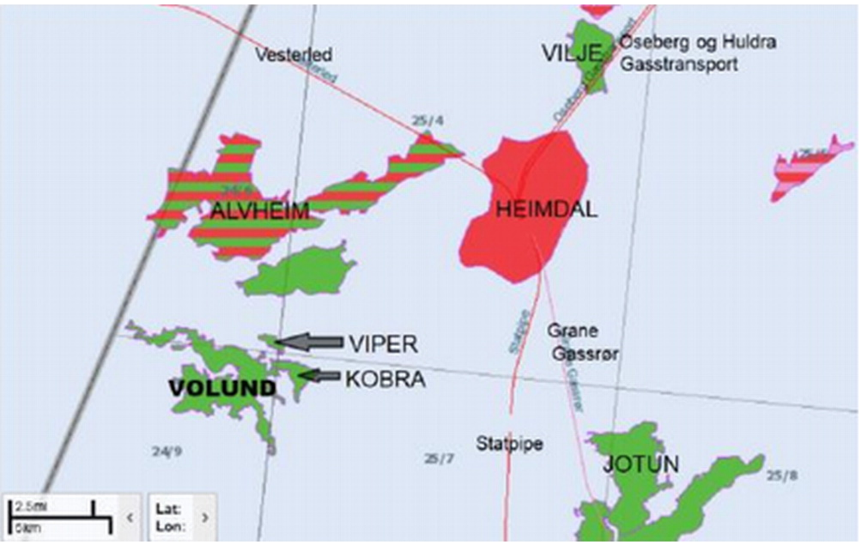

Fig. 3.3 Volund location map

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 2011 m to 2018 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 1891 m TVD MSL.

Reservoir

Volund is a massive injectite complex consisting of high quality, Darcy 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 3 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.

Status

The two infill wells that started production in 2017 have been producing at high oil rates through 2018, although with an increasing water cut.

One of the four mature oil producers at Volund is shut due to water flooding. The other three mature producers at Volund are normally closed for production optimization allowing capacity in the pipeline for Viper/Kobra production and due to gas capacity restrictions on the Alvheim FPSO. One well (P3) is planned to be sidetracked in 2019.

The water injector is injecting at 60% voidage which has proved to be enough for pressure maintenance.

The recoverable volumes of Volund are classified as «Reserves; On Production» (SPE's classification system), with the exception of the reserves related to the sidetrack of well P3, which are classified as «Reserves, Approved».

Net production at Volund averaged 11.8 mboepd in 2018 which is approximately 16% below prognosed volume. The main reason was more rapid than anticipated water cut development in one of the producers.

Cessation of production from the Volund field is expected in 2033.

Aker BP holds a 65% interest in Volund and serve as operator, while Lundin Norway AS holds the remaining 35% interest.

3.1.4 Bøyla (PL340)

The Bøyla Field is an oil field located in PL340, 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 2000 m TVD MSL. Well M-01 BH, on the north western flank, started to produce 19.01.2016 and is the main contributor. The location of the Bøyla Field is shown in Fig. 3.4.

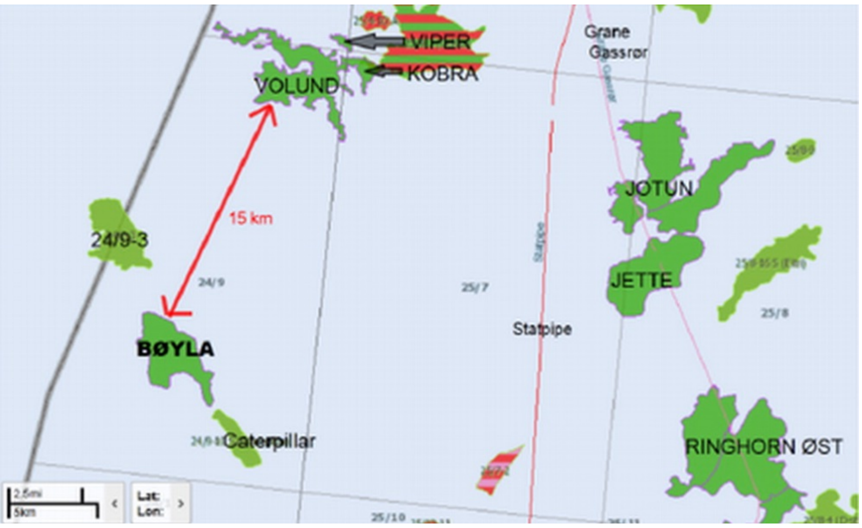

Fig. 3.4 Bøyla location map

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 a OWC at 2071 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 fan deposit. The reservoir of the field is within the Paleocene/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 underlying Heimdal member.

Two major depocenters have been recognised 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 likely.

Development

The field is a subsea development with two long horizontal producers (about 2300 m) and one water injector tied back to the Alvheim Field some 28 km to the North. Gas lift is required in the producers.

Status

M-1 performance (main producer) is less favourable than prognosed last year: water-cut has continued its steep increase with a declining oil rate. M-2 has demonstrated a better performance compared with last year's forecast, but the total field estimated ultimate recovery decreases somewhat as M-1 is still the main contributor to Bøyla production. M-2 produces with a significantly higher GOR compared with M-1. With its current production performance, M-2 provides a larger part of the total Bøyla production, causing the 2P field gas EUR to increase slightly compared with last year. Added production experience causes the uncertainty range to narrow.

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

Net production at Bøyla averaged 2.9 mboepd in 2018 which is 8% less than prognosed volumes. Cessation of production from the Bøyla field is expected in 2033 together with abandonment activities relating to the other Alvheim Area fields.

Aker BP, as operator, holds a 65% interest in Bøyla. Vår Energi AS holds a 20% interest and Lundin Norway AS holds the remaining 15%.

3.1.5 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. 3.5. The accumulations cover several licences and have been unitised 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 2400 m TVD MSL reservoir depth.

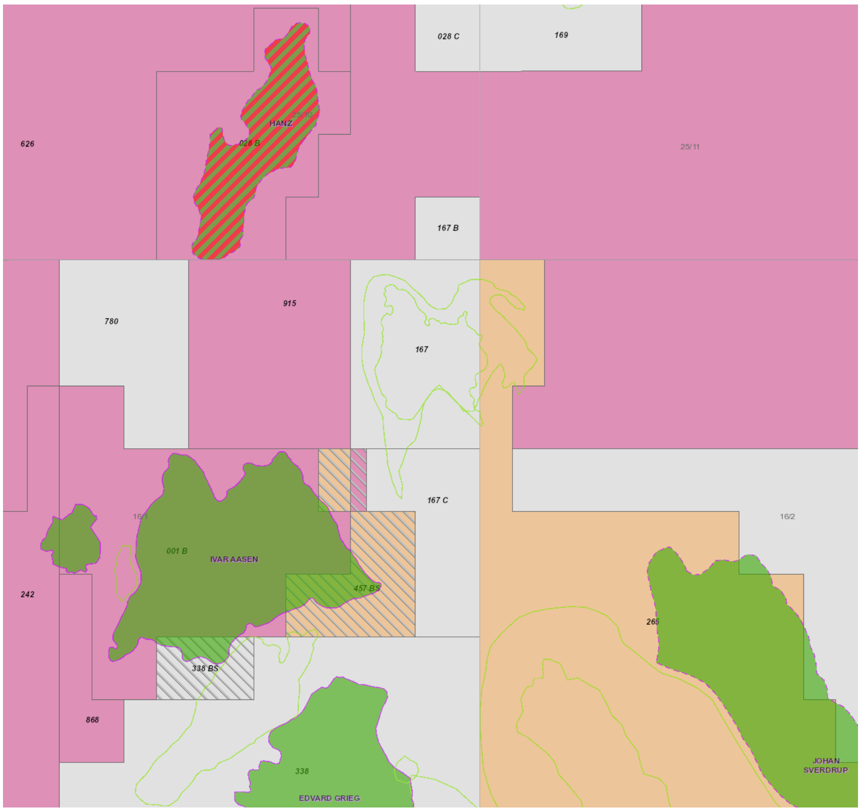

Fig. 3.5 Ivar Aasen Unit and Hanz location map

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 re-classified 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 seven producers (six 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 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.

