vår energi

Annual Statement of Reserves 2025

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Introduction

The report provides the status of hydrocarbon reserves and contingent resources for Vår Energi ASA (Vår Energi) as of 31 December 2025. The reserves and resources reported herein are those quantities represented as the internal estimates of Vår Energi ASA. International petroleum consultants DeGolyer and MacNaughton (D&M) have carried out an independent assessment of all volumes within the reserves categories proved, probable and possible, and the results have been compared to the estimates of Vår Energi presented in this report.

In 2025, the Company increased the Working Interest in Ekofisk PPF project and have brought several developments into production, leading to significant adjustment in the developed reserves.

This Annual Statement of Reserves (ASR) has been prepared in accordance with Oslo Stock Exchange listing and disclosure requirements, Circular No. 1/2013 (“Circular 1/2013”).

Assumptions and Methodology

Estimates of reserves and contingent resources herein have been prepared in accordance with the Petroleum Resources Management System (PRMS) approved in March 2007 and revised in June 2018 by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysts, and the European Association of Geoscientists & Engineers.

Figure 1 illustrates the PRMS classification framework. It is a graphical representation of the SPE-PRMS 2018 resources classification system.

Reserves are those quantities of petroleum anticipated to be commercially recoverable from known accumulations from a given date forward under defined conditions. Reserves must be discovered, recoverable, commercial, and remaining as of the evaluation's effective date. Further, reserves are categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

Contingent resources are those quantities of petroleum that are estimated, on a given date, to be potentially recoverable from known accumulations, but not currently considered to be commercially recoverable due to one or more contingencies.

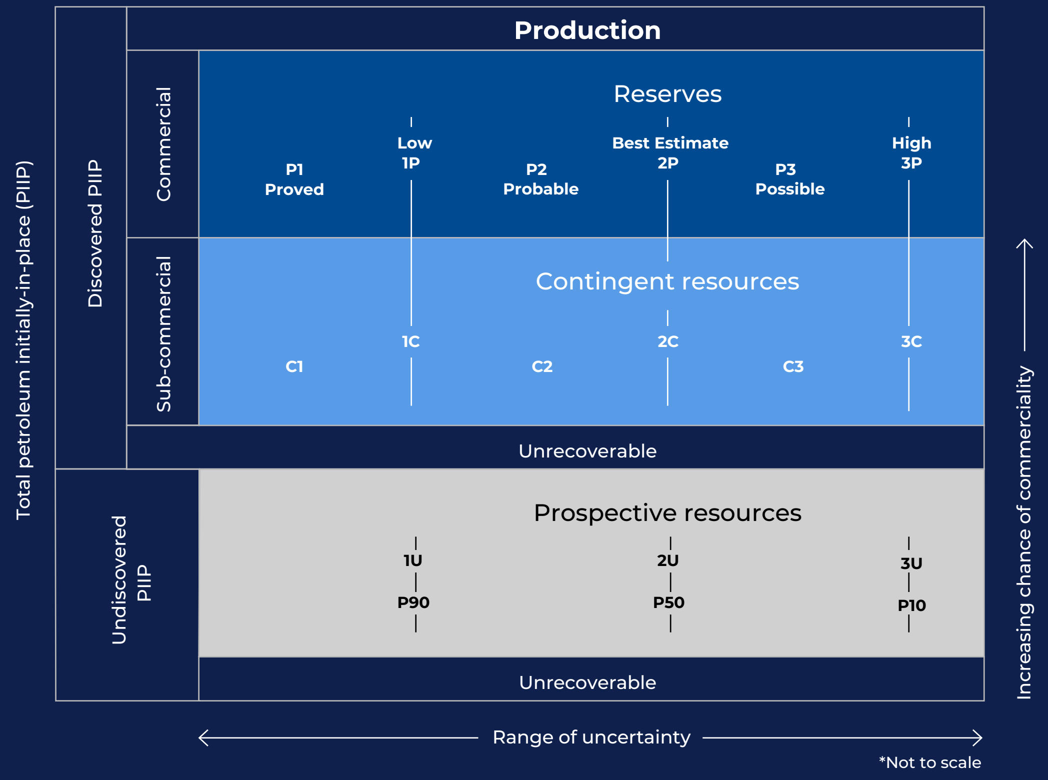


Figure 1: SPE-PRMS 2018 - Resources Classification Framework

Overview of Reserves

Vår Energi is one of the largest independent oil and gas producers in Norway, measured by production and reserves, and operates exclusively on the Norwegian Continental Shelf with a diverse mix of assets in the North Sea, Norwegian Sea and Barents Sea.

As of 31 December 2025, Vår Energi has a working interest in 46 fields containing reserves. Out of these fields, 42 are currently on production with developed reserves, 1 field (Byrding) are temporary shut in, and 3 fields, West Ekofisk, Albuskjell and Tommeliten Gamma contain undeveloped reserves only with an ongoing development phase. Several of the producing fields also have undeveloped reserves related to new drilling programs or projects.

Vår Energi's portfolio of operated and partner-operated assets are located in four major areas, the Balder Area, the Barents Sea, the Norwegian Sea and the North Sea. The full list of the fields and Vår Energi's working interest is shown in Table 1.

As of 31 December 2025, Vår Energi's total net proved (1P) reserves were estimated to be 883 million barrels of oil equivalents (mmboe). Total net proved plus probable (2P) reserves were estimated to be 1294 million barrels of oil equivalents. Further details of the reserves by asset groups and products are provided in Table 2.

The standard conversion factors published by the Norwegian Petroleum Directorate have been applied for estimates of reserves and resources in this report: (i) 6.29 barrels of oil to 1 Sm³ of oil, and (ii) 1000 Sm³ of gas to 1 Sm³ of oil equivalents (oe).

