Annual statement of reserves

2025

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Summary

Aker BP proven plus probable (2P) reserves as of 31 December 2025 are estimated at 1,526 million barrels of oil equivalent (mmboe), with proven (1P) reserves estimated at 1,035 mmboe. With a total 2025-production of 153 mmboe (corresponding to 420.1 thousand barrels of oil equivalent per day, mboepd), the company achieved a reserves replacement ratio of 72 percent (77 percent for 1P) during 2025.

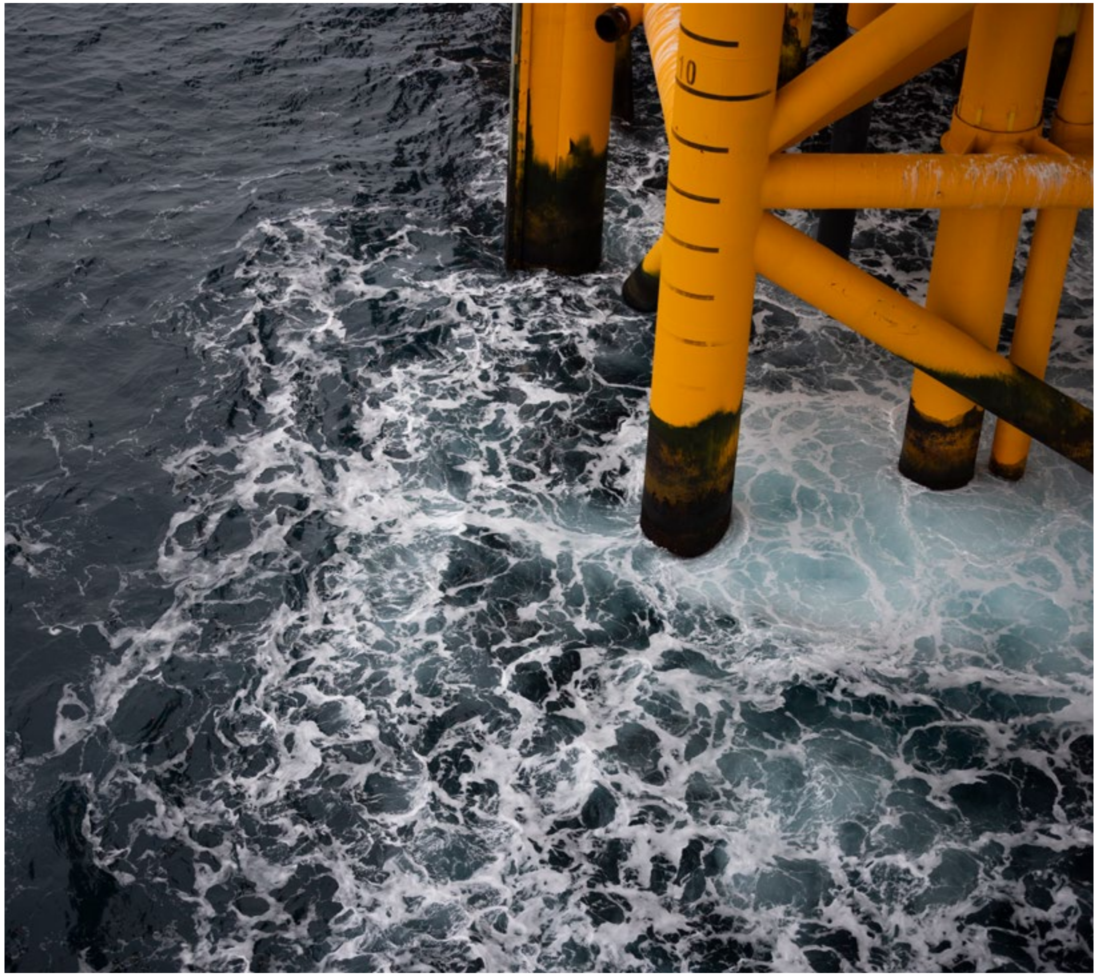
All assets contributed to this very successful outcome. After adjusting for 2025 production, reserves increased across all assets. The largest increase came from the decision to develop the Øst Frigg project in the Yggdrasil area, adding a total of 52 mmboe net reserves to Aker BP (2P). Several IOR projects contributed a total of 33 mmboe (Ivar Aasen IOR, Johan Sverdrup IOR and Phase 3, Valhall infills), while good reservoir management and general field performance caused increases totalling 31 mmboe.

Sales, acquisitions and unitisations in total caused a minor reduction in reserves: -6 mmboe.

At the end of the year, Johan Sverdrup is still the largest asset in terms of reserves, holding 28 percent of the company's 2P reserves. Yggdrasil holds 27 percent of the reserves, while Valhall has 22 percent of the 2P reserves. The Eiga area, Alvheim area and Skarv area represent 10 percent, 8 percent and 5 percent, respectively.

This report shows the reserves as of 31 December 2025 and how these volumes have changed since last year (Chapter 2). Chapters 3 through 9 describe the projects with reserves, organised within areas. These chapters describe both producing fields and the development projects.

A summary of contingent volumes can be found in Chapter 10.



1. Scope, definitions and reference points

1.1 PURPOSE OF THE REPORT

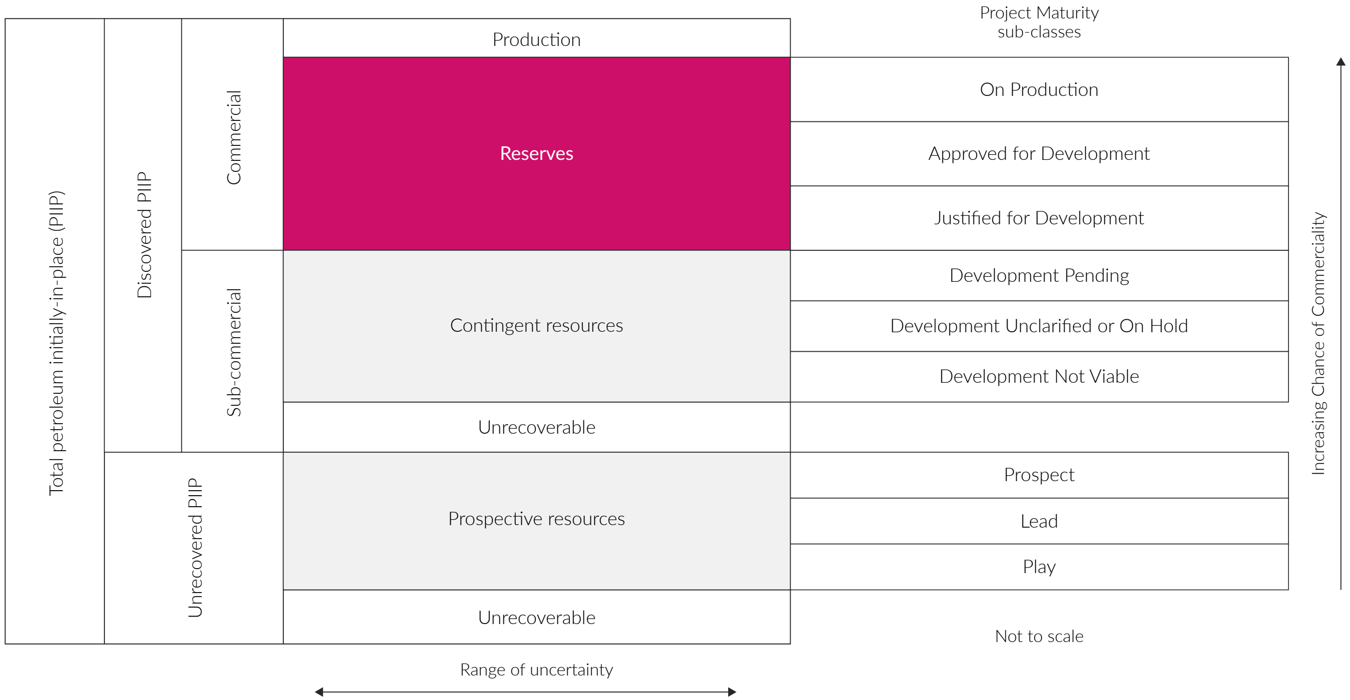
This report presents the 1P- and 2P-reserves for Aker BP, as regulated by SPE, see Chapter 1.2, and the changes from last year. Brief descriptions of projects with reserves are also included, both for projects that are producing («On production») and projects that have been decided («Justified for production») and/or approved («Approved for production»).

The report is not an in-depth technical report, but rather an overview, intended to give concentrated information for management and investors.

1.2 CLASSIFICATION AND STANDARDS

Aker BP ASA's reserve and contingent resource volumes have been classified in accordance with the Society of Petroleum Engineers' (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 Figure 1.1.

Figure 1.1 **SPE reserves and resources classification system**



2. Overall reserves and production overview

2.1 TOTAL RESERVES AS OF 31 DECEMBER 2025

Table 2.1 **Aker BP fields and projects containing reserves**

Project	Interest	Operator	Resource class
Developed reserves			
Alvheim Base	80.00%	Aker BP	On production
Boa Base	70.92%	Aker BP	On production
Bøyla Base	80.00%	Aker BP	On production
Skogul Base	65.00%	Aker BP	On production
Tyrving Base	61.19%	Aker BP	On production
Vilje Base	75.76%	Aker BP	On production
Volund Base	100.00%	Aker BP	On production
Edvard Grieg Base	65.00%	Aker BP	On production
Edvard Grieg IOR 2025 A-09	65.00%	Aker BP	On production
Edvard Grieg IOR 2025 A-19B	65.00%	Aker BP	On production
Hanz Base	35.00%	Aker BP	On production
Ivar Aasen Base	36.17%	Aker BP	On production
Solveig Base	65.00%	Aker BP	On production
Troldhaugen EWT extension	80.00%	Aker BP	On production
Johan Sverdrup Base	31.57%	Equinor Energy AS	On production
Enoch	2.00%	Bridge Petroleum 3 Limited	On production
PL212E Ærfugl Nord Base	30.00%	Aker BP	On production
Skarv Ærfugl	23.84%	Aker BP	On production
Skarv Base	23.84%	Aker BP	On production
Skarv Gråsel	23.84%	Aker BP	On production
Oda Base	15.00%	Aker BP	On production
Tambar Base	55.00%	Aker BP	On production
Tambar East K5 Sidetrack	46.20%	Aker BP	On production
Ula Base	80.00%	Aker BP	On production
Hod Base	90.00%	Aker BP	On production
Valhall Base	90.00%	Aker BP	On production

Project	Interest	Operator	Resource class
Undeveloped reserves			
Gekko Blowdown	80.00%	Aker BP	Approved for development
Kameleon Blowdown	80.00%	Aker BP	Approved for development
Ivar Aasen IOR 2026 D-11	36.17%	Aker BP	Approved for development
Ivar Aasen IOR 2026 D-12	36.17%	Aker BP	Approved for development
Ivar Aasen IOR 2026 D-17	36.17%	Aker BP	Approved for development
Ivar Aasen IOR 2026 D-6	36.17%	Aker BP	Approved for development
Solveig Ph2	65.00%	Aker BP	Approved for development
Symra	50.00%	Aker BP	Approved for development
Symra Southern wedge	50.00%	Aker BP	Approved for development
Johan Sverdrup WAG	31.57%	Equinor Energy AS	Approved for development
Johan Sverdrup IOR DP 2026	31.57%	Equinor Energy AS	Approved for development
Johan Sverdrup IOR SS 2026	31.57%	Equinor Energy AS	Approved for development
Johan Sverdrup RMLT 2025	31.57%	Equinor Energy AS	Approved for development
PL127C Alve Nord Development	58.08%	Aker BP	Approved for development
PL159D Idun Nord Development	23.84%	Aker BP	Approved for development
PL942 Ørn Development	30.00%	Aker BP	Approved for development
Fenris	77.80%	Aker BP	Approved for development
Valhall Flank West V-1 and V-10 Infills	90.00%	Aker BP	Approved for development
Valhall PWP Increased Recovery 1&2	90.00%	Aker BP	Approved for development
Valhall PWP	90.00%	Aker BP	Approved for development
Frigg Gamma Delta Development	76.72%	Aker BP	Approved for development
Frøy Development	87.70%	Aker BP	Approved for development
Fulla Development	47.70%	Aker BP	Approved for development
Krafla Askja Development	50.00%	Aker BP	Approved for development
Langfjellet Development	87.70%	Aker BP	Approved for development
Lille Frigg Development	47.70%	Aker BP	Approved for development
Øst Frigg	76.72%	Aker BP	Approved for development
Rind Development	87.70%	Aker BP	Approved for development
Johan Sverdrup Phase 3 PRMS	31.57%	Equinor Energy AS	Justified for development

In the following, the four IOR wells on Ivar Aasen have been combined into «Ivar Aasen IOR», Skarv Ærfugl, Skarv Gråsel and Skarv Base have been combined into «Skarv, incl Ærfugl and Gråsel», Johan Sverdrup IOR DP 2026 and IOR SS 2026 have been combined into «Johan Sverdrup IOR 2026» and the two Edvard Grieg IOR 2025 wells have been included in «Edvard Grieg Base».

Table 2.2 **Aker BP 1P and 2P reserves as of 31 December 2025 per projects and reserve class**

Reserves pr 31.12.2025	Interest	1P / P90 (low estimate)					2P / P50 (best estimate)				
On production		**Gross Oil**	**Gross NGL**	**Gross gas**	**Gross oe**	**Net oe**	**Gross Oil**	**Gross NGL**	**Gross gas**	**Gross oe**	**Net oe**
As of 31 December 2025	**%**	**(mmbbl)**	**(mmboe)**	**(mmboe)**	**(mmboe)**	**(mmboe)**	**(mmbbl)**	**(mmboe)**	**(mmboe)**	**(mmboe)**	**(mmboe)**
On production											
Alvheim Base	80.0%	43	1	17	60	48	50	1	20	72	57
Boa Base	70.9%	8	0	1	9	6	9	0	2	10	7
Bøyla Base	80.0%	8	0	1	9	7	9	0	1	11	8
Skogul Base	65.0%	2	0	0	2	1	5	0	0	5	3
Tyrving Base	61.2%	17	0	0	18	11	24	0	1	25	15
Vilje Base	75.8%	1	0	0	1	1	4	0	0	4	3
Volund Base	100.0%	3	0	1	4	4	5	0	1	6	6
Edvard Grieg Base	65.0%	55	3	6	65	42	69	4	8	81	52
Hanz Base	35.0%	0	0	0	0	0	0	0	0	0	0
Ivar Aasen Base	36.2%	26	4	8	37	13	31	4	9	45	16
Solveig Base	65.0%	25	3	5	33	21	30	4	6	40	26
Troldhaugen EWT extension	80.0%	0	0	0	0	0	0	0	0	0	0
Johan Sverdrup Base	31.6%	843	16	32	892	281	1,131	22	44	1,197	378
Enoch	2.0%	0	0	0	0	0	0	0	0	0	0
PL212E Ærfugl Nord Base	30.0%	0	0	3	3	1	0	0	3	3	1
Skarv, incl. Ærfugl and Gråsel	23.8%	8	14	71	93	22	11	19	99	129	31
Oda Base	15.0%	1	0	-0	1	0	1	0	0	1	0
Tambar Base	55.0%	1	0	0	2	1	2	0	0	2	1
Tambar East	46.2%	1	0	0	1	0	1	0	0	2	1
Ula Base	80.0%	2	0	0	2	1	2	0	0	2	2
Hod Base	90.0%	20	1	3	24	21	25	1	3	30	27
Valhall Base	90.0%	88	6	16	110	99	102	7	18	127	114
Total, mmboe		**1,152**	**49**	**164**	**1,364**	**583**	**1,512**	**64**	**215**	**1,791**	**750**

Table 2.2 **(continued)**

Reserves pr 31.12.2025	Interest	1P / P90 (low estimate)					2P / P50 (best estimate)				
Approved for development		**Gross oil**	**Gross NGL**	**Gross gas**	**Gross oe**	**Net oe**	**Gross oil**	**Gross NGL**	**Gross gas**	**Gross oe**	**Net oe**
As of 31 December 2025	**%**	**(mmbbl)**	**(mmboe)**	**(mmboe)**	**(mmboe)**	**(mmboe)**	**(mmbbl)**	**(mmboe)**	**(mmboe)**	**(mmboe)**	**(mmboe)**
		Approved for development									
Gekko Blowdown	80.0%	1	2	11	14	12	2	2	14	18	15
Kameleon Blowdown	80.0%	1	1	5	6	5	2	2	15	18	15
Ivar Aasen IOR	36.2%	3	0	1	4	1	8	1	1	9	3
Solveig Ph2	65.0%	15	2	3	21	14	29	4	6	39	26
Symra	50.0%	20	2	3	25	12	46	4	8	58	29
Johan Sverdrup WAG	31.6%	60	-10	-16	35	11	88	-7	-12	69	22
Johan Sverdrup IOR	31.6%	13	0	0	14	4	19	0	0	19	6
Johan Sverdrup RMLT 2025	31.6%	2	0	0	2	1	2	0	0	2	1
PL127C Alve Nord Development	58.1%	2	2	6	11	6	8	6	20	34	20
PL159D Idun Nord Development	23.8%	1	1	14	15	4	1	1	19	21	5
PL942 Ørn Development	30.0%	1	2	26	29	9	2	4	48	54	16
Fenris	77.8%	28	4	42	73	57	62	7	84	154	120
Valhall Infill wells	90.0%	7	1	2	10	9	11	1	3	14	13
Valhall PWP	90.0%	35	3	8	46	42	54	5	13	71	64
Hugin Unit	76.7%	109	1	7	116	89	164	1	9	174	134
Hugin Satellites	87.7%	61	6	19	85	75	98	10	32	140	123
Fulla Development	47.7%	5	6	28	40	19	9	10	49	68	32
Munin	50.0%	64	22	61	147	74	98	38	104	240	120
Total, mmboe		**428**	**44**	**221**	**693**	**442**	**701**	**89**	**413**	**1,203**	**762**
Justified for development		**Gross Oil**	**Gross NGL**	**Gross gas**	**Gross oe**	**Net oe**	**Gross Oil**	**Gross NGL**	**Gross gas**	**Gross oe**	**Net oe**
As of 31 December 2025	**%**	**(mmbbl)**	**(mmboe)**	**(mmboe)**	**(mmboe)**	**(mmboe)**	**(mmbbl)**	**(mmboe)**	**(mmboe)**	**(mmboe)**	**(mmboe)**
		Justified for development									
Johan Sverdrup Phase 3 PRMS	31.6%	29	1	1	31	10	42	1	2	46	14
Total, mmboe		**29**	**1**	**1**	**31**	**10**	**42**	**1**	**2**	**46**	**14**
		Total reserves									
Total, mmboe		**1,609**	**94**	**386**	**2,088**	**1,035**	**2,255**	**154**	**631**	**3,040**	**1,526**