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 covers Ivar Aasen power demand until a joint solution for power from shore is established.

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, but with more Skagerrak2 Fm. and less Hugin Fm. Two new water injection wells were drilled in 2018; namely D-6 and D-7. These wells proved somewhat thinner Hugin and Sleipner, thicker Statfjord and expected Skagerrak 2. The total in-place volumes are unchanged during 2018.

The first development well in West Cable was disappointing as top reservoir came in deeper than expected. The side track on West Cable was successful with penetration of oil filled reservoir sands. No new wells are drilled in West Cable during 2018.

The production of Ivar Aasen was slightly lower than expected in 2018, mainly due to reduced gas turbine capacity at Edvard Grieg in March-April. The challenges related to injection voidage replacement in the eastern part of the Ivar Aasen Main Field, have been mitigated by the two new injection wells, D-6 and D-7, which came on stream summer 2018. D-7 injectivity is very good, but D-6 is injecting below expectations.

Successful pressure support from water injection and positive water cross-flow from well D-12, gave lower than forecasted gas-oil-ratio and thus gas production. The field is producing with good efficiency.

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

A dedicated Skagerrak 2 producer and a separate Alluvial Fan producer is planned for 2019. These reserves have not been included earlier, and are classified as «Reserves; Justified» (SPE's classification system).

Net production at Ivar Aasen averaged 23.3 mboepd in 2018 which is 1% less than prognosed volumes. Cessation of production from the Ivar Assen field is expected in 2035.

Aker BP holds a 34.7862 interest in the Unit. The other licensees are Equinor (41.4730), Spirit Energy (12.3173%), Wintershall Norge AS (6.4615%), VNG Norge AS (2.0230%), Lundin Norway AS (1.3850%) and OKEA (Norge) AS (0.5540%).

3.1.6 Valhall (PL006B, PL033B)

Valhall is an oil field in the southern part of the Norwegian sector of the North Sea in PL006B and PL033B (unitised into the Valhall Unit) in blocks 2/8 and 2/11, Fig. 3.6. The water depth is about 70 metres.

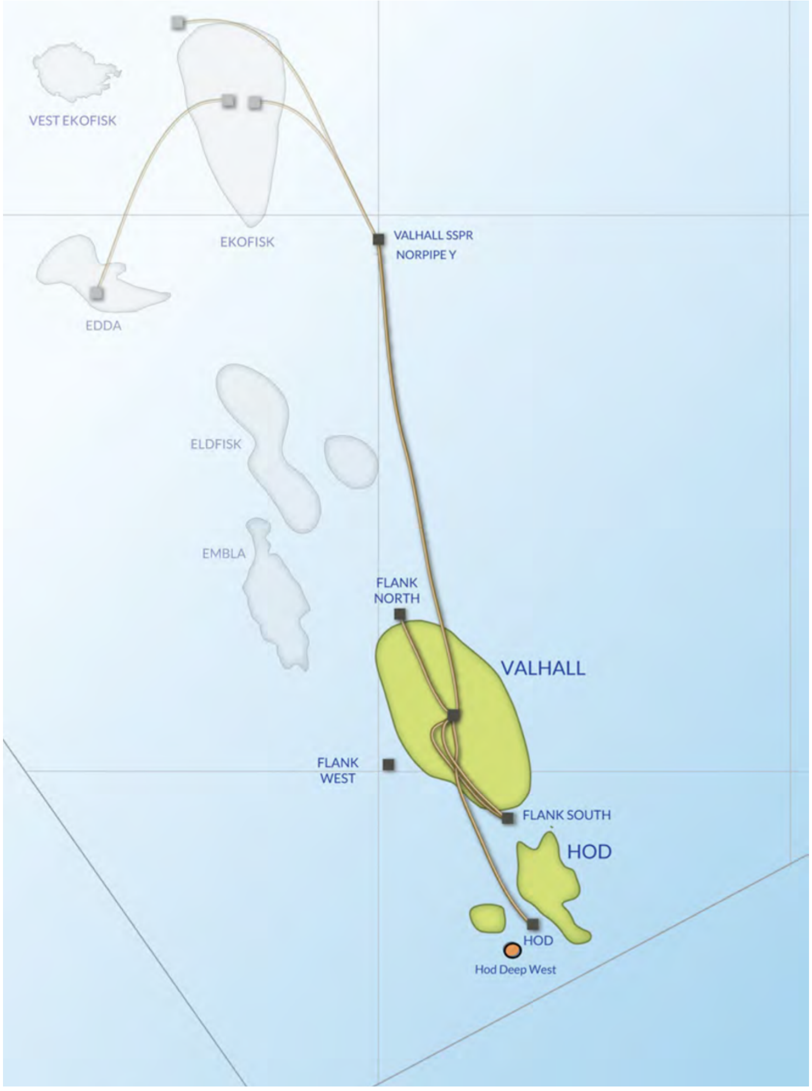

Fig. 3.6 Valhall and Hod location map

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%). Matrix permeability is in the 1-10mD range. There are areas with natural fractures with high permeability conduits. The Hod Formation porosity is 30%-38% with permeability 0.1-1mD.

The Valhall Field is subdivided into 8 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 optimise 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. 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. Bridges connect the platforms. A sixth platform (Flank West) was sanctioned in 2017 and added considerable reserves to the field.

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

Status

Gas lift has now been installed on most of the Valhall producers.

Two wells have been completed in 2017 out of the 2016 sanctioned 7 well IP drilling programme. The remaining five IP wells will be drilled and completed throughout 2018 and 2019.

The Valhall Flank West project was sanctioned and a PDO submitted December 2017. The project consists of an unmanned 12-slot wellhead platform tied back to the Valhall PH platform. 6 wells are planned to be drilled with start-up and first production in 2019.

Two producers in the Northern Basin (N-14 and N-15) were shut in during 2018. The plan is to re-open these wells as the new water injector becomes available in Q1 2019.

The North Flank Water Injection project (NFWI) has been approved in 2018. This includes a water injection line from the field centre to the North Flank platform as well as one water injector to be drilled and completed in the Northern Basin (2020).

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

Valhall IP drilling programme, Valhall Flank West, Valhall Flank North Water Injection, Valhall Flank North infill drilling and Valhall Flank South infill drilling projects have all been classified as «Approved for Development».

Valhall WP Production recovery (lower Hod development) has be classified as «Justified for Development» (SPE's classification system).

The 2P/P50 production profile indicates an economic cut-off in 2049.

Net production to Aker BP averaged 39mboepd in 2018, which is 8% less than prognosed volumes.

