BlueNord

BlueNord ASA

Annual Statement of Reserves and Resources Year End 2022

bluenord.com

The Company's formal, legal name is "Norwegian Energy Company ASA" – often referred to as "NORECO" or "Noreco". The board of directors has proposed that the name is changed to "BlueNord ASA". The change of name will become effective following, and subject to, approval by the Annual General Meeting in the Company, expected to be held on or about 25 April 2023. In anticipation of the aforementioned approval, the Company has used "BlueNord" for the purposes of this document.

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1 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 2022 data. Discounted future cash flows pre-tax are calculated for the various fields based on expected production profiles and estimated 1P, 2P and 3P reserves. Cut-off time for the reserves in a field is set at the time when the maximum cumulative net cashflow occurs, with production and costs grouped at each production hub or at end of license in year 2042. The company has used a long-term inflation assumption of 2% and a long- term exchange rate of 7.1 DKK/USD. A long-term Brent price of $65/bbl (real 2023) was used from 2024 onwards. A premium of $1.4125 was applied to adjust for oil quality compared to benchmark Brent oil. For gas, the forward curve dated December 2022 was used as sales price for physical delivery through the transfer of rights of natural gas at the Dutch Title Transfer Facility (TTF) virtual trading point, operated by Gasunie Transport Services (GTS), the transmission system operator in the Netherlands and equalling approximately €25/MWh long term from 2029 onwards.

The calculations of recoverable volumes are associated with significant uncertainties. The 2P estimate represents a best estimate of reserves, whereas the 1P reflects a low estimate, and the 3P a high estimate.

The reported contingent resources are potentially recoverable volumes from known accumulations and includes projects that are being matured in the near term.

All volumes reported are estimated by an independent third-party consultancy RISC (UK) Ltd. All production and cost profiles are included in the RISC reserves evaluation report (dated 24th March 2023) for completeness and assessment of economic cut-off. The volumes are disclosed on a non-reliance basis. RISC has consented to the form and context in which the estimated reserve volumes are presented in this Statement.

