BlueNord

Annual Statement of Reserves and Resources Year End 2025

Contents

1. Introduction

This Annual Statement of Reserves and Resources provides a comprehensive overview of BlueNord's hydrocarbon reserves and contingent resources as of 31 December 2025. The reserves and resources presented in this report are held within BlueNord's non-operated partnership in the Danish Underground Consortium (DUC), located in the Danish sector of the North Sea.

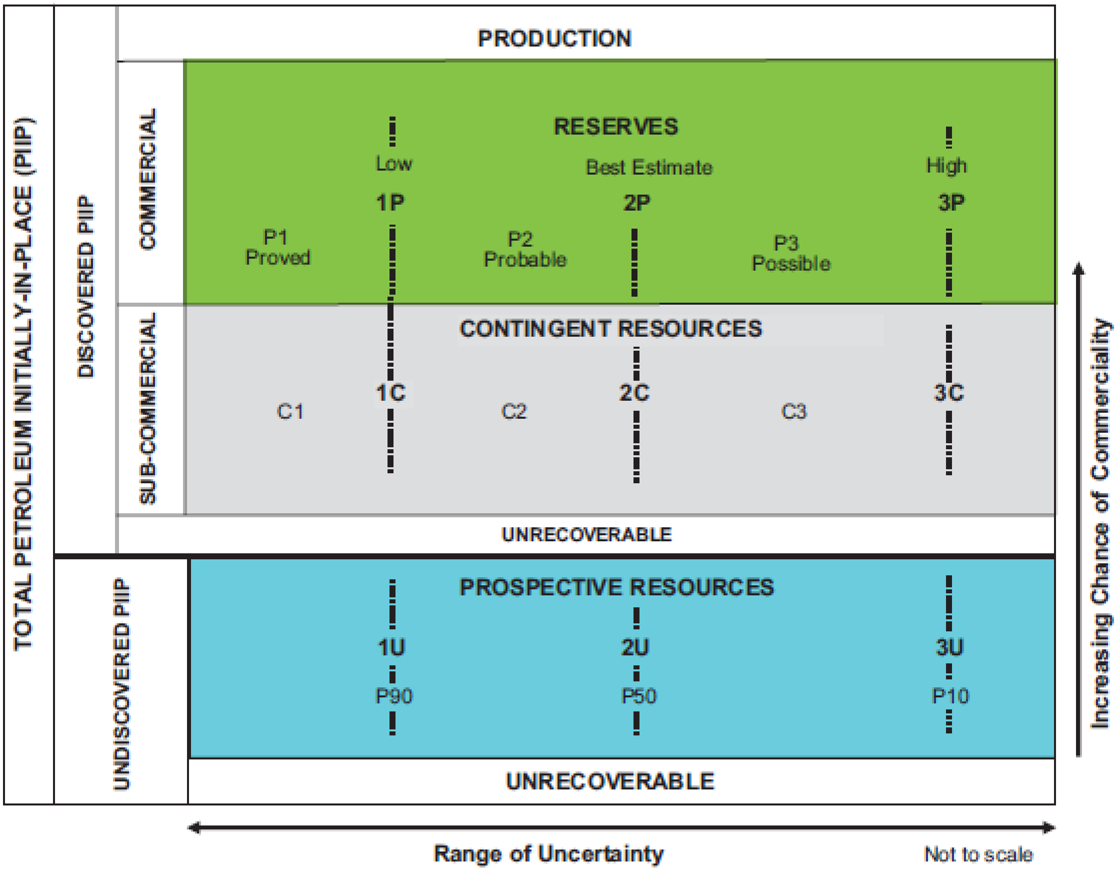
DUC is operated by TotalEnergies and comprises four main production hubs: Dan, Gorm, Halfdan, and Tyra. The Tyra hub has undergone major redevelopment, including a complete rebuild of production facilities following a shut-in in 2019 due to subsidence of the Tyra facilities. The production successfully restarted in 2024. The main theme for the year has been the ramp-up and stabilisation of production from the Tyra hub, alongside maintaining stable production from the base assets: Dan, Gorm, and Halfdan. These efforts have been key drivers for BlueNord's performance in 2025.

As in previous years, the reserves have been independently estimated by Sproule ERCE, ensuring continuity and confidence in the evaluation process. The same rigorous methodology applied in Year End 2024 and Year End 2023 has been used for the current assessment.

2. Reserves and Contingent Resources Classification

ERC Equipoise Ltd ("Sproule ERCE") has carried out an independent evaluation of the hydrocarbon Reserves and certain Contingent Resources held by BlueNord Energy Denmark A/S in the Sole Concession area, offshore Denmark. The Reserves are reported on a field gross, Company working interest and Company net entitlement basis as of 31 December 2025. Under PRMS it is the Company net entitlement that should be reported as the entity's Reserves. Both Developed and Undeveloped Reserves are reported for each hub and by product type. Gas Reserves are based on sales volumes and exclude fuel and flare. Oil equivalent Reserves are reported based on an energy equivalent conversion of the gas Reserves using a conversion of 5,200 scf per barrel of oil equivalent ("boe"). Sproule ERCE has carried out this work in accordance with the June 2018 SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE Petroleum Resources Management System ("PRMS") as the standard for classification and reporting.

Figure 1 – PRMS Resources classification framework



This report provides an overview of Developed Reserves (on production) along with four projects in the sub-class Justified for Development that have not yet been sanctioned, and five projects in Contingent Resources. The latter are only a near-term subset of the full portfolio of development projects in the Contingent Resource class. No assessment has been made of Prospective Resources (in accordance with the classification table above).

