ANNUAL STATEMENT OF RESERVES AND RESOURCES

2020

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1 Introduction

The Annual Statement of Reserves and Resources (ASR) is a full overview of the hydrocarbon volumes entitled to OKEA ASA and is prepared for both internal and external stakeholders. The reserves calculations and reporting are in line with the *Listing and Disclosure Requirements for Oil and Natural Gas Companies* as stated by the Oslo Stock Exchange.

The overview in this document is the final version of the ASR 2020, with cut-off date 31.12.2020.

2 Classification of reserves and contingent resources

OKEA's reserve and contingent resource have been classified in accordance with the Petroleum Resources Management System (PRMS) of the Society of Petroleum Engineer (SPE). This classification system is consistent with Oslo Stock Exchange's requirements for the disclosure of hydrocarbon reserves and contingent resources. The framework of the classification system is illustrated in *Figure 1*.

For completeness, OKEA reports not only 1P and 2P reserves, but also 3P reserves, as well as contingent resources and prospective resources. All categories are reported in line with the PRMS.

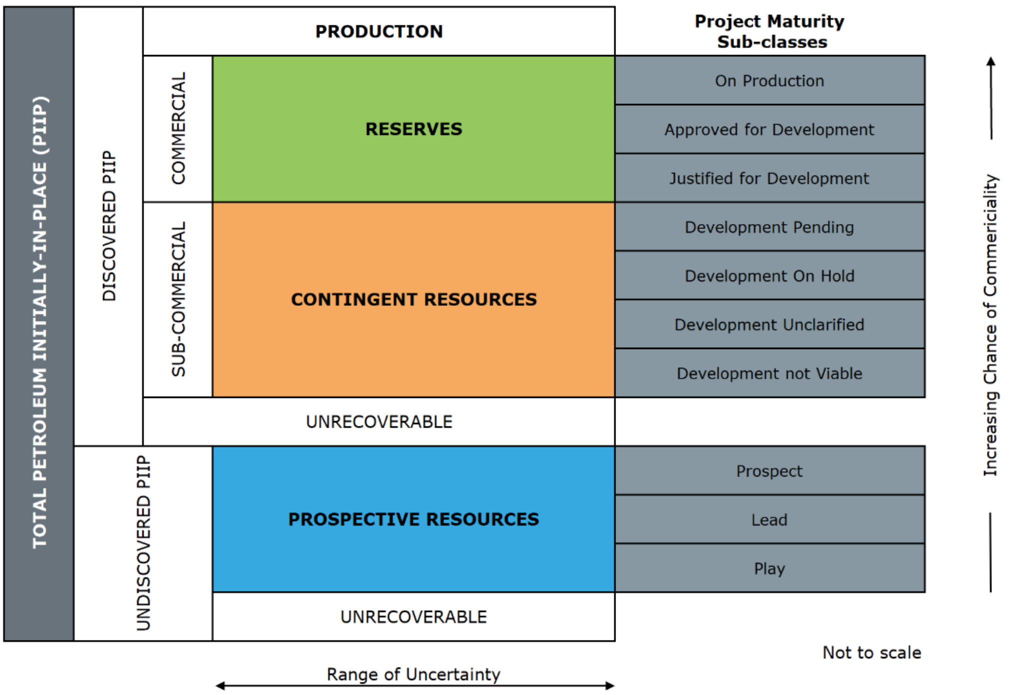

Figure 1: PRMS including sub-classes based on maturity

3 Reserves

OKEA ASA ("OKEA") has reserves distributed across four fields, listed in *Table 1*. The Project Status Category describes the maturity for each of the fields and projects according to the PRMS, c.f. *Figure 1*. Reserves categorised as "Approved for development" correspond to field developments for which the Plan for Development and Operations (PDO) is approved by the Ministry of Petroleum and Energy.

Table 1: OKEA asset portfolio with reserves

Field/Project	OKEA Working Interest	Operator	Project Status Category	Comment
Draugen field	44.560 %	OKEA	On production	Main portion of OKEA reserves
Gjøa field	12.0 %	Neptune	On production	
Ivar Aasen field	0.5540 %	Aker BP	On production	
Yme field	15.0 %	Repsol	Approved for development	First oil H2 2021

The reserves estimates are based on all technical data available including production data, logs, seismic data, cores, models, decline curve analysis etc.

For economic evaluations, the long-term oil price assumption is $65/bbl, with a long-term currency rate of USDNOK 8.0. Gas price and NGL prices are set to 1.64 NOK/Sm^3 and 466 USD/ton, respectively. A 2% annual inflation rate is used.

Note that the gas reserves are reported as sales gas, given the actual Gross Calorific Value (GCV), and not converted to 40 MJ/ Sm^3.

In addition, the following conversion factors are used:

Oil - 1 Sm^3 = 1 Sm3 oe = 6.29 bbl

Gas - 1000 Sm^3 gas = 1 Sm^3 oe

1 Sm^3 = 35.315 Scf

NGL - 1 tonne NGL = 1.9 Sm^3 oe

3.1. Total reserves estimates

OKEA's net proven reserves (1P/P90) as of 31.12.2020 are estimated at 33.6 million barrels of oil equivalents. Total net proven plus probable reserves (2P/P50) are estimated at 41.6 million barrels of oil equivalents. The reserves figures account for the effects of production in 2020. The split between oil, NGL and gas, between individual assets and between the different subcategories is given in *Table 2*. The reserves numbers are verified by a third party reserves certification performed by AGR Petroleum Services AS.

Table 2: OKEA Reserves as of 31.12.2020

Asset/Project	OKEA WI (%)	1P/P90 (Low estimate)					2P/P50 (Base estimate)				
		Gross Oil (mmboe)	Gross NGL (mmboe)	Gross Gas (mmboe)	Gross oe (mmboe)	Net oe (mmboe)	Gross Oil (mmboe)	Gross NGL (mmboe)	Gross Gas (mmboe)	Gross oe (mmboe)	Net oe (mmboe)
Reserves – On Production											
Draugen	44.56 %	44.2	0.0	0	44.2	19.7	51.5	0.0	0	51.5	23.0
Gjøa	12.00 %	2.7	12.1	28.1	42.9	5.2	3.3	15.8	36.6	55.7	6.7
Ivar Aasen	0.554 %	40.2	2.3	7.1	49.6	0.3	84.4	4.4	13.6	102.4	0.6
Total Net oe						**25.1**					**30.2**
Reserves – Approved for Development											
Yme	15.00 %	48.0	0	0	48.0	7.2	62.9	0	0	62.9	9.4
Gjøa - P1	12.00 %	2.4	2.6	6.1	11.0	1.3	3.3	3.8	8.9	16.0	1.9
Total Net oe						**8.5**					**11.4**
Reserves – Justified for Development											
Total Net oe						**0**					**0**
Reserves –Total											
Total Net oe						**33.6**					**41.6**

Please note that totals in tables above are arithmetic and not stochastic summations.

The corresponding 3P/P10 estimate of net OKEA reserves is 50.6 mmboe. For comparison, the corresponding Total Net 1P-, 2P- and 3P-reserves in ASR 2019 (31.12.2019) were 40.6, 49.5 and 57.3 mmboe, respectively, c.f. *Table 3*.