Aker BP holds a 90.0% interest in the Valhall Unit, with Pandion holding the remaining 10%.

3.1.7 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 (PL033 in block 2/11), Fig. 4.13. The water depth is approximately 70 m and the reservoir depth is about 2700 m TVD MSL.

Location of Hod is shown in Fig. 3.6.

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 Paleocene Ekofisk Formation, and the Upper Cretaceous Tor and Hod formations. The reservoir depth is approximately 2700 m. The field consists of three structures: Hod Vest, Hod Øst and Hod Saddle.

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

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 Sadel, which connects the Hod and Valhall reservoirs is currently produced through four wells drilled from Valhall. 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

A total of 12 wells has been drilled on the field of which four are currently producing. There has been no production from the Hod facility since 2012 and the four producing wells are drilled from the Valhall South Flank platform and part of these wells extend into the Hod licence. The equity split between the Valhall and Hod licences is based on 'length of well' in respective licences.

Net production to Aker BP averaged 1 mboepd in 2018.

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

Aker BP has a 90.0% interest in the Hod field, with Pandion holding the remaining 10%.

3.1.8 Ula (PL019)

Ula is an oil field in the southern part of the Norwegian sector of the North Sea in block 7/12 in PL019, Fig. 3.7. The water depth in the area is about 70 m and the reservoir depth is about 3500 m TVD MSL.

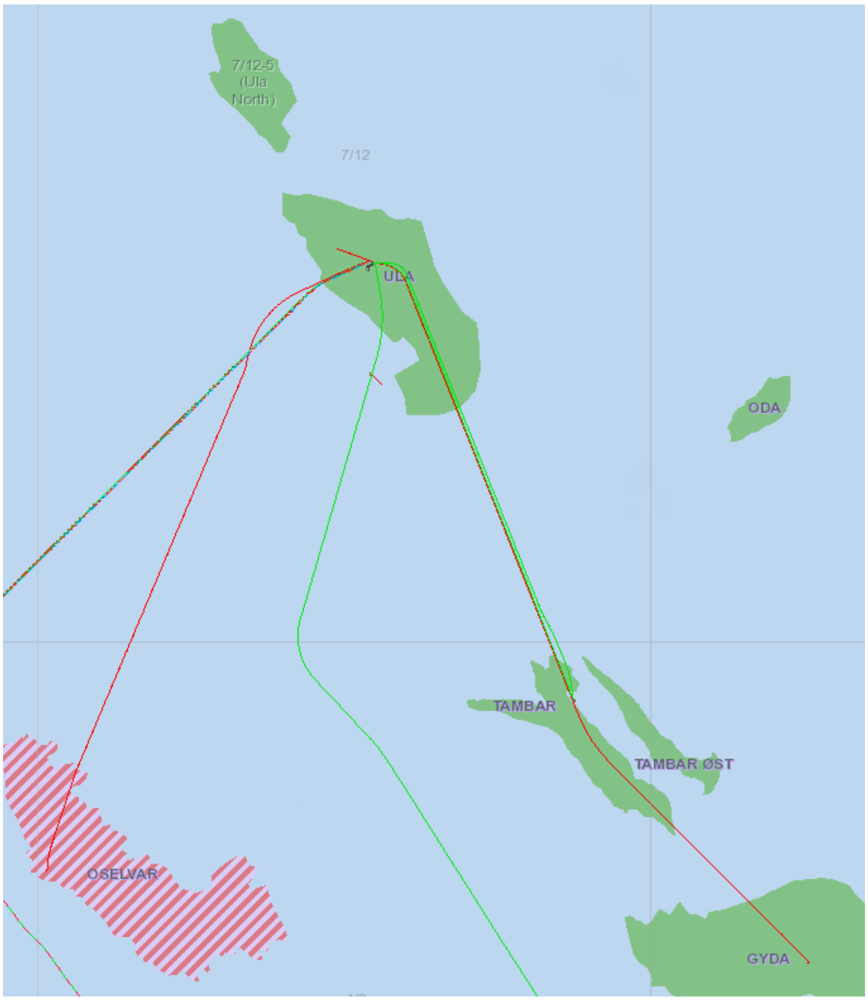

Fig. 3.7 Ula location map

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% to 28%, permeabilities from a few mD to over 2 D and water saturations from 5% to over 50%. The Ula Formation was oil bearing from top to base at 3532 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 Tambar and Blane, and will also be the processing facility for nearby Oda development. 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 3345 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) and Oselvar (2012, now ceased). Gas lift is used in the shallowest reservoir interval.

Status

42 wells have been drilled on Ula since start-up of which seven 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 PL405 decided to develop the 8/10-4 S discovery (Oda) as a tie-in to Ula and a PDO was issued November 2016. Gas from Oda will be injected into the Ula reservoir to increase recovery. In addition associated gas from the Tambar gas lift project and two new Tambar infill wells will be injected in Ula.

Injection of additional import gas from Oda and Tambar will increase reserves. The reserves from these future projects are classified as Undeveloped Reserves. In addition several non sanctioned planned infill wells will probably increase the reserves on Ula.

The 2P/P50 production profile indicates an economic cut-off in 2036.

Net production to Aker BP averaged approximately 6.1 mboepd in 2018. This is approximately 15% less than planned, primarily due to facilities related issues.

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

Aker BP is Operator and holds a 80% interest in the Ula Field. The remaining 20% shares are held by Faroe Petroleum.

3.1.9 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. 3.8. The water depth in the area is 68 metres.

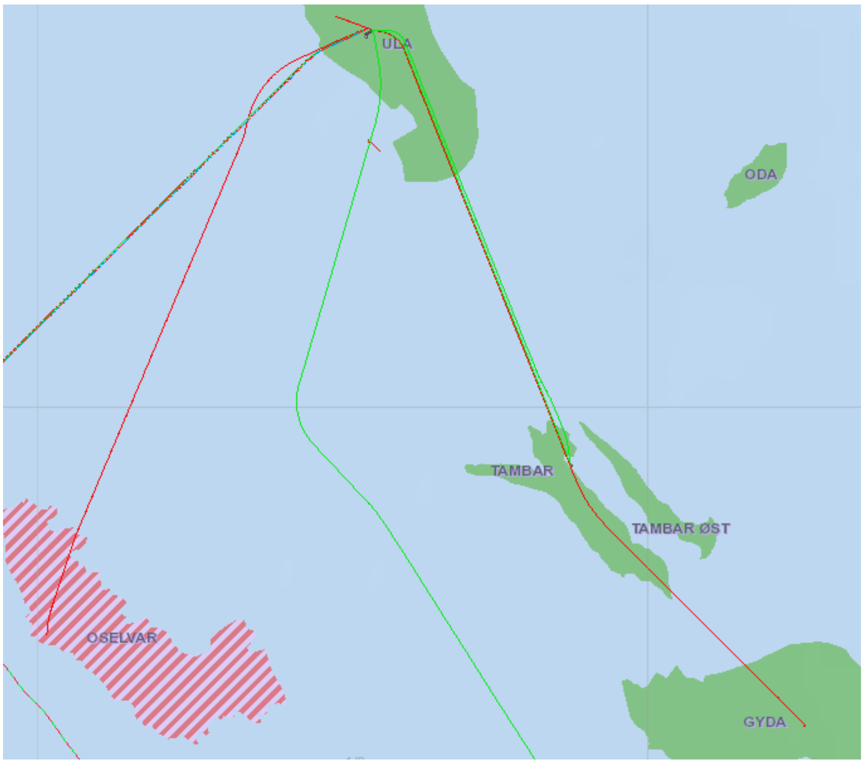

Fig. 3.8 Tambar and Tambar East location map

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 4100-4200 metres 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 Teeside 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 three wells are currently producing. The K-2 and K-4 producers started up production in 2018.