Sproule ERCE estimates of Developed Reserves in producing fields are based on decline curve analysis ("DCA") and a review of historical performance of recent well interventions and activities. Estimates of Undeveloped Reserves are based on hydrocarbon in place and recovery efficiency estimates, analogue type curves, stochastic historic well performance analysis and/or dynamic modelling. The Undeveloped Reserves in the Year End 2025 Reserves estimation are classified Approved and Justified for Development.

In accordance with the PRMS guidelines, the Cessation of Production ("CoP") date used to estimate Reserves is defined as (a) the end of the last 12 months period that the maximum cumulative operating cash flow occurs; (b) the end of the technical field life; or (c) the end of the license period[1], whichever occurs soonest.

[1] License expiry is 8 July 2042 for the Danish Underground Consortium (DUC) in which BlueNord's reserves are held.

3. Overview of 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. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates as Proved (1P), Proved plus Probable (2P) and Proved plus Probable plus Possible (3P).

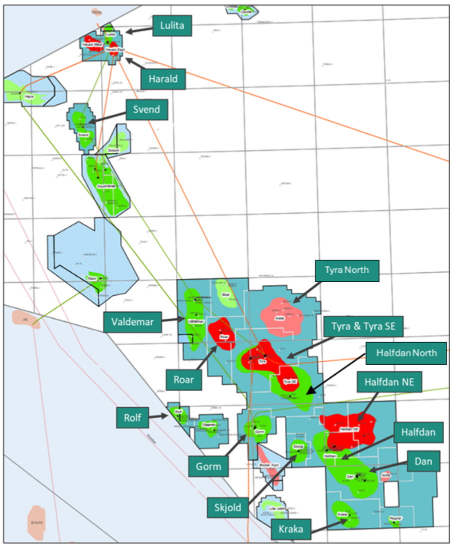
BlueNord's reserves are located within the Danish Underground Consortium (DUC), a joint venture in the Danish sector of the North Sea. DUC is operated by TotalEnergies, with BlueNord and Nordsøfonden as partners. The consortium operates under a license that expire 8 July 2042.

The DUC portfolio of assets comprises four main infrastructure and production hubs—Dan, Halfdan, Gorm, and Tyra—each of which serves as a host platform for several satellite fields. Each hub produces its own power and has at least one accommodation platform. The fields are generally mature, the oldest being the Dan field, which came on production in 1972. Dan, Halfdan, and Gorm are oil-dominated producing assets, while the Tyra hub, including its satellites, is gas-dominated. Figure 1 gives overview of the fourteen developed fields in DUC, as well as the three discoveries for which 2P reserves or 2C resources are carried by BlueNord.

As of 31 December 2025, BlueNord's 2P reserves are estimated at 172.4 million barrels of oil equivalent (MMboe). Further details, including reserves by field and product type, are presented in Tables 1, 2, and 3.

Figure 1 – DUC overview

Hub	Working interest	Field(s)	Status
Dan	36.8%	Dan	Producing
	36.8%	Kraka	Producing
Halfdan	36.8%	Halfdan	Producing
	36.8%	Halfdan NE	Producing
	36.8%	Halfdan North[1]	Discovery, Concept Select
Gorm	36.8%	Gorm	Producing
	36.8%	Skjold	Producing
	36.8%	Rolf	Producing
Tyra	36.8%	Tyra	Producing
	36.8%	Tyra SE	Producing
	36.8%	Roar	Producing
	36.8%	Valdemar	Producing
	36.8%	Valdemar Bo South[2]	Discovery, Concept Select
	36.8%	Svend[3]	Shut-in
	36.8%	Tyra North[4]	Discovery, Call for Tender
	36.8%	Harald	Producing
	28.4%	Lulita[5]	Shut-in



1. The Halfdan North discovery lies between the Dan and Halfdan fields. The development concept was reevaluated in 2025 leading to a revised concept comprising extended reach drilling from the Tyra SE TSB platform.
2. The Valdemar Bo South area is an undeveloped southern extension of the Valdemar field. Following observations of unexpected levels of pressure depletion in the Valdemar field observed after the Tyra re-start, the development concept is under review.
3. The Svend field was shut-in in 2015 due to well integrity. The Svend Reinstatement project involves a redevelopment with two infill wells tied back to the existing Svend platform.
4. The Tyra North discovery is planned to be developed with seven wells and tied back to the Tyra East facilities.
5. DUC holds a 50% unitised interest in the Lulita field. BlueNord holds a 18.4% through its DUC interest plus a further 10.0% interest through its participation in Licences 7/86 and 1/90 Lulita is planned to be brought back on production in 2026.