3.2. Development of reserves

OKEA's reserves and resources continually change through field development work, improvement of technical subsurface models, acquisitions and production. *Table 3* illustrates how the volumes have changed since ASR 2019 (31.12.2019). "Production" is primarily related to the Gjøa and Draugen assets. "Revisions of previous estimates" on Draugen and Gjøa relate to results from updated history match and model updates. For the Gjøa P1 project the revision relates to updates following results from the pilot wells drilled in 2020 and a reduction in the number of planned production wells. For some assets, 1P volumes are reduced as result of early economic cut-off.

Table 3: OKEA Reserves Development from 31.12.2019 to 31.12.2020

Reserves Development								
Net attribute mmboe	On Production		Approved for Development		Justified for Development		Total	
	1P / P90	2P / P50	1P / P90	2P / P50	1P / P90	2P / P50	1P / P90	2P / P50
Balance EOY 2019	**30**	**35.9**	**10.6**	**13.5**	**0**	**0**	**40.6**	**49.5**
Production	**-5.70**	**-5.70**					**-5.70**	**-5.70**
Draugen	-2.81	-2.81						
Gjøa	-2.77	-2.77						
Ivar Aasen	-0.12	-0.12						
New Developments	-	-	-	-			-	-
Revisions of previous estimates	**0.81**	**-0.05**	**-2.04**	**-2.18**			**-1.22**	**-2.22**
Draugen	-0.87	-0.73						
Gjøa	1.68	0.65						
Gjøa - P1			-2.17	-2.08				
Ivar Aasen	0.00	0.04						
Yme			0.14	-0.09				
Projects matured	-	-	-	-			-	-
Extensions and Discoveries	-	-	-	-			-	-
Balance EOY 2020	**25.1**	**30.2**	**8.5**	**11.4**	**0.0**	**0.0**	**33.6**	**41.6**

3.3. Description of reserves

The following section describes fields on production and fields approved / justified for development where OKEA holds a working interest.

3.3.1. Draugen (PL093)

The Draugen field is located in the Norwegian Sea at 250 meters water depth, approximately 140 km Northwest of Kristiansund, c.f. Figure 2.

Discovery

The field was discovered with discovery well 6407/9-1 in 1984, proving oil in the Rogn Formation. This was the first discovery in Rogn on the Haltenbanken terrace, and initial testing confirmed an oil rate of more than 8 000 bbl/d.

Reservoir

The oil is in the Garn and Rogn formations, of which the latter holds approximately 90% of the reserves. The reservoir quality is extremely good, with average permeability of more than 2 Darcy. The best well, A-4 A, has the offshore world record oil production rate of 77 000 bbl/d.

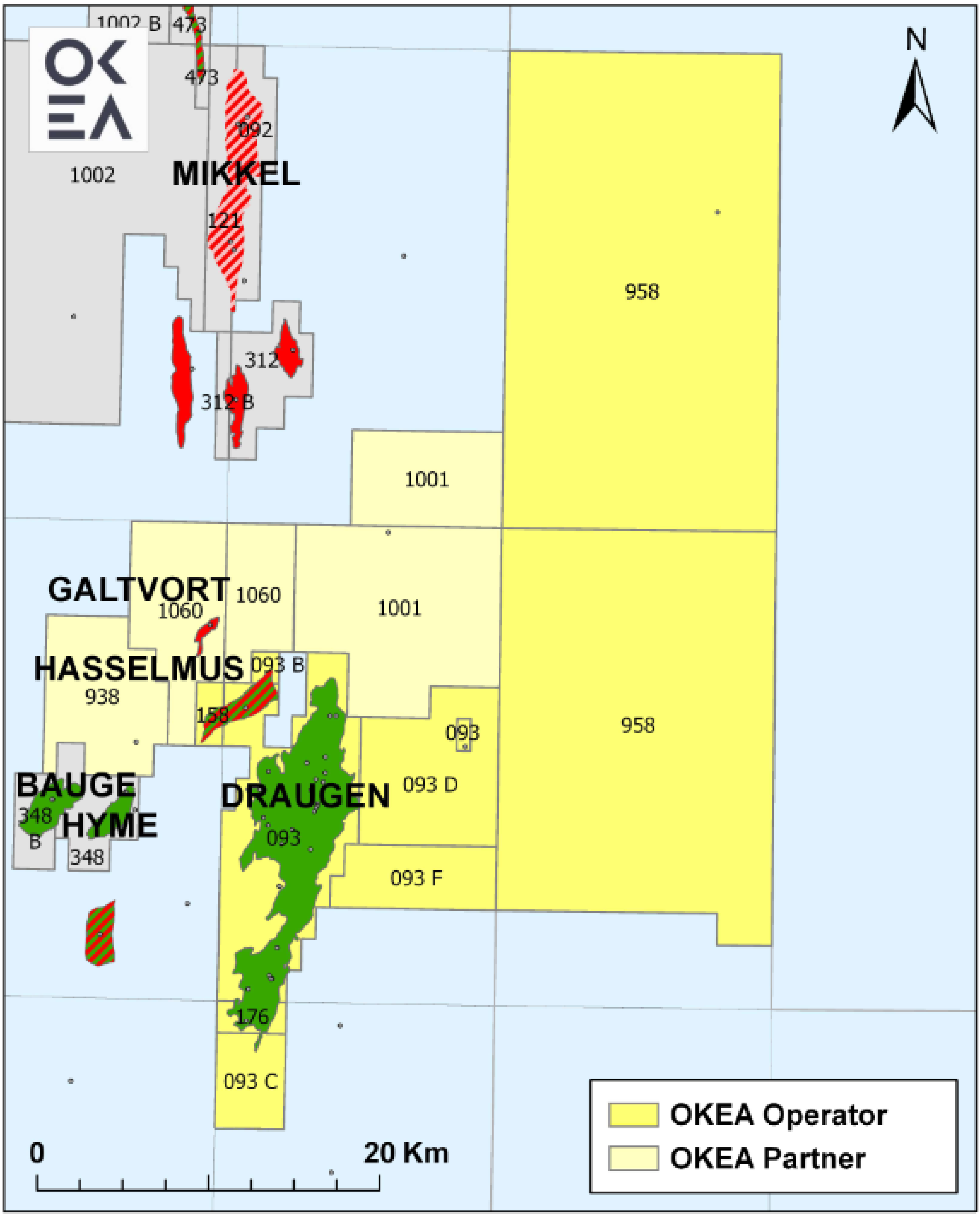

Figure 2: Draugen field location and adjacent area (Norwegian Sea). OKEA operates licences highlighted in yellow and is partner in PL1001 and PL938

Development

The field is developed with a concrete gravity-based structure (GBS), with full oil stabilisation and storage capabilities, c.f. *Figure 3*. Oil is exported by shuttle tankers. With the "Draugen long-term power project" being implemented in 2020, gas can now be both exported and imported through the gas pipeline connected to the Åsgard Transport System (ÅTS).

The drainage strategy is based on centrally located production wells, supported by down-flank water injectors. The field was initially developed with 6 platform wells and 1 subsea well and has later been supplemented by several subsea wells. The platform wells are gas lifted, while the subsea wells are produced via a subsea booster pump to lower the tubing head pressure.

Status

The current production on Draugen is in the order of 18 000 bbls of oil and 220 000 bbls of water per day. 110 000 bbls of water are reinjected to the reservoir, while the rest is discharged to sea.