28.03.2023

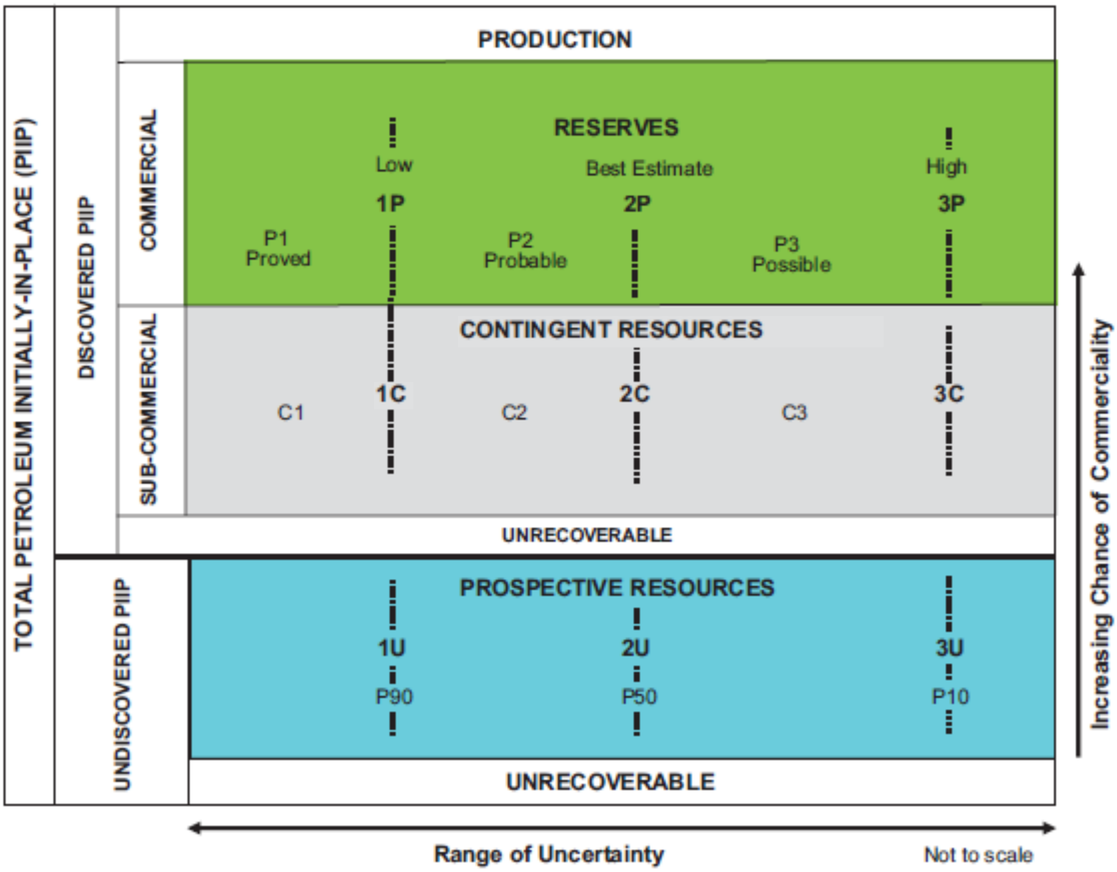
Marianne Eide

Chief Operating Officer

2 Reserves and Contingent Resources Classification

RISC (UK) Ltd (RISC) has made an independent reserves and resources evaluation based on the definitions and guidelines set out in the revised June 2018 Petroleum Resources Management System (PRMS) version 1.03 (June 2018) (Figure 1). The PRMS has been prepared by the Oil and Gas reserves Committee of Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the Society of Petroleum Engineers (SPE), the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), the Society of Petroleum Evaluation Engineers (SPEE), the Society of Exploration Geophysicists (SEG), the Society of Petrophysicists and Well Log Analysts (SPWLA) and the European Association of Geoscientists & Engineers (EAGE).

Figure 1 – Petroleum Resources Classification System



This report provides an overview of Developed Reserves (on production), Undeveloped reserves associated with the ongoing Tyra Re-development project, two projects in the sub-class Approved for Development, and two projects in the sub-class Justified for Development that have not yet been sanctioned, and three projects in Contingent Resources. The latter are only a 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) by RISC.

The Danish Underground Consortium (DUC) is a joint venture with three partners:

TotalEnergies	43.2% equity (Operator)
BlueNord	36.8% equity, except for Lulita where the equity is 28.4%
Nordsøfonden	20.0% equity (State participation, fully paying)

The DUC portfolio of assets comprises four main infrastructure and production hubs, i.e. 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 and the Tyra Hub, including satellites, are gas dominated producing assets.

The DUC license extension was granted on 29th September 2003 by the Danish Minister for Economic and Business Affairs for the period 1st January 2004 and up to 8th July 2042.

The Tyra Redevelopment (TRD) project was sanctioned in December 2017 as a result of seabed subsidence of the aging Tyra West and Tyra East platforms that posed a risk for the platform integrity under severe weather conditions. Consequently, Tyra and the associated satellite fields were closed-in at the end of Q3 2019 and production start-up from the new Tyra facility and satellites is scheduled for Q1 2024 based on a P90 start-up sequence. All associated volumes are reported as Under Development.

Reserves are based on a date of March 2024 for first gas export to Denmark from Dan, based on the Operator’s Remit Notification submitted in August 2022, with gas production from Tyra fields starting approximately one month later. The ramp-up of the fields will continue with full production expected to be achieved in Q3 2024.

One commercial project in the Halfdan North East field was sanctioned in August 2021, and one commercial infill drilling project in the Halfdan North East field was sanctioned in Q4 2022 and both are classified as Approved for Development. Further, one commercial infill drilling project in the Halfdan field and one commercial project in the Valdemar field in the Tyra hub each have a field development plan, with volumes included in the Justified for Development category.

