Annual statement of reserves

2025

Contents

1 Introduction

The Annual statement of reserves and resources (ASR) is a full overview of the hydrocarbon volumes entitled to which OKEA ASA (“OKEA”) is entitled and has been prepared for both internal and external stakeholders. The reserves calculations and reporting comply with the Listing and Disclosure Requirements for Oil and Natural Gas Companies as stated by Oslo Børs (Oslo Stock Exchange).

The overview in this document is the final version of the ASR 2025, with cut-off date 31 December 2025.

2 Classification of reserves and contingent resources

OKEA's reserves and contingent resources have been classified in accordance with the Petroleum Resources Management System (PRMS) of the Society of Petroleum Engineers (SPE). This classification system is consistent with Oslo Børs' requirements for disclosure of hydrocarbon reserves and contingent resources. The framework of the classification system is illustrated in Figure 1.

In addition to 1P and 2P reserves, OKEA also reports 3P reserves, as well as contingent resources. All categories are reported in accordance with the PRMS.

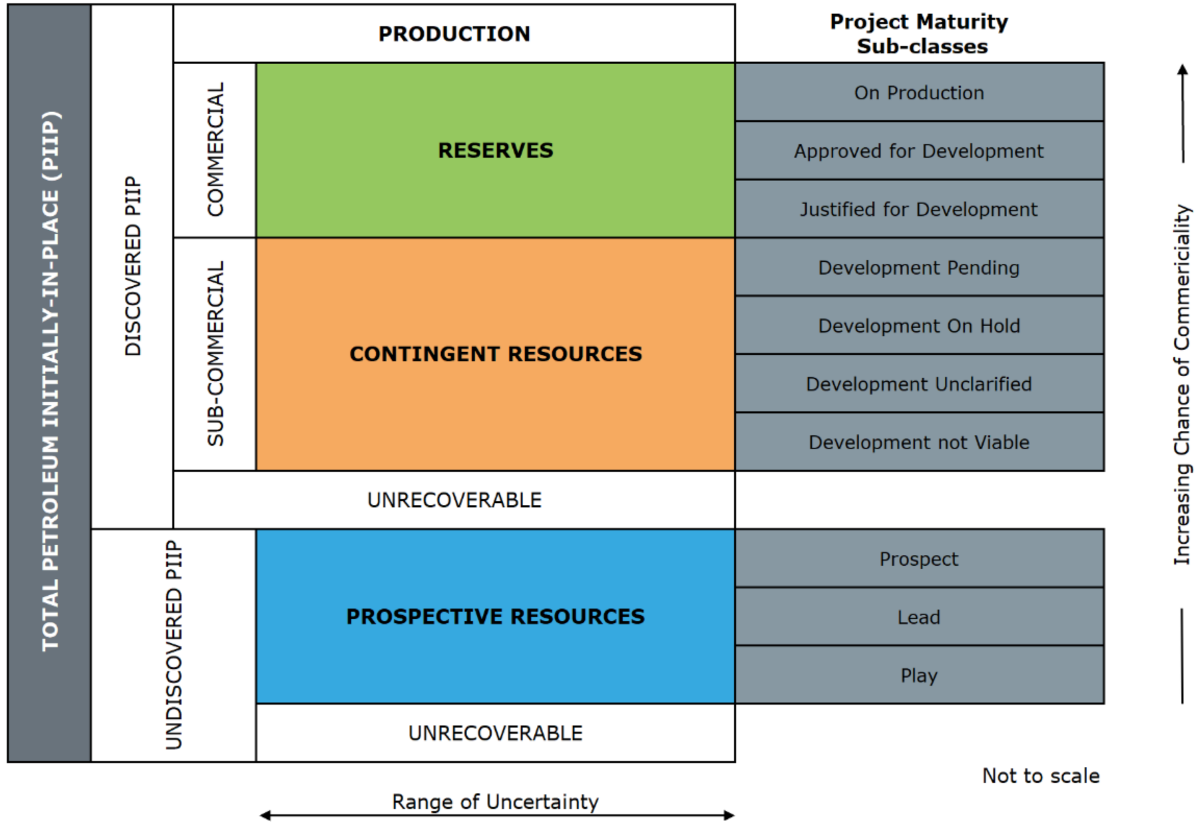

Figure 1: PRMS including sub-classes based on maturity

3 Reserves

OKEA ASA has reserves distributed across ten fields, as listed in Table 1. The project status category indicates the maturity for each of the fields and projects according to the PRMS (see Figure 1). Reserves classified as "Approved for development" correspond to field developments for which the Plan for Development and Operations (PDO) is approved by the Ministry of Energy, or an exemption from this has been given.

The reserves estimates are based on all available technical data, including production data, logs, seismic data, cores, models, decline curve analysis etc.

Table 1: OKEA asset portfolio with reserves as of 31 December 2024

Field/ Project	OKEA Working interest	Operator	Project Status Category	Comment
Draugen	44.56 %	OKEA ASA	On production	Includes Hasselmus
Bestla	39.2788 %	OKEA ASA	Approved for production	
Brage	35.20 %	OKEA ASA	On production	
Gjøa	12.00 %	Vår Energi ASA	On production	includes Gjøa Nord
Ivar Aasen	9.2385 %	Aker BP ASA	On production	
Nova	6.00 %	Harbour Energy Norge AS	On production	
Statfjord	23.9312 %	Equinor Energy AS	On production	equivalent to 28% of Norwegian share
Statfjord Øst	14.00 %	Equinor Energy AS	On production	
Statfjord Nord	28.00 %	Equinor Energy AS	On production	
Sygna	15.40 %	Equinor Energy AS	On production	

For economic evaluations, the long-term oil price assumption is 75 USD/bbl, with a long-term currency rate of USD/NOK 10.0. Gas price is set to 73 pence/therm (equivalent to 3.47 NOK/Sm^3) NGL price is set to 538 USD/tonne. All prices are in real 2025 and a 2% annual inflation rate is used.

Gas reserves are reported as sales gas with an energy content of 40 MJ/Sm^3.

In addition, the following conversion factors are used:

Oil	1 Sm^3 = 1 Sm^3 oe = 6.29 bbl
Gas	1 000 Sm^3 gas = 1 Sm^3 oe
	1 Sm^3 = 35.315 Scf
NGL	1 tonne NGL = 1.9 Sm^3 oe

3.1 Total reserves estimates

OKEA's net proven reserves (1P/P90) as of 31 December 2025 are estimated at 52.0 million barrels of oil equivalents. Total net proven plus probable reserves (2P/P50) are estimated at 74.3 million barrels of oil equivalents. The reserves figures account for the effects of production in 2025. The split between oil, NGL and gas, and between individual assets is given in Table 2.

The reserves numbers are verified through a third-party certification performed by AGR Petroleum Services AS. Please note that totals in tables above are arithmetic and not stochastic summations.

The corresponding 3P/P10 estimate of net OKEA reserves is 98.5 mmboe. For comparison, the corresponding Total Net 1P-, 2P- and 3P-reserves in ASR 2024 (31 December 2024) were 51.3, 75.6 and 101.0 mmboe, respectively, c.f. Table 3.

The reserves estimates are based on figures in the RNB2026 files reported by the operator of the individual assets with certain minor adjustments. Specifically, OKEA has a more conservative view than the operator regarding future production from Statfjord.

