ANNUAL STATEMENT OF RESERVES 2016

AKER BP ASA

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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.

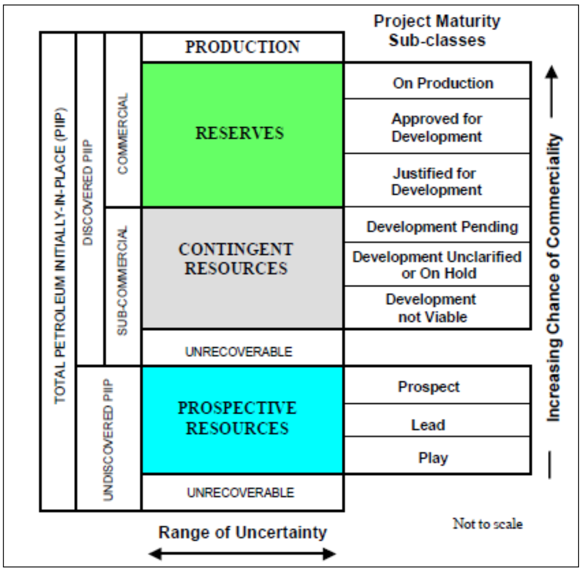

Fig. 1.1 SPE reserves and recourses classification systen

2 Reserves, Developed and Non-Developed

Note that an independent third party, AGR Reservoir Services, has certified all reserves except for the ex BP Norge Fields. These assets were evaluated by a third party in the merger process in June 2016. As this third party assessment concluded with higher reserve estimates than Aker BP's own estimates, it was decided that a new certification of these assets was not needed at this time.

Aker BP ASA has a working interest in 28 fields/projects containing reserves, see Table 2.1 . Out of these fields/projects, 13 are in the sub-class “On Production”/Developed, eight are in the sub-class “Approved for Development”/Undeveloped and seven are in the sub-class “Justified for Development”/Undeveloped. Note that the 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	Norwegian part
Viper/Kobra	65 %	Aker BP	On Production	Moved from Approved for Development
Vilje	46.9 %	Aker BP	On Production	
Volund Base	65 %	Aker BP	On Production	
Bøyla	65 %	Aker BP	On Production	
Atla	10 %	Total	On Production	
Ula Base	80 %	Aker BP	On Production	New - Det norske and BP Norge merger
Tambar Base	55 %	Aker BP	On Production	New - Det norske and BP Norge merger
Tambar East	46 %	Aker BP	On Production	New - Det norske and BP Norge merger
Valhall Base	36 %	Aker BP	On Production	New - Det norske and BP Norge merger
Hod	38 %	Aker BP	On Production	New - Det norske and BP Norge merger
Skarv	24 %	Aker BP	On Production	New - Det norske and BP Norge merger
Ivar Aasen	34.8%	Aker BP	On Production	Moved from Approved for Development
Undeveloped Reserves				
Volund infill wells	65 %	Aker BP	Approved for Development	Two infill wells 2017
Gina Krog	3.3 %	Statoil	Approved for Development	Production start 2017
Alvheim Boa Infill South	65 %	Aker BP	Approved for Development	Infill well 2017
Alvheim Boa Infill North	65 %	Aker BP	Approved for Development	Infill well 2017
Valhall 7 IP wells	36 %	Aker BP	Approved for Development	7 infill wells starting 2017
Alvheim Kameleon Gas Blowdown (Phase 3)	65 %	Aker BP	Approved for Development	Gas blowdown - start ~ 2028
Johan Sverdrup	11.7 %	Statoil	Approved for Development	Phase 1 and Phase 2
Hanz	35 %	Aker BP	Approved for Development	
Snadd test production well A-1H	24 %	Aker BP	Approved for Development	Volumes from test production well A-1H only
Ula - Effect of Tambar artificial lift project (TAL)	80 %	Aker BP	Justified for Development	New - increased gas for WAG from Tambar gas lift project
Ula - Effecct from Tambar infill well south (TIS)	80 %	Aker BP	Justified for Development	New - increased gas for WAG from Tambar infill well south
Ula - Effect from Oda tie-in	80 %	Aker BP	Justified for Development	New - increased gas for WAG from Tambar gas lift project
Tambar artificial lift project	55 %	Aker BP	Justified for Development	New - Tambar artificial lift project
Tambar infill well south	55 %	Aker BP	Justified for Development	New - infill well in Tambar south
Oda	15 %	Aker BP	Justified for Development	New - Thullow acquisition

Total net proven reserves (P90/1P) as of 31.12.2016 to Aker BP are estimated at 529 million barrels of oil equivalents. Total net proven plus probable reserves (P50/2P) are estimated at 711 million barrels of oil equivalents. The split between liquid and gas and between the different subcategories are given in Table 2.2.

Table 2.2 Aker BP 1P and 2P reserves as of 31.12.2016

As of 31.12.2016	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	65.0	58.7	-	5.7	64.4	41.9	76.0	-	9.1	85.1	55.3
Viper/Kobra	65.0	5.5	-	0.5	6.0	3.9	8.9	-	0.7	9.6	6.2
Vilje	46.9	14.3	-	-	14.3	6.7	18.9	-	-	18.9	8.9
Volund	65.0	6.1	-	0.1	6.3	4.1	12.7	-	1.0	13.7	8.9
Bøyla	65.0	7.5	-	0.3	7.8	5.1	12.7	-	0.6	13.3	8.7
Atla	10.0	0.4	-	0.2	0.6	0.1	0.4	-	0.3	0.8	0.1
Ula	80.0	24.8	1.2	-	26.0	20.8	47.7	2.4	-	50.1	40.1
Tambar	55.0	0.7	0.1	0.1	0.9	0.5	1.4	0.1	0.2	1.7	0.9
Tambar East	46.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Valhall	36.0	97.8	3.8	14.7	116.2	41.8	128.2	5.1	19.7	153.0	55.0
Hod	37.5	3.5	0.1	0.5	4.1	1.6	4.2	0.2	0.6	4.9	1.8
Skarv	23.8	28.8	31.7	119.4	179.0	42.7	45.2	32.8	147.7	225.6	53.8
Ivar Aasen	34.8	5.5	7.7	20.8	134.8	46.9	144.4	10.1	27.1	181.6	63.2
Total		**353.6**	**44.6**	**162.3**	**560.5**	**215.9**	**500.7**	**50.6**	**207.0**	**758.3**	**302.9**
Approved for Development											
Johan Sverdrup	11.6	1961.2	50.1	63.4	2074.6	240.1	2452.0	62.6	79.2	2593.8	300.2
Hanz	35.0	11.7	0.6	1.6	14.0	4.9	14.4	0.8	2.3	17.5	6.1
Alvheim Phase 3	65.0	-	-	13.1	13.1	8.5	-	-	21.1	21.1	13.7
Alvheim Boa IFS	65.0	2.9	-	0.9	**3.8**	**2.5**	4.9	-	1.3	6.2	4.0
Alvheim Boa IFN	65.0	3.1	-	1.4	4.5	2.9	4.6	-	2.0	6.6	4.3
Valhall 7 IP Wells	36.0	46.0	1.7	6.6	54.3	19.5	60.3	3.1	12.1	75.5	27.2
Volund Infill	65.0	8.9	-	0.9	9.8	6.4	13.5	-	1.2	14.7	9.6
Gina Krog	3.3	81.7	31.7	56.7	170.1	5.6	105.7	38.6	74.5	218.7	7.2
Total		**2115.4**	**84.1**	**144.6**	**2344.1**	**290.4**	2655.4	105.1	193.8	2954.2	372.3
Justified for Development											
Snadd A-1H	23.8	5.0	7.0	31.7	43.7	10.4	6.0	8.8	33.9	54.6	13.0
Ula TAL effect	80.0	0.9	0.0	-	0.9	0.8	1.9	0.1	-	2.0	1.6
Ula Oda effect	80.0	2.7	0.1	-	2.8	2.2	5.8	0.3	-	6.1	4.9
Ula Tambar IFS effect	80.0	0.3	0.0	-	0.4	0.3	2.5	0.1	-	2.6	2.1
Tambar artficial lift	55.0	2.7	0.1	0.6	3.4	1.9	4.1	0.2	0.9	5.2	2.8
Tambar infill south	55.0	3.6	0.2	1.0	4.8	2.7	6.0	0.3	1.6	7.9	4.3
Oda	15.0	28.3	-	1.7	30.0	4.5	45.2	-	2.9	48.1	7.2
Total		**43.6**	**7.5**	**35.0**	**86.1**	**22.7**	**71.3**	**9.8**	**45.3**	**126.4**	**35.9**
Total Reserves		**2512.6**	**136.2**	**341.9**	**2990.7**	**529.0**	**3227.4**	**165.5**	**446.1**	**3839.0**	**711.1**

Changes from 2015 reserve report are summarized in Table 2.3. The main reason for increased net reserve estimate is the acquisition (merger with) BP Norge. As of 31.12.2016 these assets represent approximately 28% of the company's total reserves.

