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Norwegian Energy Company ASA
Annual Statement of Reserves 2021

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1 Management's Discussion and Analysis (MD&A)

The reported 2P reserves include remaining volumes expected to be recovered based on reasonable assumptions about future technical, economical, fiscal, and financial conditions based on year end 2020 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 percent, a long- term exchange rate of 6.67 DKK/USD, and a long-term Brent oil price of 60 USD/bbl (real 2021 terms) plus a premium to account for the oil quality compared to the Brent benchmark. A gas sales price of US$4.6/MMBtu in 2021 has been assumed, with a forward profile provided by independent consultancy Rystad Energy for the European gas market. This is the price for physical delivery through the transfer of rights of natural gas at the Title Transfer Facility (TTF) virtual trading point, operated by Gasunie Transport Services (GTS), the transmission system operator in the Netherlands.

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.

All volumes reported are estimated by an independent third-party consultancy RISC (UK) Ltd. All production- and cost profiles are included in the RISC 2021 reserves evaluation report for completeness and assessment of economic cut-off. The volumes are disclosed on a non-reliance basis. All volumes reported are estimated by an independent third-party consultancy RISC (UK) Ltd. RISC has consented to the use of its report.

John Hulme

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2 Introduction

RISC (UK) Ltd (RISC) has made an independent reserves evaluation based on the definitions and guidelines set out in the revised June 2018 Petroleum Resources Management System (PRMS) version 1.01 (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)."