Major challenges restricting production are wells that die and increasing water-cut. Recently, a 4D seismic survey has been carried out to enhance reservoir management. There is special focus on well surveillance, as well as on the evaluation of IOR options, such as infill drilling and gas lift in existing wells; Tambar Infill South (TIFS), Tambar Infill North (TIFN) and Tambar Artificial Lift (TAL).

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

Net 2018 production to Aker BP from Tambar averaged approximately 3.9 mboepd.

Aker BP is Operator and holds a 55% interest in the Tambar Field. The remaining 45% shares are held by Faroe Petroleum.

3.1.10 Tambar East (PL065, PL300, PL019B)

Tambar East is a minor oil filed 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 4050-4200 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 compartmentalised.

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. 3.8. 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 the previous RNB submission cessation of production was assumed in 2017. The well was temporarily shut down in November 2017 and the assumptions 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 2018.

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

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

3.1.11 Skarv (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 metres, Fig. 3.9. The Skarv unit is a joint development of the Skarv, Idun and Ærfugl fields (former Snadd). Note that the northern part of the Ærfugl discovery («Snadd Outer») is not a part of the Skarv Unit, Fig. 3.9.

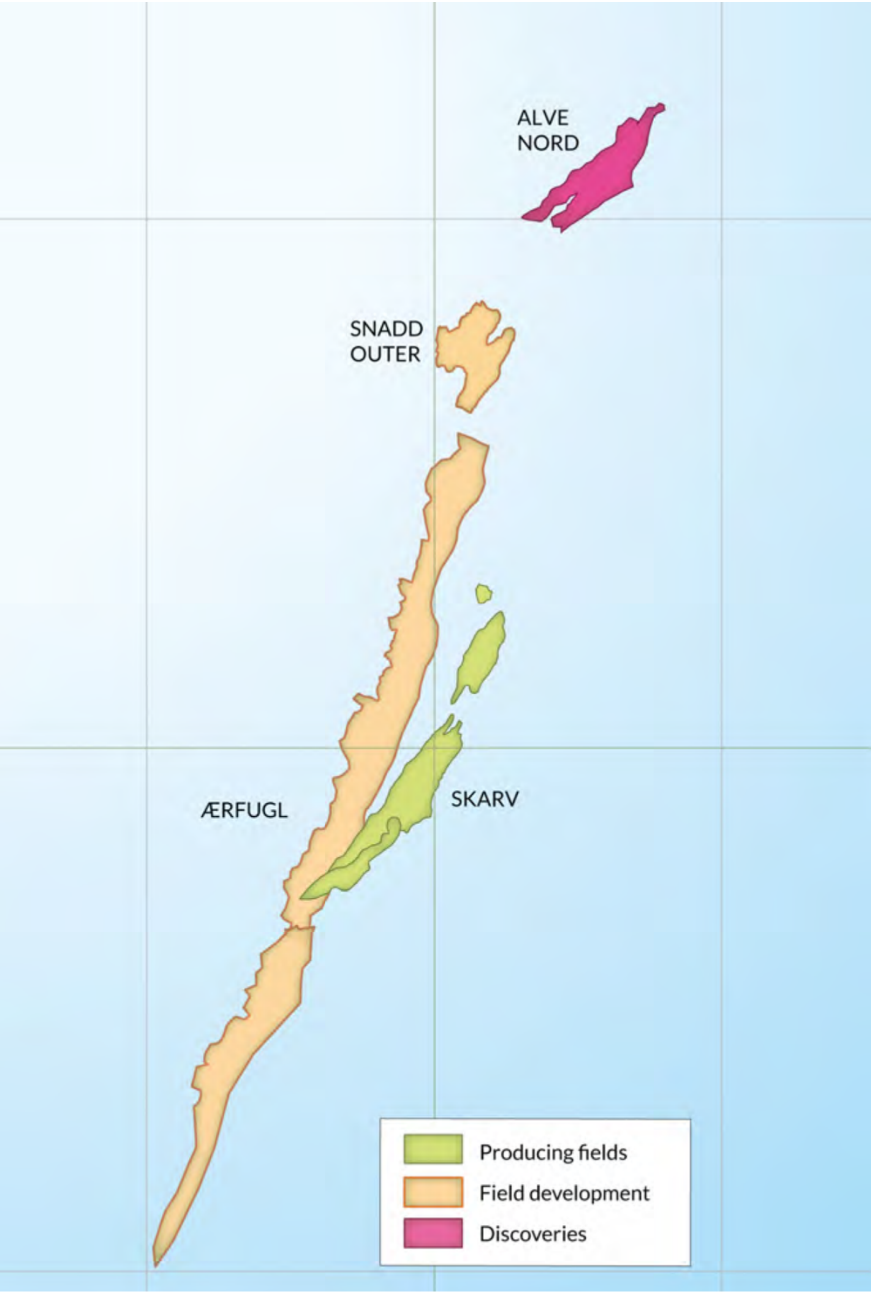

Fig. 3.9 Skarv and Ærfugl location map.

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 fifteen wells. Distribution between the well types are: 6 oil producers, 4 gas producers, 4 gas injectors and 1 Ærfugl gas producer (Ærfugl A-1H, which was previously used as a test well). Ærfugl is discussed in Chapter 3.2.3.

The oil is exported by 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, according to Aker BP.

Reservoir

The Skarv structure is defined by 3 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. Current production is close to 17 000 Sm3/d o.e. To date approx. half of the estimated ultimate recovery is produced. Four gas wells are currently producing, two in Garn A and two in Idun. All gas wells are on decline. The gas well A03 in Garn in the A segment, which failed July 2015, is now abandoned as further studies has shown that the remaining two wells will be able to drain the segment.

Total of 4 wells all had to shut in due to xmas tree failures (A03 in 2015, B06 and B08 in 2017 and B09 in 2018) and a root cause investigation was completed in 2018, with the conclusion that the trees can be repaired in-situ from now on.

The oil wells in the B and C segment are on a slight decline, and have all had 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 2018.

The western Idun well, D02, is the only well that has had water production. The water production rate stabilised and the well has seen no lifting issues and little impact on gas production for 2018. It is assumed that the water was coming from an underlying sand rather than from the main production targets.

Net production from Skarv averaged ~19.4 mboepd in 2018 which is approximately 1% below forcasted volumes. Production from the Ærfugl A-1H producer was approximately 5.9 mboepd, 12% above plan.

The estimated future production is solely based on current oil and gas producers, and thus falls within the PRMS definition for reserves. The recoverable volumes of Skarv, including volumes from the Ærfugl A-1H, are classified as «Reserves; On Production» (SPE's classification system).

The Skarv unit submitted a Plan for Development and Operation (PDO) for the Ærfugl Field 15.12.2017, see Chapter 3.2.4.

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

3.1.12 Gina Krog (PL029B)

The Gina Krog oil and gas field is situated in the south-eastern end of the Viking Graben at the north-western extension of the Sleipner Terrace, directly north of Sleipner Vest. The water depth is 120 m. Equinor is the project Operator, and a unit agreement is signed covering the licences PL048, PL029C, PL029B and PL303.