Table 2: OKEA reserves as of 31 December 2025 in mmboe

Asset/Project	OKEA WI	1P/P90 (Low estimate)				2P/P50 (Base estimate)			
		Gross Oil	Gross NGL	Gross Gas	Net OE	Gross Oil	Gross NGL	Gross Gas	Net OE
Reserves – On Production									
Brage	35.20 %	5.03	0.19	0.51	2.02	6.44	0.36	0.96	2.73
Draugen	44.56 %	39.57	0.79	1.95	18.85	44.06	1.40	3.47	21.81
Gjøa	12.00 %	0.62	6.07	11.79	2.22	0.99	7.42	14.41	2.74
Ivar Aasen	9.2385 %	25.63	3.41	7.14	3.34	30.62	4.28	8.98	4.05
Nova	6.00 %	11.54	2.65	4.29	1.11	18.71	5.97	9.23	2.03
Statfjord	23.9312 %	9.66	8.55	17.19	8.47	17.28	16.38	32.95	15.94
Statfjord Nord	28.00 %	7.68	0.25	0.47	2.35	15.89	0.55	1.01	4.88
Statfjord Øst	14.00 %	6.15	1.00	1.90	1.27	11.09	1.76	3.34	2.27
Sygna	15.40 %	0.91	0.00	0.00	0.14	1.62	0.00	0.00	0.25
Total Net					39.8				56.7
Reserves – Approved for Development									
Bestla	39.28 %	12.87	1.71	4.73	7.58	16.45	1.96	5.43	9.36
Brage (Talisker producer; Cook North)	35.20 %	1.93	0.46	1.19	1.26	4.64	1.12	2.98	3.08
Draugen (Power from Shore; Garn West Sør)	44.56 %	2.59	0.95	2.21	2.56	4.39	1.09	2.54	3.58
Ivar Aasen (IOR infill 2026)	9.2385 %	4.94	0.36	0.75	0.56	7.51	0.50	1.05	0.84
Statfjord (LPT pilot; SFC FFE)	23.9312 %	0.00	0.39	0.78	0.28	0.00	1.08	2.17	0.78
Total Net					12.2				17.6
Reserves – Total									
Total Net					52.0				74.3

3.2 Development of reserves

OKEA's reserves are continuously evolving through production, acquisitions/disposals, revisions of previous estimates (as result of e.g. production experience, data acquisitions, update of subsurface models and similar) and project maturation. Table 3 illustrates how these volumes have changed since ASR 2024 (31 December 2024).

Table 3: OKEA reserves development from 31 December 2024 to 31 December 2025 in mmboe

Asset	EoY 2024		Production		Acquisitions / Disposals		Revisions of previous estimates		Projects matured		EoY 2025	
	1P/ P90	2P/ P50	1P/ P90	2P/ P50	1P/ P90	2P/ P50	1P/ P90	2P/ P50	1P/ P90	2P/ P50	1P/ P90	2P/ P50
Bestla	6.78	8.34	0.00	0.00	0.00	0.00	0.80	1.02	0.00	0.00	7.58	9.36
Brage	2.68	4.44	-2.40	-2.40	0.00	0.00	1.74	0.69	1.26	3.08	3.28	5.81
Draugen	26.21	29.93	-3.26	-3.26	0.00	0.00	-2.79	-3.42	1.25	2.13	21.41	25.38
Gjøa	2.82	3.60	-1.47	-1.47	0.00	0.00	0.72	0.32	0.14	0.28	2.22	2.74
Ivar Aasen	1.23	3.76	-0.65	-0.65	0.00	0.00	2.91	0.95	0.41	0.83	3.90	4.89
Nova	1.46	2.57	-0.60	-0.60	0.00	0.00	-0.01	-0.31	0.26	0.37	1.11	2.03
Statfjord	7.20	16.83	-2.23	-2.23	0.00	0.00	2.37	0.11	1.41	2.02	8.75	16.72
Statfjord Nord	1.71	3.90	-0.69	-0.69	0.00	0.00	1.08	1.31	0.26	0.37	2.35	4.88
Statfjord Øst	1.08	1.94	-0.52	-0.52	0.00	0.00	0.44	0.47	0.26	0.38	1.27	2.27
Sygna	0.13	0.27	-0.07	-0.07	0.00	0.00	0.08	0.05	0.00	0.00	0.14	0.25
Total	51.3	75.6	-11.9	-11.9	0.0	0.0	7.3	1.2	5.3	9.5	52.0	74.3

Maturations in 2025 were mainly related to approval of infill drilling targets on Brage (Talisker Brent and Cook North), Draugen (Garn West Sør), Statfjord (three liquid producers and three oil hunter wells), and Ivar Aasen (IOR infill campaign 2026). One infill well was also matured on Statfjord Øst, and one on Statfjord Nord.

The negative revision of previous estimates on Draugen is due to accelerated cease of production on Hasselmus due to water breakthrough, see Section 3.3.1.

Increased reserves of Bestla are a result of positive results from drilling the observation well into Bestla West. Brage reserves are affected by both negative (downgrade of Fensfjord5000) and positive revisions (higher-than-expected production from top producers).

The positive revision of Ivar Aasen reflects effects of increased water injection and increased economic lifetime.

The revisions on Statfjord and Satellites are primarily the result of increased economic lifetime for this asset, a consequence of the approved infill wells.

3.3 Description of reserves

The following section describes fields on production and fields approved/justified for development in which OKEA holds a working interest.

3.3.1 Draugen (PL093)

The Draugen field is in the Norwegian Sea, approximately 140 km Northwest of Kristiansund, in 250 meters water depth, c.f. Figure 2.

OKEA's working interest on Draugen is 44.56%. The other licensees are Petoro AS (47.88%) and M Vest Energy AS (7.56%).

Discovery

The field was discovered by well 6407/9-1 in 1984, proving oil in the Rogn formation. This was the first discovery in Rogn on the Haltenbanken terrace.

Reservoir

The oil is in the Garn and Rogn formations, of which the latter holds more than 90% of the reserves. The reservoir quality is excellent, with average permeability of more than 2 Darcy. The best well, A-4 A, has the offshore world record oil production rate reaching a peak of 77 000 bbl per day.

Development

The field is developed with a concrete gravity-based structure (GBS), with full oil stabilisation and storage capabilities. Oil is exported by shuttle tankers. Gas is exported through the gas pipeline connected to the Åsgard Transport System (ÅTS).

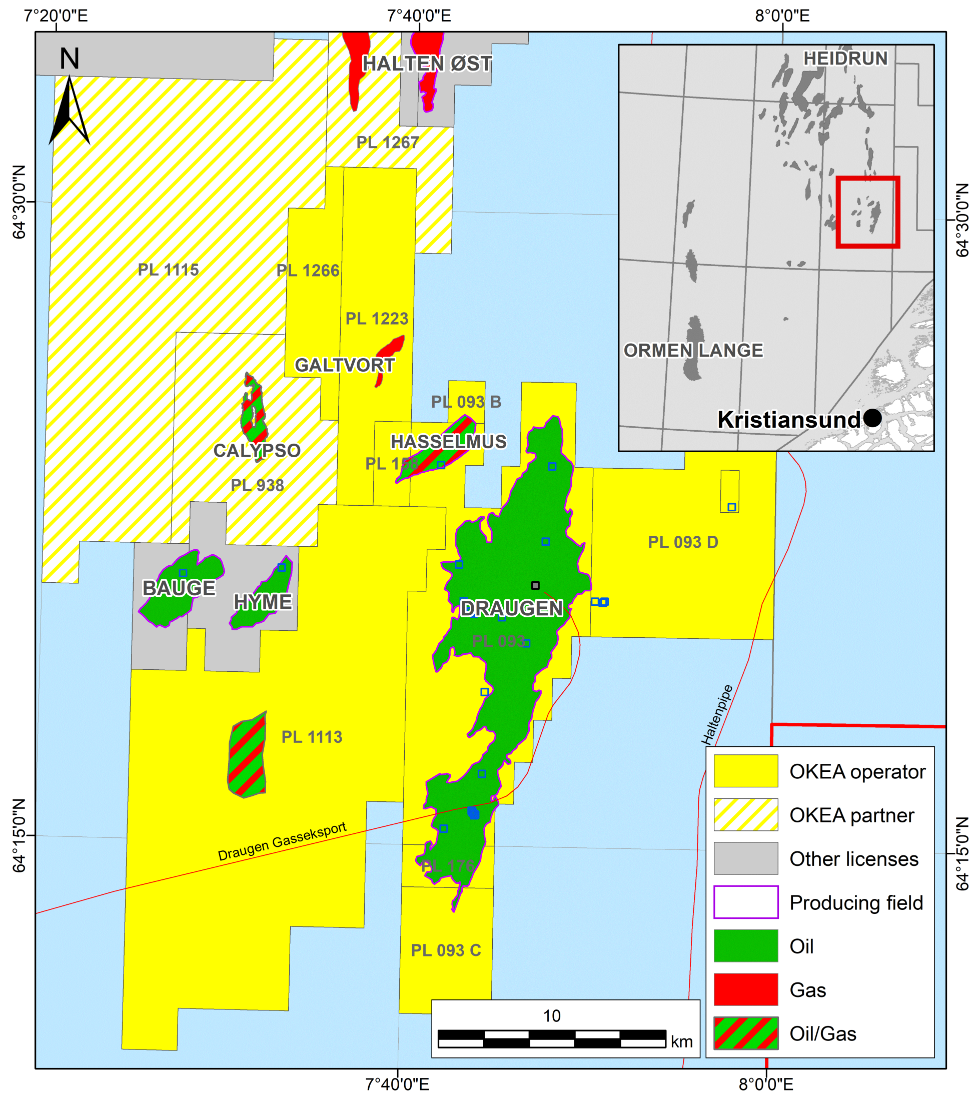

Figure 2: Draugen field location and adjacent area (Norwegian Sea)

The drainage strategy is based on centrally located production wells, supported by down-flank water injectors. The field was initially developed with 6 platform wells and 1 subsea well and has later been supplemented by several subsea wells. The platform wells have gas lift, while the subsea wells are produced via a subsea booster pump to lower the tubing head pressure.