Currently, five out of six platform wells and seven out of eleven subsea wells are in operation, in addition to two subsea water injectors. In the subsea production system, D-1 A is shut-in due to high water cut, G-3 is injecting condensate that cannot be exported. D-2 and E-1 are temporarily shut in due to well integrity issues. Subsea well G-2 and all E-wells produce on reduced choke setting due to low reservoir pressure combined with no gas lift available. Production is continuously monitored and optimized by a production management team.

Figure 3: Draugen Platform

The reserves estimates are based on the RNB2021 submission by OKEA, assuming production until economic field lifetime at end of 2035. OKEA has the ambition to extend the field lifetime to at least 2040, which would add further reserves and allow tie-in of more resources.

Contingent resources and prospective resources related to the Draugen field are described in Section 4 and 5, respectively.

OKEA's working interest on Draugen is 44.56%. The other licensees are Petoro AS (47.88%) and Neptune Energy Norge AS (7.56%).

3.3.2. Gjøa (PL153)

The Gjøa field is located in the northern part of the North Sea, 50 kilometres northeast of the Troll field, in the PL153 licence, c.f. *Figure 4*. Water depth in the area is 360 meters.

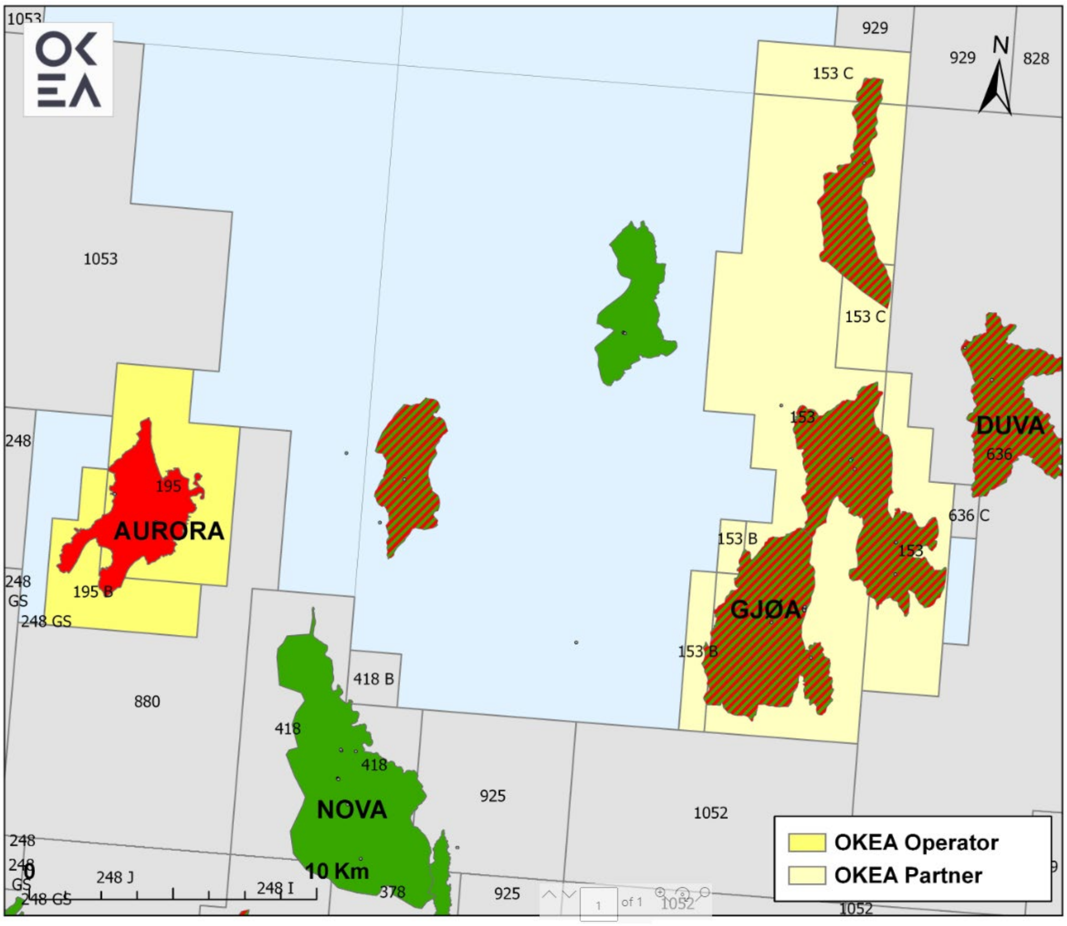

Figure 4: Gjøa field location (North Sea)

Discovery

The field was discovered by exploration well 35/9-1 / 35/9-1 R in 1989, confirming gas in the Viking and Brent groups, and oil in the Dunlin Group. Testing confirmed an oil rate of 5 680 bbl/d (Dunlin Fm.) and gas rates of 0.6 and 0.9 MSm^3/d (Brent and Viking).

Reservoir

The Gjøa reservoir comprises the Upper Jurassic Viking Group, and the middle Jurassic Brent and Dunlin groups. The oil column of 35-45m and the gas column of approximately 200m both have local variations. The reservoir is compartmentalised in seven segments, with heterogenous properties caused by alternating layers of good and poor reservoir sands, silts and shales. As a result, the porosity ranges from 10% to 27% and the permeability from hundreds of milli-Darcy to several Darcy.

Development

The drainage strategy is managed pressure depletion with concurrent oil rim production. The field is developed with eleven subsea wells, connected to five templates and directed back to a semi-submersible unit with full oil stabilisation capacities. Advanced well technology with branches and zonal control is implemented, and all wells have multiphase meters and permanent downhole gauges. The oil is exported through the Troll oil pipeline to the Mongstad terminal, and the gas is exported though the FLAGS pipeline to the St. Fergus terminal. In 2017, the production plant was upgraded to handle low pressure production to boost the reserves on Gjøa. The Gjøa platform was also the first floating platform with power from shore, reducing CO_2 emissions by 200 000 tons per year.

Status

The current production has a relatively stable gas rate of more than 8 000 MSm^3/d and a declining oil rate, currently at 1 200 Sm^3/d. Despite being expected to die in the spring of 2020, all oil wells are still on stream except the C-2 oil well, which is experiencing lift problems. The production in 2020 has been significantly better than the RNB2020-prognosis, mainly due to longer lifetime of the oil wells, but also due to a better availability than expected.

Gjøa is already host for the Vega field, and will be host for the Duva and Nova fields within 2021 and 2022, respectively.

The reserves estimate for Gjøa is based on the RNB2021 submitted by the operator, Neptune Energy, and includes reserves related to the P1 redevelopment project which was sanctioned by the licensees in February 2019. Three pilot wells were drilled in spring 2020 to help optimising the P1 project. Based on the results from the pilots, it was decided to drill only 2 producers: one gas producer and one oil producer. The reserves associated with the P1 project have consequently been reduced. The wells are currently being drilled and production start is expected in January 2021.

Contingent resources related to the Gjøa field are discussed in Section 4. Prospective volumes are addressed in Section 5.

OKEA's working interest on Gjøa is 12%. The other licensees on Gjøa are Neptune Energy Norge AS (Operator, 30%), Petoro AS (30%), and Wintershall DEA Norge AS (28%).

