ANNUAL STATEMENT OF RESERVES 2022

CONTENTS

List of Figures		4
List of Tables		4
1.	**Classification of Reserves and contigent Resources**	**5**
2.	**Reserves — Developed anD Non-developed**	**6**
3.	**Description of Reserves**	**16**
3.1	**Producing Assets**	**17**
3.1.1	Alvheim (PL036, PL088BS, PL203)	17
3.1.2	Vilje (PL036D)	19
3.1.3	Volund (PL150)	20
3.1.4	Bøyla (PL340)	21
3.1.5	Frosk (PL340)	22
3.1.6	Skogul	23
3.1.7	Ivar Aasen Unit and Hanz (PL001B, PL028B, PL242, PL338BS, PL457)	25
3.1.8	Edvard Grieg (PL338)	27
3.1.9	Solveig (PL359)	29
3.1.10	Troldhaugen (PL338C)	31
3.1.11	Skarv Unit (PL262, PL159, PL212B, PL212)	32
3.1.12	Skarv	33
3.1.13	Gråsel	34
3.1.14	Ærfugl	34
3.1.15	Ula (PL019)	35
3.1.16	Tambar (PL065)	37
3.1.17	Tambar East (PL065, PL300, PL019B)	38
3.1.18	Valhall (PL006B, PL033B)	39
3.1.19	Hod (PL033)	41
3.1.20	Johan Sverdrup (PL265, PL501, PL502, PL501B)	41
3.1.21	Oda (PL405)	43
3.1.22	Alta (PL102C)	44
3.2	**Development Projects**	**45**
3.2.1	Hanz	45
3.2.2	Kobra East and Gekko (KEG)	45
3.2.3	Tyrving	46
3.2.4	Skarv Satellite Project (SSP)	47
3.2.5	Ørn	48
3.2.6	Alve Nord	48
3.2.7	Idun Nord	48
3.2.8	Fenris	49
3.2.9	Yggdrasil	50
3.2.10	Frøy (PL364)	52
3.2.11	Frigg Gamma Delta (PL442)	52
3.2.12	Langfjellet (PL442)	53
3.2.13	Rind (PL442, 25/2-5)	53
3.2.14	Fulla and Lille-Frigg (PL873)	53
3.2.15	Munin (PL272, PL035, PL035C)	54
3.2.16	Solveig Phase 2 (PL359)	55
3.2.17	Symra (PL167 & PL167C)	56
3.2.18	Verdande	57

4.	**Contingent Resources**	**58**
4.1	**Contingent Resources by area**	**58**
4.1.1	Alvheim Area	58
4.1.2	Edvard Grieg Area	58
4.1.3	The Ivar Aasen Area	59
4.1.4	The Yggdrasil Area (renamed from NOAKA - North of Alvheim Krafla Askja)	60
4.1.5	The Valhall Area	60
4.1.6	Skarv Area	60
4.1.7	Ula Area	60
4.1.8	Partner-Operated Assets	60
4.1.9	Other	61
5.	**Management's discussion and analysis**	**62**

LIST OF FIGURES

Fig. 1.1 SPE reserves and resource classification system	5
Fig.3.1.1 Our assets and offices	16
Figure 3.1 Alvheim field location map	18
Figure 3.2 Vilje location map	19
Figure 3.3 Volund location map	20
Figure 3.4 Bøyla location map	21
Figure 3.5 Frosk field location map	22
Figure 3.6 Skogul field location map	23
Figure 3.7 Ivar Aasen Unit and Hanz location map	26
Figure 3.8 Edvard Grieg location map	28
Figure 3.9 Solveig location map	29
Figure 3.10 Segments overview Solveig	30
Figure 3.11 Troldhaugen location map	31
Figure 3.12 Skarv and Ærfugl location map location map	33
Figure 3.13 Ula location map	36
Figure 3.14 Tambar and Tambar East location map	37
Figure 3.15 Valhall and Hod location map	40
Figure 3.16 Johan Sverdrup location map	41
Figure 3.17 Johan Sverdrup field centre	42
Figure 3.18 Oda location map	43
Figure 3.19 Kobra East and Gekko (KEG) location map.	46
Figure 3.20 Tyrving location map	47
Figure 3.21 Skarv satellites location map	47
Figure 3.22 Fenris location map	49
Figure 3.23 The Yggdrasil area	51
Figure 3.24 Yggdrasil area development	52
Figure 3.25 Solveig Phase 2 location map	55
Figure 3.26 Symra location map	56
Figure 3.27 Verdande location map	57
Figure 4.1 Troldhaugen well locations	59

LIST OF TABLES

Table 2.1 Aker BP fields containing reserves	7
Table 2.2 Aker BP 1P and 2P reserves as of 31.12.2022 per projects and reserve class.	10
Table 2.3 Aker BP net 1P and 2P reserves as of 31.12.2022 per field and area.	13
Table 2.4 Aggregated reserves, production, developments, acquisitions, IOR, extensions and revisions	15

1. CLASSIFICATION OF RESERVES AND CONTIGENT RESOURCES

Aker BP ASA's reserve and contingent resource volumes have been classified in accordance with the Society of Petroleum Engineer's (SPE's) "Petroleum Resources Management System". 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 1.1.