Table 2.3 **Aker BP net 1P and 2P reserves as of 31 December 2025 per field and area**

Reserves pr 31.12.2025	1P / P90 (low estimate)					2P / P50 (best estimate)				
	Gross oil	Gross NGL	Gross gas	Gross oe	Net oe	Gross oil	Gross NGL	Gross gas	Gross oe	Net oe
	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)
Alvheim, incl. Boa, KEG/Gekko BD and Kam. BD	53	3	34	90	71	62	5	51	119	94
Bøyla	8	0	1	9	7	9	0	1	11	8
Skogul	2	0	0	2	1	5	0	0	5	3
Tyrving	17	0	0	18	11	24	0	1	25	15
Vilje	1	0	0	1	1	4	0	0	4	3
Volund	3	0	1	4	4	5	0	1	6	6
Alvheim area	**83**	**3**	**36**	**123**	**95**	**109**	**5**	**54**	**168**	**129**
Edvard Grieg	55	3	6	65	42	69	4	8	81	52
Hanz	0	0	0	0	0	0	0	0	0	0
Ivar Aasen	29	4	8	41	15	38	5	10	54	19
Solveig	40	5	8	54	35	59	8	12	79	51
Symra	20	2	3	25	12	46	4	8	58	29
Troldhaugen	0	0	0	0	0	0	0	0	0	0
Eiga area	**144**	**15**	**26**	**185**	**105**	**213**	**21**	**37**	**272**	**152**
Skarv (incl Gråsel and Ærfugl)	8	14	71	93	22	11	19	99	129	31
Ærfugl Nord	0	0	3	3	1	0	0	3	3	1
Alve Nord	2	2	6	11	6	8	6	20	34	20
Idun Nord	1	1	14	15	4	1	1	19	21	5
Ørn	1	2	26	29	9	2	4	48	54	16
Skarv area	**13**	**19**	**120**	**152**	**42**	**22**	**30**	**188**	**241**	**72**
Oda	1	0	0	1	0	1	0	0	1	0
Tambar	1	0	0	2	1	2	0	0	2	1
Tambar East	1	0	0	1	0	1	0	0	2	1
Ula	2	0	0	2	1	2	0	0	2	2
Ula area	**4**	**0**	**0**	**5**	**3**	**7**	**0**	**1**	**8**	**4**

Table 2.3 **(continued)**

Reserves pr 31.12.2025	1P / P90 (low estimate)					2P / P50 (best 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)
Fenris	28	4	42	73	57	62	7	84	154	120
Hod	20	1	3	24	21	25	1	3	30	27
Valhall	131	9	26	166	150	166	12	34	212	191
Valhall area	**178**	**14**	**71**	**263**	**228**	**254**	**21**	**121**	**396**	**338**
Fulla	5	6	28	40	19	9	10	49	68	32
Hugin Unit	109	1	7	116	89	164	1	9	174	134
Hugin Satellites	61	6	19	85	75	98	10	32	140	123
Munin	64	22	61	147	74	98	38	104	240	120
Yggdrasil	**239**	**35**	**115**	**389**	**257**	**369**	**59**	**195**	**623**	**409**
Johan Sverdrup	**947**	**8**	**18**	**973**	**307**	**1,282**	**16**	**34**	**1,332**	**421**
Enoch	0	0	0	0	0	0	0	0	0	0
Other	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total	**1,609**	**94**	**386**	**2,088**	**1,035**	**2,255**	**154**	**631**	**3,040**	**1,526**

2.2 CHANGES FROM PREVIOUS YEAR

Aker BP production in 2025 was 153 mmboe, corresponding to 420.1 mboepd daily average production rate. This was almost 7 percent above internal expectations. The main reasons for this very good result were very high production efficiency («uptime») on all assets, less decline on important wells than expected (Johan Sverdrup, Valhall, Edvard Grieg) and successful reservoir management (Alvheim).

The reserves have, neglecting the effect of production, increased significantly over the year, as shown in Table 2.4. The most important positive contributions to this increase are

- Discovery of Øst Frigg approved for development
- IOR activities (infill wells) on Johan Sverdrup, Ivar Aasen and Valhall
- Revisions following positive reservoir information and successful reservoir management in the Alvheim area (especially Tyrving and Kobra East and Gekko)

A minor negative change is recorded because of sales and acquisitions. Important changes are that Aker BP's interest in Verdande was sold, the interest in Vilje was increased and commercial agreements in the Yggdrasil area entered into.

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

	On production		Approved for development		Justified for development		Total	
Net attributed million barrels of oil equivalent (mmboe)	**1P**	**2P**	**1P**	**2P**	**1P**	**2P**	**1P**	**2P**
Balance as of 31 December 2024	675	855	392	708	3	6	1,071	1,568
Production	-153	-153	0	0	0	0	-153	-153
Transfer	7	13	-4	-7	-3	-6	0	0
Revisions	53	33	14	-2	0	0	67	31
IOR	0	0	11	18	10	14	21	33
Discovery and Extensions	0	0	35	52	0	0	35	52
Acquisition and sale	1	2	-6	-7	0	0	-5	-6
Balance as of 31 December 2025	583	750	442	762	10	14	1,035	1,526
Change 2025-2024	-92	-105	50	54	6	9	-35	-42

3. The Alvheim area

3.1 ALVHEIM, INCL. BOA

- **Licences:** PL036C, PL036G, PL088BS, PL203
- **Operator:** Aker BP
- **Ownership share:** 80 percent (Alvheim), 70.92 percent (Boa)
- **Resource class:** On production
- **First production:** 2008

Short field description

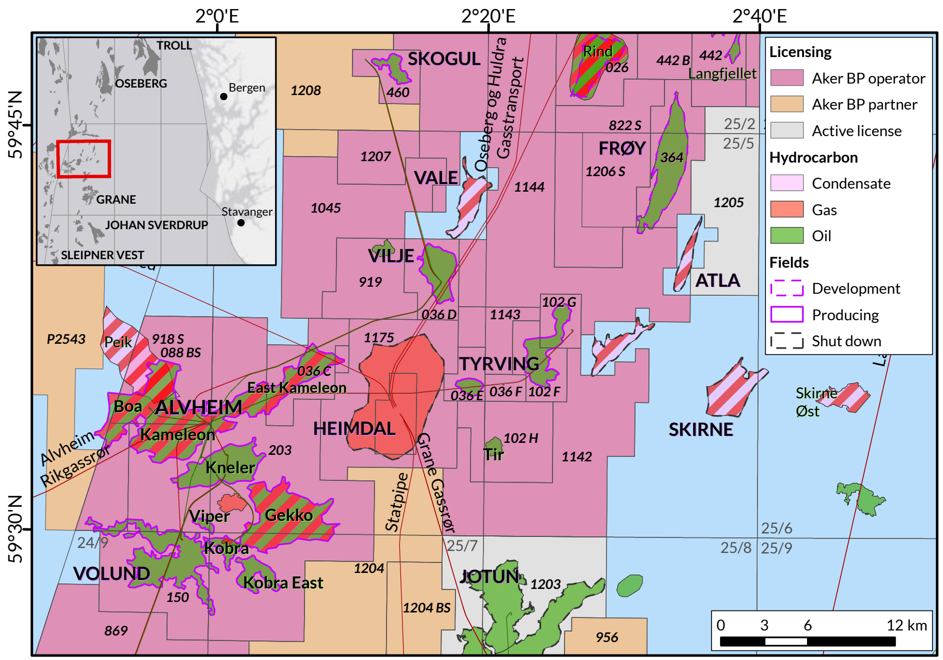
Alvheim is an oil and gas field located in the Central North Sea, west of Heimdal field and close to the UK sector border. The water depth in the area ranges from 120 to 130 metres.

The field comprises several structures: Kneler, Kameleon, East Kameleon, Boa (with 11.65 percent on the UK side), Viper, Kobra, Kobra East, and Gekko. Sales gas from the Vilje field (PL036D) is marketed by PL203 through a commercial agreement.

Most of the structures in the Alvheim area have reservoirs consisting of high porosity, high permeability sandstones from the Heimdal Formation. However, some of the structures - such as Viper, Kobra, and Kobra East - are composed of high quality, re-mobilised Hermod Formation sands.

Production is via the Alvheim FPSO, with oil exported by tanker and rich gas transported by pipeline to the SAGE system in the UK. Wells are long horizontal producers, several of which are multilateral. The wells are often completed with advanced inflow control devices (ICD/AICD technology) to manage water and gas breakthrough. The main drive mechanism is aquifer support.

Figure 3.1 **Alvheim field location map**



Status as of 31 December 2025
The Alvheim field continues its stable production with a robust well portfolio across its main structures. The number of active production wells on the Alvheim field is as follows: Boa (3), Kneler (6), Kameleon (4), East Kameleon (2), Viper (1), Kobra (1), Kobra East (1), and Gekko (3).

During 2025, the total production from Alvheim, including Boa, has been better than expected, mainly driven by strong performance from Gekko. The Gekko wells have had a later-than-estimated water cut development. In general, the optimisation of gas capacity usage on the FPSO has led to good performance and stable production with some decline on the remaining wells in Alvheim/Boa. These activities reflect a continued focus on optimising recovery from existing infrastructure and adapting to reservoir performance as it evolves.

The production strategy leverages advanced completion technologies and multilateral well designs to maximise reservoir contact and manage fluid movement, ensuring efficient hydrocarbon extraction across the complex reservoir system.

Reserves and development
The reserves estimate reflects minor revisions from the previous year, primarily driven by ongoing production, incremental infill drilling, and the implementation of improved oil recovery (IOR) measures. Reserves contribution from Kobra East and Gekko (KEG) development, which came on stream late 2023, has increased based on strong performance from these wells supported by modelling.

The development strategy for Alvheim continues to emphasise the use of horizontal and multilateral wells, ICDs/AICDs and subsea tie-backs to the Alvheim FPSO, enabling flexible and cost-effective exploitation of remaining reserves.

The field's infrastructure is designed to accommodate further infill drilling and potential future tie-ins, ensuring adaptability as the understanding of the reservoir matures.

Uncertainty and key assumptions
The future performance of the Alvheim field is subject to several key uncertainties and assumptions. One of the primary challenges is the management of increasing gas-oil ratio (GOR) and increasing water cut in the producing wells. This can impact both production rates and recovery efficiency. Aker BP addresses these uncertainties and maximise the value of the remaining resources through continuous monitoring, data acquisition, and adaptive reservoir management.

3.1.1 Alvheim Blowdown

- **Licence:** PL203
- **Operator:** Aker BP
- **Ownership share:** 80 percent (Alvheim)
- **Resource class:** Approved for development
- **First production:** 2032

Short field description
Within the Alvheim area reserves, two projects; Kameleon Blowdown and Gekko Blowdown, are classified as «Approved for development». These involve the gas cap production phase for both structures, with one new well planned for Kameleon and two for Gekko. Well timing depends on maximising gas capacity at the Alvheim FPSO and resource recovery. Gekko Blowdown is set to begin in 2032, while Kameleon Blowdown is scheduled for 2036. Some gas is already being produced via existing oil wells, covered in chapter 3.1 Alvheim, incl. Boa, meaning the volume available for dedicated blowdown wells depends on ongoing production from current wells.

Status as of 31 December 2025
The start-ups of Gekko Blowdown and Kameleon Blowdown have been moved one year, and four months, respectively, compared to previous year's reserves estimate. The updated start-up dates are a result of increased GOR in the existing oil wells in both areas. Hence, the gas available for dedicated blowdown wells is reduced.

Reserves and development
The reserves estimates are slightly lower for both Gekko Blowdown and Kameleon Blowdown due to the existing oil wells continue to produce strongly, and a bigger portion of the available gas is covered in the reserves in Chapter 3.1. Total gas in place and recoverable gas estimates remain unchanged.

Uncertainty and key assumptions
The key uncertainties regarding the future performance of the Alvheim blowdowns are primarily linked to reservoir structure, which directly affect the volumes of hydrocarbons in place. The amount of gas produced during the oil production phase also has a significant impact. As oil wells continue to produce, the associated gas production is subject to change, meaning that the estimates for gas available for blowdown operations are subject to revision over time.

3.2 BØYLA

- **Licence:** PL340
- **Operator:** Aker BP
- **Ownership share:** 80 percent
- **Resource class:** On production
- **First production:** Bøyla – January 2015, Frosk - August 2019

Short field description

The Bøyla field comprises two reservoirs, Bøyla and Frosk, located 15 km southwest of the Volund field. It is produced via subsea wells tied back through a 26 km pipe-in-pipe flowline to the Alvheim FPSO. Gas lift is required in the producers. Water depth is 120 metres.

The Bøyla structure is a flat, low relief Eocene turbidite fan deposit. The reservoir is within Paleocene/Eocene Hermod Formation with good quality sand intervals. Bøyla is developed with two long horizontal producers and one deviated water injection. The main recovery mechanism in Bøyla is water injection.

Frosk consists of injectite sands within Intra Hordaland Group and is believed to be injected from the underlying Odin sands in the Balder Formation. The main Frosk injectite forms a main dyke and sill structure with high quality reservoir properties. The field is developed with four multilateral wells, including the recently added Frosk Attic well. Aquifer pressure support is the primary recovery mechanism.

Status as of 31 December 2025

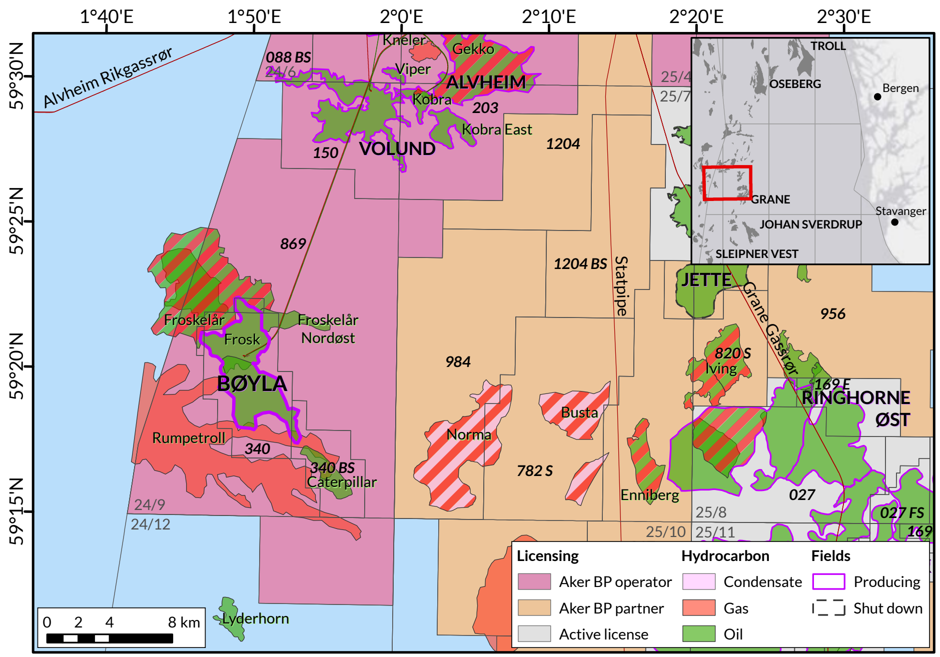
During the first half of 2025, production from the Bøyla field was affected by operational challenges, particularly related to sand production in some of the Frosk wells. In addition, the BY1 well in Frosk did not return to production due to unsuccessful intervention. Despite these setbacks, the Frosk Attic well was brought on stream in October 2025 according to schedule, just one year after being approved with initial rates meeting expectations.

Reserves and development

The reserves have been updated for 2025 performance and technical revisions after sand production mitigations. Additionally, reserves associated with production of BY1 have been written off post RNB25 as the current intervention plan is not sufficiently mature. The Aker BP team will continue to mature a solution to get the well back on production or to produce the remaining volumes with a potential infill well.

Frosk Attic will be reported within «Bøyla Base» following transfer from «approved» to «on production». Development efforts continue to focus on maintaining production efficiency and supporting long term field performance.

Figure 3.2 **Bøyla location map**



Uncertainty and key assumptions

Key uncertainties include connectivity within the Bøyla turbidite body, waterflood efficiency and injectivity control. For Frosk, injectite geometry and heterogeneities may impact sweep and sand production risk. These factors could influence overall recovery rates and long-term field performance, requiring continuous monitoring and adaptive management.