Table 2.3 Aggregated reserves, production, developments, aqcusitions, IOR, extensions and revisions

Net attibute million barrels of oil equivavalents (mmboe)	On Poduction		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 31.12.2015	**56**	**84**	**317**	**414**	**-**	**-**	**374**	**498**
Production	-28	-28	-	-	-	-	-28	-28
Transfer	56	77	-56	-77	-	-	0	0
Revisions	19	13	4	0	-	-	23	13
IOR	-	-	5	8	-	-	5	8
Discovery and Extensions	-	-	-	-	-	-	-	-
Aqcusition and sale	112	156	20	27	23	36	154	219
Balance as of 31.12.2016	**216**	**303**	**290**	**372**	**23**	**36**	**529**	**711**
Delta	**160**	**219**	**-27**	**-42**	**23**	**36**	**155**	**213**

Johan Sverdrup is still the most important contributer to Aker BP reserves. After the merger between Det norske and BP Norge however, the company reserves share from Sverdrup has been reduced from approximately 61% in 2015 to approximately 42% in 2016.

Except for acquisition of the former BP Norge fields and Oda (15% from Tullow) there has been only minor changes in reserve estimates. Ivar Aasen and Viper/Kobra commenced production in 2016 and has been reclassified from “Approved for Production” (Undeveloped”) to “On production” (Developed) reserves. In addition, two infill wells on Alvheim were sanctioned in December 2016 and have been included as “Approved for Development”.

The future oil price assumption for the reserves given in Table 1 below is 60.6 USD/bbl. A sensitivity with a higher oil price of 75 USD/bbl had only minor impact on net total reserves to Aker BP with an increase of proved net reserves of two percent compared to base price assumption. The higher oil price has no effect on net proved plus probable (2P/P50) reserves. In addition, a lower price scenario with an oil price of 45 USD/bbl has been run. This gives marginal lower reserve compared to the base price assumption with a three and two percent reduction in proved (1P/P50) reserves and proved plus probable (2P/P50) reserves respectively.

Total net production to Aker BP averaged 77 mboepd (total 28 mmboe) in 2016 including volumes from former BP Norge AS fields from September 30th 2016.

3 Description of Reserves

3.1 Producing Assets

The following chapter describes the reserve assessment from all producing fields. Please note that the 2016 produced volumes reported herein may differ slightly from volumes reported as sales volumes in quarterly reports etc. The reason is that the 2016 volumes in this report are based on actual production from January 1.st 2016 to September 30th 2016 and forecast for the period October 1st 2016 to December 31st 2016. These volumes are used for assessment of remaining reserves as of 31.12.2016.

3.1.1 Alvheim and Viper/Kobra (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

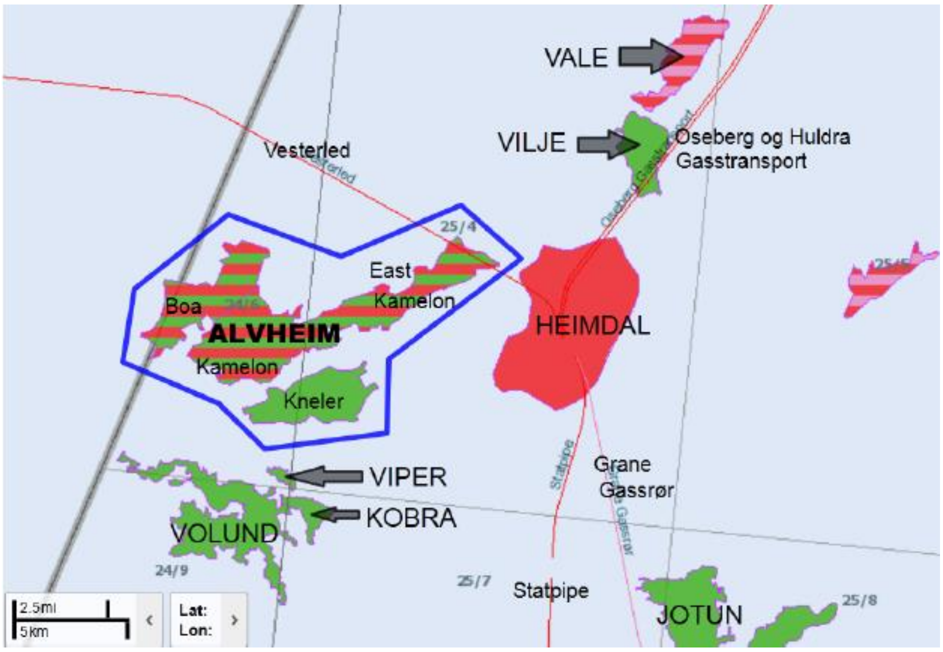

Fig. 3.1 Alvheim and Viper/Kobra Location Map
Alvheim Fiels is divided into the Boa (partly on UK side), Kameleon and Kneler structures

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 remobilized 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 oil leg and 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 and several of the wells are multilaterals. The recovery method is natural water drive from the active underlying aquifer.

Viper and Kobra were developed in 2016 with one horizontal well in Viper and a bilateral 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 pipeline and riser.

Status

The PDO for Alvheim was approved in October 2004, and production started in June 2008. Alvheim is producing beyond expectations and there has been a gradual increase in the estimated ultimate recovery (EUR) as a result of development drilling.

In May 2016 the trilateral well B5 (BoaKamNorth) started to produce from the Boa subsea manifold. The well crosses the boundary defined for the Boa and Alvheim unit areas, and reserves are split 35/65 between the Boa and Alvheim units. It was put on production with excellent results, leading to an increase in both STOIIP and reserves from the Boa and Kameleon reservoirs. Production from Viper and Kobra started in November 2016.

The field is consequently reclassified from “Approved for Development” to “On Production”. The fields produce according to plan.

Two infill wells on Alvheim were sanctioned in December 2016 and the reserves have been included as “Approved for Development” with a total 2P net reserve estimate of 8.3 mmboe. These infill wells will be targeting attic and flank oil in the Boa field.

4D seismic has been successful in targeting infill wells on Alvheim. A new repeat survey is planned for 2Q 2017 and the data will be used for Aker BP’s continuous focus on maturing additional targets for infill wells. It is anticipated that one or two additional targets will be sanctioned within 2017/2018.

The blowdown of the Kameleon gas cap is anticipated to take place from October 2028. The gas cap blowdown was covered by the original PDO and the reserves are included as “Approved for Development”.

Net production from Alvheim, including Boa and Viper/Kobra, averaged 43.4 mboepd in 2016 which is approximately 14 % 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 unitized with Maersk Oil & Gas and Verus Petroleum, who are the owners on the UK side. AkerBP's interest in the Boa unit is 57.62%. This document only describes the reserves on the Norwegian side.

3.1.2 Vilje (PL036D)

The Vilje Field is located 5 km north-east of the Heimdal production facility in block 25/4 licensed under PL036D in the North Sea. Production started in 2008. Fig. 3.2 shows the location of the asset.

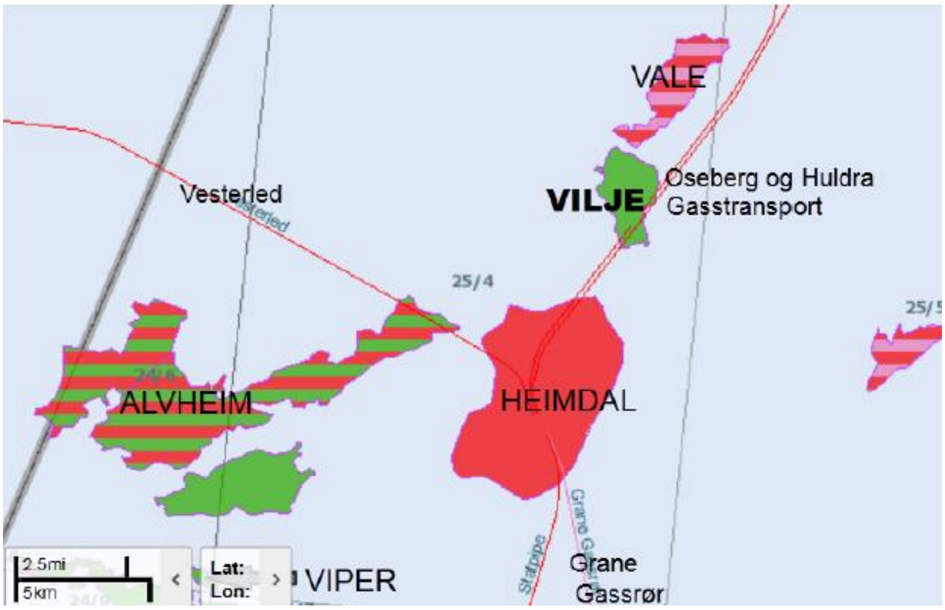

Fig. 3.2 Vilje location map

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 more or less 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- , whereof R1 and R3 are clean sands while R2 is a fine-grained muddy layer which is acting as a baffle to fluid flow.