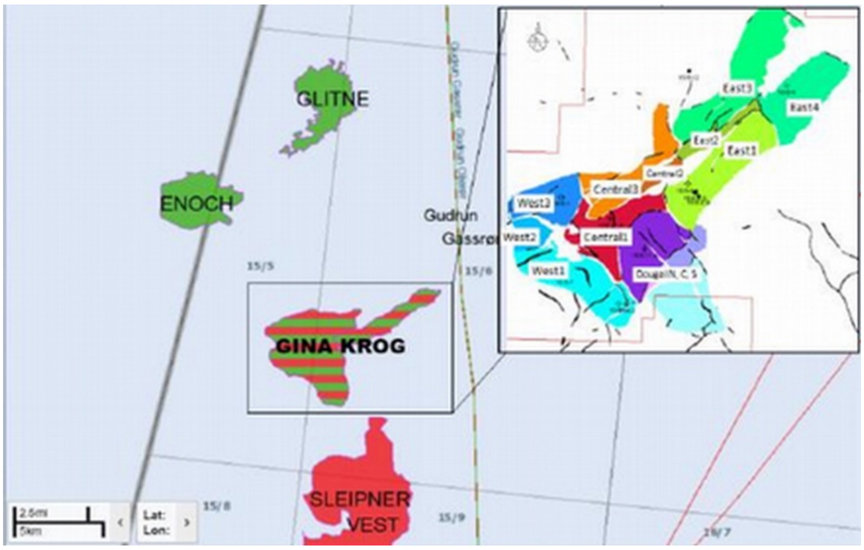

Figure 3.10 Gina Krog location map.

Discovery

Gina Krog, (segment West), was discovered in 1974 with shows in well 15/6-2 R, and in 1977 the well 15/5-1 confirmed gas/condensate. Later appraisal wells proved oil in West, gas with an oil leg in East and gas within the Central part of the field. Gina Krog is a complex field with 14 faulted segments, where five are referred to as reference segments and are included in the reserves estimate. These are West 1, West 2, West 3, Central 1 and East 1 (Fig. 4.3). Discoveries are also made in some other segments. These, are however, not included in the reserves. There are variations in both fluid properties and fluid contacts over the field.

The structure has steep flanks and a large hydrocarbon column of ~600m.

Reservoir

The reservoir comprises sandstones of the Hugin Formation (Callovian, Middle Jurassic) with moderate to poor reservoir quality at depth of 3300 - 3900 m TVD MSL. The Hugin Formation was deposited in a paralic environment with proximal to distal mouth bars, lower shore face, middle shore face and upper shore face to barrier sands and coals. The reservoir is capped by Heather shales. Base reservoir is a coal layer on top of the Sleipner Formation.

The drive mechanism will be gas injection.

Development

Gina Krog is developed with a fixed platform located on the Central 1 segment. Gas will be exported through a tie-back to Sleipner East, while oil is loaded offshore to shuttle tankers.

The drive mechanism is gas injection. The field is planned developed with eight horizontal oil producers, three gas injectors and three gas producers as defined in the PDO. The plan allows for additional wells, and the production wells are drilled using geosteering. Some changes to the original plan are expected when new well information becomes available.

Injection gas is imported from Gassled. In addition, it will also be possible to inject gas from the nearby Eirin discovery if that discovery is developed. Gas injection at the crest of the field will add to the gas cap expansion and displace condensate rich gas towards the producers. Injectors will be converted to producers when the injection phase is completed. Three wells are included to produce gas from areas without an oil rim.

Status

The PDO was approved by the authorities in May 2013. Pre-drilling of development wells was performed in 2015 and 2016. The drilling rig was used as living quarters during the hook-up and commissioning period. The current drilling plan is adjusted according to the pre-drilling experience. The facilities were installed and commissioned only slightly behind plan. After installation and commission drilling operations commenced in September 2017. One pre-drilled gas producer and three pre-drilled oil producers started production on 30.06.2017. Gas injection commenced at the end of 2017, about two months delayed.

The initial oil production has been below expectations, especially from well B-17 in the East 1 segment experiencing slugging. However, gas productivity in B-7 has been much higher than expected. It is somewhat surprising that wells B-17 and B-6 shows lower production than expected, even though the permeability along the wells was as good or higher than expected.

Net production from Gina Krog averaged 1.6 mboepd in 2018 which is approximately 22% below forcasted volumes.

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

The field is unitised and Aker BP holds an interest of 3.3% unit. The operator Equinor holds a 58.7% interest, Total E&P Norge 15%, KUFPEC Norway AS 30% and PGNiG Upstream International AS the remaining 8%.

3.1.13 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. The proved (1P/P90) and proved plus probable (2P/P50) reserve estimates reflect Skirne compensation of gas and condensate to Atla.

Net production from Atla averaged 0.03 mboepd in 2018.

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

3.2 Development Projects

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

Johan Sverdrup is a major oil field extending over three licences (PL028, PL501 and PL502), 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 1900 m TVD MSL.