Status

Production in 2025 amounted to 3.26 mmboe net to OKEA. Approximately 60% of the production stems from oil export. A large fraction of the produced water is reinjected into the reservoir, for pressure support. The rest is discharged to sea. Gas and NGL are exported through the Åsgard Transport System (ÅTS).

Currently, 5 out of 6 platform wells and 9 out of 10 subsea wells are producing, in addition to 2 subsea water injectors. Production is continuously monitored and optimised by a production management team.

The reserves estimates are based on the RNB2026 submission by OKEA, assuming production until end of economic field lifetime at end of 2040. Note that the lifetime of the field has been extended through the Power from shore project, see below.

Some of the projects that contribute to the Draugen reserves are discussed below. Contingent resources related to the Draugen field are described in Section 4.2.

Hasselmus

Hasselmus is a gas accumulation above a 5.5 meters oil leg, 7 km northwest of the Draugen field, c.f. Figure 2. The structure was discovered by well 6407/9-9 in 1999 and is now part of the Draugen field.

The reservoir is a sand-prone interval of tidally influenced shallow marine deposits, interpreted to be laterally continuous with high Net to Gross ratio, close to 100% in the gas zone. Seismic interpretation indicates that the reservoir is not affected by any major internal faults.

Hasselmus is drained by a single vertical gas producer well, placed close to the crest of the structure. The subsea well is tied back to the Draugen platform via a subsea pipeline.

Hasselmus started production 1 October 2023. Produced gas is partly used as fuel on Draugen, and partly exported together with Draugen gas. The associated export volumes are reported as reserves.

Gas expansion was planned to be the main driving mechanism, possibly assisted by limited aquifer support. The oil leg was not intended to be recovered.

The results of a pressure decline analysis in 2025 indicate relatively strong water influx on Hasselmus. This is expected to lead to an accelerated cease of production due to water breakthrough in 2028 (2P), possibly already in 2027 (1P). The Draugen team will monitor this closely, and take measures to mitigate the risk of a possible fuel deficiency.

Power from shore

The Draugen-Njord electrification shall provide electric power from shore (PfS) to both the Draugen field and the Njord field. The project was sanctioned (DG3) by the Draugen license and the Njord unit in 2022. Authority approval was obtained in December 2023. This measure will not only reduce emissions from the two platforms drastically but also lower OPEX and enable increased gas export from Draugen. Expected start up for PfS on Draugen is 2028, and this is reflected in the RBN2026 submission.

Garn West Sør

During 2020 and 2021, the infill well target Garn West Sør close to the existing producer well D-2 H was identified. The observation well 6407/9-15 was drilled during the summer 2023, and confirmed the presence of commercially viable oil volumes in Garn West Sør.

A project for maturing this infill target passed DG3 April 2025. The new well D-1 BH is drilled from December 2025 as a shallow sidetrack.

3.3.2 Brage (PL055)

The Brage field is located in the North Sea, 125 km west of Bergen and between the Troll and Oseberg field at a water depth of 140 meters, c.f. Figure 3.

OKEA's working interest on Brage is 35.20%. The other licensees are Lime Petroleum AS (33.8434%), DNO Norge AS (14.2567%), Petrolia NOCO AS (12.2575%) and M Vest Energy AS (4.4424%).

Discovery

The Brage field was discovered with well 31/4-3 in 1980, proving oil and gas in Jurassic sandstones.

Reservoir

Brage produces oil from sandstones of Lower Jurassic age in the Statfjord Group and Cook Formation, and sandstones of Middle Jurassic age in the Brent Group and the Fensfjord Formation. There is also oil and gas in Upper Jurassic sandstones in the Sognefjord Formation. The reservoirs lie at a depth of 2,000-2,300 meters. The reservoir quality varies from poor to excellent.

Development

The plan for development and operation (PDO) was approved in 1990. The field has been developed with an integrated processing, drilling and accommodation facility with a steel jacket. Production started in 1993.

The Brage field is currently producing from five different reservoirs with different characteristics and recovery methods; the Statfjord, Cook, Fensfjord, Sognefjord formations, and the Brent group.

Due to the limited natural pressure support, water injection is required to maintain reservoir pressure.

Oil is transported by pipeline to the Oseberg field and further through the Oseberg Transport System (OTS) pipeline to the Sture terminal. A gas pipeline is tied-back to Statpipe transporting gas to Kårstø for processing and further export.

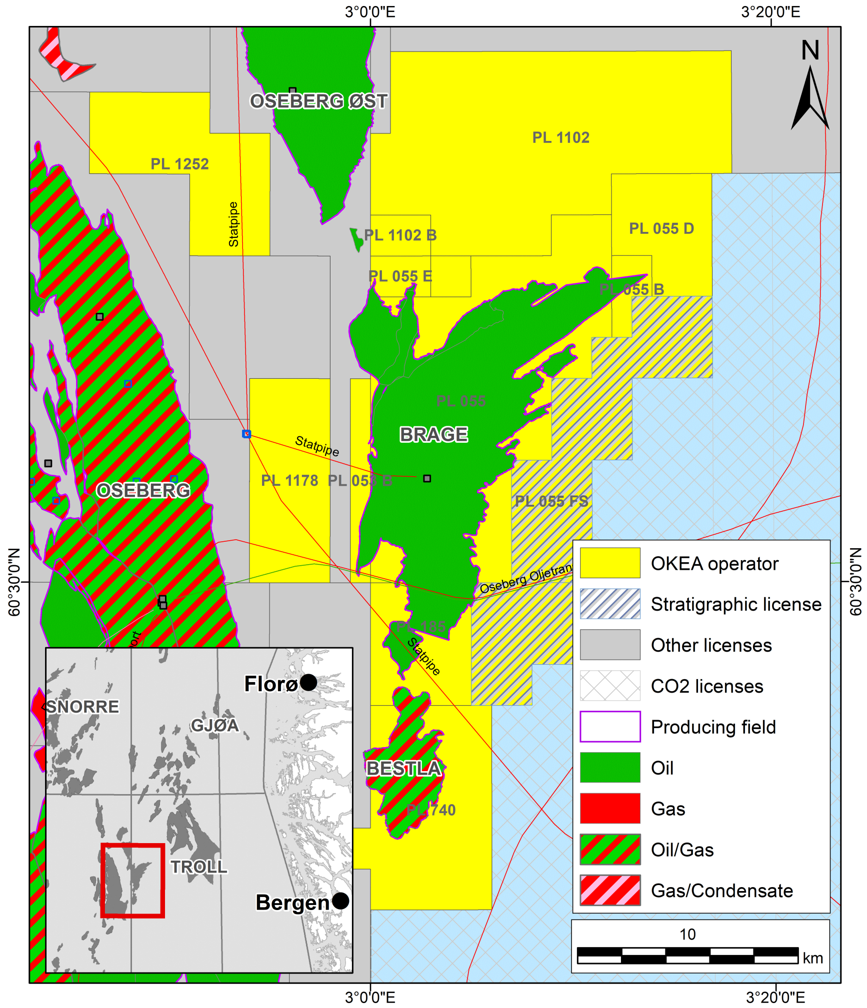

Figure 3: Location of the Brage Unit, the Bestla field, and adjacent area (North Sea)

Status

Production in 2025 amounted to 2.40 mmboe net to OKEA. More than 70% of the production stems from oil export.