3 Reserves Estimation

RISC has conducted a review of the information and technical work provided by BlueNord and formed an independent view of the reserves on a field-by-field basis. The reserves reported are net for the interests (36.8%) in the DUC portfolio. These are arithmetically summed Developed[1] (in production) and Undeveloped[2] reserves (Approved or Justified for Development). All reserves[3] conform to the PRMS.

RISC has reviewed the historical production and injection performance, and the production forecast for the producing fields have been estimated using Decline Analysis or based on a review of the Operator's YE 2022 reserves forecasts (simulation work). The forecasts appear reasonable for initial production rate, with the general assumptions following historical trends.

Reserves have been categorised accordingly to the probability for the reserves to be produced.

- **1P** - Proved Reserves: Low estimate of reserves.
- **2P** - Proved + Probable Reserves: Best estimate of reserves.
- **3P** - Proved + Probable + Possible Reserves: High estimate of reserves.

In accordance with the PRMS guidelines, cut-off date for the reserves in a field is set when the maximum cumulative net cashflow occurs, with production and costs grouped at each production hub. This can be no later than at the end of license, in July 2042. The total Reserves for the different fields, are arithmetic summed as recommended in the PRMS reporting guidelines. However, it should be noted that the aggregated Proved Reserves (1P) may be a conservative estimate and the aggregated Proved plus Probable plus Possible (3P) may be optimistic. It is likely that the Proved (1P) total will statistically be a downside estimate and the Proved plus Probable plus Possible (3P) will statistically be an upside estimate, for this large diverse package of assets. The aggregated Proved plus Probable (2P) reserves typically exhibit less portfolio effect. Hence, the statistical median will tend to approach the mean of the distribution.

4 Reserves

The developed reserves are comprised of the fields on production from the Dan, Halfdan and Gorm hubs. The undeveloped reserves comprise of reserves from the Tyra redevelopment project, two development projects in the Halfdan Area and one in the Valdemar Area. As per previous disclosures, the reserves for Tyra, Roar and the new developments could not be independently audited, and RISC's forecasts are based on the Operator's forecasts. RISC has reviewed these forecasts to appear reasonable for initial production rate, with the general assumptions following historical trends.

[1] Developed Reserves are expected quantities to be recovered from existing wells and facilities.

[2] Undeveloped Reserves are quantities expected to be recovered through future investments.

[3] Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a give date forwards under defined conditions. Reserves must further satisfy four criteria: They must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development projects applied.

Table 1 – BlueNord 1P, 2P and 3P reserves as of 31.12.2022

Reserves		1P/P90				2P/P50				3P/P10
		Gross liquids	Gross gas	Gross boe	Net boe	Gross liquids	Gross gas	Gross boe	Net boe	Net boe
as of 31.12.2022	*Interest*	*mmbbl*	*mmboe*	*mmboe*	*mmboe*	*mmbbl*	*mmboe*	*mmboe*	*mmboe*	*mmboe*
On Production										
Dan	36.8%	37.0	2.6	39.6	14.6	71.1	5.6	76.7	28.2	35.6
Kraka	36.8%	3.6	0.1	3.7	1.4	6.9	0.2	7.1	2.6	3.2
Halfdan	36.8%	36.1	11.3	47.4	17.4	76.5	23.7	100.2	36.9	52.0
Gorm	36.8%	14.4	-	14.4	5.3	21.8	-	21.8	8.0	9.0
Skjold	36.8%	20.2	-	20.2	7.4	30.9	-	30.9	11.4	12.7
Rolf	36.8%	1.1	-	1.1	0.4	2.3	-	2.3	0.8	1.3
Total		**112.5**	**14.0**	**126.5**	**46.5**	**209.5**	**29.5**	**239.1**	**88.0**	**113.7**
Under Development										
Tyra Hub	36.8%	63.9	90.1	154.1	56.6	83.0	119.3	202.3	74.4	84.4
Total		**63.9**	**90.1**	**154.1**	**56.6**	**83.0**	**119.3**	**202.3**	**74.4**	**84.4**
Approved for Development and Justified for Development										
Halfdan HCA gas lift	36.8%	0.5	2.7	3.2	1.2	1.1	6.0	7.1	2.6	3.3
Valdemar Bo South	36.8%	12.4	4.4	16.8	6.2	20.1	8.8	28.9	10.6	15.0
Halfdan Tor NE infills	36.8%	2.3	0.8	3.0	1.1	4.8	2.9	7.7	2.8	4.5
Halfdan Ekofisk infills	36.8%	2.2	1.4	3.5	1.3	5.7	5.0	10.7	3.9	5.5
Total		**17.4**	**9.3**	**26.5**	**9.8**	**31.7**	**22.7**	**54.4**	**20.0**	**28.3**
On Production plus Under Development										
Total		**176.4**	**104.1**	**280.5**	**103.2**	**292.5**	**148.9**	**441.4**	**162.3**	**198.1**
On Production plus Under Development plus Approved for Development plus Justified for Development										
Total Reserves		**193.7**	**113.3**	**307.0**	**112.9**	**324.2**	**171.6**	**495.7**	**182.3**	**226.4**

