Annual statement of reserves 2023

vår energi

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Introduction

The report provides the status of hydrocarbon reserves and contingent resources for Vår Energi ASA as of 31 December 2023. 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 the reserves, and the results have been compared to the estimates of Vår Energi ASA in this report.

In 2024, the company reached an important milestone with the completion of the acquisition of Neptune Energy Norge AS on 31 January 2024. A pro-forma statement on the combined reserves is presented in this document. An audit of Neptune portfolio reserves as of 31 December 2023 was performed by ERC Equipoise Limited.

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.

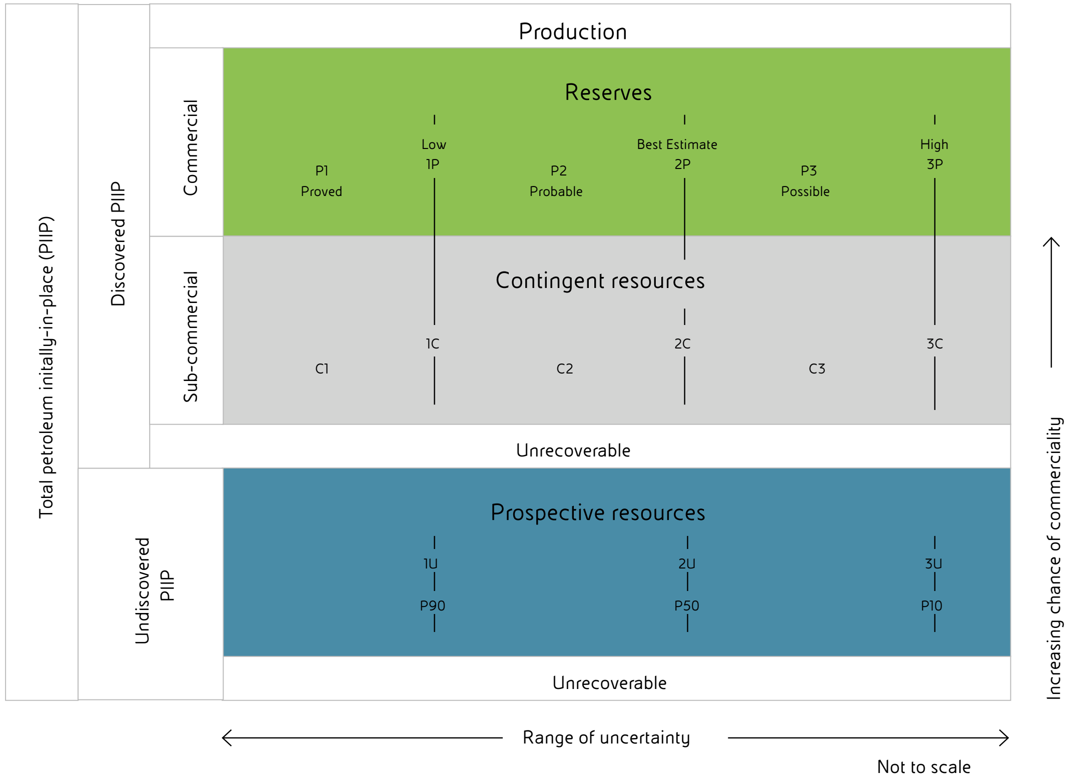

Figure 1: SPE-PRMS 2018 - Resources Classification Framework

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 2023, Vår Energi has a working interest in 42 fields containing reserves. Out of these fields, 39 are currently on production with developed reserves and 3 fields (Johan Castberg, Halten Øst and Verdande) 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 Area, the Norwegian Sea Area and the North Sea Area, as shown in Figure 2. The full list of the fields and Vår Energi's working interest is shown in Table 1.