Approximately half of the produced water is re-injected to the reservoir, whereas the rest is discharged to sea. In addition, water from Utsira is injected into the reservoir; this water is withdrawn from the Utsira formation using two water producers. Currently, Brage is producing from 22 producers and injecting water in 4 injectors.

During 2025, two infill projects were matured to reserves: the Talisker Brent producer (A-15 D) and a Cook North producer. On the other hand, a planned investment decision for the Fensfjord5000 project was not achieved, and associated volumes were downgraded from reserves to contingent resources.

The reserves estimates are based on the RNB2026 submission by OKEA. Contingent resources related to the Brage field are described in Section 4.2.5.

3.3.3 Bestla (PL740)

The Bestla field (formerly known as the Brasse discovery) is located in the PL740 license, in Block 31/7, approximately 13 km south of Brage and 13 km east of the Oseberg field, c.f. Figure 3.

OKEA's working interest in the Bestla field is 39.2788%. The other licensees are DNO Norge AS (39.2788%), Lime Petroleum AS (17%), and M Vest Energy AS (4.4424%).

Discovery

Discovered in June 2016 by well 31/7-1, the field consists of a low relief, three-way dip-closed structure with a stratigraphic pinch-out component to the north. The structure has been penetrated by six wellbores in total.

Reservoir

The main reservoir interval in the discovery is represented by the Sognefjord Formation (Upper Jurassic) with a gross hydrocarbon column of approximately 45 m, consisting of approximately 22 m of oil (36 °API) with a gas cap. The oil-water contact in the central and southern areas of the field is located at approximately 2,172.5 mTVD SS, with the gas-oil contact varying between 2148 mTVD SS (observed in well 31/7-1) and 2155 mTVD SS (observed in well 31/7-2 A). Well 31/7-3 A, drilled in the northern area of the field, encountered three oil-filled intervals, where the two deepest intervals had different oils (34°API) compared to the main area in the south. The two deeper sand intervals have been interpreted as smaller local closures separated from the main area.

Development

The field will be developed by two horizontal wells which will be tied back to the Brage platform.

Status

OKEA became partner and operator of the license in 2023. A PDO was submitted in march 2024, and approved in November 2024. The Bestla project is progressing in accordance with the established plan: The subsea template was installed, and all planned wells were drilled and completed successfully in 2025. As anticipated, hydrocarbons were proved in the West segment.

Subsea deliveries are advancing as planned, and the most critical topside installation activities at Brage have been finalized. Riser pull-in is planned for in the first half of 2026, and production is planned to start in 2027.

3.3.4 Gjøa (PL153)

The Gjøa field is in the northern part of the North Sea, 50 kilometres northeast of the Troll field, in the PL153 license, c.f. Figure 4. Water depth in the area is 360 meters.

OKEA's working interest on Gjøa is 12.0%. The other licensees are Vår Energi ASA (Operator, 30%), Petoro AS (30%), and Harbour Energy Norge AS (28%).

Discovery

The field was discovered by exploration well 35/9-1 / 35/9-1 R in 1989, confirming gas in the Viking Group and Brent Group, and oil in the Dunlin Group.

Reservoir

The Gjøa reservoir comprises the Upper Jurassic Viking Group, and the middle Jurassic Brent and Dunlin Groups. The oil column of 30-45 m and the gas column of approximately 200 m both have local variations. The reservoir is compartmentalised in seven segments, with heterogenous properties caused by alternating layers of good and poor reservoir sands, silts and shales. As a result, the porosity ranges from 10% to 27% and the permeability from hundreds of millidarcy to several darcy.

Development

The drainage strategy is managed pressure depletion with concurrent oil rim production. The field is developed with thirteen subsea wells (of which seven currently are shut in), connected to five templates and directed back to a semi-submersible unit with full oil stabilisation capacities. Advanced well technology with branches and zonal control is implemented, and all wells have multiphase meters and permanent downhole gauges. Oil is exported through the Troll oil pipeline to the Mongstad terminal, and gas is exported though the FLAGS pipeline to the St. Fergus terminal. In 2017, the production plant on Gjøa was upgraded to handle low pressure production to boost the reserves on Gjøa. The Gjøa platform was also the first floating platform with power from shore, reducing CO_2 emissions by 200 000 tonnes per year. Gjøa is host for the Vega, Duva and Nova fields.

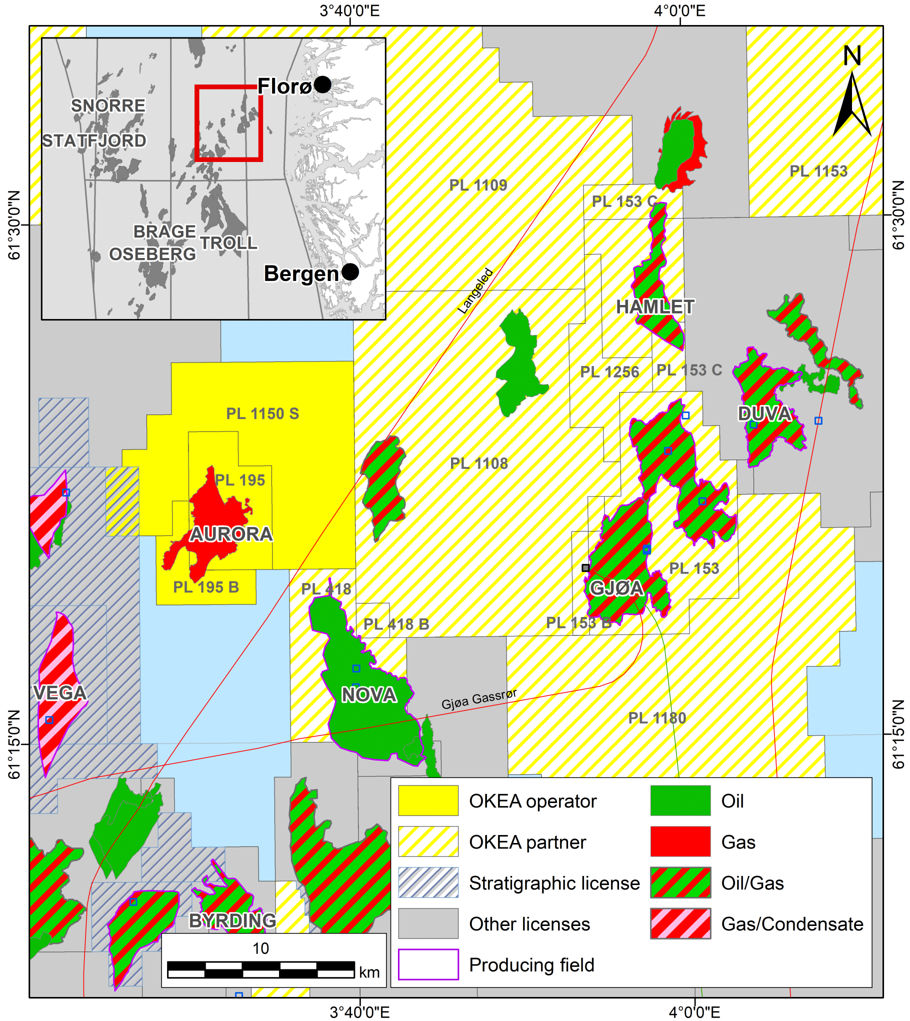

Figure 4: Gjøa field location and adjacent area (North Sea)

Status

Production in 2025 amounted to 1.46 mmboe net to OKEA. Approximately 90% of the production stems from export of gas and associated NGL.

The reserves estimate for Gjøa is based on the RNB2026 submitted by the operator, and includes reserves from the main field, the P1 redevelopment project. The B-1 LWI as well as the LLP project have both been approved in 2025 and hence included into the main field reserves.

Contingent resources related to the Gjøa field are discussed in Section 4.2.7.

3.3.5 Ivar Aasen Unit (PL338 BS)

The Ivar Aasen field is located in the North Sea, 8 km north of the Edvard Grieg field and around 30 km south of Grane and Balder, c.f. Figure 5. The water depth is 110 meters.

OKEA holds a 9.2385% working interest in the unit. The other licensees are Aker BP ASA (Operator, 36.1712%), Equinor Energy AS (41.473%), Sval Energi AS (12.3173%) and M Vest Energy AS (0.8%).

Discovery

Ivar Aasen was discovered with well 16/1-9 in 2008, proving oil and gas in Jurassic and Triassic sandstones. The Ivar Aasen field includes two accumulations: Ivar Aasen and West Cable. The accumulations cover several licences and have been unitised into the Ivar Aasen Unit.