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

Status
The PDO was approved in March 2005, and production started from the Vilje Main structure in August 2008. Vilje South was put on production in April 2014. Plateau oil production was 5000-6000 Sm3/d until July 2012. Water breakthrough occurred in July 2011 and currently the oil rate is approximately 12.6 mbpd. The lower branch in well VI2 was shut-in in 2011 and was reopened in April 2016, increasing the production rate with over 6.3 mboepd. However, due to increased water-cut, the production is again declining since the reopening. The upper branch of VI2 has been shut-in from July 2016. The plan is to re-open this branch in October 2017.

Net production from Vilje averaged 6.8 mboepd in 2016 which is approximately 40% 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 2031, 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 license and serves as operator. The other license partners are Statoil Petroleum AS 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 located 10 km south of the Alvheim Field and in block 24/9 licensed under PL 150 in the North Sea. Production started in 2010. Aker BP acquired Marathon's share and operatorship in 2014. Fig. 3.3 shows the location of the asset.

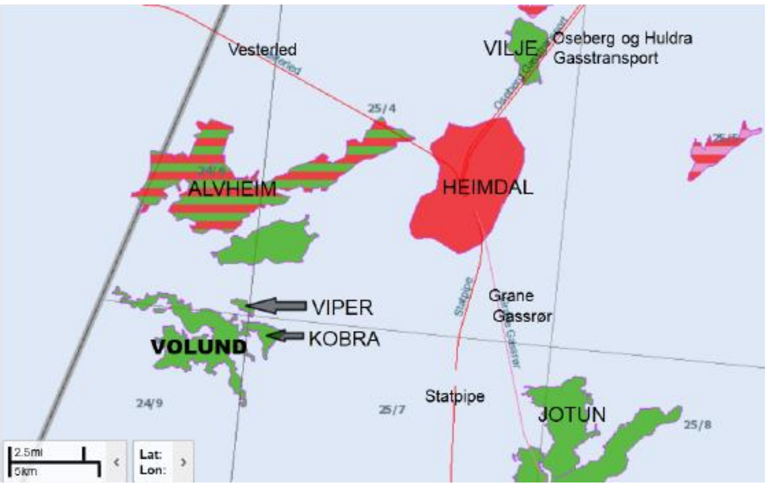

Fig. 3.3 Volund location map

Discovery
Volund Field was discovered in 1994 by well 24/9-5. The Intra Balder Formation sandstone was encountered with oil in the interval 2011 m to 2018 m MD (oil down to). The discovery was appraised by wells 24/9-6 and 24/9-7, confirming a fieldwide 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 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, the majority within cross-cutting dykes.

The production from 4 wells with a total of 5 producing laterals is supported by water injection in one water injector and by natural water influx.

Development
The Volund field is located approximately eight km south of Alvheim, and was the second field developed as a subsea tieback to Alvheim. The Volund field, comprising of four production wells and one water injection well, started producing in 2009 and was initially utilized as a swing producer towards the Alvheim processing facilities. The field was opened for regular production in 2010.

The current 5 producing laterals (3 single-laterals and 1 dual-lateral) target the ~100 m oil column in the wings, supported by a water injector in the sill in addition to natural water influx.

Status
A drilling campaign consisting of two infill wells was sanctioned in 2015. These two wells are included as reserves “Approved for Development”. The drilling of these wells started in December 2016 and production is expected to mid 2017.

The recoverable volumes for the existing producers are classified as "Reserves; On Production", while the volumes from the two infill wells are classified as "Reserves; Approved for Development" (SPE's classification system).

Net production at Volund averaged 5.0 mboepd in 2016 which is approximately 14% 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 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 2000 m TVD MSL. The location of the Boyla Field is shown in Fig. 3.4.

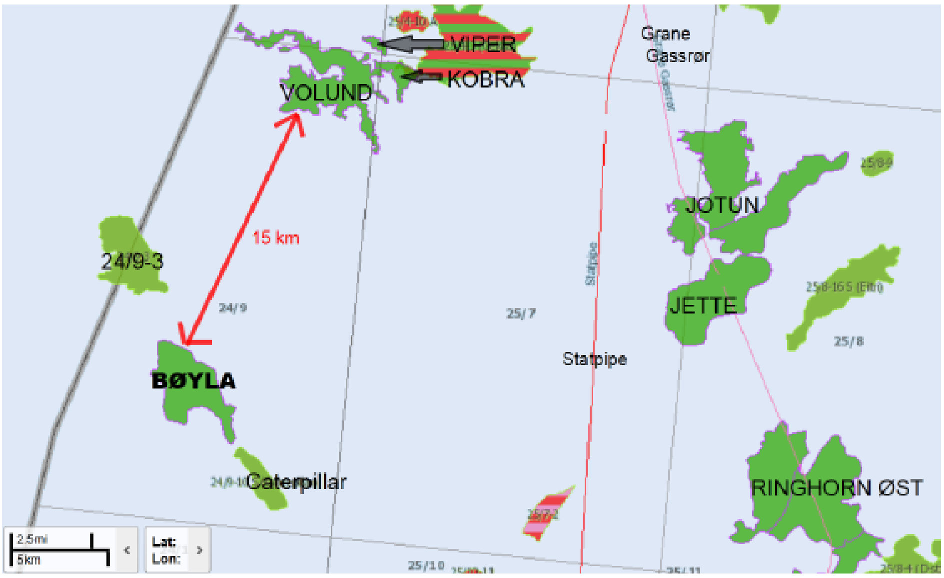

Fig. 3.4 Bøyla location map

Discovery
The Boyla Field was discovered in 2009 by well 24/9-9 S. The initial discovery name was "Marihone A". The well proved under-saturated oil at normal pressure with a WOC at 2071 m TVD MSL. Subsequent pilot and development wells have confirmed the WOC across the field.

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 sandstone is thought 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. The connectivity between these two parts of the reservoir is limited even though the pre-drilled wells confirmed a consistent oil water contact. Injection testing of the single water injector has proved sufficient injectivity and interference between the injector (M3) and the western producer (M1) but communication between the injector and the eastern producer (M2) appears very limited.

Development
The Bøyla field is located south of Volund approximately 28 kilometers from Alvheim at a water depth of 120 meters. The field is developed with two horizontal producers (targeting each of the eastern and western structural closures) and one water injector, located at the eastern edge of the western structural closure and between the two producers. The field produces via a four-slot subsea production manifold and is tied-back to the Alvheim FPSO via the Kneler A production manifold.

Status
The PDO was submitted in June 2012. Well M-01 BH, on the north western flank, started to produce in January 2015. Injector M-02 AH started March 2015 and the second producer on the south eastern flank M-02 HT3 started in August 2015.

Net production at Bøyla averaged 7.4 mboepd in 2016 which is in line with prognosed volumes. Cessation of production from the Bøyla field is expected in 2033 together with abandonment activities relating to the other Alvheim Area fields.

The recoverable volumes are classified as "On production" (SPE's classification system).

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

3.1.5 Atla (PL102C)

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

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 meters.

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 is predicted to cease in 2017. The proved (1P/P90) and proved plus probable (2P/P50) reserve estimates reflect Skirne compensation of gas and condensate to Atla. The base 2P/P50 case consider 2 months of Atla production in 2017, which means 2 months without condensate transfer from Skirne. The volumes not transferred in 2017 will be transferred in 2018 instead. Skirne gas transfer to Atla can be performed while the two fields are producing simultaneously.

Net production from Atla averaged 0.1 mboepd in 2016.

Aker BP holds a 10% interest in the license. 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.

3.1.6 Jette (PL027D), PL169C, PL504)

Jette is a small oil field in the central part of the North Sea in a water depth of 127 meters.

Discovery
The Jette Field was discovered in 2009 by well 25/8-17.

Reservoir
The reservoir consists of a submarine fan system in the Heimdal Formation of Late Palaeocene age, and lies at a depth of approximately 2,200 meters. The depletion strategy has been natural depletion with support from natural water influx.

Development
The field has been developed with a subsea installation tied back to the Jotun B platform. The development includes of two subsea completed horizontal producers tied back to Jotun A.

Status
Production from Jette ceased in December 2016 and no reserves are reported as of 31.12.2016. Net production from Jette averaged 0.6 mboepd in 2016.

Aker BP interest in the Jette unit is 70% while Petoro AS holds the remaining 30% interest.

3.1.7 Jotun (PL027B, PL203B)

Jotun is an oil field located in the central part of the North Sea in a water depth of approximately 126 meters.

Discovery
The Jotun Field was discovered in 1995 by well 25/8-5 S.

Reservoir
The Jotun unit comprises three structures; the easternmost structure has a small gas cap. The reservoirs consist of sandstones in the Heimdal Formation of Palaeocene age. The reservoirs, which consist of deposits of a submarine fan system, are at a depth of about 2,000 meters. To the west, the reservoir quality is good, while the shale content increases towards the east. The depletion strategy has been natural depletion with support from natural water influx and gaslift.

Development
The Jotun installations comprise of an FPSO, Jotun A, and a wellhead platform, Jotun B. Production commenced in 1999. A firm plan for closing down the Jotun production has been establish and the production ceased in Decemebr 2016.

