AGR
An ABL Group Company

ABL Group Norway AS

Reservoir Management Division

Oslo

Lime
PETROLEUM

Qualified Person's Report 31.12.2024

For Lime Petroleum AS

March 2025

ABL Group Norway AS

Qualified Person's Report 31.12.2024

Approval			
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Qualifications

AGR (ABL Group Norway AS, previously AGR Energy Services AS) is an independent consultancy specialising in, amongst others, petroleum reservoir evaluation, reserves auditing and economic analysis. The company address is Karenslyst allé 4, 0278 Oslo, Norway. AGR has conducted evaluations for numerous energy companies and financial institutions. Except for the provision of professional services on a fee basis, AGR does not have any commercial arrangement with any other persons or companies involved in the assets that are the subject of this report.

This Qualified Person's Report (QPR) was managed by Gudmund Olsen (MSc in Petroleum Engineering), AGR Manager Reservoir Engineer and member of Society of Petroleum Engineers (SPE). Mr. Olsen has 30+ years of international and Norway experience.

The report was reviewed by Erik Lorange (MSc in Petroleum Geology), AGR Vice President Reservoir Management. Mr. Lorange, has 35+ years of international and Norway experience.

The report was reviewed and signed off by Steinar S. Johansen (MSc Petroleum Engineering), AGR Advisor Reservoir Engineer. Mr. Johansen, member of Society of Petroleum Engineers (SPE), has 30+ years of international and Norway experience including reserves and resource reporting.

The report was signed and approved by Svein Egil Sollund, AGR CEO.

Evaluation Standard

In this Audit of reserves and contingent resources, AGR has applied the standard petroleum engineering techniques. The Audit is based on the joint definitions of Society of Petroleum Engineers (SPE), World Petroleum Council (WPC), American Association of Petroleum Geologists (AAPG), Society of Petroleum Evaluation Engineers (SPEE), Society of Exploration Geophysicists (SEG), Society of Petrophysicists and Well Log Analysts (SPWLA), European Association of Geoscientists & Engineers (EAGE); Petroleum Resources Management System (PRMS) revised in 2018 and in accordance with the Singapore Exchange Securities Trading Limited Listing Manual.

Basis of Opinion

The evaluation presented in this report reflects our informed judgment based on accepted standards of professional investigation but is subject to generally recognized uncertainties associated with the interpretation of geological, geophysical and subsurface reservoir data. Any evaluation, particularly one involving exploration and future petroleum developments, may be subject to significant variations over short periods of time as new information becomes available.

Disclaimer

This report relates specifically and solely to the subject petroleum licence interests and is conditional upon the assumptions made therein. This report must therefore be read in its entirety. This report was prepared in accordance with standard geological and engineering methods generally accepted by the oil and gas industry, particularly PRMS. Estimates of hydrocarbon reserves and resources should be regarded only as estimates that may change as production history and additional information become available. Not only are reserves and resource estimates based on the information currently available, but they are also subject to uncertainties inherent in the application of judgmental factors in interpreting such information. ABL Group Norway AS shall have no liability arising out of, or related to, the use of the report.

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1 Executive Summary

This Qualified Person's Report (QPR) is issued for use by Lime Petroleum's majority shareholder Rex International Holding Ltd (hereafter shortened to Rex). Rex holds an indirect ownership stake in Lime Petroleum of 80.14% (in 2024 there was a restructuring of ownership in Lime, whereby Rex's share in Lime was reduced from 91.652% to the current 80.14%). Rex is listed on the Singapore Stock Exchange.

ABL Group Norway AS (AGR) has conducted an audit of reserves and contingent resources as of 31.12.2024 [1] for Lime Petroleum AS (hereafter shortened to Lime) for four assets on the NCS, in accordance with the Petroleum Resources Management System (PRMS) of SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE, revised in 2018. This QPR is an abridged version of the Lime audit report and includes a summary of the reserves and contingent resources net to Rex Holdings Limited as well as an overview of changes compared to the 31.12.2023 QPR.

The QPR includes three assets with reserves audited by AGR; Yme, Brage and Bestla fields. The PDO for Bestla (previously Brasse) was submitted in May 2024 and was approved in November 2024 by the authorities. Bestla is therefore now included in reserves for the first time. These assets also include projects with contingent resources. A new asset, the PL838 Lunde discovery is also included this year in contingent resources.

In 2024 Lime Petroleum AS acquired a 15% share in Yme from OKEA with effective date 01.01.2024 [2].

AGR has performed economic evaluations to determine reserves. The technical production and cost profiles have been provided by Lime and reviewed by AGR. The economic assumptions in Table 1.1 below were provided by Lime, and applied in the evaluations by AGR. The price forecast is based on a forecast of Brent spot oil price by Deloitte [3] and used by Lime Petroleum. Lime uses an NGL and gas price of 80% of the oil price on an oil equivalent basis.

Table 1.1 Price and financial assumptions from Lime

	Units	2025	2026 -> EOFL*
Oil/Condensate Price	USD/bbl (real2025)	74.5	72.4
Gas Price (40 MJ/Sm3)	NOK/Sm3 (real2025)	4.12	4.01
NGL Price	USD/boe (real2025)	59.6	57.9
Exchange rate	NOK/USD	11.0	11.0
Inflation rate	2% p.a.		
Present value reference date	01.01.2025		
Discount hurdle rate	8% p.a. (nominal)		
Tax	78% (22% corporate tax rate + 56% special tax rate)		

* EOFL - End of Field Life

Reserves as of 31.12.2024
The audited gross and net reserves as of 31.12.2024 endorsed by AGR, are shown in Table 1.2 below.

Table 1.2 Gross field and net Lime and net Rex Reserves as of 31.12.2024

Asset			100% (MMboe)			Lime Petroleum AS net (MMboe)			Rex 80.14% interest in Lime (MMboe)**		
	Lime Petroleum AS interest (%)	PRMS project maturity	1P	2P	3P	1P	2P	3P	1P	2P	3P
Yme	25.0000*	On Production	13.47	16.82	24.93	3.37	4.21	6.23	2.70	3.37	4.99
Brage	33.8434	On Production / Approved for Development***	9.33	12.42	16.03	3.16	4.20	5.43	2.53	3.37	4.35
Bestla	17.0000	Approved for Development	17.21	21.69	26.28	2.93	3.69	4.47	2.34	2.96	3.58
Total			**40.01**	**50.93**	**67.24**	**9.46**	**12.10**	**16.13**	**7.57**	**9.69**	**12.92**

Total in table may differ slightly from sum of fields due to rounding

* Lime's share in Yme has increased from 10% to 25% in 2024, this is reflected in the volumes reported 31.12.2024.

**Rex's share in Lime Petroleum has changed from 91.652% to 80.14% in Q4-2024.

*** Brage has some undeveloped reserves in Approved for Development category. This relates to two infill wells planned to be drilled in 2025.

Changes in reserves since 31.12.2023
Table 1.3 shows the changes in Rex net 2P reserves for the three Lime NCS assets with reserves. Rex's share in Lime has changed from 91.652% to 80.14% in 2024; this change is included in "Revisions and other changes". A more detailed overview of changes in Gross reserves per field is found in Section 3 Asset Descriptions.

Table 1.3 Changes in net Rex 2P reserves since 31.12.2023

Asset	2P Reserves 31.12.2023 (MMboe)	Production (MMboe)	Revisions and other changes (MMboe)	2P Reserves 31.12.2024 (MMboe)
Yme	3.62	1.50	1.25	3.37
Brage	3.41	1.80	1.76	3.37
Bestla	0.00	0.00	2.96	2.96
Total	**7.03**	**3.30**	**5.97**	**9.69**

Total in table may differ slightly from sum of fields due to rounding

*Lime's share in Yme has increased from 10% to 25% in 2024, this is reflected in the volume change.

The reasons for the changes in reserves are summarised below:

Yme Field:

- Production in 2024
- A significant increase in OPEX forecast for the period 2025-2035 leads to a significantly earlier economic cut-off.
- The change of methodology for forecast from reservoir simulation to DCA has resulted in a reduction in the 2P Technically Recoverable Resources (TRR) of approximately 20%.

Brage Field:

- Production in 2024
- Increase in Brage reserves due to later cut-off now resulting from the Bestla project (hub effect)
- Two additional infill wells approved and matured to reserves
- Good production performance in 2024

Bestla Field:

- Bestla (previously Brasse) had a PDO submitted and approved in 2024, hence Bestla is classified as reserves as of 31.12.2024. In the 31.12.2023 audit this asset was classified as Contingent Resources.

Contingent Resources as of 31.12.2024
The audited gross and net contingent resources as of 31.12.2024 endorsed by AGR, are shown in Table 1.4 below.

Table 1.4 Gross and net Lime and net Rex Contingent Resources as of 31.12.2024

Asset			100% (MMboe)			Lime Petroleum AS net (MMboe)			Rex 80.14% interest in Lime (MMboe)**		
	Lime Petroleum AS interest (%)	PRMS sub-class	1C	2C	3C	1C	2C	3C	1C	2C	3C
Yme	25.0000*	Development Unclarified / Development Pending	6.56	8.36	10.33	1.64	2.09	2.58	1.31	1.68	2.07
Brage	33.8434	Development Unclarified / Development on Hold / Development Pending	20.03	41.87	66.06	6.78	14.17	22.36	5.43	11.36	17.92
Bestla	17.0000	Development on Hold	2.73	4.45	4.15	0.46	0.76	0.71	0.37	0.61	0.57
Lunde	30.0000	Development Pending	4.65	7.27	10.28	1.39	2.18	3.08	1.12	1.75	2.47
Total			**33.97**	**61.95**	**90.82**	**10.27**	**19.20**	**28.73**	**8.24**	**15.39**	**23.02**

Total in table may differ slightly from sum of fields due to rounding

* Lime's share in Yme has increased from 10% to 25% in 2024 (effective 29.11.2024), this is reflected in the volumes.

**Rex's share in Lime has changed from 91.652% to 80.14% in Q4-2024.

Contingent resources for Yme are related to infill drilling and well interventions.

Contingent resources for Brage includes seven potential projects, including infill drilling, EOR and lifetime extension. The significant increase is due to different projects being added to the QPR 31.12.2024.

Contingent resources for Bestla are related to the potential life extension beyond 2031, which has to be considered in conjunction with a possible extension of the Brage lifetime.

Contingent resources for Lunde are related to development drilling; Lunde is classified as contingent resources since the project has not yet progressed to DG3 / Final Investment Decision.

Table 1.5 shows the changes in Rex net 2C contingent resources for the four Lime NCS assets with contingent resources. Rex's share in Lime has changed from 91.652% to 80.14% in 2024; this change is included in "Revisions and other changes". A more detailed overview of changes in Gross contingent resources per field is found in 3 Asset Descriptions.

Table 1.5 Changes in net Rex 2C resources since 31.12.2023

Asset	2C Contingent resources 31.12.2023 (MMboe)	Revisions and other changes (MMboe)	2C Contingent resources 31.12.2024 (MMboe)
Yme	0.75	0.93	1.68
Brage	3.92	7.44	11.36
Bestla**	4.07	-3.46	0.61
PL838 Lunde	-	1.75	1.75
Total	**8.74**	**6.66**	**15.39**

Sum Total in table may differ slightly from sum of fields due to rounding

* Lime's share in Yme has increased from 10% to 25% in 2024, this is reflected in the volume change.

** Bestla was previously named Brasse. Most of the volumes reported as Contingent Resources 31.12.2023 are now moved to Reserves as the PDO was submitted and approved in 2024.

2 Introduction and Methodology

Introduction
AGR (address Karenslyst allé 4, 0278 Oslo, Norway) has conducted an audit of Lime reserves and contingent resources as of 31.12.2024 in accordance with the Petroleum Resources Management System (PRMS) of SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE and the Singapore Exchange Securities Trading Limited Listing Manual.

This report covers:

- Audit of 1P, 2P and 3P reserves for the following assets:
  - Yme (Repsol is the operator and Lime owns a 25% share, see Fig. 2.1 for location)
  - Brage (OKEA is the operator and Lime owns a 33.8434% share, see Fig. 2.2 for location)
  - Bestla (OKEA is the operator and Lime owns a 17% share see Fig. 2.2 for location)

- Audit of 2C Contingent Resources in:
  - Yme
  - Brage
  - Bestla
  - PL838 Lunde - First time audit, Lime owns a 30% share (see Fig. 2.3 for location)

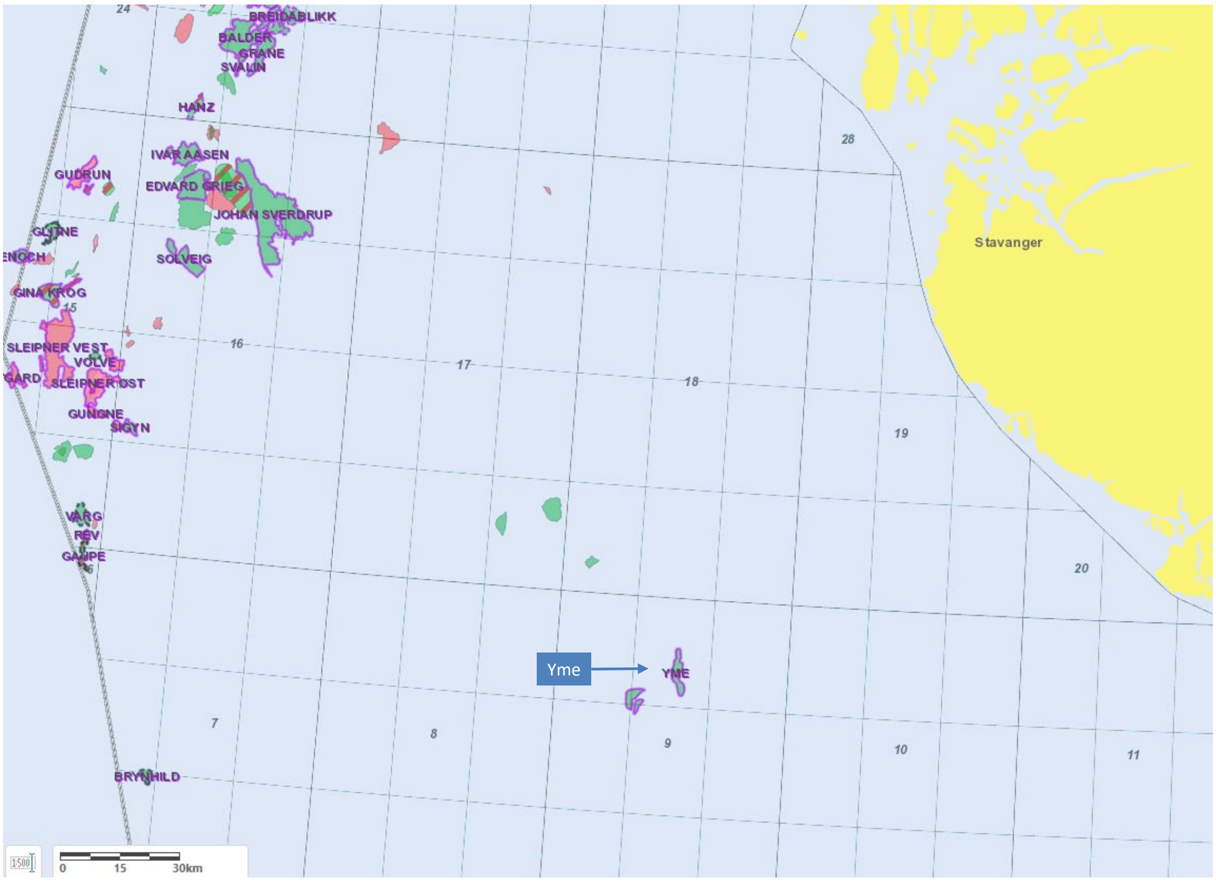

Fig. 2.1 Yme location map
Source: Norwegian Offshore Directorate (NOD) factmaps (www.sodir.no)