Figure 2: Vår Energi key areas

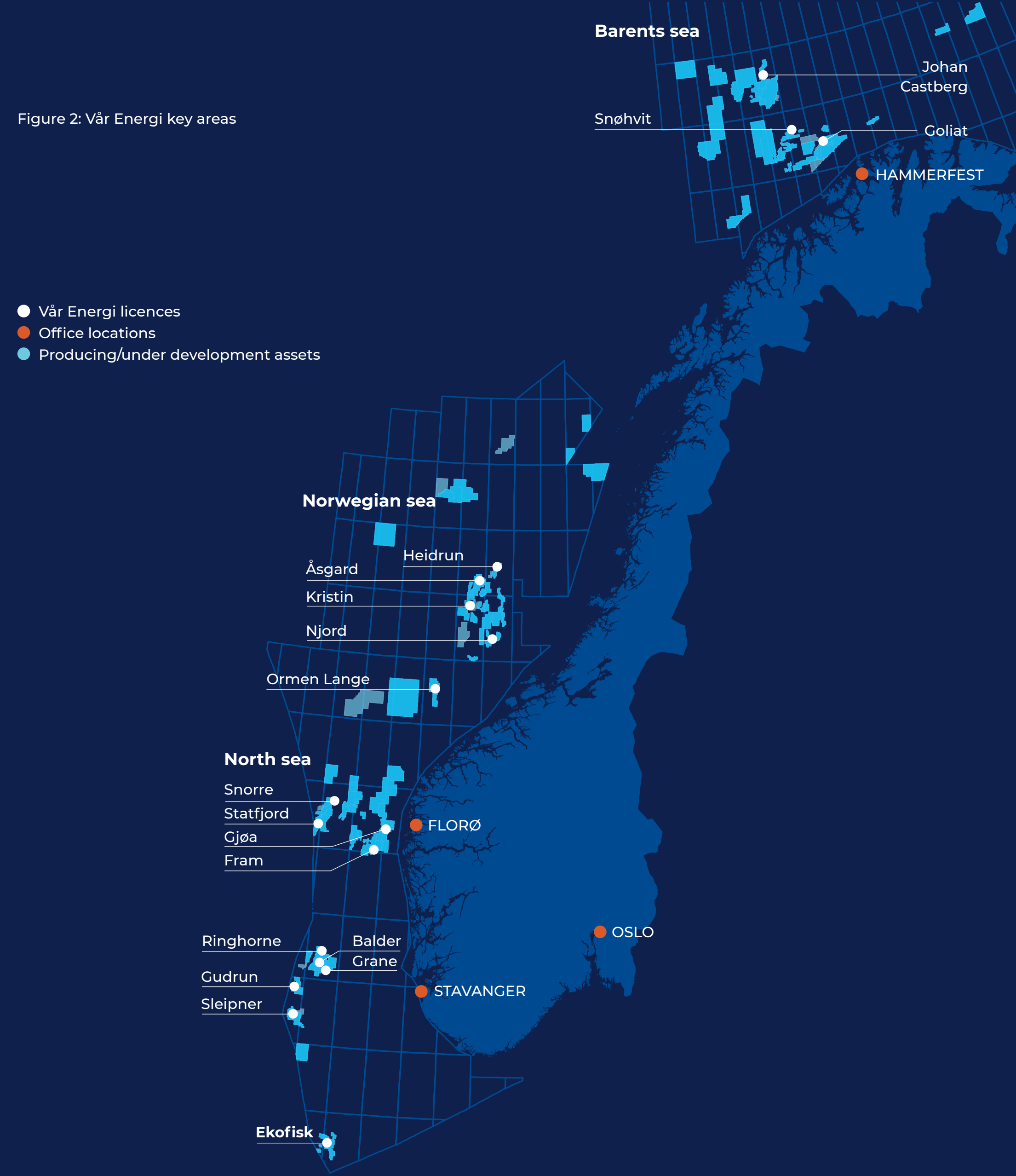


Table 1: Vår Energi's fields with reserves as of 31 December 2025

Area	Field/Project	Operator	Working Interest	Field/Asset Status
Balder	Balder	Vår Energi ASA	90,00 %	On production
Balder	Breidablikk	Equinor Energy ASA	34,40 %	On production
Balder	Grane	Equinor Energy ASA	28,32 %	On production
Balder	Ringhorne East	Vår Energi ASA	92,60 %	On production
Balder	Svalin	Equinor Energy ASA	13,00 %	On production
Barents Sea	Goliat	Vår Energi ASA	65,00 %	On production
Barents Sea	Johan Castberg	Equinor Energy ASA	30,00 %	On production
Barents Sea	Snøhvit	Equinor Energy ASA	12,00 %	On production
Norwegian Sea	Åsgard	Equinor Energy ASA	22,65 %	On production
Norwegian Sea	Bauge	Equinor Energy ASA	30,00 %	On production
Norwegian Sea	Fenja	Vår Energi ASA	75,00 %	On production
Norwegian Sea	Halten East	Equinor Energy ASA	24,60 %	On production
Norwegian Sea	Heidrun	Equinor Energy ASA	5,18 %	On production
Norwegian Sea	Hyme	Equinor Energy ASA	30,00 %	On production
Norwegian Sea	Kristin (incl. Lavrans)	Equinor Energy ASA	16,66 %	On production
Norwegian Sea	Mikkel	Equinor Energy ASA	48,38 %	On production
Norwegian Sea	Morvin	Equinor Energy ASA	30,00 %	On production
Norwegian Sea	Njord	Equinor Energy ASA	22,50 %	On production
Norwegian Sea	Ormen Lange	A/S Norske Shell	6,34 %	On production
Norwegian Sea	Trestakk	Equinor Energy ASA	40,90 %	On production
Norwegian Sea	Tyrihans	Equinor Energy ASA	18,02 %	On production
North Sea	Byrding	Equinor Energy ASA	15,00 %	Temporary shut-in
North Sea	Duva	Vår Energi ASA	30,00 %	On production

Area	Field/Project	Operator	Working Interest	Field/Asset Status
North Sea	Ekofisk	ConocoPhillips AS	12,39 %	On production
North Sea	Eldfisk	ConocoPhillips AS	12,39 %	On production
North Sea	Embla	ConocoPhillips AS	12,39 %	On production
North Sea	Albuskjell	ConocoPhillips AS	52,28 %	Development
North Sea	West Ekofisk	ConocoPhillips AS	52,28 %	Development
North Sea	Fram	Equinor Energy ASA	40,00 %	On production
North Sea	Gjøa	Vår Energi ASA	30,00 %	On production
North Sea	Gudrun	Equinor Energy ASA	25,00 %	On production
North Sea	Gungne	Equinor Energy ASA	13,00 %	On production
North Sea	Sigyn	Equinor Energy ASA	40,00 %	On production
North Sea	Sleipner East	Equinor Energy ASA	15,40 %	On production
North Sea	Sleipner West	Equinor Energy ASA	17,24 %	On production
North Sea	Snorre	Equinor Energy ASA	18,16 %	On production
North Sea	Statfjord	Equinor Energy ASA	21,37 %	On production
North Sea	Statfjord North	Equinor Energy ASA	25,00 %	On production
North Sea	Statfjord East	Equinor Energy ASA	20,55 %	On production
North Sea	Sygna	Equinor Energy ASA	21,00 %	On production
North Sea	Tommeliten Alpha	ConocoPhillips AS	9,09 %	On production
North Sea	Tommeliten Gamma	ConocoPhillips AS	9,13 %	Development
North Sea	Tor	ConocoPhillips AS	10,82 %	On production
North Sea	Tordis	Equinor Energy ASA	16,10 %	On production
North Sea	Vega	Harbour Energy Norge AS	3,30 %	On production
North Sea	Vigdis	Equinor Energy ASA	16,10 %	On production

Table 2: Vår Energi's total reserves as of 31 December 2025

Total Reserves		1P (P90/low estimate)				2P (P50/base estimate)			
Area	**Asset Group**	**Net Oil mmboe**	**Net NGL mmboe**	**Net Gas mmboe**	**Net Total mmboe**	**Net Oil mmboe**	**Net NGL mmboe**	**Net Gas mmboe**	**Net Total mmboe**
Balder	Balder Area	155	0	18	173	197	0	21	218
Balder	Grane Area	40	0	1	41	75	0	4	79
Barents Sea	Goliat	35	3	38	76	51	5	58	115
Barents Sea	Johan Castberg	120	0	5	126	179	0	6	185
Barents Sea	Snøhvit	7	5	81	93	9	7	99	115
Norwegian Sea	Åsgard Area	12	11	32	55	20	19	54	93
Norwegian Sea	Kristin Area	3	5	17	25	5	7	23	35
Norwegian Sea	Ormen Lange	1	0	19	19	1	0	23	24
Norwegian Sea	Njord Area	15	9	22	47	26	14	32	71
Norwegian Sea	Heidrun	7	1	7	15	8	2	8	18
North Sea	Fram Area	29	2	14	45	45	2	20	67
North Sea	Gjøa Area	1	3	7	10	1	4	11	15
North Sea	Greater Ekofisk Area	43	3	42	88	57	4	60	120
North Sea	Sleipner Area	3	1	8	12	7	1	18	26
North Sea	Snorre Area	40	2	4	45	80	2	6	88
North Sea	Statfjord Area	5	2	6	14	9	4	11	24
Total		**517**	**46**	**321**	**883**	**770**	**71**	**453**	**1294**