Status
Production from Jotun ceased in December 2016 and no reserves are reported as of 31.12.2016.

Aker BP (Det norske) reported no reserves from Jotun as of 31.12.2015. The reason being that the anticipated 2016 production would be cash negative. The field continued however to produce until December 2016. Net production at Jotun averaged 0.08 mboepd in 2016.

Aker BPs interest in the unit is 7%. The operator is ExxonMobil Exploration & Production Norway AS with a 90% interest. The other licensee is Faroe Petroleum Norge AS with a 3% interest.

3.1.8 Varg (PL038)

The Varg Field is an oil field located in the central part of the North Sea at a water depth of 84 meters.

Discovery
The Varg Field was discovered in 1985 by well 15/12-4.

Reservoir
The reservoir is in Upper Jurassic sandstones at a depth of approximately 2,700 meters. The structure is segmented and includes several isolated compartments with varying reservoir properties. Varg has been drained with support from water- and gas injection and gas lift in all producers. Initially all gas was used for injection until gas export commenced in 2014.

Development
Varg is developed with a wellhead platform, Varg A, and an FPSO, Petrojarl Varg. Varg A is

normally unmanned. The wellhead platform and the FPSO are connected through flexible pipelines for oil production, water and gas injection and umbilical for power supply and control. The oil is offloaded from the FPSO to shuttle tankers via a discharging system located on the FPSO. A gas pipeline was installed beween Varg and the nearby gas field Rev for gas export to UK via the Central Area Transmission System (CATS)

Status
Production from Varg ceased in June 2016.

Also for the Varg Field Aker BP did not report any commercial reserves as of 31.12.2015. The field continued however to produce until June 2016.

Net production from Varg averaged 0.17 mboepd in 2016.

Aker BP holds a 5% interest in the license, while the operator Repsol Norge holds 65%. The remaining 30% is held by Petoro AS.

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

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 Ivar Aasen Field includes two accumulations; Ivar Aasen and West Cable, Fig. 3.5. The accumulations cover several licenses and have been unitized into the Ivar Aasen Unit.

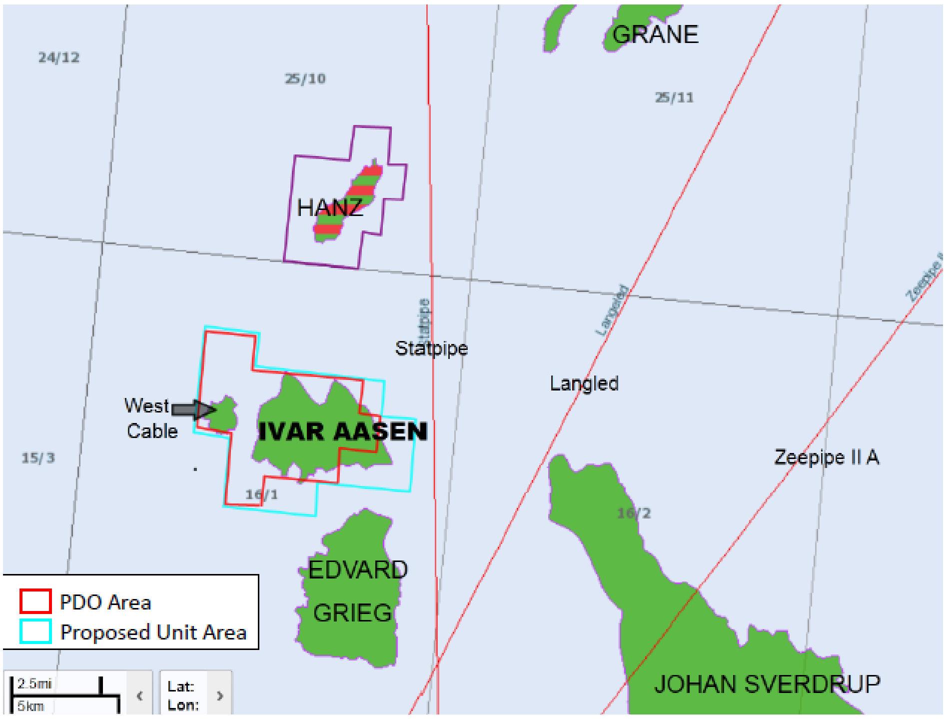

Fig. 3.5 Ivar Aasen Unit and Hanz location map

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 first

classified as dry, but was re-classified as an oil discovery after re-examination. 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 consists of shallow marine sandstones in the Hugin Formation and fluvial sandstones in the Sleipner and Skagerrak Formations. The reservoir contains oil at a depth of approximately 2,400 meters. The reservoir ha a small overlying gascap.

Development
The Ivar Aasen unit development plan (Ivar Aasen and West Cable discoveries) includes production of the reserves also from the Hanz (PL028B) discovery. The approved PDO sets out that Ivar Aasen and West Cable (Ivar Aasen Unit) will be developed in the first phase and Hanz in the second phase.

The Ivar Aasen and West Cable discoveries are developed with a steel jacket including living quarters and process facilities located at a water depth of 110 metres, with dry well heads on the platform drilled from a jack-up rig. Water will be removed from the well stream on the platform and oil and gas rates are measured before transportation through multiphase pipelines to the Edvard Grieg installation for stabilization and export. Edward Grieg will also cover Ivar Aasen power demand until a joint solution for power from shore is established.

The drainage strategy for the Ivar Aasen structure assume water injection for pressure maintenance. West Cable will be produced through natural pressure support where the major driving force will be natural water influx and formation of a secondary gas cap.

In total seven producers (six targeting the Ivar Aasen structure and one in West Cable) and six water injectors (in the Ivar Aasen structure) are planned for the Ivar Aasen Field. The production wells will be completed with mechanical sand control and ICD completion while the injectors will have cemented perforated liners.

In Phase 2 of the area, the Hanz structure is planned developed with two subsea wells tied-back to the Ivar Aasen platform.

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.

Several development wells have been drilled on Ivar Aasen during 2015/2016. This includes five producers and and three injectors. All wells came in as expected, however, with more Skagerrak 2 Fm. and less Hugin Fm. compared to the previous geomodel. An up-dated geomodel was established after drilling of the 5 producers and the first injector. This model confirms the ultimate recovery reported in 2015 and there is consequently no changes to the reserve estimate.

After some initial slugging challenges in the Edvard Grieg flowline the field produces now steady according to the agreement with Edvard Grieg. Five wells are successfully been put on production. Water injection is scheduled to start in March/April 2017.

The recoverable volumes are classified as "Reserves / On Production".

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

3.1.10 Valhall (PL006B, PL033B)

Through the merger between Det norske Oljeselskap ASA and BP Norge AS in 2016 Aker BP acquired 36 % in the Valhall Field. The official takeover date for all the assets were 30th of September 2016. Hence Aker BP had production from these assets in 4th quarter 2016 only.

Valhall is an oil field in the southern part of the Norwegian sector of the North Sea, Fig. 3.6. The water depth is about 70 metres.

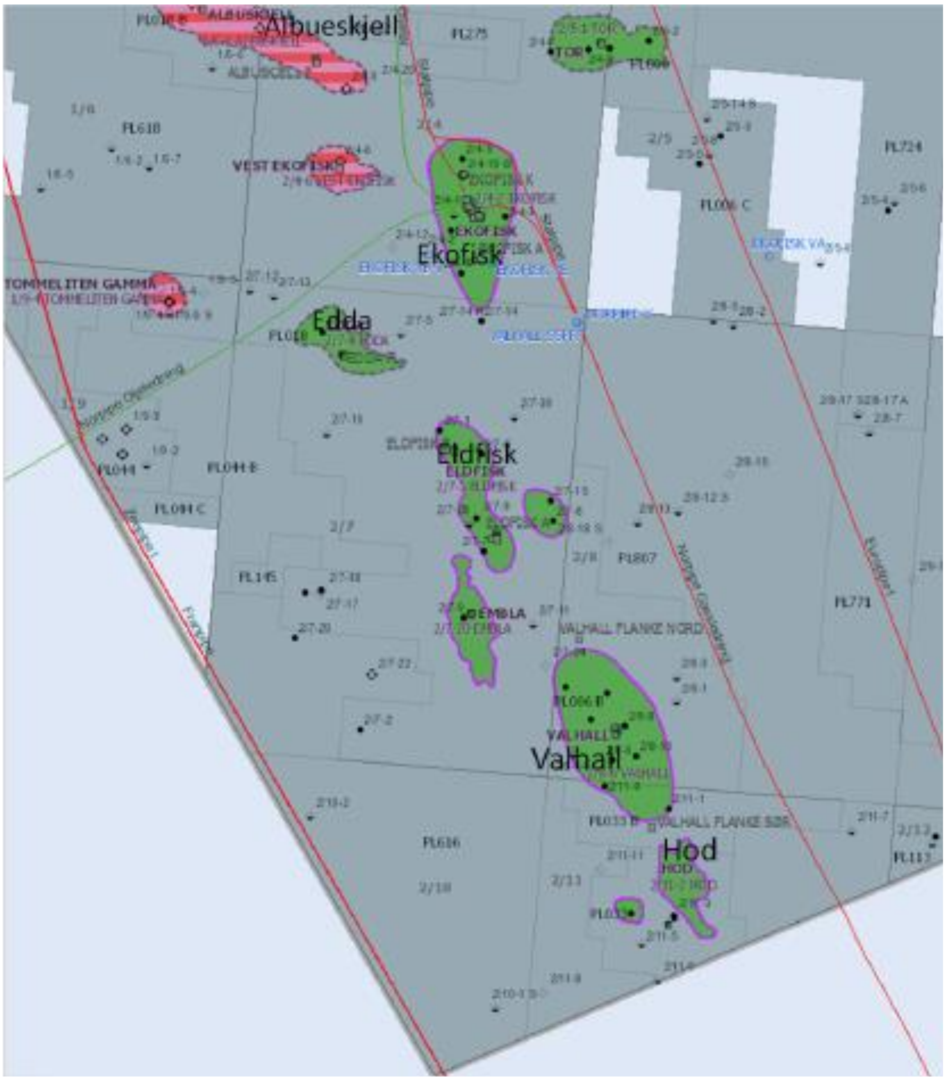

Fig. 3.6 Valhall and Hod location map

Discovery
Valhall was discovered by well 2/8-4-in 1973.