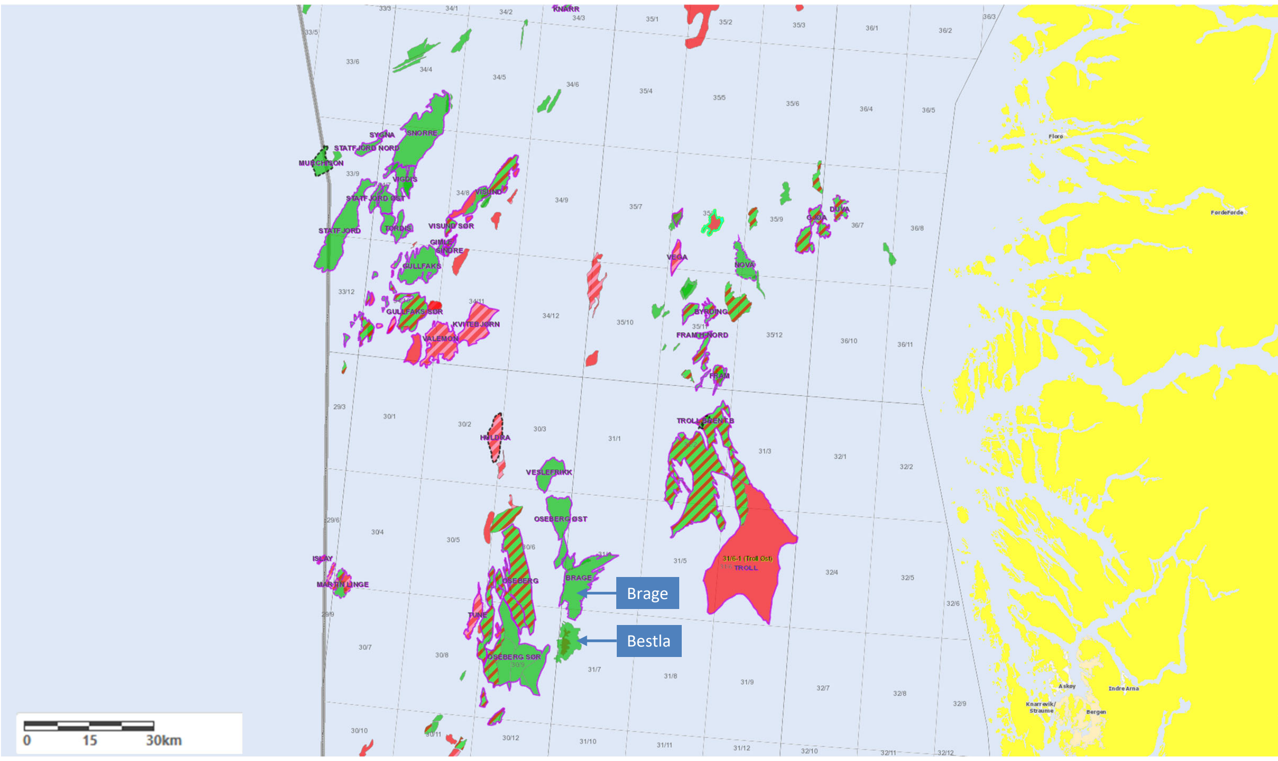

Fig. 2.2 Brage and Bestla location map
Source: Norwegian Offshore Directorate (NOD) factmaps (www.sodir.no)

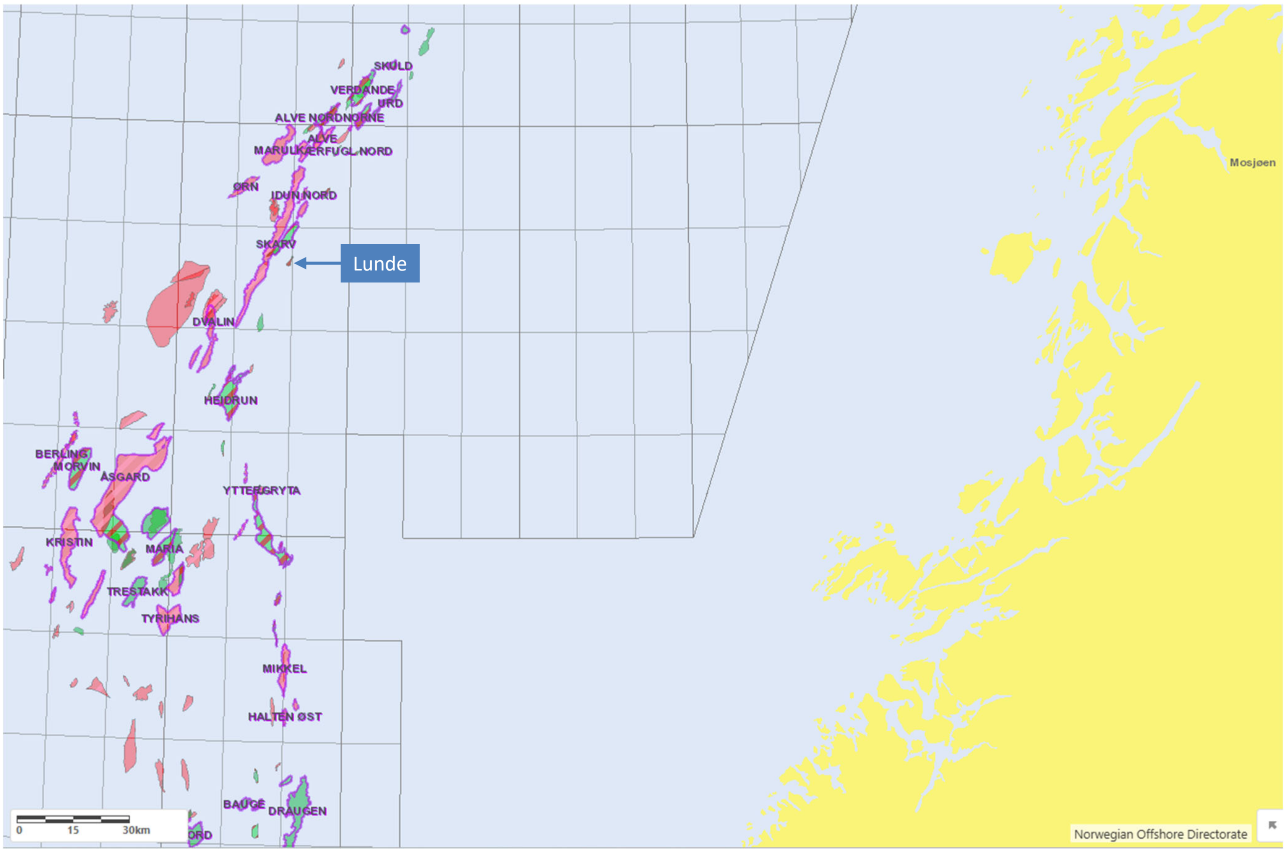

Fig. 2.3 Lunde location map
Source: Norwegian Offshore Directorate (NOD) factmaps (www.sodir.no)

Reserves, contingent resources and Petroleum Initially-In-Place (PIIP) received from Lime and audited by AGR, are expressed in field units (MMbbl and Bcf). The combined oil equivalent is expressed in MMboe.

Whenever the term "Technically Recoverable Resources (TRR)" is used with production volumes or profiles, it refers to the estimates before the economic evaluation, i.e. before an economic cut-off has been applied to determine reserves. The cumulative volumes are including sales volumes from 01.01.2025 to end of the profiles.

The reserves and contingent resources per 31.12.2024 audited by AGR were provided to AGR by Lime in the form of "Annual Statement of Reserves" for each of the four assets. This included production and cost forecasts for Low, Best and High cases.

This is the first time the Lime resources on Lunde are audited by AGR.

No site inspections nor visits was conducted as part of this study.

Methodology
The methodology applied in this report was (assuming relevant data/information was available):

- Review of the available data, interpretations and resulting models and reports
- Check of the critical parameters in terms of origin of the data, the interpretation and application thereof
- Review of the methodology applied to generate production forecasts and resources estimates
- Review and analysis of the available Petrel™ and Eclipse™ models. No new modelling has been performed except using existing models to enhance understanding and to verify results
- Review of uncertainty evaluations and how key uncertainties impact the project
- Review the subsurface and the overall project risks
- Review of costs and technical lifetime of facilities and wells
- Economic evaluations of the technical profiles to determine economic cut-off and reserves
- For all assets, the Lime profiles are based on the Revised National Budget 2025 submissions by the Operators to the Authorities (RNB2025) with some adjustment by Lime and some adjustments to comply with PRMS. The cost profiles are based on RNB2025. The RNB low case is assumed to represent the P90 case, the base case is assumed to be close to and practically equal to the P50 case and the high case is assumed to represent the P10 case.
- The gas reserves are reported as sales gas at 40 MJ/Sm3.
- Recovery Factor (RF) in this report is defined as the economically recoverable volumes divided by the Petroleum Initially-In-Place (PIIP). Note that with this definition the gas recovery factor may not represent the correct value since
  - Gas reserves are reported as dry sales gas and not rich gas at the wellhead
  - Not all produced gas may be sold due to fuelling and flaring
- The 2024 produced volumes are actuals provided by Lime. These volumes are used for assessment of reserves as of 31.12.2024.
- Classification of the reserves according to the PRMS (SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE) and SGX rules
  - This classification system recommends that no reserves are booked beyond licence expiry date. However, it is a common practice on the Norwegian Continental Shelf that licence period extensions are granted. It is, therefore, assumed that licence periods will be extended and reserves may be recovered beyond the existing licence expiry dates.

Main units and conversion factors
The main units and prefixes as follows:

- bbl = barrels
- boe = barrels oil equivalent
- Scf = standard cubic feet
- boe = barrels of oil equivalents
- M = prefix; a thousand when used with bbl
- MM = prefix; a million when used with bbl
- B = billion

SI units and prefixes as follows:

- Sm3 = Standard cubic meters
- k = thousand, 1 000
- M = million, 1 000 000
- G = billion, 1 000 000 000
- T = trillion, 1 000 000 000 000

The following conversion factors are applied in the report:

- Oil and condensate
  - 1 Sm3 = 6.29 bbl (barrel)
  - 1 Sm3 = 1 Sm3 oe = 6.29 boe

- Gas
  - 1000 Sm3 gas = 1 Sm3 oe = 6.29 boe
  - 1 Sm3 = 35.315 Scf

- NGL
  - 1 tonne NGL = 1.9 Sm3 oe
  - 1 Sm3 oe = 6.29 boe

3 Asset Descriptions

The following sections contain brief asset descriptions and an overview of the resources as of 31.12.2024 for these assets with some commentary on methodology and changes since the estimates reported 31.12.2023. The resource estimates presented in the sections below are on gross and net to Lime. In order to convert those numbers to estimates net attributable to Rex, the estimates should be multiplied by Rex's 80.14% share in Lime.

The resource estimates net attributable to Rex are found in Section 1 Executive Summary as well as in Appendix A.1 Summaries of Oil and Gas Reserves and Resources.

3.1 Yme

Asset Overview
The Yme Field is located in the Norwegian part of the Norwegian Danish Basin, blocks 9/1, 9/2 and 9/5 in production licences PL 316 and PL 316 B, 140 km southwest of Stavanger, see Fig. 3.1. The water depth is 93 m [4].

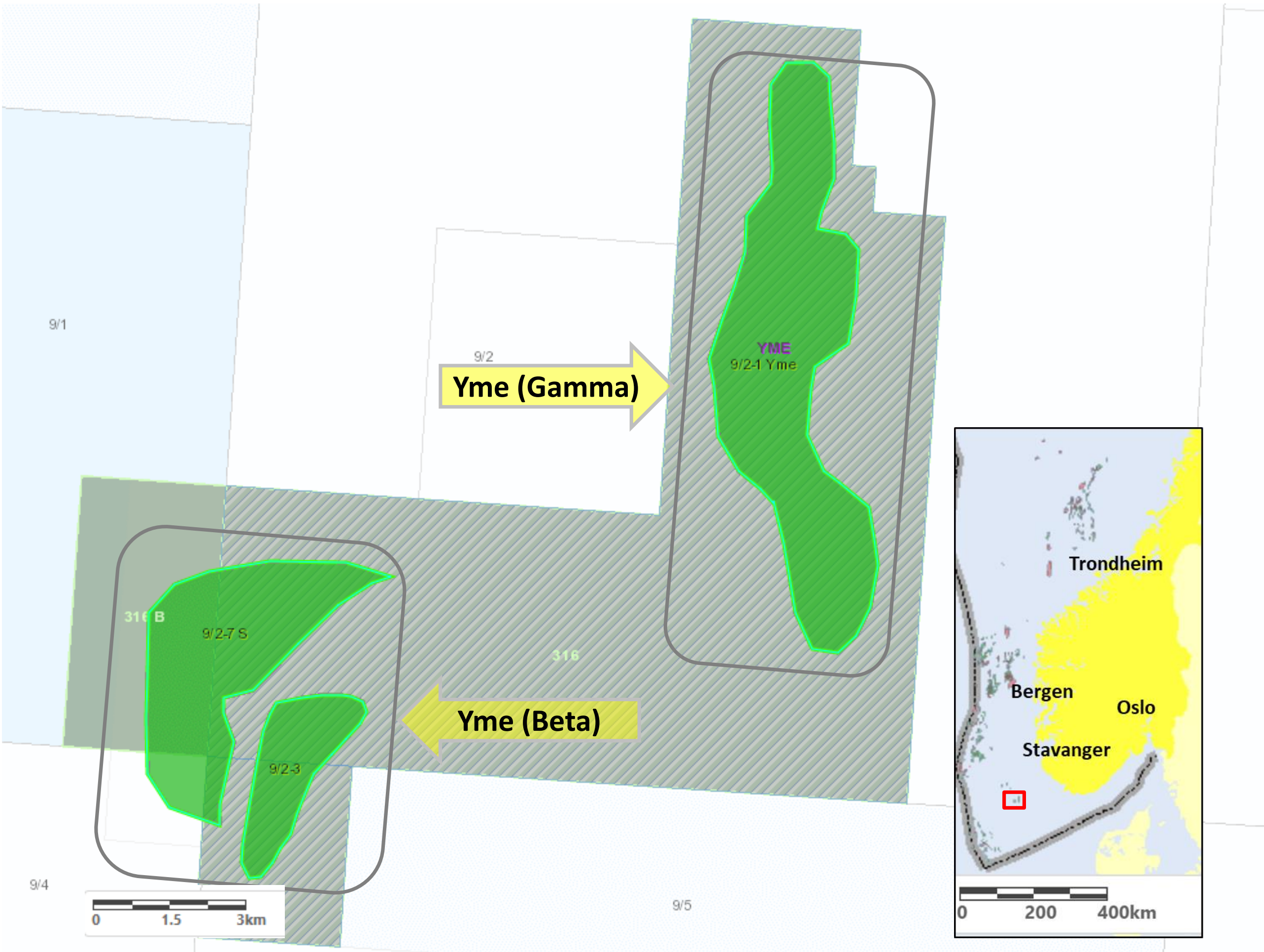

Fig. 3.1 Yme Field Location Map
Source: Norwegian Offshore Directorate (NOD) factmaps (www.sodir.no)

The field was discovered by Equinor (at that time Statoil) in 1987 and was put on production in 1996. Yme ceased production in 2001 after having produced 51 MMbbl of oil, as operation was no longer profitable. However, the oil recovery factor was 13% only, hence significant volumes were left in the field. In 2007 a redevelopment plan was submitted by the new Operator, Talisman. In 2013, after drilling nine new development wells and two appraisal wells, the redevelopment project was abandoned due to structural deficiencies in the offshore production unit. In 2015 another redevelopment project “Yme New Development” was initiated. The new development plan was submitted by the current Operator Repsol and the PDO was approved by the authorities in March 2018. The production restarted in October 2021. PL 316 licence expiry is 18.06.2030 [4].

Licence details summary is shown in Table 3.1. The production licence gives the licensees full rights to explore and produce hydrocarbons at all stratigraphic levels within the licence area.

This audit has been based on the information provided by Lime, which included Lime's Statement of Reserves (SoR) [5], the Operator's RNB2025 submission [6], meeting documents (RC, TC, MC) from 2024, monthly status reports from 2024, work program and budget (WP&B) 2025, production data for the individual wells, as well as Lime's answers to AGR's questions and clarification requests.

Table 3.1 Yme summary table

Asset name/ Country	Lime's interest (%)	Development Status	Licence expiry date	Licence Area (km2)	Type of mineral, oil or gas deposit	Remarks
PL 316 / 316 B (Yme) / Norway	25	On production	18.06.2030	140	Oil	-

The licence shares are shown in Table 3.2. Lime acquired OKEAS's 15% share with effective date 1.1.2024 increasing its ownership to 25%.

Table 3.2 Yme licence shares (%)

Licence	Repsol Norge AS (Op.)	ORLEN Upstream Norway AS	Lime Petroleum AS
PL 316 / 316 B (Yme)	55.00	20.00	25.00

Discovery
The Yme Field was discovered in 1987 by well 9/2-1 on the Gamma structure, containing undersaturated oil at about 3150 m TVD MSL reservoir depth. In 1990, another oil discovery was made by the 9/2-3 well on the Beta structure, 12 km west of the Gamma structure. The discovery was made in reservoir sandstones of Sandnes formation of Late Jurassic age. In the discovery well, OWC was in the transition zone from 3201 to 3210 m TVD MSL[4].

Reservoir
The Yme Field consists of two accumulations Gamma and Beta, which are about 12 km apart. Each is subdivided into three segments separated by faults: Beta East, Beta North, Beta West, Gamma West, Gamma South East and Gamma North East. All segments have 3-way dip closures. All segments, except Beta West, has been redeveloped.

The reservoir in Yme is the Middle to Upper Jurassic Sandnes Formation. The current understanding is that the Sandnes Formation was deposited in a period of transgression with shoreface sediments in a sandy delta. Channel belt complexes associated with this delta correspond to main feeder channel systems and have the best reservoir properties and thickness of two to six meters. Laterally, these sands are relatively continuous. Some coal layers have been observed in cores and in logs, but these are not continuous. The average thickness of the Sandnes Formation is 150 m for Gamma and 115 m for Beta. Vertically, the reservoir is heterogeneous since sediments are deposited from Lower Marine, Estuarine and Upper Marine settings stratigraphically upward. The porosity varies from 8 to 23% and permeability from 1 to 2000 mD. The Estuarine sandstones show high permeability which have already been produced by earlier Operator (Statoil), whereas Lower Marine sandstones have low permeability and are the main target for the current Operator (Repsol). The Gamma East accumulation is communicating with a regional aquifer. Both Gamma and Beta structures are compartmentalized.