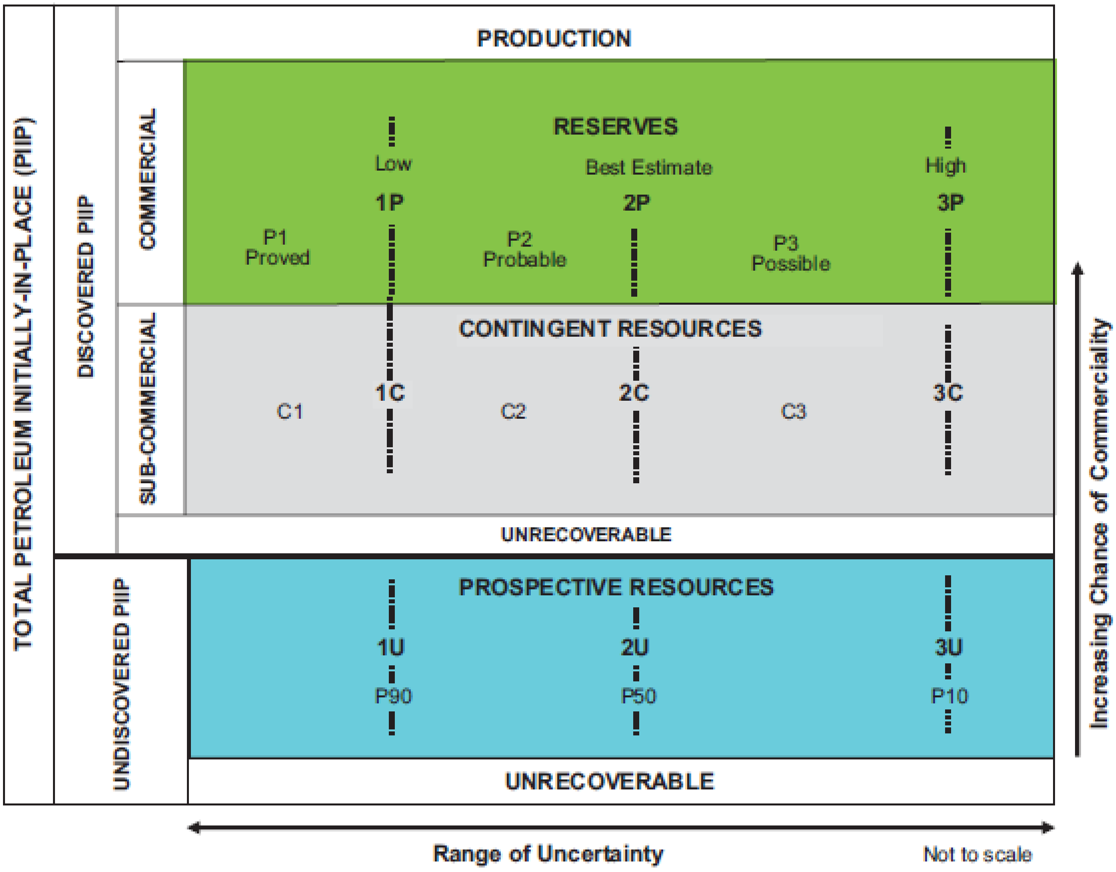

Figure 1 – Petroleum Resources Classification System

This report provides an overview of Developed Reserves (on production), Undeveloped reserves associated with ongoing projects, and three projects in the sub-class Justified for Development that has not yet been sanctioned. No assessment has been made of contingent or prospective resources (in accordance with the classification table above) by RISC.

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

Total	43.2% equity (Operator)
Noreco	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.

License extension agreement where granted 29th September 2003, with the Danish Minister for economic and Business Affairs for the period 1st January 2004 and up to 8th July 2042.

Seabed subsidence of the aging Tyra West and Tyra East platforms posed a risk for the platform integrity under severe weather conditions. Consequently, the DUC partners made a final investment decision (FID) and sanctioned the Tyra Redevelopment project in December 2017. Tyra and the associated satellite fields were closed-in end of Q3 2019 and production start-up from the new Tyra facility and satellites are scheduled for 2023. All associated volumes are reported as Under Development.

COVID-19 resulted in restrictions at the fabrication yard, delays in the supply chain, and reductions in offshore manning levels in 2020. This resulted in a delay to the expected restart of the Tyra facilities and fields to July 2023 at 50% and ramp-up finished by November 2023, where the Tyra hub will be on full production. The Tyra delay does not have a material impact on the total reserves from the Tyra hub given license expiry in 2042.

Two commercial projects at the Halfdan production hub and one commercial project at the Valdemar field in the Tyra hub have field development plans underway and volumes are included in the Justified for Development category.

3 YE20 – Developed and Undeveloped Reserves

The developed reserves are comprised of the fields on production from the Dan, Halfdan and Gorm hubs and until end of field life. The undeveloped reserves comprise of reserves from the Tyra redevelopment project and two development projects in the Halfdan Area and one in the Valdemar Area.

Table 1 – Noreco 1P, 2P and 3P reserves as of 31.12.2020 per reserve class

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 31.12.2020	*Interest*	*mmbbl*	*mmboe*	*mmboe*	*mmboe*	*mmbbl*	*mmboe*	*mmboe*	*mmboe*	*mmboe*
On Production										
Dan	36.8%	43.8	2.5	46.3	17.0	71.2	3.8	75.0	27.6	33.3
Kraka	36.8%	6.3	0.2	6.5	2.4	9.4	0.3	9.7	3.6	3.9
Halfdan	36.8%	63.6	15.3	78.9	29.1	116.1	27.0	143.1	52.7	64.6
Gorm	36.8%	13.7	-	13.7	5.0	18.2	-	18.2	6.7	8.6
Skjold	36.8%	21.0	-	21.0	7.7	27.0	-	27.0	9.9	12.8
Rolf	36.8%	1.6	-	1.6	0.6	2.5	-	2.5	0.9	1.3
Total		**149.9**	**18.1**	**168.0**	**61.8**	**244.4**	**31.1**	**275.5**	**101.4**	**124.4**
Under Development										
Tyra Hub	36.8%	62.4	88.7	151.1	55.5	84.5	121.5	206.0	75.7	86.0
Total		**62.4**	**88.7**	**151.1**	**55.5**	**84.5**	**121.5**	**206.0**	**75.7**	**86.0**
Justified for Development										
Halfdan HCA gas lift	36.8%	0.2	3.2	3.3	1.2	0.3	6.4	6.8	2.5	3.1
Halfdan North	36.8%	14.6	1.7	16.2	6.0	25.6	2.8	28.3	10.4	16.8
Valdemar Bo South	36.8%	12.4	4.4	16.8	6.2	20.8	9.4	30.2	11.1	15.8
Total		**27.1**	**9.2**	**36.3**	**13.4**	**46.7**	**18.6**	**65.3**	**24.0**	**35.8**
On Production plus Under Development										
Total		**212.3**	**106.7**	**319.0**	**117.3**	**328.9**	**152.7**	**481.5**	**177.1**	**210.4**
On Production plus Under Development plus Justified for Development										
Total Reserves		**239.4**	**116.0**	**355.4**	**130.7**	**375.6**	**171.2**	**546.8**	**201.1**	**246.1**

