BlueNord

Annual Statement of Reserves and Resources Year End 2023

Contents

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 2023 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 changed Reserves Evaluator for the Year End 2023 Reserves and Resources estimation. The Reserves Evaluator ERC Equipoise Ltd ("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 2023.

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 2024, 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 75.5, and a long term gas price of 93.6 pence/therm. These prices are in 2024 real terms and are subject to annual inflation of 2.0% to determine nominal (money of the day) prices. ERCE's NBP natural gas price forecast is converted from p/therm to EUR/MWh assuming 1 Mscf = 10.37 therm and 1 MWh = 329.4 scf.

Though the after tax NPV10 estimates as of 31 December 2023 form an integral part of fair market value estimations, without consideration for other economic criteria they are not to be construed as 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.

18.03.2024

M. W. Eide

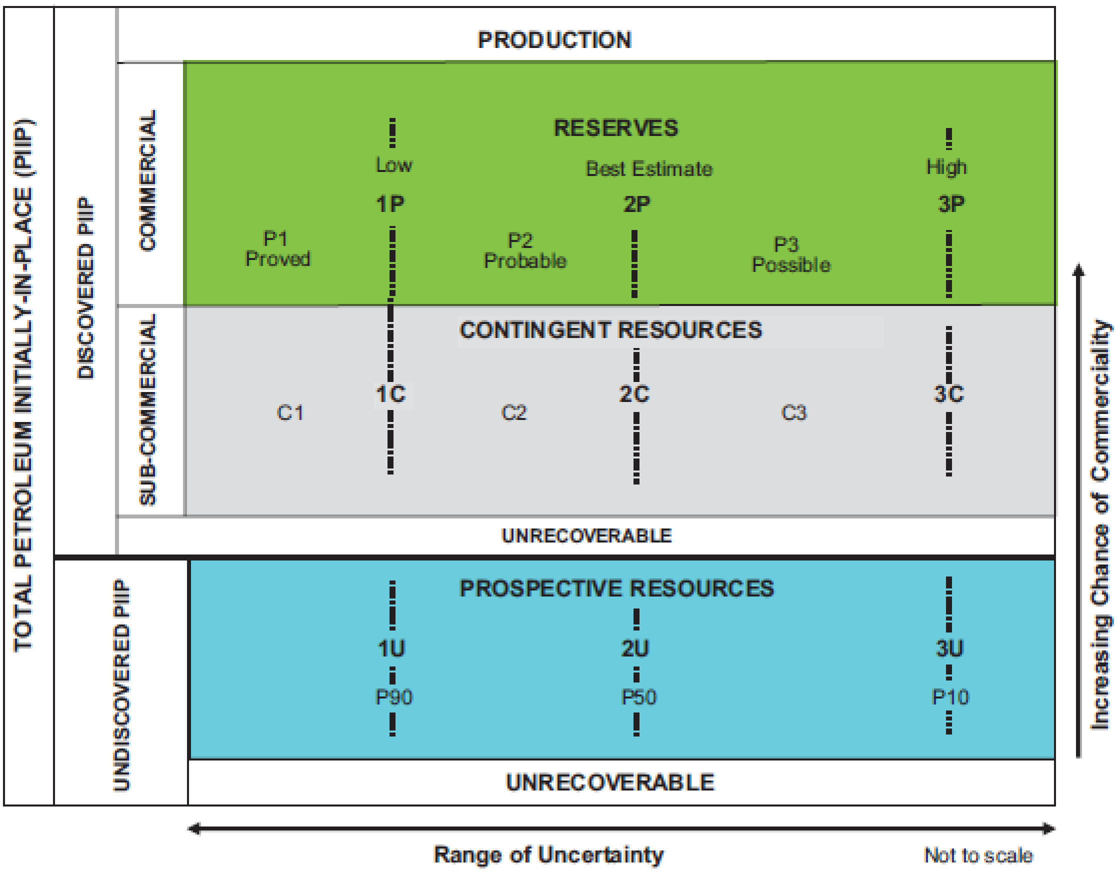
Marianne Eide

Chief Operating Officer

2. Reserves and Contingent Resources Classification

ERC Equipoise Ltd ("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 2023. 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"). 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), Undeveloped Reserves associated with the ongoing Tyra II project, one project in the sub-class Approved for Development, and three projects in the sub-class Justified for Development that have not yet been sanctioned, and four 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).