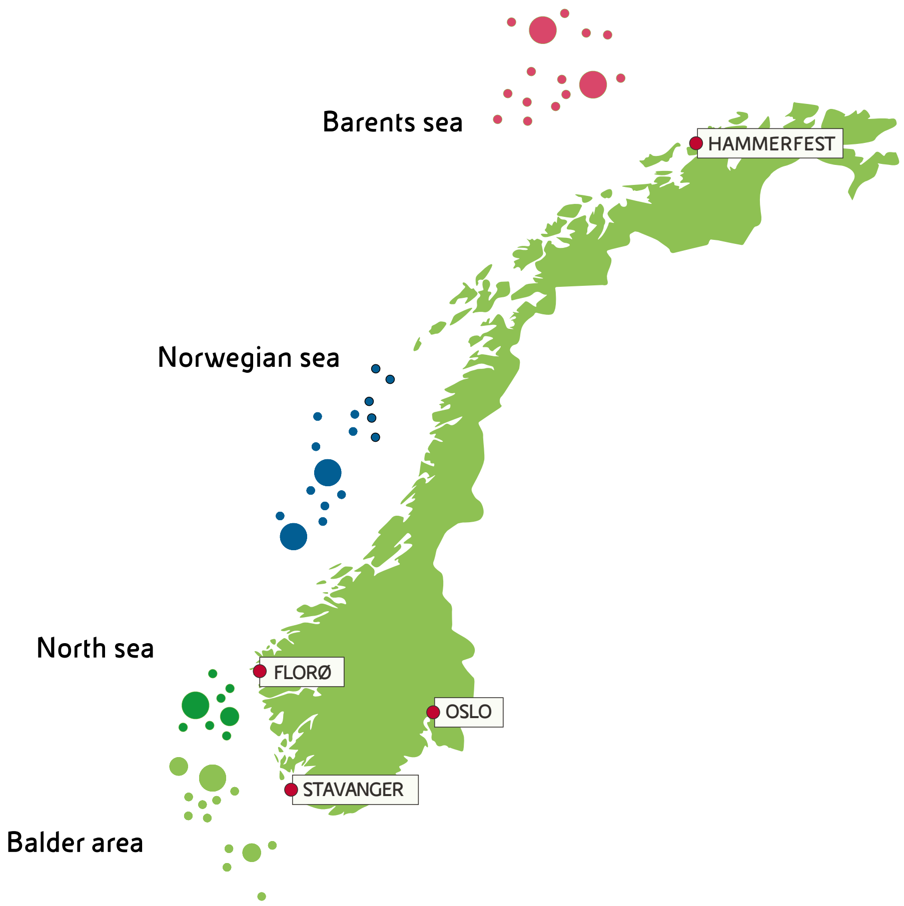

Figure 2: Vår Energi key areas

Table 1: Vår Energi's fields with reserves as of 31 December 2023

Area Field/Asset Status	Field/Project	Operator	Working interest	Field/Asset Status
Balder	Balder	Vår Energi ASA	90,0 %	On production
Balder	Breidablikk	Equinor Energy ASA	34,4 %	On production
Balder	Grane	Equinor Energy ASA	28,3 %	On production
Balder	Ringhorne Øst	Vår Energi ASA	70,0 %	On production
Balder	Svalin	Equinor Energy ASA	13,0 %	On production
Barents Sea	Goliat	Vår Energi ASA	65,0 %	On production
Barents Sea	Johan Castberg	Equinor Energy ASA	30,0 %	Development
Norwegian Sea	Åsgard	Equinor Energy ASA	22,7 %	On production
Norwegian Sea	Bauge	Equinor Energy ASA	17,5 %	On production
Norwegian Sea	Fenja	Neptune Energy AS	45,0 %	On production
Norwegian Sea	Halten Øst	Equinor Energy ASA	24,6 %	Development
Norwegian Sea	Heidrun	Equinor Energy ASA	5,2 %	On production
Norwegian Sea	Hyme	Equinor Energy ASA	17,5 %	On production
Norwegian Sea	Kristin (incl. Lavrans)	Equinor Energy ASA	16,7 %	On production
Norwegian Sea	Marulk	Vår Energi ASA	20,0 %	On production
Norwegian Sea	Mikkel	Equinor Energy ASA	48,4 %	On production
Norwegian Sea	Morvin	Equinor Energy ASA	30,0 %	On production
Norwegian Sea	Norne	Equinor Energy ASA	6,9 %	On production
Norwegian Sea	Ormen Lange	A/S Norske Shell	6,3 %	On production
Norwegian Sea	Skuld	Equinor Energy ASA	11,5 %	On production
Norwegian Sea	Trestakk	Equinor Energy ASA	40,9 %	On production
Norwegian Sea	Tyrihans	Equinor Energy ASA	18,0 %	On production