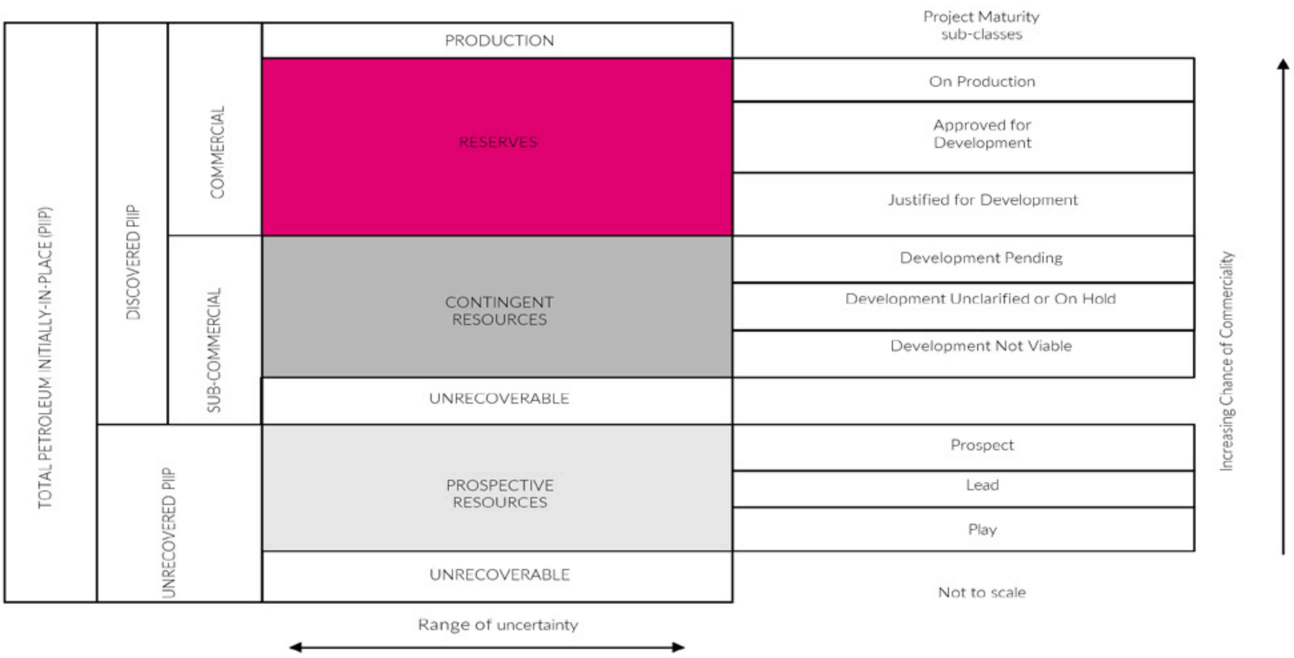


Figure 1.1 SPE reserves and resourses classification system

2. RESERVES — DEVELOPED AND NON-DEVELOPED

All reserve estimates are based on all available data including seismic, well logs, core data, drill stem tests and production history. Industry standards are used to establish 1P and 2P. This includes decline analysis for mature fields in which reliable trends are established. For undeveloped fields and less mature producing fields, reservoir simulation models or simulation models in combination with decline analysis have been used to generate profiles.

Note that an independent third party, AGR Petroleum Services, has certified all reserves except for the minor assets Atla and Enoch, representing approximately 0.003% of total 2P reserves.

Aker BP ASA has a working interest in 49 fields/projects containing reserves, see Table 2.1. Of these fields/projects, 24 are in the sub-class "On Production"/Developed, 9 are in the sub-class "Approved for Development"/Undeveloped and 16 are in the sub-class "Justified for Development"/Undeveloped. Note that several fields have reserves in more than one reserve sub-class.

Table 2.1 Aker BP fields containing reserves

Field/Project	Interest	Operator	Resource class	Comments
		Developed Reserves		
Field / Project	Interest	Operator	Resource class	Comments
Developed Reserves				
Alvheim Base	80 %	Aker BP	On Production	
Boa Base	71 %	Aker BP	On Production	
Bøyla Base	80 %	Aker BP	On Production	
Frosk Test Production	80 %	Aker BP	On Production	
Skogul Base	65 %	Aker BP	On Production	
Vilje Base	47 %	Aker BP	On Production	
Volund Base	100 %	Aker BP	On Production	
Edvard Grieg Base	65 %	Aker BP	On Production	
Troldhaugen EWT	80 %	Aker BP	On Production	Previously called Rolvsnes EWT
Solveig Ph1	65 %	Aker BP	On Production	
Ivar Aasen Base	36 %	Aker BP	On Production	
Johan Sverdrup Base	32 %	Equinor Energy AS	On Production	Phase 2 started production 15.12.2022
Oda Base	15 %	Sval Energi AS	On Production	
PL212E Ærfugl Nord Base	30 %	Aker BP	On Production	
Skarv Base	24 %	Aker BP	On Production	
Skarv Gråsel	24 %	Aker BP	On Production	
Skarv Idun Tunge	24 %	Aker BP	On Production	
Skarv Ærfugl	24 %	Aker BP	On Production	
Tambar Base	55 %	Aker BP	On Production	
Ula Base	80 %	Aker BP	On Production	
Hod Base	90 %	Aker BP	On Production	
Valhall Base	90 %	Aker BP	On Production	
Atla	10 %	TotalEnergies EP Norge AS	On Production	
Enoch	2 %	Repsol Sinopec	On Production	