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 sales gas.

Table 2 – Noreco 1P, 2P and 3P On Production plus Under Development reserves as of 31.12.2020 per associated hub

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 31.12.2020	*Interest*	*mmbbl*	*mmboe*	*mmboe*	*mmboe*	*mmbbl*	*mmboe*	*mmboe*	*mmboe*	*mmboe*
Dan	36.8%	43.8	2.5	46.3	17.0	71.2	3.8	75.0	27.6	33.3
Kraka	36.8%	6.3	0.2	6.5	2.4	9.4	0.3	9.7	3.6	3.9
Dan Hub		**50.1**	**2.7**	**52.8**	**19.4**	**80.6**	**4.1**	**84.7**	**31.2**	**37.1**
Halfdan	36.8%	63.6	15.3	78.9	29.1	116.1	27.0	143.1	52.7	64.6
Halfdan Hub		**63.6**	**15.3**	**78.9**	**29.1**	**116.1**	**27.0**	**143.1**	**52.7**	**64.6**
Gorm	36.8%	13.7	-	13.7	5.0	18.2	-	18.2	6.7	8.6
Skjold	36.8%	21.0	-	21.0	7.7	27.0	-	27.0	9.9	12.8
Rolf	36.8%	1.6	-	1.6	0.6	2.5	-	2.5	0.9	1.3
Gorm Hub		**36.3**	**0.0**	**36.3**	**13.3**	**47.7**	**0.0**	**47.7**	**17.5**	**22.7**
Tyra	36.8%	28.4	61.8	90.2	33.2	38.3	85.6	123.9	45.6	51.3
Valdemar	36.8%	28.2	12.8	41.1	15.1	39.2	18.8	58.0	21.3	25.2
Roar	36.8%	4.3	9.4	13.8	5.1	5.4	12.2	17.6	6.5	6.8
Harald	36.8%	0.8	4.2	5.0	1.8	0.9	4.5	5.4	2.0	2.2
Lulita	28.4%	0.7	0.4	1.1	0.3	0.7	0.5	1.2	0.3	0.3
Tyra Hub		**62.4**	**88.7**	**151.1**	**55.5**	**84.5**	**121.5**	**206.0**	**75.7**	**86.0**
Total Reserves		**212.3**	**106.7**	**319.0**	**117.3**	**328.9**	**152.7**	**481.5**	**177.1**	**210.4**

Table 3 – Noreco 1P, 2P and 3P reserves development from 31.12.2019 to 31.12.2020