3.3 SKOGUL

- **Licence:** PL460
- **Operator:** Aker BP
- **Ownership share:** 65 percent
- **Resource class:** On production
- **First production:** 2020

Short field description

The Skogul oil field is located approximately 40 km north of Alvheim and is produced via a subsea well, tied back to the Alvheim FPSO via the Vilje template and pipeline. The water depth is about 107 metres in the area. The crest of the structure is estimated to be 2,097 metres TVD MSL.

The reservoir consists of Eocene Upper Balder and Frigg Formation sandstones with good reservoir properties. Skogul is developed with one bilateral producer, and the drive mechanism is depletion with natural aquifer support.

Status as of 31 December 2025

Skogul continued to perform well through 2025, with the main producer delivering as expected. The operating strategy focused on optimising combined pipeline capacity with Vilje and managing water cut, while maintaining stable drawdown to preserve productivity.

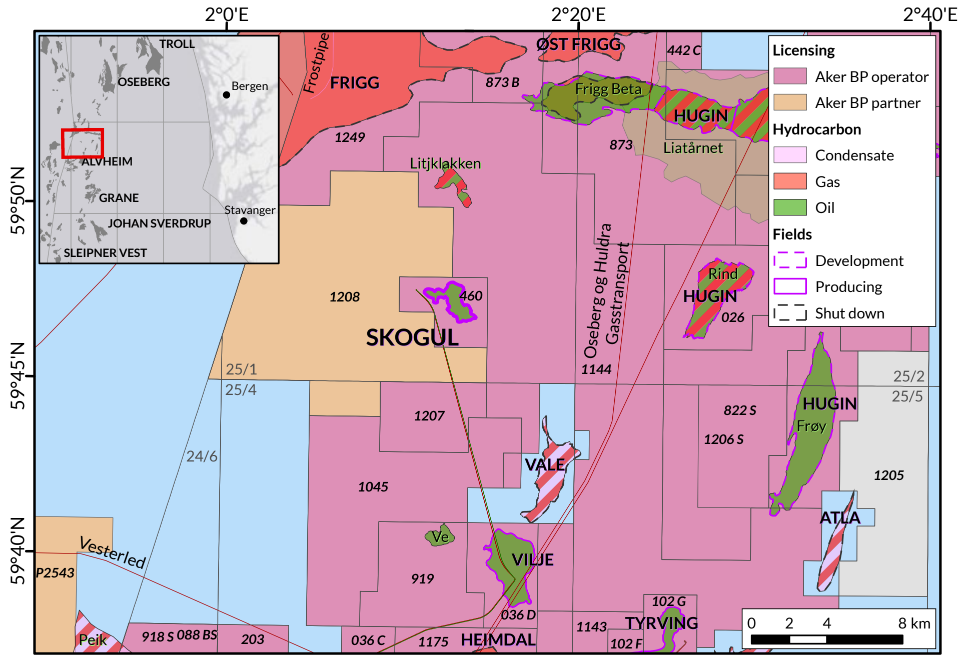
Reserves and development

The reserves basis has been updated for 2025 production history and technical learnings. No major concept changes were introduced; value is pursued through high-uptime operations, surveillance, and small-scope optimisations that sustain rates within pipeline constraints shared with Vilje.

Uncertainty and key assumptions

Key uncertainties include long-term aquifer support strength, future water cut development, and pipeline interactions with Vilje during high-rate periods. It is assumed continued strong well deliverability and effective joint optimisation with Vilje.

Figure 3.3 **Skogul location map**



3.4 TYRVING

- **Licence:** PL102F/PL102G, PL036E/PL036F – unitised as Tyrving.
- **Operator:** Aker BP
- **Ownership share:** 61.19 percent
- **Resource class:** On production
- **First production:** 2024

Short field description
The Tyrving oil field is located in the central part of the Norwegian sector in the North Sea, east of the Heimdal field. The field is developed by three subsea wells tied back to the Alvheim FPSO through a 15 km pipeline to the East Kameleon flowline.

Tyrving is unitised and consists of three structures, Trell and Trell North located in block 25/5 in production license PL102 F/G and Trine located in block 25/4 in production license PL036 E/F. The water depth in the area is 110 metres, and the reservoir is located between 2,100-2,200 metres TVD MSL.

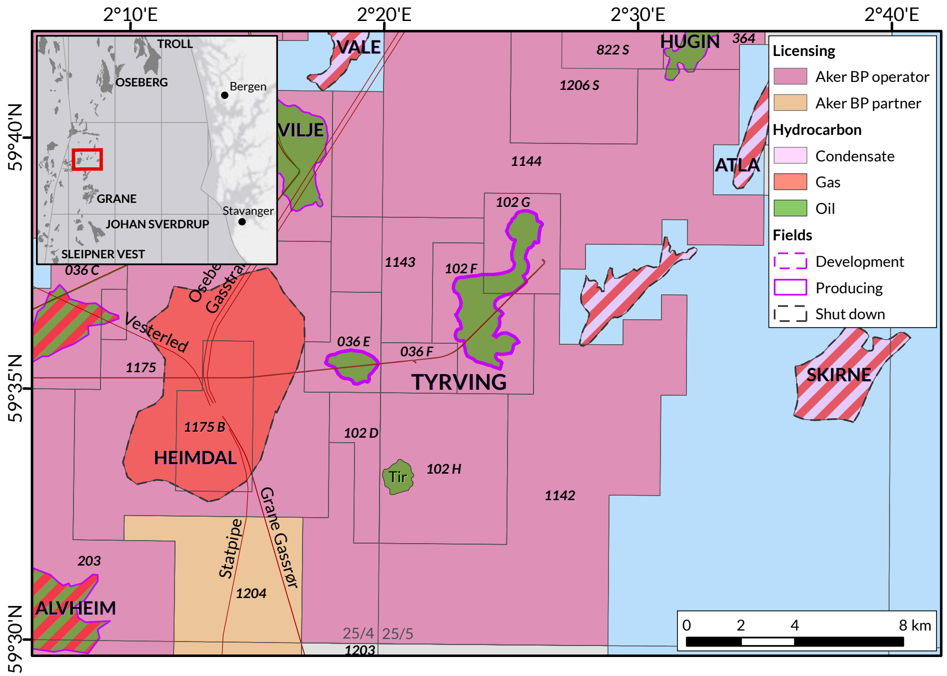
Trell, Trell North and Trine are three relatively small four-way closures located close to one another. The reservoir is Late Paleocene Heimdal Formation and consists of turbidite sandstones with excellent reservoir properties. The development includes three subsea wells, a trilateral well at Trell, a single-branch well at Trell North, and a bilateral well at Trine. The main drive mechanism is aquifer support.

Status as of 31 December 2025
All three wells came on stream in the second half of 2024, with first oil achieved on 3 September 2024. The initial performance, particularly in terms of water cut development, was better than anticipated. Higher performance resulted in Tyrving producing significantly above estimated volumes during 2025. Current understanding suggests that the later than estimated water development is likely due to the presence of vertical baffles in the reservoir, which has led to improved production and, therefore, increased total reserves for Tyrving.

Reserves and development
The three Tyrving wells have all shown strong performance, with water cut rising later than initially predicted. The result is increased reserves, supported by updated modelling. In the near term, the focus will be on balancing branches and managing drawdown to maintain liquid production and control the GOR, supported by ongoing data collection and refinement of models.

Uncertainty and key assumptions
Early life uncertainty is primarily influenced by aquifer behaviour, variations in productivity between branches, and changes in GOR with increased drawdown. The assumptions are consistent facility capacity at Alvheim, effective management of branch flow, and ongoing monitoring of water cut.

Figure 3.4 **Tyrving location map**



3.5 VILJE

- **Licence:** PL036D
- **Operator:** Aker BP
- **Ownership share:** 75.757 percent
- **Resource class:** On production
- **First production:** 2008

Short field description

Vilje is an oil field located 5 km northeast of the Heimdal gas field, and is a subsea development tied back to the Alvheim FPSO. The reservoir is located at a depth of approximately 2,200 metres TVD MSL, with a water depth around 120 metres.

The reservoir consists of Heimdal Formation sandstones with very good reservoir properties. Vilje is produced by three subsea horizontal wells; one bilateral and two single wells. The recovery mechanism is natural water drive from the regional aquifer.

Sales gas from the Vilje field is marketed by Alvheim field (PL203) through a commercial agreement.

Status as of 31 December 2025

Vilje production continued to perform well through 2025, delivering as expected. Operations continued to prioritise joint optimisation with Skogul through shared line capacity. Targeted choke management was applied to mitigate back-out in the flowline and maintain stable drawdown.

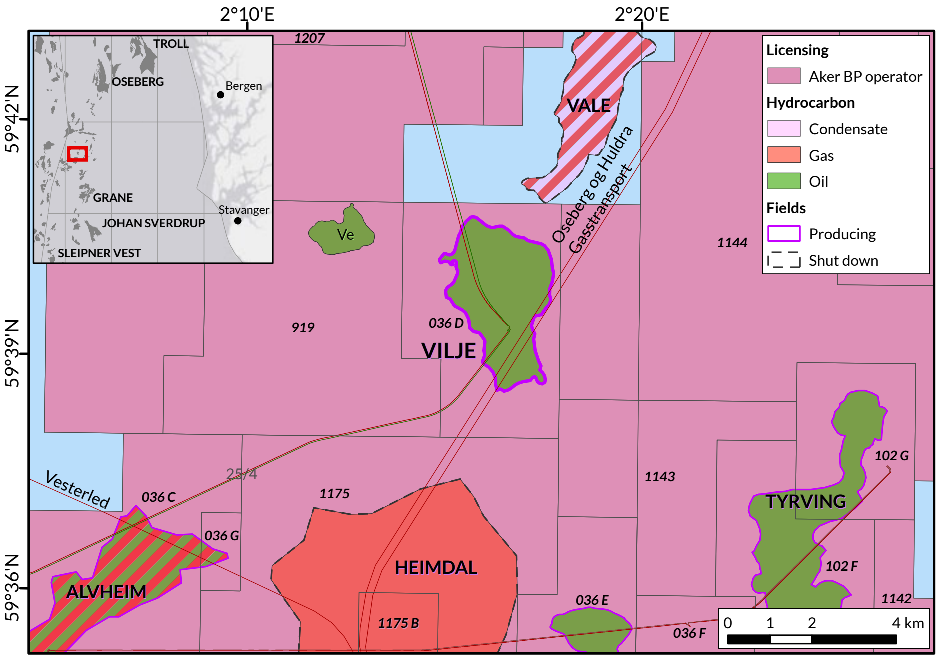
Reserves and development

The 2025 reserves update reflects production history, minor technical revisions, and area accounting adjustments with Aker BPs increasing ownership share in Vilje. Besides increased ownership share, no major concept changes were introduced; value is pursued through high-uptime operations, surveillance, and small-scope optimisations that sustain rates within pipeline constraints shared with Skogul.

Uncertainty and key assumptions

Key uncertainties include long term water cut development, local baffles in the reservoir, and pipeline interactions with Skogul during high-rate periods. Aker BP assume that strong aquifer support will continue and that combined optimisation with Skogul will remain effective.

Figure 3.5 **Vilje location map**



3.6 VOLUND

- **Licence:** PL150
- **Operator:** Aker BP
- **Ownership share:** 100 percent
- **Resource class:** On production
- **First production:** 2010

Short field description
Volund is an oil field located 8 km south of the Alvheim field, developed as a subsea tie-back to the Alvheim FPSO. The reservoir depth is about 1,900 metres TVD MSL and the water depth in the area is about 120-130 metres.

Volund is a massive injectite complex consisting of high-quality sandstone that was injected from the early Eocene Hermod Formation into the overlying shales of the Sele, Balder, and Hordaland Formations. Volund is unique in that the entire hydrocarbon accumulation is contained within the injected sands. Most of the hydrocarbons reside in the cross-cutting dykes rising from a central lower sill, which results in a «bathtub» shape, open to the west.

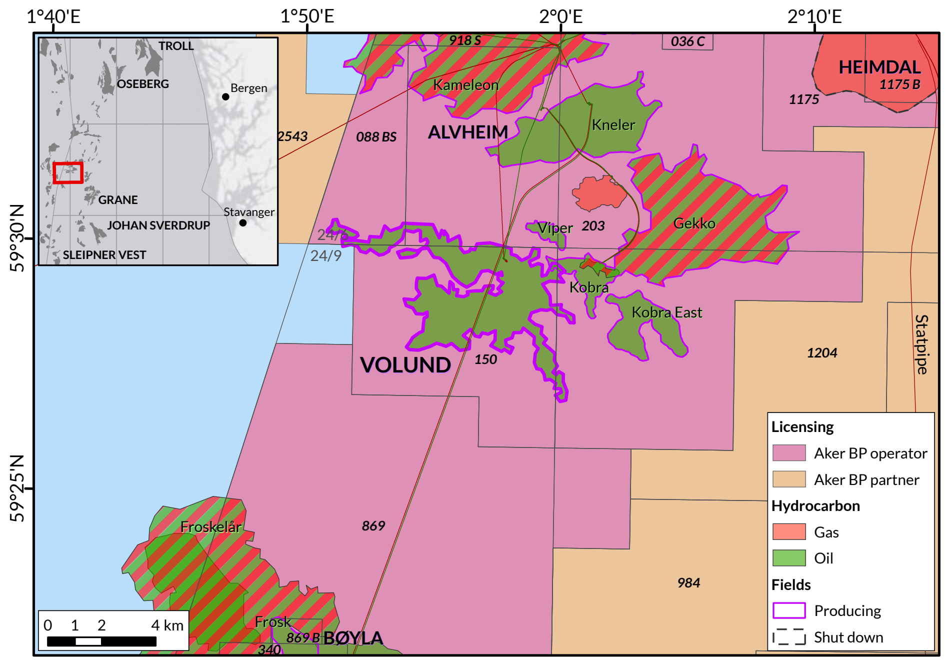
The field is developed with six producers and one injector. Recovery is supported by water injection in the sill and regional aquifer effects.

Status as of 31 December 2025
Volund maintained stable production in 2025 but remained on the lower side of the 2P estimates from 2024. This was driven by prioritised optimisation of the Viper and Kobra wells, which share the same flowline and therefore delayed Volund production.

Reserves and development
Reserves showed a positive development due to strong performance exhibited by key producers, despite a low production level in 2025 triggered by cross-license production optimisation within FPSO constraints. The development strategy emphasises well-by-well optimisation, including zonal control and selective shut-offs, with readiness for future low-cost workovers or branch additions, where justified by surveillance and 4D indications.

Uncertainty and key assumptions
Primary uncertainties are injectite connectivity between dykes and sills, local heterogeneity impacting sweep, and sand-management constraints. Assumptions include reliable water-injection support, stable FPSO capacity, and continued success of surveillance-led optimisation.

Figure 3.6 **Volund location map**



4. The Eiga area

4.1 EDVARD GRIEG

- **Licence:** PL338
- **Operator:** Aker BP
- **Ownership share:** 65 percent
- **Resource class:** On production
- **First production:** 2015

Short field description

The Edvard Grieg field is located in Block 16/1, PL338, on the western side of the Utsira High, approximately 180 km west of Stavanger, with a water depth of around 109 metres. The top reservoir is approximately 1,850 metres TVD MSL.

The Edvard Grieg field is developed with a PDQ jacket solution, equipped with a total of 20 well slots. A full processing facility is installed on the platform, which is connected to the Oseberg Transport System (OTS) via the Edvard Grieg Oil Pipeline (EGOP) and the Grane Oil Pipeline (GOP), as well as to the Scottish Area Gas Evacuation System (SAGE) via the Utsira High Gas Pipeline (UHGP). The Ivar Aasen, Solveig, and Troldhaugen extended well test (EWT) are currently tied back to the Edvard Grieg platform.

The primary drainage strategy for Edvard Grieg involves voidage replacement water injection to ensure pressure maintenance. To date, 15 producers and five injectors have been drilled, including infill drilling campaigns in 2021, 2023 and 2025. The Edvard Grieg platform was fully electrified in December 2022.

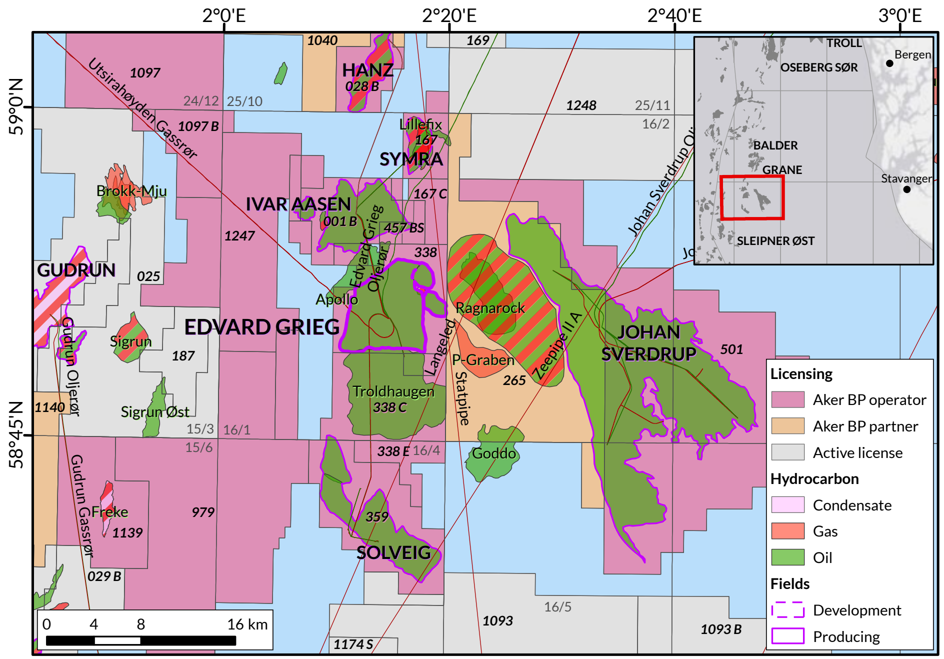
Status as of 31 December 2025

The production in 2025 from Edvard Grieg has been better than Aker BP's 2024 forecast. Reduced gas production from Hanz has increased the overall gas capacity availability to EG, resulting in less choking and increased gas lift. Two new infill wells were drilled in Q1/Q2 2025. The first well, A-9, came on stream in July. The second well, A-19 Y-2, drilled as a retrofit multilateral, came on stream in October, and delivered a production uplift of 1,200 Sm³/d.