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 29 September 2003 by the Danish Minister for Economic and Business Affairs for the period 1st January 2004 and up to 8 July 2042.

The Tyra II project was sanctioned in December 2017 because 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 31 March 2024 and a ramp-up of four months based on REMIT Notification issued 22 January 2024. All associated volumes are reported as Under Development. Once the Tyra facilities are restarted, the Undeveloped Reserves in the Tyra hub fields are expected to be reclassified as Developed Reserves.

3. Reserves Estimation

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).

The Reserves are reported on a field gross, Company working interest and Company net entitlement basis as of 31 December 2023. 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").

The 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.

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, whichever occurs soonest.

4. Reserves

The Developed Reserves include the fields on production from the Dan, Halfdan and Gorm hubs. The Undeveloped Reserves includes Reserves from the Tyra II project, two Halfdan infill wells and three other development projects.

Table 1 – BlueNord 1P, 2P and 3P Reserves as of 31.12.2023

Reserves as of 31.12.2023	Interest	1P Gross Liquids MMstb	1P Gross Gas Mmboe	1P Gross boe Mmboe	1P Net boe Mmboe	2P Gross Liquids MMstb	2P Gross Gas Mmboe	2P Gross boe Mmboe	2P Net boe Mmboe	3P Net boe Mmboe
On Production										
Dan	36.8%	30.9	1.7	32.6	12.0	60.4	4.5	64.9	23.9	33.0
Kraka	36.8%	3.5	0.0	3.5	1.3	6.9	0.1	7.1	2.6	3.6
Dan Hub	36.8%	**34.3**	**1.7**	**36.1**	**13.3**	**67.4**	**4.6**	**72.0**	**26.5**	**36.5**
Halfdan	36.8%	37.8	12.5	50.2	18.5	77.6	24.9	102.6	37.7	53.0
Halfdan hub	36.8%	**37.8**	**12.5**	**50.2**	**18.5**	**77.6**	**24.9**	**102.6**	**37.7**	**53.0**
Gorm	36.8%	8.4	-	8.4	3.1	14.4	-	14.4	5.3	7.8
Skjold	36.8%	13.4	0.1	13.5	5.0	22.4	1.2	23.7	8.7	13.3
Rolf	36.8%	1.5	-	1.5	0.5	2.4	-	2.4	0.9	1.3
Gorm hub	36.8%	**23.3**	**0.1**	**23.3**	**8.6**	**39.3**	**1.2**	**40.5**	**14.9**	**22.5**
Total		**95.4**	**14.3**	**109.7**	**40.4**	**184.3**	**30.8**	**215.1**	**79.1**	**112.0**
Under Development										
Tyra	36.8%	17.3	43.7	61.0	22.4	31.6	83.2	114.8	42.2	65.4
Valdemar	36.8%	24.6	12.6	37.3	13.7	38.4	21.3	59.7	22.0	30.4
Roar	36.8%	3.8	9.3	13.2	4.8	7.0	16.1	23.1	8.5	12.3
Lulita	28.4%	0.8	0.5	1.2	0.4	1.0	0.6	1.6	0.4	0.5
Harald	36.8%	0.6	3.5	4.1	1.5	1.1	5.5	6.7	2.5	3.3
Total		**47.1**	**69.6**	**116.8**	**42.9**	**79.0**	**126.8**	**205.8**	**75.6**	**111.9**
Approved for Development and Justified for Development										
Halfdan HCA Gas Lift	36.8%	0.2	3.8	4.0	1.5	0.6	7.4	8.0	2.9	3.2
Valdemar Bo South	36.8%	9.3	4.0	13.3	4.9	17.2	7.7	24.9	9.2	14.9
Adda (Phase 1)	36.8%	7.7	12.2	20.0	7.4	17.2	23.0	40.2	14.8	25.1
Halfdan Infill (Ekofisk)	36.8%	3.6	1.8	5.5	2.0	5.7	5.1	10.8	4.0	6.0
Total		**20.9**	**21.9**	**42.8**	**15.7**	**40.7**	**43.1**	**83.8**	**30.8**	**49.3**
On Production plus Under Development										
Total		**142.5**	**83.9**	**226.4**	**83.2**	**263.3**	**157.6**	**420.9**	**154.7**	**223.9**
On Production plus Under Development plus Justified for Development										
Total Reserves		**163.4**	**105.8**	**269.2**	**99.0**	**304.0**	**200.6**	**504.6**	**185.6**	**273.2**