3.3.3. Ivar Aasen Unit (PL338 BS)

The Ivar Aasen Field is located in the North Sea, 8 km north of the Edvard Grieg Field and around 30 km south of Grane and Balder (Figure 5), at a water depth of 110 meters. The Ivar Aasen Field includes two accumulations: Ivar Aasen and West Cable. The accumulations cover several licences and have been unitised into the Ivar Aasen Unit.

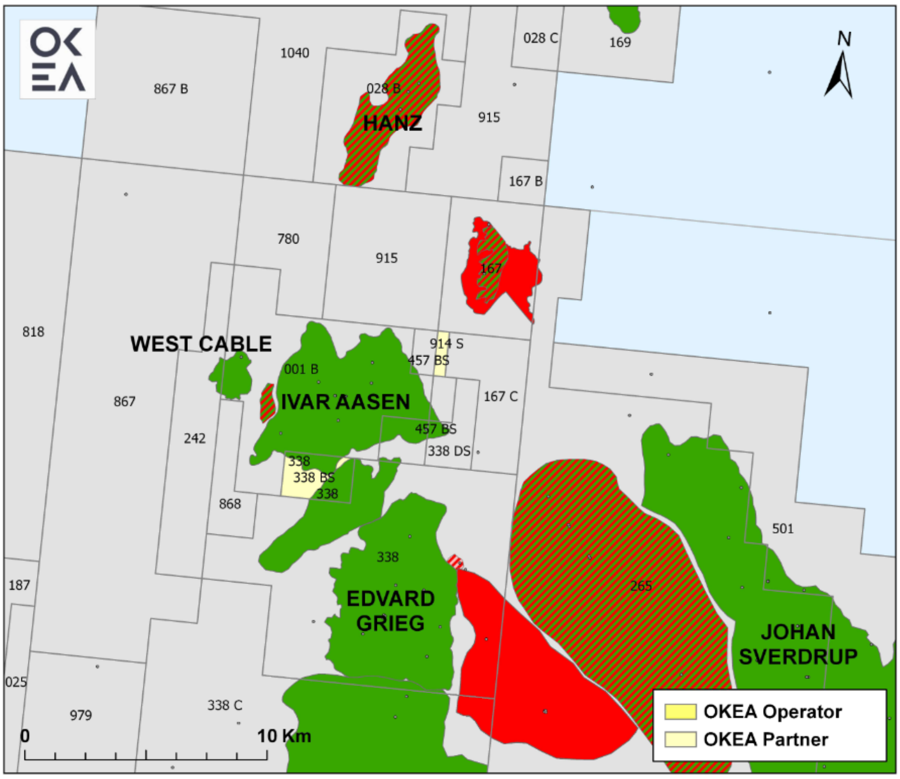

Figure 5: Ivar Aasen and West Cable location map, North Sea

Discovery

Ivar Aasen was discovered with well 16/1-9 in 2008, proving oil and gas in Jurassic and Triassic sandstones.

Reservoir

The two accumulations are located on the Gudrun Terrace between the Southern Viking Graben and the Utsira High. The reservoir consists of shallow marine sandstones in the Hugin Formation and fluvial sandstones in the Sleipner and Skagerrak formations, and is of Jurassic and Triassic age. The reservoir depth is approximately 2 400 meters. The Ivar Aasen reservoir has a small overlying gas cap. The West Cable reservoir is in Sleipner fluvial sandstone of Middle Jurassic age, and is located at 2 950 meters depth.

Development

The Ivar Aasen and West Cable discoveries are developed with a steel jacket platform, with living quarters and processing facilities. Drilling and completion operations are performed from a mobile jack-up rig adjacent to the Ivar Aasen platform. Water is removed from the well stream on the platform and oil and gas rates are measured before transportation through multiphase pipelines to the Edvard Grieg installation for stabilisation and export. Edvard Grieg will also cover Ivar Aasen power demand until a joint solution for power from shore is established.

The drainage strategy for Ivar Aasen assumes water injection for pressure maintenance. West Cable will be produced through natural pressure support where the major driving force will be natural water influx and formation of a secondary gas cap.

The Ivar Aasen unit development plan (Ivar Aasen and West Cable discoveries) also includes production of the reserves from the Hanz (PL028B) discovery. The approved PDO sets out that Ivar Aasen and West Cable (Ivar Aasen Unit) will be developed in the first phase and Hanz in the second phase. OKEA has no ownership interest in the Hanz field.

Status

Production from Ivar Aasen started in December 2016, and the current production is approximately 50 000 bbl/d, together with some associated gas. The oil production from Ivar Aasen during 2020 was slightly below the RNB2020 prognosis. The key causes for the production losses during 2020 relate to operational challenges at Edvard Grieg, drilling operations, and export restrictions. In addition, production was reduced in order to preserve long term reserves by maintaining reservoir pressure. During 2020 voidage replacement met the target of 105% on a field basis. The drainage pattern in the east segment - and in particular in the Skagerrak Formation - is still the main uncertainty in the reservoir.

Drilling of two multilateral oil producers (D-17 and D-20) started in 2020 and is expected to be completed in early 2021. D-20 is a 3-lateral dedicated Skagerrak 2 producer in the east segment. D-17 will be a 2-lateral dedicated Alluvial Fan producer in the west segment.

The reserves estimate for Ivar Aasen is based on the RNB2021 submitted by the operator, Aker BP. OKEA holds a 0.5540% working interest in the licence. The other licensees are Aker BP (Operator, 34.7862%), Equinor Energy AS (41.4730%), Spirit Energy Norway AS (12.3173%), Wintershall Norge AS (6.4615%), Neptune Energy Norge AS (3.0230%) and Lundin Norway AS (1.3850%).

3.3.4. Yme (PL316)

The Yme field in the Egersund Basin was discovered by Statoil in 1987 and put on production in 1996. The field is located 160 km northeast of the Ekofisk field, c.f. Figure 6, in a water depth of 93 meters. Yme ceased production in 2001 after having produced 51 mmboe, as operation was deemed no longer profitable at the prevailing petroleum prices. However, there were significant volumes left in the field, and in 2007 a redevelopment plan was submitted by the new operator, Talisman. In 2013, after drilling nine new development wells and two new appraisal wells, the redevelopment project was abandoned due to structural deficiencies in the mobile offshore production unit. In 2015, the "Yme New Development" project was initiated, and in 2018 a revised PDO was approved by the authorities.