Deficiencies in fuel gas in the Dan and Gorm Hubs are supplied from the Halfdan Hub and/or Tyra Hub and hence, the total gas is aggregate Sales Gas reserves entering the Export gas pipeline(s).

For total MMBoe, Gas reserves have been added to the Oil and Liquid reserves, using a conversion factor of 5.2 Bscf/MMBoe, from the Operator, based on actual calorific value of the gas sales.

Table 2 – BlueNord 1P, 2P and 3P On Production plus Under Development reserves as of 31.12.2022

Reserves per hub		1P/P90				2P/P50				3P/P10
		Gross liquids	Gross gas	Gross boe	Net boe	Gross liquids	Gross gas	Gross boe	Net boe	Net boe
as of 31.12.2022	*Interest*	*mmbbl*	*mmboe*	*mmboe*	*mmboe*	*mmbbl*	*mmboe*	*mmboe*	*mmboe*	*mmboe*
Dan	36.8%	37.0	2.6	39.6	14.6	71.1	5.6	76.7	28.2	35.6
Kraka	36.8%	3.6	0.1	3.7	1.4	6.9	0.2	7.1	2.6	3.2
Dan Hub		**40.6**	**2.7**	**43.4**	**16.0**	**78.0**	**5.8**	**83.8**	**30.8**	**38.7**
Halfdan	36.8%	36.1	11.3	47.4	17.4	**76.5**	**23.7**	**100.2**	**36.9**	52.0
Halfdan Hub		**36.1**	**11.3**	**47.4**	**17.4**	**76.5**	**23.7**	**100.2**	**36.9**	**52.0**
Gorm	36.8%	14.4	-	14.4	5.3	21.8	-	21.8	8.0	9.0
Skjold	36.8%	20.2	-	20.2	7.4	30.9	-	30.9	11.4	12.7
Rolf	36.8%	1.1	-	1.1	0.4	2.3	-	2.3	0.8	1.3
Gorm Hub		**35.7**	**-**	**35.7**	**13.1**	**55.0**	**-**	**55.0**	**20.2**	**23.0**
Tyra	36.8%	29.4	63.4	92.7	34.1	38.1	85.2	123.2	45.3	51.1
Valdemar	36.8%	28.9	13.1	42.0	15.5	38.4	18.3	56.7	20.9	24.6
Roar	36.8%	4.5	9.9	14.3	5.3	5.2	11.8	17.1	6.3	6.7
Harald	36.8%	0.7	3.4	4.1	1.5	0.7	3.6	4.3	1.6	1.8
Lulita	28.4%	0.5	0.3	0.9	0.3	0.6	0.4	1.0	0.3	0.3
Tyra Hub		**63.9**	**90.1**	**154.1**	**56.6**	**83.0**	**119.3**	**202.3**	**74.4**	**84.4**
Total Reserves		**176.4**	**104.1**	**280.5**	**103.2**	**292.5**	**148.9**	**441.4**	**162.3**	**198.1**

Table 3 – BlueNord 1P, 2P and 3P Reserves Development from 31.12.2021 to 31.12.2022