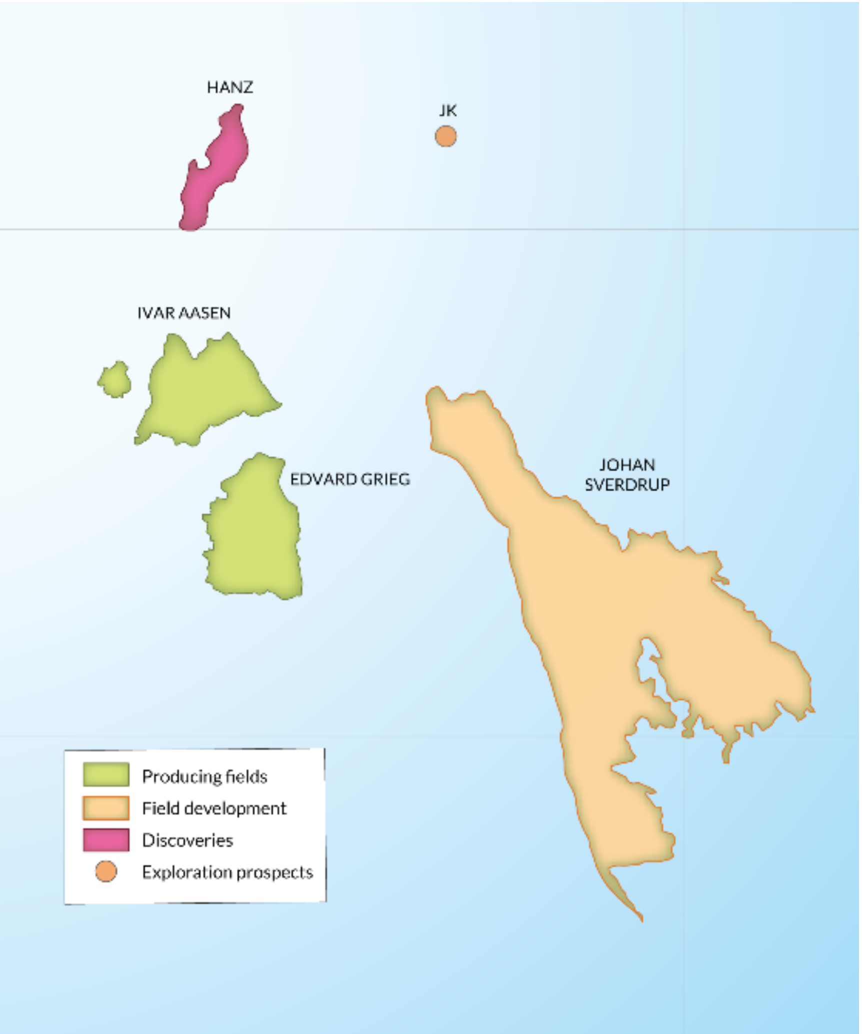

Fig. 3.11 Johan Sverdrup location map

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 characterised by excellent reservoir properties. The apex of the field is located at approximately 1800 m TVD MSL and the free water levels (FWL) encountered are in the range of 1922 - 1934 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 will in general be 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 core of the Phase 1 development plan will be a field centre with four platforms; processing platform, drilling platform, riser and export platform and living quarters and utilities platform; Fig. 3.10. The platforms will be installed on steel jackets linked by bridges. Phase 1 also includes 18 oil production and 16 water injection wells and 3 subsea water injection templates. Planned production start for Phase 1 is December 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 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 wells will be a mixture of satellite wells and additional wells drilled from the central drilling platform DP. The fringe areas will be developed with subsea templates tied back to the riser platform (RP).

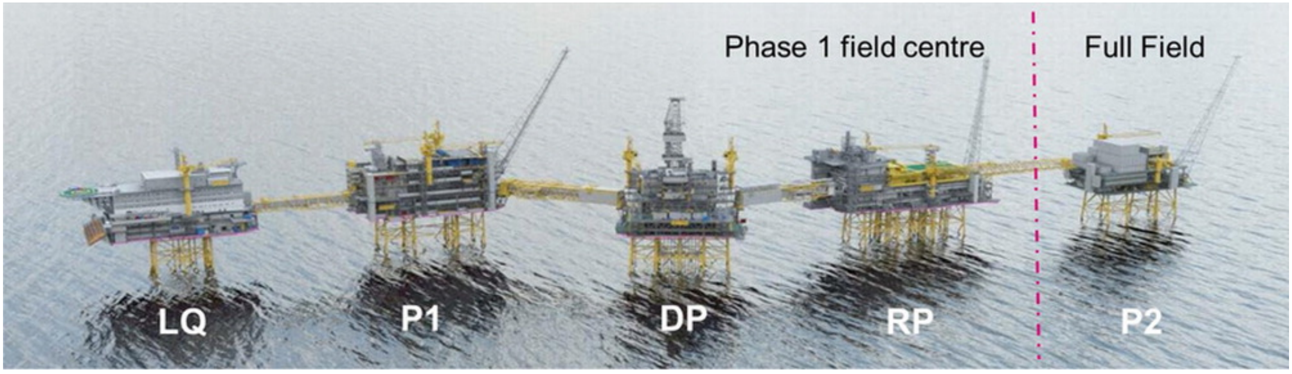

Fig. 3.12 Johan Sverdrup field center

Fully developed, 62 oil production and water injection wells are planned to be drilled on Johan Sverdrup. The oil plateau production is expected to be approximately 660 mbopd.

The export solution for oil and gas will be transportation to shore via dedicated pipelines. The oil will be transported to the Mongstad terminal and the gas will be transported via the Statpipe system to Kårstø for processing and onward transportation.

Status

The PDO for Phase 1 was approved by the authorities in August 2015. The production start-up was estimated to be at 01.12.2019. PDO for Phase 2 was submitted in August 2018. Production start for Phase 2 is planned in 2022.

A total of 20 development wells have been drilled, 8 producers and 12 water injectors.

The updated modelling by the operator before the Phase 2 decision shows an increase in both in-place and recoverable resources compared to the Operator's previous models. The Ref. Case from «Phase 2 preliminary DG3 model» is very close to the Aker BP Ref. case from 2015. As a consequence, Aker BP has decided to use the Operator's production prognosis and gross reserves estimates in the current reserves report.

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 licence).

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% share of the field. The remaining shares are held by Equinor (40.0267%), Lundin (22.6000%), Petoro (17.3600%) and Total (8.4400%).

3.2.2 Oda (PL405)

The Oda Field is located 14 km west of the Ula Field in block 8/10 in PL405 in the Central Graben in the Norwegian North Sea. Fig. 3.13 shows the location of the asset. The water depth is about 66 m in the area, and the crest of the structure is estimated to be at 2300 m TVD MSL.

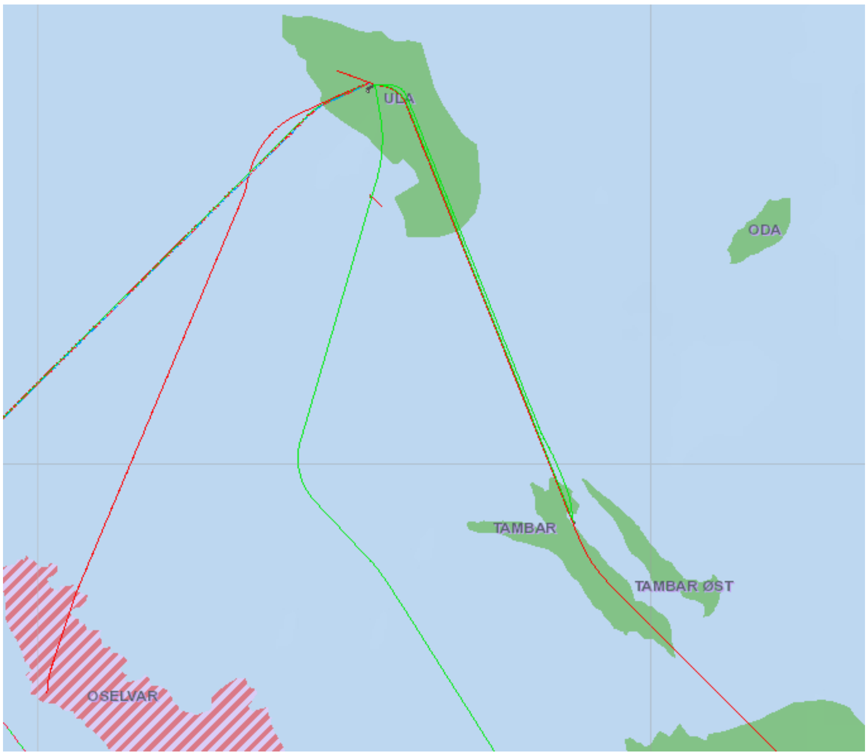

Fig. 3.13 Oda location map

Discovery

The discovery well 8/10-4 S was drilled in 2011 in the north-western part of the salt-induced structure. The well proved an oil-down-to situation in the Ula Fm. A water gradient in a downflank sidetrack suggests a FWL at 2985 m TVD MSL. East and south-west segments were drilled dry in 2014.

Reservoir

The reservoir consists of the Upper Jurassic Ula Formation; a sandstone reservoir with high quality properties. The Oda structure forms the flank of a steep dipping salt diapir. The oil column is about 685 m of light oil.

The drainage strategy calls for pressure maintenance via seawater injection. Two oil producers and one water injector is planned.

Development
The development concept is a subsea tie-in to the Ula Platform and re-usage of Oselvar subsea isolation valve (SSIV) inlet facility and separator at the Ula Platform. Modifications at Ula include installation of a new water injection system, riser caisson for water injection, and umbilical and new equipment for incremental water handling.