Reserves and development

Only minor adjustments have been made to the reserves compared to last year's reserve reporting. The changes are related to updates of decline curves (production history) and the assumptions (PE and capacities) in the Eiga pForecast model used for reserve calculations.

Figure 4.1 **Edvard Grieg location map**



Uncertainty and key assumptions

There have been no changes in key assumptions since last year. The EG platform will serve as a HUB for several other tie-in fields in the area.

4.2 SOLVEIG

- **Licence:** PL359
- **Operator:** Aker BP
- **Ownership share:** 65 percent
- **Resource class:** On production
- **First production:** 2021

Short field description

The Solveig field is an oil and gas discovery located on the Utsira High, 15 km south of the Edvard Grieg field. The water depth at the location is around 109 metres. The top reservoir is at approximately 1,890 metres TVD MSL.

Solveig phase 1 was finished in February 2022 containing three oil producers and two water injectors. All the Phase 1 wells are single satellites, which are commingled and tied back to the Edvard Grieg platform.

The oil and gas are processed at Edvard Grieg before export. The Edvard Grieg platform is connected to Oseberg Transport System (OTS) through the Edvard Grieg Oil Pipeline (EGOP) and Grane Oil Pipeline (GOP) and to the Scottish Area Gas Evacuation System (SAGE) through the Utsira High Gas Pipeline (UHGP).

Status as of 31 December 2025

The production from Solveig has been better than forecast in 2025. The water production has been much lower than expected and the oil production has been maintained above 3,000 Sm^3/d by optimising production with the flexible completion solution installed in the Solveig wells. Solveig has produced via the EG test separator, where the gas capacity has been the limiting constraint to handle gas slugging occurring in the pipeline connecting Solveig to the EG host. After the TAR in September 2025, when a X-over between primary and secondary inlet separator was installed, Solveig started producing via the secondary inlet separator, lifting the oil production rate to about 4,000 Sm^3/d.

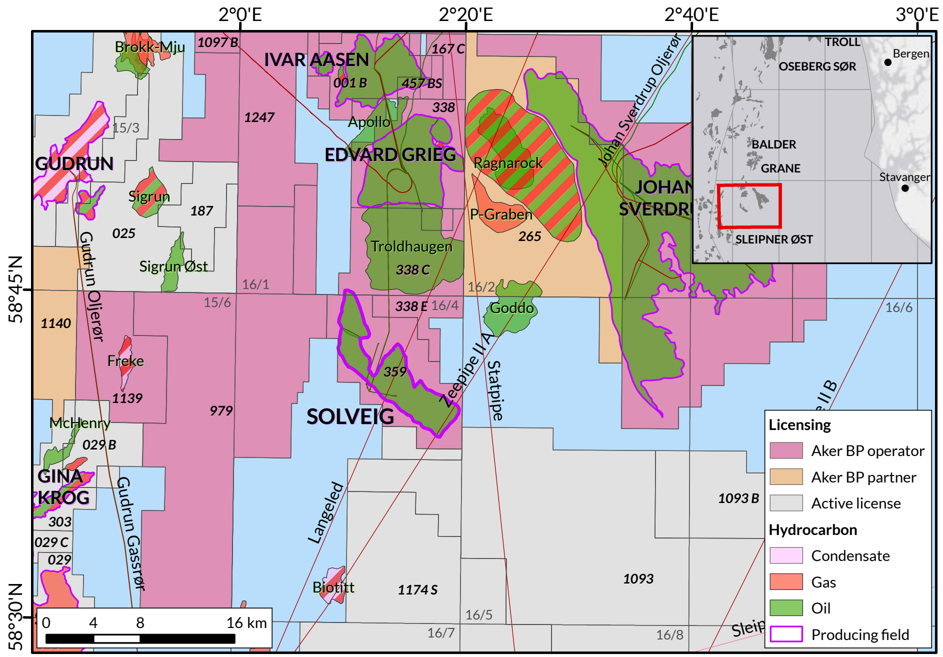
Reserves and development

Only minor adjustments have been made to the reserves compared to last year's reserve reporting. The changes are related to updates of decline curves (production history) and the assumptions (PE and capacities) in the Eiga pForecast model used for reserve calculations.

Uncertainty and key assumptions

There have been no changes in key assumptions since last year.

Figure 4.2 **Solveig location map**



4.2.1 Solveig Phase 2

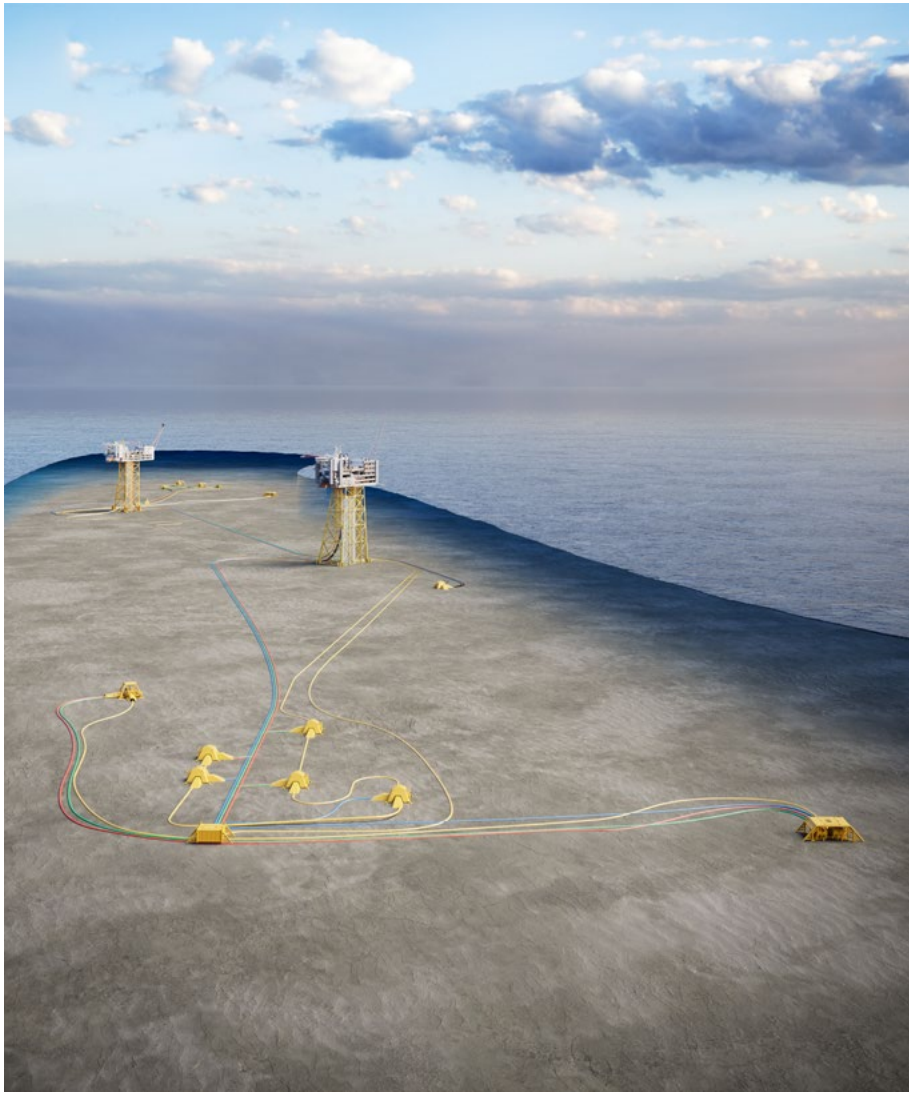
- **Licence:** PL359
- **Operator:** Aker BP
- **Ownership share:** 65 percent
- **Resource class:** Approved for development
- **First production:** 2026

Short field description
The Solveig Phase 2 development was sanctioned in December 2022 and consists of three new wells, two producers and one injector. The Phase 2 development will focus on the Synrift reservoir with additional wells in Segment B, plus the inclusion of Segment A and Segment D. When drilling Segment D, BG-1 in 4Q 2025, the well penetrated Outer Wedge reservoir not only in branch Y-1 as planned, but also in Y-2.

Status as of 31 December 2025
The drilling of the BG-1 (Segment D) started in December 2025, and the drilling campaign is expected to be completed within 1Q 2026.

Reserves and development
Only minor adjustments have been made to the reserves compared to last year's reserve reporting.

Uncertainty and key assumptions
There have been no changes in key assumptions since last year.



4.3 IVAR AASEN UNIT

- **Licences:** PL001B, PL242, PL338BS, PL457
- **Operator:** Aker BP
- **Ownership share:** 36.1712 percent
- **Resource class:** On production
- **First production:** 2016

Short field description
The Ivar Aasen field is located in the North Sea, approximately 8 km north of the Edvard Grieg field and around 30 km south of the Grane and Balder fields.

The field contains both oil and free gas and consists of two accumulations: Ivar Aasen and West Cable. These accumulations span multiple licenses and have been unitised into the Ivar Aasen Unit.

The Ivar Aasen field is developed with a steel jacket, which includes living quarters and process facilities, situated at a water depth of 110 metres. The platform features dry wellheads, and wells are drilled using a jack-up rig. The well stream is partially processed on the platform before being transported through pipelines to the Edvard Grieg installation for final stabilisation and export. Edvard Grieg also supplied power to Ivar Aasen until a joint power from shore solution was established in December 2022.

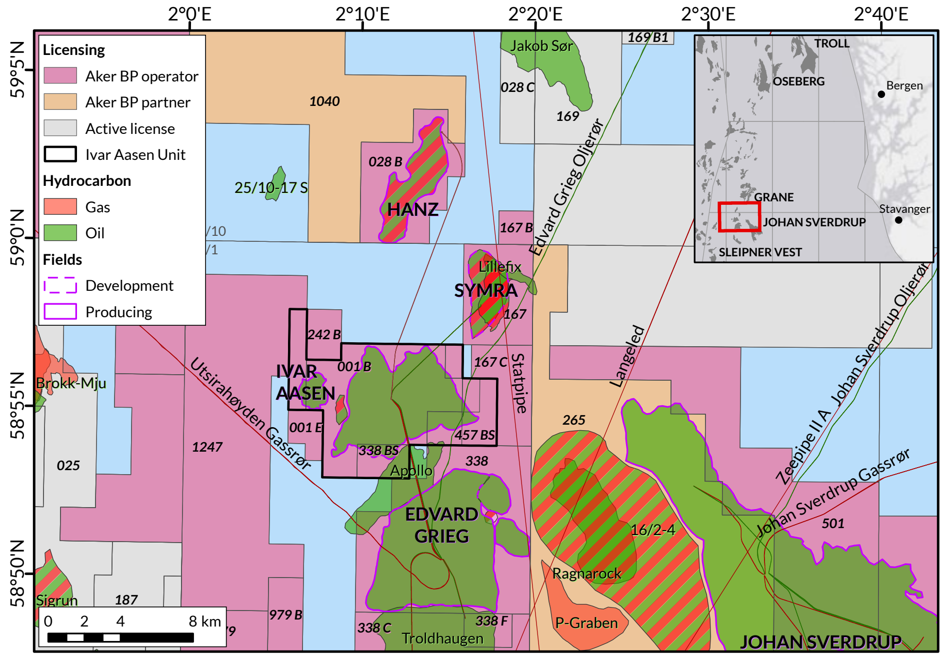
The Ivar Aasen platform has a total of 20 slots, of which 12 are producer slots and 8 injector slots. The drainage strategy for the Ivar Aasen structure relies on water injection for pressure maintenance.

Status as of 31 December 2025
The production from Ivar Aasen has been better than forecast in 2025. High water injection and regularity have resulted in a positive voidage replacement and arrested the field's decline.

Reserves and development
The reserves basis has been updated for 2025 production history in addition to a new statical/dynamical model of the field, slightly increasing the in-place volumes of oil and gas, compared to last year. The reserves are calculated by use of well by well decline curves fed into a pForecast model for the whole Eiga area for regularity and capacity corrections.

Uncertainty and key assumptions
There have been no changes in key assumptions since last year.

Figure 4.3 **Ivar Aasen Unit and Hanz location map**



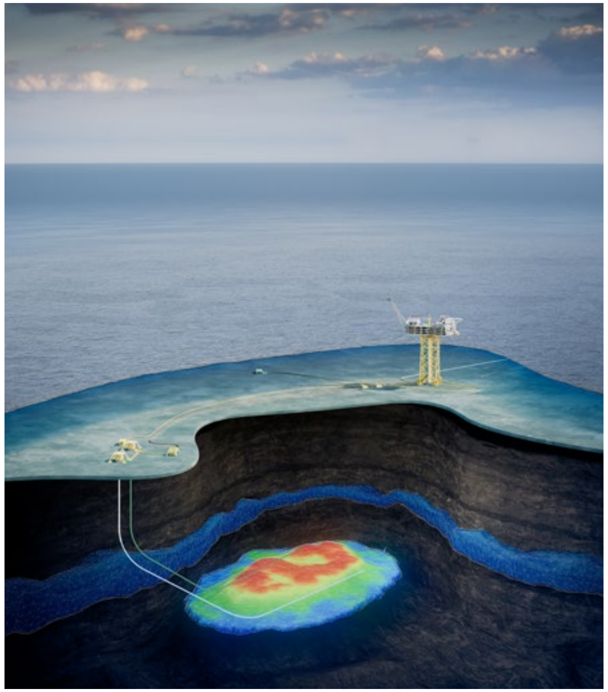
4.3.1 *Ivar Aasen IOR*

- **Licences:** PL001B, PL242, PL338BS, PL457
- **Operator:** Aker BP
- **Ownership share:** 36.1712 percent
- **Resource class:** Approved for development
- **First production:** 2026

Short field description
The Ivar Aasen field is described above

Status as of 31 December 2025
The license sanctioned a new four well infill campaign in May (IA IOR2026) with an expected drilling start in June 2026. Two of the wells (D-12A and D-17B) are planned as producers in the Skagerak 2 Formation. The D-6C is planned as a hybrid well (start as a producer, then converted into an injector), while the fourth well, D-11B, is planned as a retrofit lateral well into the alluvial fan reservoir.

Reserves and development
The reserves basis has been updated for 2025 production history in addition to a new statical/dynamical model of the field, slightly increasing the in-place volumes of oil and gas, compared to last year.



Uncertainty and key assumptions
There have been no changes in key assumptions since last year.

4.4 HANZ

- **Licence:** PL028B
- **Operator:** Aker BP
- **Ownership share:** 35 percent
- **Resource class:** On production
- **First production:** 2024

Short field description
The Hanz oil field is located in the North Sea, 6 km north of the Ivar Aasen field and around 25 km south of the Grane and Balder fields. The water depth in the area is approximately 110 metres and the main reservoir at Hanz is found at about 2,400 metres TVD MSL.

The Hanz field is developed with two subsea wells, which are tied back to the Ivar Aasen platform. Hanz is produced through a 14-kilometre pipeline to the Ivar Aasen platform. The drainage strategy for Hanz utilises pressure support from a crossflow water injector, which draws water from the Heimdal aquifer reservoir located approximately 300 metres above the Hanz Draupne reservoir. Both the producer and the crossflow water injector have horizontal well sections exceeding 2,000 metres in the Draupne reservoir. The wells are located about 700 metres apart and penetrate all major hydrocarbon sands in the Draupne Horst structure.

Status as of 31 December 2025
The reservoir pressure at Hanz has continued to fall in 2025. The pressure support from the crossflow injector has been disappointing, probably due to faults and barriers (shale layering between thin sands). The free gas production has gradually decreased during 2025 because of falling reservoir pressure, resulting in a significant drop in the gas oil ratio (GOR). The water production has gradually increased throughout 2025. In the end of August 2025, just prior to the planned production stop, the Hanz producer stopped producing due to lifting problems. In October 2025, when the well was opened after two months shut in, a leak in the gas lift valve was discovered.

The Hanz producer, C-01H, is categorised as an orange well due to the gas lift valve being the second barrier. In December 2025, the well was opened for production, reducing the risk of leaking to sea, by reducing the reservoir pressure. An intervention to plug the well is planned for in November 2026 by an intervention vessel.

Reserves and development
Due to well integrity issues in the Hanz producer there are not booked any more reserves from the field

Uncertainty and key assumptions
The pressure and production behaviour from 'pressure relief production' at Hanz will determine the scope for the upcoming intervention job.

4.5 TROLDHAUGEN

- **Licences:** PL338C, PL338E
- **Operator:** Aker BP
- **Ownership share:** 80 percent
- **Resource class:** On production
- **First production:** 2021

Short field description

Troldhaugen is a subsea tie-back to Edvard Grieg via the Troldhaugen EWT infrastructure consisting of one production pipeline, umbilical and gas lift. Well 16/1-CA-1 H has conducted an extended well test (EWT) with production from weathered basement since 2021.

Status as of 31 December 2025

Production from Troldhaugen was better than forecast in 2025. Production experience demonstrated that a 'balanced' reservoir withdrawal rate of around 0.6-0.8 mboepd is sustainable. This strategy arrests the water cut development to about 75% with a flowing bottomhole pressure in the range of 125 – 130 bar. The license has received permit to extend the test production by one year until 31 December 2026.