Field/Project	Interest	Operator	Resource class	Comments
		Undeveloped Reserves		
Kameleon Gas Cap Blow Down	80 %	Aker BP	Approved for development	
Alvheim East KAM L5	80 %	Aker BP	Approved for development	
Frosk	80 %	Aker BP	Approved for development	
Kobra East/Gekko	80 %	Aker BP	Approved for development	
Edvard Grieg IOR	65 %	Aker BP	Approved for development	
Hanz	35 %	Aker BP	Approved for development	
Ivar Aasen IOR	36 %	Aker BP	Approved for development	
Johan Sverdrup IOR	36 %	Equinor Energy AS	Approved for development	
Johan Sverdrup WAG	32 %	Equinor Energy AS	Approved for development	
Tyrving	61 %	Aker BP	Justified for development	Previously called Trell and Trine
Solveig Ph2	65 %	Aker BP	Justified for development	
Symra	50 %	Aker BP	Justified for development	Previously called Lille-Prinsen
Frigg Gamma Delta Development	88 %	Aker BP	Justified for development	Part of the Hugin-fields
Frøy Development	88 %	Aker BP	Justified for development	Part of the Hugin-fields
Fulla Development	48 %	Aker BP	Justified for development	
Langfjellet Development	88 %	Aker BP	Justified for development	Part of the Hugin-fields
Lille Frigg Development	48 %	Aker BP	Justified for development	
Rind Development	88 %	Aker BP	Justified for development	Part of the Hugin-fields

Field/Project	Interest	Operator	Resource class	Comments
		Undeveloped Reserves		
Munin Development	50 %	Aker BP	Justified for development	
PL127C Alve Nord Development	68 %	Aker BP	Justified for development	
PL159D Idun Nord Development	24 %	Aker BP	Justified for development	
PL942 Ørn Development	30 %	Aker BP	Justified for development	
Verdande Development	7 %	Equinor Energy AS	Justified for development	
Fenris	78 %	Aker BP	Justified for development	
Valhall PWP	90 %	Aker BP	Justified for development	

Aker BP's total net proven reserves (P90/1P) as of 31 December 2022 are estimated at 1251 million barrels of oil equivalent. Total net proven plus probable reserves (P50/2P) are estimated at 1859 million barrels of oil equivalent. The split between liquid and gas and between the different subcategories for all fields/projects is provided in Table 2.2.

Table 2.2 Aker BP 1P and 2P reserves as of 31 December 2022 per projects and reserve class

Reserves per 31. Dec. 2022	Interest	1P/P90 (low estimate)					2P/P50 (best estimate)				
On production		Gross oil	Gross NGL	Gross gas	Gross oe	Net oe	Gross oil	Gross NGL	Gross gas	Gross oe	Net oe
As of 31 Dec. 2022	%	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)
On production											
Alvheim Base	80 %	25	0	6	31	25	32	0	7	39	31
Boa Base	71 %	9	0	1	10	7	13	0	2	14	10
Bøyla Base	80 %	0	0	0	0	0	2	0	0	2	2
Frosk Test Production	80 %	1	0	0	1	1	2	0	0	2	2
Skogul Base	65 %	2	0	0	3	2	4	0	0	5	3
Vilje Base	47 %	7	0	0	7	4	11	0	0	11	5
Volund Base	100 %	3	0	0	3	3	5	0	0	5	5
Edvard Grieg Base	65 %	69	5	8	82	53	104	7	12	123	80
Troldhaugen EWT	80 %	0	0	0	0	0	0	0	0	0	0
Solveig Ph1	65 %	29	3	6	39	25	48	7	9	64	42
Ivar Aasen Base	36 %	30	2	7	39	14	43	3	10	56	20
Johan Sverdrup Base	32 %	1,415	24	42	1,480	467	1,892	38	63	1,993	629
Oda Base	15 %	4	0	0	4	1	5	0	0	6	1
PL212E Ærfugl Nord Base	30 %	0	1	6	7	3	1	2	8	11	4
Skarv Base	24 %	7	17	78	102	25	8	18	84	110	27
Skarv Gråsel	24 %	3	1	4	8	2	4	1	5	10	2
Skarv Idun Tunge	24 %	0	0	1	1	0	0	0	2	2	0
Skarv Ærfugl	24 %	10	13	61	85	20	14	20	93	127	30
Tambar Base	55 %	1	0	0	1	0	2	0	0	2	1
Ula Base	80 %	0	0	0	0	0	0	0	0	0	0
Hod Base	90 %	24	1	4	29	27	32	1	5	39	35
Valhall Base	90 %	123	7	24	154	138	154	8	31	193	174
Atla	10 %	0	0	0	0	0	0	0	0	0	0
Enoch	2 %	0	0	0	0	0	0	0	0	0	0
Total, mmboe		**1,763**	**74**	**249**	**2,085**	**816**	**2,377**	**106**	**332**	**2,815**	**1,103**