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 field 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. ERCE has assumed each hub provides its own fuel gas and imports fuel gas if it is fuel gas deficient.
5. The Halfdan WROM I/II programme and the recently drilled infill Well HBA-27B are included in the Halfdan Hub Developed Reserves.
6. Halfdan Hub Undeveloped Reserves include the HCA gas lift project and two Ekofisk infill wells.
7. The Gorm Hub Developed Reserves include Skjold field Developed Reserves based on the Skjold gas acceleration project.
8. Tyra Hub Undeveloped Reserves include the Valdemar Bo South and Adda (Phase 1) developments.

Table 2 – BlueNord 1P, 2P and 3P Developed plus Under Development Reserves as of 31.12.2023

Reserves per hub *as of 31.12.2023*	*Interest*	1P Gross liquids *mmbbl*	1P Gross gas *mmboe*	1P Gross boe *mmboe*	1P Net boe *mmboe*	2P Gross liquids *mmbbl*	2P Gross gas *mmboe*	2P Gross boe *mmboe*	2P Net boe *mmboe*	3P Net boe *mmboe*
Dan	36.8%	30.9	1.7	32.6	12.0	60.4	4.5	64.9	23.9	33.0
Kraka	36.8%	3.5	0.0	3.5	1.3	6.9	0.1	7.1	2.6	3.6
Dan Hub		**34.3**	**1.7**	**36.1**	**13.3**	**67.4**	**4.6**	**72.0**	**26.5**	**36.5**
Halfdan	36.8%	37.8	12.5	50.2	18.5	77.6	24.9	102.6	37.7	53.0
Halfdan Hub		**37.8**	**12.5**	**50.2**	**18.5**	**77.6**	**24.9**	**102.6**	**37.7**	**53.0**
Gorm	36.8%	8.4	0.0	8.4	3.1	14.4	0.0	14.4	5.3	7.8
Skjold	36.8%	13.4	0.1	13.5	5.0	22.4	1.2	23.7	8.7	13.3
Rolf	36.8%	1.5	0.0	1.5	0.5	2.4	0.0	2.4	0.9	1.3
Gorm Hub		**23.3**	**0.1**	**23.3**	**8.6**	**39.3**	**1.2**	**40.5**	**14.9**	**22.5**
Tyra	36.8%	17.3	43.7	61.0	22.4	31.6	83.2	114.8	42.2	65.4
Valdemar	36.8%	24.6	12.6	37.3	13.7	38.4	21.3	59.7	22.0	30.4
Roar	36.8%	3.8	9.3	13.2	4.8	7.0	16.1	23.1	8.5	12.3
Harald	36.8%	0.8	0.5	1.2	0.4	1.0	0.6	1.6	0.4	0.5
Lulita	28.4%	0.6	3.5	4.1	1.5	1.1	5.5	6.7	2.5	3.3
Tyra Hub		**47.1**	**69.6**	**116.8**	**42.9**	**79.0**	**126.8**	**205.8**	**75.6**	**111.9**
Total Reserves		**142.5**	**83.9**	**226.4**	**83.2**	**263.3**	**157.6**	**420.9**	**154.7**	**223.9**

Table 3 – BlueNord 1P, 2P and 3P Reserves Development from 31.12.2022 to 31.12.2023

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
YE2022 Reserves	**46.5**	**88.0**	**113.7**	**56.6**	**74.4**	**84.4**	**9.7**	**20.0**	**28.3**	**112.8**	**182.4**	**226.4**
2023 Production	9.1	9.1	9.1	0	0	0	0	0	0	9.1	9.1	9.1
Acquisitions and disposals												
Revisions	3.0	0.2	7.4	-13.7	1.2	27.5	-0.9	-3.1	-2.8	-11.7	-1.6	32.1
Discovery and Extensions												
Additions												
Projects Matured							6.9	13.9	23.8	6.9	13.9	23.8
YE2023 Reserves	**40.4**	**79.1**	**112.0**	**42.9**	**75.6**	**111.9**	**15.7**	**30.8**	**49.3**	**99.0**	**185.6**	**273.2**
Delta (YE2023-YE2022)	**-6.1**	**-8.9**	**-1.7**	**-13.7**	**1.2**	**27.5**	**6.0**	**10.8**	**21.0**	**-13.9**	**3.2**	**46.8**