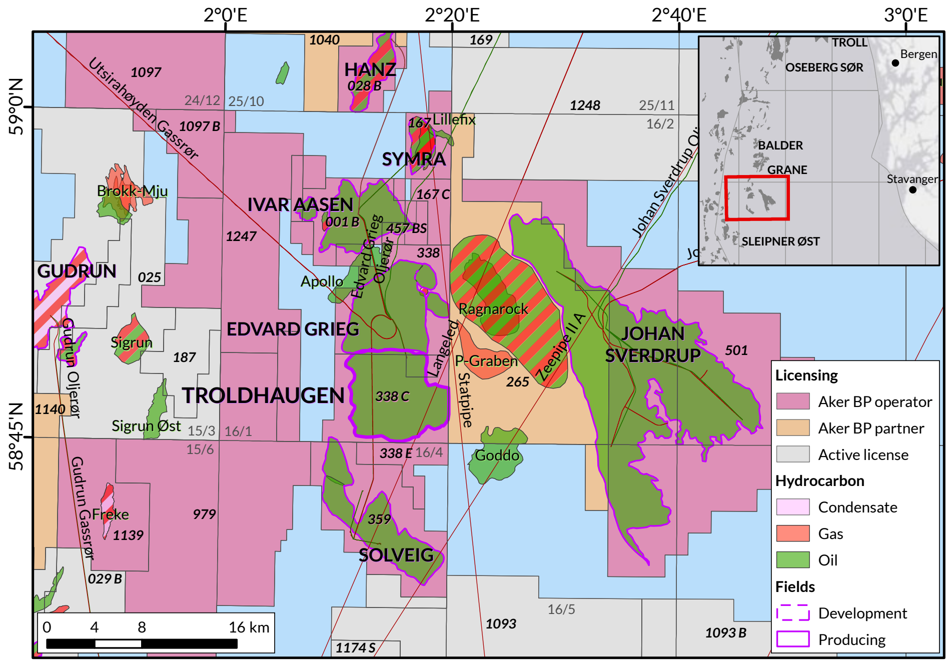
Reserves and development

The reserves for Troldhaugen are estimated based on projected production through the extended test period ending 31 December 2026.

Uncertainty and key assumptions

The EWT is planned to be continued by a multilateral sidetrack of the existing Troldhaugen test producer. The timing of this sidetrack is dependent on experience from the drilling of a multilateral well in basement scheduled to be drilled in 2Q 2026 at the Symra field.

Figure 4.4 **Troldhaugen location map**



4.6 SYMRA

- **Licences:** PL167, PL167C
- **Operator:** Aker BP
- **Ownership share:** 50 percent
- **Resource class:** Approved for development
- **First production:** 2026

Short field description
The Symra structure includes several segments and reservoirs of different ages including Heather Formation sandstones, Zechstein Formation carbonates, and weathered basement reservoirs.

The Symra field is planned as a subsea development, with tie-back to the host platform at Ivar Aasen (distance approximately 7.5 km). Final processing of the Symra oil and gas will occur at Edvard Grieg with export through the existing EG oil and gas downstream transport system. The selected concept for the subsea layout is one 4-slot ITS/template and drill centre, with the SURF scope covering pipelines for oil, gas lift, water injection and umbilical. The reference case drainage strategy consists of four oil producers. Two of the oil producers can be converted to injectors and the Outer Wedge South well (EA-2) is planned converted into a water injector, 18 months post first oil.

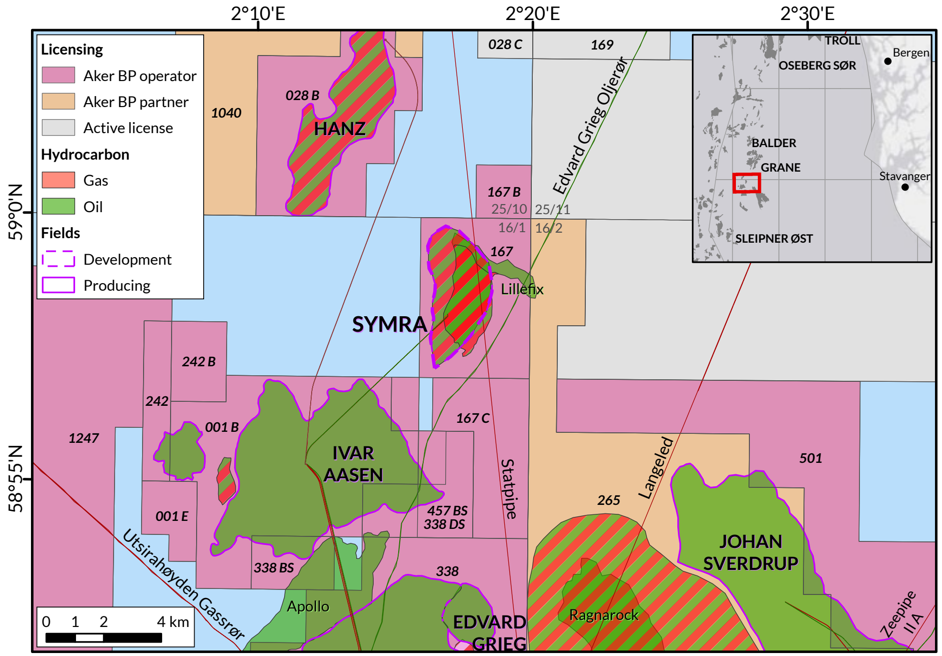
Status as of 31 December 2025
Two wells (EA-3 Zechstein Formation producer and EA-2 Outer Wedge South) have been drilled and completed in 2025. Production start-up is planned in April, when the tie-in scope to the IA host is scheduled to be completed. There were uncertainties of which type of reservoir in the Outer Wedge South well, EA-2, would penetrate before drilling, and in the PDO this well was classified as contingent resources with 1/3 risk of not finding any reservoir. The well penetrated Zechstein Formation reservoir of same type and quality as drilled in well EA-3.

The two last wells are planned to be drilled after the ongoing Solveig phase 2 drilling campaign, currently at the end of 1Q 2026.

Reserves and development
Only minor adjustments have been made to the reserves compared to last year's reserve reporting (no change in input profiles). The changes are related to update of the assumptions (PE and capacities) in the Eiga pForecast model used for reserve calculations.

Uncertainty and key assumptions
The uncertainties at Symra have not changed since the PDO. The risk for not finding reservoir in EA-2 is removed, but the connectivity and pressure support to the Zechstein reservoir is still an issue. The reservoir quality and production properties from the multilateral basement well EA-1 are also a large risk.

Figure 4.5 **Symra location map**



5. Johan Sverdrup

5.1 JOHAN SVERDRUP BASE

- **Licences:** PL265, PL501, PL502, PL501B
- **Operator:** Equinor
- **Ownership share:** 31.5733 percent
- **Resource class:** On production
- **First production:** 5 October 2019

Short field description
Johan Sverdrup is a major oil field extending over four licences: PL265, PL501, PL502 and PL501B. The PDO was approved in 2015, and the field is developed in two phases (end 2025) and started production in October 2019.

The field lies in a half-graben on the Utsira High in the North Sea, about 160 kilometres west of Stavanger, in blocks 16/2, 16/3 and 16/5.

The water depth is 110–120 metres and the reservoir depth is around 1,900 metres TVD MSL. The reservoir has excellent properties, hydrostatic pressure, and under-saturated oil with a low gas-oil ratio.

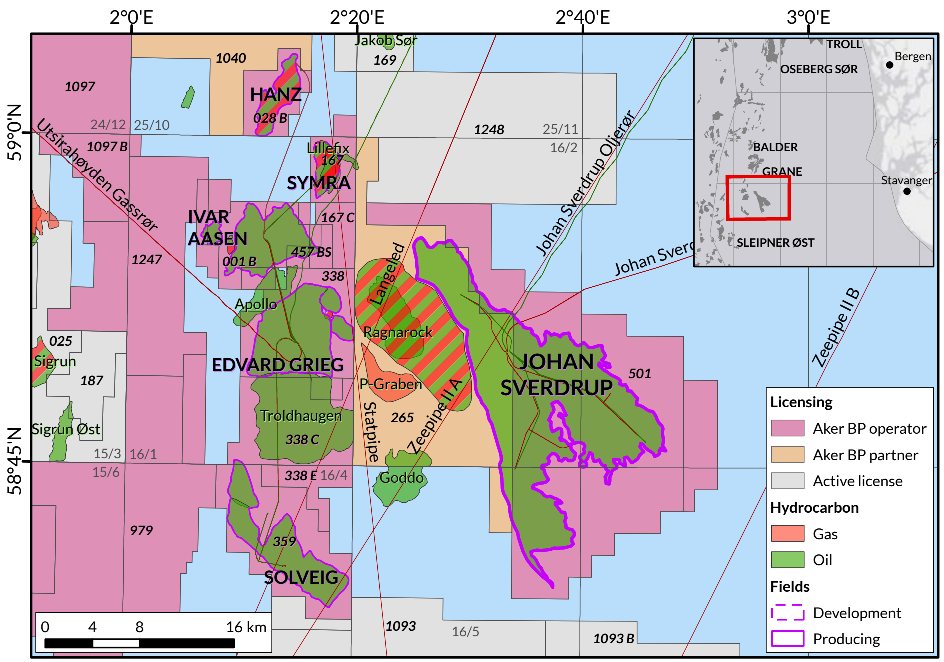
Status as of 31 December 2025
Johan Sverdrup remains a key contributor to Aker BP's portfolio. Oil output in 2025 was higher than internal prognoses and stable at around 110 kSm³/d, slightly lower than end 2024 (approximately 120 kSm³/d) mainly due to water production increase.

As of end 2025, 43 oil producers and 26 injectors were on stream, with six new producer branches (sidetracks and retrofit multilateral wells (RMLTs)) and one injector drilled since 31 December 2024.

Reserves and development
Reserves update applying the same methodology as previous years, including a full revision of all input data (individual well potential profiles, drilling schedule, capacities, production efficiency). Well profiles derived from the latest operator's fast model update (FMU) ensemble model and matched to recent well behaviour (water cut).

Changes from 31 December 2024 include the addition of three RMLT wells drilled from existing platform wells and online in 2025: D-4 Y2, D-17 B (sidetrack planned as RMLT) and D-6 Y2; and one ongoing drilling RMLT with production estimated by early 2026 (D-18 Y2).

Figure 5.1 **Johan Sverdrup location map**



The positive reserve revisions since 31 December 2024 are confirmed by high oil production and very high production efficiency in 2025. In addition, the field maintained an oil production capacity of 115–120 kSm³/d for longer than forecast.

Uncertainty and key assumptions
Sweep efficiency versus water production development is the main uncertainty going forward. Relative permeability of oil and water during water flooding is considered to contribute most to this uncertainty. From December 2022 to April 2025, water production kept a steady increase, that became steeper since May 2025 mainly due to water coning. The water production development indicates a risk to ultimate recovery.

Short term production forecast is highly dependent on the performance of individual wells. Well potential is limited by water cut increase and reduced productivity in some wells (bottomhole pressure and drawdown limitations).

Total liquid capacity is expected to be the primary production constraint from early 2026 on.

5.2 JOHAN SVERDRUP – PROJECTS

- **Licences:** PL265, PL501, PL502, PL501B
- **Operator:** Equinor
- **Ownership share:** 31.5733 percent
- **Resource class:** Approved for development / Justified for Development (Phase 3)
- **First production:** 2026

Short field description
In terms of development, four projects are included in the reserves: Water Alternating Gas-injection (WAG), 2026 infill drilling programmes from both drilling platform and subsea (IOR DP (2026) and IOR SS (2026)) and Phase 3 development.

- The field is produced by water injection as pressure support. The plan is to implement large scale WAG injection gradually from 2026 to improve oil recovery.
- An active infill drilling programme is ongoing to optimise recovery by accelerating reserves and delaying water development. Infill wells including RMLTs, and sidetracks to existing wellbores have been added to the reserves.
- The Phase 3 PDO includes two subsea templates tied back to Johan Sverdrup with first oil planned by October 2027.

Status as of 31 December 2025
- WAG full field implementation has been delayed since the 31 December 2024 reporting. The current plan is to start gas injection in the wells on the DP-platform in early 2026, E-F template wells in early 2027, and full field implementation from 2028.
- Four infill wells drilled from the drilling platform, three subsea wells and one subsea well work-over are included in the reserves and are planned for 2026.
- The Phase 3 project was approved by the partners in June 2025 and is pending authorities' approval.

Reserves and development
- The WAG profile represents the delta increment of FMU ensemble runs with and without WAG. Only the timing has changed for this profile, the reserves remain unchanged.
- The 2026 individual infill profiles are a combination of analytical approach (RMLTs) and FMU ensemble simulations with and without the wells (sidetracks).
- The Phase 3 profile is scaled from the operator's profile (at final investment decision, DG3) resulting in reserves acceleration, but final recovery close to DG3.

There is an acceleration and increase in 2P estimated ultimate recovery (EUR) due to the new projects included in the reserves update (Phase 3 and infill drilling).

Uncertainty and key assumptions
Same uncertainty and key assumptions as for Johan Sverdrup Base.

6. The Skarv area

6.1 SKARV UNIT

- **Licences:** PL159, PL212, PL212B, PL262
- **Operator:** Aker BP
- **Ownership share:** 23.835 percent
- **Resource class:** On production
- **First production:** 2012

Short field description
Skarv Unit constitutes the structures Skarv, Idun, Ærfugl and Gråsel. Skarv and Gråsel are originally oil fields, while Idun and Ærfugl are gas and gas condensate fields, respectively. They are located about 35 km south-west of Norne in the northern part of the Norwegian sea in blocks 6507/2, 6507/3, 6507/5 and 6507/6.

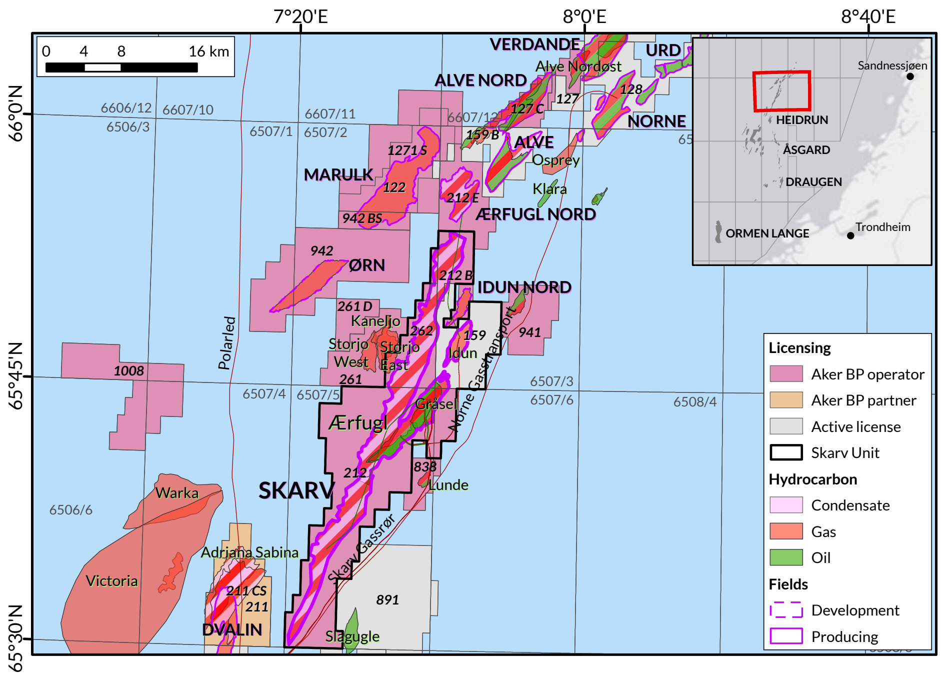
The Skarv structure is defined by three segments, A, B and C, separated by faults. Each segment constitutes Jurassic Garn, Ile and Tilje Formations. The Garn Formation is a high-quality reservoir, and the deeper Ile and Tilje Formations are more heterogeneous with poorer reservoir quality. Idun is a separate, gas filled structure with no communication to the Skarv A, B and C segments. Gråsel is situated stratigraphically above the Skarv structure. A Late Cretaceous Lange Formation forms the main reservoir. Ærfugl is a 60 km long and 2-3 km wide Cretaceous Lysing Formation.

Production is through subsea templates to the Skarv FPSO. Oil is exported by tanker and rich gas is transported by pipeline through the Åsgard Transport System. The production strategy is oil production in combination with gas injection, keeping the pressure constant, followed by gas blowdown. Gas blowdown started in the Skarv B and C segments in March 2022 and in Tilje and Gråsel in October 2025. The gas-filled structures are produced by depletion.

Status as of 31 December 2025
The production has been better than forecast due to high uptime for Skarv FPSO and strong performance from the wells as the pressure is decreasing. Accelerating blowdown in Tilje and Gråsel from 2026 to October 2025 also contributed to increased production. A continuous focus on production optimisation has extended the lifetime of several wells with only one well, B-8 H, ceasing production during 2025. As of 31 December 2025, there are 17 active wells distributed as follows: Skarv (8), Idun (2), Gråsel (1) and Ærfugl (6).