Reservoir
The reservoir consists of chalk in the Upper Cretaceous Tor and Hod Formations. Reservoir depth is approximately 2 400 meters. 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 field was initially produced with pressure depletion and compaction drive. Water injection in the central parts of the field started in 2004. Gas lift is used to optimize production in most of the production 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.

The PDO for Valhall flank development was approved in 2001. This development consisted of two wellhead platforms, one installed in the south of the field in 2003, and one in the north, installed in 2004. A PDO for Valhall Redevelopment was approved in 2007, with an accommodation and processing platform (PH) to replace ageing facilities on the field. The PH-platform started up in january 2013 and is supplied with power from shore.

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

Nearly 150 productive wells have been drilled on Valhall since start-up of which 49 wells are currently producing and 6 are injecting.

Work to establish gas lift in the wells on the flanks of the field is completed. Ocean Bottom Cable Seismic are utilised for reservoir management and to identify new well targets for remaining oil.

The reserves reported includes production from seven planned infill wells drilled from the injection platform in addition to the base production. The infill drilling campaign will commence in 1Q 2017 and fist oil is estimates late 2017.

Several other projects including development of the West Flank with a new wellhead platform as well as other identified projects and infill well targets are planned sanctioned in 2017 and onwards and will probably increase reserves further.

The 2P/P50 production profile indicates an economic cut-off in 2038.

Net production to Aker BP averaged 17.5 mboepd in the period October 1st to December 31st 2016.

Aker BP is Operator and holds a 35.95313% interest in the Valhall Unit. The remaining 64.04688% is held by Hess Norge AS.

3.1.11 Hod (PL033)

Through the merger between Det norske Oljeselskap ASA and BP Norge AS in 2016 Aker BP acquired 37.5 % in the Hod Field. The official takeover date for all the assets were 30th of September 2016. Hence Aker BP had production from these assets in 4th quarter 2016 only.

Hod is an oil field 13 kilometres south of the Valhall Field in the southern part of the Norwegian sector in the North Sea. There is a continuous hydrocarbon accumulation through a saddle area between the Valhall and Hod structures. The water depth is 72 metres. See Fig. 3.6

Discovery
Valhall was discovered by well 2/11-2 in 1974.

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 2 700 metres. The field consists of three structures: Hod Vest, Hod Ost and Hod Sadel.

The field is produced by pressure depletion.

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 4 are currently producing. The 4 producing wells are drilled from the Valhall South Flank platform and part of these wells extend into the Hod license. The equity split (between Valhall and Hod license) is based on 'length of well' in respective licenses. The allocated production rate to the 'Hod field'is in the range of 1500 boepd with a gentle decline towards 2035 (expected life time of Hod Saddle wells).

Net production to Aker BP averaged 0.6 mboepd in the period October 1st to December 31st 2016.

Aker BP is Operator and holds a 37.5 % interest in the Field. The remaining shares are held by Hess Norge AS (62.5%).

3.1.12 Ula (PL019)

Through the merger between Det norske Oljeselskap ASA and BP Norge AS in 2016 Aker BP acquired 80 % in the Ula Field. The official takeover date for all the BP Norge assets were 30th of September 2016. Hence Aker BP had production from these assets in 4th quarter 2016 only.

Discovery
Ula was discovered by well 7/12-2 in 1976.

Development
Ula is an oil field in the southern part of the Norwegian sector of the North Sea, Fig. 3.7. The water depth in the area is about 70 metres. The 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, Blane and Oselvar, and will

also be the processing facility for Oda. The oil is transported by pipeline via Ekofisk to Teesside in the UK. All gas is reinjected into the reservoir to increase oil recovery.

Fig. 3.7 Ula location map

<u>Reservoir</u>

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). Gas lift is used in the shallowest reservoir interval.

<u>Status</u>

42 wells have been drilled on Ula since start-up of which 7 wells are currently producing and 4 are injecting.

Based on the positive experiences with WAG effect on oil recovery, gradually more WAG wells are planned. In 2016, the partnership in production licence 405 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 2034.

Net production to Aker BP averaged approximately 5.1 mboepd in the period October 1st to December 31st 2016.

Aker BP is Operator and holds a 80% interest in the Ula Field. The remaining 20% shares are held by Dong E&P Norge AS.

3.1.13 Tambar (PL065)

Through the merger between Det norske Oljeselskap ASA and BP Norge AS in 2016 Aker BP acquired 55% in the Tambar Field. The official takeover date for all the BP Norge assets were 30th of September 2016. Hence Aker BP had production from these assets in 4th quarter 2016 only.

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 three producers have been drilled on Tambar since start-up of which one well is currently producing.

An artificial lift project is currently in progress on Tambar which will increase reserves and prolong field lifetime. Production start is scheduled to 2018. In addition an infill well in partly undepleted area south-east of well K-6 is planned drilled in 2018. The potential from the area is supported by 4D seismic. Reserves from these two project are classified as Undeveloped reserves.

Estimated cease of production for the Tambar Field is 2024 assuming gas lift availability and 1 infill well.

Net production to Aker BP from Tambar and Tambar East averaged approximately 2.1 mboepd in the period October 1st to December 31st 2016.

Aker BP is Operator and holds a 55% interest in the Tambar Field. The remaining 45% shares are held by Dong E&P Norge AS.

3.1.14 Tambar East (PL065, PL300, PL019B)

Through the merger between Det norske Oljeselskap ASA and BP Norge AS in 2016 Aker BP acquired 46.2 % in the Tambar East Field. The official takeover date for all the BP Norge assets were 30th of September 2016. Hence Aker BP had production from these assets in 4th quarter 2016 only.

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 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. 6.2. 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
There is one producer (K-5A) on Tambar East, and the well is currently producing cyclically with an average rate of 0.15 mboepd. The Tambar East well is anticipated to shut down in 2017 and no concrete plans for prolonging the production currently exist.

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%), Dong E&P Norge AS (5.44%) and KUFPEC Norway AS (0.80%).

3.1.15 Skarv/Snadd (PL262, PL159, PL212B, PL212)

Through the merger between Det norske Oljeselskap ASA and BP Norge AS in 2016 Aker BP acquired 23.835 % in the Skarv Field and the Snadd discovery. The official takeover date for all the BP Norge assets were 30th of September 2016. Hence Aker BP had production from these assets in 4th quarter 2016 only.

Skarv is located about 35 km southwest of the Norne Field in the northern part of the Norwegian Sea, Fig. 3.8. The water depth in the area is 350-450 metres. The Snadd discovery is located slightly West of the Skarv Field, Fig. 3.9. The water depth in the area is 350-450 metres. The Snadd discovery is located slightly west of the Skarv Field, Fig. 3.9