Reserves per 31. Dec. 2022	Interest	1P/P90 (low estimate)					2P/P50 (best estimate)				
On production		Gross oil	Gross NGL	Gross gas	Gross oe	Net oe	Gross oil	Gross NGL	Gross gas	Gross oe	Net oe
As of 31 Dec. 2022	%	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)
Approved for development											
Kameleon Gas Cap Blow Down	80 %	1	0	6	6	5	0	0	19	19	15
Alvheim East KAM L5	80 %	2	0	2	4	3	4	0	3	7	5
Frosk	80 %	6	0	0	6	5	9	0	1	10	8
Kobra East/Gekko	80 %	17	0	24	40	32	22	0	29	51	41
Edvard Grieg IOR	65 %	9	1	1	11	7	14	1	1	16	11
Hanz	35 %	9	1	2	12	4	15	1	3	20	7
Ivar Aasen IOR	36 %	3	0	0	1	0	2	0	1	3	1
Johan Sverdrup IOR	32 %	4	0	0	4	1	5	0	0	5	2
Johan Sverdrup WAG	32 %	54	-6	-12	36	12	88	-6	-11	71	22
Total, mmboe		**105**	**-5**	**24**	**124**	**71**	**164**	**-4**	**46**	**207**	**114**

Reserves per 31. Dec. 2022	Interest	1P/P90 (low estimate)					2P/P50 (best estimate)				
On production		Gross oil	Gross NGL	Gross gas	Gross oe	Net oe	Gross oil	Gross NGL	Gross gas	Gross oe	Net oe
As of 31 Dec. 2022	%	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)
Justified for development											
Tyrving	61 %	13	0	0	13	8	21	0	0	21	13
Solveig Ph2	65 %	16	2	3	22	14	28	3	5	37	24
Symra	50 %	17	2	4	24	12	27	2	4	34	17
Frigg Gamma Delta Development*)	88 %	45	1	4	51	45	78	3	8	89	78
Frøy Development*)	88 %	21	1	3	25	22	30	2	7	40	35
Fulla Development	48 %	3	4	23	29	14	5	9	46	60	29
Langfjellet Development*)	88 %	11	1	4	17	15	26	2	7	35	31
Lille Frigg Development	48 %	2	1	6	9	4	3	3	14	19	9
Rind Development*)	88 %	28	4	11	43	38	40	5	14	58	51
Munin Development	50 %	70	26	59	155	78	109	49	110	268	134
PL127C Alve Nord Development	68 %	2	2	8	11	8	9	6	21	35	24
PL159D Idun Nord Development	24 %	0	0	6	7	2	0	1	9	10	2
PL942 Ørn Development	30 %	1	1	23	26	8	2	3	50	55	17
Verdande Development	7 %	20	0	2	23	2	29	1	6	35	2
Fenris	78 %	28	4	40	71	56	57	7	82	146	114
Valhall PWP	90 %	36	2	8	45	41	55	3	12	70	63
Total, mmboe		**314**	**54**	**205**	**572**	**364**	**518**	**99**	**394**	**1,012**	**642**
Total reserves											
Total, mmboe		**2,181**	**123**	**477**	**2,781**	**1,251**	**3,060**	**201**	**772**	**4,033**	**1,859**

Table 2.3 Aker BP net 1P and 2P reserves as of 31 December 2022 per field and area

Reserves per 31. Dec. 2022	1P/P90 (low estimate)					2P/P50 (best estimate)				
On production	Gross oil	Gross NGL	Gross gas	Gross oe	Net oe	Gross oil	Gross NGL	Gross gas	Gross oe	Net oe
As of 31 Dec. 2022	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)
Alvheim	36	0	15	51	40	49	0	30	79	62
Bøyla	0	0	0	0	0	2	0	0	2	2
Frosk + Test Production	7	0	0	7	6	11	0	1	12	10
Skogul	2	0	0	3	2	4	0	0	5	3
Vilje	7	0	0	7	4	11	0	0	11	5
Volund	3	0	0	3	3	5	0	0	5	5
Kobra East/Gekko	17	0	24	40	32	22	0	29	51	41
Tyrving	13	0	0	13	8	21	0	0	21	13
Alvheim Area	**86**	**0**	**39**	**124**	**94**	**127**	**0**	**60**	**187**	**141**
Tambar	1	0	0	1	0	2	0	0	2	1
Tambar East	0	0	0	0	0	0	0	0	0	0
Ula	0	0	0	0	0	0	0	0	0	0
Ula Area	**1**	**0**	**0**	**1**	**0**	**2**	**0**	**0**	**2**	**1**
Fenris	28	4	40	71	56	57	7	82	146	114
Hod	24	1	4	29	27	32	1	5	39	35
Valhall	159	9	32	199	179	209	11	42	263	237
Valhall Area	**210**	**13**	**76**	**300**	**261**	**298**	**20**	**129**	**447**	**385**
Edvard Grieg	78	6	9	93	60	118	8	13	139	90
Troldhaugen	0	0	0	0	0	0	0	0	0	0
Solveig	46	5	9	61	39	77	10	14	101	66
Ivar Aasen	33	2	7	43	15	49	3	11	63	23
Hanz	9	1	2	12	4	15	1	3	20	7
Symra	17	2	4	24	12	27	2	4	34	17
Grieg / Aasen Area	**184**	**16**	**32**	**233**	**132**	**286**	**25**	**46**	**357**	**203**