Development
The Yme New Development is based on a combination of re-use from the Talisman operated project and new equipment specifically designed for the Yme New Development project:

Reused facilities on the field:

- Storage tank
- Caisson with risers and wells
- Pipelines, umbilicals and subsea facilities at the Beta location
- Submerged Loading System (SLS)

Changes and new facilities:

- Redeployment and modification of Mærsk Inspirer, a jack-up rig with processing and drilling facilities
- A new wellhead module (WHM) on top of the existing caisson

- A new support structure for the caisson
- Beta North: A new subsea template with three wells tied in to the existing Beta manifold

The field is producing from ten horizontal production wells (six on Gamma and four on Beta) supported by two Water Alternating Gas injectors (WAG) in Gamma and three Water Injectors (WI), one on Gamma and two on Beta. A total 9 out of 15 wells were pre-drilled on Yme Beta and Gamma. These wells were completed during the 2009 - 2010 period (Talisman). All 15 well slots have been used as of 31.12.2024.

Produced water re-injection in combination with a regional aquifer provides reservoir pressure support, and contribute to sweep of the reservoir. Artificial lift for the production wells is primarily provided by gas lift, but Gamma East wells utilise Electrical Submersible Pumps (ESP). Further use of ESPs are under consideration (changing out gas lift to ESP in some wells). The oil is exported by tankers and gas is used for power generation, gas-lift and WAG.

<u>Technical lifetime of the wells and facilities</u>

The technical lifetime of the Yme New Development facilities is specified to be 15 years. The current technical lifetime of the Maersk Inspirer is 10 years from installation on the field (January 2021). To extend the lifetime further, a new 5 year classing of the Maersk Inspirer needs to be approved and performed. The umbilicals, cranes and module supports are reported to have technical lifetimes that expire in 2029, 2027 and 2030, respectively.

Status
The main reference for this section is the Statement of Reserves for Yme [5], Yme audit presentation and Annual Status Report 2024.

Currently, there are 6 platform producers (C-1, C-2, C-3 A, C-4, C-8 A and C-9) accessing the Yme Gamma area with 2 WAG injectors (C-5 and C-6) and one new water injector C-7; Two subsea tie-back producers are currently producing from the Yme Beta area supported by two water injectors. Two subsea producers are shut in (D-1H and D-2H) due to process instability problems.

During 2024, the Gamma North East well C-7 drilled in 2023, finally started on water injection in March 2024. The C-3 A multilateral well started production in July 2024, with a great contribution to the Yme production. To date, Beta wells and C-9 have been producing with low water cut, suggesting a successful completion strategy. In C-8 A increasing water-cut after shutdowns are experienced. However, after the turnaround (TAR, planned maintenance shutdowns) in September 2024, C-8 A is still producing with water-cuts higher than before the TAR. The C-3A multilateral well had increasing water cut shortly after start-up. Well surveillance and remediation activities are budgeted for 2025.

The actual production in 2024 (including estimates from 01.11.2024) is 9% lower than the Base forecast in the RNB2024 submission. The main reasons for this reduced production are:

- Unexpected downtime in the form of significant time during winter waiting on weather to connect to the tanker to offload crude.
- Significant drilling delay for many months of the remaining PDO wells (C-8A, C-3A MLT etc).
- Delayed completions and problems related to the ESP well C-8A
- It is however noted that the field experienced higher PE than prognosed, helping to reduce the gap between actual and prognosed production.

In general production efficiency has improved from 2023 to 2024, with an average production efficiency of 83.65% (of 01.09.2024) vs. average of 74.81% (2023).

There are plans for further development of the field by infill drilling in both the Gamma and Beta structures in 2026.

Petroleum Initially in Place (PIIP)
The PIIP estimates as of 31.12.2024 is listed in Table 3.3 below. The estimate below is consistent with the RNB2025 submission. The RNB2025 PIIP estimates are based on the Phase II static model built in 2020,

which is updated with post-drill results of Beta infill wells (Infill campaign 2022). The model has been history matched with production data.The subsurface uncertainties incorporated in the static model were Top reservoir structure, FWL in different segments and property modeling. Among these, structure uncertainty was considered to be the most influence on the PIIP volume. There is no change to PIIP estimate since 31.12.2023.

Table 3.3 Yme PIIP estimate as of 31.12.2024 (source:Norwegian Offshore Directorate)

	PIIP, 31.12.2024 (Best Estimate)
Oil/Condensate (MMbbl)	362
Gas (BScf)	122

Production and cost profiles presented by Lime
The recoverable volumes from Yme are classified as Reserves and Contingent Resources according to PRMS.

The Reserves include the following project:

- Yme Base Production

The Contingent Resources include the following project:

- Yme Beta infill drilling
- Artificial Lift
- Yme Gamma Drilling

Description of the production profiles

The forecast for oil production is shown in Fig. 3.2. The plot shows the technical profile before any economic cut-off. For Yme there is no gas or NGL sales. The production profiles are derived from a combination of dynamic simulation models and Decline Curve Analysis (DCA) models.

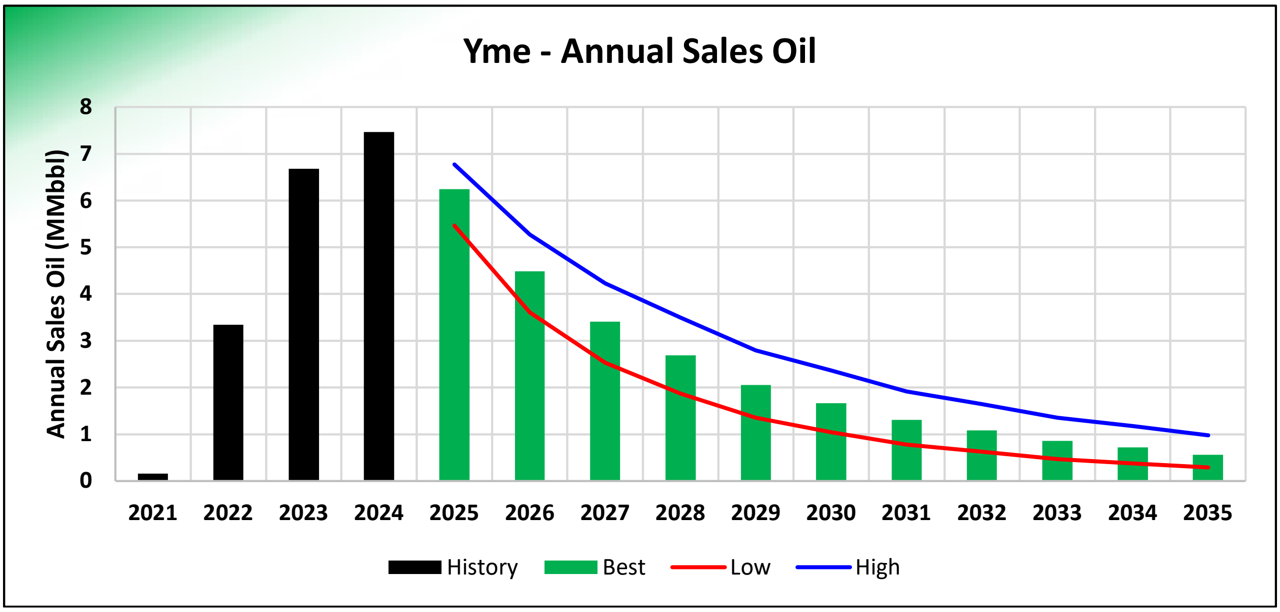

Fig. 3.2 Production Forecast - Yme

- Newly drilled wells without decline curves are estimated using the dynamic model combined with DCA based scaling factors.
- The production history is frequently back-allocated following test separator production tests which in turn updates the Operator's decline curves.
- In general, the work is heavily relying on DCA models

- A future production efficiency of 90% is assumed
- The Operator assumes lifetime extension and run technical profiles to 2035.

The reserves profiles include the following wells:

- Base production, includes production from wells C-1, C-2, C-3A, C-4, C-8A, C-9, E-1 and E-3.
- WAG injection wells C-5 and C-6
- Water injection wells E-2, D-3 and C-7

The TRR Low estimate is 27% lower, and the High estimate is 28% higher, than the Base estimate.

Contingent resources

- Beta infill Drilling: the project includes 2 infill wells at Beta. Initially planned DG3 was in 2024, but limited rig availability has postponed DG3 to 2025.
- Artificial Lift: the project includes workover changing two wells at Gamma from Gas lift to ESP
- Yme Gamma Drilling: the project includes infill drilling of one well at Gamma

Description of the cost profiles

The OPEX, CAPEX and ABEX profiles in the Lime Statement of Reserves [5] are based on the RNB2025[6] and the 2025 Work Program and Budget (WP&B). The Yme facilities performance has improved since the start-up of the "Yme new development" project in 2022 when several operating challenges were experienced. The average production efficiency for 2024 was 84%. From 2031, the lease contract of the Mærsk Inspirer expires, and the rig will be owned by the Yme licence which results in a reduction in OPEX. According to Lime there is a commitment in the lease contract that Yme will have to pay the lease rate up to 2031 even if the cash flow is negative prior to 2031.

Reserves and Contingent Resources audited by AGR

Comments to PIIP

AGR has checked the Phase II static model and supporting document which are used for the PIIP generation. The model includes historical wells (earlier Operators Statoil and Talisman) and infill wells drilled until 2022 with logs and base case model 'PHASE_II_YME_02_WIR2500_BaseCase'. The static model has been updated and history matched. AGR has reviewed available documents with following comments:

- The PIIP numbers are consistent with those in the RNB2025 submission[6].
- The PIIP figures presented by Lime have not changed since 31.12.2023.
- AGR accepts the PIIP numbers presented by Lime.

Comments to production profiles

AGR has reviewed the production performance of the wells currently on production. The database is updated to 31.12.2024. AGR checked the procedure in using the DCA as basis for the RNB2025 production profiles.

- In general, the current dynamic simulation models do not sufficiently match historical data. The history match is poor in certain areas of the field: some wells have several tens of bar mismatch in their bottomhole pressures, some wells have no water cut whereas in reality they have been tested with significant water cut.
- The combination of well-established DCA models with 3D simulation model results for making production profiles are in line with best practices.
- It is noted that the forecasts in RNB2025 for existing wells are mostly based on DCA work, which reflect more realistic field production picture compared to reservoir simulation which defined the base case in RNB2024. DCA gives lower oil production compared to 3D simulation, particularly for wells experiencing high water cuts.

- There are significant uncertainties related to the future water-cut development due to uncertainties in compartmentalization and rock properties.

Comments to contingent resources

Gamma drilling work on hold as the operator is focusing on Beta drilling, of which a completion of DG2 is planned for Q1 2025. Yme Gamma is thought to have more life than Yme Beta, so the Gamma infill campaign can begin after the Yme Beta campaign. AGR considers the recovery potential for the infill wells reasonable, compared with other wells on the Gamma structure.

Comments to facilities and cost profiles

Lime has applied the cost profiles in line with the Yme RNB2025 [6], which AGR finds reasonable. AGR has some comments to the RNB profiles provided below.

- There is no CAPEX included for the years 2026 onwards. Costs normally considered as CAPEX may have been defined as OPEX.
- The current OPEX forecast for Yme is significantly increased compared to last year and more in line, but still lower, than the actual OPEX experienced the recent years.
- Repsol is considering Cessation of Production (COP) in 2035. AGR can not see that the cost of classing of the Mærsk Inspirer and other required upgrades as described above are reflected in the current cost profiles.
- Due to lack of fuel gas, Yme will experience increasing demand for diesel which will impact the operating cost.
- Contractual commitment to pay the lease rate up to 2031.

Economic evaluation and reserves determination

AGR has performed an economic evaluation to determine the reserves with the economic assumptions shown in Appendix A.1 Summaries of Oil and Gas Reserves and Resources. The technical project production and cost profiles have been evaluated to ensure project commerciality and the correct economic cut-off. The resulting TRR and gross and net to Lime reserves are shown in Table 3.4 below. Gross and net to Lime contingent resources are shown in Table 3.5 (please note that contingent resources are not subject to an economic evaluation or economic limit test). Net to Rex reserves and net contingent resources are found in 1 Executive Summary and A.1.1 Yme - Summary of Oil and Gas Reserves and Resources

- For the Base price scenario, the economic cut-off is:
  - 1P: end of 2028, seven years earlier than technical cut-off
  - 2P: end of 2028, seven years earlier than technical cut-off
  - 3P: end of 2030, five years earlier than technical cut-off
- The reserves are classified according to PRMS as follows:
  - "On Production": Yme New Development project

Changes in Reserves and Contingent Resources since audit 31.12.2023

The gross Yme balance sheet for reserves is shown in Table 3.6 below and for contingent resources in Table 3.8 below.

Changes to Reserves:

- Production in 2024
- Revisions
  - A significant increase in OPEX for the period 2025-2035 compared to last year leads to earlier cut-off.
  - The change to method for forecast from simulation to DCA has resulted in a reduction in the 2P TRR of approximately 20%.

Changes to Contingent Resources:

- Two new projects included; Beta infill drilling and Artificial Lift.
- Infill drilling (three wells) on Beta and Gamma are matured further, and the resource estimates and uncertainty range have been refined

Comments to recovery factors and reserves ranges

- The recovery factor after the initial development was 13%. In the PDO of 2017 the P50 recovery factor assuming 10 years production was estimated to be 30%.
- The P50 oil recovery factors estimated for this audit are shown in Table 3.9. AGR finds the final recovery factor of 23% to be moderate but reasonable taken into account the complexity of the field combined with the pre-mature economic cut-off for the field, driven by high OPEX forecasts.
- The 1P reserves estimate is -20% and 3P is +48% versus 2P. The upside is impacted by the later economic cut-off compared to the base and low cases.
- The estimated ultimate recovery factor of 23% is below the average on the NCS, which is 47%. It should thus be feasible to achieve the planned extractable volumes. However, considering recent and likely future integrity issues, and the high water cut development, active reservoir management will probably be necessary, such as drilling of more wells, recompletions, adjustments to production facilities etc., to achieve the predicted rates.

Conclusions

- The Yme reserves reported by Lime are based on the RNB2025 submission.
- The uncertainty on Yme is high with respect to future water cut in existing wells, but also possible previous flooding in the new potential producer locations (contingent resource infill wells).
- The current recovery factor is low, and it should be possible to achieve the planned recoverable volumes.
- AGR endorses the Yme Reserves and Contingent Resources as reported by Lime in the Lime Statement of Reserves[5].

Table 3.4 TRR and reserves as of 31.12.2024 - Yme

	TRR (Gross 100 %)			Reserves (Gross 100 %)			Reserves (Net Lime, 25%)*		
	Low	Best	High	1P	2P	3P	1P	2P	3P
1st Production	25 October 2021								
Cut-off (year-end)	2035	2035	2035	2028	2028	2030	2028	2028	2030
Oil/condensate (MMbbl)	18.39	25.04	31.99	13.47	16.82	24.93	3.37	4.21	6.23
Gas (BScf)	-	-	-	-	-	-	-	-	-
NGL, (MMbboe)	-	-	-	-	-	-	-	-	-
Total (MMboe)	**18.39**	**25.04**	**31.99**	**13.47**	**16.82**	**24.93**	**3.37**	**4.21**	**6.23**

* Net reserves in Table above are net to Lime. Rex's share in Lime is 80.14%. For reserves net to Rex, see 1 Executive Summary and A.1.1 Yme - Summary of Oil and Gas Reserves and Resources.

Table 3.5 Gross and net to Lime contingent resources as of 31.12.2024 - Yme

Yme		**GROSS (100%)**			**Net to Lime (25%)***		
Contingent resources (MMboe)	**PRMS subclass**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
Infill Drilling	Development Pending	5.13	6.32	7.68	1.28	1.58	1.92
Artificial Lift	Development on Hold & Development Unclarified	1.43	2.04	2.65	0.36	0.51	0.66
Total, MMboe		**6.56**	**8.36**	**10.33**	**1.64**	**2.09**	**2.58**

* Net contingent resources in Table above are net to Lime. Rex's share in Lime is 80.14%. For contingent resources net to Rex, see 1 Executive Summary and A.1.1 Yme - Summary of Oil and Gas Reserves and Resources.

Table 3.6 Balance sheet - Yme Reserves (100%)

Gross reserves balance, 31.12.2023 - 31.12.2024, for Yme (100%)							
Reserves class	**Status 31.12.2023**	**Production (Positive)**	**Revisions**	**Acquisitions or sales**	**IOR**	**Discoveries/ New Projects**	**Status 31.12.2024**
Oil and condensate (MMbbl)							
1P	22.65	7.47	-1.72	-	-	-	13.47
2P	39.47	7.47	-15.18	-	-	-	16.82
3P	41.97	7.47	-9.57	-	-	-	24.93
Gas (BScf)							
1P	-	-	-	-	-	-	-
2P	-	-	-	-	-	-	-
3P	-	-	-	-	-	-	-
NGL (MMboe)							
1P	-	-	-	-	-	-	-
2P	-	-	-	-	-	-	-
3P	-	-	-	-	-	-	-
Oil equivalents (MMboe)							
1P	**22.65**	**7.47**	**-1.72**	**-**	**-**	**-**	**13.47**
2P	**39.47**	**7.47**	**-15.18**	**-**	**-**	**-**	**16.82**
3P	**41.97**	**7.47**	**-9.57**	**-**	**-**	**-**	**24.93**

Table 3.7 TRR and reserves as of 31.12.2024 - Yme

-	**-**	**-**	**-**	**-**	**-**

Table 3.8 Balance sheet - Yme Contingent Resources (100%)

Gross contingent resource balance, 31.12.2023 - 31.12.2024, for Yme_CR (100%)							
Resource class	**Status 31.12.2023**	**Production (Positive)**	**Revisions**	**Acquisitions or sales**	**IOR**	**Discoveries/ New Projects**	**Status 31.12.2024**
Oil and condensate (MMbbl)							
1C	2.30	-	2.83	-	-	1.43	6.56
2C	8.20	-	-1.88	-	-	2.04	8.36
3C	9.55	-	-1.87	-	-	2.65	10.33

Note that the balance sheets above include the effect of Lime's increase in licence share from 10% to 25% effective from 01.01.2024.