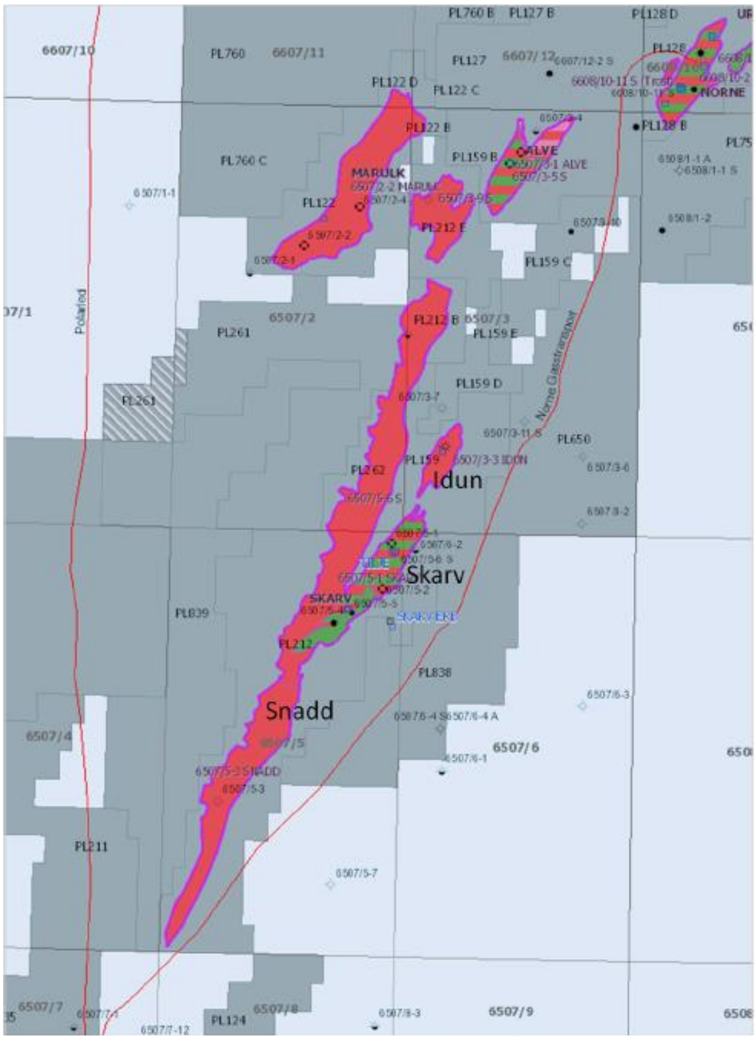

Fig. 3.9 Skarv and Snadd location map.

Discovery
Skarv was discovered in 1998 by well 6507/5-1. The Snadd discovery was proved gas bearing by well 6507/5-3 in 2000.

Development
Skarv is a joint development of the Skarv/Idun Field. The Snadd discovery is part of the Skarv Unit, but is presently not included in the current Skarv development. The Skarv development concept is a production, storage and offloading vessel (FPSO) tied to five subsea templates with 15 wells. The oil is loaded on to tankers, while the gas is exported in an 80 km pipeline connected to the Åsgard Transport System.

A plan for Development and Operation (PDO) for the Snadd discovery is planned late 2017. A test production well was however drilled on Snadd in 2013 utilizing an available slot on the Skarv subsea template A. The well is still on test production.

Reservoir
The reservoirs in Skarv contains gas and oil in Middle and Lower Jurassic sandstones in the Garn, Ile and Tilje Formations. The Garn Formation has good reservoir quality, while the Tilje Formation has relatively poor quality. The reservoirs are divided into several fault segments and lie at a depth of 3 300-3 700 m.

The Snadd reservoir consists of Cretaceous Lysing Fm sandstones which are high quality turbidite deposits. The reservoir is approximatively 60 km in a north-south direction and is 2-3 km wide

Status
Skarv production started in 2012. Further plans on Snadd is to issue a PDO (DG3) for the field in 2017 with assumed production startup in 2020. The development concept is satellite wells tied back to existing Skarv templates. Additional net reserves to Aker BP are estimated at 38 mmboe.

All reserves from Skarv reported herein are from producing wells and there are currently no plans for further development of the field.

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

3.2 Development Projects

3.2.1 Johan Sverdrup (PL265, PL501, PL502; Pl501B)

Johan Sverdrup is a giant oil field extending over four licences (PL265, PL501, PL501B and PL502), for which the unit agreement was signed by all parties in August 2015. The field is located on the eastern side of the Utsira High in the North Sea, approximately 155 km west of Stavanger; Fig. 3.10. The giant size calls for a phased development of the field. The PDO for the phase 1 development was issued in February 2015 and approved by the authorities in August 2015. A unit agreement was signed by all parties in August 2015. The unit agreement gives Aker BP an 11.5733% share of the field.

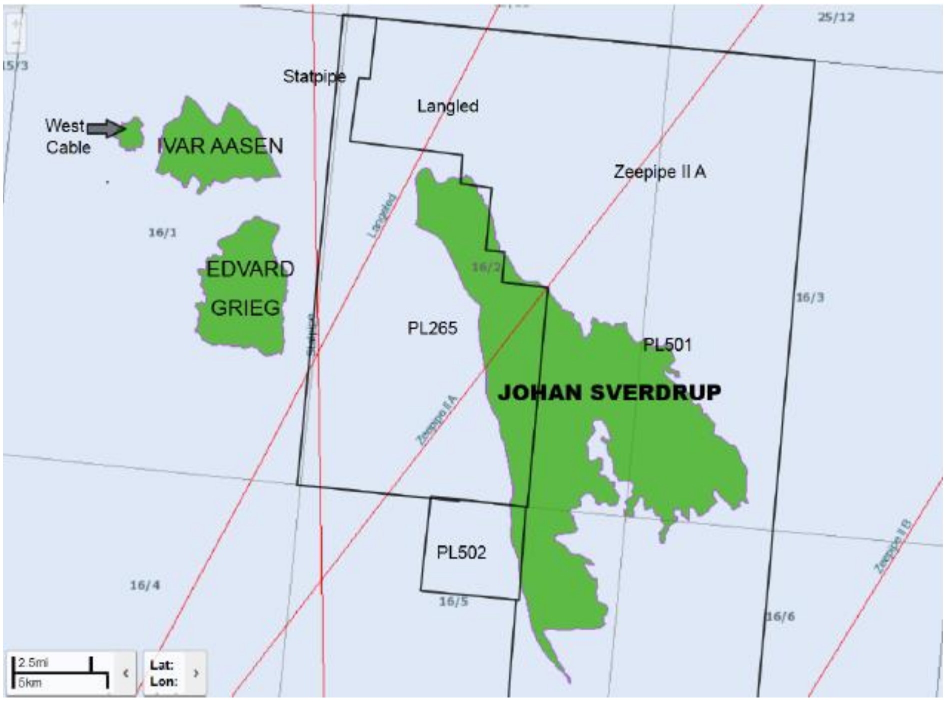

Fig. 3.10 Johan Sverdrup location map

Discovery

The discovery well 16/2-6 on the Johan Sverdrup discovery was drilled in 2010. The well proved oil in Jurassic and Triassic sandstones on the eastern part of the Utsira High. Since that time, almost 40 appraisal wells including sidetracks and pilots have been drilled plus 8 predrilled oil producers Seven drill stem tests have confirmed excellent reservoir properties with massive continuous sands with permeability of tens of Darcy in most of the field.

Reservoir

The reservoir consists of mid to late Jurassic sediments in the Draupne sandstone and in the older Statfjord Fm/Vestland group. The reservoir is characterized by excellent reservoir properties. The apex of the field is estimated 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 very 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 at the brink of seismic resolution.

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

The field will in general be developed with 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 center 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 the future phases is planned for the second half of 2018 and production start is planned in 2022. Fully developed, approximately 62 oil production and water injection wells will be drilled on Johan Sverdrup and the oil plateau production is expected to be approximately 660 mbopd.

DG2 for phase 2 is scheduled in March 2017. The development includes an additional processing platform (P2) located next to the riser platform at the field center, Fig. 3.11. 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, potentially plus one unmanned wellhead platform (UWP) in the eastern part of the field (final decision on this issue has not yet been taken).

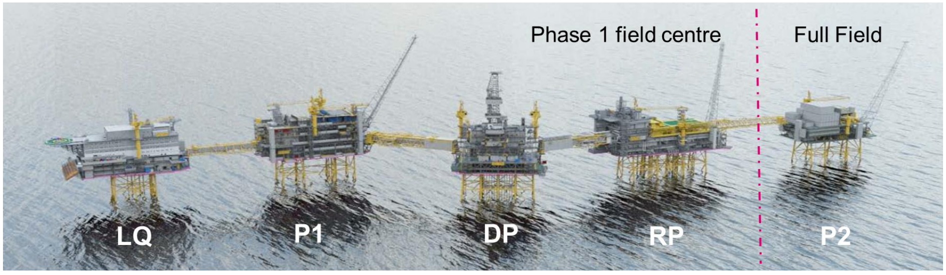

Fig. 3.11 Johan Sverdrup field center

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

Since last years report Statoil has predrilled eight producers and six pilot/ appraisal/ exploration wells including two sidetracks. All the predrilled producers which are located on the thicker central part of the field confirmed the reservoir model. Four of the appraisal wellbores proved thicker reservoir than predicted while an appraisal (exploration) well in the northern extreme part of the field did not find sufficient oilfilled reservoir for inclusion in the Phase 2 field development plan. Overall the pilot/ appraisal/ exploration well program confirmed the reservoir model.

Phase 1 development is proceeding closely according to plan. The facilities progress was at year end 2016 45.2% vs. 46.1% planned.

Substantial sub surface work has been carried out both of the Operator and Aker BP throughout 2016 indicating slightly higher full field reserve potential than reported last year. Aker BP has, however decided not to change the reserve estimates before more well results are available.

Note also that Aker BP has included reserves assuming a full field development of the field in the reserve base (both Phase 1 and Phase 2).