Table 1 – BlueNord 1P, 2P and 3P Reserves as of 31.12.2025

Reserves		1P				2P				3P
		Gross	Gross	Gross	Net	Gross	Gross	Gross	Net	Net
		Liquids	Gas	boe	boe	Liquids	Gas	boe	boe	boe
as of 31.12.2025	Interest	MMstb	MMboe	MMboe	MMboe	MMstb	MMboe	MMboe	MMboe	MMboe
On Production										
Dan	36.8%	23.8	1.9	25.8	9.5	49.4	5.6	55.0	20.2	27.7
Kraka	36.8%	3.6	0.1	3.7	1.4	7.9	0.2	8.1	3.0	3.9
Dan Hub		**27.5**	**2.0**	**29.5**	**10.8**	**57.3**	**5.8**	**63.0**	**23.2**	**31.6**
Halfdan	36.8%	29.1	14.8	43.9	16.1	61.2	30.7	91.9	33.8	45.7
Halfdan hub		**29.1**	**14.8**	**43.9**	**16.1**	**61.2**	**30.7**	**91.9**	**33.8**	**45.7**
Gorm	36.8%	4.8	0.1	4.9	1.8	9.7	0.4	10.1	3.7	7.6
Skjold	36.8%	8.1	0.2	8.3	3.0	14.8	0.7	15.5	5.7	10.5
Rolf	36.8%	0.5	0.0	0.5	0.2	1.2	0.0	1.2	0.5	1.0
Gorm hub		**13.4**	**0.3**	**13.7**	**5.0**	**25.8**	**1.1**	**26.9**	**9.9**	**19.1**
Tyra	36.8%	16.0	41.4	57.4	21.1	30.0	78.7	108.7	40.0	61.0
Valdemar	36.8%	21.2	9.4	30.6	11.3	34.3	17.6	51.9	19.1	26.7
Roar	36.8%	2.8	6.3	9.1	3.3	6.0	13.0	19.0	7.0	10.4
Lulita	28.4%	1.2	0.7	2.0	0.6	1.8	1.1	2.9	0.8	1.3
Harald	36.8%	6.3	17.7	24.0	8.8	9.5	28.6	38.1	14.0	20.4
Tyra hub		**47.6**	**75.5**	**123.1**	**45.1**	**81.6**	**139.0**	**220.6**	**80.9**	**119.8**
Total		**117.6**	**92.5**	**210.1**	**77.2**	**225.8**	**176.6**	**402.5**	**147.9**	**216.3**
Under Development										
		-	-	-	-	-	-	-	-	-
Total		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Approved for Development and Justified for Development										
Halfdan Infill (Ekofisk)	36.8%	3.1	1.7	4.8	1.8	5.4	4.8	10.1	3.7	5.5
Tyra SE Extension	36.8%	5.8	0.3	6.1	2.2	11.7	0.4	12.2	4.5	7.1
Valdemar UC Infill	36.8%	2.1	1.7	3.7	1.4	3.1	3.1	6.1	2.3	2.8
Tyra North (Ph 1)	36.8%	7.8	11.8	19.7	7.2	17.1	21.2	38.3	14.1	21.4
Total		**18.8**	**15.5**	**34.3**	**12.6**	**37.3**	**29.5**	**66.8**	**24.6**	**36.8**
On Production plus Under Development										
Total		**117.6**	**92.5**	**210.1**	**77.2**	**225.8**	**176.6**	**402.5**	**147.9**	**216.3**
On Production plus Under Development plus Approved and Justified for Development										
Total Reserves		**136.4**	**108.0**	**244.4**	**89.8**	**263.1**	**206.1**	**469.3**	**172.4**	**253.1**

Notes:
1. Gross Reserves represent 100% of the Reserves to be recovered from the licence.
2. Net Reserves are based on the working interest share of the gross Reserves. As there are no royalties to be deducted, Net Reserves are equal to Net Entitlement Reserves.
3. Barrels of oil equivalent are calculated using a conversion of 5,200 scf/boe.
4. Gas Reserves are based on sales volumes and exclude fuel and flare. Sproule ERCE has assumed each hub provides its own fuel gas and imports fuel gas if it is fuel gas deficient.
5. Gorm Hub Developed Reserves on Production include the planned Gorm WROM III programme.
6. Halfdan Hub Undeveloped Reserves include two Ekofisk infill wells classified as Justified for Development
7. Tyra Hub Justified for Development Reserves include a Valdemar UC infill well, Phase 1 of the planned Tyra North development and the TSEE project to develop Halfdan North.

Table 2 – BlueNord 1P, 2P and 3P Developed Reserves as of 31.12.2025

Reserves per hub		1P				2P				3P
		Gross	Gross	Gross	Net	Gross	Gross	Gross	Net	Net
		Liquids	Gas	boe	boe	Liquids	Gas	boe	boe	boe
as of 31.12.2025	Interest	*MMbbl*	*MMboe*	*MMboe*	*MMboe*	*MMbbl*	*MMboe*	*MMboe*	*MMboe*	*MMboe*
Dan	36.8%	23.8	1.9	25.8	9.5	49.4	5.6	55.0	20.2	27.7
Kraka	36.8%	3.6	0.1	3.7	1.4	7.9	0.2	8.1	3.0	3.9
Dan Hub		**27.5**	**2.0**	**29.5**	**10.8**	**57.3**	**5.8**	**63.0**	**23.2**	**31.6**
Halfdan	36.8%	29.1	14.8	43.9	16.1	61.2	30.7	91.9	33.8	45.7
Halfdan hub		**29.1**	**14.8**	**43.9**	**16.1**	**61.2**	**30.7**	**91.9**	**33.8**	**45.7**
Gorm	36.8%	4.8	0.1	4.9	1.8	9.7	0.4	10.1	3.7	7.6
Skjold	36.8%	8.1	0.2	8.3	3.0	14.8	0.7	15.5	5.7	10.5
Rolf	36.8%	0.5	0.0	0.5	0.2	1.2	0.0	1.2	0.5	1.0
Gorm hub		**13.4**	**0.3**	**13.7**	**5.0**	**25.8**	**1.1**	**26.9**	**9.9**	**19.1**
Tyra	36.8%	16.0	41.4	57.4	21.1	30.0	78.7	108.7	40.0	61.0
Valdemar	36.8%	21.2	9.4	30.6	11.3	34.3	17.6	51.9	19.1	26.7
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Lulita	28.4%	1.2	0.7	2.0	0.6	1.8	1.1	2.9	0.8	1.3
Harald	36.8%	6.3	17.7	24.0	8.8	9.5	28.6	38.1	14.0	20.4
Tyra hub		**47.6**	**75.5**	**123.1**	**45.1**	**81.6**	**139.0**	**220.6**	**80.9**	**119.8**
Total Reserves		**117.6**	**92.5**	**210.1**	**77.2**	**225.8**	**176.6**	**402.5**	**147.9**	**216.3**