Reserves and development
Reserves are increased for Skarv Unit driven by a revision of abandonment pressures due to excellent

Figure 6.1 **Skarv and Ærfugl location map**

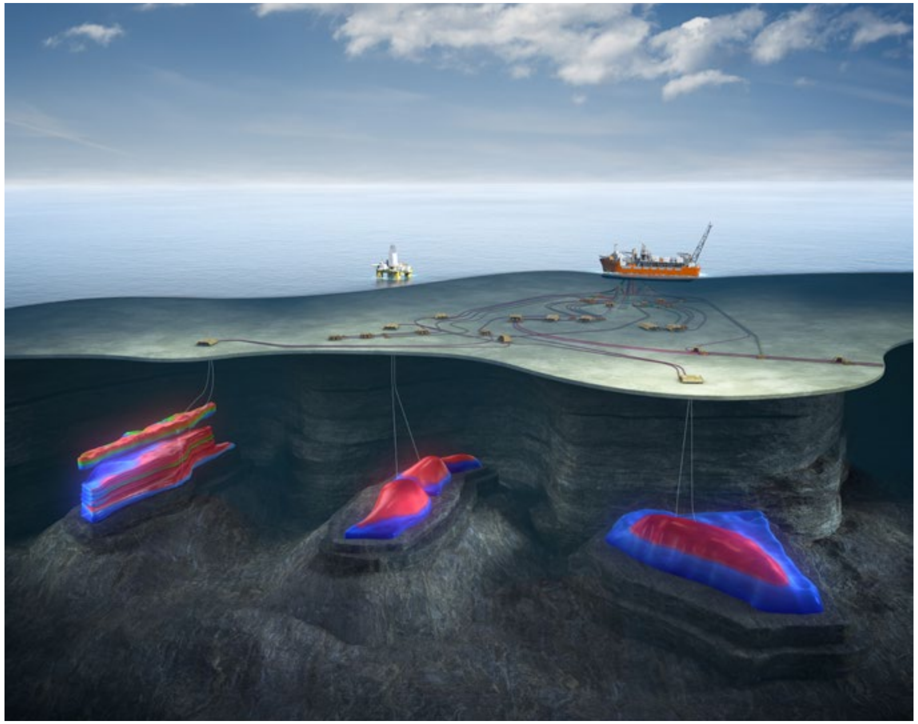


production from Skarv A at low reservoir pressures. Furthermore, an expected water breakthrough in Ærfugl has not yet started, contributing to increased reserves supported by modelling.

The development strategy for Skarv Unit focuses on infill wells in Ærfugl and interventions to promote gas production in declining oil wells in Skarv B and C segments.

Uncertainty and key assumptions
Abandonment pressure and early water breakthrough remain the main uncertainties for Skarv Unit.

6.2 ÆRFUGL NORD



- **Licence:** PL212E
- **Operator:** Aker BP
- **Ownership share:** 30 percent
- **Resource class:** On production
- **First production:** 2021

Short field description
Ærfugl Nord is the northern part of the Ærfugl gas condensate field but is not a part of Skarv Unit. The field is Cretaceous Lysing and contains one well, G-1 H. It produces towards the Skarv FPSO via a subsea template.

Status as of 31 December 2025
G-1 H saw a rapid decline in production following water breakthrough in 2024. The well was shut after an attempted water shutoff in February 2025. As of 31 December 2025, there is no production from the well, but the licence still produces through a redelivery programme in agreement with Skarv Unit.

Reserves and development
The reserves from G-1 H have been removed and the remaining reserves in Ærfugl Nord are from the fixed redelivery programme with Skarv Unit. Modelling shows that there is still potential in the area and a sidetrack is under consideration.

Uncertainty and key assumptions
There are no changes to the key assumptions and uncertainty tied to the remaining reserves of Ærfugl Nord.

6.3 IDUN NORD

- **Licence:** PL159D
- **Operator:** Aker BP
- **Ownership share:** 23.835 percent
- **Resource class:** Approved for development
- **First production:** 2026

Short field description
Idun Nord is a gas condensate field in the Garn Formation from the Middle Jurassic and is located north of the Skarv and Idun fields. The field is developed as a subsea tie-back to the Skarv FPSO as part of the Skarv Satellite Project (SSP).

Status as of 31 December 2025
Both wells have been drilled and completed during 2025 according to plan. First gas is expected in 4Q 2026.

Reserves and development
The Idun Nord reserves have increased due to the I-2 H well confirming volumes in segment 1B that were previously unproven. The reservoir properties have been confirmed by the production wells.

Uncertainty and key assumptions
Segment 1B was the main uncertainty for the Idun Nord project but is now removed as a risk and included in the reserves estimate. Segment 2A is not proven and is not included in the reserves estimates.

6.4 ALVE NORD

- **Licence:** PL127C
- **Operator:** Aker BP
- **Ownership share:** 58.0825 percent
- **Resource class:** Approved for development
- **First production:** 2026

Short field description
Alve Nord is an oil and gas field 37 km north-east of the Skarv FPSO and 9 km west of the Norne FPSO. It has two main reservoirs in the Cretaceous Lange Formation and the Jurassic Båt and Fangst groups. The field is developed as a subsea tie-back to the Skarv FPSO as part of the SSP.

Status as of 31 December 2025
The Jurassic well P-2 H has been drilled down to top Garn and will be finalised and completed in 2026. The Cretaceous P-3 H well is drilled and completed according to plan. First oil is expected in 4Q 2026

Reserves and development
Reserves are unchanged.

Uncertainty and key assumptions
The main uncertainties for Alve Nord include the position of the free water level, net to gross ratio in the Cretaceous Lange Formation and the flow properties for the Jurassic oil zones in Ile/Tofte.

6.5 ØRN

- **Licences:** PL942
- **Operator:** Aker BP
- **Ownership share:** 30 percent
- **Resource class:** Approved for development
- **First production:** 2026

Short field description
Ørn is a lean gas and condensate field north-west of the Skarv field. The main reservoirs are the Middle Jurassic Garn and Ile Formations. The field is developed as a subsea tie-back to the Skarv FPSO as part of the SSP.

Status as of 31 December 2025
The tophole drilling has started, and the two producer wells will be drilled and completed during 2026. First gas is expected in 4Q 2026.

Reserves and development
The 1P reserves are increased due to changing the basis of the 1P estimate from 'gas down to' to a P90 estimate from an ensemble model.

Uncertainty and key assumptions
The main uncertainties for Ørn include the position of the free water level, the segmentation in the reservoir and the ability of the wells to sustain production.

7. The Ula area

7.1 ULA

- **Licence:** PL019
- **Operator:** Aker BP
- **Ownership share:** 80 percent
- **Resource class:** On production
- **First production:** 1986

Short field description
Ula is an oil field in the southern part of the Norwegian sector of the North Sea in block 7/12 in PL019. The water depth in the area is about 70 metres, and the reservoir depth is about 3,500 metres TVD MSL.

Ula was discovered in 1976 by well 7/12-2, which encountered a substantial Late Jurassic reservoir in the Ula Formation with a net thickness of 128 m, oil bearing from top to base. The 7/12-2 well was drilled to a depth that included a Triassic hydrocarbon bearing sequence, comprising low quality sands interbedded with shales.

Ula started producing in 1986, water injection started in 1988 and water-alternating gas (WAG) injection started in 1998. The Ula development consists of three conventional steel facilities for production, drilling and accommodation, which are connected by bridges. Ula receives production from Tambar, Tambar East, Oda and Blane for processing and export. Previously, also the Oselvar field produced to Ula.

Status as of 31 December 2025
The Ula field is presently producing 5,000-6,000 bopd and the cumulative production is 485 mmbbls.

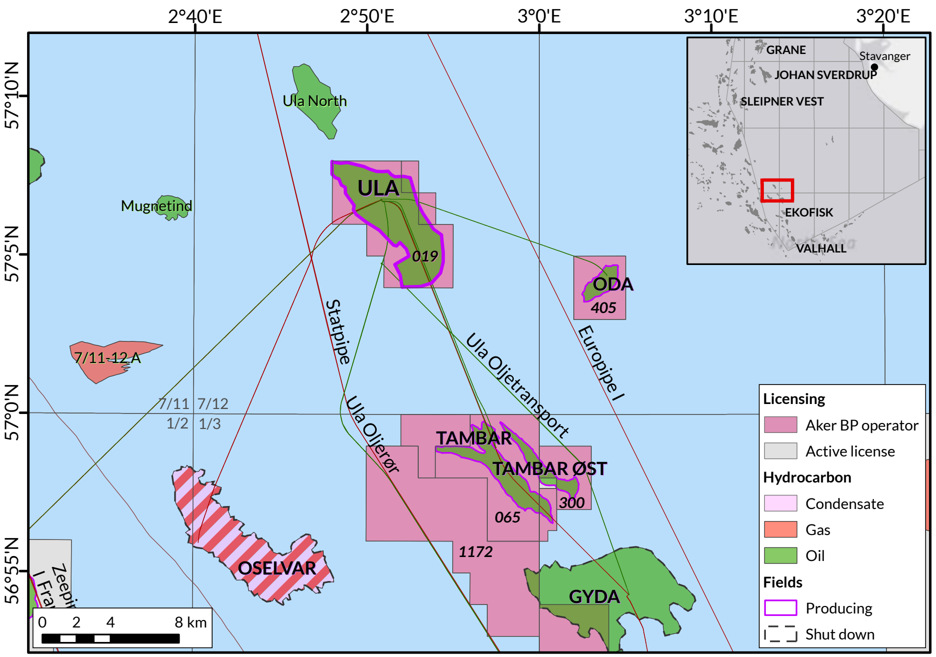
There are eight active producers, seven in the Jurassic reservoir, supported by four WAG injectors, and one in the Triassic reservoir, producing in natural depletion. No changes to active producers or injectors in the past year.

Reserves and development
Reserves update applying the same methodology as previous year, which is decline analysis of the producing wells.

Many of the Ula development wells are old. To account for risks of wells falling over due to leaks or other mechanical problems, probability distributions of remaining lifetime are used. This reduces the predicted volumes until CoP, compared to pure decline type predictions.

A slight upwards revision of the reserves was done based on the 2025 performance.

Figure 7.1 **Ula location map**



Uncertainty and key assumptions
No new projects are planned on Ula.

Uncertainties to the production estimate are:

- Wells falling over for mechanical problems
- Availability of gas for injection. With declining gas rates from Ula and the satellite fields and a near constant requirement for fuel gas, the availability of gas for injection is dropping.

7.2 TAMBAR

- **Licence:** PL065
- **Operator:** Aker BP
- **Ownership share:** 55 percent
- **Resource class:** On production
- **First production:** 2001

Short field description

Tambar is an oil field about 16 kilometres southeast of the Ula field in the southern part of the Norwegian sector of the North Sea. The water depth in the area is 68 metres. Tambar was discovered in 1983 by well 1/3-3. The reservoir consists of Upper Jurassic sandstones in the Ula Formation, deposited in a shallow marine environment. The reservoir lies at a depth of 4,100-4,200 metres, and the reservoir characteristics are generally very good. The field is produced by pressure depletion, with expansion and aquifer support as the main reservoir drive mechanisms. The field was developed with a remotely controlled wellhead facility without processing equipment. The produced fluids are transported to Ula through a pipeline. Production started in 2001.

Status as of 31 December 2025

Tambar is presently producing around 3,000 bopd, and the cumulative production is 74 mmbbls.

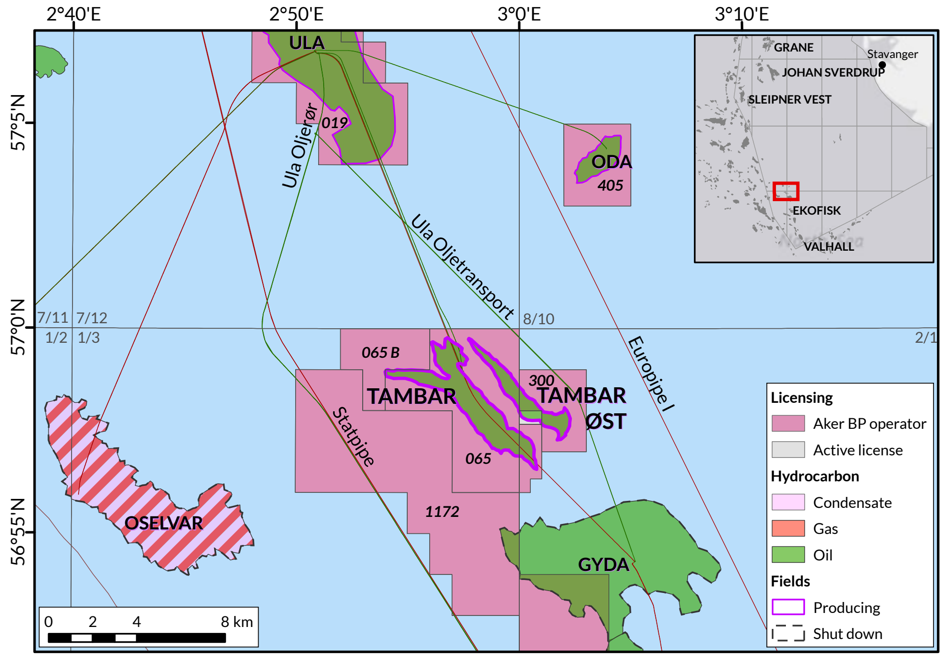
There are three active producers, same as previous year, while a newly worked over producer is going to be started in the first quarter of 2026.

Reserves and development

At present, the Tambar production is dominated by the K-1 producer. The two other producers, K-2B and K-4, share one flow line and can produce only one at the time. Both are cyclic in nature, each with a potential around 40 percent of the K-1 rate at the start of a cycle. The rate then drops gradually and after some months this motivates a well swap. There are no changes to the rate predictions vs cumulative production relations, established from decline analysis, for the three mentioned wells since last year.

The reserves for the K-3 worked over producer were moved from the «Approved» category to «On production», as the well is ready to be opened after pulling a plug, re-perforating the C-sand and adding new perforations in the A-sand, all which is scheduled to happen during the first quarter of 2026. The reason for not opening the well earlier is that the limited capacity of the Tambar – Ula pipeline has been taken by the Tambar East K-5B producer since its opening in April 2025. This is also the reason why all three presently active Tambar producers were kept shut since April 2025, until K-1 could be opened in October, after a sufficient degree of decline of the K-5B rate had been reached. The expected reserves from the K-3 well were revised upwards by a small amount, stemming from the recent decision to add perforations in the A-sand.

Figure 7.2 **Tambar, Tambar East and Oda location map**



Uncertainty and key assumptions

No new projects or major changes to the modus operandi are planned.

Uncertainties are production performance, influenced by:

- Wells falling over for mechanical problems
- Regularity of the multiphase pump (MPP) . This pump allows the wells to produce against a lower tubing head pressure, and the presently biggest producer (K-1) is dependent on it. The low regularity of this pump is the main reason for the Tambar Production Efficiency being as low as 60 percent.
- Performance of the worked-over K-3 producer

7.3 TAMBAR EAST

- **Licences:** PL065, PL300, PL019B
- **Operator:** Aker BP
- **Ownership share:** 46.2 percent
- **Resource class:** On production
- **First production:** 2007

Short field description
Tambar East is a minor oil field located east of Tambar about 16 kilometres southeast of the Ula field in the southern part of the Norwegian sector of the North Sea. The field was discovered in 2007 by well 1/3-K-5.

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

The only development well, the oil producer K-5, was drilled from the Tambar platform. The produced fluids are 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. The first version of the Tambar East producer, the K-5, horizontal in the C-sand, was opened in 2007. It was permanently shut early 2024 and then sidetracked as K-5B, the main purpose being drainage of the deeper A-sand. The sidetrack K-5B was opened for production in April 2025.

Status as of 31 December 2025
Tambar East is presently producing around 3,000-4,000 bopd and the cumulative production is 2.3 mmbbl.

The sidetracked K-5 producer (K-5 B) was opened to production in April 2025. It produced very well after opening but during the fourth quarter of 2025 it has started to fall below the initial prognosis. Transient pressure build-up analyses have revealed a more complex reservoir geometry than assumed.

Reserves and development
Production rate versus cumulative production trended below pre-drill expectations late in 2025, leading to a downward revision of the reserves.

Uncertainty and key assumptions
Current plan is to continue production as-is with no new projects.

The pre-drill uncertainties were mainly the structural complexity of the reservoir, and the degree of water encroachment. Transient pressure build-up interpretations together with production performance to date have revealed that the reservoir is somewhat more structurally complex than the base assumption. This has led to a moderate reduction the reserves, even if there are no indications that the petroleum initially in place (PIIP) is lower than the pre-drill numbers.

7.4 ODA

- **Licence:** PL405
- **Operator:** Aker BP
- **Ownership share:** 15 percent
- **Resource class:** On production
- **First production:** 2019

Short field description
The Oda field is located 14 km east of the Ula field in Block 8/10, PL405, on the eastern side of the Central Graben in the Norwegian North Sea. The water depth is about 66 metres. The crest of the structure is estimated at approx. 2,300 metres TVD MSL. The PDO was approved by the authorities in May 2017. Production commenced in March 2019. The discovery well, 8/10-4 S, was drilled in 2011 in the north-western part of a salt-induced structure. The well proved an oil-down-to situation in the Ula Formation Based on pressure measurement, the oil-water contact is estimated to be at 2,985 metres TVD MSL from sidetrack wells 8/10-4 A T2. The Oda reservoir consists of the Upper Jurassic Ula Formation; a sandstone reservoir with high quality properties, on the western flank of the steeply dipping salt diapir. The oil column is about 485 metres of high quality, light crude oil. The development concept is a subsea tie-in to the Ula Platform. The Oda reservoir is drained by two producers supported by one water injection well. All the wells have been drilled from an integrated subsea template, and there are two oil producers and one water injector. One of the oil producers, B-1 H, watered out in 2022, it was sidetracked to a new location and the sidetrack started producing in the same year. The producers don't have artificial lift installed and there are no facilities for this in the Oda installations.

Status as of 31 December 2025
Oda is presently producing 4,000-5,000 bopd from two producers. One of them, the B-1 AH, has a water cut in the range 95-97 percent and an oil rate between 200 and 500 bopd. The second one, the B-3 H, is producing water-free and the oil rate is between 3,500 and 4,500 bopd. Sea water is injected in the B-2 H injector.