Table 3: Vår Energi's developed reserves as of 31 December 2025

Developed Reserves		1P (P90/low estimate)				2P (P50/base estimate)			
Area	**Asset Group**	**Net Oil mmboe**	**Net NGL mmboe**	**Net Gas mmboe**	**Net Total mmboe**	**Net Oil mmboe**	**Net NGL mmboe**	**Net Gas mmboe**	**Net Total mmboe**
Balder	Balder Area	118	0	15	132	140	0	16	155
Balder	Grane Area	37	0	1	38	69	0	2	71
Barents Sea	Goliat	27	0	0	27	38	0	0	38
Barents Sea	Johan Castberg	70	0	5	75	95	0	6	101
Barents Sea	Snøhvit	2	1	24	27	3	2	27	31
Norwegian Sea	Åsgard Area	11	9	28	48	17	16	44	77
Norwegian Sea	Kristin Area	2	4	15	22	3	6	19	29
Norwegian Sea	Ormen Lange	1	0	18	19	1	0	23	23
Norwegian Sea	Njord Area	10	5	14	29	18	7	20	46
Norwegian Sea	Heidrun	3	1	4	7	3	1	4	9
North Sea	Fram Area	3	1	5	9	5	1	7	13
North Sea	Gjøa Area	1	2	7	10	1	3	10	14
North Sea	Greater Ekofisk Area	27	1	11	40	35	2	17	54
North Sea	Sleipner Area	2	0	4	6	5	1	9	14
North Sea	Snorre Area	33	0	3	35	66	0	4	70
North Sea	Statfjord Area	5	2	6	13	8	4	10	22
Total		**350**	**28**	**158**	**536**	**506**	**42**	**219**	**767**

Table 4: Vår Energi's undeveloped reserves as of 31 December 2025

Undeveloped Reserves		1P (P90/low estimate)				2P (P50/base estimate)			
Area	**Asset Group**	**Net Oil mmboe**	**Net NGL mmboe**	**Net Gas mmboe**	**Net Total mmboe**	**Net Oil mmboe**	**Net NGL mmboe**	**Net Gas mmboe**	**Net Total mmboe**
Balder	Balder Area	37	0	4	40	58	0	5	63
Balder	Grane Area	3	0	0	3	7	0	2	9
Barents Sea	Goliat	8	3	38	49	13	5	58	77
Barents Sea	Johan Castberg	51	0	0	51	84	0	0	84
Barents Sea	Snøhvit	5	3	57	66	7	5	73	84
Norwegian Sea	Åsgard Area	1	2	4	7	3	4	9	16
Norwegian Sea	Kristin Area	1	1	2	3	1	1	3	6
Norwegian Sea	Ormen Lange	0	0	1	1	0	0	1	1
Norwegian Sea	Njord Area	6	5	8	19	8	6	11	26
Norwegian Sea	Heidrun	4	1	3	8	5	1	3	9
North Sea	Fram Area	26	1	9	36	40	2	12	54
North Sea	Gjøa Area	0	0	0	0	0	0	1	1
North Sea	Greater Ekofisk Area	16	1	31	48	22	2	43	66
North Sea	Sleipner Area	1	0	4	5	2	1	9	12
North Sea	Snorre Area	7	2	1	10	14	2	2	18
North Sea	Statfjord Area	0	0	0	1	1	0	1	2
Total		**167**	**19**	**162**	**348**	**263**	**29**	**234**	**527**

Changes from the Annual Statement of Reserves 2024 are summarised in Table 5. The main contributors for increased net reserves estimates (i.e., disregarding produced 2024 volumes) are:

- The sanctioning of Ekofisk PPF projects in the North Sea.
- Inclusion of BalderVI and a portion of the Balder Next project in Balder Area.
- Inclusion of the reserves from Goliat Gas Export as well as the Isflak development related to Johan Castberg in the Barents Sea.

Main downward revisions were:

- Reduction in Snorre reserves as a direct result of the redermination leading to reduced working interest.
- Smaller downward revision in Reserves related to the Fenja field.

Table 5: Vår Energi’s reserves changes compared to Annual Statement of Reserves 2024

	Developed		Undeveloped		Total	
Net attributable mmboe	**1P/P90**	**2P/P50**	**1P/P90**	**2P/P50**	**1P/P90**	**2P/P50**
Balance as of 31.12.2024	331	530	445	657	**776**	**1187**
Production	-125	-125	0	0	**-125**	**-125**
Acquistition/disposal	0	0	28	39	**28**	**39**
Extensions/discoveries	1	2	1	3	**2**	**5**
New developments	0	0	106	164	**106**	**164**
Transfers to developed	254	349	-254	-349	**0**	**0**
IOR	0	0	14	16	**14**	**16**
Revisions	75	11	7	-3	**82**	**8**
Balance as of 31.12.2025	**536**	**767**	**348**	**527**	**883**	**1294**

The 2025 production numbers are approximate, based on actual production estimates made in November 2025. Final actuals may be adjusted slightly.

Description of Reserves

The portfolio consists of reserves spread across our 4 main areas with no area contribution of less than 19% of the total 2P reserves.

Since 2024 our developed portion of reserves has increased significantly with 59% of the 2P reserves currently classified as developed. About 35% of the 2P reserves are gas, 6% NGL while the remaining 59% are oil reserves. Fuel contributes to 3% of the 2P Reserves.

The Year end 2025 reserves represent a 2P reserves replacement ratio (RRR) of 185% for the year and 174% over the last 3 years in average. (Defined as reserves additions divided by production in the period.)

The following includes a brief description of the fields within the asset groups presented in Tables 2-4 in the previous section.

A brief description of the field development is provided together with a description of the status of ongoing or planned project or drilling activities.