Table 3 – BlueNord 1P, 2P and 3P Reserves Development from 31.12.2024 to 31.12.2025

Reserves, net	On production			Under Development			Approved/Justified for Develop.			Total		
Units in MMboe	1P	2P	3P	1P	2P	3P	1P	2P	3P	1P	2P	3P
YE2024 Reserves	**91.0**	**160.4**	**234.0**	**0.0**	**0.0**	**0.0**	**16.9**	**33.3**	**47.5**	**107.9**	**193.7**	**281.5**
2025 Production	13.6	13.6	13.6	0	0	0	0	0	0	13.6	13.6	13.6
Acquisitions and disposals												
Revisions	-2.5	-2.6	-8.3				-0.3	-0.7	-0.8	-2.8	-3.3	-9.1
Discovery and Extensions										0.0	0.0	0.0
Additions												
Projects Matured	2.2	3.7	4.2	0.0	0.0	0.0	-3.9	-8.0	-9.9	-1.7	-4.3	-5.7
YE2025 Reserves	**77.2**	**147.9**	**216.3**	**0.0**	**0.0**	**0.0**	**12.6**	**24.6**	**36.8**	**89.8**	**172.4**	**253.1**
Delta (YE2025-YE2024)	**-13.9**	**-12.5**	**-17.7**	**0.0**	**0.0**	**0.0**	**-4.2**	**-8.7**	**-10.7**	**-18.1**	**-21.3**	**-28.5**

Notes
1. The line 'Production 2025' is the BlueNord share of sales volumes (in mmboe).

Production performance across the DUC fields in 2025 was marked by steady output from the base assets, supported by an intensive maintenance programme and targeted interventions. During the year, efforts were concentrated on ramping up production at Tyra and ensuring operational stability throughout the portfolio. The most significant activities undertaken to maximize production potential are described below:

- A major well-workover campaign was carried out on Dan, restoring production from five previously shut-in wells and safeguarding long-term integrity in another. These interventions, together with comprehensive maintenance such as pressure vessel inspections and compressor servicing, have positioned Dan for consistent delivery and reduced unplanned downtime going forward.
- The HCA Gas Lift module was successfully installed and commissioned in Halfdan NE, improving the performance of wells previously restricted by liquid loading. This upgrade enabled immediate stabilization in addition to extending the production lives of the HCA wells.
- At Tyra, the focus was on a controlled production ramp-up following the 2024 restart, with structured workstreams to improve process capacity, facility reliability, and well potential. This work is planned to continue into 2026 and stable production at the full export potential is expected to be reached by mid-2026.

The YE 2025 2P reserves estimation resulted in a total 2P reserves replacement ratio of -56%. The downward revision is mainly driven by changing the development concept of Halfdan North to the more economically viable Tyra SE extension (TSEE) development. However, the reserves replacement ratio for the 2P Reserves on Production is positive at 8%.

The 2P Reserves on Production has an overall increase of 1.1 MMboe and consists of both upward and downward revisions. The key drivers are related to the following:

- Production in 2025 (-13.6 MMboe)
- HCA gas lift project matured from Approved for Development (+3.1 MMboe)
- Gorm WROM III project matured from Contingent Resources (+0.7 MMboe)
- Upward revision of HEMJ (+1.7 MMboe), due to technical revision of in place volumes based on production performance
- Lower than estimated gas production in Halfdan field, partly due to reduction of scope of the WROM II campaign completed in 2025. Remaining WROM scope is expected to be executed in the Halfdan WROM campaign planned for 2027
- Delayed ramp-up of the Tyra facilities leading to deferment of production beyond current license expiry

To sustain high production levels in 2026 and beyond, the Operator will maintain a high operational efficiency by keeping focus on reducing unplanned shortfalls, and conducting planned platform-based maintenance across Dan, Gorm, and Halfdan hubs. This approach will uphold integrity and set the foundation for improved operational efficiency in future years. On Gorm, a platform-based WROM campaign (WROM III) is planned for 2026, which includes restoration of six wells that have been shut-in for several years.

For Tyra, production is expected to increase steadily through the first half of 2026, supported by bringing additional wells on stream, as well as improvements in Tyra's operational efficiency towards 92 percent by mid-2026 following permanent facility upgrades during a planned shutdown in June 2026.

The 2P YE2025 reserves for the Approved and Justified for Development class have an overall downward revision of -8.7 MMboe which is driven by the following revisions:

- HCA gas lift project matured to On Production (-3.1 MMboe)
- Maturation of the concept for the Halfdan North development to Tyra South East Extension (TSEE), reducing overall costs and planning infill drilling from existing facilities rather than spending CAPEX for installation of new facilities and infrastructure. The Halfdan North area is well understood, and current work is to optimize the concept. The reserves revision related to Halfdan North is -5.0 MMboe.
- Delays to first oil or gas for infill wells and Tyra North leading to deferment of production beyond license expiry (-0.7 MMboe).

4. Description of Reserves – On Production

The DUC assets consist of fourteen developed fields. All fields are located on the Danish Continental Shelf. The developments consist of four producing hubs: Dan, Gorm, Halfdan and Tyra. Production started from the Dan field in 1972. Oil is exported to shore via an oil pipeline from Gorm, and gas is exported both via NOGAT to the Netherlands and via Tyra East to shore in Denmark.