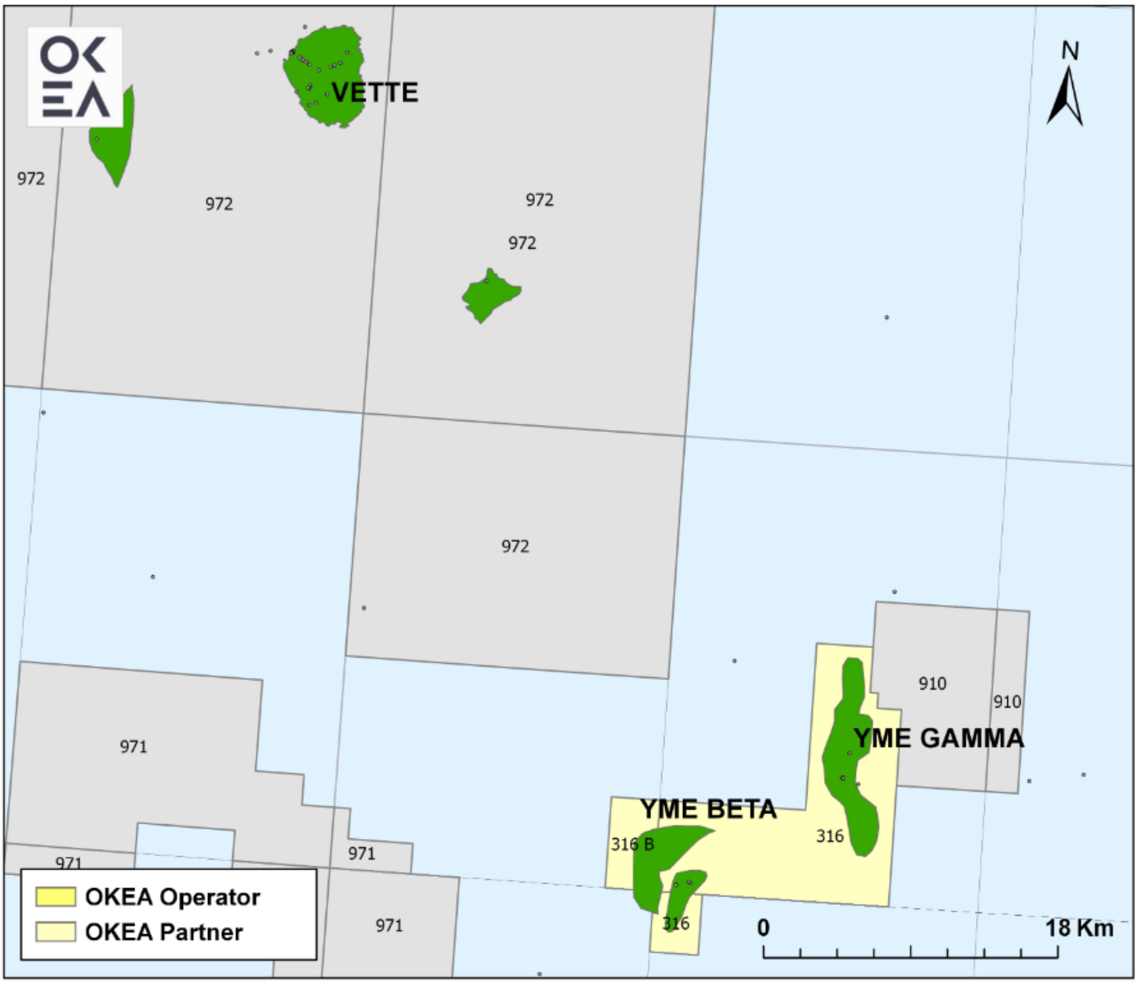

Figure 6: Yme Gamma and Beta location map, North Sea

Discovery

The Yme field was discovered in 1987 by the 9/2-1 well in the Gamma structure, with test oil rate of 4 145 bbl/d oil. In 1990, oil another discovery was made by the 9/2-3 well in the Beta structure, 12 km west of the Gamma structure.

Reservoir

The reservoir in Yme is the Middle Jurassic to Upper Jurassic Sandnes Fm at a depth of approximately 3 200 meters. Vertically, the reservoir is heterogeneous, and the permeability varies from milli-Darcy to several Darcy. However, the sands are laterally extensive and continuous. The two main structures, Gamma and Beta, located in the Egersund basin, are each subdivided in three segments separated by faults. All these segments, except Beta West, will be redeveloped.

Development

As part of the "Yme New Development", the Yme field will be developed with a jack-up MOPU equipped with processing facilities. This will be connected to the existing MOPUSTOR tank, and oil will be exported by tanker.

The field will produce from 12 horizontal production wells, supported by two WAG (Water Alternating Gas) injectors and three water injectors. Produced water reinjection, in combination with a regional aquifer, will maintain the reservoir pressure, and provide significant sweep towards the producers. Production wells will be artificially lifted by ESPs and gas lift.

Status

The revised PDO was delivered in December 2017 and approved by the authorities in March 2018. The maximum plateau oil production rate is estimated to approximately 53 000 bbl/d.

During 2019, the caisson permanent support (CPS) and the well-head module were both installed.

Upgrade of the production unit Maersk Inspirer requires more time than initially planned for, such that the hook update had to be postponed to Q1 2021. Production start-up is expected in H2 2021.

The subsurface and well engineering teams are performing final modelling and detailed well planning of the new wells on both Gamma and Beta structures. Drilling of new Gamma wells is scheduled to start in 2021, while the new Beta wells are planned to be drilled in 2022-23.

The reserves on Yme are based on RNB2021 as submitted by the operator, Repsol, which in turn are based on the DG3/FID profiles for the field, apart from an adjustment related to postponed start-up date. OKEA holds 15 percent in Yme. The remaining interests are held by Repsol Norge AS (Operator, 55%), LOTOS Exploration & Production Norge AS (20%) and KUFPEC Norway AS (10%).

Contingent resources on Yme relate to a lifetime extension, see Section 4.

4 Contingent resources

Contingent resources are potentially recoverable volumes from proven accumulations, which are not currently considered commercially viable. This essentially includes projects that are being matured but that have not passed a Final Investment Decision (FID).

OKEA holds contingent resources in several licences, as shown in *Table 4*. The contingent resources are verified by a third party reserves certification performed by AGR Petroleum Services with the exception of Hasselmus and Aurora which were revised after the certification. The following chapter gives a brief description of these contingent resources.

Table 4: OKEA Contingent Resources as of 31.12.2020

PL	Discovery/Project	OKEA Interest	Gross Oil equivalents (mmboe)			Net Oil equivalents (mmboe)		
			Low	Base	High	Low	Base	High
093/158	Hasselmus (6407/9-9)	44.560 %	7.44	10.85	15.02	3.32	4.83	6.69
	Draugen - Infill Drilling	44.560 %	3.47	13.76	16.62	1.55	6.13	7.41
	Draugen - Increased water injection	44.560 %	3.47	13.76	16.62	1.55	6.13	7.41
	Draugen - Power from Shore	44.560 %	0.84	1.02	1.12	0.37	0.45	0.50
	Draugen - Restart of Gas Export	44.560 %	1.75	2.63	5.53	0.78	1.17	2.47
	Draugen - Production past cut off	44.560 %	6.25	8.46	9.97	2.79	3.77	4.44
	Draugen (incl. Hasselmus)		**23.23**	**50.47**	**64.89**	**11.42**	**23.69**	**29.22**
153	Gjøa - Oil well interventions	12.0 %	1.33	1.71	2.05	0.16	0.21	0.25
	Gjøa - Tail production	12.0 %	5.58	7.15	14.22	0.67	0.86	1.71
	Gjøa		**6.91**	**8.86**	**16.27**	**0.83**	**1.06**	**1.96**
Ivar Aasen Unit	IAA - Infill Drilling IAOP-Horst	0.5540 %	1.80	3.61	5.41	0.01	0.02	0.03
	IAA - Infill Drilling IAWI-S	0.5540 %	1.42	2.83	4.25	0.01	0.02	0.02
	IAA - Infill Drilling IAOP-E-V	0.5540 %	1.45	2.89	4.34	0.01	0.02	0.02
	IAA - More infill wells	0.5540 %	2.89	5.79	8.68	0.02	0.03	0.05
	Ivar Aasen		**7.56**	**15.12**	**22.68**	**0.04**	**0.08**	**0.13**
038 D	Grevling (15/12-21)	35.0 %	28.98	45.80	66.46	10.14	16.03	23.26
974	Storskrymten (15/12-18 A)	60.0 %	1.24	2.34	3.62	0.74	1.41	2.17
316	Yme - lifetime extension	15.0 %	7.37	9.24	12.00	1.11	1.39	1.80
195	Aurora (35/8-3)	40.0 %	5.81	14.11	22.72	2.32	5.64	9.09
1060	Galtvort (6407/8-4 S)	40.0 %	6.04	10.69	32.71	2.41	4.28	13.08
Total Contingent Volumes						**29.0**	**53.6**	**80.7**

Please note that totals in tables above are arithmetic and not stochastic summations. The aggregate Low (1C) may be a very conservative estimate and aggregate High (3C) may be a very optimistic one. Aggregates of Base (2C) results typically have less portfolio effect.