Reservoir

The two accumulations are located on the Gudrun Terrace between the Southern Viking Graben and the Utsira High. The reservoir consists of shallow marine sandstones in the Hugin Formation and fluvial sandstones in the Sleipner and Skagerrak Formations and is of Jurassic and Triassic age. The reservoir depth is approximately 2 400 meters. The Ivar Aasen reservoir has a small overlying gas cap. The West Cable reservoir is in Sleipner fluvial sandstone of Middle Jurassic age and is located at 2 950 meters depth.

Development

The Ivar Aasen and West Cable discoveries are developed with a steel jacket platform, with living quarters and processing facilities. Drilling and completion operations are performed from a mobile jack-up rig adjacent to the Ivar Aasen platform. Water is removed from the well stream on the platform and oil and gas rates are measured before transportation through multiphase pipelines to the Edvard Grieg installation for stabilisation and export.

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

The Ivar Aasen unit development plan (Ivar Aasen and West Cable discoveries) also includes production of the reserves from the Hanz (PL028B) discovery. The approved PDO sets out that Ivar Aasen and West Cable (Ivar Aasen Unit) will be developed in the first phase and Hanz in the second phase. OKEA has no working interest in the Hanz field. Ivar Aasen started production in 2016.

Status

Production in 2025 amounted to 0.65 mmboe net to OKEA. Approximately 77% of the production stems from oil export.

During 2025, the an infill campaign scheduled for 2026 was matured by the operator and approved by the licencees.

The reserves estimate for Ivar Aasen is based on the RNB2026 submitted by the operator. The drainage pattern in the east segment - particularly in the Skagerrak Formation - is still the main uncertainty in the reservoir.

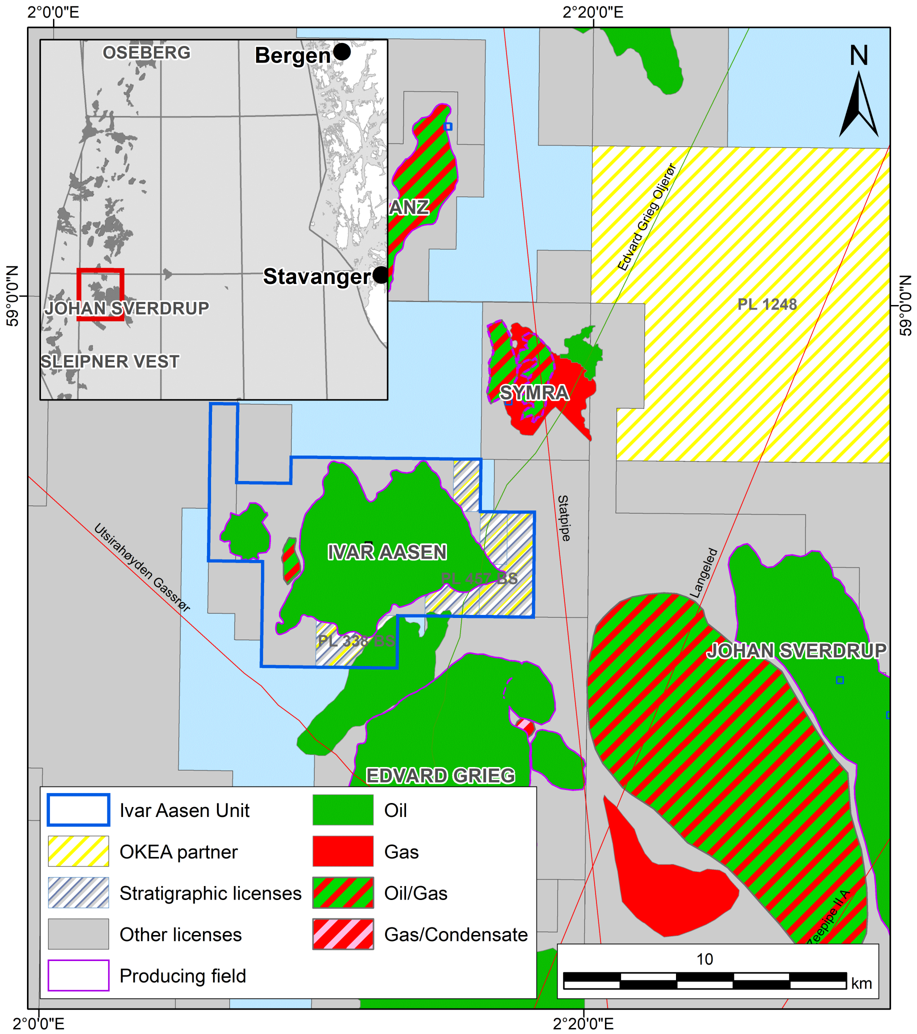

Figure 5: Ivar Aasen field location and adjacent area (North Sea)

3.3.6 Nova (PL418)

Nova lies in Block 35, license PL 418, in the northern North Sea, 17 km southwest of Gjøa, c.f. Figure 4. Water depth is 370 m. The field was discovered in 2012, with the well 35/9-7. The PDO was approved in 2018.

OKEA's working interest in Nova is 6%. The other licensees are Harbour Energy Norge AS (operator, 39%), Sval Energi AS (45%) and Pandion Energy AS (10%).

Reservoir

Intra Heather sands constitute the reservoir at Nova. These late Jurassic sands have been deposited in a turbiditic system and are eroded towards the southwest. The trap is stratigraphic with a structural component. The field can be split in three main areas: Main, Southeast and East, the first one being the most important one. The Intra Heather 2 Lower and Upper units constitute the main part of the reservoir. They are separated by a shale but are in communication through the faults. The Lower Unit has a 95% NTG, good connectivity and is of excellent quality. The upper Unit has a 60% NTG with a complex facies composition.

Development

The field is developed with two subsea templates: one four slot production template and one four slot template for water injection. The field is drained through pressure maintenance by water injection and gas lift. The producers are slanted to horizontal, completed with sand screens and gas lift. The production is tied back to Gjøa. The oil is exported through the Troll pipeline to the Mongstad terminal. The gas is exported though the FLAGS pipeline to the St. Fergus terminal.

Status

Production started in 2022. Initial problems with pressure support by water injection have been mitigated through drilling of a new injector W-1 AH and through additional perforations in W-2 H. However, lower-than-expected pressure support is still a limiting factor for production since the reservoir pressure needs to be kept above bubble point pressure to avoid the loss of reserves.

Production in 2025 amounted to 0.60 mmboe net to OKEA. Approximately 63% of the production stems from oil export. The reserves estimate for Nova is based on the RNB2026 submitted by the operator.

3.3.7 Statfjord (PL037)

Statfjord is one of the oldest producing fields on the NCS and located in the North Sea in the Tampen area on the border between the Norwegian and the UK sector, c.f. Figure 6. The field was discovered in 1974 and the PDO was approved in 1976. Production from the first platform, Statfjord A, commenced in 1979. Approximately 15% of the field is located in the UK sector.

OKEA's working interest on Statfjord is 23.9312%. The other licensees are Equinor Energy AS (operator, 40.17029%), Vår Energi ASA (21.36717%), and Equinor UK Limited (14.53131%). OKEA's working interest with respect to the Norwegian part of the Statfjord field is thus 28%.

Reservoir

The main producing intervals on the Statfjord field are the Brent (Middle Jurassic) and Statfjord (Late Triassic-Early Jurassic) Groups, with additional production from the Cook Formation in the Dunlin Group. The reservoirs of the Brent and Statfjord Groups are generally composed of shallow marine to alluvial plain deposits of excellent quality. The Statfjord Group demonstrates more heterogeneity than the Brent Group and a higher degree of baffling.

Observed permeabilities are highly variable laterally and vertically, ranging from 0.001 to 1 millidarcy. The Statfjord Field has a very active aquifer giving natural pressure support.

Development

The Statfjord field is developed with three fully integrated concrete platforms; Statfjord A placed centrally on the field, Statfjord B in the southern part of the field with production start-up in 1982 and Statfjord C in the northern part of the field with production start-up in 1985.

In 2005 the Statfjord Late Life (SFLL) project was sanctioned. This introduced partial depressurisation of the Statfjord Field through accelerated liquid offtake to liberate gas from remaining oil, and to produce it together with the previously injected gas.