Area Field/Asset Status	Field/Project	Operator	Working interest	Field/Asset Status
Norwegian Sea	Urd	Equinor Energy ASA	11,5 %	On production
Norwegian Sea	Verdande	Equinor Energy ASA	10,5 %	Development
North Sea	Bøyla (incl. Frosk)	Aker BP ASA	20,0 %	On production
North Sea	Ekofisk	ConocoPhillips AS	12,4 %	On production
North Sea	Eldfisk	ConocoPhillips AS	12,4 %	On production
North Sea	Embla	ConocoPhillips AS	12,4 %	On production
North Sea	Fram	Equinor Energy ASA	25,0 %	On production
North Sea	Gungne	Equinor Energy ASA	13,0 %	On production
North Sea	Sigyn	Equinor Energy ASA	40,0 %	On production
North Sea	Sleipner Øst	Equinor Energy ASA	15,4 %	On production
North Sea	Sleipner Vest	Equinor Energy ASA	17,2 %	On production
North Sea	Snorre	Equinor Energy ASA	18,6 %	On production
North Sea	Statfjord	Equinor Energy ASA	21,4 %	On production
North Sea	Statfjord Nord	Equinor Energy ASA	25,0 %	On production
North Sea	Statfjord Øst	Equinor Energy ASA	20,6 %	On production
North Sea	Sygna	Equinor Energy ASA	21,0 %	On production
North Sea	Tommeliten Alpha	ConocoPhillips AS	9,1 %	On production
North Sea	Tor	ConocoPhillips AS	10,8 %	On production
North Sea	Tordis	Equinor Energy ASA	16,1 %	On production
North Sea	Vigdis	Equinor Energy ASA	16,1 %	On production

As of 31 December 2023, Vår Energi's total net proved (1P) reserves were estimated to 609 million barrels of oil equivalents. Total net proved plus probable (2P) reserves were estimated to 985 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).

Table 2: Vår Energi's reserves as of 31 December 2023

Total Reserves		1P (P90 / low estimate)				2P (P50 / best 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	113	-	10	124	182	-	15	197
Balder	Grane Area	55	-	4	58	91	-	6	97
Barents Sea	Goliat	33	-	-	33	51	-	-	51
Barents Sea	Johan Castberg	118	-	6	125	168	-	7	175
Norwegian Sea	Åsgard Area	11	11	31	54	21	23	65	108
Norwegian Sea	Kristin Area	2	4	14	20	5	7	24	36
Norwegian Sea	Ormen Lange	1	-	23	23	1	-	31	32
Norwegian Sea	Fenja Area	16	3	7	26	22	4	9	35
North Sea	Snorre Area	53	0	2	55	84	0	2	86
North Sea	Statfjord Area	7	2	6	15	14	3	11	28
North Sea	Greater Ekofisk Area	33	2	11	46	61	3	21	86
North Sea	Fram Area	2	1	8	11	3	2	12	17
Norwegian/ North Sea	Others	9	3	8	20	16	5	16	37
Total		**455**	**26**	**128**	**609**	**719**	**48**	**219**	**985**

Developed and undeveloped reserves per asset group and product are shown in Table 3 and Table 4, respectively.

Table 3: Vår Energi's developed reserves as of 31 December 2023

Total Reserves		1P (P90 / low estimate)				2P (P50 / best 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	30	-	0	30	36	-	0	36
Balder	Grane Area	29	-	4	32	48	-	4	52
Barents Sea	Goliat	32	-	-	32	47	-	-	47
Barents Sea	Johan Castberg	-	-	-	-	-	-	-	-
Norwegian Sea	Åsgard Area	7	7	20	34	12	13	39	65
Norwegian Sea	Kristin Area	1	3	11	16	3	5	17	24
Norwegian Sea	Ormen Lange	0	-	13	14	1	-	16	17
Norwegian Sea	Fenja Area	15	3	7	24	20	4	9	33
North Sea	Snorre Area	46	0	2	48	68	0	2	70
North Sea	Statfjord Area	6	1	5	12	11	2	9	23
North Sea	Greater Ekofisk Area	26	1	7	34	39	2	13	54
North Sea	Fram Area	2	1	8	11	3	2	12	17
Norwegian/North Sea	Others	6	2	7	15	9	3	13	25
Total Developed		**201**	**19**	**83**	**303**	**297**	**31**	**135**	**463**

Table 4: Vår Energi's undeveloped reserves as of 31 December 2023

Undeveloped Reserves		**1P (P90 / low estimate)**				**2P (P50 / best 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	83	-	10	93	147	-	14	161
Balder	Grane Area	26	-	-	26	43	-	2	45
Barents Sea	Goliat	1	-	-	1	4	-	-	4
Barents Sea	Johan Castberg	118	-	6	125	168	-	7	175
Norwegian Sea	Åsgard Area	4	5	12	20	8	10	26	44
Norwegian Sea	Kristin Area	1	1	2	4	2	3	7	12
Norwegian Sea	Ormen Lange	0	-	9	10	0	-	15	15
Norwegian Sea	Fenja Area	1	0	0	1	2	0	0	2
North Sea	Snorre Area	7	0	0	7	16	0	0	16
North Sea	Statfjord Area	1	0	1	2	3	1	2	5
North Sea	Greater Ekofisk Area	7	1	4	12	22	1	9	33
North Sea	Fram Area	-	-	-	-	-	-	-	-
Norwegian/North Sea	Others	3	1	1	5	7	2	3	12
Total Undeveloped		**253**	**7**	**45**	**306**	**422**	**16**	**84**	**522**