Table 3.9 Yme P50 Recovery Factors

	Oil 31.12.2024	Oil at EUR	Gas 31.12.2024	Gas at EUR
Produced (MMbbl/ GSm3)	68.15	84.36	0	0
Recovery factor	19%	23%	0%	0%

3.2 Brage

Asset Overview
Brage is an oil field located east of the Oseberg Field and west of the Troll Field in the northern part of the North Sea within production licences PL 053B, 055, 055B, 055D, 055E, 055FS and 185; and blocks 30/6, 31/4 and 31/7[4]. The field is unitised in the Brage Unit. The water depth varies from 130 to 170 m and the reservoir depth varies between 2000 and 2300 m TVD MSL. See Fig. 3.3 for the location map. The field has been on production since 1993 [4]. Brage Licence expiry is 06.04.2030.

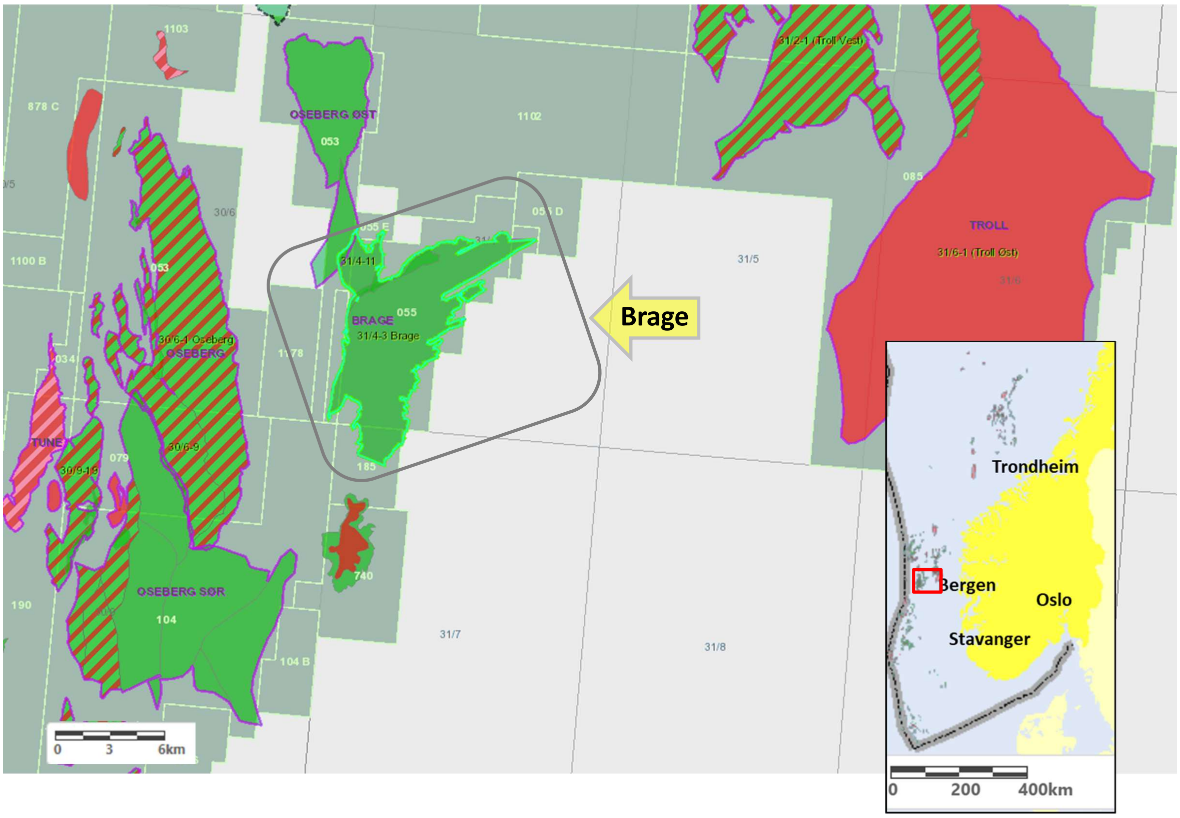

Fig. 3.3 Brage Field Location map
Source: Norwegian Offshore Directorate (NOD) factmaps (www.sodir.no)

This audit of reserves and contingent resources has been based on the information provided by Lime.

Licence details summary is shown in Table 3.10. The production licence give the licencees full rights to explore and produce hydrocarbons at all stratigraphic levels within the licence area.

This audit has been based on the information provided by Lime, which included Lime's Statement of Reserves (SoR) [7], the Operator's RNB2025 submission[8], meeting documents (RC, TC, MC) from 2024, monthly status reports from 2024, work program and budget (WP&B), as well as Lime's answers to AGR's questions and clarification requests.

Table 3.10 Brage summary table

Asset name/ Country	Lime's interest (%)	Development Status	Licence expiry date	Licence Area (km2)	Type of mineral, oil or gas deposit	Remarks
Brage Unit / Norway	33.8434	On production	06.04.2030	183.33	Oil and gas	-

The Brage Unit licence shares are listed in Table 3.11.

Table 3.11 Brage Unit licence shares (%)

Licence	OKEA ASA (Op)	Lime Petroleum AS	DNO Norge AS	Petrolia NOCO AS	M Vest Energy AS
Brage Unit	35.2000	33.8434	14.2567	12.2575	4.4424

Discovery
Brage was discovered in 1980 by well 31/4-3. Two separate hydrocarbon-bearing sandstone intervals were encountered. The Oxfordian to Kimmeridgian Sognefjord Formation proved oil and gas with the OWC between 2023 - 2029 m TVD MSL. The Callovian Fensfjord Formation was oil bearing with a possible OWC at 2148 m TVD MSL. In 1984, appraisal well 31/4-7 proved oil in Statfjord Formation west of the main field in a horst structure with a higher reservoir pressure[4]. In addition, the near-by well 31/4-2 on the northern part of the Brage Horst proved oil and gas in the Brent Group. The field also has proven oil and gas accumulation in A-13 E Sognefjord East (Kimmeridgian sandstones, the Kim discovery).

Reservoir
The Brage Field is part of a series of Middle Jurassic highs located on the Bjørgvin Arch, between the Viking Graben to the West and the Horda Platform to the East. Brage mainly produces oil from sandstones of Late Jurassic Sognefjord Formation and of the Early Jurassic Statfjord Group. Sandstones of Middle Jurassic age in the Brent Group and the Fensfjord Formation also produce oil and gas[4]. The Brage field is a low relief structural trap, consisting of a narrow horst structure at the west of the Field and a larger sector located downflank and east of the horst. The main sector contains the Fensfjord and the overlying Sognefjord deposits (containing oil and gas in respective Formations). Here, Sognefjord Formation is mainly distributed in the central and northeast part of the main sector in Brage. The northern part of the Brage horst consist of Bowmore, Knockando and Talisker (East and West) deposits/structures: Bowmore contains oil and gas in Fensfjord Formation, Sognefjord Formation and Lower Oseberg Formation, in the Brent Group. Knockando and Talisker segments contain oil and gas in the Oseberg Formation of the Brent Group. The central and southern part of the Brage horst consist of two deposits/structures: the Statfjord and the Cook deposits, both containing oil and gas in respective Formations.[4][8] The Sognefjord East deposit (former Kim discovery) in the south consist of oil and gas in the Sognefjord Formation. In general, the reservoir quality varies from poor to excellent[4] and there is no communication between the reservoirs and structural elements. In addition, gas has been proven in thin chalk intervals of the Shetland Group, overlying the main sector of Brage.

Development
The drainage strategy is water injection in Statfjord, Fensfjord and Brent, and depletion with pressure support from aquifer in Sognefjord. In Sognefjord there is also a small gas cap. Older wells are slanted while the newer ones are mostly horizontal. Gas lift is used in most of wells to maintain production at high water cuts and improve recovery.

Brage has been developed with a fixed integrated production, drilling and accommodation facility on a steel jacket. The platform has 40 well slots. The oil is transported by pipeline to Oseberg and through the Oseberg Transport System (OTS) pipeline to the Sture terminal in Norway. The gas export pipeline is tied back to Statpipe gas line with the gas being processed at the onshore Kårstø gas plant before export to Europe.

<u>Technical lifetime of the wells and facilities</u>

In 2013 the Licence period was extended to 2030. At that time, the facilities were assessed to last at least for such a period, provided proper maintenance. Brage have experienced some technical integrity issues, and corrosion is still considered as a major risk.Although not formally decided, OKEA has an ambition to increase the technical lifetime beyond 2030, and has hence increased both the onshore and the offshore work force with a corresponding impact on the yearly operating cost.

Status
The Brage Field has been producing for more than 30 years. A continuous drilling and well maintenance program is necessary in order to maintain production due to high water-cut in many of the producers. The field production is currently constrained by gas processing capacity.

There are currently 25 active wells; 17 oil and gas producers, 5 water injectors, 2 Utsira water producer providing injection-water and 1 cuttings re-injection well.

Brage average field 2024 oil production rate was approximately 13 000 stb/d, with a water-cut of 93%. The 2024 production is higher than the 2023 production mainly due to higher production from the Talisker East development project. Production efficiency (availability) achieved up to mid-October 2024 is at 94%, whilst the planned availability was 92%.

Three new development wells, two producers and one water injector, have been brought on stream during 2024. Water injection in Talisker East (A-40C) was successfully started in February and the 2nd Talisker East producer (A-21A) was put on production in May. The 1st Talisker East producer (A-11E), put on production in 2023, is currently the highest volume Brage producer accounting for more than 40% of the total field oil production. An infill production well in Fensfjord northern area, also named Bowmore (A-28 DT2), was put on stream in December 2024.

A combined production (A-23 H) and appraisal well (A-23 F & G, into Prince prospect) project to develop the Sognefjord East area, is ongoing. The oil producer is located in the Kim-area south on the field. The Kim deposit was discovered by the A-13 E in Q3 2023 and an application for PDO exemption is currently with the Authorities. A new licence PL055FS in the Kim Area was awarded to the Brage Unit on 15.11.2024. Production start-up from this producer is foreseen in the middle of 2025.

Petroleum Initially in Place (PIIP)
The PIIP estimates as of 31.12.2024 are shown in Table 3.12.

Table 3.12 Brage PIIP estimate as of 31.12.2024 (source:Norwegian Offshore Directorate)

	PIIP, 31.12.2024 (Best Estimate)
Oil/condensate (MMbbl)	1101
Gas (BScf)	777

Production and cost profiles presented by Lime
The recoverable volumes from Bestla are classified as Reserves and Contingent Resources according to PRMS.

The Reserves include the following projects:

- Brage Base production:
  - Production from existing wells
  - Talisker East Development: A-21 A producer and A-40 C water injector well pair
- A Fensford well (Fensfjord5000, planned production November 2025)
- Brage Bowmore (Well A-28 DT2, production start-up December 2024)
- Sognefjord East first producer (well A-23 H is planned for July 2025)

The Contingent Resources include the following projects:

- Development Pending
  - Two producers in Talisker, DG4 March 2026
- Development On Hold
  - Brage Extended Lifetime (year 2032 - 2035), from existing producers
  - Brage unit IOR infill wells (one Brent Bowmore producer and one Statfjord SN Attic oil producer)
- Development Unclarified
  - Brage Unit EOR (CO2 injection in Statfjord and Sognefjord)
  - Sognefjord Template Project (potential in Brage north-east area)
  - Brage unit IOR upside (immature infill well project)
  - Shetland (gas in chalk)

Description of the production profiles

The forecast for the main producing phase (oil) is shown in Fig. 3.4.

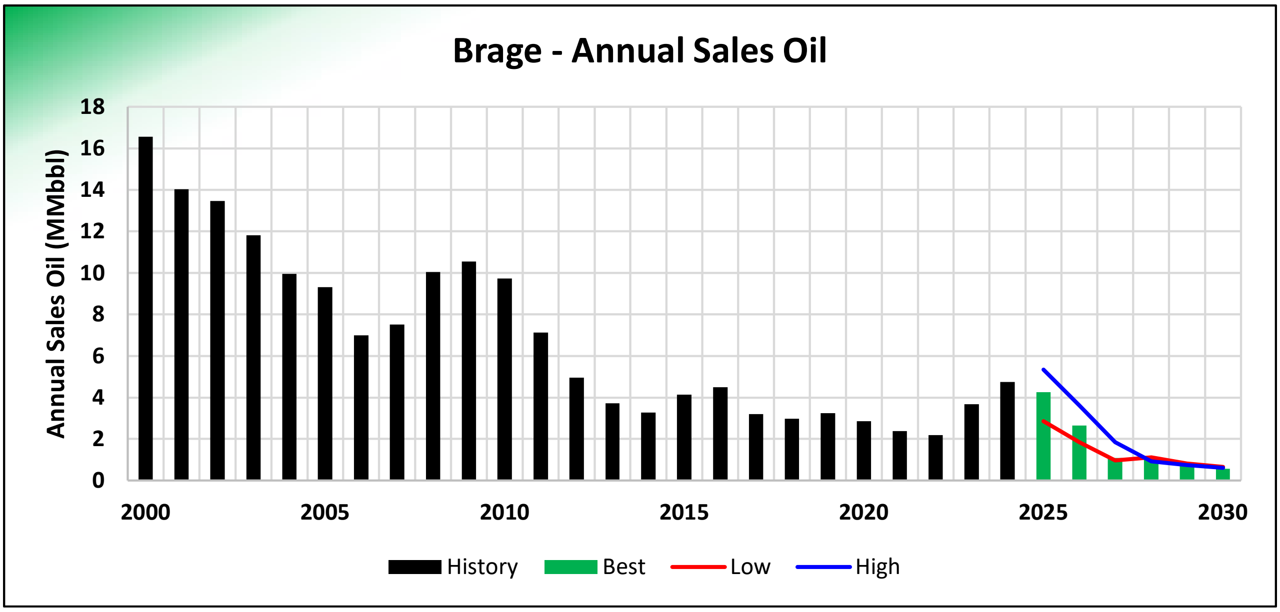

Fig. 3.4 Production Forecast - Brage

- Lime's basis for the forecast is production profiles from DCA in combination with history matched dynamic reservoir simulation model for existing wells with less production history, as for the Operator.
- Production profiles for future infill/re-drill is based on a combination of ensemble realizations from history matched dynamic reservoir simulation model and analogue well performance.
- The field production is constrained by gas processing capacity.
- Bestla is included in the base profile as a reduction in gas capacity.

Description of the cost profiles

- The cost profiles applied by Lime in Statement of Reserves [7] are in line with the Brage RNB2025 [8] and the work program and budget (WP&B), The CAPEX and OPEX profiles are based on experienced cost from recent years. The OPEX reflects the ambition to extend the technical lifetime beyond 2030.

Reserves and contingent resources audited by AGR
Comments to production profiles

AGR has reviewed Lime's asset presentation and available documentation including licence meeting handouts, RNB2025[8], Lime Statement of Reserves[7], Brage Long Term Plan 2024 and Lime's decline curve analysis.

- AGR has checked the DCA from the Operator and from Lime, and found them both reasonable. The DCA from Lime and the Operator is well aligned.
- Reservoir quality varies from poor to excellent in Fensfjord, Statfjord, Brent and Sognefjord formations, facing individual challenges in terms of pressure support, productivity, water cut development and drainage efficiency.
- AGR acknowledges that a continuous drilling and well maintenance program is required to maintain production, and that the field production is constrained by gas processing capacity.
- The profiles presented by Lime differ slightly from the RNB2025 profiles, with 6% higher oil volumes and with less gas and NGL. However, the total oil equivalent volumes are similar.
- In AGR's views, the production profiles presented by Lime are an acceptable basis for Reserves determination.

Comments to contingent resources

The contingent resources have limited documentation regarding volumes and target areas for the potential wells. These wells are at an early stage of evaluation, and estimates of contingent resources are likely to be revised as these opportunities are matured further. AGR considers that there is a low probability of commercial success for many of these projects; in particular the two contingent resource projects with the highest impact on resources (ref. Table 3.14).

- Brage Unit EOR
- Sognefjord Template Project

Comments to facilities and cost profiles

- The cost profiles applied by Lime are based on the Brage RNB2025 and the WP&B 2025. The WP&B includes the cost of several not yet sanctioned wells. There will be no drilling in 2026 due to the tie-in activities of Bestla.
- The technical lifetime of the facilities is assumed in RNB2025 to be 2031. OKEA has increased the efforts to extend the technical lifetime. The associated cost for lifetime extension is reflected in the OPEX.
- The production regularity is currently good, however, Brage has been in production since 1993 and may in the future experience issues due to the ageing facilities which could potentially have an impact on the OPEX and regularity of the facilities.
- AGR has reviewed these costs in light of historical cost on Brage and found the costs presented to be reasonable.

Economic evaluation and reserves determination

AGR has performed an economic evaluation to determine the reserves with the economic assumptions shown in Appendix A.1 Summaries of Oil and Gas Reserves and Resources. The technical project production and cost profiles have been evaluated to ensure project commerciality and the correct economic cut-off. The Brage and Bestla fields are considered as a Hub and economic cut-off is thus determined by jointly evaluating the two fields forecasts when running the economics. This leads to a much later economic cut-off for Brage compared to Brage on a stand-alone basis. The resulting TRR and gross reserves are shown in Table 3.13 below. Gross and net to Lime contingent resources are shown in Table 3.14(please note that contingent resources are not subject to an economic evaluation or economic limit test). Net to Rex reserves and net contingent resources are found in 1 Executive Summary and A.1.2 Brage - Summary of Oil and Gas Reserves and Resources.