4.1 Dan Hub

The Dan hub includes the Dan and Kraka fields.

Dan is an oil field which was discovered in 1971 and brought on production in 1972. The field produces oil and gas from the Ekofisk and Tor chalk reservoir and the production drive mechanisms are gas cap drive/solution gas expansion and waterflooding. Dan is a domal structure, where a major fault separates the NW downthrown A-block from the SE Upthrown B-block. The West Flank area of the field is located between the Dan A-block and the Halfdan field and was developed at a later stage than the A- and B-blocks.

Initially, the field was developed with vertical and deviated wells and later full field development by horizontal wells. Water injection was tested in 1991 and expanded to full field scale in 1995. A total of approximately 126 wells have been drilled, with currently 41 active oil wells and 34 active water injectors. By end of 2025 the field has produced 769 MMstb of oil and 1,023 Bscf of gas.

Kraka is a tie-back to the Dan field and is an oil field located 8 km to the southeast of the Dan field. The field was brought on production in 1991 and produces oil and gas from the Ekofisk chalk reservoir by a combination of solution gas drive and aquifer support. 10 wells have been drilled and currently seven oil wells are producing. By end of 2025 the field has produced 42 MMstb of oil and 66 Bscf of gas.

4.2 Halfdan Hub

The Halfdan hub includes the Halfdan Main and the Halfdan North East fields.

Halfdan Main was discovered in 1998 and brought on production in 1999. The field produces oil and gas from the Tor Chalk reservoir by gas cap drive/solution gas expansion and waterflooding. The Halfdan NE field was brought on production in 2000 and produces gas from the Ekofisk Chalk reservoir by depletion drive. The Halfdan Main oil accumulation is contiguous with the Dan accumulation and thins towards SW and NE.

Halfdan Main has been developed in four phases and 71 wells have been drilled, with currently 34 active oil producers and 26 active water injectors. By end of 2025 the field has produced 549 MMstb of oil and 618 Bscf of gas.

Halfdan North East has been developed in three phases and 20 wells have been drilled, with currently 17 active gas producers. By end of 2025 the field has produced 17 MMstb of oil and 840 Bscf of gas.

In YE25 the HCA Gas Lift project was matured from Approved for Developed to On Production. The Halfdan HCA platform hosts ten naturally flowing gas wells. Due to natural depletion, the gas rates are declining, and wells have experienced liquid loading problems resulting in low uptimes. The HCA Gas lift module was installed during summer 2025 and commissioning was finalized with start-up in July 2025. Gas lift has been applied to wells previously affected by liquid loading, hereby significantly improving their uptime to be in line with the other Halfdan NE wells. Further, the lift gas prolongs the producing life of the wells. Additional HCA wells will receive lift gas as they experience liquid loading due to natural decline of the gas rates. The project is now assigned as being On Production.

4.3 Gorm Hub

The Gorm hub includes the Gorm, Skjold and Rolf fields.

The Gorm field was discovered in 1971 and brought on production 1981. The field produces oil and gas from the Ekofisk and Tor Chalk reservoirs. The field is a domal structure divided into a deeper western A-block and the shallower eastern B-block. Ekofisk is absent across most of the B-block and thickens down flank on the B-block. The production mechanism is dominated by secondary waterflooding. 46 wells have been drilled, with currently 14 active producers and 6 active water injectors. By end of 2025 the field has produced 405 MMstb of oil and 602 Bscf of gas and 305 Bscf gas has been injected (no injection since 2005). Gorm acts further as the oil gathering center and export hub for all DUC fields.

A WROM campaign (referred to as "WROM III") is planned in the Gorm field in 2026. In YE25 this project was matured from Contingent Resources to On Production. The campaign comprises the restoration of six wells, all of which are currently shut-in and have been for some years.

The Skjold field is an oil satellite tie-back to Gorm. It was discovered in 1977 and brought on production in 1982. The field is a dome shaped structure with a relative thin chalk reservoir on the crest, which thickens towards the outer crest and flank areas. The chalk is highly fractured with low matrix permeability, and the main drive mechanism is waterflooding. 30 wells have been drilled, with currently 16 active oil producers and 5 active water injectors. By end of 2025 the field has produced 319 MMstb of oil and 166 Bscf of gas.

The Skjold gas acceleration project was implemented in 2024, where water injections have stopped in part of the field to allow for a partial depletion strategy in the field. To date, the performance of the acceleration project has been in line with expectations, with increased oil and gas production.

Rolf is an oil field, which has been developed as a satellite to Gorm. The field was discovered in 1981 and brought on production in 1985. The field produces from the Ekofisk and Tor Chalk reservoir with intervals of good permeability with fracture connected matrix porosity. The field is four-way dip-closed anticline structure overlying a salt diapir. The production mechanisms are solution gas drive and aquifer support. 3 wells have been drilled, with currently 2 active oil producers. By end of 2025 the field has produced 31 MMstb of oil and 8 Bscf of gas.

4.4 Tyra Hub

The Tyra hub includes the Tyra Main, Tyra South East, Valdemar, Roar, Harald East, Harald West and Lulita fields.