Changes from the Annual Statement of Reserves 2022 are summarized in Table 5. The main reasons for increased net reserves estimates (i.e., disregarding produced 2023 volumes) are:

- Authorization of one additional well in Tommeliten Alpha project, following the successful results obtained during the development drilling performed last year.
- Initiatives to increase recovery from producing fields by drilling additional infill wells, primarily in the Statfjord and Grane areas as well as Tyrihans, Vigdis, Svalin and Sleipner West fields.
- Field performance exceeding expectations resulting in positive 1P/P90 revisions.

Main downward revisions were:

- Vår Energi's selling of Brage assets as part of portfolio optimization process.
- Ormen Lange and Statfjord long term profiles revision by the operator based on the latest understanding of the field.
- Delay in start-up and revised volumes for Åsgard Low Pressure Production phase 3 (LPP3) Project.
- Revision of the Balder V project scope (6 wells versus 7 considered in the previous year's evaluation).

Table 5: Vår Energi's reserves changes compared to Annual Statement of Reserves 2022

	Developed		Undeveloped		Total	
Net attributable mmboe	**1P/P90**	**2P/P50**	**1P/P90**	**2P/P50**	**1P/P90**	**2P/P50**
Balance as of 31.12.2022	312	450	361	620	673	1070
Production	-78	-78	-	-	-78	-78
Acquisitions/disposals	-1	-1	-	-	-1	-1
Extensions/discoveries	-	-	-	-	-	-
New developments	-	-	+9	+14	+9	+14
Transfers to developed	+61	+97	-61	-97	-	-
Revisions	+9	-5	-4	-15	+5	-20
Balance as of 31.12.2023	303	463	305	522	609	985

Note that the production numbers are approximate, based on actual production estimates made in November 2023. Final actuals may differ slightly.

Description of Reserves

This section 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. The field descriptions are to a large extent extractions from www.norskpetroleum.no, a website run in cooperation by the Ministry of Petroleum and Energy and the Norwegian Petroleum Directorate.

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 Øst field is also tied-back to Balder via the Ringhorne platform. Ringhorne Øst was discovered in 2003, and the plan for development and operation (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 includes lifetime extension and relocation of the Jotun FPSO, and drilling of new subsea wells. The Jotun FPSO is currently at a shipyard undergoing maintenance and upgrades. It is scheduled to be back on the field in 2024. Ringhorne Øst will also benefit from the amended Balder and Ringhorne PDO. Field lifetime will be prolonged, and production can benefit from increased capacity in the area.

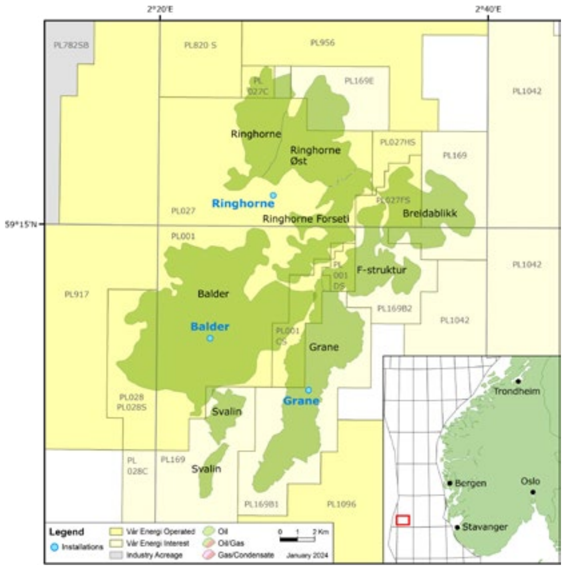

Figure 3: Balder/Ringhorne, Grane, Breidablikk and Svalin location map

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 drilling of a new infill well is ongoing, and it is planned to start-up production in 2024.

The Breidablikk field is located ten kilometers 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 being developed with four subsea templates tied-back to the Grane platform. The field started production in October 2023.

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 plan for development and operation (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 in-fill well will be drilled Q1/2 2024 and likely 2 more during 2025. Two successful exploration wells in the Goliat area (Lupa and Countach) were drilled in Q4 2022 and Q1 2023, respectively.