- For the Base price scenario, the economic cut-off is:
  - 1P: end of 2031, same as technical cut-off
  - 2P: end of 2031, same as technical cut-off
  - 3P: end of 2031, same as technical cut-off
- The reserves are classified according to PRMS as follows:
  - "On Production": Production from existing wells
  - "Approved for Development": A-23 H Sognefjord East well and F5000 Fensfjord well

The economic lifetime of Brage may potentially be extended beyond the current economic cut-off date through further drilling (maturation of contingent resources), optimisation of production and operating costs and a lifetime extension of the production facilities.

Changes in Reserves and Contingent Resources since audit 31.12.2023

The gross Brage balance sheet for reserves is shown in Table 3.15 below and for contingent resources in Table 3.16 below. The decrease in gas reserves is due to the Brage field going gas negative in the final years, meaning gas produced on Brage is less than what is needed for fuel and flare (this may be alleviated by purchasing gas from Bestla for use as fuel).

Changes to Reserves since audit 31.12.2023:

- Production in 2024
- New projects
  - Brage Bowmore
  - Fensfjord5000
  - Sognefjord East first producer
  - Effect of Bestla tie-in (negative), included in base
- Revisions:
  - Economic cut-off is now later for 1P, 2P and 3P due to the effect of Bestla (hub effect)

Changes to Contingent Resources:

- New projects
  - Brage unit IOR upside
  - Brage Unit EOR
  - Sognefjord Template project
- Revisions
  - Contingent projects matured to Reserves (Fensfjord F5000 well and A-23H Sognefjord East well)
  - Revisons to volume estimates for some of the contingent resource projects
  - Some projects removed (Climate response project, Sognefjord East 2 projects)

Comments to recovery factors and reserve ranges

- The oil and gas recovery factors are shown in Table 3.17 below. The modest overall recovery factor reflects the variety of reservoir quality from poor to excellent in Fensfjord, Statfjord, Brent and Sognefjord formations, with varying degrees of individual drainage efficiency. AGR considers the recovery factors to be reasonable taken into account the complexity of the field. It is, however, significantly lower than the average of approximately 47% for an oil field on the NCS. Note that the low recovery for gas shown is influenced by the consumption for fuel (reported recovery factor only takes into account sales volumes)
- The oil equivalent uncertainty range is -40%/+37% versus 2P (Table 3.13). The uncertainty range is high, but reflect the uncertainty in new projects and the complexity of the field.

Conclusions

- AGR considers that the PIIP presented by Lime is acceptable.
- The recovery factors shown are modest but reasonable considering the complexity of the field and compared to NCS fields with similar drainage strategies.
- An uncertainty range in recoverable oil equivalent volumes is high, but reasonable, considering introduction of new uncertain projects, complexity of the field and sensitivity to commercial cut-off.
- AGR finds the costs figures presented reasonable to be used for economic analyses.
- AGR considers the two Contingent Resource projects with the highest impact on resources (Brage Unit EOR and Sognefjord Template Project) to have a low probability of commercial success.
- The Brage Reserves and Contingent Resources reported by Lime are well documented and based on sound industry practice. The profiles differ slightly from the RNB2025, although the total hydrocarbons reserves are similar.
- AGR endorses the Brage Reserves and Contingent Resources as reported by Lime in the Lime Statement of Reserves[7].

Table 3.13 TRR and reserves as of 31.12.2024 - Brage

	TRR (Gross 100 %)			Reserves (Gross 100 %)			Reserves (Net Lime, 33.8434%)*		
	Low	**Best**	**High**	**1P**	**2P**	**3P**	**1P**	**2P**	**3P**
1st Production	23 September 1993								
Cut-off (year-end)	2031	2031	2031	2031	2031	2031	2031	2031	2031
Oil/condensate (MMbbl)	8.65	11.00	13.72	8.65	11.00	13.72	2.93	3.72	4.64
Gas (BScf)	3.61	7.09	10.58	3.61	7.09	10.58	1.22	2.40	3.58
NGL, (MMboe)	0.03	0.16	0.43	0.03	0.16	0.43	0.01	0.05	0.15
Total (MMboe)	**9.33**	**12.42**	**16.03**	**9.33**	**12.42**	**16.03**	**3.16**	**4.20**	**5.43**

* Net reserves in Table above are net to Lime. Rex's share in Lime is 80.14%. For reserves net to Rex, see 1 Executive Summary and A.1.2 Brage - Summary of Oil and Gas Reserves and Resources.

Table 3.14 Gross and net to Lime Contingent Resources as of 31.12.2024 - Brage

Brage		GROSS (100%)			Net to Lime (33.8434%)*		
Contingent Resources (MMboe)	**PRMS subclass**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
Brage Unit EOR	Development Unclarified	6.72	13.45	20.17	2.28	4.55	6.83
Brage unit IOR infill wells	Development Unclarified	1.15	2.45	3.99	0.39	0.83	1.35
Talisker	Development Pending	2.29	4.65	7.16	0.78	1.57	2.42
Sognefjord template project	Development Unclarified	6.87	13.74	20.62	2.33	4.65	6.98
Brage unit IOR upside	Development Unclarified	3.75	6.56	10.74	1.27	2.22	3.63
Shetland	Development Unclarified	0.00	0.94	2.52	0.00	0.32	0.85
Brage Extended Lifetime	Development Unclarified	-0.75	0.08	0.87	-0.25	0.03	0.29
Total, MMboe		**20.03**	**41.87**	**66.06**	**6.78**	**14.17**	**22.36**

Sum of total may not add up to sum of individual resources due to rounding

* Net contingent resources in Table above are net to Lime. Rex's share in Lime is 80.14%. For contingent resources net to Rex, see 1 Executive Summary and A.1.2 Brage - Summary of Oil and Gas Reserves and Resources.

Table 3.15 Balance sheet - Brage Reserves (100%)

Gross reserves balance, 31.12.2023 - 31.12.2024, for Brage (100%)							
Reserves class	**Status 31.12.2023**	**Production (Positive)**	**Revisions**	**Acquisitions or sales**	**IOR**	**Discoveries/ New Projects**	**Status 31.12.2024**
Oil and condensate (MMbbl)							
1P	6.03	4.76	5.77	-	-	1.61	8.65
2P	8.23	4.76	4.30	-	-	3.23	11.00
3P	11.28	4.76	2.36	-	-	4.84	13.72
Gas (BScf)							
1P	7.61	7.80	1.49	-	-	2.31	3.61
2P	11.90	7.80	-1.62	-	-	4.61	7.09
3P	16.00	7.80	-4.54	-	-	6.92	10.58
NGL (MMboe)							
1P	0.40	0.50	0.01	-	-	0.14	0.03
2P	0.66	0.50	-0.28	-	-	0.28	0.16
3P	0.88	0.50	-0.37	-	-	0.42	0.43
Oil equivalents (MMboe)							
1P	**7.79**	**6.65**	**6.03**	-	-	**2.16**	**9.33**
2P	**11.01**	**6.65**	**3.73**	-	-	**4.33**	**12.42**
3P	**15.01**	**6.65**	**1.18**	-	-	**6.49**	**16.03**

Table 3.16 Balance sheet - Brage Contingent Resources (100%)

Gross contingent resource balance, 31.12.2023 - 31.12.2024, for Brage_CR (100%)							
Resource category	**Status 31.12.2023**	**Production (Positive)**	**Revisions**	**Acquisitions or sales**	**IOR**	**Discoveries/ New Projects**	**Status 31.12.2024**
Oil equivalents (MMboe)							
1C	6.20	-	-3.51	-	10.47	6.87	20.03
2C	12.64	-	-4.52	-	20.01	13.74	41.87
3C	22.12	-	-7.59	-	30.91	20.62	66.06

Note: Revisions include projects that have moved from Contingent Resources to Reserves. New projects are Sognefjord Template and Brage Unit EOR.

Table 3.17 Brage P50 Recovery Factors

	Oil 31.12.2024	**Oil at EUR**	**Gas 31.12.2024**	**Gas at EUR**
Produced (MMbbl/ Bscf)	388	398	166	169
Recovery factor	35%	36%	21%	21%

3.3 Bestla

Asset Overview
The Bestla Field (previously named Brasse) is an oil and gas field located in production licence PL 740 approximately 13 km South of the Brage Field and 13 km East of the Oseberg Sør Field in the North Sea. A location map of the field is shown in Fig. 3.5. The Plan for Development and Operation (PDO) was approved in November 2024. Water depth in the area is about 120 m TVD MSL. The depth of the reservoir is near 2200 m TVD MSL. The current licence shares are reflected in Table 3.19.

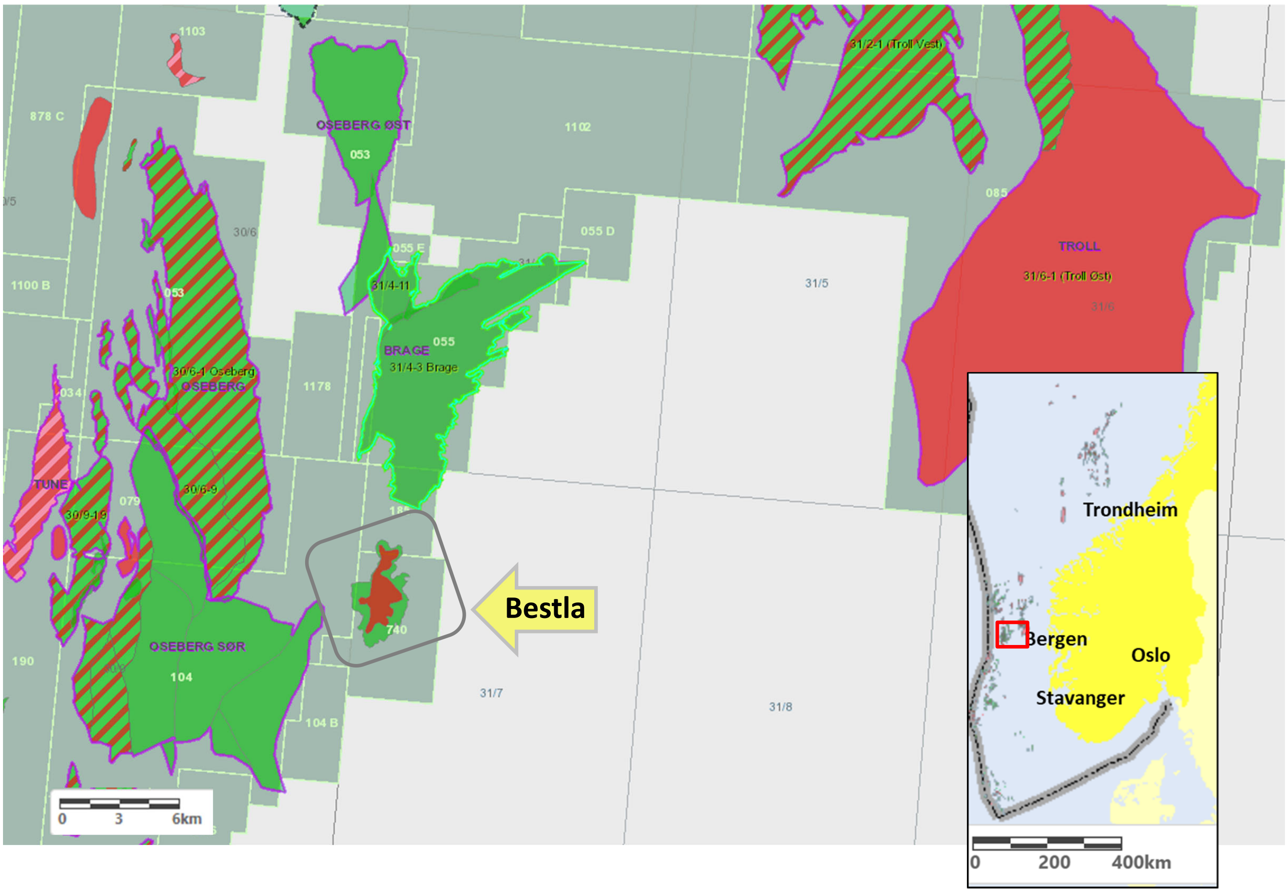

Fig. 3.5 Bestla Field location map
Source: Norwegian Offshore Directorate (NOD) factmaps (www.sodir.no)

This audit of reserves and contingent resources has been based on the information provided by Lime, which included Lime's Statement of Reserves (SoR)[9], the Operator's RNB2025 submission[10], meeting documents (RC, TC, MC) from 2024, monthly status reports for 2024, work program and budget (WP&B) 2025, Brasse DG3 subsurface support Document, Bestla PDO as well as Lime's answers to AGR's questions and clarification requests (Q&A).

Licence details summary is shown in Table 3.18. The production licence give the licences full rights to explore and produce hydrocarbons at all stratigraphic levels within the licence area.

Table 3.18 Bestla summary table

Asset name/ Country	Lime's interest (%)	Development Status	Licence expiry date	Licence Area (km2)	Type of mineral, oil or gas deposit	Remarks
PL 740 (Bestla) / Norway	17.0000	Development Approved	07.02.2024*	55	Oil and gas	-

** Licence extension for full existing PL740 license area was applied for in February 2024, prior to submittal of Bestla DG3/PDO. PDO was approved in November 2024. According to Lime, the Norwegian Offshore Directorate (NOD/Sodir) has indicated that the licence extension approval can be expected before the summer of 2025.*

The Bestla licence shares are listed in Table 3.19.

Table 3.19 Bestla licence shares (%)

Licence	OKEA ASA (Op)	DNO Norge AS	M Vest Energy AS	Lime Petroleum AS
PL 740 (Bestla)	39.2788	39.2788	4.4424	17.0000

Discovery
Bestla Field was discovered in 2016 by well 31/7-1. The well confirmed gas and oil in Late Jurassic, Oxfordian to Kimmeridgian/Volgian, sandstones and siltstones of the Sognefjord Formation, Viking Group. The structure has been penetrated by six wellbores in total. No wells are drilled in the West segment. The reservoir depth is approximately at 2200 m TVD MSL. An 18 m gas column and 24.4 m oil column were identified and the MDT pressure data proved an OWC at 2172 m TVD MSL, and a general Gas Oil Contact (GOC) at 2148 m TVD MSL [4].

Reservoir
The Bestla Field is a 14 km2 low relief, three-way dip closure with a stratigraphic pinchout to the north as result of the north-south oriented fault block rotation and erosion. The Field consists of three segments: Bestla Main, Bestla North and Bestla West.

The reservoir rock is the Upper Jurassic (Oxfordian-Kimmeridgian) Sognefjord Formation. Net reservoir and net pay are variable from excellent in the south to poor in the north. The Sognefjord reservoir sands were deposited in marginal to shallow marine environment with several cyclical events in the form of regressive cycles (dominated by deltas front, mouth bars) and transgressive cycles (characterised by tidally influenced lobes and tidal bars). The Kimmeridgian reservoir is limited to the north-eastern area only (31/7-3 S). Well 31/7-3 A, drilled in the northern area of Bestla, encountered reservoir intervals filled with different oils (34 ° API) compared to all reservoir levels in the main area to the south (36°API). These sand intervals have been interpreted as smaller local closures separated from the main area to the south. In general, the reservoir properties vary from excellent in southern area to poor in north, with the average porosity for the zones in the range of 16 - 24% and permeability varies in the range of 50 mD and 5 D (up to 13 D).

The appraisal wells have shown that Bestla in 2018 was depleted by approximately 20 bar (~2 bar/year which is still ongoing). This pressure depletion, observed in all six wells drilled in Bestla, is considered to be caused by production from the giant Troll Field, located approximately 35 km northeast, and connected to Bestla via a massive regional aquifer.

Development
Bestla will be developed as a 13 km subsea tie back to the Brage field host facility. The drainage strategy is depletion, with the aquifer as the primary and the gas cap as secondary support. The development plan comprises two horizontal oil producers in the main segment approximately centered in the 24 m oil column. Bestla West appraisal is planned as a pilot drilled from the first oil producer, and if successful, the producer will be configured as a 2-branch multilateral with one lateral in Bestla West and mainbore in Bestla Main.

The two satellite wells will produce commingled through a common manifold and back to the Brage Field through a 10-inch Pipe-in-Pipe flowline for processing on the Brage platform. From Brage, the oil will be transported by pipeline to Oseberg and through the Oseberg Transport System (OTS) to the Sture terminal in Norway. The gas will be exported via a tie back to the Statpipe gas line with gas processing at the onshore Kårstø gas plant before export to Europe.

Technical lifetime of the wells and facilities

The design life of the Bestla wells and subsea facilities is expected to be sufficient for the current and potentially extended production life of Brage. Current production life is 2031, same as the technical lifetime of Brage. The Bestla lifetime may however be extended as a result of the ongoing lifetime extension activities on Brage.

Status
The PDO was sanctioned by the authorities 19 November 2024. In that connection the name was formally changed from Brasse to Bestla. Production commencement is planned for first quarter 2027.

Petroleum Initially in Place (PIIP)
The PIIP estimate as of 31.12.2024 is shown in Table 3.20. The Total PIIP estimates are based on the stochastic P90/P50/P10 volumes presented in the PDO. These are derived from the full field reservoir model for DG2, using the re-processed CGG Horda Multi-client survey for the seismic interpretation. The model is updated with the re-evaluation of the CGG23M03 for DG3 in 2023 and includes the results from all drilled wells. The PIIP linked to Reserves corresponds to the PIIP in the Main segment only. The PIIP in North segment is part of the discovered resources, but it is not linked to a plan for development and the West segment is considered prospective (un-discovered resources).