In Cook Formation and in some isolated reservoir segments in the eastern part of the field water and/or gas are injected to maximise oil recovery and support producers.

In 2019 the FLX (Field Lifetime eXtension) project was launched with further acceleration of the depressurisation and the gas liberation by an extensive drilling program targeting the main field.

Status

During 2025, six new producers and two ESP recompletions have come on stream whilst seven wells and five ESP recompletions were on the drilling schedule at the beginning of the year.

Production in 2025 amounted to 2.23 mmboe net to OKEA. Approximately 50% of the production stems from oil export.

Gas production in 2025 was significantly below expectations. Accordingly, OKEA has somewhat lower expectations than the operator regarding future production from Statfjord.

3.3.8 Statfjord Nord (PL037)

Statfjord Nord (SFN) is located north of Statfjord, in the Tampen area, c.f. Figure 6. Statfjord Nord was discovered in 1977 and the PDO was approved in 1990. Production started in 1995.

OKEA's working interest on Statfjord Nord is 28%. The other licensees are Equinor Energy AS (operator, 17%), Petoro AS (30%), and Vår Energi ASA (25%).

Reservoir

Production on Statfjord Nord is from reservoirs of the Upper Jurassic Munin Formation (turbidites) and the shoreface sands of the Etive and Rannoch Formations (Brent Group), both of which exhibit excellent reservoir quality.

Development

Statfjord Nord is a subsea development with two 4-slot production templates (E and F) with a total of 8 production wells and a single 4-slot injection template (D) with three injection wells to Statfjord Nord and one injection well to Sygna. The well stream is transferred through pipelines to the Statfjord C platform for processing, metering, and onward transportation.

Status

Production in 2025 amounted to 0.69 mmboe net to OKEA. Approximately 91% of the production stems from oil export.

Notable events in 2025 were a seven weeks long shutdown of the F-template due to topside corrosion and a scale treatment campaign of E and F wells.

A exploration target in the neighbouring PL1214 license has been matured, which likely will be drilled from slot F-04 in Q3 2026. The plans include a fallback target in Statfjord Nord. The ownership of PL1214 is identical to the one of PL037. The reserves estimate for Statfjord Nord is based on the RNB2026 submitted by the operator.

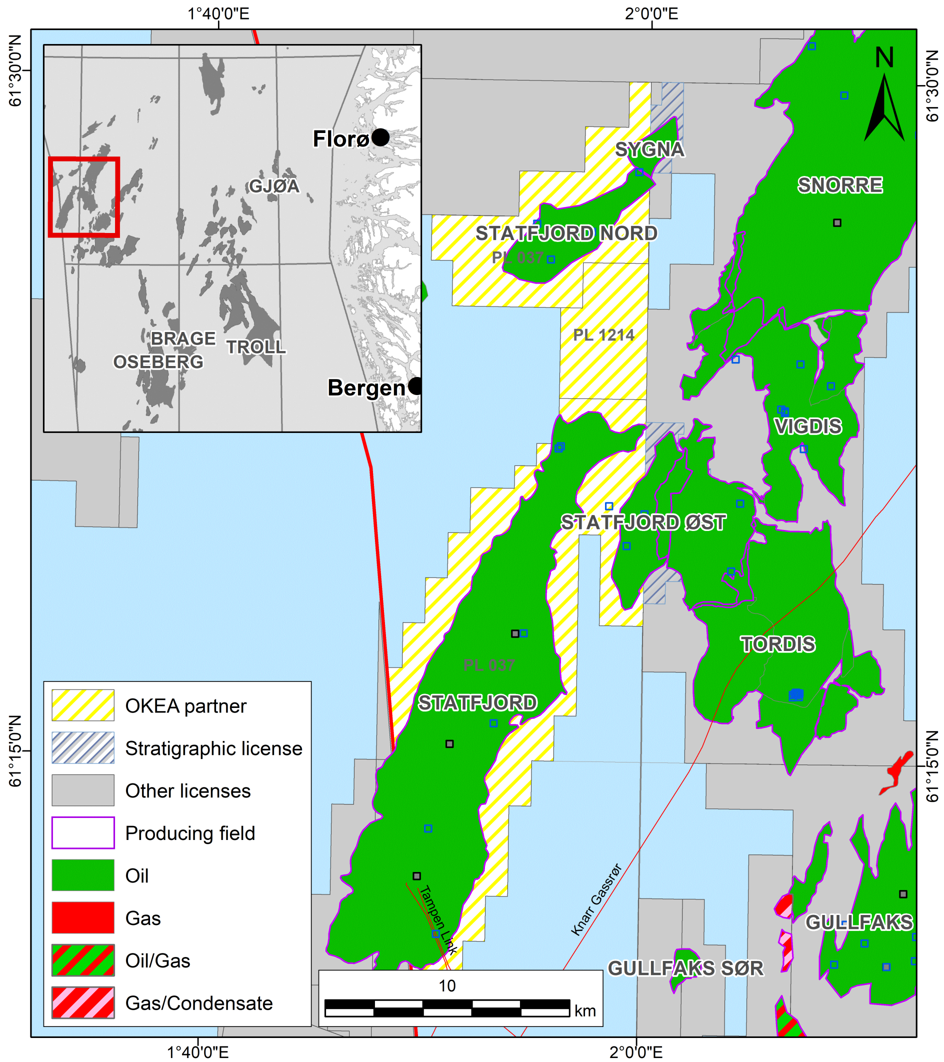

Figure 6: Statfjord area map (North Sea)

3.3.9 Statfjord Øst (PL037)

The Statfjord Øst field is located in the Tampen area and northeast of the Statfjord field, c.f. Figure 6. Statfjord Øst was discovered in 1976. The PDO was approved in 1990 and the field started production in 1994.

OKEA's working interest on Statfjord Øst is 14%. The other licensees are Equinor Energy AS (operator, 29.25%), Petoro AS (30%), Vår Energi ASA (20.55%), JAPEX Norge AS (4.8%), and Harbour Energy Norge AS (1.4%).

Reservoir

Production on Statfjord Øst is from high quality shoreface sands of the Upper to Lower Brent Group (Rannoch, Etive, Ness and Tarbert Formations).

Development

The Statfjord Øst field was originally developed with two production subsea templates (L and M) and one injection subsea template (K). The field is in pressure communication with the Statfjord field and has been on depletion since the cessation of water injection in 2008.

A revised PDO was approved in 2021 to provide gas lift to the two templates and redrill 2 wells on the L-template and 3 wells on the M-template. These wells were drilled between March 2023 and February 2024. The first well started production in August 2023.

Status

Production in 2025 amounted to 0.52 mmboe net to OKEA. Approximately 61% of the production stems from oil export.

The main activities for Statfjord Øst in 2025 have been related to testing of milling of FS2 valves to gain LWI access to wells with partially open valves (in particular M-02), and maturation of an exploration/infill target on the hanging wall to the East of Statfjord Øst, including a fallback-target in the south of the field.

3.3.10 Sygna (PL037)

Sygna is located in the Tampen area and northeast of the Statfjord Nord field, c.f. Figure 6. Sygna was discovered in 1996. The PDO was approved in 1999 and production started the year after.

OKEA's working interest on Sygna is 15.4%. The other licensees are Equinor Energy AS (operator, 28.025%), Petoro AS (30%), Vår Energi ASA (20.995%), JAPEX Norge AS (4.32%), and Harbour Energy Norge AS (1.26%).

Reservoir

Production on Sygna is from high quality shoreface sands of the Etive and Rannoch Formations (Brent Group).

Development

Sygna is a subsea development with a 4-slot subsea production template with 3 producers (N-1 H, N-2 AH, and N-3 H). The well stream is transferred through pipelines to the Statfjord C platform for processing, metering and onward transportation. The production strategy for Sygna is full voidage replacement maintaining the reservoir pressure around 330 bar.

The production wells on Sygna are placed high on the structure, whereas the water injector is located low on the structure in the western part of the field.

Status

Production in 2025 amounted to 0.07 mmboe net to OKEA. All production stems from oil export.

The main reportable activity in 2025 on Sygna was an LWI operation in N-02, which led to successful start-up in November 2025.