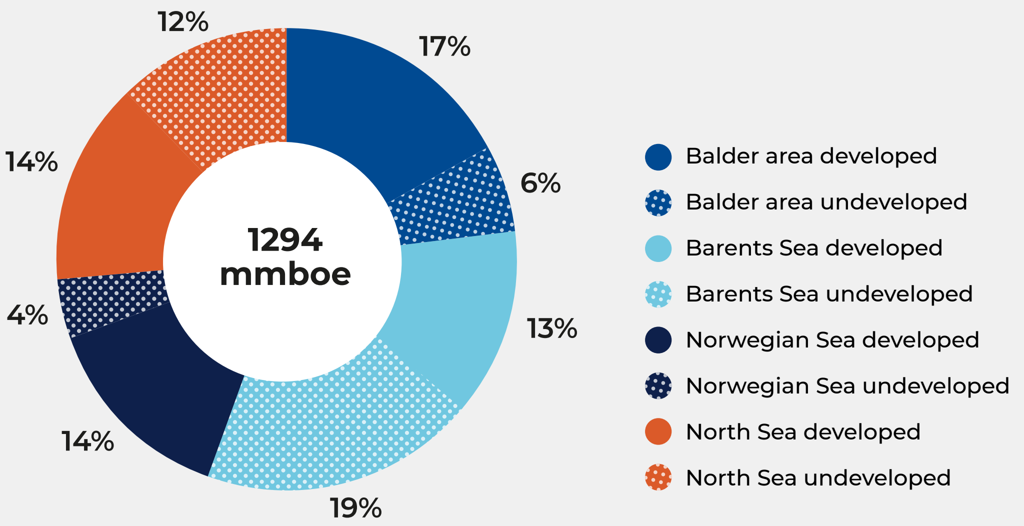
4.1 Balder Area

4.1.1 Balder

The Balder Asset group consists of the Balder, Ringhorne and Ringhorne East fields. Balder is a field in the central part of the North Sea, just west of the Grane field. The water depth is 125 metres. Balder was discovered in 1967, and the initial plan for development and operation (PDO) was approved in 1996. Production started in 1999. The field has been developed with subsea wells tied-back to the Balder production, storage and offloading vessel (FPSO). The Ringhorne field, located nine kilometres north of the Balder FPSO, is included in the Balder complex. Ringhorne is developed with a combined accommodation, drilling and pre-processing facility with a steel jacket, tied back to the Balder FPSO for final processing, crude oil storage and gas export.

The nearby Ringhorne East field is also tied-back to Balder via the Ringhorne platform. Ringhorne East was discovered in 2003, and the PDO was approved in 2005. The field is developed with four production wells drilled from the Ringhorne platform. Production started in 2006. A PDO amendment for Balder and Ringhorne was approved in 2020. The development plan included lifetime extension and relocation of the Jotun FPSO, and drilling of new subsea wells. In 2025 this project was concluded and production from the Jotun FPSO commenced. This has resulted in a significant amount of reserves being reclassified from undeveloped to developed status.

2P Reserves



In 2025 several new projects have been included in the reserves base.

- Balder VI, final investment decision was taken. This included one trilateral well where drilling will commence in 2026.
- Balder Next, a debottlenecking project has passed final investment decision and the first 3 wells in the drilling campaign is included in the reserves. Drilling will commence in 2027.
- Ringhorne. 2 wells for drilling in 2026 has been accelerated and are included in the reserves for year-end 2025.

4.1.2 Grane Area

The Grane Area consists of the Grane, Svalin and Breidablikk fields.

Grane is a field in the central part of the North Sea, just east of the Balder field.

The water depth is 130 metres. Grane was discovered in 1991, and the PDO was approved in 2000. The field has been developed with an integrated accommodation, drilling and processing facility with a steel jacket. The facility has 40 well slots. Production started in 2003. Oil recovery is maintained by gas injection and drilling of new wells, including sidetracks from existing producers. Future planning includes gas processing and export.

The Svalin field is located six kilometres southwest of the Grane field. The water depth is 120 metres. Svalin was discovered in 1992, and the PDO was approved in 2012. The Svalin C structure is developed with a subsea template tied-in to the Grane facility, and Svalin M is developed with a multilateral well drilled from Grane. Production started in 2014.

The Breidablikk field is located ten kilometres northeast of the Grane field. The water depth is 130 metres. Breidablikk includes two discoveries, D-structure and F-structure, discovered in 1992 and 2013, respectively. The PDO was approved in June 2021. The field is developed with four subsea templates tied-back to the Grane platform. The field started production in October 2023, and wells are started up as they are being finalised. Currently 18 of 23 the planned wells are on production.

4.2 Barents Sea

4.2.1 Goliat

Goliat is a field in the Barents Sea, 50 kilometres southeast of the Snøhvit field. The water depth is 360-420 metres. Goliat was discovered in 2000, and the PDO was approved in 2009. The field is developed with a cylindrical floating production, storage and offloading facility (Sevan 1000 FPSO). Eight subsea templates with a total of 32 well slots are tied-back to the FPSO. Production started in 2016. Goliat was granted a PDO exemption for the Snadd reservoir in 2017 and the Goliat West reservoir in 2020. Production from these reservoirs started in 2017 and 2021, respectively. Several infill wells have been drilled since start-up. 1 additional infill well was drilled in 2024 and two in 2025. There are plans to drill 2 infill wells per year the next three following years. An ongoing project to export the Goliat Gas will unlock the gas value, extend the field life with approximately 10 years and lead to reservoir management flexibility. In addition, there is significant exploration activity in the area aiming to increase the reserves base.

4.2.2 Johan Castberg

Johan Castberg is a field in the Barents Sea, 105 kilometres northwest of the Snøhvit field. The water depth is 370 metres. Johan Castberg consists of the Skrugard, Havis and Drivis accumulations, discovered between 2011 and 2013. The discoveries are developed together, and the PDO was approved in June 2018. The development concept is a FPSO combined with a subsea solution.

The field started up production in March 2025 and currently 7 oil producers, 5 water injectors and 2 gas injectors are on stream. In total it is planned for 18 oil producers, 8 water injectors and 4 gas injectors. There are plans for further development with infill wells to extend the plateau production. The tie-in development, Isflak passed DG3 in December 2025 and are planning for DG4 in Q4 2028. The Isflak development plan includes 1 multiltareal oil producer and 1 water injector from a new 4-slot template. The start up of Johan Castberg is resulting in a significant reclassification from undeveloped to developed reserves in 2025.

4.2.3 Snøhvit

Snøhvit is a field in the central part of the Hammerfest Basin in the southern part of the Barents Sea. The water depth is 310-340 metres. Snøhvit was discovered in 1984, and the PDO was approved in 2002. Snøhvit was the first field development in the Barents Sea. The field includes the Snøhvit, Albatross and Askeladd structures, and has been developed in multiple phases. The development includes several subsea templates. Two well slots are used for CO_2 injection. The production started in 2007. An amended PDO for onshore gas compression and full electrification was approved in 2023 and this is currently under development. Offshore subsea gas compression is also part of future plans for the field. On 19 September 2025 production started from the Askeladd Vest with two wells in a new template tied back to the Askeladd field.

4.3 Norwegian Sea

4.3.1 Åsgard Area

The Åsgard Area consists of the Åsgard, Mikkel, Trestakk, Morvin and Halten East fields.

Åsgard is a field in the central part of the Norwegian Sea. The water depth is 240-300 metres. Åsgard was discovered in 1981, and the PDO was approved in 1996. The Åsgard field includes the Smørbukk, Smørbukk South, Midgard accumulations and Smørbukk North, where a development plan was submitted in 2022 with production start-up in 2024. The Åsgard field has been developed with subsea wells tied-back to a FPSO, Åsgard A, and a floating, semi-submersible facility for gas and condensate processing, Åsgard B. Åsgard B is connected to a floating storage and offloading vessel for condensate, Åsgard C. Production from Åsgard A started in 1999 and gas export started in 2000.