Table 3.20 Bestla PIIP estimate as of 31.12.2024 (source: Lime)

	PIIP, 31.12.2024 (Best Estimate)
Oil/Condensate (MMbbl)	55.4
Gas (BScf)	82.8

Production and cost profiles presented by Lime
The recoverable volumes from Bestla are classified as Reserves and Contingent Resources according to PRMS.

The Reserves include the following projects:

- Bestla base (with two wells in main segment). Technical cut-off date December 2031, same as Brage.

The Contingent Resources include the following projects:

- Bestla Extended Lifetime (Brage LTE) from January 2032 to end 2035, same as Brage.

Description of the production profiles

The forecast for the main producing phase (oil) is shown in Fig. 3.6.

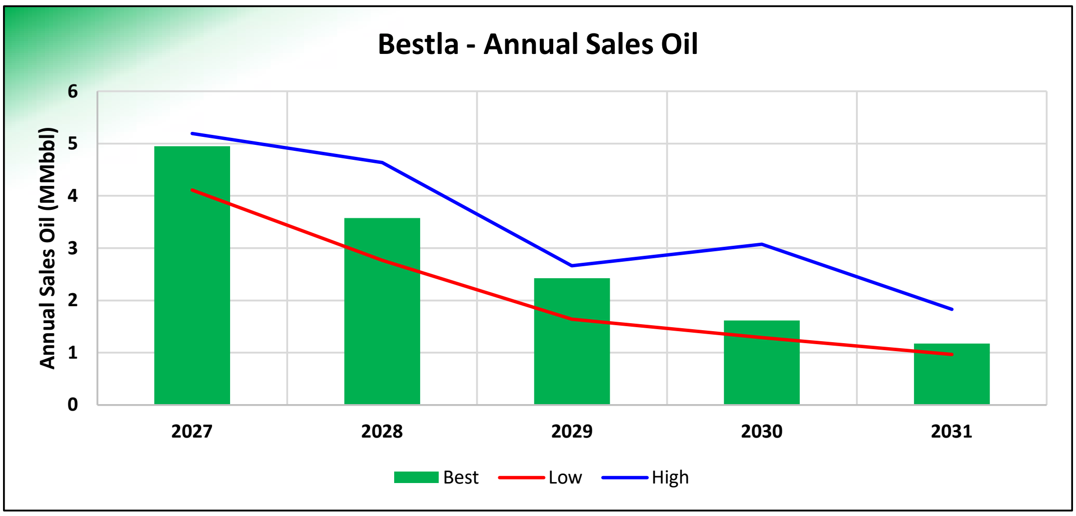

Fig. 3.6 Production Forecast - Bestla

- The production profile is based on a Bestla full field reservoir simulation model.
- The simulation model covers Bestla Main, North and West segments. The two producers are completed only in the Main segment. The potential volumes from North and the prospective West segment are not included in the base production profile for this audit.
- The pressure communication and inflow from North and West segments into main segment, is limited.
- Bestla is planned to come on stream January 2027 and production ends year-end 2031, in alignment with Brage.
- There is a term sheet agreement in place where Brage is compensated in cash due to gas processing limitations (i.e. no deferral profile).

Description of the cost profiles

- The Bestla PDO was approved in November 2024 with a cost estimate in line with the DG3 cost estimate.

Reserves and Contingent Resources audited by AGR

Comments to PIIP

AGR has reviewed the following documentation: Bestla RNB2025, Lime Statement of Reserves and Bestla PDO, with the following comments. Note that neither static nor dynamic models were available and therefore these are not evaluated by AGR.

- The PIIP is consistent with the volumes reported in the RNB2025.
- AGR agrees on the main uncertainties described by the Operator and considers that the following factors may constitute additional uncertainty:
  - The large, lateral heterogeneity of the reservoir rocks (deltaic depositional environments) could reduce the total PIIP by incorporating poorer properties to the average porosity values.
  - The vertical isolation of reservoirs, given the extensive shales that might be deposited at every maximum flooding surface.
  - Oil of type of Brage Sognefjord interval found in 31/7-3 A. AGR suggests that this may be a sign of communication between the northern segment of Bestla and the Brage Field.
- Based on the documentation reviewed, AGR believes that PIIP estimate presented by Lime is reasonable. AGR considers that only the PIIP from the Main segment of Bestla is associated with Reserves.

Comments to production profiles

AGR has reviewed Lime's asset presentations, available documentation including licence meeting handouts, Brasse DG3 subsurface report, Lime Statement of Reserves and RNB2025.

Comments to Bestla Base (with two wells in main segment). Technical cut-off date December 2031, same as Brage:

- The two planned development wells are located in the main segment which is the primary target. The simulation model suggests very limited pressure communication and inflow from North and West segments into main segment (assessed to approximately 5% of the P50 volumes in the North and West segments, respectively).
- There are several parameters indicating a more complex reservoir that could potentially influence drainage efficiency and the recovery of volumes, such as:
  - Reservoir properties are deteriorating from excellent in southern area to poor in the northern area.
  - The formation pressure analysis indicates some degree of vertical baffling between the different reservoir sands. This can be explained by the existence of a total of four maximum flooding surfaces within Sognefjord Formation proven by biostratigraphy analyses indicating the presence of extensive, lateral transgressional shales. These might vertically isolate each reservoir.
  - Pressure depletion induced by the production from Troll has resulted in current reservoir pressure

  - which varies slightly across the field.
  - GOC and OWC are not flat surfaces, but vary locally as a function of pressure (depletion) and reservoir properties.
- Relative permeability is also considered an area with large uncertainty, according to the uncertainty study in the PDO.
- Low relief structure in combination with a thin oil column (~24 m) with a gas cap may be challenging in terms of effective sweep and oil recovery.
- The short planned production lifetime of five years emphasise the importance of schedule risk. Lifetime extension will reduce this risk.
- A two-well development relies on high availability of both wells to secure the TRR volumes.
- The profile presented by Lime differs from the RNB2025 profiles which include the prospective volumes from the West segment. The audited profile only includes resources from the proven main segment in accordance with the PRMS reserves definition.
- In AGR's opinion the production profiles presented by Lime are reasonable.

<u>Comments to contingent resources</u>

- The high oil equivalent volume (3C) is lower than the base (2C). This may be an effect of the methodology for picking the low, base and high, which picks the runs according to cumulative oil. Arbitrarily, the low gas volume in the high case caused the sum of the hydrocarbons to be lower than the base.

<u>Comments to facilities and cost profiles</u>

- The costs applied by Lime are identical to the RNB2025 [10] and in line with the Work Program & Budget (WP&B). AGR finds the applied costs for the Bestla development reasonable.

<u>Economic evaluation and reserves determination</u>

AGR has performed an economic evaluation to determine the reserves with the economic assumptions shown in appendix A.1 Summaries of Oil and Gas Reserves and Resources. The technical project production and cost profiles have been evaluated to ensure project commerciality and the correct economic cut-off. The Brage and Bestla fields are considered as a Hub and economic cut-off is thus determined by jointly evaluating the two fields forecasts when running the economics. The resulting TRR and gross and net to Lime reserves are shown in Table 3.21 below. Gross and net to Lime contingent resources are shown in Table 3.22 (please note that contingent resources are not subject to an economic evaluation or economic limit test). Net to Rex reserves and net to Rex contingent resources are found in 1 Executive Summary and A.1.3 Bestla - Summary of Oil and Gas Reserves and Resources.

- The Bestla development project is confirmed commercial
- For the Base price scenario, the economic cut-off is:
  - 1P: end of 2031, same year as technical cut-off
  - 2P: end of 2031, same year as technical cut-off
  - 3P: end of 2031, same year as technical cut-off
- The reserves are classified according to PRMS as follows:
  - Approved for Development

Gross Contingent Resources are shown in Table 3.22 below.

<u>Changes in Reserves and Contingent Resources since audit 31.12.2023</u>

The gross Bestla balance sheet for Reserves and Contingent Resources is shown in Table 3.23 and Table 3.24.

- The PDO was approved by the authorities November 2024. The profiles for the year 2027-2031 are thus reclassified from contingent resources to reserves (PRMS class "Approved for Development").
- The base profile is extended with one year (from four to five years).

Comments to recovery factors and resource ranges

- The oil and gas recovery factors are shown in Table 3.25 (excluding lifetime extension). The oil recovery factor is 25% based on the STOIIP of the main segment (development area). The oil recovery factor is lower than average on the NCS, but reasonable taken into account thin oil column, variable reservoir properties, drainage by depletion only and pressure depletion from Troll Field.
- The oil equivalent uncertainty range is -21%/+21% versus 2P (Table 3.21). The range is narrow for a project at this maturity level, but considered reasonable given the low overall recovery factor.

Conclusions

- AGR considers the PIIP presented by Lime to be acceptable, with only the Bestla Main segment linked to Reserves. Bestla North segment is not part of the development. Bestla West segment is a prospect, but with high probability of discovery.
- The short planned production lifetime of five years emphasises the importance of schedule risk. Lifetime extension will reduce this risk.
- A two-well development relies on high availability of both wells to secure the TRR volumes.
- The Bestla Reserves and Contingent Resources reported by Lime are well documented and based on sound industry practice.
- The Reserves definition is not consistent with RNB2025, which also includes the prospective resources from the West segment. For the audited Reserves, contribution from the West segment is excluded.
- AGR endorses the Bestla Reserves and Contingent Resources, as reported in Lime's Statement of Reserves [9].

Table 3.21 TRR and Reserves as of 31.12.2024 - Bestla

	TRR (Gross 100 %)			**Reserves (Gross 100 %)**			**Reserves (Net Lime, 17%)***		
	Low	**Best**	**High**	**1P**	**2P**	**3P**	**1P**	**2P**	**3P**
1st Production	01.01.2027								
Cut-off (year-end)	2031	2031	2031	2031	2031	2031	2031	2031	2031
Oil/condensate (MMbbl)	10.77	13.73	17.39	10.77	13.73	17.39	1.83	2.33	2.96
Gas (Bcf)	26.94	33.28	37.17	26.94	33.28	37.17	4.58	5.66	6.32
NGL, (MMboe)	1.64	2.03	2.27	1.64	2.03	2.27	0.28	0.35	0.39
Total (MMboe)	**17.21**	**21.69**	**26.28**	**17.21**	**21.69**	**26.28**	**2.93**	**3.69**	**4.47**

* Net reserves in Table above are net to Lime. Rex's share in Lime is 80.14%. See 1 Executive Summary and A.1.3 Bestla - Summary of Oil and Gas Reserves and Resources for reserves net to Rex.

Table 3.22 Gross and net to Lime Contingent Resources as of 31.12.2024 - Bestla

Contingent Resources (MMboe)		**GROSS (100%)**			**Net to Lime (17%)***		
Resources	**PRMS subclass**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
Extended Lifetime	Development On Hold	2.73	4.45	4.15	0.46	0.76	0.71
Total, MMboe		2.73	4.45	4.15	0.46	0.76	0.71

* Net contingent resources in Table above are net to Lime. Rex's share in Lime is 80.14%. See 1 Executive Summary and A.1.3 Bestla - Summary of Oil and Gas Reserves and Resources for contingent resources net to Rex.

Table 3.23 Balance sheet - Bestla Reserves (100%)

Gross reserves balance, 31.12.2023 - 31.12.2024, for Bestla (100%)							
Resource class	**Status 31.12.2023**	**Production (Positive)**	**Revisions**	**Acquisitions or sales**	**IOR**	**Discoveries/ New Projects**	**Status 31.12.2024**
Oil and condensate (MMbbl)							
1P	-	-	-	-	-	10.770	10.770
2P	-	-	-	-	-	13.732	13.732
3P	-	-	-	-	-	17.392	17.392
Gas (Bscf)							
1P	-	-	-	-	-	26.936	26.936
2P	-	-	-	-	-	33.278	33.278
3P	-	-	-	-	-	37.172	37.172
NGL (MMboe)							
1P	-	-	-	-	-	1.644	1.644
2P	-	-	-	-	-	2.031	2.031
3P	-	-	-	-	-	2.268	2.268
Oil equivalents (MMboe)							
1C	-	-	-	-	-	**17.211**	**17.211**
2C	-	-	-	-	-	**21.690**	**21.690**
3C	-	-	-	-	-	**26.281**	**26.281**

Table 3.24 Balance sheet - Bestla Contingent Resources (100%)

Gross contingent resource balance, 31.12.2023 - 31.12.2024, for Bestla_CR (100%)							
Resource class	**Status 31.12.2023**	**Production (Positive)**	**Revisions**	**Acquisitions or sales**	**IOR**	**Discoveries/ New Projects**	**Status 31.12.2024**
Oil equivalents (MMboe)							
1C	19.94	-	-17.21	-	-	-	2.73
2C	26.14	-	-21.69	-	-	-	4.45
3C	30.43	-	-26.28	-	-	-	4.15

Table 3.25 Bestla 2P Recovery Factors

	Oil 31.12.2024	**Oil at EUR**	**Gas 31.12.2024**	**Gas at EUR**
Produced (MMbbl/ Bscf)	-	13.7	-	33.3
Recovery Factor	-	25%	-	40%

3.4 PL838 Lunde

Asset Overview
Lunde is an oil discovery with a gas cap. The discovery is named Shrek in the Norwegian Offshore Directorate's Factpages, but the licence has chosen to rename the discovery Lunde. The Lunde discovery is located in production licence PL 838, approximately 5 km south-east of the Skarv Field in the Norwegian Sea. A location map of the field is shown in Fig. 3.7. The water depth in the area is about 350-400 m. The reservoir depth is at about 1970 m TVD MSL.

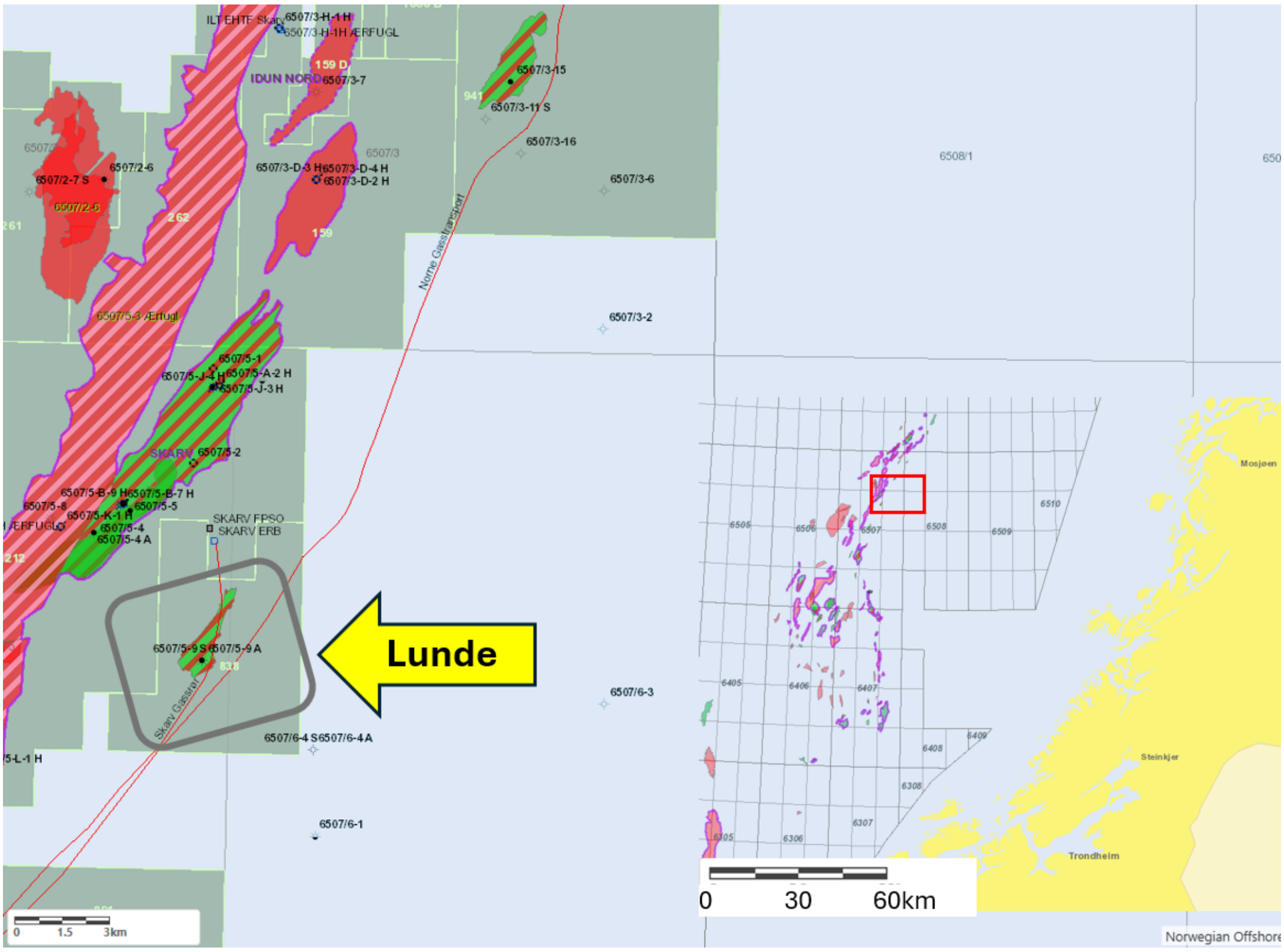

Fig. 3.7 Lunde Discovery location map
Source: Norwegian Offshore Directorate (NOD) factmaps (www.sodir.no)

The PL 838 licence was awarded in 2016 to a licence group consisting of Tullow, DEA and PGNiG, with PGNiG as Operator. The Lunde discovery was made in 2019. Lime farmed in to the licence in 2019 after the Lunde discovery well was drilled. In April 2020, Operatorship changed to Aker BP ASA. The current licence shares are shown in Table 3.27.