Notes

1. The line 'Production 2023' is the BlueNord share of sales volumes (in mmboe).

The production performance in 2023 was excellent mainly due to a high level of well intervention and restimulation activities as well as a high operational efficiency.

Through 2022 and 2023, the Operator carried out a Well Reservoir Optimisation Management I ("WROM I") campaign which included more than 40 wells across the Dan field. One well in 2024 concludes the campaign on Dan, and a WROM II campaign will be carried out on Halfdan from 2024 through to Q1 2025 with 24 planned activities.

The delivered operational efficiency was 86% which was delivered despite unplanned production losses in connection to a crack in the flare piping on Gorm C and a leak on the inlet manifold of the Haldan BD compressor. This was possible because of excellent operational performance by the Operator as well as by the Halfdan re-route work on Dan and Halfdan being completed ahead of schedule with less than expected impact on the Dan and Halfdan production.

As an acknowledgement of the good production performance of the Gorm hub, life extension activities were initiated by the partnership in 2023. The purpose of these activities is to ensure the integrity of the facilities into the future.

Routine flaring has been eliminated in DUC as of the 6 of July 2023. The routine flaring was caused by flaring of excess gas from the final stabilisation of Halfdan oil on Gorm as there was no available export route. This routine flaring was eliminated through the Halfdan reroute project, where the oil from Halfdan is now being routed to Dan for final stabilisation.

Between 2020 and 2022, eight new Tyra platforms were installed including six wellhead platforms, an accommodation platform and a processing platform. These new facilities will serve as the new hub for production from Tyra and its satellite fields. The process of unplugging Tyra and Tyra SE wells began in late 2023 and will continue through Q1 and Q2 2024. First gas is scheduled 31 March 2024 and production will be ramped up over a period of four months with full production potential expected to be achieved in Q3 2024 as per REMIT notification dated 22 January 2024

The YE 2023 2P reserves estimation resulted in a 2P reserves replacement of 135% and consists of both upward and downward revisions.

The key drivers of the revisions of **Reserves On Production** which has an overall reduction of 1.6 MMboe are related to the following:

- A downward revision on Dan field based on the Reserves Evaluator's view on production/cost.
- An upward revision on Kraka field based on the Reserves Evaluator's view on production/cost.
- An upward revision of Halfdan Main is based on the field performance in 2023 confirming a reduced reservoir production decline during 2023.
- An upward revision of Halfdan Main due to inclusion of WROM II and transfer of HBA-27B from Undeveloped to Developed Reserves
- A downward revision of Gorm, Skjold and Rolf driven mainly by a reduced economic limit of the Gorm Hub based on the Reserves Evaluator's view on production/cost.

To keep production high in 2024 and beyond, the plan for 2024 is to continue with workovers on the Dan field, maintain the high uptime with continued focus on the unplanned shortfalls, carry out well optimization through restimulations on all hubs and WROM I/II on Halfdan. Finally, one infill well in Ekofisk will be drilled in the Halfdan Main field. An exploration keeper well is planned for 2024 in Harald East Middle Jurassic area. In case of success the well will increase production through the Harald platform. This well is not included in the Reserves and Contingent Resources as it has a 70% PoS and thus sits under Exploration.

The YE 2023 reserves estimation for the **Approved and Justified for Development** has an overall increase of 13.9 MMboe, and the key drivers for the upward and downward revisions are related to the following:

- An upward revision on HCA gas lift based on the Reserves Evaluator's view on production/cost.
- Maturation of the Adda project Phase 1 from Contingent Resources into Justified for Development
- HBA-27B transferred from Approved for Development to Developed Reserves
- A downward revision of Halfdan NE due to the infill well HBA-15 being contingent on HBA-27B results and results of recently acquired 4D seismic.