Reserves per 31. Dec. 2022	1P/P90 (low estimate)					2P/P50 (best estimate)				
On production	Gross oil	Gross NGL	Gross gas	Gross oe	Net oe	Gross oil	Gross NGL	Gross gas	Gross oe	Net oe
As of 31 Dec. 2022	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmbbl)	(mmboe)	(mmboe)	(mmboe)	(mmboe)
Skarv (incl. Gråsel and Idun Tunge)	10	16	74	100	24	12	18	83	112	27
Ærfugl (incl. Ærfugl Nord)	11	16	75	102	25	16	23	109	149	37
Alve Nord	2	2	8	11	8	9	6	21	35	24
Idun Nord	0	0	6	7	2	0	1	9	10	2
Ørn	1	1	23	26	8	2	3	50	55	17
Verdande	20	0	2	23	2	29	1	6	35	2
Skarv Arera	**44**	**36**	**189**	**269**	**68**	**67**	**51**	**278**	**396**	**109**
Johan Sverdrup	**1473**	**17**	**30**	**1,521**	**480**	**1,984**	**32**	**53**	**2,069**	**653**
Frigg Gamma Delta Development*)	45	1	4	51	45	78	3	8	89	78
Frøy Development*)	21	1	3	25	22	30	2	7	40	35
Fulla Development	3	4	23	29	14	5	9	46	60	29
Langfjellet Development*)	11	1	4	17	15	26	2	7	35	31
Lille Frigg Development	2	1	6	9	4	3	3	14	19	9
Rind Development*)	28	4	11	43	38	40	5	14	58	51
Munin Development	70	26	59	155	78	109	49	110	268	134
Yggdrasil	**180**	**39**	**110**	**329**	**215**	**291**	**73**	**206**	**569**	**367**
Oda	4	0	0	4	1	5	0	0	6	1
Atla	0	0	0	0	0	0	0	0	0	0
Enoch	0	0	0	0	0	0	0	0	0	0
Other	**4**	**0**	**0**	**4**	**1**	**6**	**0**	**0**	**6**	**1**
Total, mmboe	**2,181**	**123**	**477**	**2,781**	**1,251**	**3,060**	**201**	**772**	**4,033**	**1,859**

*) Part of the Hugin field

An oil price of 80 USD/bbl (2023), 70 USD/bbl (2024) and 65 USD/bbl (following years) has been used to estimate reserves. Low and high case sensitivities with oil prices of 40 USD/bbl and 90 USD/bbl, respectively, have been performed by AGR. The low price resulted in a reduction in total net proven (1P/P90) reserves and net proven plus probable (2P/P50) reserves of approximately 40%. The high oil price scenario resulted in a marginal increase in reserves of less than 2% to the proven (1P/P90) estimates and no change to the proven plus probable (2P/P50) estimates.

Changes from the 2021 reserves report are summarised in Table 2.4. The main reasons for the increased net reserve estimate (i.e. disregarding produced volumes) are the acquisition of Lundin Energy, 14 PDOs that were submitted during 2022 (see Chapter 3) and IOR activities in all fields (except Ula). On the negative side, reserves were reduced in Valhall, primarily due to well difficulties and thinner reservoirs on flanks, on Johan Sverdrup (due to a 2% mapped reduction in in-place volumes) and on Ula (reduced lifetime, well difficulties and reduced WAG performance).

Table 2.4 Aggregated reserves, production, developments, acquisitions, IOR, extensions and revisions

Net million barrels of oil equivalent (mmboe)	On Production		Approved for Development		Justified for Development		Total	
	Total	2P/P50	1P/P90	2P/P50	1P/P90	2P/P50	1P/P90	2P/P50
Balance as of 31 Dec. 21	**467**	**601**	**128**	**194**	**4**	**6**	**599**	**802**
Production	-112	-112	0	0	0	0	-112	-112
Transfer	141	216	-155	-238	15	22	0	0
Revisions	-39	-75	2	5	0	0	-38	-70
IOR	0	0	13	20	22	33	35	53
Dicovery and Extensions	0	0	0	0	323	579	323	579
Acquisition and sale	360	473	83	132	1	1	444	606
Balance as of 31 Dec. 22	**816**	**1,103**	**71**	**114**	**364**	**642**	**1,251**	**1,859**
Delta 2022-2021	**349**	**502**	**-57**	**-80**	**360**	**636**	**652**	**1,057**

The acquisition of Lundin Energy was completed during 2022. The 2022 production number in Table 2.4 excludes approximately 32 mmboe production from Lundin's fields before the acquisition date (1 July 2022).

Johan Sverdrup Phase 2, Hod field development and one infill well on Alvheim and Valhall started production in 2022,and were transferred to resource category "On production".