The Åsgard facilities are an important part of the Norwegian Sea infrastructure. The Mikkel, Halten East and Morvin fields are tied to Åsgard B for processing, and gas from

Åsgard B is sent to the Tyrihans field for gas lift. The PDO for a subsea gas compression facility at Midgard was approved in 2012 and started operations in 2015. The Trestakk field is tied back to Åsgard A.

Work is ongoing to increase the recovery from the Åsgard field, while third party tie-ins to Åsgard will prolong the lifetime of the facilities. In 2025 the Low Pressure Production project, LPP3 started to produce.

The Mikkel field is located in the eastern part of the Norwegian Sea. It was discovered in 1987, and the PDO was approved in 2001. The field is developed with two subsea templates tied-back to the Åsgard B facility. Production started in 2003. During 2025 the Mikkel Flow Conditioning Unit project was sanctioned.

Trestakk is located 20 kilometres south of the Åsgard field. Trestakk was discovered in 1986 and the PDO was approved in 2017. The development concept consists of one subsea template with four well slots and an additional satellite well. The subsea development is tied-back to the Åsgard A facility for processing and gas injection. Production started in 2019.

Morvin is located 15 kilometres west of the Åsgard field. Morvin was discovered in 2001, and the PDO was approved in 2008. The field is developed with two 4-slot subsea templates, tied to the Åsgard B facility. Production started in 2010.

Halten East includes six discoveries (Flyndretind, Gamma, Harepus, Nona, Natalia and Sigrid) located east of the Åsgard field. The water depth is 200-300 metres. The PDO was approved in February 2023. The development concept includes five subsea templates that is tied back to the existing infrastructure on the Åsgard field. Production from the first 3 wells, Gamma, Flyndretind and Sigrid started in 2025, and the last 3 wells will start up early in 2026.

4.3.2 Heidrun

Heidrun is a field on Haltenbanken in the Norwegian Sea, 30 kilometres northeast of the Åsgard field. The water depth is 350 metres. Heidrun was discovered in 1985, and the PDO was approved in 1991. The field has been developed with the world's first ever floating concrete tension-leg platform (TLP), installed over a large subsea template with 56 well slots. Six subsea templates in the southern and northern areas are additionally tied-back to the TLP. The production started in 1995. The floating storage unit (FSU) Heidrun B is permanently moored at the Heidrun platform. The PDO for the Heidrun northern flank was approved in 2000. There are currently plans for a further northern Heidrun extension project aiming to increase the recovery from the field.

4.3.3 Kristin Area

The Kristin Area consists of the Kristin (including Lavrans) and Tyrihans fields.

Kristin is located a few kilometres southwest of the Åsgard field. The water depth is 370 metres. Kristin was discovered in 1997, and the PDO was approved in 2001. The field is developed with four 4-slot subsea templates tied-back to a semi-submersible facility for processing. Production started in 2005. The Tyrihans field is tied back to the Kristin facility.

A PDO for Kristin South, including development of the Kristin-Q area and Lavrans, was approved in February 2022. Kristin South is developed as a subsea tie back to the Kristin facility for processing and export. The Kristin South development is still ongoing with 3 new wells to be drilled in 2026. Two wells are currently producing.

The Tyrihans field was discovered in 1983 and the PDO was approved in 2005. The field is developed with five subsea templates tied-back to the Kristin platform, four templates for production and gas injection and one template for seawater injection. Gas lift is supplied from the Åsgard B platform. Production started in 2009. Plans for more wells in the northern area is currently being discussed.

4.3.4 Ormen Lange

Ormen Lange is a field in the southern part of the Norwegian Sea, 120 kilometres west-northwest of the Nyhamna processing plant. The water depth varies from 800 to more than 1,100 metres. Ormen Lange was discovered in 1997, and the PDO was approved in 2004. The field has been developed in several phases. The development is comprised of four 8-slot subsea templates with a total of 24 gas production wells. Production started in 2007 from two subsea templates in the central part of the field tied back to Nyhamna. In 2009 and 2011, two additional templates were installed in the southern and northern parts of the field, respectively.

Onshore gas compression at the Nyhamna terminal started operation in 2017, and a PDO for subsea gas compression was approved in 2022. The subsea compression system was put in operation in 2025 elevating the production from the Ormen Lange field significantly.

4.3.5 Njord Area

The Njord Area consists of the Njord host and the subsea tie-back fields Fenja, Bauge and Hyme.

Njord is a field in the Norwegian Sea, 130 kilometres northwest of Kristiansund. The water depth is 330 metres. The Njord field was discovered in 1986, and the PDO was approved in 1995. Njord is developed with a semi-submersible platform with drilling facilities, Njord A, containing drilling and processing facilities, and a storage vessel, Njord Bravo. The production started in 1997 and stopped temporarily in 2016 when the Njord A platform was shut down and towed to land for reinforcement and modifications. An amended Njord Future PDO for the upgrade was approved in 2017. Production from the Njord field resumed at the end of 2022. Additional production wells sanctioned as part of the Njord Future PDO is currently being drilled and 3 new wells has been put on production in 2025. The fields Hyme, Bauge and Fenja are tied-back to Njord.

The Vår Energi operated Fenja field is located in the Norwegian Sea, 35 kilometres southwest of the Njord field. The water depth is 325 metres. Fenja was discovered in 2014, and the PDO was approved in 2018. The field is developed with two subsea templates with a total of four wells, tied-back to Njord A facility. The field started production in April 2023.

Bauge is located 15 kilometres east of the Njord field. The water depth is 280 metres. Bauge was discovered in 2013, and the PDO was approved in 2017. The field is developed with two production wells tied-back to the Njord A facility and a future water injection well to be drilled from the subsea template on the Hyme field. The field started production in April 2023.

Hyme is located 19 kilometres northeast of the Njord field. The water depth is 250 metres. Hyme was discovered in 2009, and the PDO was approved in 2011. The field is developed with a subsea template including one production well and one water injection well, tied back to the Njord A facility. Production started in 2013; however, it was temporarily stopped in 2016 when the Njord A facility was shut down and towed to shore for reinforcement and modifications. Hyme resumed production in April 2023.

4.4 North Sea

4.4.1 Fram Area

The Fram Area consists of the Fram field, as well as the temporary shut-in Byrding and Fram H-North fields.

Fram is a field in the northern part of the North Sea, 20 kilometres north of the Troll field. The water depth is 350 metres. Fram was discovered in 1990 and is comprised of two main structures, Fram West and Fram East. The PDO for Fram West was approved in 2001, and production started in 2003. The PDO for Fram East was approved in 2005, and production started in 2006. Both structures are developed with two subsea templates each, tied-back to the Troll C platform. A PDO exemption for Fram C-East was approved in 2016; the development included a long oil producer drilled from the B2-template on Fram East. Another PDO exemption was granted in 2018 for two wells in the Fram East Brent reservoir, drilled from one of the existing templates on Fram East.

A Fram dedicated gas module was installed on the Troll C platform and started operation in 2020. A new development in the Fram Area named Fram South is planned for development and consist of production from the Echino South, Fram-West, Blasto and Dermata accumulations.

Fram H-North is a field just north of Fram. It is not contributing to our current reserves estimates and are not further described.