5. Developed Fields

The DUC assets consist of fourteen developed fields. All fields are situated 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 during the Tyra II project, gas is exported to the Netherlands via the NOGAT pipeline. After the Tyra hub is back on production, gas will be exported both via NOGAT to Netherlands and via Tyra II to shore in Denmark.

5.1 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 43 active oil wells and 34 active water injectors. By end of 2023 the field has produced 759 MMstb of oil and 1001 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 7 oil wells are producing. By end of 2023 the field has produced 41 MMstb of oil and 65 Bscf of gas.

5.2 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 33 active oil producers and 26 active water injectors. By end of 2023 the field has produced 536 MMstb of oil and 604 Bscf of gas.

In July 2023, an infill well HBA-27B was spudded and after several drill string failures, a third sidetrack successfully drilled into the Tor reservoir. The well is currently completed and is expected to be stimulated and brought on production March 2024.

Halfdan North East has been developed in three phases and 17 wells have been drilled, with currently 17 active gas producers. By end of 2023 the field has produced 17 MMstb of oil and 801 Bscf of gas.

5.3 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 15 active producers and 6 active water injectors. By end of 2023 the field has produced 403 MMstb of oil and 600 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 drive mechanism is waterflooding. 30 wells have been drilled, with currently 16 active oil producers and 8 active water injectors. By end of 2023 the field has produced 314 MMstb of oil and 160 Bscf of gas.

A gas acceleration project is planned to be implemented in 2024 in the Skjold field. The project will see 4 of the 8 injection wells turned off to enable a switch to depletion in the East and West areas of the field. The expectation is that this will lead to increased gas and oil production in the near-term. Additional gas will provide fuel gas for Gorm hub operations and following modifications to allow gas export from Gorm to Halfdan, a portion of the increased gas production is expected to be available for export.

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 1 active oil producer. By end of 2023 the field has produced 31 MMstb of oil and 8 Bscf of gas.

5.4 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 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 referred to as the Tyra II project. In that connection, production from the entire Tyra hub has been closed in since Q3 2019. The Tyra II 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. The estimated start-up of the new Tyra facility and the Tyra Satellites is scheduled for March 2024. A total of 93 wells have been drilled on Tyra Main and SE. In Tyra Main the plan is to reinstate 31 wells. By end of 2023, the field has produced 172 MMstb and 3,774 Bscf of gas. In the Tyra SE field, the plan is to reinstate 16 wells. By end of 2023, the field has produced 35.5 MMstb of oil and 477 Bscf of gas.

Tyra acts further as the gas gathering center and export hub for all DUC fields. During the Tyra II project, Dan acts as the temporary 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 a plan to reinstate 22 oil and gas producers. By end of 2023 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 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 a plan to reinstate all 4 producers. By end of 2023 the field has produced 589 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. 4 wells have been drilled, 2 on Harald West and 2 on Harald East, and all 4 wells are planned to be reinstated. By end of 2023 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. 2 wells have been drilled, however only 1 is planned to be reinstated. By end of 2023 the field has produced 7.4 MMstb of oil and 28 Bscf of gas. DUC holds an 50% interest in the Lulita field with Ineos (40%) and BlueNord (10%) as partners.

6. Development Projects - Reserves

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

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 2025 due to the strong production performance in 2023 still driven by the successful restimulation in June 2022 and the reduction of Tubing Head Pressure (THP) in June/August 2023 resulting in improved gas production. The project will convert an 8-inch condensate export line to import gas-lift gas from the HBB platform with the HCA 16-inch gas export line converted to a multi-phase pipeline. The project is assigned Undeveloped Reserves.

6.2 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. There are plans to drill two Ekofisk infill wells in the Halfdan field starting in Q4 2024. The well locations will be optimised based on the results and interpretation of the 2023 4D seismic survey. The two wells are considered firm and have been assigned Undeveloped Reserves, although FID has not been taken at the date of the Evaluation.

6.3 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 Valdemar Bo South FDP was submitted in 2020 and the proposed development 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 128" multiphase pipeline.

The project is currently nearing the end of the Front-End Engineering Design ("FEED") stage with the only outstanding issue being a design change on the diameter of the pipeline to the VCA platform to reduce the risk of any issues during pigging. First oil is scheduled in Q4 2027. The Valdemar Bo South Undeveloped Reserves are classified as Justified for Development.