Tyra Main is a gas dominated field discovered in 1968 and Tyra SE is an oil dominated field discovered in 1991. Tyra Main was brought on production in 1984 and Tyra SE in 2002. The Tyra field lies on an inverted structure on the Valdemar-Tyra-Igor low relief ridge. The field produce mainly from the Ekofisk and Tor Chalk reservoirs. The field was developed from 1984 to 1991 with gas plateau production from 1992 to 2007. One horizontal well has been drilled into the Lower Cretaceous Chalk, Tuxen Fm. The gas in the flank area towards Tyra SE was developed during 1998 to 2008. The recovery mechanism is depletion by gas expansion and rock compaction.

The Tyra East and West did comprise of 11 platforms but due to subsidence, the field has been redeveloped referred to as the Tyra II project. Tyra II project started ramping up wells in Q4 2024. The Tyra II project scope included the replacement of the existing accommodation and processing platforms by one single accommodation and one processing platform. The wellhead jackets have been raised, and topsides replaced. A total of 93 wells have been drilled on Tyra Main and SE. In Tyra Main the plan is to reinstate 31 wells and currently 21 wells have been started up. By end of 2025, the field has produced 173 MMstb and 3,787 Bscf of gas and 1,337 Bscf gas has been injected (no injection since 2012). In the Tyra SE field, the plan is to reinstate 16 wells and currently

12 wells have been started up. By end of 2025, the field has produced 36.1 MMstb of oil and 478 Bscf of gas.

Tyra acts further as the gas export hub for all DUC fields. During the Tyra II project, Dan has acted as the temporary host for gas export via a by-pass pipeline connecting Dan F to the Tyra-NOGAT pipeline system to in the Netherlands. This setup has been made permanent, which means that there are two gas export routes for DUC, one to Denmark and one to the Netherlands.

The Valdemar field is an oil and gas field discovered in 1977 and further appraised in 1985 and brought on production in 1993. The Lower Cretaceous chalk, Tuxen Fm has been the primary development target and horizontal wells have been drilled and completed with sand prop fractures. The field is produced by depletion and rock compaction drive under controlled bottom hole pressure constrained mode. 26 wells have been drilled on Valdemar, with a plan to reinstate 21 oil and gas producers. By end 2025, 18 wells were producing and 3 wells are commissioned but offline. By end of 2025 the field has produced 91 MMstb of oil and 262 Bscf of gas.

Roar is a gas field with an oil rim tie-back to Tyra East. The field was discovered in 1968 and further appraised in 1981. The field was brought on production in 1996. The field produces gas and condensate from the Ekofisk and Tor Chalk reservoir. The gas column thickens towards South, while the oil rim has been encountered by the wells towards the North. 4 gas producer wells have been drilled, with currently three wells online and one offline but has been commissioned. By end of 2025 the field has produced 593 Bscf of gas and 19 MMstb of condensate.

Harald is a gas/condensate field located in the Northwestern part of the Danish sector. The Harald field comprises of three accumulations; Harald East discovered in 1980, Harald West discovered in 1983, and Harald East Middle Jurassic (HEMJ) discovered in 2024. The fields were brought on production in 1997. The Harald West and HEMJ reservoirs consist of Middle Jurassic sandstones, and Harald East is an elongated dome structure in the Upper Cretaceous Ekofisk and Tor Fm. The production mechanism is depletion drive. The HEMJ accumulation was discovered in October 2024 by an exploration well which was brought on production in December 2024. In total 5 wells have been drilled, 2 on Harald West, 2 on Harald East, and 1 on HEMJ. The two Harald West wells and the HEMJ well are currently producing. The Harald East wells are not planned to be brought back online as the flowline of one of the wells is being used for the HEMJ well and the other well was unable to restart. By end of 2025 Harald West has produced 625 Bscf of gas and 32 MMstb of condensate, Harald East has produced 290 Bscf of gas and 20 MMstb condensate, and HEMJ has produced 19 Bscf of gas and 1.3 MMstb of condensate.

Lulita is an oil field with a gas cap discovered in 1991 which was brought on production in 1998. The field is a NE dipping monocline with a main fault boundary in the west and structural dip closure to the SE. The reservoir consists of Middle Jurassic sandstones. The production mechanism is aquifer encroachment, gas cap drive and solution gas expansion. 2 wells have been drilled, 1 well is planned to be re-opened in 2026. By end of 2025 the field has produced 7.4 MMstb of oil and 28 Bscf of gas. DUC holds a 50% interest in the Lulita field with Ineos (40%) and BlueNord (10%) as partners.

5. Description of Reserves - Undeveloped

The Undeveloped Reserves include development projects classified as approved for Development as well as Justified for Development.

5.1 Halfdan Ekofisk infill wells

The Halfdan Ekofisk Main opportunity targets oil and gas above the Halfdan Main Tor development. The Ekofisk Main development potential was confirmed by the drilling of HBB-04 in 2017 and HBB-05 in 2019, respectively. Two Ekofisk infill wells are planned to be drilled in the Halfdan field starting production from HDA-35 in April 2027 and from HDA-31 in August 2027. The well locations will be optimized based on the results and interpretation of the 2023 4D seismic survey. The two wells are considered firm and have been assigned Undeveloped Reserves as Justified for Development. The request for approval covering the first Ekofisk infill well was provided by the Operator in May 2024 and subsequently approved by the DUC Partners in June. FID for the second Ekofisk infill well is expected in Q2 2026.

5.2 Halfdan North (Tyra SE Extension, TSEE)

The Halfdan North discovery comprises the undeveloped area between the Halfdan Main and the Tyra SE fields.

An FDP was submitted in 2020 including a concept of developing the discovery with a 12-slot unmanned wellhead platform tied back to the HBD platform in the Halfdan field. To reduce costs, the Operator has put forward an alternative development concept of Halfdan North which comprises extended reach drilling wells from the TSB platform in the Tyra SE field. This project is referred to as Tyra SE Extension ("TSEE").