Status
The PDO was approved by the authorities in May 2017. Production start is expected in August 2019, with a tie-in to the Ula Field. The Ula Field is operated by Aker BP.

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

Aker BP holds a 15% interest in the Unit. The remaining shares are held by Spirit Energy (40%, Operator), Suncor Energy Norge AS (30%) and Faroe Petroleum Norge AS (15%).

3.2.3 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 2800 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 6507/3-9 S for Ærfugl 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%, permeability 234 mD and net/gross of 0.85).

Development
The Ærfugl Field will be produced through the existing facilities on Skarv. The depletion plan includes 6 new highly deviated subsea wells plus the existing test well A-1 H tied into the Skarv FPSO with heated flowlines. Phase I includes 3 wells on Ærfugl South with production start Q4 2020. Phase II includes 3 wells on Ærfugl North and Outer with tie-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. Future volumes predicted from this well are considered as «Reserves / On Production» (SPE's classification system).

The other recoverable volumes of Ærfugl are classified as «Reserves / Justified for development» (SPE's classification system).

The southern part of the Ærfugl Field is located in the Skarv Unit. Aker BP holds a 23.8% share in the the Unit. The northern part of the field is located in licence PL212E in which Aker BP holds a share of 30%.

3.2.4 Skogul

The Skogul oil field is located approximately 40 km north of Alvheim in block 25/1 under PL460 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 2097 m TVD MSL. The PDO was submitted in December 2017.

Discovery

The discovery well 25/1-11 R and the sidetrack 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 2126 mTVDSS. A deviated (29°) sidetrack 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 2106 mTVDSS and a 12 m oil column.

Reservoir

The reservoir consists of the Lower Eocene Upper Balder-Frigg Formation sandstones; sandstone reservoirs 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%, giving a net-to-gross ratio of 92.4%. 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%, giving a net-to-gross ratio of 89.2%.

Development

Skogul is planned to be developed as a tie-in to Alvheim FPSO via the Vilje pipeline. The concept is one bilateral producer, requiring a new two-slot manifold. A pilot will be drilled in order to ensure an optimal depth. Skogul is assumed to lie within a region with an extensive aquifer system, hence the drive mechanism will be by depletion and natural aquifer support. The pressure support ability from this aquifer is one of the main uncertainties, and poor aquifer support will be mitigated by assisted pressure support by constructing a conduit for water flow from the aquifer, along the northern well and into the reservoir. The subsea system will be tied back to Alvheim FPSO via the Vilje template. Production from Skogul will be measured by a dedicated subsea multiphase meter. The commingled production from Vilje and Skogul will be measured through a dedicated topside multiphase meter on Alvheim. Screens, ICDs and swell packers will be used in order to avoid sand production and minimise water production.

Status

The PDO was submitted Q4 2017, and first oil is expected Q1 2020.

Aker BP is Operator and holds a 65% interest in the Skogul Field. The remaining 35% shares are held by PGNiG.

3.2.5 Frosk (PL340)

The Frosk discovery 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 in January 2018, drilled by wells 24/9-12 S, 24/9-12 ST2, and 24/9-12 AT2.

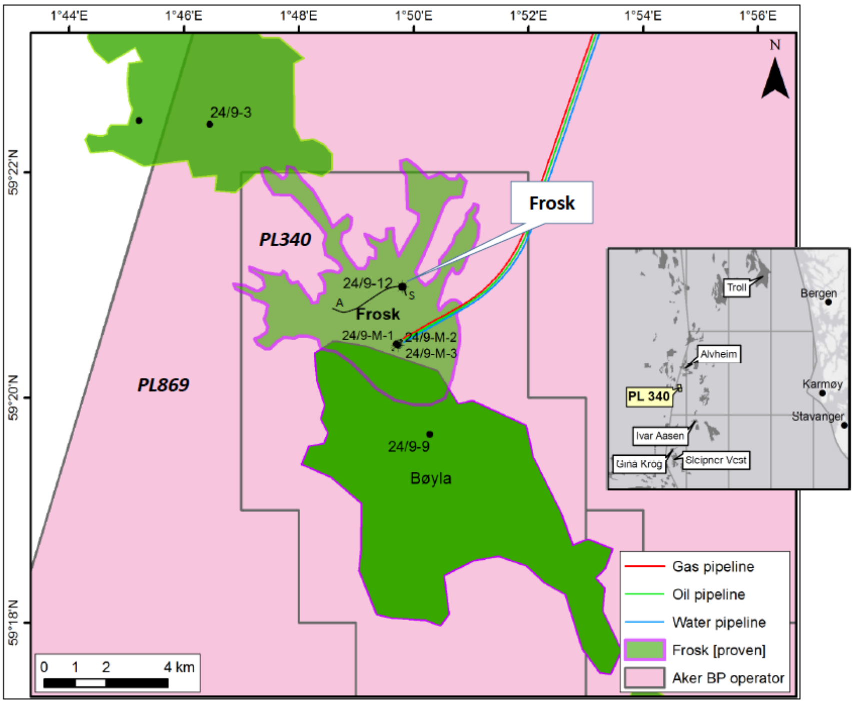

Figure 3.14 Frosk Field location map

The Frosk Field lies within PL340 and is located in block 24/9 of the Norwegian sector of the North Sea. Forty metres 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 1861.5 m TVDSS. The GOC was calculated to be 1786 m TVDSS based on pressure data and supported by the calculated PVT bubble point pressure. A gas bearing thinner injectite was penetrated in the sidetrack 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 injected sill located 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 there are several small dykes and sills, acting as «fingers». The injection process has enhanced the reservoir properties, with average porosity of 32% and permeabilitites up to 10 Darcy. The main sill is very homogeneous, with a net to gross close to 100%. The behaviour of 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. Approximately 26 m above the main injectite there is a zone of breccia and fractured shale. The injected sand in this zone is of similar quality as the main injectite, filled with oil and gas and in pressure communication with the main sill. This zone is not visible on seismic – and represents an upside potential for a future Frosk development.

Development

The development of Frosk will commence with an extended production test. The Frosk reserves are consequently associated with the Frosk Test Production well, only. The well is planned as a horizontal bi-lateral production well that targets two segments of the Frosk injectite sands (Main Injectite and Upper Zone). Drilling operations are on track for spud by Feb. 2019 with planned startup of production in July 2019.

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.

No water injection wells or facilities are currently planned as a part of the Frosk Test Producer Project, thus depletion with aquifer support is the main drive mechanism for the test production.

Status

Aker BP has applied for a production test period of two years. A permission to produce six months have been granted, with a statement that further production may be applied for provided acceptable data for reservoir performance are acquired.

A plateau oil production rate of 2000 sm3/d has been calculated/modelled. Production profiles have been derived from a simulated sensitivity study using an integrated Frosk simulation model, yielding incremental volumes produced through the Bøyla manifold.

Aker BP is operator with a 65% share and partners are Vår Energi AS (20%) and Lundin Petroleum (15%).

Reserves have been booked for the test production well, and for the first two years, only. Volumes for the first six months are classified as «Reserves, Approved», whereas volumes for the next 18 months are classified as «Reserves, Justified».

4 Contingent Resources

Aker BP has contingent resources in a wide range of assets. The total net contingent resources estimates included in the resource classes «Development Pending» and «Development not clarified or on hold», Fig. 1.1, ranges from 512 mmboe to 1340 mmboe, with a 2C volume of 946 mmboe. Approximately 25% 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 Alveim and Askja/Krafla) and the King Lear-volumes. Further development of the Valhall and Hod fields with estimated sanctions in the period 2020 to 2022 will also add significant reserves to the company. The two most important projects being further infill drilling on the Valhall field and the Hod Redevelopment project.