Reserves Development	On Production			Under Development			Approved/ Justified for Development			Total		
Net attributable mmboe	1P/P90	2P/P50	3P/P10	1P/P90	2P/P50	3P/P10	1P/P90	2P/P50	3P/P10	1P/P90	2P/P50	3P/P10
Balance as of 31.12.2021	**61.0**	**101.1**	**122.8**	**54.2**	**75.5**	**85.9**	**13.5**	**22.9**	**33.7**	**128.6**	**199.5**	**242.4**
Production 2022	9.8	9.8	9.8	-	-	-	-	-	-	9.8	9.8	9.8
Acquisition and disposals	-	-	-	-	-	-	-	-	-	-	-	-
Revisions	-4.7	-3.4	0.8	2.4	-1.1	-1.5	-6.2	-9.7	-15.4	-8.5	-14.2	-16.1
Discovery and Extensions	-	-	-	-	-	-	-	-	-	-	-	-
New Developments	-	-	-	-	-	-	2.4	6.8	10.0	2.4	6.8	10
Projects matured	-	-	-	-	-	-	-	-	-	-	-	-
Balance as of 31.12.2022	**46.5**	**88.0**	**113.7**	**56.6**	**74.4**	**84.4**	**9.7**	**20.0**	**28.3**	**112.8**	**182.4**	**226.4**
Delta (2022-2021)	**-14.5**	**-13.2**	**-9.0**	**2.4**	**-1.1**	**-1.5**	**-3.8**	**-2.9**	**-5.4**	**-15.8**	**-17.1**	**-16.0**

The line 'Production 2022' is the BlueNord share of sales volumes (in mmboe).

The production performance in 2022 was high and at a similar level to 2021. The main reasons for the strong performance were a higher level of well optimization and restoration activities, and a higher uptime. A highlight during the year was the restimulation of the eight Halfdan North East wells, where the utilization of new technology resulted in new areas of the reservoir being accessed. Well reinstatement work on the Dan field increased the well count with five wells resulting in a significantly higher production. Gorm had a higher production level than expected due to the well stimulations performed late 2021, and again in November 2022.

The Operator's assumption for uptime was 86% while an uptime of 90% was achieved. This exceptional performance was delivered through systematic work by the Operator, with detailed analysis of unplanned shortfalls from the previous two years and addressing the causes leading to the largest shortfalls.

The Operator reported in August 2022 that the first gas date of the Tyra II project was revised from June 2023 to Winter 2023/2024 with a Remit Notification data of end March 2024. The delay was mainly driven by global supply chain challenges that impacted the extent to which fabrication work on the process module was completed prior to sail-away from the McDermott yard in Indonesia as well as a revised plan for offshore hook-up and commissioning based on learnings from the Tyra East hook-up and commissioning work. The probabilistic range of first gas export from Tyra II is as follows:

- P10: October 2023
- P50: December 2023
- P90: March 2024

In October 2022, the final platform, the processing module (the TEG) was lifted and installed at the Tyra field, and the ongoing offshore hook-up and commissioning work met several important milestones during the year. Key milestones for 2023 will include start-up of gas turbine generators and first gas introduced to the process module.

In 2022 BlueNord and the rest of the DUC partnership decided to prioritize gas production and as such the new developments included in the YE 2022 reserves reflect a focus on gas production. This resulted in a postponement of the Halfdan North development with a subsequent reclassification from Justified for Development to Contingent Resources. However, the Halfdan North development was substituted by two drilling campaigns with two infill wells each, both in the Halfdan hub (new at YE 2022). The four new infill wells are planned (two for Halfdan Tor NE with FID approved in Q4 2022 and two for Halfdan Ekofisk with FID expected in Q2 2023) with drilling expected to commence in April 2023. The HCA gas lift, already approved, has been postponed to 2024 due to the strong production performance in 2022. In the Tyra hub, three projects are planned: the Valdemar Bo South with FID expected in Q4 2023 (unchanged); the Svend Reinstatement project with FID expected in Q4 2023 (new at YE 2022); and Adda with FID expected in Q4 2024 (new at YE 2022). The three projects, Halfdan North, Adda and Svend Reinstatement are classified as Contingent Resources and are expected to be the next projects to be matured as reserves. These projects are only a subset of the full portfolio of projects in DUC.