6.4 Adda Phase 1

The Adda discovery is located ~12 km northeast of the Tyra East facility. It was discovered in 1977 and appraised by a further five wells between 1981 and 1997. Adda 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 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 ERCE's assessment).

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 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 has 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.

An FDP was submitted to the DEA in 2021 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 Adda development includes five horizontal production wells in the Tuxen reservoir and one horizontal production well in the Hod reservoir. The current expectation is for first gas in Q2 2028. Phase 1 Undeveloped Reserves are classified as Justified for Development. The FDP includes additional development wells in Phase 2, but these are classified as Contingent Resources.

7. 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 ERCE as Reserves, the assets include quantities that have been classified by ERCE as Contingent Resources. ERCE's estimates of Contingent Resources are based on an independent evaluation of data provided by BlueNord. Estimates are based on decline curve analysis in conjunction with volumetric methods and reviews of reports such as field development plans.

No economic analysis has been performed on the Contingent Resources and, therefore, their economic status is undetermined.

Table 4 – BlueNord 1C, 2C and 3C contingent resources as of 31.12.2023

		1C				2C				3C
Contingent Resources 31.12.2023	Interest	Gross Liquids MMstb	Gross Gas MMboe	Gross boe MMboe	Net boe MMboe	Gross Liquids MMstb	Gross Gas MMboe	Gross boe MMboe	Net boe MMboe	Net boe MMboe
Halfdan Tor NE Infill (HBA-15)		0.7	0.5	1.2	0.4	1.4	1.0	2.4	0.9	1.3
Adda Phase 2	36.8%	1.6	5.7	7.3	2.7	3.4	10.5	14.0	5.2	8.9
Halfdan North	36.8%	20.8	3.1	24.0	8.8	38.4	5.9	44.3	16.3	25.3
Svend Re-development	36.8%	5.3	0.8	6.1	2.2	11.4	1.7	13.1	4.8	7.4
Total		**28.4**	**10.1**	**38.5**	**14.2**	**54.7**	**19.0**	**73.7**	**27.1**	**42.8**

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 three projects: Halfdan North, Adda and Svend Reinstatement are classified by ERCE as Contingent Resources. The Halfdan Tor NE infill HBA-15 was reclassified from Approved for Development Reserves to Contingent Resources at YE 2023, see Section 8.1. 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 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), but this has now been deferred to Q3 2025, and this second well is contingent on the performance of Well HBA-27B and evaluation of the 4D seismic acquired in 2023 in the Dan-Halfdan area and as such has been assigned Contingent Resources and sub-classified as Development Pending.

8.2 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.

An FDP was submitted in 2020 to the DEA which proposes the discovery is developed with a 12-slot unmanned wellhead platform tied back to the HBD platform in the Halfdan field. Five horizontal production wells and four horizontal water injection wells will be drilled in an alternating, line-drive pattern. The production wells will have CAJ liner completions and injection wells will be hydraulically fractured. The Operator currently expects first oil to be in 2029 or 2030. Contingent Resources are sub-classified as Development on Hold due to the timeframe to development.

8.3 Adda Phase 2

The Adda Phase 2 project consists of two additional horizontal gas production wells in the 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 Adda development but are also located in a more structurally and stratigraphically complex area of the discovery which poses drilling risks.

The Contingent Resources are sub-classified as Development On Hold based on the timeframe to potential development. Production from Phase 1 of the Adda development is scheduled in Q2 2028, meaning any Phase 2 development would likely occur in late 2028 or 2029.

8.4 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. The wells have been abandoned and the unmanned wellhead platform has been left in "lighthouse mode" ahead of a potential re-development of the field with two new infill wells.

The Svend re-development project involves drilling two infill wells (one in the north and one in the south) and upgrading the facilities to reinstate production. A solution to address flow assurance issues by the conceptual studies will be defined following the results of the Harald East Mid-Jurassic Exploration well, which are expected in Q3 2024.

The Contingent Resources are sub-classified as Development Unclarified based on the need for further conceptual study following the results of the Harald East Mid-Jurassic exploration well.

9. ProspectiveResources

No prospective resources have been included in this report.