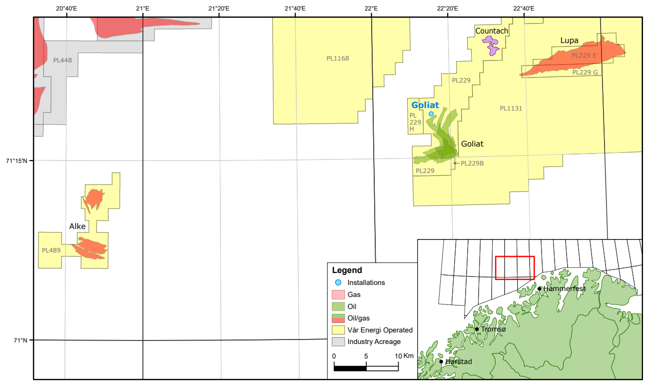

Figure 4: Goliat and Alke location map

4.2.2 Johan Castberg

Johan Castberg is a field in the Barents Sea, 100 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 will be developed together, and the PDO was approved in June 2018. The development concept is a production, storage and offloading vessel (FPSO) with additional subsea solutions including 18 horizontal production wells and 12 injection wells. The field is currently under development, and production is scheduled to start Q4 2024.

4.3 Norwegian Sea

4.3.1 Åsgard Area

The Åsgard Area consists of the Åsgard, Mikkel, Trestakk, Morvin and Halten Øst 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 plan for development and operation (PDO) was approved in 1996. The Åsgard field includes the Smørbukk, Smørbukk Sør, Midgard accumulations and Smørbukk Nord, where a development plan was submitted in 2022 with production start-up expected in 2024. The Åsgard field has been developed with subsea wells tied-back to a production, storage and offloading vessel (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 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. In 2023, the Blåbjørn well was successfully drilled in the Cretaceous accumulation. This is the first well to produce from the Lysing formation in the Åsgard area and will provide production experience from this reservoir.

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.

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.

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 Øst 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 will be tied back to the existing infrastructure on the Åsgard field. Halten Øst will be developed in two phases. Production from the first and second phase is scheduled to start in 2025 and 2029, respectively.

4.3.2 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 and Maria fields are 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 will be developed as a subsea tie back to the Kristin facility for processing and export. The Kristin South development is ongoing and expected production start-up is in 2024.

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. A new oil producer in the Tyrihans Southwest segment is planned for 2024.

4.3.3 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. Subsea gas compression is currently under execution and start-up is expected in 2025.

4.3.4 Fenja Area

The Fenja Area consists of the Fenja, Bauge and Hyme fields.

The 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 was shut down and towed to land for reinforcement and modifications. Hyme resumed production in April 2023.

4.4 North Sea

4.4.1 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 plan for development and operation (PDO) was approved in 1988. The field is developed with the Snorre A, 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. Possible third party tie-ins may lead to further development of the field.

In 2020, an amended PDO for the development of the Hywind Tampen wind farm was approved. The wind farm consists of 11 floating turbines which supply part of the electricity needed for the Snorre and Gullfaks fields, the first platforms in the world to receive power from a floating wind farm. The Hywind Tampen wind farm started up in November 2022.

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.

4.4.2 Statfjord Area

The Statfjord Area consists of the Statfjord Unit, Statfjord Nord, Statfjord Øst and Sygna fields.

Statfjord is a field in the Tampen area, and it is located in both the Norwegian and UK sectors. The Norwegian share of the field is 85.47 per cent. 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 Øst, Statfjord Nord and Sygna have a dedicated inlet separator on Statfjord C. A PDO for Statfjord Late Life was approved in 2005.

Statfjord Nord is located 17 kilometres north of the Statfjord field. The water depth is 250-290 metres. Statfjord Nord 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. A new infill well will be drilled from an existing well slot in 2024 to recover remaining attic oil in the Etive fm.

Statfjord Øst is located seven kilometres northeast of the Statfjord field. The water depth is 150-190 metres. Statfjord Øst 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 Øst 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 first well in the gas lift project came on stream in August 2023, and all five wells are expected on stream in 2024.

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. Satellite fields tied-back to Statfjord as well as nearby discoveries will benefit from the lifetime extension.