The YE 2022 reserves estimation has both upward and downward revisions. The key drivers of the revisions of **Reserves On Production** are related to the following:

- An upward revision on Dan based on higher 2022 oil rates due to successful reinstatement of five producers, an increase in uptime due to reduction in unplanned shortfalls, and 10 well interventions successfully completed
- A downward revision on Kraka based on reallocation of production to the Dan field
- A downward revision on Halfdan Main based on the relatively immature field still being impacted by water breakthrough from the fracture network, and it has not reached a slower decline from the matrix waterflooding (BlueNord observation)
- An upward revision on Halfdan North East due to the positive impact of the HCA restimulations and a higher uptime
- An upward revision of Gorm and Skjold based on the positive impact of restimulation, higher uptime and an extended economic limit of the Gorm hub
- The minor downward revisions of fields in the Tyra hub are due to higher fuel gas requirements for the Gorm hub due to an extended economic limit, and a delay of Tyra from Q2 2023 to Q1 2024

To keep production on producing assets high in 2023 and beyond, the plan for 2023 is to continue with workovers on Dan and Halfdan fields, maintain the high uptime with continued focus on the unplanned shortfalls, carry out more than 20 well interventions on the Dan field, carry out restimulations on all hubs, enable gas export from Gorm to Halfdan, and re-route stabilization of Halfdan oil to Dan instead of Gorm resulting in reduced flaring. Finally, two infill wells will be drilled in Halfdan Tor North East field.

The key drivers for the upward and downward revisions on Justified for Development and Approved for Development reserves are related to the following:

- A downward revision resulting from a change in focus from oil to gas, where the Halfdan North development project was delayed with FID expected in Q1 2025 and subsequently reclassified as Contingent Resources.
- An upward revision resulting from the maturation of four new infill wells in the Halfdan hub being included in the Undeveloped Reserves category:
    - Two infills in the Halfdan Tor NE field classified as Approved for Development (FID was approved in December 2022) with drilling expected to commence in April 2023
    - Two infills in the Halfdan Ekofisk classified as Justified for Development (FID expected in Q2 2023)

5 Developed Fields

The DUC assets consist of eleven fields with reserves. All fields are situated on the Danish Continental Shelf. The developments can be divided into four main 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 during the Tyra re-development project, gas is exported to the Netherlands via the NOGAT pipeline. After the Tyra hub is back on production, gas will be exported both to Netherlands and via Tyra II to shore in Denmark.

5.1 Dan Hub

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 secondary by pressure support from waterflooding. Dan is a domal structure divided by a major fault into a NW downthrown A-block and a SE Upthrown B-block.

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 33 active water injectors. By end of 2022 the field has produced 753 MMstb of oil and 989 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 6 oil wells are producing. By end of 2022 the field has produced 40.3 MMstb of oil and 64.9 Bscf of gas.

5.2 Halfdan Hub

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 secondary waterflooding. The Halfdan NE area 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 35 active oil producers and 26 active water injectors. By end of 2022 the field has produced 531 MMstb of oil and 634 Bscf of gas.

Halfdan NE has been developed in three phases and 17 wells have been drilled, with currently 17 active gas producers. By end of 2022 the field has produced 14.2 MMstb of oil and 744 Bscf of gas.

5.3 Gorm Hub

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 16 active producers and 6 active water injectors. By end of 2022 the field has produced 401.4 MMstb of oil and 599 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.

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 production drive mechanism is waterflooding. 30 wells have been drilled, with currently 16 active oil producers and 7 active water injectors. By end of 2022 the field has produced 311 MMstb of oil and 158 Bscf of gas.

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 production mechanisms are solution gas drive and aquifer support. 3 wells have been drilled, with currently 1 active oil producer. By end of 2022 the field has produced 30.6 MMstb of oil and 7.8 Bscf of gas.