4.1. Grevling (PL038 D) and Storskrymten (PL974)

The Grevling discovery was made by Talisman in 2009. The licence was transferred to Repsol when they acquired Talisman in 2015. In 2017, operator Repsol relinquished their ownership in the licence and supported the transfer of operatorship to OKEA. The discovery is located approximately 20 km south of the Sleipner field (Figure 7), at a water depth of 86 meters. The neighbouring Storskrymten discovery is located in PL974, which was awarded in the APA 2018 round.

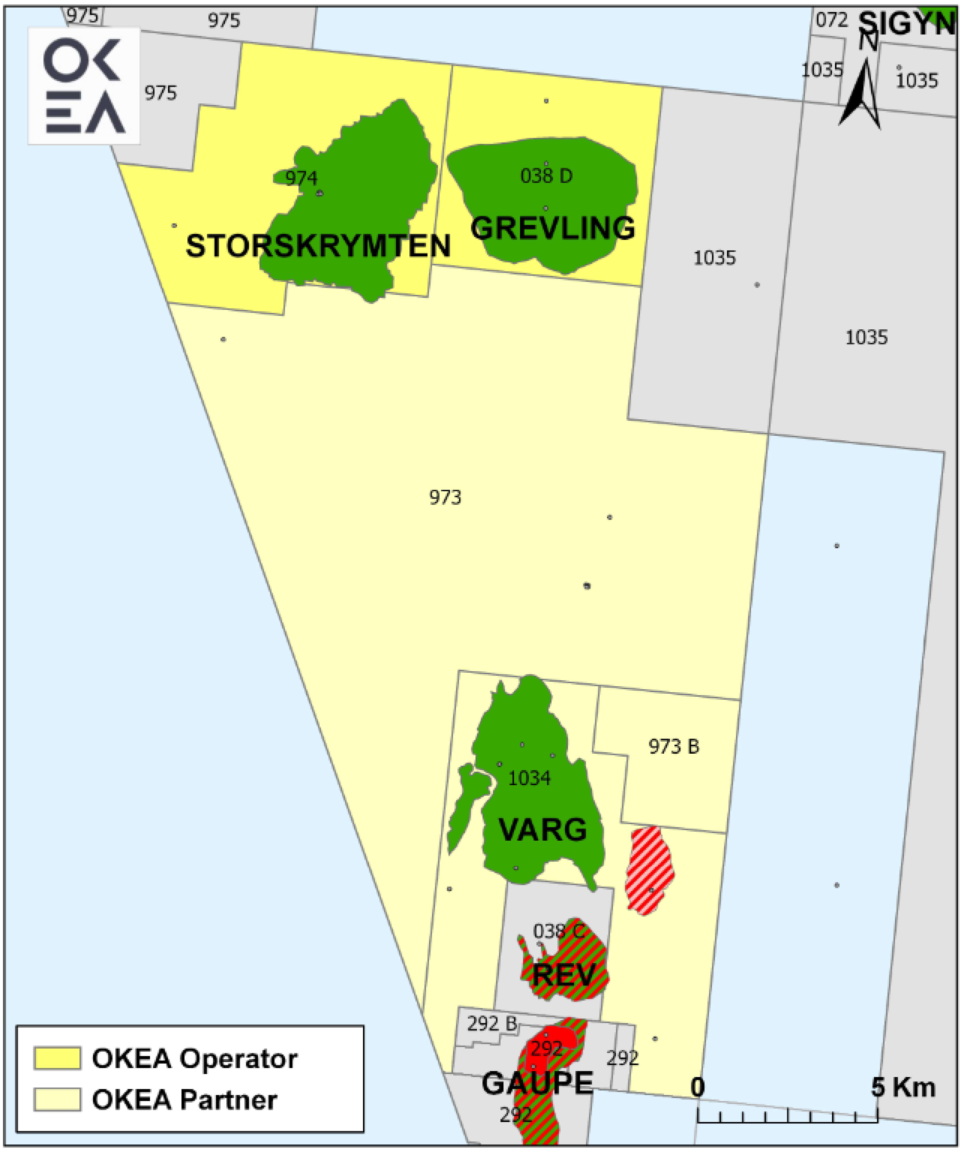

Figure 7: Grevling and Storskrymten location map, North Sea

Discovery

The Grevling discovery was made in 2009 by the 15/12-21 well. The total oil column was 67 meters, and the well tested at rates of up to 780 bbl/d. The discovery was later appraised by a side-track in 15/12-21 A, a new well 15/12-23 and a side-track 15/12-23 A. Storskrymten was discovered in 2007 by the 15/12-18 S well, with a 16m oil column.

Reservoir

The reservoir in Grevling is the Middle Jurassic Hugin and Sleipner formations and the Triassic Skagerrak Fm. The Sleipner coal Fm separates the Hugin from the Bryne/Skagerrak formations and the accumulation is further subdivided in an eastern and a western segment by a large north-south trending fault. Storskrymten has reservoir in the Paleocene Ty and Heimdal formations.