A feasibility study for the TSEE project was completed by the Operator in December 2025, which included an evaluation of the infill drilling and completion design and the modifications needed for the facilities. Wells with a similar length have been drilled in the Tyra field and topside modifications to the TSB platform are expected to be minor. An FID is scheduled for 2028 ahead of first oil in 2032. Sproule ERCE has classified the TSEE development of Halfdan North as Undeveloped Reserves Justified for Development.

Halfdan North is a well-known and studied area. Work is still outstanding to optimize the updated development concept including flow assurance and optimal well placement. This work will continue in 2026-27.

5.3 Valdemar UC Infill

An infill well is planned in the Valdemar field targeting the Upper Cretaceous reservoir in an undrilled location between the North Jens and Bo areas. The well will be drilled from an available slot on the VAB platform.

Through 2024, the Operator has matured the infill opportunity and finalized part of the planning work for execution. The schedule for drilling and start-up has been revised to align with the Tyra production ramp-up, as well as the implementation of well workovers and the Ekofisk infills in the Halfdan field. The environmental assessment and FDP are planned to be submitted to the DEA in May 2026 with the FID expected in Q1 2027. First oil is scheduled for Q2 2028.

5.4 Tyra North (Adda) Phase 1

The Tyra North (Adda) discovery is located ~12 km northeast of the Tyra East facility. It was discovered in 1977 and further appraised by five additional wells between 1981 and 1997. Tyra North is a four-way dip-closed anticline structure created by salt tectonics and has a series of east-west trending faults across the field. Gas is contained in the Tuxen Formation and oil is contained in the overlying Hod Formation. The proposed development project includes an unmanned well head platform with 8 slots and a 4-leg jacket tied back to Tyra East E platform. The development includes seven wells drilled and tied back to the platform. The project will have three phases:

- Phase 1: Crest development, 4 Tuxen wells + 1 Hod well;
- Phase 2: Flank development, 2 Tuxen wells;
- Phase 3: Potential for additional Hod well or Tuxen flank well (excluded from Sproule ERCE 's assessment).

The well design is similar to existing wells in the Valdemar field. The field will be produced under natural depletion (with gaslift) and drawdown limits imposed based on the geomechanical stability of the reservoir rock. The production mechanisms in the Tuxen are compaction and gas expansion, and for the Hod this is compaction drive and solution gas drive.

Four well tests have been carried out in the Tuxen reservoir with gas rates observed between 2.5 – 20.0 MMscf/d. Well tests and PVT analysis have determined the reservoir pressure to be very close to the dew point pressure of the gas-condensate. Two well tests have been carried out in the Hod reservoir with oil rates observed between 4,100 – 6,270 stb/d.

A draft FDP was submitted to the DEA in 2021, and the final FDP was submitted in April 2024 and is awaiting approval. The discovery will be developed by a normally unmanned 8-slot wellhead platform tied back to the Tyra East E platform via a 10" multiphase pipeline. Phase 1 of the development includes four horizontal production wells in the Tuxen reservoir and one horizontal production well in the Hod reservoir. The FID is planned for Q4 2026 with the current expectation for first gas in Q4 2029. Based on the maturity of the development, Sproule ERCE has classified Phase 1 of the development as Reserves. Phase 2 is contingent on the performance of Phase 1 and as such is classified as Contingent Resources. Phase 3 is currently not included in the near-term resource base and will, once matured, potentially add further value to the Tyra hub.

6. Contingent Resources

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorised in accordance with the level of certainty associated with the estimates as 1C, 2C and 3C.

In addition to quantities that are classified by Sproule ERCE as Reserves, the assets include quantities that have been classified by Sproule ERCE as Contingent Resources. Sproule ERCE's estimates of Contingent Resources are based on an independent evaluation of data provided by BlueNord. Estimates are typically based on hydrocarbon in place and recovery efficiency estimates, analogue type curves, stochastic historic well performance analysis and/or dynamic modelling.

No economic analysis has been carried out on the Contingent Resources.

Table 4 – BlueNord 1C, 2C and 3C contingent resources as of 31.12.2025

		1C				2C				3C
Contingent Resources as of 31.12.2025	Interest	Gross Liquids MMstb	Gross Gas Bscf	Gross boe MMboe	Net boe MMboe	Gross Liquids MMstb	Gross Gas Bscf	Gross boe MMboe	Net boe MMboe	Net boe MMboe
Halfdan Tor NE Infill	36.8%	0.7	2.5	1.2	0.4	1.4	5.0	2.4	0.9	1.3
Tyra SE Tor Infill	36.8%	0.9	0.9	1.0	0.4	2.9	2.9	3.5	1.3	2.8
Tyra North (Ph 2)	36.8%	1.6	29.6	7.3	2.7	3.4	54.7	14.0	5.1	8.9
Valdemar Bo South	36.8%	10.3	28.4	15.7	5.8	18.5	52.0	28.5	10.5	17.4
Svend Re-development	36.8%	5.3	4.0	6.1	2.2	11.4	8.7	13.1	4.8	7.4
Total		**18.7**	**65.4**	**31.3**	**11.5**	**37.7**	**123.3**	**61.4**	**22.6**	**37.8**

Notes:
1. Gross Contingent Resources represent 100% of the Contingent Resources of the project.
2. Net Contingent Resources are based on BlueNord's working interest share (36.80%) of the Gross Contingent Resources.
3. Contingent Resources are based on wellhead volumes prior to any shrinkage or additional recovery of liquids during processing.
4. These are unrisked Contingent Resources that have not been risked for chance of development.
5. There is no certainty that it will be economically viable to produce some, or any, of the Contingent Resources.
6. The total Contingent Resources presented are based on aggregating individual projects with different levels of risk and as such should be used with caution.