5.4 Tyra Hub, currently closed in for re-development

Tyra Main is a gas dominated field discovered in 1968 and Tyra SE is an oil dominated field area 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 produces mainly from the Ekofisk and Tor Chalk reservoirs. The field was developed during 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 comprises of 11 platforms and due to subsidence, the field is currently being redeveloped. The Tyra Redevelopment project scope include 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. No new wells are planned. The estimated start-up of the new Tyra facility and the Tyra Satellites is scheduled for Q4 2023/Q1 2024. A total of 93 wells have been drilled on Tyra Main and SE, with currently 47 active oil and gas producers. By end of 2022 the field has produced 208 MMstb of oil and 4,251 Bscf of gas.

Tyra acts further as the gas gathering center and export hub for all DUC fields. During the Tyra redevelopment project, Dan is temporary the host for gas export via a by-pass pipeline connecting Dan F to the Tyra-NOGAT pipeline system to the F/3 in 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 currently 22 active oil and gas producers. By end of 2022 the field has produced 89 MMstb of oil and 257 Bscf of gas.

Roar is a gas field with an oil rim tie-back to Tyra East. The field was discovered in1968 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 all currently being active. By end of 2022 the field has produced 588 Bscf of gas and 18 MMstb of condensate.

Harald is a gas/condensate field located in the northwestern part of the Danish sector. The Harald field comprises of two structures; Harald East discovered in 1980 and Harald West discovered in 1983. The fields were brought on production in 1997. The Harald West reservoir consists 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. Four wells have been drilled, two on Harald West and two on Harald East, and all four wells are currently active. By end of 2022 the field has produced 902 Bscf of gas and 51 MMstb of condensate.

Lulita is an oil field with a gas cap discovered in 1991 which were 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. Two wells have been drilled, however only one is currently producing. By end of 2022 the field has produced 7.4 MMstb of oil and 28.3 Bscf of gas. DUC holds an 50% interest in the Lulita field with Ineos (40%) and BlueNord (10%) as partners.

6 Development Projects - Reserves

6.1 HCA Gas Lift Project

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. This will be mitigated by making gas lift available to nine of the wells to lift liquids, enabling continued steady production from the wells and reduce their technical rate limits. The HCA gas lift, although approved, has been postponed to 2024 due to the strong production performance in 2022.

6.2 Halfdan Tor North East infill wells

The Halfdan Tor NE development opportunity targets oil and gas northeast of Halfdan Main oil development and below Halfdan North East gas development. The Tor NE development potential was confirmed by the drilling of HBB-10 in 2017.

6.3 Halfdan Ekofisk infill wells

The Halfdan Ekofisk Main opportunity targets oil and gas above 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.

6.4 Valdemar Bo South

The Valdemar Bo South (VBS) development targets oil from the Tuxen reservoir in the undeveloped area located south of the Valdemar BA platform. The Tuxen reservoir is part of the Lower Cretaceous (LC) hydrocarbon pool of the greater Valdemar Field. The reservoir in the development area is appraised by wells JUDE-1X, the distal part of VBA-06E and BO-3X. All wells confirmed oil-bearing Tuxen Fm reservoir. The development is based on 5 parallel horizontal production wells, drilled from a single new platform.

7 Contingent Resources

The resources reported are net for the interests (36.8%) in the DUC portfolio. These are arithmetically summed. All resources conform to the PRMS guidelines. RISC has conducted a review of the information and technical work provided by BlueNord and formed an independent view of the resources on a project basis. For these fields the operator's forecasts (based on simulations) were reviewed. The simulation models and simulation reports were not available to BlueNord or RISC. The forecasts were not supported by sufficient detail to enable them to be audited but the simulation forecasts appear plausible for initial production rate and the general decline trends follow historical trends. In the absence of other information, RISC has adopted the operator's 1P, 2P and 3P for its 1P, 2P and 3P respectively, making changes to expand the range of uncertainty. The contingent reserves comprise of resources from the Halfdan North, Adda and Svend reinstatement projects.