Johan Sverdrup is the most important field, contributing approximately 35% of the company's 2P reserves.

Total net production to Aker BP averaged 397 mboepd (total ~145 mmboe) in 2021. This is slightly below the forecast from 2021. Adjusted for the agreement with Lundin, net production was ~308 mboepd (total ~112 mmboe).

Note that the production numbers are approximate, based on actual production for the first 10 months and a prognosis for the last two months of 2022. Actual final numbers may differ slightly.

3. DESCRIPTION OF RESERVES

The following chapter describes the reserve assessment from all producing fields. Please note that the produced volumes reported herein may differ slightly from volumes reported as sales volumes in quarterly reports, etc. The reason is that the volumes in this report are based on actual production from 1 January 2022 to 31 October 2022 and forecast for the period 1 November 2022 to 31 December 2022. These volumes are used for assessment of remaining reserves as of 31 December 2022.

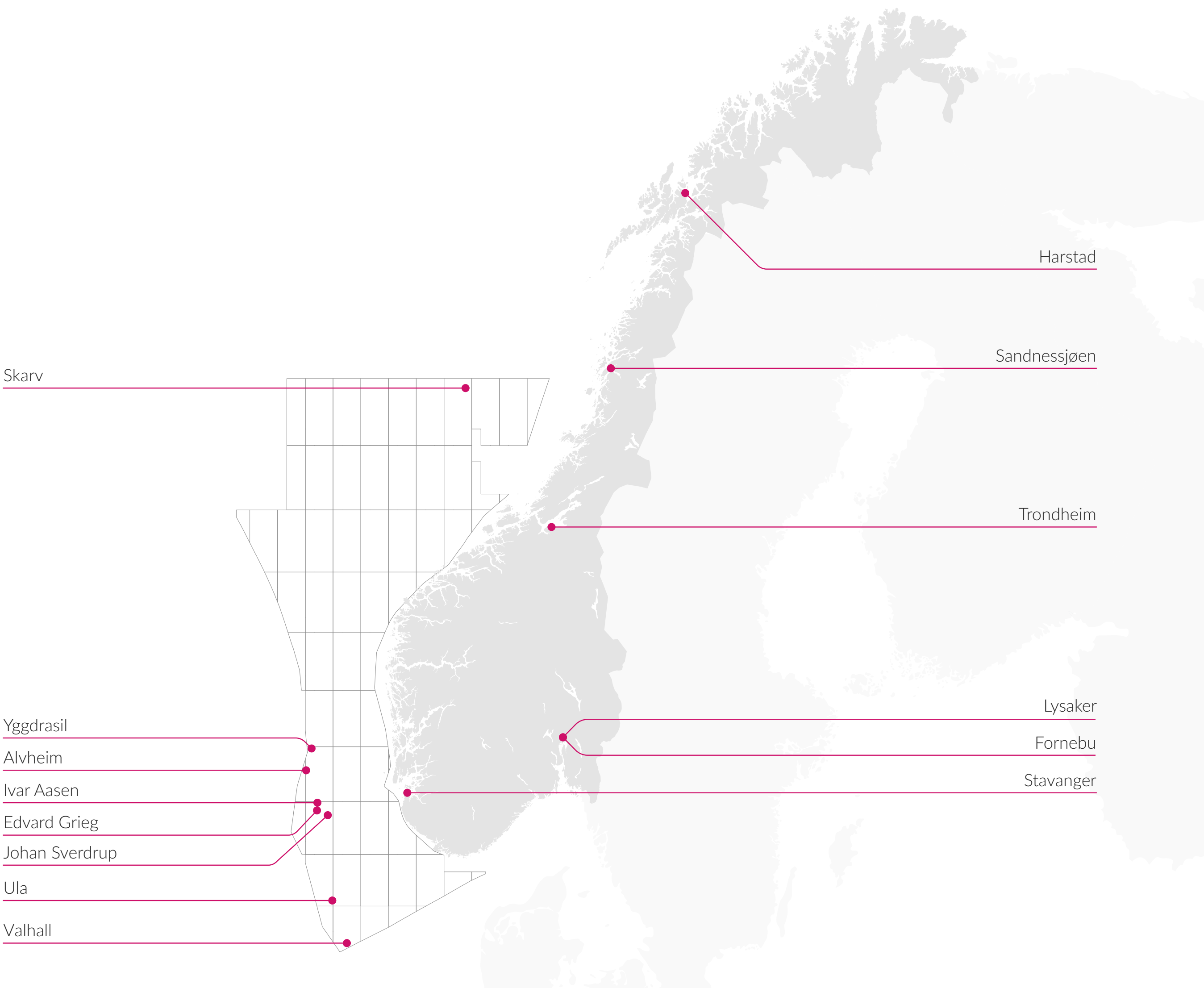


Figure 3.1.1 Our assets and offices

3.1 PRODUCING ASSETS

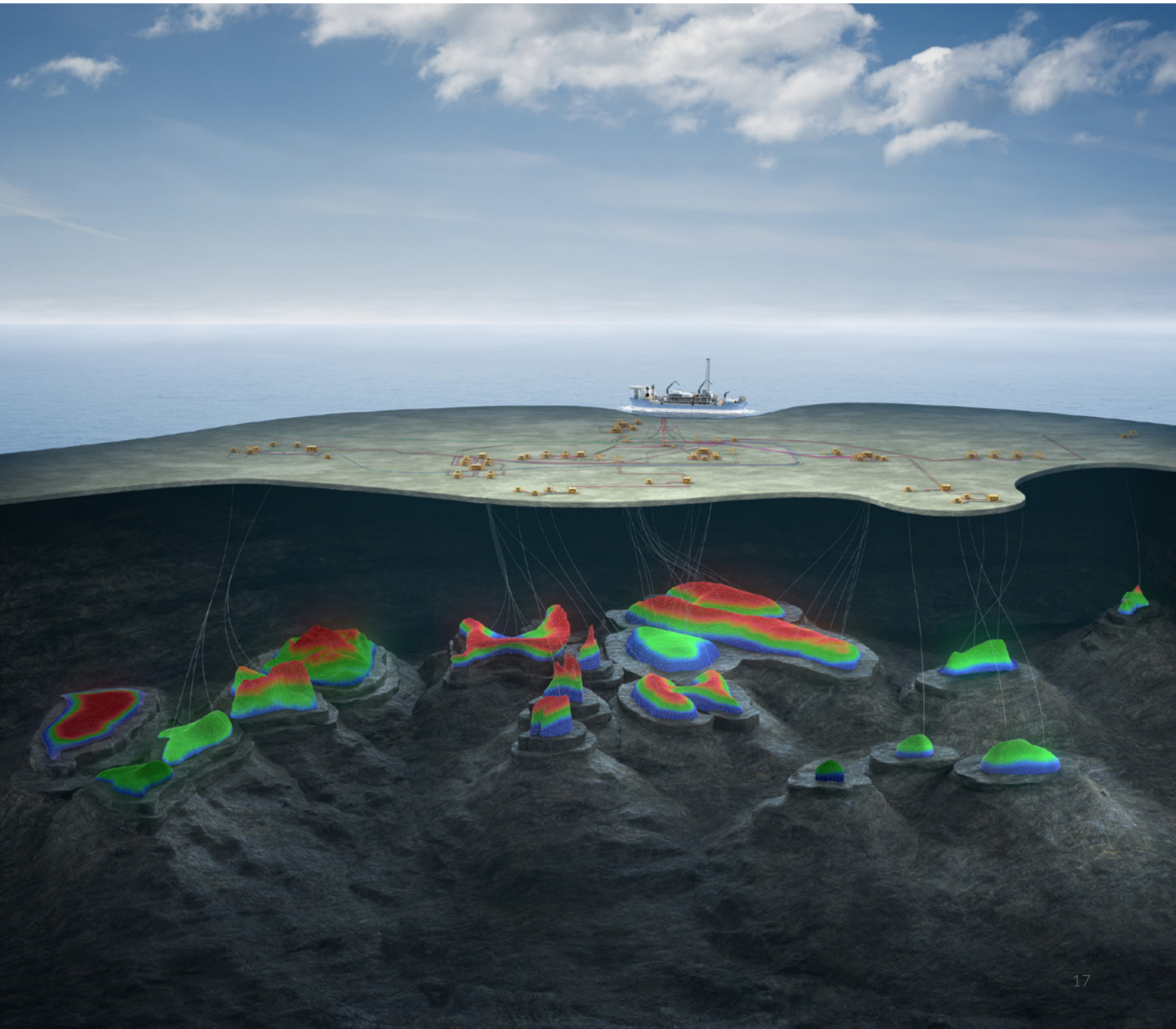
3.1.1 Alvheim (PL036, PL088BS, PL203)

Alvheim is an oil and gas field in the central part of the North Sea, west of Heimdal and near the UK sector border. It comprises licences covered by PL203, PL088 and PL036C. The producing Alvheim structures are Kneler, Kameleon, East Kameleon, Boa (11.65% on UK side), Viper and Kobra. The Kobra East & Gekko project is approved for development and covered in Chapter 3.2.2. Sales gas from the Vilje (PL036D) field is sold by PL203 through a commercial agreement. The water depth in the area is 120 – 130 m. First production was in 2008.

Discovery

The Alvheim field was discovered in 1998 with well 24/6-2, which encountered oil and gas in sandstones in the Heimdal Formation in the Kameleon structure. The gross gas and oil columns were 52 m and 17 m, respectively. Further discoveries in the Heimdal Formation were 24/6-4 (Boa structure) and 25/4-7 (Kneler structure) in 2003.

The Kobra discovery was made in 1997 with well 25/7-5, which proved oil in the Hermod Formation, and the Viper discovery was made in 2009 with well 25/4-10S, which proved oil in Hermod Formation injection sands.