The DG3 milestone was postponed by AkerBP with a planned DG3/FID in Q1 2025. This has however recently been postponed further with an DG3/FID now expected in early 2026.

Licence details summary is shown in Table 3.26. The production licence give the licences full rights to explore and produce hydrocarbons at all stratigraphic levels within the licence area.

Table 3.26 Lunde summary table

Asset name/ Country	Lime's interest (%)	Development Status	Licence expiry date	Licence Area (km2)	Type of mineral, oil or gas deposit	Remarks
PL 838 (Lunde) / Norway	30	DG3/FID 2026	05.02.2026	34	Oil and gas	-

Table 3.27 Lunde licence shares (%)

Licence	Aker BP ASA (Op)	ORLEN Upstream Norway AS	Lime Petroleum AS
PL838 (Lunde)	35	35	30

Discovery
Lunde was discovered in 2019 with well 6507/5-9 S. The well discovered a 45 m gas column and a 39 m oil column in good to excellent reservoir quality sandstones of Fangst and Båt Groups. The structure is segmented, the East segment was proven by well 6507/5-9 S. To appraise down-faulted West segment, a sidetrack well 6507/5-9 A was drilled later in 2019. The appraisal well encountered a total oil and gas column of about 63 m in the Fangst and Båt Groups, of which about 45 m of column was in sandstones with mainly good to very good reservoir quality.[4]

Reservoir
The Lunde discovery is situated within the Revfallet Fault Complex on the western edge of the NE-SW trending Nordland Ridge. The reservoir of the Lunde discovery is Fangst Group (Garn Formation) and Båt Group (Tofte and Åre Formations), dated to Lower to Middle Jurassic age. The sandstones are deposited in a wide range of depositional environments including fluvial, marginal marine, marine to tide dominated estuarine, with good to excellent reservoir quality. Reservoir sandstones of the Garn Formation were developed in upper to lower shoreface setting, characterised with porosities close to 30% and high permeabilities in the hundreds to thousands of mD. The reservoir sandstones of Åre Formation were developed in bayhead delta and stacked bay fill in fluvial plain setting, characterised with 33% to 35% average porosities and permeabilities in the 1000 mD range. The area has undergone extensive truncation and erosion of the Garn, Tofte and Åre Formations.

The structure is complex due to faulting and onlapping wedges. The trap is a combined four-way closure and hanging wall trap and the top seal is provided by Melke Formation shales. The discovery is quite segmented and the structure is defined by four main fault segments; East, West, North-east and South-east. The East and West segments have been proven by wells 6507/5-9 S and 6507/5-9 A with GOC at ~2033 m TVD MSL and OWC at ~2072 m TVD MSL in the former well and GOC at ~2034 m TVD MSL and OWC at ~2074 m TVD MSL in the latter well [4]. Both wells have encountered gas-oil and oil-water contacts at slightly different depth that supports compartmentalization between Lunde East and Lunde West segments. Due to fault bounded segments and contacts at different depth, there is an increased probability of finding different hydrocarbon contacts and compartmentalization of the undrilled independent segments.

The reservoir contains heavy oil (18° API), with 4 cP viscosity, GOR of 340–410 Scf/bbl, initial pressure of 211 bar, and temperature of 72°C.

Development
The oil and gas will be produced to the Skarv FPSO via existing infrastructure and existing well template on the seabed. The Lunde development relies on an extended reach well (ERD) from the Skarv West Template. The well is planned to have an 1800 m long reservoir section, completed with sand screens and inflow control devices (ICDs). The heel will be completed in the gas cap before landing the horizontal section in the middle of the 40 m thick oil column. The well is primarily a gas well (80% of the hydrocarbons). The gas cap gas will act as natural gas lift. The ICV's will enable shutting off/on the gas from the gas cap and possible water stream from the horizontal section. Drive mechanism is natural depletion, mainly from gas cap expansion.

Status
The concept select (DG2) was passed in May 2024. A potential partner approval of the DG3 was planned for early 2025, but has now been postponed until 2026. If and when approved, the commercial resources from Lunde will be defined as reserves according to PRMS.

If DG3 is approved in 2026 then drilling may potentially start in 2026 with likely start-up of production in 2026 or 2027.

Petroleum Initially in Place (PIIP)
The PIIP estimates as of 31.12.2024 are listed in Table 3.28. The PIIP numbers are the total PIIP from three segments; East, West and South-East of the Lunde structure. The given PIIP numbers is without North-East segment. Lunde is a first time certification and no PIIP was reported 31.12.2023.

Table 3.28 Lunde PIIP estimate as of 31.12.2024 (source: Lime)

	PIIP, 31.12.2024 (Best Estimate)
Oil/Condensate (MMbbl)	43
Gas (BScf)	52

Production and cost profiles presented by Lime
Description of the production profiles

- The production profile is based on the Operator's full field ensemble simulation model.
- In the base case production profile, a gas rate of 35 MMscf/d (1.0 MSm3/d) is found optimum to maximise net present-value.
- Less than 10% of the ensemble suffers from high water production, hence the risk of severe water produ tion problems is considered low.
- A 10% risk for not entering the East segment is added in the uncertainty workflow to mitigate risk for failure in drilling or completion if drilling through thick coal layers.
- The Lime's Statement of Reserves corresponds to RNB2025.

Description of the cost profiles

- The estimated cost of the extended reach development well is expected to be very high.
- Other development and operating costs have not been reviewed by AGR since the Lunde volumes are not yet classified as reserves.

Contingent Resources audited by AGR
The recoverable volumes for the Lunde development project are classified as Contingent Resources according to PRMS. This is because the project has not yet passed the DG3 / FID decision milestone.

Comments to PIIP

AGR has reviewed the following documentation: RNB2025[11], Lime Statement of Reserves [12], Lime Q&A, and Lunde draft DG3 Subsurface Support Document and meeting handouts with the following comments:

- The PIIP numbers presents in the Table 3.28 are consistent to those with RNB2025 submission.
- Uncertainty assessed in the Lunde discovery are structure, contacts, porosity followed by NE segment in descending order. These main uncertainties are sensitive to volume estimation both for STOIIP and GIIP.
- Garn formation constitutes more than 50% of the PIIP volume.
- AGR finds the Operator's subsurface work robust for PIIP estimation, hence considers the estimated PIIP reasonable.

Comments to contingent resources

AGR has reviewed available documentation provided by Lime; Lime Statement of Reserves, RNB 2025, DG3 draft and DG1 documentation, and have the following comments:

- There is a high drilling risk to the only producer on the field (almost 8 000 m long), with possibility of not reaching the total length and potential completion problems. This is catered for in the ensemble when, in 10% of the simulation cases, the well is not drilled into the East segment due to drilling difficulties. However, the largest risk is related to the extension into the oil rim. A shorter horizontal is not likely to significantly reduce the gas recovery.
- The viscous oil (4 cP) gives a very unfavourable mobility ratio between the oil and the water/gas, leading to fingering of water and gas through the oil leg. This is incorporated into the model, which gives an extremely low recovery factor for oil of only 3 %, which is also caused by the rapid extraction of the gas cap with associated pressure depletion.
- In AGR's opinion the production profiles presented by Lime are reasonable.

Comments to facilities and cost profiles

The Lunde development drilling cost of 1230 million NOK has been reviewed by AGR and viewed reasonable.

Economic evaluation and reserves determination

The recoverable volumes of Lunde are classified as Contingent Resources according to PRMS, and have therefore not been subject to an economic evaluation or economic limit test. The gross and net to Lime Contingent Resources for Lunde are shown in Table 3.29 below. Net to Rex contingent resources are found in 1 Executive Summary and A.1.4 PL838 Lunde - Summary of Reserves and Resources.

Changes since certification 31.12.2023

The gross Lunde balance sheet for Contingent Resources is shown in Table 3.30.

- Lunde is a first time certification.

Comments to recovery factors and resource ranges

- The oil and gas recovery factors are shown in Table 3.31. The oil recovery factor of 3% is very low. The recovery factor is still reasonable when taken into consideration that the well is drilled as a gas well, the oil is viscous and there is rapid out-take of gas (which lowers the field pressure and gives lift problems). Note that the recovery factor for gas of 54% is based on sales gas divided by the GIIP given in wet gas volumes. The gas recovery factor with produced wet gas volume is 64%.
- The oil equivalent uncertainty range is -36%/+41% versus 2C (Table 3.29). The range is high, but reasonable considering the relatively high risk of the project.

Conclusions

- AGR considers the PIIP related to the West, East and South-East segments presented by Lime to be acceptable.
- The project risk is considered high due to the extended reach drilling, the viscous oil and the uncertainty in the oil water contact in undrilled segments.
- The well is primarily a gas well. The oil recovery factor is thus only 3% due to the viscous oil, rapid extraction of gas cap and the well placement.
- The Contingent Resources reported by Lime are well documented, based on sound industry practice and consistent with RNB2025.
- AGR endorses the Lunde Contingent Resources as reported by Lime in the Lime Statement of Reserves[12].

Table 3.29 Gross and net to Lime Contingent Resources as of 31.12.2024 - Lunde

Contingent Resources		GROSS (100%)			Net to Lime (30%)*		
Resources	**PRMS subclass**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
Lunde Development	Development Pending	4.65	7.27	10.28	1.40	2.18	3.08
Total, MMboe		**4.65**	**7.27**	**10.28**	**1.40**	**2.18**	**3.08**

* Net contingent resources in Table above are net to Lime. Rex's share in Lime is 80.14%. See 1 Executive Summary and A.1.4 PL838 Lunde - Summary of Reserves and Resources for contingent resources net to Rex.

Table 3.30 Balance sheet - Lunde Contingent Resources (100%)

Gross contingent resource balance, 31.12.2023 - 31.12.2024, for Lunde_CR (100%)							
Resource class	**Status 31.12.2023**	**Production (Positive)**	**Revisions**	**Acquisitions or sales**	**IOR**	**Discoveries/ New Projects**	**Status 31.12.2024**
Oil and condensate (MMbbl)							
1C	-	-	-	-	-	0.523	0.523
2C	-	-	-	-	-	1.396	1.396
3C	-	-	-	-	-	2.420	2.420
Gas (Bscf)							
1C	-	-	-	-	-	19.954	19.954
2C	-	-	-	-	-	28.434	28.434
3C	-	-	-	-	-	38.030	38.030
NGL (MMboe)							
1C	-	-	-	-	-	0.569	0.569
2C	-	-	-	-	-	0.811	0.811
3C	-	-	-	-	-	1.085	1.085
Oil equivalents (MMboe)							
1C	-	-	-	-	-	**4.646**	**4.646**
2C	-	-	-	-	-	**7.272**	**7.272**
3C	-	-	-	-	-	**10.279**	**10.279**

Table 3.31 Lunde P50 Recovery Factors

	Oil RF by 31.12.2024	**Oil RF at EUR**	**Gas RF by 31.12.2024**	**Gas RF at EUR**
Lunde	-	3%	-	54%

4 Appendices

A.1 Summaries of Oil and Gas Reserves and Resources

Economic evaluations have been conducted to determine reserves by using the AGR economic model reflecting the fiscal regime governing the oil and gas industry on the Norwegian Continental Shelf. The price and financial assumptions in Table 4.1 below were provided by Lime and AGR consider these assumptions to be reasonable and have applied them in the economic evaluations.

The technical production and cost profiles used in the economic evaluations have been supplied by Lime and reviewed by AGR. The price forecast is based a forecast of Brent spot oil price by Deloitte [3] and used by Lime Petroleum. Lime uses an NGL and gas price of 80% of the oil price on an oil equivalent basis. Processing and transportation tariffs used are 0.5 NOK/Sm3 for oil, 0.5 NOK/Sm3 for Gas and 0.5 NOK/Sm3 oe for NGL - as provided by Lime.

Gas prices and volumes reported assume a calorific value of 40 MJ/Sm3.

The evaluations are forward looking from 01.01.2025, thus any historical costs prior to that date have been ignored. Economic cut-off year is estimated as the year of maximum cumulative net cash-flow. Abandonment costs are shifted to the first year after economic cut-off. When production profiles extend beyond the available cost profiles, it is assumed that the cost level is kept unchanged. The Brage and Bestla fields are considered as a Hub and economic cut-off is thus determined by jointly evaluating the two fields forecasts when running the economics.

Table 4.1 Price and financial assumptions from Lime

	Units	**2025**	**2026 -> EOFL***
Oil/Condensate Price	USD/bbl (real2025)	74.5	72.4
Gas Price (40 MJ/Sm3)	NOK/Sm3 (real2025)	4.12	4.01
NGL Price	USD/boe (real2025)	59.6	57.9
Exchange rate	NOK/USD	11.0	11.0
Inflation rate	2% p.a.		
Present value reference date	01.01.2025		
Discount hurdle rate	8% p.a. (nominal)		
Tax	78% (22% corporate tax rate + 56% special tax rate)		

* EOFL - End of Field Life

A.1.1 Yme - Summary of Oil and Gas Reserves and Resources

The Summary of Oil and Gas Reserves and Resources for Yme as of 31.12.2024 is shown in Table 4.2 below.

Table 4.2 Yme - Summary of Oil and Gas Reserves and Resources

Category	Gross Attributable to Licence (100%)	Net Attributable Lime (25.00% Lime share)	Net Attributable Rex[1] (80.14% Rex Int. share of Lime)	Change[2] from previous update (%)	Risk Factors[3]	Remarks
	(MMbbl / Bcf)	(MMbbl / Bcf)	(MMbbl / Bcf)			
Reserves						
Oil Reserves						
1P	13.47	3.37	2.70	+ 30.0%	N.A.	-
2P	16.82	4.21	3.37	- 6.8%	N.A.	-
3P	24.93	6.23	4.99	+ 29.8%	N.A.	-
Natural Gas Reserves						
1P	-	-	-	-	-	-
2P	-	-	-	-	-	-
3P	-	-	-	-	-	-
Natural Gas Liquids Reserves						
1P	-	-	-	-	-	-
2P	-	-	-	-	-	-
3P	-	-	-	-	-	-
Contingent Resources						
Oil						
1C	6.56	1.64	1.31	+ 523.4%	0.68	Weighted average of 3 projects (infill drilling and artificial lift)
2C	8.36	2.09	1.68	+ 123.0%	0.68	
3C	10.33	2.58	2.07	+ 136.6%	0.68	
Natural Gas						
1C	-	-	-	-	-	-
2C	-	-	-	-	-	-
3C	-	-	-	-	-	-
Natural Gas Liquids						
1C	-	-	-	-	-	-
2C	-	-	-	-	-	-
3C	-	-	-	-	-	-

- *1P: Proved*
- *2P: Proved + Probable*
- *3P: Proved + Probable + Possible*
- *MMbbl: Millions of barrels*
- *Bcf: Billions of cubic feet*

Name of Qualified Person: Steinar S. Johansen

Date: 28. February 2025

Professional Society Affiliation / Membership:

- Society of Petroleum Engineers (SPE)
- European Association of Geoscientists and Engineers (EAGE)
- London Petrophysical Society (LPS)
- CFA Institute

Notes:

1) Net Attributable to Rex International Holding Ltd means the volumes attributable to Rex International Investments Pte. Ltd., a wholly owned subsidiary of Rex which has an 80.14% ownership in Lime Petroleum Holding AS. Lime Petroleum Holding AS owns 100% of Lime Petroleum AS which is the licencee of the Norwegian production licences.

2) Change from previous update means the change in the volume attributable to Rex International Holding Ltd. The overall change shown includes changes in estimates of the remaining recoverable volumes for the field as well as the change in Lime's working interest in Yme (increased from 10% to 25%) and the change in Rex' ownership share in Lime (reduced from 91.652% to 80.14%).

3. Applicable to Contingent Resources. "Risk Factor" for Contingent Resources means the estimated chance, or probability, that the volumes will be commercially extracted. NA denotes Not Applicable.

A.1.2 Brage - Summary of Oil and Gas Reserves and Resources

The Summary of Oil and Gas Reserves and Resources for Brage as of 31.12.2024 is shown in Table 4.3 below.