The five projects: Halfdan Tor NE Infill, Tyra SE Tor Infill, Tyra North (Ph 2), Valdemar Bo South and Svend Reinstatement are classified by Sproule ERCE as Contingent Resources. These projects are expected to be the next projects to be matured as reserves and are only a subset of the near-term part of the full portfolio of projects in DUC.

6.1 Halfdan Tor North East infill wells

Within the Halfdan field an infill well (Well HBA-27B) was drilled during 2023 targeting the Tor reservoir. Original plans were to immediately follow this with a second infill well (Well HBA-15B). However, due to the poorer than expected results of Well HBA-27B, the resource estimates and commerciality of the second well are now being reassessed, and the well is contingent on the performance of Well HBA-27B and evaluation of the 4D seismic acquired in 2023 in the Dan-Halfdan area. The well is classified as Contingent Resources in the sub-class Development Pending.

6.2 Tyra SE Tor Infill

A target has been identified to the southeast of Tyra SE in the Tor reservoir between Wells TSB-03A and E-08X. Well TSB-03A has produced oil from the Tor but Well E-08X flowed water on test. The Operator has planned a subsurface scope of work through 2026 to mature the opportunity.

The Contingent Resources are sub-classified as Development Pending based on the ongoing studies to mature the target.

6.3 Tyra North (Adda) Phase 2

The Tyra North (Adda) Phase 2 project consists of two additional horizontal gas production wells located in the north/northeastern area of the Tuxen reservoir in the Adda discovery. The wells are contingent on the results of Phase 1 of the Tyra North development but are also located in a more structurally and stratigraphically complex area of the discovery.

The Contingent Resources are sub-classified as Development On Hold based on the timeframe to potential development. Production from Phase 1 of the development is scheduled in Q4 2029, meaning any Phase 2 development would likely occur no earlier than 2031.

6.4 Valdemar Bo South

The Valdemar Bo South development project targets the Tuxen Formation in an undeveloped area of the Valdemar field immediately south of the developed area. The Valdemar Bo South FDP was submitted in 2020 and the development concept includes five horizontal production wells drilled from a normally unmanned 6-slot wellhead platform. The platform will be tied back to the existing VCA platform via a 2.5 km 12" multiphase pipeline.

Following observations of unexpected levels of pressure depletion in the Valdemar field obtained when the Valdemar wells were brought back on production after the Tyra shutdown, the Valdemar Bo South development project has been delayed. Updated modelling studies are currently being carried out by the Operator and the development concept is under review.

The Contingent Resources are sub-classified as Development Unclarified, based on the need for a re-design of the development concept.

6.5 Svend Re-development

The Svend field is located 20 km south of the Harald field and was on production from 1996 to 2015, when it was shut-in due to well integrity issues. Some work remains to do the final abandonment in three wells, otherwise the wells have all been abandoned.

The Svend re-development project involves drilling of two infill wells (one in the North and one in the South) and upgrading the existing Svend facilities to reinstate production. Following production from Well HEA-04 (HEMJ), flow assurance studies for Harald-Svend-Tyra can now be completed. The Svend Reinstatement project is scheduled for FID in 2027.

The Contingent Resources are sub-classified as Development Unclarified based on the need for completion of flow assurance studies and subsequent concept update.

7. Prospective Resources

No prospective resources have been included in this report.

8. Management's Discussion and Analysis (MD&A)

The reported reserves (Developed and Undeveloped) include remaining volumes expected to be recovered based on reasonable assumptions about future technical, economic, fiscal, and financial conditions based on year end 2025 data. The reported contingent resources are potentially recoverable volumes from known accumulations and includes projects that are being matured in the near term.

BlueNord has used same Reserves Evaluator for the Year End 2025 Reserves and Resources estimation as for 2024 and 2023. The Reserves Evaluator ERC Equipoise Ltd ("Sproule ERCE") has carried out an independent evaluation of the hydrocarbon Reserves and certain Contingent Resources held by BlueNord Energy Denmark A/S in the DUC Sole Concession area, offshore Denmark. This report has been prepared to support regulatory reporting and for financing purposes. The effective date of this report is 31 December 2025.

ERCE has carried out this work in accordance with the June 2018 SPE/WPC/AAPG/ SPEE/SEG/SPWLA/EAGE Petroleum Resources Management System ("PRMS") as the standard for classification and reporting.

ERCE's forecasts, dated 1 January 2026, of Brent crude oil and National Balancing Point ("NBP") natural gas prices were used for the evaluation, with a long term oil price of US$/bbl 70.80, and a long term gas price of 21.47 EUR/MWh. These prices are in 2025 real terms and are subject to annual inflation of 2.0% to determine nominal (money of the day) prices.

Though the after tax NPV10 estimates as of 31 December 2025 form an integral part of fair market value estimations, without consideration for other economic criteria they are not to be construed as Sproule ERCE's opinion of fair market value. There is no assurance that the forecast production and cost profiles contained in this report will be attained and variances could be material. The recovery and estimates of the company's oil and natural gas resources are estimates only and there is no guarantee that the estimate will be recovered. Actual volumes recovered may be greater than or less than the estimates stated in this report. Further, a significant change in commodity prices may also impact the reserves and lead to reduction or extension of the currently estimated lifetime of the fields.

18.03.2026

Miriam Lykke

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Chief Operating Officer