Reserves and development
There was an upwards revision of reserves this year, due to performance, using decline analysis on the recent trends.

Uncertainty and key assumptions
The main uncertainty for reserves and production is when water will break through in the crest producer B-3 H, and the subsequent water cut development.

8. Valhall area

8.1 VALHALL

- **Licences:** PL006B, PL033B
- **Operator:** Aker BP
- **Ownership share:** 90 percent
- **Resource class:** On production
- **First production:** 1982

Short field description
Valhall is an oil field in the southern part of the Norwegian sector of the North Sea. The reservoir consists of chalk in the Upper Cretaceous Tor and Hod Formations. Reservoir depth is approximately 2,400 metres. The Tor Formation chalk is fine grained and soft with high porosity (up to 50 percent). Matrix permeability is in the 1-10 mD range. There are areas with natural fractures with high permeability conduits. The Hod Formation porosity is 30 percent-38 percent with permeability 0.1-1 mD.

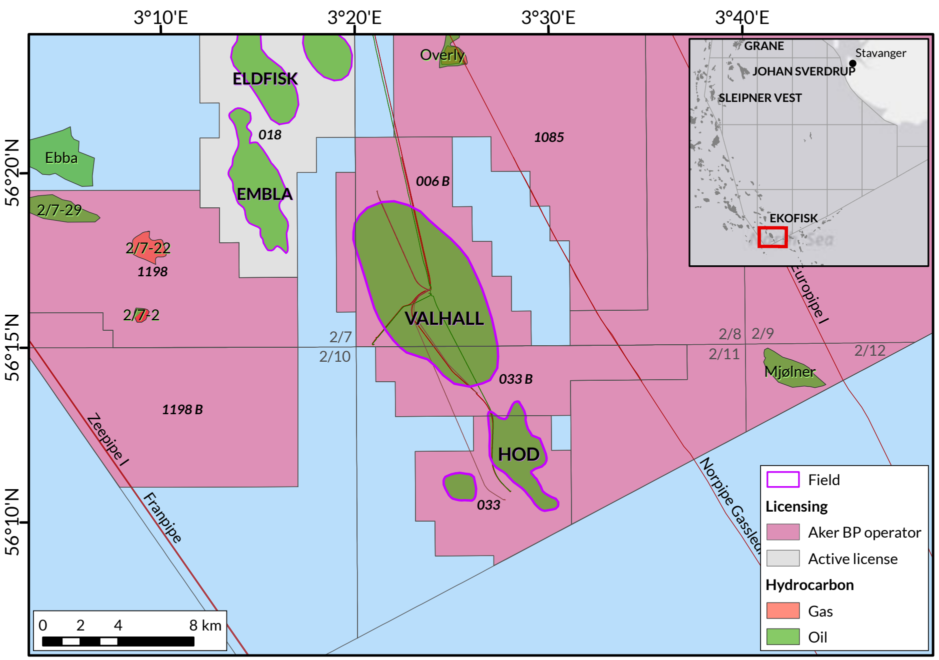
The field has produced with pressure depletion and a very effective compaction drive since 1982. As a result of the pressure depletion the chalk has compacted, and the seabed subsided. Water injection in the centre of the field started in 2004. This has reduced pressure depletion and hence subsidence.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

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

The Valhall PWP project delivered a PDO in 2022 consisting of a joint development for the Valhall and Fenris Fields. For Valhall, the project consists in 14 development wells that are currently being drilled – see section 8.1.1 Valhall Projects.

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

Figure 8.1 **Valhall and Hod location map**



Status as of 31 December 2025
Valhall has 52 active producers and 9 water injectors. The production in 2025 was stable and above expectations. No wells were lost due to chalk influx this year.

The oil production is declining due to falling pressure and increasing water cut (currently around 39 percent).

Reserves and development
No major changes to Valhall base reserves were made in 2025. Volume from 2 infill wells on the East Flank were added to the reserves in 2025 – see section 8.1.1 Valhall Projects.

Uncertainty and key assumptions
Main uncertainties affecting the reserves are

- Well life (assuming 30 years for flank wells and 24 years for crest wells)
- Rate adding and rate restoring well interventions.
- Waterflood sweep efficiency.
- Long term decline in wells on depletion (aquifer influx and/or long-term compaction energy).
- Well re-stimulations (re-stimulation is re-evaluated continuously, and upsides related to well work are not accounted for in the most likely profile).
- Well downtime due to chalk influxes.

8.1.1 Valhall Projects

In terms of development, two projects are included in the reserves: Valhall PWP and Valhall Infills.

- **Licences:** PL006B, PL033B
- **Operator:** Aker BP
- **Ownership share:** 90 percent
- **Resource class:** Approved for development
- **First production:** 2026 and 2027

Short field description
- The Valhall Infill project consists of 4 infill producers on the West and East Flank areas. The wells target formations and areas with remaining oil potential. Available slots on the Valhall Flank West and Valhall PWP platforms will be used.
- The Valhall PWP (Production and Wellhead Platform) project consists of a common development for the Valhall and Fenris Fields. For Valhall, 11 producers and 3 water injectors targeting both the Tor and Hod Formations will be drilled. A waste injector is also included in the project.

The wells are split into a pre-drill campaign starting in 2025 and a main campaign in 2026.

Status as of 31 December 2025
- Valhall Infills: Drilling is expected to start in 2026.
- Valhall PWP: 2 wells in the pre-drill campaign have been drilled. Drilling of the third well is ongoing.

Reserves and development
- Valhall Infills: Reserves for the 2 West Flank wells were booked in 2024 while the reserves for the 2 East Flank wells are new in 2025.
- Valhall PWP: No changes to the reserves are made in 2025.

Uncertainty and key assumptions
The main reservoir uncertainties are reservoir thickness, water saturation, permeability, pressure and compaction. There is also a risk of water flooding – particularly in the Crest area.

The anticipated well life for the wells on the East Flank has been revised from the standard flank well assumption of 30 years to 20 years. This change reflects earlier than expected production cessation in several East Flank wells. Well life remains a key source of uncertainty for the project.

Pressure differential along the well trajectory can impact the well length and consequently rates and reserves.

8.2 HOD

- **Licences:** PL033
- **Operator:** Aker BP
- **Ownership share:** 90 percent
- **Resource class:** On production
- **First production:** 1990

Short field description
Hod is an oil field 13 km south of the Valhall field in the southern part of the Norwegian sector in the North Sea.

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

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

The field was initially developed with an unmanned production wellhead platform (Hod A) which was remotely controlled from Valhall. Since 2012, there has been no production from Hod A. The Hod Saddle reservoir is currently produced through three wells drilled from Valhall Flank South. In 2021, a new unmanned wellhead platform (Hod B) was installed with 12 well slots. Six new wells were drilled in 2021 and 2022, and production from all these wells started in 2022. The initial Hod facility (Hod A) awaits decommissioning and disposal.

Transport of oil and NGL from Hod and 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 as of 31 December 2025
Hod field is currently produced from six Hod B wells and three wells drilled from the Valhall South Flank platform that extends into the Hod license

The production in 2025 was stable and above expectations.

The oil production is declining due to falling pressure and increasing water cut (currently around 37 percent).

Reserves and development
No major changes to Hod reserves were made in 2025.

Uncertainty and key assumptions
Main uncertainties affecting the reserves are

- Well life.
- Rate adding and rate restoring well interventions.
- Long term decline in wells on depletion (aquifer influx and/or long-term compaction energy).
- Well re-stimulations (re-stimulation is re-evaluated continuously, and upsides related to well work are not accounted for in the most likely profile).
- Well downtime due to chalk influxes.

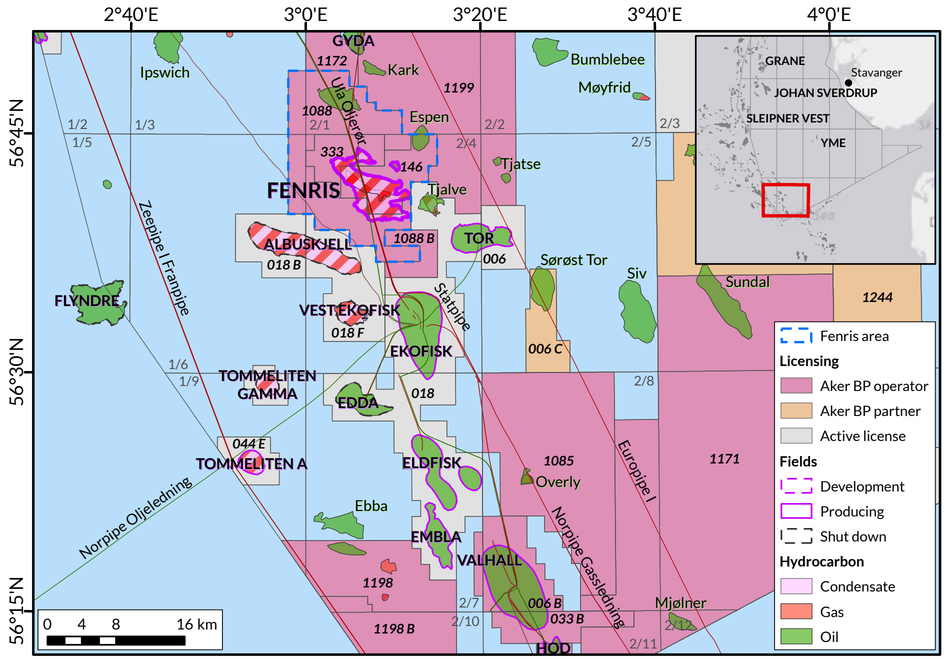
8.3 FENRIS

- **Licences:** PL146/PL146 B/PL333/PL1088
- **Operator:** Aker BP
- **Ownership share:** 77.8 percent
- **Resource class:** Approved for development
- **First production:** 2027

Short field description
Fenris is a gas condensate field comprising two Upper Jurassic reservoirs located at approximately 5,000 metres depth. The depositional environment is turbidites for the Farsund Formation, and shallow marine sandstones for the Ula Formation. The field is associated with high pressure (950–1,050 bar) and high temperature (165–185 ºC).

Fenris is being developed with an eight-slot unmanned installation, connected to Valhall via a 50 km pipeline, where gas and condensate will be processed for export. The drainage strategy for Fenris is depletion, with two vertical wells in each formation.

Figure 8.2 **Fenris location map**



Status as of 31 December 2025
All wells are drilled and completed. Static well results are in line with expectations. The wells are currently waiting for the PWP-platform to be installed and will be perforated and put on production in 2027.

Reserves and development
No change to reserves from 2024.

Uncertainty and key assumptions
The main reservoir uncertainties are connected in-place volumes and effective permeability. The only dynamic data is a 7–11 month long underground blowout in well 2/4-14 in the Farsund formation in 1989, and a mini-DST in the Ula formation in well 2/4-23 S in 2015.

9. Yggdrasil

The Yggdrasil development is the joint development for four units: Hugin Unit, Hugin Satellites, Fulla and Munin. Yggdrasil is situated in the North Sea, north of the Alvheim field and southwest of the Oseberg field. Each of these is described below.

The Yggdrasil development includes:

- A PDQ platform, central processing, Hugin A, on FGD
- A NUI wellhead platform, Hugin B, on Frøy
- An unmanned processing platform, Munin
- Ten subsea templates

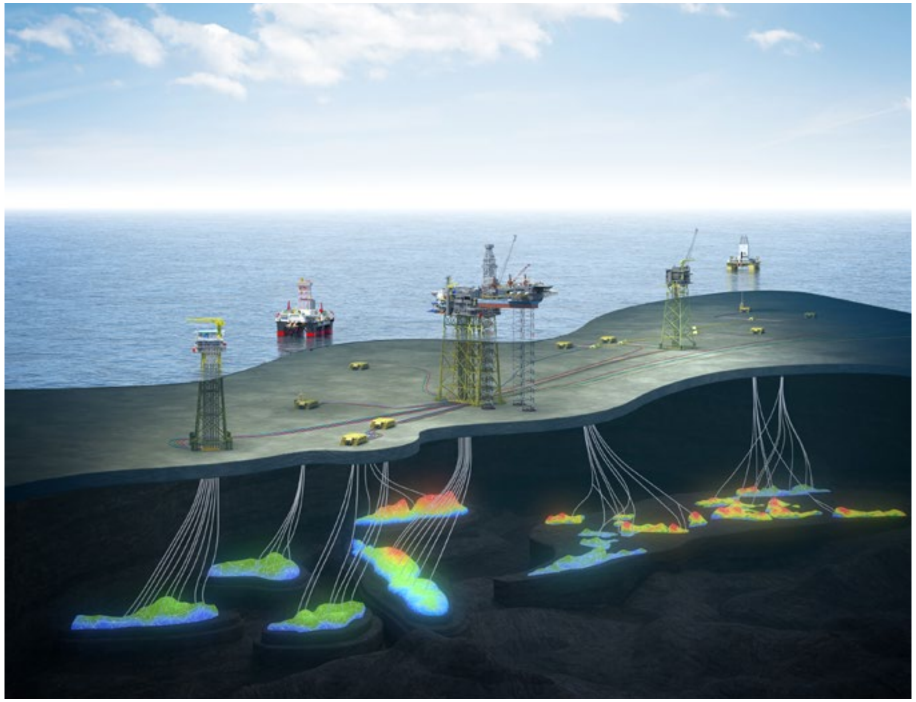
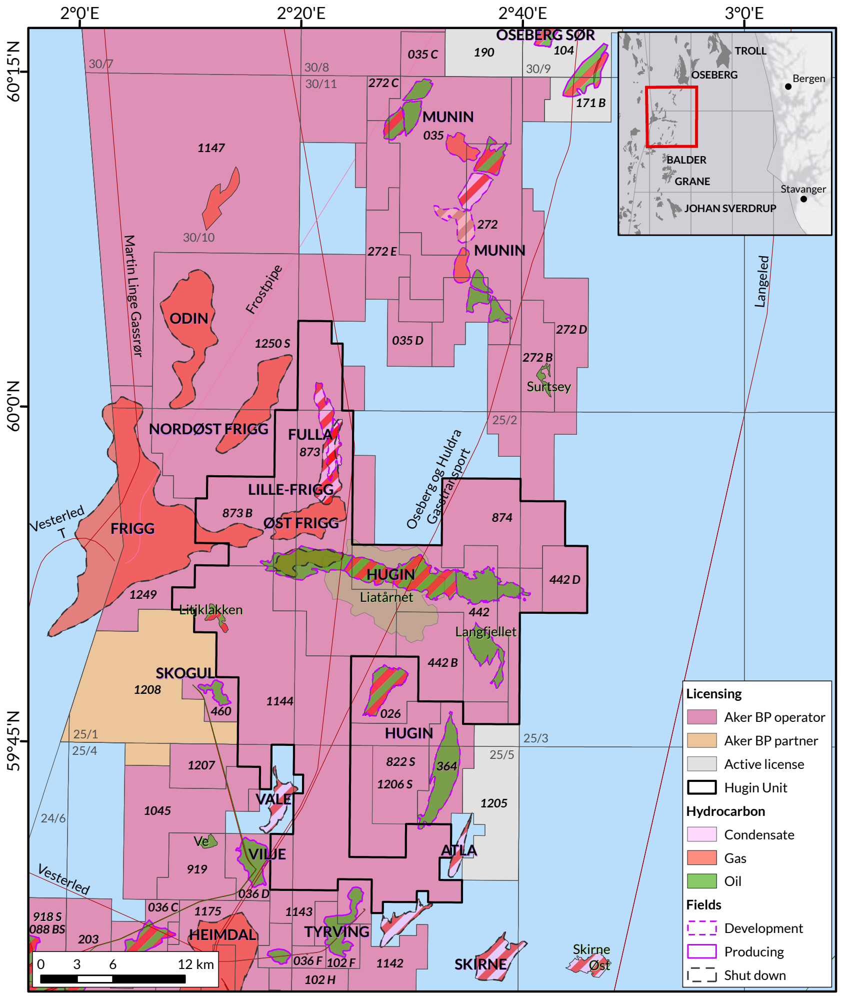


Figure 9.1 **The Yggdrasil area**



9.1 HUGIN UNIT

- **Licences:** PL026 B, PL442, PL442 B, PL442 D, PL873, PL873 B, PL874, PL1144
- **Operator:** Aker BP
- **Ownership share:** 76.7224 percent
- **Resource class:** Approved for development
- **First production:** 2027

Short field description

Frigg Gamma Delta (FGD) received development approval in 2023, while Øst Frigg was decided to be included in the development in 2025. A new business arrangement, the Hugin Unit Agreement, covering FGD, Epsilon and Øst Frigg Beta in licences PL026 B, PL442, PL442 B, PL442 D, PL873, PL873 B, PL874 and PL1144, was signed on 13 June 2025 and approved by the Ministry of Energy in October 2025. The Hugin Unit is separated stratigraphically 50 m above Frigg formation and 75 m below base Hermod. The business arrangement resulted in an Aker BP working interest of 76.7224 percent.

The Frigg Gamma Delta and Øst Frigg reservoirs are located within the Frigg Formation, characterised by gravity driven deep marine sediments, including classical turbidites, debrites, and slumps stacked in lobe complexes. The depositional lobes primarily consist of sandstones, with occasional shaly interbeds.

Status as of 31 December 2025

The PDO was submitted in December 2022. The Hugin Unit is under development with onshore and offshore installation work ongoing. The first production well spudded at the end of 2025.