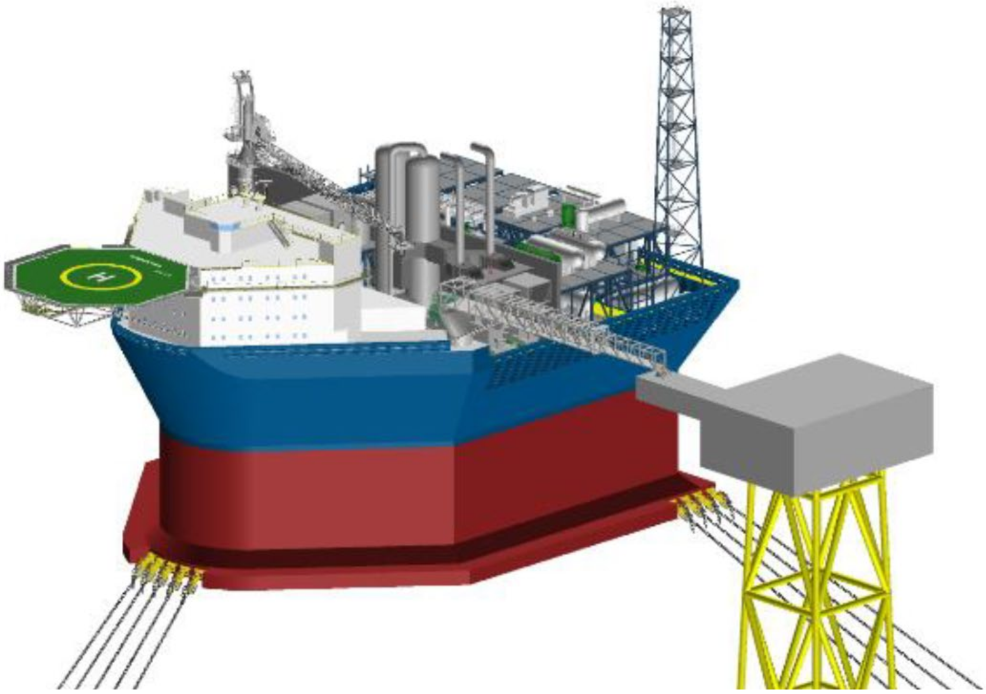

Figure 8: Sketch of FPSO concept with unmanned wellhead platform

Development

The Grevling reservoirs are planned drained by pressure maintenance through water injection. The current drainage strategy is based on long horizontal reservoir sections for both injectors and producers. In total eleven wells are planned: seven oil producers (incl. one 2-lateral well), five water injectors and one Utsira water producer. The Storskrymten reservoir is planned developed by one oil producer and an optional water injector in case of inefficient aquifer support.

Status

The development project passed the BoK milestone (proof of feasibility) in 2019 and is currently awaiting results from exploration drilling in license PL973 before a BoV (decision to continue) can be made which is scheduled for H2 2021. The exploration licence PL973 is described in chapter 5. Contingent resources for Grevling and Storskrymten are based on preliminary BoV documentation, as reported in RNB2021.

OKEA is the operator of PL038D and holds a 35% working interest in the license. Other partners are Petoro (30%) and Chrysaor Norge (35%). OKEA also operates PL974 with a 60% working interest, together with Chrysaor Norge (40%) as partner.

4.2. Draugen increased oil recovery

In late 2019 a "Draugen IOR Programme" was initiated to increase focus on increasing recovery from the field. Following screening of several alternative IOR methods/technologies, infill drilling and increased water injection (with existing injection wells or with additional wells) are considered as the most promising possibilities and will be further matured.

4.3. Hasselmus

The main contingent resources on Draugen relate to a development of the Hasselmus discovery, c.f. *Figure 2*. The Hasselmus discovery holds both gas and oil, but only the gas is being evaluated for development through tie-in to Draugen. The gas will partly be used for fuel at Draugen, and partly for export through the Åsgard Transport pipeline. After a successful BoV (DG2) in February 2020, a PDO (DG3) is expected in Q2 2021 with a target of first gas by mid-2023.

4.4. Gjøa – B-1 well and tail production

A change-out of the gas lift valve for the B-1 well was originally planned for 2020 but was postponed to 2023. The operator also reports in RNB2021 contingent volumes related to a possible tail production, and these are included in the ASR.

4.5. Yme lifetime extension

Yme lifetime extension is associated with extending the lifetime of the Maersk Inspirer rig. The existing class approval period extends for 10 years, and contingent volumes are related to a possible 5-year extension.

4.6. Aurora

The Aurora discovery is situated in licences PL195 and PL195 B, approximately 20 km west of Gjøa, as shown in *Figure 4*. OKEA became operator of the two licences in October 2020 and holds a 40% working interest in each. Other partners are Petoro AS (35%) and Wintershall Dea Norge AS (25% - notified withdrawal from the licence effective 1st March 2021).

Discovery

Aurora was discovered in 1988 through well 35/8-3. The well proved hydrocarbons in the Intra-Heather Fm. sandstones. No gas/water contact was apparent, indicating gas down to 3511 m TVDSS. The water depth in the area is about 373 m.

The discovery was appraised by well 35/8-4, which encountered no hydrocarbons, indicating water up to 3 611 m TVDSS. Seismic data suggests a major fault east of the discovery well. Consequently, any hydrocarbons east of this fault are considered prospective volumes.

Reservoir

Log analyses of the Heather sands indicated a probable gross gas column of 70 m with a net pay of 31.9m. Average porosity in the net sand was 15.6% with an estimated average water saturation of 22%. Reservoir temperature is about 90 degree Celsius and pressure is around 400 bar. No fluid samples were taken, but available data suggests that the gas has similar quality as Vega North.

Development

OKEA has initiated a project regarding a development of the Aurora discovery as a tie-in to Gjøa. Currently, the discovery is envisioned to be produced by means of a single gas producer well, possibly deviated, using pressure depletion as major driving mechanism. Tie-back to Gjøa can be accomplished by utilising existing infrastructure in the area, related to the Vega, Nova and/or Gjøa developments.

Status

The development project was initiated in September 2020, working towards a feasibility milestone (DG1) in Q2 2021. A decision to drill an appraisal well in 2021 is likely to be part of this milestone. First gas from Aurora could be produced already in 2024, given good progress in the project and available capacity at Gjøa.

4.7. Galtvort

The Galtvort gas discovery is located in license PL1060, approximately 12 km northwest of the Draugen field, c.f. Figure 2. Equinor is the operator with a 40% interest, partners are OKEA (40%) and Chrysaor (20%).

Discovery

Galtvort was discovered in 2008 through well 6407/8-4 S, with a sidetrack 8-4 A into the northern segment. The gas bearing reservoir is located in Garn and Tilje formations and with a total column of 65m.

Reservoir

The reservoir quality at Galtvort is good, with permeability ranging from 100-1000 mD and porosity averaging around 30%. The discovery is divided in 2 segments, Galtvort Central and Galtvort South, divided by a local saddle point. The GWC identified in 8-4S is located at 2 160m, and pressure is hydrostatic.

Development

The discovery is likely be developed with one horizontal well and depletion as drive mechanism. A low-cost tie-back to Draugen can be achieved by building on the planned Hasselmus development only 5 km south and midway between Draugen and Galtvort as described above.

Status

A Galtvort development project is not yet formally initiated. Instead, planning of an exploration well for the Ginny prospect in PL1060 is ongoing. This well has to be drilled by 14 February 2022 as part of the work commitments. Dependent on the results of the Ginny well, the Galtvort discovery may be developed either as tie-back to Draugen via Hasselmus (as sketched above) or together with the new discovery. A Galtvort development may also be initiated earlier. If developed through Hasselmus, an investment decision and submission of a PDO in 2024 is likely.

5 Prospective resources

Prospective resources are defined as potential, recoverable volumes from undiscovered accumulations. *Table 5* shows the total overview of these resources. Following the APA 2019 round, OKEA was awarded production licenses PL1034 and PL1060, as well as extension production licenses PL973 B and PL093 F. PL1060 was awarded on a firm well commitment on the Ginny prospect. During the year, OKEA farmed into PL938, where the license partners have sanctioned an exploration well on the Calypso prospect, likely to be drilled in 2022. During 2020 PL910 was surrendered, while PL1003 lapsed.

Since ASR 2019, unrisked prospective resources have increased from 269 to 348 mmboe mainly as result of an increase in number of licences in the OKEA portfolio.