Byrding is four kilometres north of the Fram H-North field. Byrding was discovered in 2005, and the PDO was approved in 2017. The development concept is a two-branch multilateral (MLT) well drilled from the Fram H-North template. The production started in 2017. Byrding is temporarily shut-in due scaling risk, plan to re-open after well intervention in first quarter 2026.

4.4.2 Snorre Area

The Snorre Area consists of the Snorre, Vigdis and Tordis fields.

Snorre is a field in the Tampen area in the northern part of the North Sea. The water depth is 300-350 metres. Snorre was discovered in 1979, and the PDO was approved in 1988, production started in 1992. The field is developed with the Snorre A platform, located in the southern part of the field, Snorre B in the northern part and two subsea systems tied-back to Snorre A (SPS and SEP). Snorre A is a floating tension-leg platform for accommodation, drilling and processing, and Snorre B is a semi-submersible integrated drilling, processing and accommodation facility.

In 2018, an amended PDO for the Snorre Expansion Project (SEP) was approved. It includes six subsea templates, each with four wells tied-back to Snorre A. Production started in 2020. Several measures to increase oil recovery from Snorre are being considered and the Snorre gas export project was sanctioned in 2025. Possible third-party tie-ins may lead to further development of the field.

In 2024 the final redetermination for the Snorre Unit was called and initiated. The redetermination process is now finalised. We have reflected the results in our YE reserves estimates.

Vigdis is located in the Tampen area between the Snorre, Statfjord and Gullfaks fields. The water depth is 280 metres. Vigdis was discovered in 1986, and the PDO was approved in 1994. The field is developed with seven subsea templates and two satellite wells connected to the Snorre A facility. Production started in 1997. Oil from Vigdis is processed in a dedicated processing module on Snorre A.

Tordis is a located in the Tampen area between the Statfjord and Gullfaks fields. The water depth is 150-220 metres. Tordis was discovered in 1987, and the PDO was approved in 1991. The field has been developed with a central subsea manifold tied-back to the Gullfaks C facility, which also supplies water for injection. Seven single-well satellites and two 4-slots subsea templates are tied-back to the manifold. Production started in 1994.

4.4.3 Gjøa Area

The Gjøa Area consists of the Gjøa field as well as the tie-back fields Duva and Vega.

Gjøa is a field in the northern part of the North Sea, 50 kilometres northeast of the Troll field. The water depth is 360 metres. Gjøa was discovered in 1989, and the plan for development and operation (PDO) was approved in 2007. The field comprises several segments. Gjøa is developed with a semi-submersible production facility and includes five 4-slot templates. The field is partly supplied with power from shore. The production started in 2010. In 2019, Gjøa was granted a PDO exemption for the redevelopment of the P1 segment, including a 4-slot template. In 2025, the Low pressure production project was implemented during the turnaround to reduce the receiving pressure at the Gjøa facilities to increase production. The Vega and Duva fields are tied-back to Gjøa.

Duva is a field in the northern part of the North Sea, six kilometres northeast of the Gjøa field. The water depth is 350 metres. Duva was discovered in 2016, and the PDO was approved in 2019. Duva is developed with a 4-slot subsea template including three oil production wells and one gas production well tied-back to the Gjøa platform. The production started in 2021.

Vega is a field in the northern part of the North Sea, 30 kilometres west of the Gjøa field. The water depth is 370 metres. Vega was discovered in 1981. The field consists of three separate structures: Vega North, Vega Central and Vega South. The plan for development and operation (PDO) for Vega North and Vega Central was approved in 2007. In 2011, the field was unitised with Vega South. The field has been developed with three 4-slot subsea templates, one on each structure. They are tied to the processing facility on the Gjøa platform. A total of nine production wells has been drilled. The production started in 2010.

There is significant activity in the area with ongoing projects on several discoveries.

4.4.4 Sleipner Area

The Sleipner Area consists of the Sleipner East, Sleipner West, Gudrun, Gungne and Sygin fields. Sleipner East is a field in the central part of the North Sea. The water depth is 80 metres. Sleipner East was discovered in 1981, and the plan for development and operation (PDO) was approved in 1986. The field has been developed with Sleipner A, an integrated processing, drilling and accommodation facility with a concrete base structure. The development includes the Sleipner R riser facility, which connects Sleipner A to the pipelines for gas transport, and the Sleipner T facility for processing and CO_2 removal. The production started in 1993. Since then, further developments have been executed in the Alpha North and Loke areas in Sleipner East. The removed CO_2 is injected into the Utsira Formation via a dedicated well at Sleipner A. The Sigyn, Gungne and Gudrun fields are tied-back to Sleipner A.

Sleipner West is a field in the central part of the North Sea, 12 kilometres west of Sleipner East. The water depth is 110 metres. Sleipner West was discovered in 1974, and the PDO was approved in 1992. The field is developed with two platforms: the normally unmanned wellhead platform Sleipner B, which is remotely operated from the Sleipner A facility on the Sleipner East field, and the gas treatment platform Sleipner T, connected by a bridge to Sleipner A.

The production started in 1996. Two new infill wells are being drilled by year-end 2025 and two wells will be drilled in 2026.

Gungne is a field in the Sleipner Area in the central part of the North Sea. The water depth is 85 metres. Gungne was discovered in 1982, and the PDO was approved in 1995. The field has been developed by three wells drilled from the Sleipner A installation. The production started in 1996. A PDO exemption was granted for the Skagerrak and Hod Formations in 2000, and for a well to the Gamma High structure in 2007.

Gudrun is a field in the central part of the North Sea, 50 kilometres north of the Sleipner East field. The water depth is 110 metres. Gudrun was discovered in 1975, and the PDO was approved in 2010. The field is developed with a steel jacket and a topside with process facility and living quarters. Gudrun is tied-back to the Sleipner A facility with two pipelines, one for oil and one for wet gas. A PDO exemption was granted for the discovery 15/3-9 in 2013. The production started in 2014. Two new infill wells will be drilled in 2026-2027.

Sigyn is a field in the central part of the North Sea, 12 kilometres southeast of the Sleipner East field. The water depth is 70 metres. Sigyn was discovered in 1982, and the PDO was approved in 2001. The field is developed with a 4-slot subsea template tied-back to the Sleipner A facility. The production started in 2002.

4.4.5 Statfjord Area

The Statfjord Area consists of the Statfjord Unit, Statfjord North, Statfjord East and Sygna fields.

Statfjord is a field in the Tampen area and is located in both the Norwegian and UK sectors. The Norwegian share of the field is 85.47%. The water depth is 150 metres. Statfjord was discovered in 1974, and the PDO was approved in 1976. The field has been developed with three fully integrated concrete platforms: Statfjord A, Statfjord B and Statfjord C. Statfjord A, centrally located on the field, came on stream in 1979. Statfjord B, in the southern part of the field, in 1982, and Statfjord C, in the northern part, in 1985. The subsea satellite fields Statfjord East, Statfjord North and Sygna have a dedicated inlet separator on Statfjord C. A PDO for Statfjord Late Life was approved in 2005.

Statfjord North is located 17 kilometres north of the Statfjord field. The water depth is 250–290 metres. Statfjord North was discovered in 1977, and the PDO was approved in 1990. The field has been developed with two subsea production templates and one water injection template tied-back to the Statfjord C facility. Production started in 1995. The Kyllinglår prospect will be drilled in 2026 and will be tied back in case of discovery. If not, the plan is to drill a back-up target in the main field.