4.4.3 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 initial plan for development and operation (PDO) was approved in 1972. Eldfisk was discovered in 1970, and the PDO was approved in 1975. The Embla field is located just south of the Eldfisk field. Embla was discovered in 1988, and the PDO was approved in 1990. The field has been developed with an unmanned wellhead facility, which is remotely controlled from Eldfisk. Production started in 1993. 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. The Eldfisk North is a subsea development and includes 14 wells, where nine are producers and five are water injectors. Eldfisk North will be tied back to the Eldfisk Complex in the North Sea. 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 A 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 per cent. The water depth is 75 metres. Tommeliten A was proven in 1977 and the plan for development and operation (PDO) 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. Following the successful delineation of the Tommeliten Alpha structure during the development drilling performed in the past year, one additional well in Tommeliten Alpha project has been approved in the license to maximize the recovery from the field.

4.4.4 Fram Area

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 Vest and Fram Øst. The PDO for Fram Vest was approved in 2001, and production started in 2003. The PDO for Fram Øst 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-Øst was approved in 2016; the development included a long oil producer drilled from the B2-template on Fram Øst. Another PDO exemption was granted in 2018 for two wells in the Fram-Øst Brent reservoir, drilled from one of the existing templates on Fram Øst.

A Fram dedicated gas module was installed on the Troll C platform and started operation in 2020. A new infill well in the Fram Vest reservoir was drilled and started up in December 2023.

Neptune Energy Norge AS acquisition

In 2023, Vår Energi ASA ("Vår Energi") signed a purchase agreement to acquire Neptune Energy Norge AS. The included the acquisition of 12 producing assets, of which three are operated. The assets are located near existing hub area, as shown in Figure 5.

After the completion of the sale on 31 January 2024, the following fields became part of Vår Energi's portfolio.

Area Field/Asset Status	Field/Project	Operator	Working interest	Field/Asset Status
Barents Sea	Snøhvit	Equinor Energy ASA	12,0 %	On production
Norwegian Sea	Bauge	Equinor Energy ASA	12,5 %	On production
Norwegian Sea	Fenja	Neptune Energy AS	30,0 %	On production
Norwegian Sea	Hyme	Equinor Energy ASA	12,5 %	On production
Norwegian Sea	Njord	Equinor Energy ASA	22,5 %	On production
North Sea	Byrding	Equinor Energy ASA	15,0 %	Temporary shut-in
North Sea	Duva	Neptune Energy AS	30,0 %	On production
North Sea	Fram	Equinor Energy ASA	15,0 %	On production
North Sea	Fram H-Nord	Equinor Energy ASA	10,8 %	On production
North Sea	Gjøa	Neptune Energy AS	30,0 %	On production
North Sea	Gudrun	Equinor Energy ASA	25,0 %	On production
North Sea	Vega	Wintershall Dea Norge AS	3,3 %	On production