Table 5: OKEA Prospective Resources as of *31.12.2020.*

Name of prospect	License	Interest (%)	COS	Net unrisked resources (mmboe)		
				Low	Base	High
Springmus E	PL093	44.56 %	37 %	0.2	2.8	7.9
Springmus W	PL093	44.56 %	33 %	0.1	1.2	3.5
Løkka	PL093 D/F	44.56 %	16 %	0.3	6.7	64.5
Draugen NE	PL1001	20 %	22 %	4.5	23.5	65.5
Pegasus	PL1001	20 %	13 %		22.8	
Rialto	PL958	50 %	12 %	46.8	158.0	303.5
Ginny	PL1060	40 %	33 %	2.5	11.2	23.8
Hermine	PL1060	40 %	36 %	2.2	4.6	8.6
Draco	PL1060	40 %	17 %	0.4	1.2	2.2
Nottung	PL1060	40 %	30 %	1.6	3.3	5.2
Blunka	PL1060	40 %	11 %	4.5	12.1	21.9
Holk	PL1060	40 %	29 %	3.5	5.1	6.9
Calypso	PL938	30 %	52 %	2.8	6.6	10.9
Calypso ile	PL938	30 %	20 %		1.5	
Calypso North	PL938	30 %	19 %		3.9	
Prometheus	PL938	30 %	35 %	0.7	7.2	15.8
Hamlet	PL153	12 %	56 %	1.7	2.0	2.6
Jerv	PL973	30 %	51 %	10.8	15.9	21.6
Ilder	PL973	30 %	32 %	7.5	17.1	27.3
Mår	PL973	30 %	18 %	8.7	21.1	35.1
Blondie	PL973 B	30 %	28 %	8.7	14.4	19.0
Fleming E	PL1034	40 %	16 %	3.6	5.6	7.8
Total prospective volumes					**348**	

5.1. PL093, PL093 D and PL093 F – Springmus, Løkka

Several exploration targets exist in the Draugen licences. The targets include Springmus East and West, which may be in fact continuations of the main field. On the east side of Draugen, the Løkka prospect lies in PL093 D and F. It is a subtle anticline, where the target is Rogn Fm. sand. PL093 F was awarded as part of APA 2019.

5.2. PL1001 – Draugen NE, Pegasus

PL1001 contains the Draugen NE and Pegasus prospects, in the same Rogn Formation play as the

Draugen field. The licence, awarded as part of the APA 2018 round and operated by ConocoPhillips, has now a "Drill or Drop" decision by March 2022, after an approved application for a 1 year extension due to Covid-19 and late arrival of new seismic data.

5.3. PL958 - Rialto

The PL958 licence to the east of Draugen on the Trøndelag Platform contains several prospects. The most promising is the Rialto prospect, identified by a typical sand signature with significant lateral extent in the 2D seismic data. The play is the same as on Draugen, with reservoir in the Late Jurassic Rogn Formation. The source is likely the Spekk Formation, charging Rialto via spill from Draugen. Hydrocarbon charge of the structure is the main risk. The license had new 3D seismic data delivered in Q4 2020. This dataset will form the basis of updated prospectivity assessments of the area.

5.4. PL938 - Calypso

OKEA farmed into PL938 during the year. The license is located over the Bremstein Fault Complex fault zone, consisting of several rotated fault blocks. The most promising of these, forming the Calypso prospect, will be drilled in 2022. Calypso has significant risking uplift based on a seismic DHI. Several other fault blocks in the licence contain prospective resources.

5.5. PL1060 - Ginny

Together with Equinor (operator) and Chrysaor, OKEA was awarded PL1060 in APA 2019. As in PL938, the block is located in the Bremstein Fault complex. The licence was awarded with a firm well commitment on the Ginny prospect. Ginny is located in an upper Jurassic growth wedge, anticipating a late Jurassic sand, eroded and redeposited from the adjacent foot wall. Ginny will be drilled in H2 2021. In addition, the licence contains several prospects in rotated fault blocks with potential reservoirs of Middle Jurassic age.

5.6. PL153 - Hamlet

The Hamlet prospect, within the Gjøa licence, is a Cretaceous prospect, analogue to the nearby Duva and Agat discoveries. Hamlet is believed to be connected with the Agat (35/9-3 T2) discovery to the north by a saddle. Hence, a high COS is assumed. The reservoir consists of turbidite flows originating from the southeast.

The well was sanctioned by the Gjøa licensees, and the site survey was acquired in 2019 and a rig assignment made for drilling. Due to the drop in oil and gas prices in 2020, the assignment was cancelled and the timing of Hamlet drilling is, at present, uncertain.

5.7. PL973 and PL973 B – Jerv, Ilder, Mår, Blondie

The Ilder and Jerv prospects are sanctioned for drilling. The initial target was to drill back-to-back in Q4 2020, but due to Covid-19, the timeline has slipped into 2021. The Ilder prospect is upflank from the 15/12-2 well, in the Hugin and Ula formations, on a salt-supported, structural 4-way closure. The main risk for Ilder is migration. The Jerv prospect is a northern continuation of the Fleming field on the UKCS into Norwegian sector. It targets a possible Paleocene, Ty/Maureen Formation, turbidite sand deposit. The main risk is depletion from production of Fleming.

The Mår prospect is still regarded as immature for drilling, as it will be further de-risked by the ongoing work program. Mår is located in a Late Jurassic growth wedge on the flank of a structural high, with requirement for an upflank pinch-out. This play is not proven in the area.

The Blondie prospect is located partly in the license extension PL973 B. It sits on a structural high between the Varg field and the Ilder prospect. The main risks are migration and reservoir quality, as it may be Skagerrak Fm. reservoir. The Ilder well help de-risk migration and test the hypothesis of the Ula Fm. fairway.

5.8. PL1034 – Fleming East

Fleming East is a possible continuation of the Fleming field eastward, further upflank, onlapping the Varg High. It is in the Paleocene Ty/Maureen Fm. turbidite. The Northern producers on UKCS Fleming field indicate presence of gas volumes outside of the mapped boundary of the field. The primary thesis is that these volumes are located in the Jerv prospect in PL973, which is explored in 2021. Should Jerv be dry, the secondary thesis, pre-Jerv exploration, is that the volumes could be located in Fleming East in PL1034.

6 Management discussion and analysis

The reported 2P/P50 reserves include volumes which are believed to be recoverable based on reasonable assumptions about future economical, fiscal and financial conditions. Discounted future cash flows after tax are calculated for the various fields on the basis of expected production profiles and estimated proven and probable reserves. Cut-off time for the reserves is set at zero cash flow or when facility leases expire. The company has used a long-term inflation assumption of 2 percent, a long-term exchange rate of NOK/USD 8.0, and a long-term oil price of 65 USD/bbl (real 2020 terms).

The calculations of recoverable volumes are however associated with significant uncertainties. The 2P/P50 estimate represents our best estimate of reserves/resources while the 1P/P90 figures reflect our high confidence estimates. The methods used for subsurface mapping do not fully clarify all essential parameters for either the actual hydrocarbons in place or the producibility of the hydrocarbons. Thus, there is a risk that actual results may be lower than the 1P/P90. A significant change in oil prices may also impact the economical reserves. Low oil prices may force the licensees to close down producing fields early and lead to lower production. Similarly, better-than-expected reservoir performance or higher oil prices may extend the lifetime of the fields beyond what is currently assumed.

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OKEA is an oil and gas company contributing to the value creation on the Norwegian continental shelf delivering safe and cost-effective field developments and operational excellence.

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