Table 4 – BlueNord 1C, 2C and 3C contingent resources as of 31.12.2022

Recources		1C				2C				3C
		Gross liquids	Gross gas	Gross boe	Net boe	Gross liquids	Gross gas	Gross boe	Net boe	Net boe
as of 31.12.2022	*Interest*	*mmbbl*	*mmboe*	*mmboe*	*mmboe*	*mmbbl*	*mmboe*	*mmboe*	*mmboe*	*mmboe*
Halfdan North	36.8%	11.8	1.5	13.4	4.9	33.1	4.3	37.4	13.8	22.4
Adda	36.8%	9.7	13.7	23.4	8.6	16.9	33.6	50.4	18.6	30.6
Svend reinstatement	36.8%	7.0	0.9	8.0	2.9	11.4	1.8	13.2	4.8	6.5
Total		**28.6**	**16.2**	**44.7**	**16.5**	**61.4**	**39.6**	**101.0**	**37.2**	**59.5**

The three incremental projects: Halfdan North, Adda and Svend Reinstatement are classified by RISC as Contingent Resources. Halfdan North was reclassified from Justified for Development Reserves to Contingent Resources at YE 2022, and both Adda and Svend are new projects not yet matured into Reserves. These projects are expected to be the next projects to be matured as reserves. These projects are only a subset of the full portfolio of projects in DUC.

8 Projects – Contingent Resources

8.1 Halfdan North

Halfdan North is an undeveloped discovery between the Halfdan field and the Tyra Southeast field, in the same geological units (Upper Cretaceous Tor formation chalk). The field was discovered by the HDN-2X well as part of the exploration and appraisal of the Halfdan field but remained undeveloped due to the thinner oil column and smaller volumes. Since that time the Halfdan field has matured, and the Operator now plans to develop this field. The Operator reported that a development well in Tyra SE (TSEB-03A) appraised the Halfdan North accumulation, confirming the Northern end of the accumulation and showed better reservoir properties than expected.

The selected development concept consists of a normally unmanned wellhead platform, tied-back to the Halfdan BD (HBD) platform. The full development consists of 9 wells, with 4 horizontal water injectors alternating with 5 horizontal producers to give a line drive waterflood. An initial stage will be 3 producers and 2 water injectors. In past year, only this initial stage was reported as reserves.

A concept select phase for Halfdan North was completed in June 2019 with a development plan identified, and FEED was completed in March 2021. All technical work has been completed. However, due to the changing priorities of the DUC partners, the Halfdan North field has been delayed, with other projects taking its place in the development and drilling schedule. The FID for the project was delayed until Q3 2027, with an anticipated start up in Q4 2029. Due to the lower priority of this project and the delay to the start of any development activity, RISC has reclassified the Halfdan North Development as Contingent Resources. The resources now relate to the full development of 9 wells, instead of just the initial 5 wells reported in previous years. As a result, the technical ultimate recovery is higher than at YE2021.

8.2 Adda

The Adda field was discovered in 1977 and will be developed as a satellite tieback to the Tyra complex. The crestal area is appraised by four wells and thus well constrained. The proposed Adda development project includes a greenfield normally unmanned well head platform with 8 slots and a 4-leg jacket with a fully rated pipeline 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 RISC's assessment).

The subsurface and conceptual studies were completed in Q2 2021 and the field development plan was submitted to the DEA in Q3 of 2021. The project is due to re-commence FEED, with the FID expected in Q4 2024. Only Phase 1 and 2 was included in RISC's analysis. The Adda 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 geo-mechanical stability of the reservoir rock. The production mechanisms in the Tuxen are compaction and expansion gas, and for the Hod this is compaction drive and solution gas drive.

8.3 Svend Re-instatement

The existing Svend A wellhead platform is normally unmanned and has 7 well slots including 2 spares. The field ceased production in 2015. The Svend reinstatement project will include the abandonment of existing wells, refurbishing the existing platform by replacing the HIPPS, and adding two new wells to reinstate production. The project is currently in the basic engineering phase and FID is anticipated in Q4 2023 with the platform ready for start-up in Q1 2026.

No prospective resources have been included in this report.