Statfjord East is located seven kilometres northeast of the Statfjord field. The water depth is 150-190 metres. Statfjord East was discovered in 1976, and the PDO was approved in 1990. The field has been developed with two subsea production templates and one water injection template, tied-back to the Statfjord C platform. In addition, two production wells have been drilled from Statfjord C. Production started in 1994. The main activity for Statfjord East currently is related to the gas lift project, which includes providing a gas lift solution for both subsea production templates and drilling of five new wells capable of producing with gas lift. The project is close to complete. An additional sixth well is planned for 2026.

Work is ongoing to extend the lifetime of the Statfjord field and tie-backs, including drilling of several new wells in the years to come. Operating cost reductions through reduced facilities are also planned for. Satellite fields tied-back to Statfjord as well as nearby discoveries will benefit from the lifetime extension.

4.4.6 Greater Ekofisk Area

The Greater Ekofisk Area consists of the Ekofisk, Eldfisk and Embla fields, while the adjacent Tor and Tommeliten Alpha fields are also included in this asset group.

Ekofisk and Eldfisk are oil fields in the southern part of the Norwegian sector in the North Sea. The water depth is approximately 70 metres. Ekofisk was discovered in 1969, and the PDO was approved in 1972. Since then several additional fields in the area have been put on production with Eldfisk and Embla being to major contributors.

Production from Ekofisk and Eldfisk is maintained through continuous water injection, drilling of production and injection wells, and well interventions. Infill drilling is expected to continue throughout the lifetime of the fields.

A PDO for the Eldfisk North project was approved in December 2022. Eldfisk North is a subsea development and includes 14 wells, where nine are producers and five are water injectors. Eldfisk North is tied back to the Eldfisk Complex. In 2025 the Eldfisk North extension project was sanctioned, adding to the reserves base.

The Tor field is located 13 kilometres northeast of the Ekofisk field. The water depth is 70 metres. Tor was discovered in 1970, and the PDO was approved in 1973. The field was shut down in 2015. A new PDO for the redevelopment of Tor was approved in 2019. The development includes two subsea templates with eight horizontal production wells, tied-back to the Ekofisk Centre.

Production started again in 2020.

Tommeliten Alpha is located 25 kilometres southwest of the Ekofisk field. The field is located on the border to the UK sector and the Norwegian share of the field is 99.57%. The water depth is 75 metres. Tommeliten Alpha was proven in 1977 and the development was approved in 2022. The Tommeliten Alpha development concept includes two 6-slot Subsea Production Station templates, tied-back to the Ekofisk Complex including a new processing module. The field started production in October 2023. The original PDO included 10 wells. Based on well results one additional well was added to the development in 2024.

In 2025 a joint development project of three gas condensate Previously Produced Fields (PPF) in Ekofisk was sanctioned. It includes the drilling of 6 wells in Albuskjell, 3 wells in West Ekofisk and 2 wells in Tommeliten Gamma with start-up expected in 2028. Vår Energi increased our share in this redevelopment project in 2025.

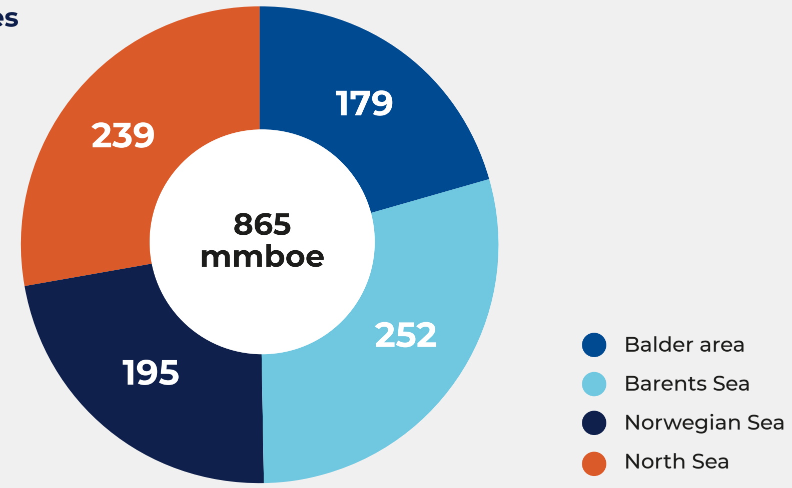
Contingent Resources

Vår Energi carries contingent resources across the portfolio at different maturity levels. Selected contingent resources are included in this section, where approximately two thirds of the contingent resources are associated with new development projects in the vicinity of our existing fields containing reserves.

The selected 2C resources included in this report equals 865 mmboe as of 31 december 2025.

The main projects in vicinity of our existing fields being matured towards an investment decision are additional Balder Area development phases, including further Balder Next wells, Ringhorne North, King as well as Cerisa, Ofelia and Gjøa North in the Gjøa Area. In the Barents sea several further opportunities related to gas export as well as infill drilling are being developed. In general infill projects are planned across the majority of our producing assets.

2C Resources



A large portion of the contingent resources are also linked to discoveries such as Goliat Ridge, Vidsyn, Dugong, Alke, Lupa, and several discoveries in the Barents Sea near the Johan Castberg field.

The following includes a brief description of the main contingent resources within Vår Energi's portfolio.

Balder Area

There are significant remaining resources to be targeted in the Balder and Ringhorne fields through future infill drilling programs. In addition, Ringhorne North was discovered in 2024. The area development plan is being matured and includes several projects under evaluation.

Goliat Area

The resources include future plans for infill drilling, to be matured during the next years. In addition there are oil discoveries in the Goliat Ridge (Countach, Zagato and Goliat North), as well as gas discoveries (Lupa and Alke). Two successful exploration wells in the Goliat Area (Lupa and Countach) were drilled in Q4 2022 and Q1 2023, and Countach was appraised in Q4 2024. Further Goliat Ridge appraisal took place in 2025 and based on this the Goliat Ridge development project was initiated with an aim to tie the oil discoveries back to the Goliat FPSO.

The significant gas discoveries in the area, Lupa and Alke, are contingent on downstream gas export capacity while. Lupa in the Goliat Area together with the Alke discovery in the Snøhvit Area has a positive impact on the likelihood of moving towards an expansion of the Barents Sea gas export capacity.

There is significant exploration activity in the area, and the resources may grow further based on up to three additional exploration and appraisal wells being drilled near Goliat over the next years. This may especially impact area solutions for gas export from the Barents Sea.

3D and 4D seismic was acquired in the Goliat Area during 2025. The new seismic is expected to support the development of contingent resources in the Goliat Field and the Goliat Ridge but also support further exploration activity over the next years.

Snøhvit Area

Snøhvit contingent resources covers infill drilling of several wells to increase recovery from the different reservoir segments, in addition to debottlenecking, Askeladd compression and the Tornerose discovery. The Alke gas discovery is operated by Vår Energi in PL489 in the Hammerfest Basin, about 54 kilometres south of the Snøhvit field in a water depth of 160 metres.

Johan Castberg Area

Contingent resources are mainly related to nearby discoveries within subsea tie-in distance to the Johan Castberg FPSO, i.e. Iskrystall, Kayak, Kramsnø, Skavl, Skruis and Snøfonn North. The planned gas blowdown at the end of the field life is also included in contingent resources.