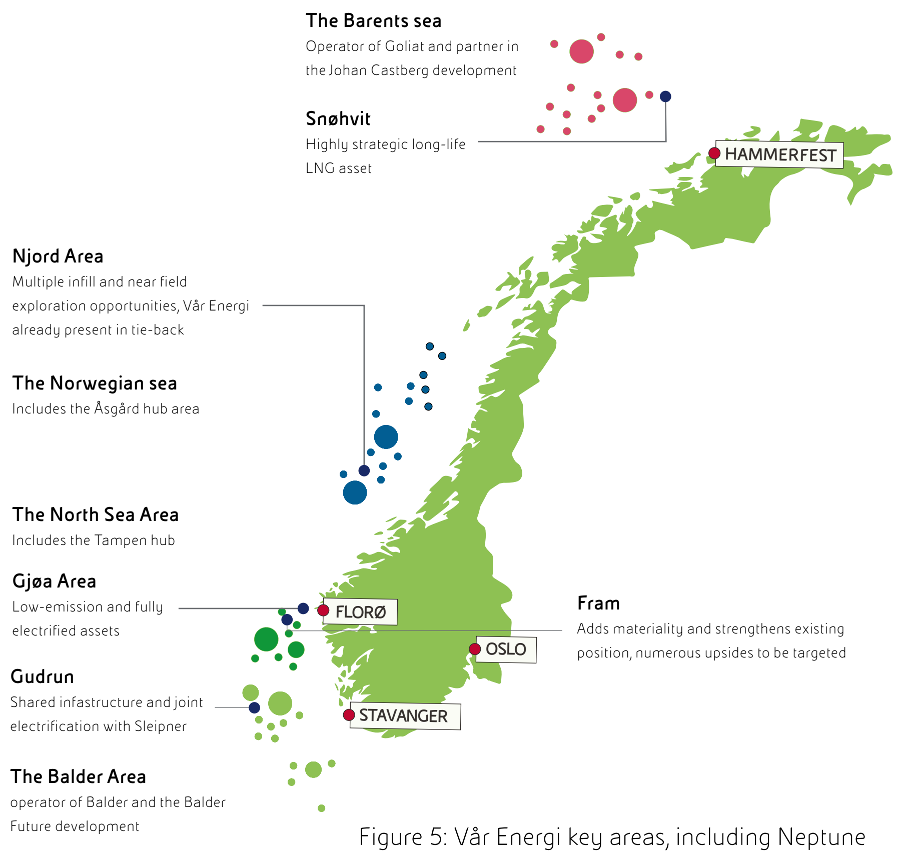

Figure 5: Vår Energi key areas, including Neptune Energy Norge AS fields

As of 31 December 2023, Neptune Energy Norge AS total net proved (1P) reserves were estimated to 184 million barrels of oil equivalents. Total net proved plus probable (2P) reserves were estimated to 256 million barrels of oil equivalents. Further details of the reserves by products are provided in Table 7.

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).

Table 7: Neptune Energy Norge AS reserves as of 31 December 2023

Total Reserves	**1P (P90 / low estimate)**				**2P (P50 / best estimate)**			
Area	**Net Oil mmboe**	**Net NGL mmboe**	**Net Gas mmboe**	**Net Total mmboe**	**Net Oil mmboe**	**Net NGL mmboe**	**Net Gas mmboe**	**Net Total mmboe**
Developed Reserves	20	8	41	68	33	12	67	111
Undeveloped Reserves	16	9	91	116	24	11	109	145
Total Reserves	**35**	**17**	**132**	**184**	**57**	**23**	**176**	**256**

With the acquisition completed in January 2024, Neptune Energy Norge AS assets became fully owned by Vår Energi ASA.

The year-end 2023 pro-forma reserves presented in the image below represent an approximate measure of the performance of the combined group on an annualised basis and to provide a reference point for comparison in future periods. The pro-forma figure for the Group has been calculated as if the asset acquisition and the merger had taken place on 31 December 2023. The pro-forma figure for 2023 has been collected directly from Neptune Energy Norge AS.

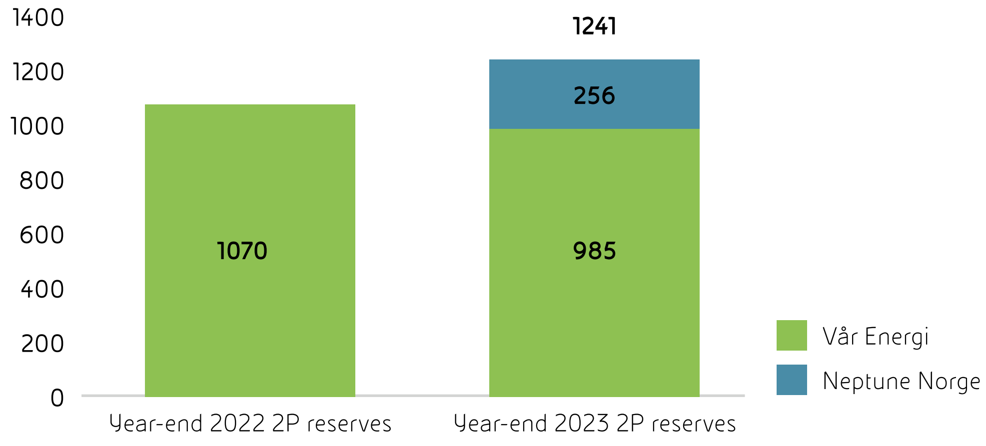

Figure 6: Year-end 2022 2P reserves and pro-forma year-end 2023 2P reserves

Contingent Resources

Approximately 61% of Vår Energi ASA's contingent resources as of 31 December 2023 are associated with new development projects in the vicinity of existing fields. The main projects being matured towards an investment decision are additional Balder Area development phases, including Balder Phase VI, Ringhorne Phase V and King, the development of Goliat gas resources, new infill drilling and activities being matured to extend Snorre and Åsgard fields life and the development of discoveries and drilling in the Fram area. The remaining contingent resources are linked to discoveries such as Alke, Garantiana, Lupa, Countach and several discoveries in the Barents Sea near the Johan Castberg field.

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

Balder Area (including King & Prince)

There are significant remaining resources to be targeted in the Balder and Ringhorne fields through future infill drilling programs. In addition, the 2021 exploration campaign included King & Prince discoveries. The area development plan is being matured and includes several projects under evaluation, including Balder Phase VI, Ringhorne Phase V and King.