Table 4.3 Brage - Summary of Reserves and Resources

Reserves						
Oil Reserves						
1P	8.65	2.93	2.35	+ 25.5%	N.A.	-
2P	11.00	3.72	2.98	+ 16.9%	N.A.	-
3P	13.72	4.64	3.72	+ 6.3%	N.A.	-
Natural Gas Reserves						
1P	3.61	1.22	0.98	- 58.5%	N.A.	-
2P	7.09	2.40	1.92	- 47.9%	N.A.	-
3P	10.58	3.58	2.87	- 42.2%	N.A.	-
Natural Gas Liquids Reserves						
1P	0.03	0.01	0.01	- 92.6%	N.A.	-
2P	0.16	0.05	0.04	- 76.1%	N.A.	-
3P	0.43	0.15	0.12	- 50.8%	N.A.	-
Contingent Resources						
Oil						
1C	15.68	5.31	4.25	+ 110.4%	0.26	Weighted average of 7 projects
2C	30.63	10.37	8.31	+ 153.0%	0.26	
3C	46.07	15.59	12.49	+ 153.2%	0.26	
Natural Gas						
1C	17.27	5.84	4.68	+ 45331.5%	0.26	Weighted average of 7 projects
2C	46.32	15.68	12.56	+ 285.0%	0.26	
3C	83.49	28.26	22.65	+ 143.8%	0.26	
Natural Gas Liquids						
1C	1.27	0.43	0.35	+484.8%	0.26	Weighted average of 7 projects
2C	3.00	1.01	0.81	+ 1333.2%	0.26	
3C	5.12	1.73	1.39	+ 410.5%	0.26	

- *1P: Proved*
- *2P: Proved + Probable*
- *3P: Proved + Probable + Possible*
- *MMbbl: Millions of barrels*
- *Bcf: Billions of cubic feet*

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Notes:

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2) Change from previous update means the change in the volume attributable to Rex International Holding Ltd. The overall change shown includes changes in estimates of the remaining recoverable volumes for the field as well as the change in Rex' ownership share in Lime (reduced from 91.652% to 80.14%).

3) Applicable to Contingent Resources. "Risk Factor" for Contingent Resources means the estimated chance, or probability, that the volumes will be commercially extracted. NA denotes Not Applicable.

A.1.3 Bestla - Summary of Oil and Gas Reserves and Resources

The Summary of Oil and Gas Reserves and Resources for Bestla as of 31.12.2024 is shown in Table 4.4 below.

Table 4.4 Bestla - Summary of Reserves and Resources

Category	Gross Attributable to Licence (100%)	Net Attributable Lime (17.00% Lime share)	Net Attributable Rex[1] (80.14% Rex Int. share of Lime)	Change[2] from previous update (%)	Risk Factors[3]	Remarks
	(MMbbl / Bcf)	(MMbbl / Bcf)	(MMbbl / Bcf)			
Reserves						
Oil Reserves						
1P	10.77	1.83	1.47	-	-	31.12.24 is first time Bestla has bookable reserves
2P	13.73	2.33	1.87	-	-	
3P	17.39	2.96	2.37	-	-	
Natural Gas Reserves						
1P	26.94	4.58	3.67	-	-	31.12.24 is first time Bestla has bookable reserves
2P	33.28	5.66	4.53	-	-	
3P	37.17	6.32	5.06	-	-	
Natural Gas Liquids Reserves						
1P	1.64	0.28	0.22	-	-	31.12.24 is first time Bestla has bookable reserves
2P	2.03	0.35	0.28	-	-	
3P	2.27	0.39	0.31	-	-	
Contingent Resources						
Oil						
1C	2.14	0.36	0.29	- 85.5%	0.65	Bestla moved to Reserves. New: Extended Lifetime
2C	2.75	0.47	0.38	- 85.4%	0.65	
3C	2.99	0.51	0.41	- 87.2%	0.65	
Natural Gas						
1C	2.48	0.42	0.34	- 92.6%	0.65	Bestla moved to Reserves. New: Extended Lifetime
2C	7.08	1.20	0.96	- 84.7%	0.65	
3C	4.83	0.82	0.66	- 89.9%	0.65	
Natural Gas Liquids						
1C	0.15	0.03	0.02	- 92.6%	0.65	Bestla moved to Reserves. New: Extended Lifetime
2C	0.43	0.07	0.06	- 84.7%	0.65	
3C	0.30	0.05	0.04	- 89.9%	0.65	

- *1P: Proved*
- *2P: Proved + Probable*
- *3P: Proved + Probable + Possible*
- *MMbbl: Millions of barrels*
- *Bcf: Billions of cubic feet*

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Notes:

1) Net Attributable to Rex International Holding Ltd means the volumes attributable to Rex International Investments Pte. Ltd., a wholly owned subsidiary of Rex which has an 80.14% ownership in Lime Petroleum Holding AS. Lime Petroleum Holding AS owns 100% of Lime Petroleum AS which is the licencee of the Norwegian production licences.

2) Change from previous update means the change in the volume attributable to Rex International Holding Ltd. The overall change shown includes changes in estimates of the remaining recoverable volumes for the field as well as the change in Rex' ownership share in Lime (reduced from 91.652% to 80.14%).

3) Applicable to Contingent Resources. "Risk Factor" for Contingent Resources means the estimated chance, or probability, that the volumes will be commercially extracted. NA denotes Not Applicable.

A.1.4 PL838 Lunde - Summary of Reserves and Resources

The Summary of Oil and Gas Reserves and Resources for PL838 Lunde as of 31.12.2024 is shown in Table 4.5 below.

Table 4.5 PL838 Lunde - Summary of Reserves and Resources

Category	Gross Attributable to Licence (100%)	Net Attributable Lime (30% Lime share)	Net Attributable Rex[1] (80.14% Rex Int. share of Lime)	Change[2] from previous update (%)	Risk Factors[3]	Remarks
	(MMbbl / Bcf)	(MMbbl / Bcf)	(MMbbl / Bcf)			
Reserves						
Oil Reserves						
1P	-	-	-	-	-	
2P	-	-	-	-	-	
3P	-	-	-	-	-	
Natural Gas Reserves						
1P	-	-	-	-	-	
2P	-	-	-	-	-	
3P	-	-	-	-	-	
Natural Gas Liquids Reserves						
1P	-	-	-	-	-	
2P	-	-	-	-	-	
3P	-	-	-	-	-	
Contingent Resources						
Oil						
1C	0.52	0.16	0.13	-	0.80	31.12.24 is first time Lunde has bookable resources
2C	1.40	0.42	0.34	-	0.80	
3C	2.42	0.73	0.58	-	0.80	
Natural Gas						
1C	19.95	5.99	4.80	-	0.80	31.12.24 is first time Lunde has bookable resources
2C	28.43	8.53	6.84	-	0.80	
3C	38.03	11.41	9.14	-	0.80	
Natural Gas Liquids						
1C	0.57	0.17	0.14	-	0.80	31.12.24 is first time Lunde has bookable resources
2C	0.81	0.24	0.19	-	0.80	
3C	1.09	0.33	0.26	-	0.80	

- *1P: Proved*
- *2P: Proved + Probable*
- *3P: Proved + Probable + Possible*
- *MMbbl: Millions of barrels*
- *Bcf: Billions of cubic feet*

Name of Qualified Person: Steinar S. Johansen

Date: 28. February 2025

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- London Petrophysical Society (LPS)
- CFA Institute

Notes:

1) Net Attributable to Rex International Holding Ltd means the volumes attributable to Rex International Investments Pte. Ltd., a wholly owned subsidiary of Rex which has an 80.14% ownership in Lime Petroleum Holding AS. Lime Petroleum Holding AS owns 100% of Lime Petroleum AS which is the licencee of the Norwegian production licences.

2) Change from previous update means the change in the volume attributable to Rex International Holding Ltd. The overall change shown includes changes in estimates of the remaining recoverable volumes for the field as well as the change in Rex' ownership share in Lime (reduced from 91.652% to 80.14%).

3) Applicable to Contingent Resources. "Risk Factor" for Contingent Resources means the estimated chance, or probability, that the volumes will be commercially extracted. NA denotes Not Applicable.

A.2 Abbreviations and definitions

Abbreviation	Definition
1C	Low estimate scenario for Contingent Resources.
1P	Proved Reserves; denotes low estimate scenario for Reserves
2C	Best estimate scenario for Contingent Resources.
2P	Proved plus Probable Reserves; denotes best estimate scenario for Reserves
3C	High estimate scenario for Contingent Resources.
3P	Proved plus Probable plus Possible Reserves; denotes high estimate scenario for Reserves
4D	Four Dimensional (time lapse seismic)
AAPG	American Association of Petroleum Geologists
ABEX	ABandonment EXpenditures
AVO	Amplitude Versus Offsets
bbl	Volume unit, 1 barrel = 42 US gallons ≈ 159 Liters
BHP	Bottom Hole Pressure
Bo	Formation volume factor for oil
BRV	Bulk Rock Volume
CAPEX	CAPital EXpenditures
CGR	Condensate Gas Ratio
COP	Cessation of Production
CoS	Chance of success
CPI	Computer Processed Interpretation
D	Darcy
DCA	Decline Curve Analysis
DG1	Decision Gate 1; At least one technical concept is demonstrated economical
DG2	Decision Gate 2; Concept selection
DG3	Decision Gate 3; Project sanction; deliver PDO
DST	Drill Stem Test
EAGE	European Association of Geoscientists and Engineers
EC	Engineering Committee
EOR	Enhanced Oil Recovery
EOS	Equation Of State
EOY	End Of Year
ESP	Electrical Submersible Pump
EUR	Estimated Ultimate Recovery; the sum of reserves and historic production
FFM	Full Field Model
FLAGS	Far North Liquids and Associated Gas System
Fm	Formation
FMT	Formation Multi-Tester™ (Weatherford); formation pressure data, also MDT, RCI, RFT
FOL	Free Oil Level
FPSO	Floating Production Storage and Offloading vessel
FWL	Free Water Level
GBS	Gravity Base Structure
GCV	Gross Calorific Value
GDT	Gas Down To
GIIP	Gas Initially In Place
GOC	Gas-Oil Contact
Gp	Group
G	billion (Giga) SI unit multiplier = 1 000 000 000
GWC	Gas-Water Contact
HCPV	Hydrocarbon Pore Volume

Abbreviation	Definition
HM	History Match
ICD	Inflow Control Device
IOR	Increased Oil Recovery
km	Kilometre
LQ	Living Quarters
LWD	Logging While Drilling
m	meter, milli
mm	million; oilfield unit multiplier
mmbbl	million barrels of stock tank oil
mmboe	million barrels of oil equivalent
mmbtu	million British thermal units
mD	millidarcy, permeability unit
M	million (Mega) SI unit multiplier = 1 000 000
MBAL	Material Balance (software)
MC	Management Committee
mD	milli Darcy (a measure of permeability)
MD	Measured Depth
MDT	Modular Formation Dynamics Tester™ (Schlumberger); formation pressure data, also FMT, RCI, RFT
MJ	megajoule (million joules)
MNOK	Million NOrwegian Kroner
MOD	Money Of the Day
MOPU	Mobile Offshore Production Unit
MODPU	Mobile Offshore Drilling and Production Unit
MSL	Mean Sea Level
Mt	Million tonnes
MUSD	Million US Dollars
MWD	Measurement While Drilling
NCS	Norwegian Contintental Shelf
NGL	Natural Gas Liquids
NOD	Norwegian Offshore Directorate
NOK	Norwegian Kroner
NPD	Norwegian Petroleum Directorate
NPV	Net Present Value
oe	Oil Equivalent. 1 Sm3 oe = 1 Sm3 oil =1000 Sm3 gas
OED	Olje og Energi Departementet (Ministry of oil and energy)
ODT	Oil Down To
OPEX	OPerating EXpenditures
OTS	Oseberg Transport System
OWC	Oil-Water Contact, identical to WOC
PDO	Plan for Development and Operations
PDQ	Processing Drilling and Quarter
PIIP	Petroleum Initially In Place
PLT	Production Logging Tool
PRMS	Petroleum Resources Management System
PSA / PTIL	Petroleum Safety Authority of Norway
PSDM	Pre-Stack Depth Migration
PVT	Pressure Volume Temperature; fluid properties
PV	Present Value
QC	Quality Control (Quality Check)

Abbreviation	Definition
RC	Resources category (in the NPD's resources classification system), Reservoir Committee
RCA	Routine Core Analysis, identical to CCA
RCI	Reservoir Characterization Instrument™ (Baker Hughes); formation pressure data, also FMT, MDT, RFT
RF	Recovery Factor
RFT	Repeat Formation Tester™ (Schlumberger); formation pressure data, also FMT, MDT, RCI
RKB	Rotary Kelly Bushing
RMP	Reservoir Management Plan
rm3	Reservoir cubic metre
RNB	Revised National Budget; sheets/forms (Norwegian Offshore Directorate)
RT	Real Terms
Scf	Square foot
Sm3	Standard cubic meter
Sw	Water Saturation
SWAG	Simultaneous Water And Gas injection
SCAL	Special Core Analysis
SEG	Society of Exploration Geophysicists
SGX	Singapore Stock Exchange
SLS	Submerged Loading System
Sodir	Sokkeldirektoratet
SoR	Statement of Reserves
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
SPWLA	Society of Petrophysicists and Well Log Analysts
STOIIP	Stock Tank Oil Initially In Place (at the discovery time)
TAR	Turnaround. Planned maintenance shutdowns.
THP	Tubing Head Pressure
Technical	Used with volumes. Refers to values calculated without economic cut-off
TRR	Technically Recoverable Resources. Quantities producible using currently available technology and industry practices, regardless of commercial considerations.
TVD	True Vertical Depth
TDVSS	True Vertical Depth measured from mean sea level (MSL)
VSH	Volume of Shale
UK	United Kingdom
USD	US Dollar
WCT	Water Cut
WHM	Well Head Module
WI	Water Injector
WOC	Water-Oil Contact, identical to OWC
WP&B	Work Program and Budget
WPC	World Petroleum Congress
WUT	Water Up To
ÅTS	Åsgard Transportation System

A.3 Summary of 2018 SPE Petroleum Resources Classification

The following table has paragraphs that are quoted from the 2018 Petroleum Resources Management System and summarise the key resources classes and categories, while the figure below shows the recommended sub-classes based on project maturity.

Table 4.6 Summary of 2018 Petroleum Resources Management System

Class/Sub-class	Definition
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.
On Production	The development project is currently producing and selling petroleum to market.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.
Development Unclarified	A discovered accumulation where project activities are under assessment and where justification as a commercial development is unknown based on available information.
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.

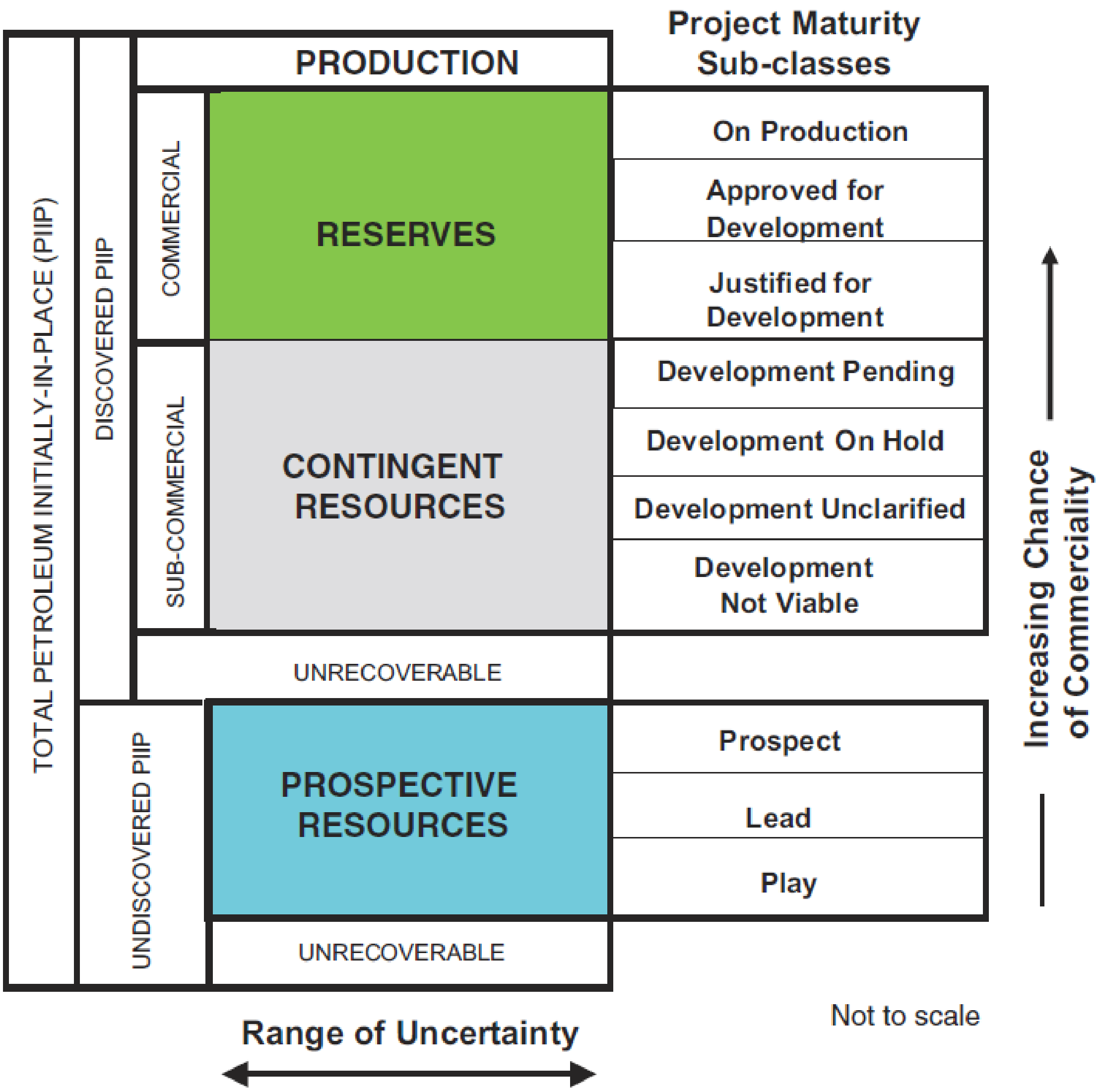

Fig. 4.1 Illustration of the SPE's reserves classification system
Source: www.spe.org

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