Several IOR/EOR technics are identified which may increase the reseves on Johan Sverdrup. The most promising are WAG (water alternating with gas injection) and infill drilling with a common potential in the range of some 25 mmboe net to Aker BP.

The unit agreement gives Aker BP an 11. 5733% share of the field. The remaining shares are held by Statoil (40.0267%), Lundin (22.6000%), Petoro (17.3600 %) and Maersk (8.4400%).

3.2.2 Gina Krog (PL029B)

The Gina Krog oil and gas field (previously the 15/5-1 Dagny Discovery) is situated in the south-eastern end of the Viking Graben at the north-western extension of the Sleipner Terrace, directly north of the Sleipner Vest Alfa Nord segment, Fig. 3.12. The water depth is 120 m. Statoil is the project Operator, and a unit agreement is signed covering the licences PL048, PL029C, PL 029B and PL 303.

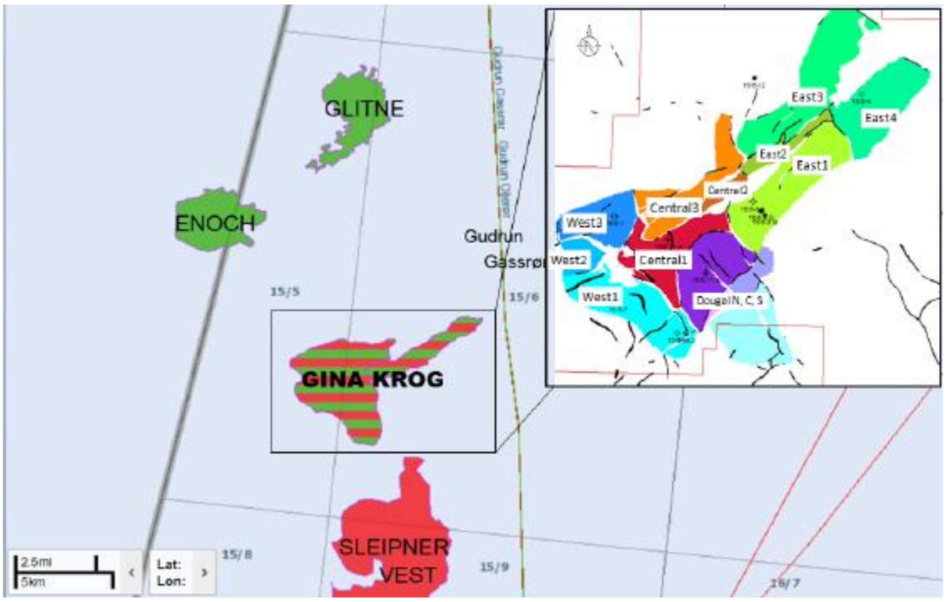

Fig. 3.12 Gina Krog location map.

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. According to the PDO the Gina Krog Field development will comprise of eight horizontal oil producers, three gas injectors and three gas producers.

Development

The development solution for Gina Krog is a new steel platform and a storage vessel for oil with a capacity of 850,000 barrels. Drilling is planned using a jack-up rig. Oil will be transported by tankers via offshore loading (FSU). The rich gas will be transported to Sleipner for processing and onto Gassled for export. Condensate and NGL will be exported to Kårstø, in Norway.

Injection gas will be imported from Gassled for crest gas injection. The gas injectors will be converted to gas producers when the injection phase is completed. In addition three gas producers are planned on structures containing gas only.

Status

The PDO was approved by the authorities in May 2013.

The development is proceeding according to plans and the offshore topside hook-up/ commissioning and completion work has commenced. During 2015/2016 four producers have been drilled. Results from the pre-drill campaign showed somewhat varying results. Updates of geomodels are ongoing and initial results indicates no reason for updating reserves on the field.

First oil is scheduled for second quarter 2017 and gas injection is scheduled to start late 2017.

The recoverable volumes are classified as "Reserves / Approved for development" (SPE's classification system).

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

3.2.3 Oda (PL405)

Aker BP acquired 15 % of the Oda Field (previously Butch) from Tullow Oil in 2016.

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 66m in the area, and the crest of the structure is estimated to be at 2300 m TVD MSL.

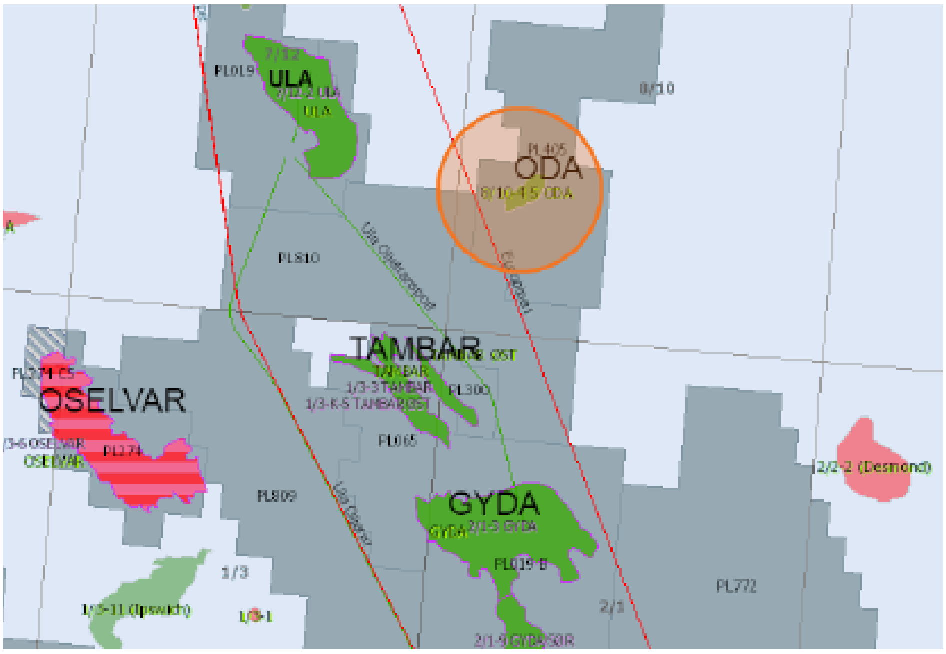

Fig. 3.13 Oda location map

Discovery
The discovery well 8/10-4 S was drilled in 2011 in the north-eastern 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 submitted on November 2016. Production start is expected in 019.

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

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 365 mmboe to 860 mmboe. Approximately 28% of this is associated with further development of the fields containing reserves described in 3 Description of Reserves

The most important contributors to this is the full field development of the Snadd Field with a scheduled sanction in 2017 and development of the Valhall West Flank with a scheduled sanction in 2018. 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 the Lower Hod Fm development on Valhall development 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.

North of Alvheim Area (NoA)
A possible development of the North of Alvheim includes the Frøy Field, The Frigg Gamma Delta discovery and the 2016 Langfjellet discovery.

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 is the operator for all the discoveries in the area and holds 100% interest in Frøy

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

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

Langfjellet (PL442, 25/2-18) was discovered 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. The wells were drilled four kilometres south of Frigg Gamma Delta and eight kilometres north of Frøy.

Aker BP holds 90.26% interest in the Langfjellet discovery.

The North of Alvheim (NoA) area is considered developed with a common hub on Frigg Gamma Delta, and tie-in of surrounding fields to the hub. Concepts that are being evaluated are fixed platforms and FPSOs as hub, and subsea templates and unmanned installations for tie-ins. Number of wells and complexity of the fields will determine which concepts that are selected for tie-ins. A DG2 decision is scheduled in late 2017 and DG3 one year later in Q4 2018. First oil is expected in Q1 2021.

An alternative solution is a combined development of the NOA and Askja/Krafla area.

Fig. 4.1 shows a North of Alvheim location map including Krafla/Askja area and the Rind and Storklakken discoveries.