Goliat Area

Contingent resources in Goliat are associated with the development of the gas resources in the field. Solutions for gas export have been evaluated and a Decision Gate 2 (DG2) was passed Q4 2023. The resources also include future plans for infill drilling, to be matured during the next years. Two successful exploration wells in the Goliat area (Lupa and Countach) were drilled in Q4 2022 and Q1 2023 and are now part of the area potential and several appraisal and exploration wells will be drilled during 2024/2025 to mature the discoveries further.

Alke

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 meters. The planning of a possible development of the Alke field is ongoing. Decision Gate 1 (DG1) was passed Q2 2019.

Ekofisk Area

Contingent resources in PL018 are related to EOR and in particular low salinity water injection where a pilot is in progress on Ekofisk field and which will be basis for further fieldwide EOR evaluation. Previously produced fields in the area are being evaluated for possible re-developments. Future infill drilling candidates are also considered.

Fram Area development

Contingent resources are related to future infill drilling in Fram, and for the recent Echino South and Blasto discoveries. The development project for these two discoveries passed Decision Gate 1 (DG1) in June 2022.

Garantiana

Garantiana is a discovery in the northern North Sea, 15 kilometres north of the Visund field. The water depth is 380 metres. The discovery was proven in 2012 and delineated in 2014. In 2021, a new discovery was made in a separate structure just west of Garantiana.

Johan Castberg Area

Contingent resources are related to nearby discoveries, including two 2022 discoveries, within subsea tie-in distance to the Johan Castberg FPSO, i.e. Isflak, Iskrystall, Kayak, Kramsnø, Nunatak, Skavl (Tubåen and Stø), Skruis and Snøfonn Nord. The planned gas blowdown at the end of the field life is also included in contingent resources.

Snorre

Snorre field contingent resources include new infill drilling and new activities being matured that also will contribute to extend field life.

Statfjord Area

Contingent resources consist of new activities aimed to increase field reserves related to 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. Some activities are expected to be matured into reserves in the near term, including late-life activities on Mikkel.

Neptune Norge AS Contingent Resources

Gjøa Area

Contingent resources are related two nearby discoveries Gjøa Nord and Ofelia (discovery in two stratigraphic layers) with an opportunity for a combined tie-back. Ofelia proved gas in Kyrre formation with a sidetrack in Q4 2023 from the Ofelia Agat appraisal well.
A potential infill well in the Gjøa P4 segment is also included in contingent resources.

Snøhvit

Snøhvit contingent resources covers infill drilling of several wells to increase recovery from the different segments, in addition to debottlenecking, Askeladd compression and the Tornerose discovery.

Dugong

The Dugong oil discovery was made in 2020 and appraised in 2021. Dugong is located in the North Sea, less than 10 kilometers from the Snorre Field. Dugong development is under evaluation.

Njord area

Njord contingent resources includes Noatun and North West Flank, North Flank 2 and 3 discoveries. Noatun a gas condensate discovery made in 2008 located 18 km north of Njord A with synergies to the North West Flank and North Flank 2 and 3 discoveries.

Calypso

The Calypso discovery is located in block 6407/8 in the Norwegian Sea, approximately 7 km North of the Bauge field and 10 km West of the Draugen field at a water depth of 271 m MSL. A subsea development with tie back to Draugen or Njord through Hyme is being evaluated.

Management Discussion and Analysis

Vår Energi ASA'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 ASA 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 ASA's fields that have remaining hydrocarbon volumes classified as reserves. The assessment was based on input data provided by Vår Energi ASA, 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.

Regarding Neptune's portfolio, a third-party independent assessment has been performed by international

petroleum consultants ERCE on all Neptune Energy Norge AS's fields that have remaining hydrocarbon volumes classified as reserves or contingent resources. The assessment was based on input data provided by Neptune Energy Norge AS, as well as publicly available data about the fields. The results of the independent assessment indicate no material difference compared to the company reserves.

The 2P reserves estimates represents the expected outcome for the fields based on the performance observed to date, planned activities in the licenses and reasonable assumptions about future economic and fiscal conditions. The Company has applied a long-term oil price assumption of 73 USD/bbl (real 2023 terms), a long-term gas price of €31/MWH (real 2023 terms), long-term inflation assumption of 2.0% and a long-term exchange rate assumption of 9.0 NOK/USD in the economic evaluation of its reserves. For Neptune Energy Norge AS portfolio, a long-term oil price assumption of 80 USD/bbl (real 2024 terms), a long-term gas price of €35/MWH (real 2024 terms), long-term inflation assumption of 2% and a long-term exchange rate assumption of 10.0 NOK/USD has been considered 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 ASA 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
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