Reserves Development	On Production			Under Development			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 31.12.2019	**89.1**	**118.4**	**140.1**	**57.9**	**77.0**	**88.0**	**8.7**	**13.4**	**20.2**	**155.7**	**208.9**	**248.3**
Production	10.4	10.4	10.4	-	-	-	-	-	-	10.4	10.4	10.4
Acquisition and disposals	-	-	-	-	-	-	-	-	-	-	-	-
Revisions	-16.9	-6.6	-5.3	-2.4	-1.3	-2.0	-1.5	-0.5	-0.2	-20.8	-8.5	-7.5
Discovery and Extensions	-	-	-	-	-	-	-	-	-	-	-	-
New Developments	-	-	-	-	-	-	6.2	11.1	15.8	6.2	11.1	15.8
Projects matured	-	-	-	-	-	-	-	-	-	-	-	-
Balance as of 31.12.2020	**61.8**	**101.4**	**124.4**	**55.5**	**75.7**	**86.0**	**13.4**	**24.0**	**35.8**	**130.7**	**201.1**	**246.1**
Delta (2020-2019)	**-27.3**	**-17.0**	**-15.7**	**-2.4**	**-1.3**	**-2.0**	**4.7**	**10.6**	**15.6**	**-25.0**	**-7.8**	**-2.2**

2020 production (Noreco share) is the Available for Sales volume based on actual production, fuel and flare and re-injected volumes determined by Noreco.

The main reason for the **Reserves On Production** revision is related to the following:

- A revised decline on Dan based on a reduction in wells online at end 2020 due to COVID-19 restrictions preventing well service activities
- A revised decline on Halfdan Main is based on a reduction in wells online end 2020 due to COVID-19 restrictions preventing well service activities, a revision of the expected reservoir performance and a lower uptime in 2020.

- The lower 1P forecasts on Dan and Halfdan main resulted in 5 year earlier economic cut-off compared to the year end 2019 estimate.

Initiatives were put in place to increase activities during Q4 2020 with the aim to continue well services activities at a higher level during 2021 compared to 2020

The reason for the reserves write-down of the **Reserves Under Development** is related to the following:

- The delay of the Tyra Redevelopment Project with a small volume now pushed beyond license expiry in 2042.

No contingent or prospective resources has been included in this report.

4 Reserves – Technical Evaluation

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 guidelines. RISC has conducted a review of the information and technical work provided by Noreco and formed an independent view of the reserves on a field by field basis.

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 Operators YE20 reserves forecasts (simulation work). These simulations and reports were not available to Noreco or RISC. They were not auditable, but the simulation forecasts appear reasonable for initial production rate, with the general trends following historical trends.

Reserves has been classified accordingly to the associated risk and 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, the cessation of production (COP) date used to estimate Reserves is defined as the latest year with positive operating cash flow, or the end of the technical field life (typical end of the license period), whichever occur soonest. 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 typical exhibit less portfolio effect. Hence, the statistically median will tend to approach the mean of the distribution.

5 Assets Portfolio

5.1 Introduction

The DUC assets consist of eleven active 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 in 1972 and oil and gas are exported to shore via one oil pipeline from Gorm and two gas pipelines from Tyra.

[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.

5.2 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 has been drilled, with currently 37 active oil wells and 33 active water injectors. By end of 2020 the field has produced 741 MMstb of oil and 970 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 2020 the field has produced 39 MMstb of oil and 64 Bscf of gas.

5.3 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 has been drilled, with currently 32 active oil producers and 26 active water injectors. By end of 2020 the field has produced 513 MMstb of oil and 608 Bscf of gas.

Halfdan NE has been developed in three phases and 18 wells have been drilled, with currently 16 active gas producers. By end of 2020 the field has produced 13.1 MMstb of oil and 709 Bscf of gas.

5.4 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 17 active producers and 6 active water injectors. By end of 2020 the field has produced 398 MMstb of oil and 596 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 2020 the field has produced 306 MMstb of oil and 155 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 producers. By end of 2020 the field has produced 30 MMstb of oil and 7.5 Bscf of gas.

5.5 Tyra Hub

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 produce 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 Re-development project scope include replacing the existing accommodation and processing platforms by one single accommodation and one processing platform. The wellhead jackets will be 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 Q2 2023. A total of 93 wells have been drilled on Tyra Main and SE, with currently 47 active oil and gas producers by end of 2019 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 has 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 2019 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 2019 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 2019 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 2019 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 Noreco (10%) as partners.