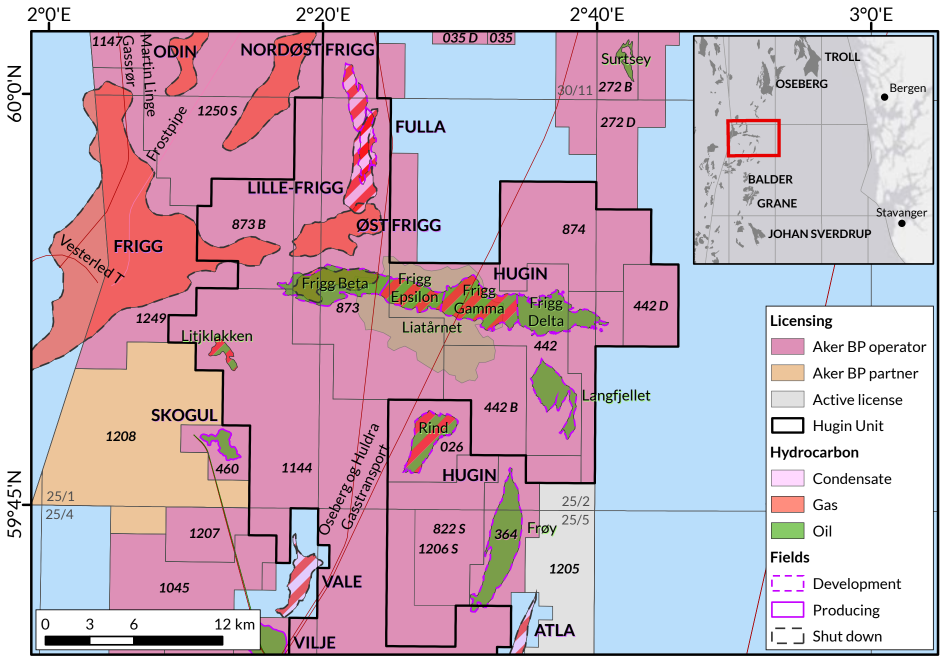
Reserves and development

Frigg Gamma Delta consists of five multilateral horizontal producers and two water injectors, drilled from Hugin A. The primary drive mechanism is aquifer pressure support; the injectors handle produced-water disposal from the platform. Øst Frigg Beta and Epsilon is a subsea development consisting of four multilateral horizontal producers and is tied back to Hugin A.

Øst Frigg, previously not included in the reserves, was designated 1P and 2P reserves under the Approved for development category following passing of Decision Gate 3 and unitisation approval by the Department of Energy in 2025.

The reserves for year end 2025 have been driven by new static and dynamic models for Frigg Gamma Delta and Øst Frigg. The new model is integrating data from 27,000 m of reservoir data from pilot wells, new Ocean Bottom Node seismic survey, reservoir characterisation studies, and optimised well placement and completion strategies.

Figure 9.2 **Hugin location map**



Uncertainty and key assumptions

There are still uncertainties related to construction and drilling of the development wells start-up of production and processing capacity. The main reservoir uncertainty is related to the occasional shaly interbeds that can impact sweep efficiency and water production, as well as structural uncertainty affecting in-place volumes.

9.2 HUGIN SATELLITES

- **Licences:** PL442, PL442B, PL026, PL026B, PL364
- **Operator:** Aker BP
- **Ownership share:** 87.7 percent
- **Resource class:** Approved for development
- **First production:** 2027

Short field description
The Hugin Satellite fields submitted the Plan for Development and Operation in 2022 and it was approved in 2023.

Langfjellet
Langfjellet was discovered by exploration well 25/2-18 with three entry points into the reservoir. The well proved oil in sandstones of the Hugin Formation and condensate in the Sleipner Formation. The Langfjellet discovery wells show that both vertical and lateral barriers are present, creating multiple compartments. Langfjellet will be developed with two 6-slot subsea templates that are tied-back to the Hugin A platform. Three producers, two water injectors and an infill (depending on result of a pilot well) well are initially planned, leaving six spare slots for future use. The producers are U-shaped or sinus-shaped wells with two or more deviated cuts across the oil bearing stratigraphy, to mitigate any barriers in the reservoir.

Frøy
The Frøy re-development targets the Middle Jurassic Hugin and Sleipner Formations, which were deposited in a range of fluvial to marginal marine environments with varying degrees of tidal influence. The resulting reservoir exhibits a complex architecture and highly variable properties, with significant contrasts in flow characteristics between different zones. The Frøy field has been produced before, but shut down in 2001 due to high water cut and barium sulfate scale. The redevelopment of Frøy includes long horizontal wells that will target remaining reserves in a partly flooded reservoir. Scale mitigation measures in terms of chemical injection have been planned for.

Rind
The Hugin reservoir is approximately 100 m thick and comprises shallow to marginal marine strata. The Sleipner reservoir, around 50 m thick, consists of fluvio-deltaic and coal-bearing paralic strata. The deeper Statfjord reservoir is approximately 200 m thick and is made up of fluvial to marginal marine strata. Due to its channelised nature and predominantly low permeability, the Statfjord reservoir is assumed to exhibit a relatively low degree of connectivity. The Statfjord reservoir is separated from Hugin/Sleipner by a 150 m thick Dunlin shale.

Status as of 31 December 2025
The Hugin Satellites are under development with onshore and offshore installation work ongoing.

Reserves and development
The reserves for year end 2025 have been driven by new static and dynamic models. The new models incorporate, new Ocean Bottom Node seismic survey, reservoir characterisation studies, and optimised well placement and completion strategies.

Uncertainty and key assumptions
There are still uncertainties with relation to construction and drilling of the development wells and start-up of production. The main reservoir uncertainties are reservoir segmentation, pressure communication and maintenance, and sweep efficiency.

9.3 FULLA

- **Licences:** PL873
- **Operator:** Aker BP
- **Ownership share:** 47.7 percent
- **Resource class:** Approved for development
- **First production:** 2027

Short field description
The Fulla fields submitted the Plan for Development and Operation in 2022 and it was approved in 2023.

The Fulla & Lille-Frigg area consists of the Tarbert Formation which is mostly characterised by delta front and estuarine depositional environments. The Tarbert Formation on both Fulla and Lille-Frigg is generally very sand prone, with the best reservoir properties found in fluvial and/or deltaic distributary channel deposits.

Status as of 31 December 2025
Fulla is under development with onshore and offshore installation work ongoing.

Reserves and development
The reserves for year end 2025 have been driven by new static and dynamic models. The new models incorporate, new Ocean Bottom Node seismic survey, reservoir characterisation studies, and optimised well placement and completion strategies.

Uncertainty and key assumptions
There are still uncertainties with relation to construction and drilling of the development wells and start-up of production. The main reservoir uncertainty for Fulla is migration into Fulla South and communication to the aquifer. Lille Frigg has uncertainties to erosion and faulting on the norther part of the field.

9.4 MUNIN

- **Licences:** PL035, PL035C, PL272, PL272B, PL272C
- **Operator:** Aker BP
- **Ownership share:** 50 percent
- **Resource class:** Approved for development
- **First production:** 2027

Short field description
The Munin fields submitted the Plan for Development and Operation in 2022 and it was approved in 2023.

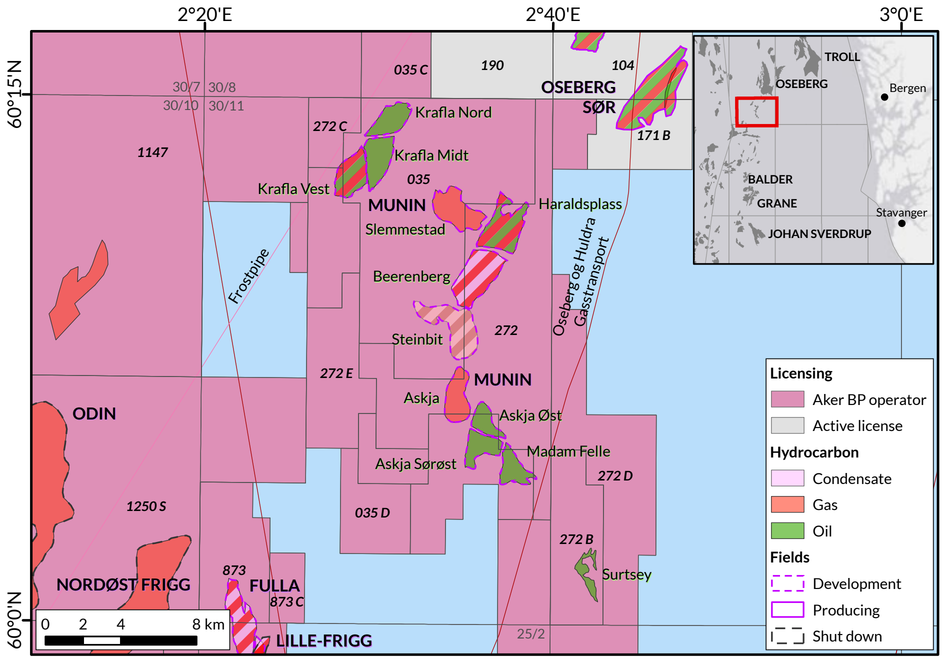
The Brent group was deposited as a major delta system comprising sandstone, siltstones, shale, calcite and coals. Deposition of the Tarbert Formation has occurred in the retrogradational phase of the Brent delta, generally in marginal marine estuarine environment or shallow marine environments, during early rift initiation.

Munin is divided into three areas: Krafla, Sentral and Askja.

- Krafla has three proven segments: Krafla Vest, Krafla Midt, and Krafla Nord. Varying pressures, fluid phases and contacts have been observed across these compartments.
- Sentral has three proven segments: Beerenberg, Slemmestad and Haraldsplass. There are different fluid types and contacts observed in these segments.
- Askja has four proven segments: Askja Vest, Askja Øst, Askja Sørøst and Madam Felle. Askja Vest is separated from Askja Øst based on difference in fluid phase (gas/oil) and different pressures across a fault. Askja Øst is separated from Askja Sørøst by a likely sealing fault.

Status as of 31 December 2025
Munin is under development with onshore and offshore installation work ongoing and drilling of develop-ment wells.

Figure 9.3 **Munin location map**



Reserves and development
The reserves for year end 2025 have been driven by new static and dynamic models. The new models incorporate, new Ocean Bottom Node seismic survey, reservoir characterisation studies, and optimised well placement and completion strategies.

Uncertainty and key assumptions
There are still uncertainties with relation to construction and drilling of the development wells and start-up of production. The main reservoir uncertainties are reservoir segmentation, pressure communication and maintenance, and sweep efficiency.

10. Contingent resources

Aker BP has contingent resources in a wide range of assets and at different stages of maturation. The total net contingent resources estimate reported here include volumes as defined in Figure 1.1. Discoveries that need more data acquisition to define the way forward, such as Rondeslottet and Liatårnet, are not included.

The contingent resources range from 580 to 1,200 mmboe, with a 2C volume of 866 mmboe. Approximately 80 percent of this is associated with discoveries and further development of the fields containing reserves described in 3 Description of Reserves. The most important contributors to the contingent resources in these areas are the discoveries in the Yggdrasil area and volumes in the Valhall area.

The most important discoveries outside the producing asset areas are Wisting, Kjøttkake, Alta/Gohta, Garantiana and Lupa.

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

CONTINGENT RESOURCES BY AREA

Alvheim area

The most mature contingent resources in the Alvheim area (resource class «Development pending», see Fig.1.1) is Froskelår Future and Vilje infill well.

Several less mature projects (resource class «Development not clarified or on hold»,) exist as well:

- Caterpillar
- Rumpetroll
- Froskelår NE
- Tir
- Firfisle
- Infill wells in several of the fields in the area

The combined net contingent resource potential for the Alvheim area ranges from 20 to 75 mmboe.

Eiga area

Several projects have been identified in the Edvard Grieg area. These projects include further IOR activities in Edvard Grieg, Ivar Aasen, Symra and Solveig as well as development of nearby resources to the existing fields.

The largest potential development so far identified is Troldhaugen.

The net contingent resource potential in the Eiga area ranges from approximately 55 to 135 mmboe.

The Yggdrasil area

The contingent resources in Yggdrasil are spread over five fields as outlined below. The Yggdrasil facilities are designed with flexibility to tie in the contingent resources with limited additional investment.

Contingent resources in Yggdrasil:

- Segment 3 (Langfjellet 4b/5)
- Krafla
  - Eldfjel
- Sentral
  - Haukeland
  - Samantha
- Askja
  - Askja Nord
  - Magdalena
  - Katarina

A discovery in Omega Alfa was made during 2025 and is expected to be a considerable contribution to the Yggdrasil volumes.

The net contingent resource potential in the Yggdrasil area ranges from approximately 65 to 145 mmboe.

The Valhall area

Several projects have been identified which may significantly increase the reserves from the Valhall, Hod and Fenris fields. Some of the projects included in the resource class «Development Pending» Figure 1.1, are listed below.

- Valhall Infills (incl from PWP)
- Valhall Flank West Waterflood
- Valhall Redrills and Late Sidetracks
- Valhall Extended Production
- Valhall Diatomite Test Producer
- Hod field Development Expansion
- Fenris IUS
- Fenris Infill Wells
- Fenris extended production

Some of these projects may be approved by the end of 2026, while others are later life options (2030+).

Several projects in resource class «Development not Clarified or on Hold» have also been identified, including further development of the diatomite reservoir, infill drilling and extended waterflood, EOR, etc. Pending further maturation, these projects are at present not included in the Valhall area contingent resources estimate below.

Aker BP holds 90 percent interest in all Valhall and Hod projects and 77.8 percent in Fenris.

The net resource potential in resource categories 4 and 5 for Aker BP in the Valhall area ranges from approximately 110 to 235 mmboe.

Skarv area

The contingent resources in resource class «Development Pending» and «Development not Clarified or on Hold», ref Fig.1.1 in the Skarv area are:

- Storjo development
- Lunde development
- Adriana/Sabina development
- Infill wells in several of the fields in the area

The net contingent resource potential for the Skarv area ranges from approximately 40 to 85 mmboe.

Ula area

At present no contingent volumes are recorded on Ula.

Partner-operated assets

Several discoveries where Aker BP holds interest are operated by other companies. The most important of these projects are

- Garantiana
- Ofelia
- Kjøttkake
- Kveikje
- Wisting

The net contingent resource potential in the partner-operated assets ranges from approximately 170 to 280 mmboe.

Other discoveries

Other resources classified as contingent resources include discoveries that are either outside of asset areas or have not yet reached a high level of maturation, such as the

- Barents Sea discoveries (Alta, Gotha, Lupa)
- Carmen
- Ringhorne Nord
- Enniberg
- Norma
- Busta

Volumes estimates range from approximately 110 to 240 mmboe.

Management commentary (MD&A)

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 reserves and resource accounting is coordinated and quality controlled by a small group of professionals, led by a reservoir engineer with more than 40 years of experience in such assessments.

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

The reported 2P/P50 reserves include volumes which are believed to be recoverable based on reasonable assumptions about future economical, fiscal and financial conditions. Discounted future cash flows after tax are calculated for the various fields based on expected production profiles and estimated proven and probable reserves. Cut-off time for the reserves in a field or project is set at the time when the maximum cumulative net cashflow for each project occurs. The company has used a long term inflation assumption of 2.0 percent and a long term exchange rate of 10.0 NOK/USD. Oil prices of 70 USD/bbl (2026), and 75 USD/bbl thereafter have been used.

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

Karl Johnny Hersvik
CEO

Appendix

LIST OF ABBREVIATIONS AND DEFINITIONS

1P (proved reserves)	Reserves with a high degree of certainty, corresponding to P90 estimates
2P (proved and probable reserves)	Reserves with reasonable certainty, corresponding to P50 estimates
AICD (autonomous inflow control device)	Completion technology used to control inflow and delay water or gas breakthrough
BOE (barrels of oil equivalent)	Unit of energy used to compare oil, gas and natural gas liquids
CoP (cessation of production)	Point in time when production from a field permanently stops
DST (drill stem test)	Well test used to evaluate reservoir properties and fluid behaviour
FPSO (floating production, storage and offloading unit)	Floating facility used for production, storage and export of hydrocarbons
GOR (gas-oil ratio)	Ratio of produced gas volume to produced oil volume
ICD (inflow control device)	Completion equipment used to balance inflow along the wellbore
IOR (improved oil recovery)	Methods applied to increase hydrocarbon recovery beyond primary and secondary recovery
ITS	Intelligent Transport System
mmboe (million barrels of oil equivalent)	Volumetric unit representing one million barrels of oil equivalent
mboepd (thousand barrels of oil equivalent per day)	Average daily production rate expressed in thousand barrels of oil equivalent
NGL (natural gas liquids)	Liquid hydrocarbons separated from produced natural gas
NTG (net-to-gross ratio)	Ratio of effective reservoir rock to total rock volume
OWC (oil-water contact)	Depth at which oil and water meet in the reservoir
P50 (probability 50)	Best estimate of recoverable volumes. There should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
P90 (probability 90)	Conservative estimate of recoverable volumes. There should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the conservative (low) estimate.
PDO (plan for development and operation)	Regulatory document required for field development approval
PDQ	Production, Drilling and Quarters platform
PE	Production Efficiency. The fraction of theoretical maximum production volume that has been produced in a specified period of time
pForecast	pForecast is a statistical analysis software to establish production forecasts, delivered by Powersim Software AS.
PIIP (petroleum initially in place)	Total volume of hydrocarbons originally contained in the reservoir
RMLT	Retrofit Multilateral well
Sm^3/d	Standard cubic metres per day
SPE (Society of Petroleum Engineers)	Professional organisation defining standards for reserves and resources classification
SURF	Subsea umbilical risers flowline
TVD MSL (true vertical depth mean sea level)	Vertical depth referenced to mean sea level
WAG	Water-alternating gas injection

AkerBP

Design: Headspin