The following is a short description of the most important discoveries within the company's core areas containing contingent resources. Only contingent resources in the resource classes «Development Pending» and «Development not clarified or on hold» are included, Fig. 1.1.

4.1 The NOAKA Area (North of Alvheim Krafla Askja)

The area includes 10 discoveries over a 60km long trend, south of Oseberg and North-east of Alvheim, See Fig. 4.1. The Aker BP proposed concept is a PQ hub located centrally with tie-in of all the fields, with subsea templates and well head platforms. An alternative solution proposed is a small production hub in the north with a possible small production hub in the south.

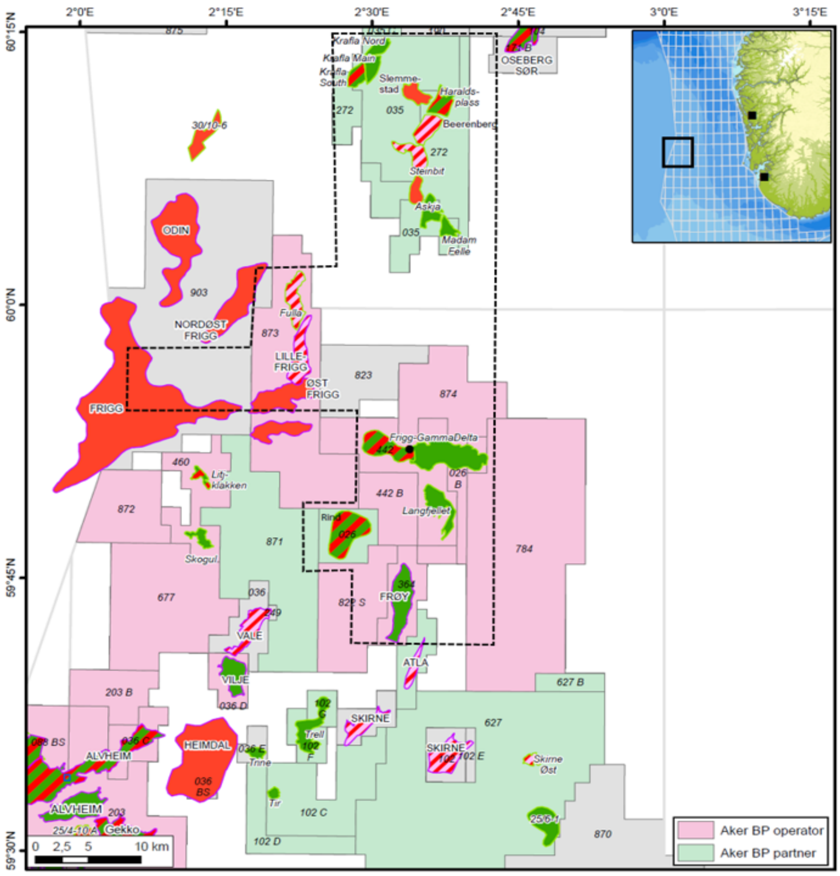

Fig 4.1 The NOAKA area (North of Alvheim Krafla Askja)

The discoveries include:

The Frøy Field (PL364) was in production from 1995 to 2001 with Elf as the operator. The field was shut-down the field 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% 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 metres. 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 metres 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% 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 sidetracks were drilled and two successful formation tests (DST) were conducted in well 25 /2-18A. The maximum production rate was 3800 mbopd through a 40/64 inch choke in the lower oil zone.

Aker BP holds 90.26% interest in the Langfjellet discovery.

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

Frigg (PL903) is a re-development of the Frigg field based on the remaining gas reserves migrated towards the top of the structure. Aker BP has no ownership in this licence.

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.

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 2900 mTVD to approximately 3800 mTVD.

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

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 proposed in March 2019 and DG3 is planned in late 2019. First oil is expected in Q4 2022. The schedule dependent on a concept select being agreed in the licences.

The gross resource potential in the NOAKA area is more than 550 mmboe. The net resource potential for Aker BP for the NOAKA area ranges from 200 to 430 mboe.

4.2 Alvheim Area

The Gekko (PL203) gas discovery is located approximately 10 km south-east of Alvheim, see Fig.3.2, and was discovered back in 1974. The reservoir sandstones are within the Paleocene Heimdal Formation. Current plan involves drilling an appraisal well in end 2020, and to develop the field with two gas producers with production through a subsea template towards Alvheim FPSO. Possible production start is 2021. Aker BP holds a 65% share in the discovery.

Other promising discoveries in the Alvheim area are Trine (6 to 19 mmboe), Trell (3-10 mmboe) and the volumes of the Frosk development beyond the two years of test production (18-30 mmboe), all volumes net to Aker BP.

4.3 Valhall Area

Several projects which may incease 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 Additional infill drilling
- Valhall Water Flooding West Flank
- Valhall South West Flank Infill
- Valhall North Flank Injection
- Valhall WP waterflooding
- Hod Redevelopment including 6 wells
- Hod Field development expansion
- Valhall and Hod Diatomite developments

Some of these projects are expected to be sanctioned within 2019/2020, while other will need further maturing prior to sanction.

The combined net resource potential for Aker BP for the Valhall Area ranges from 156 to 452 mmboe.

4.4 Skarv Area

The largest undeveloped discovery in the Skarv area is the Alve Nord. Alve Nord was acquired from Total during 2018, and is expected to be tied into the Skarv FPSO. The resources are primarily located in mid/lower Juraasic sands in the Fangst- and Båtgruppen. Alve Nord has a resource potential between 34 and 65 mmboe. Aker BP holds 100% in Alve Nord.

The Gråsel discovery may contribute with minor amount of oil and gas. The Gråsel discovery was made by the Skarv discovery well 6507/5-1 in 1998. The reservoir units consists of the Late Cretaceous Lange Fm. The discovery has been penetrated by five Skarv wells and current development plan includes reuse of one Skarv producer and one Skarv injector. The net resource potential for Aker BP Gråsel ranges from 1 to 3 mmboe.

4.5 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 100% of King Lear.

In addition, using the gas from King Lear to supplement the WAG-process in the Ula field is expected to generate another up to 31 mmboe net volumes (based on an Aker BP share of 80% in the Ula field).

Other interesting resources in the Ula area includes Ula Triassic development (3-17 mmboe net) and development of the Krabbe discovery (10 to 16 mmboe net).

4.6 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 3700 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 un-appraised.

Up-dated volume estimates indicates a net resource potential ranging from 15 to 20 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 indicates production start in 2024.

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

4.7 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 third appraisal well is currently under evaluation, with a possible drilling date in 2020.

A possible development will most likely be a common development with the Alta discovery. Current net recourse potential to Aker BP ranges from 10 to 69 mmboe.

Lundin is operator for the licence and Aker BP holds a 60% share in PL492.

Other

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

The combined net resource potential for Aker BP for these projects ranges from 6 to 27 mmboe.

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 on the basis of 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 7.5 NOK/USD, and a long term oil price of 65 USD/bbl (real 2018 terms).

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 close down producing fields early and lead to lower production. Higher oil prices may extend the life time of the fields beyond what is currently assumed.

Karl Johnny Hersvik
CEO