Gjøa Area

Contingent resources are related to nearby discoveries, Cerisa, Ofelia and Gjøa North. These discoveries were discovered in 2024, 2022 and 1997 respectively and they are being worked actively with the aim to have a combined tie-back to Gjøa.

Ekofisk Area

Contingent resources are related to Enhanced Oil Recovery initiatives and future infill drilling candidates are also considered.

Snorre

Snorre field contingent resources includes new infill drilling and other activities under maturation.

In addition, the Dugong oil discovery was made in 2020 and appraised in 2021. Dugong is located in the North Sea, less than 10 kilometres from the Snorre Field. Dugong development is under evaluation as a joint development with Beta, another oil discovery in the vicinity of Snorre.

Statfjord Area

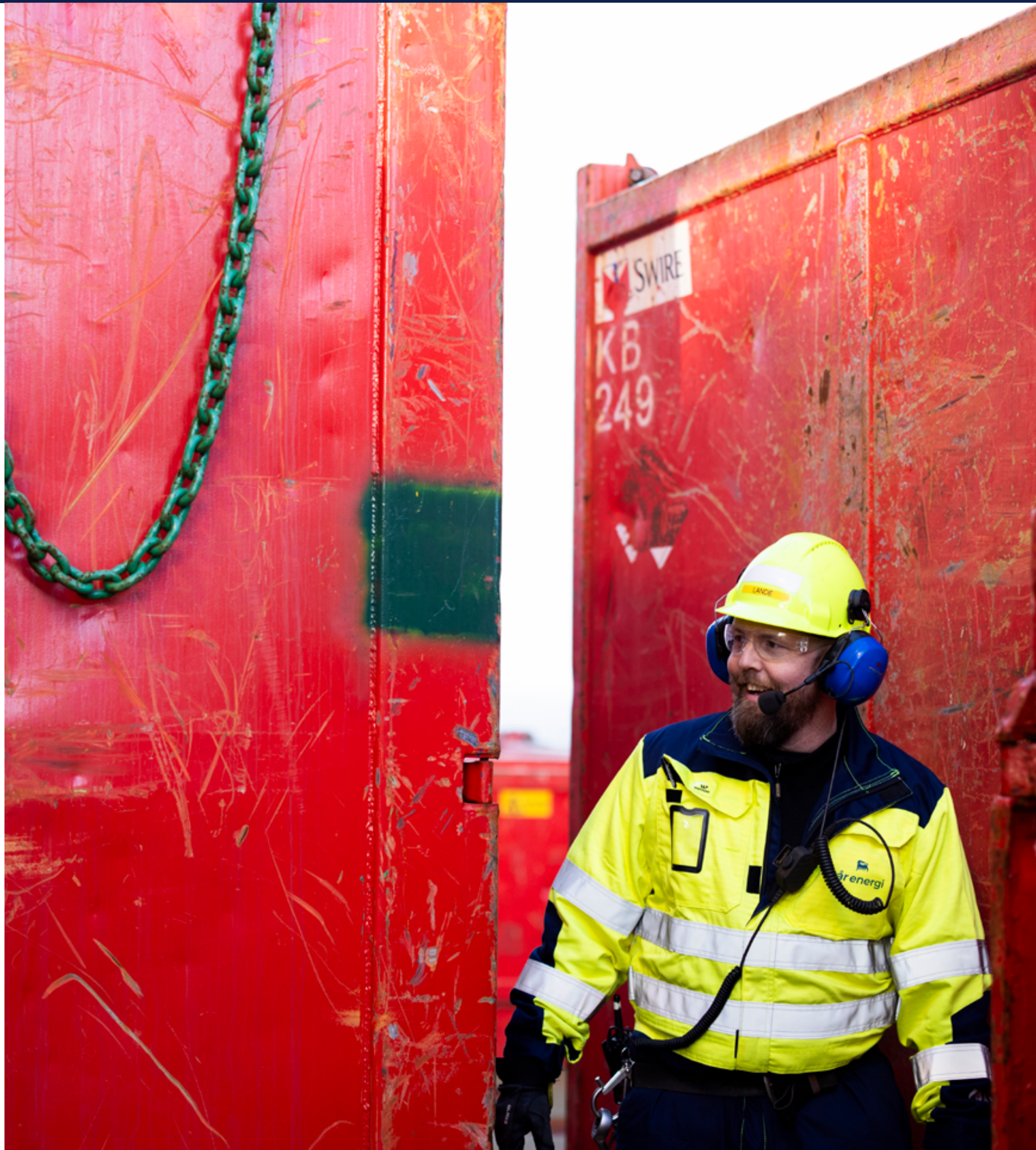
Contingent resources consist of new activities aimed to increase field reserves. This is made possible by the Statfjord Life Extension Project.

Åsgard Area

Contingent resources comprise future phases of Lavrans, low pressure projects, tail production from Kristin and Åsgard B as well as future infill drilling candidates.

Njord Area

Njord contingent resources includes Noatun and Northwest Flank, Northflank 2, 3 addtional discoveries and future drilling from Njord platform. Noatun a gas condensate discovery made in 2008 located 18 kilometres north of Njord A with synergies to the Northwest Flank and Northflank 2 and 3 discoveries. A significant discovery, Vidsyn, was made in the Fenja licence in 2025. The discovery is under evaluation and has been matured through DG0 in 2025.



Management Discussion and Analysis

Vår Energi's reserves and resources estimates are based on standard industry practices and methodologies. The evaluations and assessments have been performed by experienced professionals in Vår Energi with extensive industry experience, and the methodology and results have been quality controlled as part of the Company's internal reserves estimation procedures.

A third-party independent assessment has been performed by international petroleum consultants DeGolyer and MacNaughton (D&M) on all Vår Energi's fields that have remaining hydrocarbon volumes classified as reserves. The assessment was based on input data provided by Vår Energi, as well as publicly available data about the fields. The results of the independent assessment indicate no material difference compared to the Company reserves presented herein.

The 2P reserves estimates represents the expected outcome for the fields based on the performance observed to date, planned activities in the licences and reasonable assumptions about future economic and fiscal conditions. The Company has applied a long-term oil price assumption of 79 USD/bbl (real 2026 terms), a long-term gas price of €31/MWH (real 2026 terms), long-term inflation assumption of 2.0% and a long-term exchange rate assumption of 10.5 NOK/USD in the economic evaluation of its reserves.

The estimation of recoverable volumes is associated with geological and economic uncertainties. The 1P reserves reflect the Company's estimate of volumes with reasonable certainty to be recovered, however there is remaining risk that actual results may be lower than the 1P estimates. Lower and higher oil prices may also shorten or extend the economic life of fields, resulting in lower or higher recoverable volumes than what is assumed.

The report, including this Management's Discussion and Analysis (MD&A), contains and was prepared on the basis of forward-looking information and statements. Such information and statements are based on management's current assumptions, expectations, estimates and projections and are therefore subject to risks and uncertainties that could cause actual results, performance or events to differ materially. Vår Energi can give no assurance that those assumptions, expectations, estimates and projections will occur or be realized, and readers should not place undue reliance on forward-looking statements.

Nick Walker

CEO

vår energi