4 Contingent resources

Contingent resources refer to discovered volumes of oil and gas for which commercial production has not yet been sanctioned. This category also includes petroleum volumes associated with potential improved recovery projects.

4.1 Total contingent resources estimates

OKEA holds contingent resources in several licenses, as shown in Table 4. The contingent resources are verified by a third-party certification performed by AGR Petroleum Services.

Table 4: OKEA contingent resources as of 31 December 2025

Field or Discovery	OKEA WI	Gross Oil equivalents (mmboe)			Net Oil equivalents (mmboe)		
	WI	1C/P90	2C/P50	3C/P10	1C/P90	2C/P50	3C/P10
Aurora	65.00 %	9.74	12.97	19.12	6.33	8.43	12.43
Brage	35.20 %	37.91	67.57	100.65	13.34	23.78	35.43
Bestla	39.2788 %	2.21	4.98	8.32	0.87	1.96	3.27
Calypso	30.00 %	3.64	6.45	9.67	1.09	1.93	2.90
Draugen (incl. Hasselmus)	44.56 %	36.17	53.35	76.34	16.12	23.77	34.02
Galtvort	44.56 %	6.79	9.97	12.08	3.03	4.44	5.38
Gjøa (incl Gjøa Nord)	12.00 %	10.97	23.00	36.00	1.32	2.76	4.32
Ivar Aasen	9.2385 %	5.20	10.34	17.19	0.48	0.96	1.59
Mistral Sør	20.00 %	18.81	38.31	56.92	3.76	7.66	11.38
Nova	6.00 %	13.54	25.29	36.96	0.81	1.52	2.22
Statfjord	23.9312 %	24.93	25.61	45.19	5.97	8.39	10.81
Statfjord Nord	28.00 %	3.98	5.45	6.92	1.11	1.53	1.94
Statfjord Øst	14.00 %	3.38	4.51	5.64	0.47	0.63	0.79
Total Contingent Volumes					54.7	87.8	126.5

Please note that totals in the table above are arithmetic and not stochastic summations. The aggregate Low (1C) may be a very conservative estimate and aggregate High (3C) may be a very optimistic one. Aggregates of Base (2C) results typically have less portfolio effect.

Corresponding numbers in ASR EoY2024 were 43.6, 66.1 and 92.9 mmboe, respectively. The significant increase is predominantly related to new volumes from the Mistral Sør discovery, the Talisker discoveries on Brage, and new infill targets on Draugen.
It is worth noting that total recoverable volume estimates from Talisker Statfjord and Cook formations combined have increased from 16 – 33 to 23 – 44 mmboe gross, c.f. press release from

march 2026. This increase is not reflected in Table 4. A large portion of these volumes is expected to be matured to reserves during 2026.

4.2 Description of contingent resources

The following section describes fields/discoveries with contingent resources where OKEA holds a working interest.

4.2.1 Aurora (PL195)

The Aurora discovery is situated in licenses PL195 and PL195 B, approximately 20 km west of Gjøa, c.f. Figure 4. The water depth in the area is about 373 m.

OKEA became operator of the two licenses in October 2020 and holds a 65% working interest in each. The other partner is Petoro AS (35%).

Discovery

Aurora was discovered in 1988 through well 35/8-3. The well proved hydrocarbons in the Intra-Heather Formation sandstones. No gas-water contact was apparent, indicating gas down to 3,511 m TVDSS.

The discovery was appraised by well 35/8-4, which encountered no hydrocarbons, indicating water up to 3 611 m TVDSS. Seismic data suggests a major fault east of the discovery well. Consequently, any hydrocarbons east of this fault are considered prospective volumes.

Reservoir

Log analyses of the Heather sands indicated a probable gross gas column of 70 m with a net pay of 31.9 m. Average porosity in the net sand was 15.6% with an estimated average water saturation of 22%. Reservoir temperature is about 90 degree Celsius, and pressure is around 400 bar. No fluid samples were taken.

Development

OKEA has initiated a project regarding development of the Aurora discovery as a tie-in to Gjøa. Currently, the discovery is envisioned to be produced by means of a single gas producer well, possibly deviated, using pressure depletion as major driving mechanism. Tie-back to Gjøa can be accomplished by utilizing existing infrastructure in the area, related to the Vega, Nova and/or Gjøa developments.

Status

The development project was initiated in September 2020 and is currently working towards a decision to drill an appraisal well in 2028. First gas from Aurora could then be produced in 2031, given a positive outcome of the appraisal well and available capacity at Gjøa.

4.2.2 Calypso (PL938)

The Calypso gas and oil discovery is located in license PL938, approximately 12 km northwest of the Draugen Field, c.f. Figure 2.

Vår Energi ASA is the operator with a 50% interest. Partners are OKEA (30%) and Pandion Energy AS (20%).

Discovery

Calypso was discovered in November 2022 with the 6407/8-8 S exploration well. The well encountered an estimated 8 meter thick gas column and a 33 m thick oil column in a 132 m thick Garn Formation.

Reservoir

The reservoir is of good to very good quality, with average permeability ranging from 100-1000 millidarcy and porosity averaging around 21%. The OWC is interpreted from pressure points and a total column from the oil-water contact to the crest of the structure is 41 m. The pressure is close to hydrostatic.

Development

The discovery is likely to be developed with one multilateral well with potentially one water injector as drive mechanism. Aquifer strength is currently being evaluated to better understand the need for water injection. A tie-back to Draugen may be achieved with pressure depletion as the main driving mechanism (depending on aquifer study outcome). The operator also considers Njord (via Hyme) as an alternative host.

Status

The development project was initiated in August 2023 and is currently working towards a DG1 in Q1 2026.

4.2.3 Galtvort (PL1223)

The Galtvort gas discovery is located in license PL1223, approximately 5 km northwest of the Hasselmus, c.f. Figure 2.

OKEA is the operator with a working interest of 44.56%. The other licensees are Petoro AS (47.88%) and M Vest Energy AS (7.56%). The working interests are the same as for the Draugen field.

Discovery

Galtvort was discovered in 2008 with wells 6407/8-4 S and –4 A. The wells encountered a gas column in the Garn and Tilje Formations.

Reservoir

The reservoir is of good to very good quality, with average permeability ranging from 100-1000 millidarcy and porosity averaging around 21%. The GWC is interpreted from pressure points at 2160 mTVD MSL close to hydrostatic pressure.

Development

The discovery is likely to be developed with one production well tied back to Draugen via the existing Hasselmus infrastructure.

Status

The development project was initiated in 2024 and passed DG1 in Q2 2025.

4.2.4 Draugen IOR

The Draugen asset is described in Section 3.3.1.

The observation well 6407/9-14 was drilled during the summer 2023, targeting the Springmus structure. The well confirmed the presence of commercially viable oil volumes. A project to evaluate sidetrack possibilities into Springmus East passed DG1 in 2025, and the project is working towards a DG2 early in 2026, aiming for production start mid 2027.

There are also more immature IOR targets, mainly on the west flank of Draugen that will be further investigated. Here, reprocessing of seismic data in 2026 is considered, in order to obtain a better understanding of the volumes on the flanks. Finally, a potential further extension of Draugen lifetime beyond 2040 is being evaluated.

4.2.5 Brage IOR

The Brage asset is described in Section 3.3.2. IOR activities at Brage are mainly associated with infill drilling and well interventions on the main field, and the appraisal and development of flank targets.

Special focus is drawn to the discoveries in the Statfjord and Cook Fm of the Talisker structure (well A-15 B) from 2025, and current plans imply to drill the first producer into Talisker Statfjord in Q1 2027, right after the one-year drilling break due to Bestla tie-in. The commerciality of another discovery from 2025, called Purple Rain (A-23 G), is currently being investigated.

Other IOR methods are being evaluated for potential future activities such as test production from the Shetland interval planned in Q1 2026. Based on the results from this test production, the potential in Shetland will be further evaluated.

The RNB2026 contains also contingent volumes related to a possible extension of production beyond 2031. In addition, one new project was added to the category “Development Unclarified” (RC 7A), namely “Fensfjord revitalization” which includes several well targets in Fensfjord reservoir.

Following further subsurface maturation after finalising figures for this report the estimated gross recoverable resources (P50) from the Talisker West Statfjord disvocery has increased from 19 to 28 million barrels of oil equivalents.

4.2.6 Bestla IOR

The Bestla asset is described in Section 3.3.3. The RNB2026 contains contingent volumes related to a possible lifetime extension.