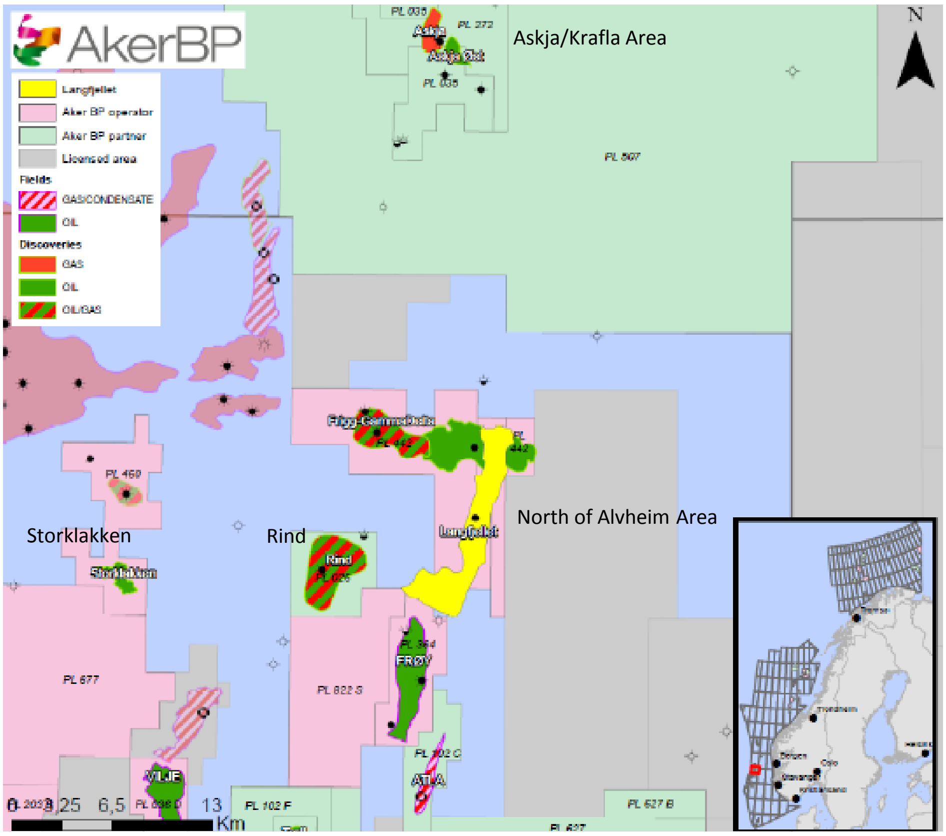

Fig. 4.1 North of Alvheim location map
Askja /Krafla area located north of NoA and the Rind and Storklakken discoveries to the west.

The combined net resource potential for Aker BP for the North of Alvheim Area ranges from 102 to 217 mmboe.

Askja/Krafla Area (PL272, PL035, PL035C)

The Krafla discoveries Krafla Main and Krafla West (wells 30/11-8S and 30/11-8A drilled in 2011) are located in the northern part of the North Sea, between the Oseberg and Frigg fields. The water depth is 108 meters. The Krafla discoveries were the first discoveries in the area.

Since the Krafla Main and Krafla West discoveries, several wells have been drilled within the licence. These includes:

- 30/11-8S, **Askja East** prospect in 2013 - oil discovery

- 30/11-9ST2, **Askja West** prospect in 2013/2014 - gas discovery
- 30/11-10S, **Krafla North** prospect in 2014 - oil discovery
- 30/11-10A, **Krafla Main** appraisal 2014/2015
- 30/11-11S, **Madame Felle** prospect in 2016 - oil discovery
- 30/11-11A, Viti prospect in 2016 - dry
- 30/11-12S, **Askja South East** prospect in 2016 - oil discovery
- 30/11-12A Askja SE downflank in 2016 - oil discovery
- 30/11-13 **Beerenberg** prospect in 2016 - gas discovery
- 30/11-14 **Slemmestad** prospect in 2016 - gas discovery
- 30/11-14B **Haraldsplass** prospect in 2016 gas discovery

Fig. 4.2 shows a location map of the Krafla/Askja area.

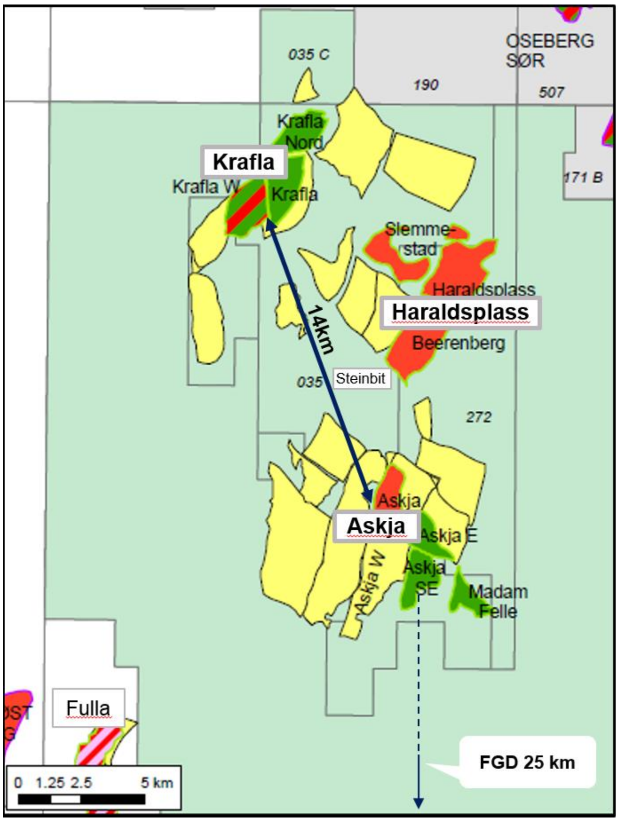

Fig. 4.2 Krafla/Askja area location map

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.

All the discoveries has been estimated using state of the art reservoir evaluation tools utilizing all available data. The combined net resource potential for Aker BP for the area ranges from 75 to 217 mmboe.

The Krafla project is in the concept selection phase, and the current schedule implies a DG2 in 2017.

Aker BP interest in license PL035/PL035C and PL272 is 50%. Statoil Petroleum AS is operator for the license and holds the remaining 50%.

Alvheim Area
The Gekko (PL203) gas discovery is located approximately 10 km south-east of Alvheim 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

The Caterpillar (PL340 BS) oil discovery is located some 35 km south of Alvheim and approximately 6 km south east of Bøyla and was discovered in March 2011. The reservoir consist of the Hermod Formation of late Paleocene age. Current volumes and profiles are based on an updated uncertainty assessment in August 2015. Base case development scenario assumes a single producer subsea tieback development to Alvheim FPSO with gas lift. Start-up is assumed in 2022.
Aker BP holds a 65% share in the discovery which gives net resource potential ranging from 4 to 7 million barrels of oil equivalents.

The Storklakken (PL460) oil discovery operated by Aker BP contains oil in the Heimdal Formation of Paleocene age. The discovery was made in 2010 and is located approximately 20 km northwest of Frøy and approximately 30 km northeast of Alvheim. The discovery will most likely be developed as a one multilateral subsea completed well tied back to the Alvheim FPSO. Current plans calls for a DG2 in 2017 and DG3 in 2018 with first oil in 2020.

Aker BP holds a 100% interest in PL460.

The combined net resource potential for Aker BP for the Alvheim area ranges from 20 to 41 mmboe.

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 New Wellhead Platform/West Flank Development
- Valhall Water Flooding West Flank NUI
- Valhall South Flank Infill
- Valhall North Flank Injection
- Lower Hod Development
- Valhall IP/WP Infill drilling
- Hod Redevelopment including 6 wells
- Hod East - Hod water flooding

Some of these projects are expected to be sanctioned within 2017 and 2018 while other will need further maturing prior to sanction.

The combined net resource potential for Aker BP for the Valhall Area ranges from 60 to 148 mmboe.

Skarv Area

Sanction of further development of the **Snadd Field** beyond the test production is expected within 2017. After more than three years of test production and five well penetrations the resource potential from the Field is well defined. A development solution satellite subsea wells tied back to the Skarv subsea templates with gas processing and export on the Skarv FPSO. The development will most likely take place in two phases with Phase 1 first gas in 2020 and Phase 2 first gas in 2024.

High quality turbidite sandstones of the Cretaceous Lysing Formation constitutes the reservoir section in Snadd.

In addition to the Snadd Field ther 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 combined net resource potential for Aker BP for the Skarv area ranges from 29 to 51 mmboe.

Garantiana (PL554)

The Garantiana discovery is an elongated structure with a gross ~100m 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 middle area has poorer characteristics and the northern area is un-appraised

Up-dated volumes estimates indicates a net resource potential ranging from 13 to 36 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 2021.

Total E&P is operator and Aker BP holds a 30% share in PL554.

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 planned in 2017 targeting more reservoir units in the northern part of the structure.

A possible development will most likely be a common development with a nearby discoveries. Current net recourse potential to Aker BP ranges from 47 to 110 mmboe.

Lundin is operator for the license and Aker BP holds a 40% share in PL492.

Other

Other resources classified in the resource classes "Development Pending" and "Development not clarified or on hold" includes the two Total operated Rind (PL026, 1976) and Trell (PL102F, 2014) discoveries, a very likely WAG project on Johan Sverdrup, infill wells on Gina Krog 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 20 to 40 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 20 years of experience in such assessments.

Additionally, all volumes included in former Det norske portfolio within the reserve category (except for the minor Enoch and Atla) have been certified by an independent third party consultancy (AGR Petroleum Services AS). These are the producing fields Alvheim (including Boa and Viper/Kobra), Vilje, Volund, Bøyla, Ivar Aasen and the fields under development; Hanz, Gina Krog, Johan Sverdrup and Oda.

The former BP Norge have not been certified by AGR. All production- and cost profiles are however included in AGR certification report for completeness and assessment of economic cut-off with Aker BP SPE PRMS price assumptions. These assets were evaluated by a third party in the merger process in June 2016. As this third party assessment is consequently more aggressive with higher reserve estimates than Aker BP's own estimates, Aker BP decided that a new certification of these assets for the year end reserve assessment was not necessary.

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 is set at zero cash flow or when facility lease expires. 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 60.6 USD/bbl (real 2016 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