4.2.7 Gjøa IOR

The Gjøa asset is described in Section 3.3.4. The operator reports in RNB2026 contingent volumes related to infill drilling in the P4 segment and Gjøa Nord, described in Section 4.2.8.

4.2.8 Hamlet

The Hamlet discovery was proven in spring 2022 by Neptune and is located in the licenses PL153 (Gjøa) and PL153 C. It is now referred to as Gjøa Nord.

Reservoir

The Hamlet discovery is composed of stacked turbiditic sands from the Agat Fm. Three main sands are identified from seismic and well observations with permeabilities between 10 and 400 millidarcy.

Development

The drainage strategy is pressure depletion with at least one producer well. The well flow would be brought back to Gjøa via the G template (P1 segment). An investment decision was attempted ("Gjøa Nord project"), but not obtained in December 2022. The license is now evaluating the possibility to develop Hamlet together with the Ofelia and Cerisa discoveries. The revised Gjøa Nord project has passed DG1 in December 2024.

4.2.9 Ivar Aasen IOR

The Ivar Aasen asset is described in Section 3.3.5. The operator reports in RNB2026 contingent resources related to infill drilling and gas blowdown. These resources are included in the ASR.

4.2.10 Nova IOR

The Nova asset is described in Section 3.3.6. The operator reports in RNB2026 contingent resources related to well interventions, infill drilling and other IOR measures. These projects are included in the ASR.

4.2.11 Statfjord IOR

The Statfjord asset is described in Section 3.3.7. The operator reports in RNB2026 contingent resources related to several IOR measures, including infill drilling, recompletions and modifications. These projects are included in the ASR.

4.2.12 Statfjord Nord IOR

The Statfjord Nord asset is described in Section 3.3.8. The operator reports in RNB2026 contingent resources related to infill drilling and a change of the sweep pattern ("turn sweep"). These projects are included in the ASR.

4.2.13 Statfjord Øst IOR

The Statfjord Øst asset is described in Section 3.3.9. The operator reports in RNB2026 contingent resources related to infill drilling. These projects are included in the ASR.

4.2.14 Mistral Sør (PL1119)

Mistral Sør is a gas/condensate discovery from March 2025, situated in PL1119 about 60 km south of Åsgard B, see Figure 7.

Equinor Energy AS is the operator with a 50% interest. Partners are OKEA (20%), INPEX Idemitsu Norge AS (20%) and DNO Norge AS (10%).

Discovery

The exploration well 6406/6-7 S proved a gas/condensate column of 46 meters in the Garn Formation, with a gas water contact at 3780 m TVDSS.

Reservoir

The Mistral Sør reservoir is situated in the Garn formation with a high net-to-gross ratio and relatively high permeability. The reservoir is situated in an isolated horst block. Mistral Sør contains a very rich, super critical gas condensate at a reservoir pressure of 674 bara. Dew point pressure has been established at 380 bara, which means that the resources most likely will be produced above dew point.

Development

The development of Mistral Sør will likely be a subsea development that involves a branch T-off from the planned Linnorm pipeline to Åsgard B. Mistral Sør will most likely be drained by a single horizontal producer, placed as high on the structure as possible.

Status

The license aims at passing DG1 jointly with the Linnorm development project, presumably late in 2025.

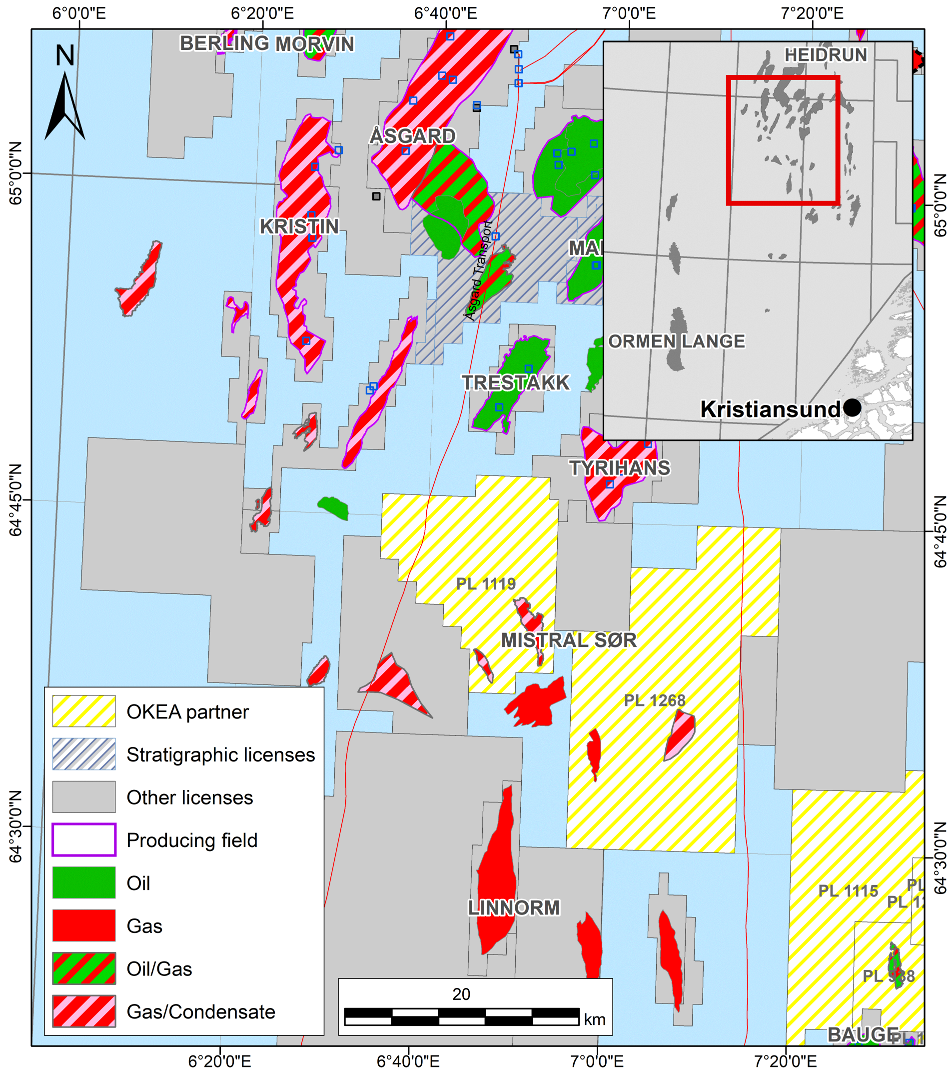

Figure 7: Mistral discovery and surrounding area (Norwegian sea)

5 Management discussion and analysis

The reported 2P/P50 reserves include volumes which are believed to be recoverable based on reasonable assumptions about future economical, fiscal and financial conditions. Discounted future cash flows after tax are calculated for the various fields on the basis of expected production profiles and estimated proven and probable reserves. Cut-off time for the reserves is set at zero cash flow. The company has used a long-term inflation assumption of 2%, a long-term exchange rate of USD/NOK 10.0, and a long-term oil price of 75 USD/bbl (real 2025 terms).

The calculations of recoverable volumes are however associated with significant uncertainties. The 2P/P50 estimate represents our best estimate of reserves/resources while the 1P/P90 figures reflect our high confidence estimates. The methods used for subsurface mapping do not fully clarify all essential parameters for either the actual hydrocarbons in place or the recoverability of the hydrocarbons. Thus, there is a risk that actual results may be lower than the 1P/P90. A significant change in oil prices may also impact the economical reserves. Low oil prices may force the licensees to shut down producing fields early and lead to lower production. Similarly, better-than-expected reservoir performance or higher oil prices may extend the lifetime of the fields beyond what is currently premised.

During 2025, net reserves decreased slightly, from 75.6 to 74.3 mmboe. The positive contributions from maturations of various IOR-measures on Brage, Draugen, Ivar Aasen, Statfjord and Gjøa, were offset by volumes produced during the year, and a significant negative revision of existing estimates on Draugen. A key focus for OKEA in the coming year will be to continue develop volumes by infill drilling at Brage and other assets, whilst looking for inorganic growth opportunities.

The company is also building a portfolio of exploration opportunities in the Norwegian Sea and North Sea basins, and will take part in the drilling of three exploration wells in 2026.

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