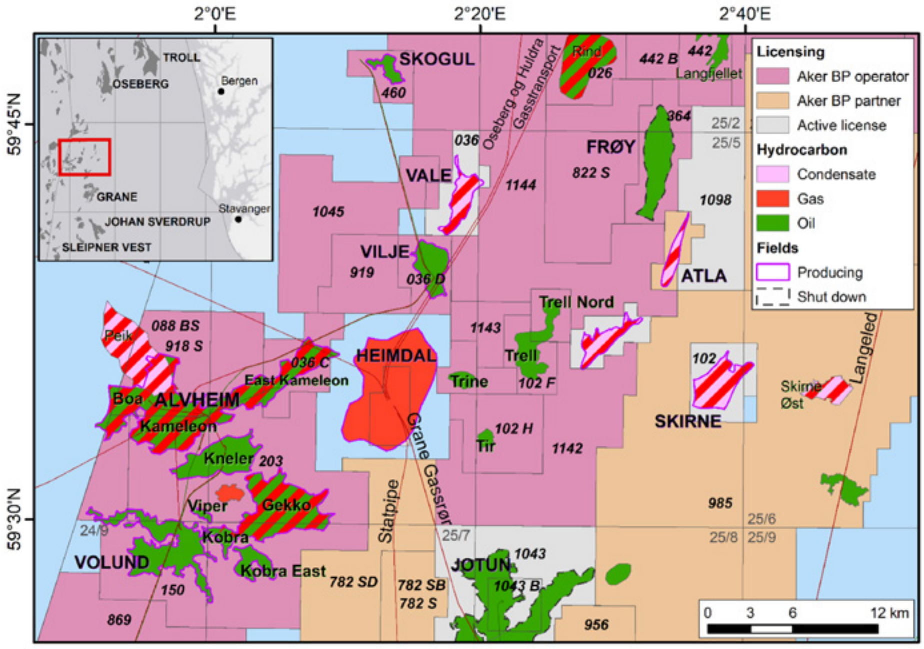


Figure 3.1 Alvheim field location map

Reservoir
The reservoir at Alvheim consists of high porosity, high permeability sandstones in the Heimdal Member from the Paleocene. The reservoir quality is generally excellent, although local variations do occur. The sand was deposited as sub-marine fan (turbidite) deposits fed from the East-Shetland Platform.

The Viper and Kobra structures are composed of very good quality, remobilised Hermod sands. Viper is an injection feature cutting through the overlying stratigraphy (dyke) whilst Kobra sands consist of injection features mainly sub-parallel to stratigraphy (sills). A common oil water contact (OWC) is drilled, and it is likely that Viper and Kobra communicate both in the oil leg and the aquifer.

Development
The Alvheim field is developed with a production vessel, the "Alvheim FPSO", and subsea wells. The oil is stabilised and stored on the production vessel before being exported by tanker. Processed rich gas is transported by pipeline from Alvheim to the Scottish Area Gas Evacuation (SAGE) pipeline system on the British continental shelf. Alvheim is produced through long horizontal wells completed with Inflow Control Devices (ICDs) and more recently Autonomous Inflow Control Devices (AICDs). Several of the wells are multilaterals. The (A) ICDs are used to limit water coning from the aquifer and gas coning from the gas cap, which is especially important in the thin oil rim reservoirs. The recovery method is bottom aquifer drive.

Viper and Kobra were developed in 2016 with one horizontal well in Viper and a bilateral well in Kobra; with one lateral in the main sill and one lateral shallower in injection dykes (Kobra shallow). The wells are tied back to the Volund manifold system.

Status
The recoverable volumes on Alvheim field Base are classified as "Reserves; On Production" (SPE's classification system). Since the last assessment, one infill well, Kameleon Infill West (KIW), has been drilled and put on production and is now part of base production. The number of active production wells are: Boa (4), Kneler (6), Kameleon (4), East Kameleon (3), Viper (1), Kobra (1).The actual production in 2022 was higher than the 2P estimate for 2022.

An additional infill, Alvheim East KAM L5, well has been planned and budgeted for in 2023. The recoverable volumes are classified as "Reserves; Approved for Development"» (SPE's classification system).

Blowdown of the Kameleon gas cap is assumed to start in October 2034. A new assessment of the gas in place has increased the recoverable volumes. The recoverable volumes from Kameleon Gas Cap Blow Down are classified as "Reserves; Approved for Development" (SPE's classification system).

The recoverable volumes from Kobra East &Gekko (field development) are classified as "Reserves; Approved for Development" (SPE's classification system). Kobra East & Gekko (KEG) is described in more detail in Section 3.2.2.

Aker BP is the operator of the Alvheim field with an 80 percent working interest in the Norwegian parts. Aker BP increased its share from 65% to 80% after the merger with Lundin Energy Norway AS, leaving ConocoPhillips Skandinavia AS as the only partner (20% interest in the Norwegian parts). The Boa reservoir straddles the Norway-UK median line. The Boa reservoir is unitised with NEO Energy, who are the owners on the UK side. Aker BP's interest in the total Boa unit is 70.92 percent.

3.1.2 Vilje (PL036D)

The Vilje field is an oil field located 5 km northeast of the Heimdal production facility in block 25/4, licensed under PL036D in the North Sea. The reservoir depth is about 2,200 m TVD MSL and the water depth in the area is approximately 120 m. Production started in 2008.

Discovery

The Vilje field was discovered in 2003 by well 25/4-9 S. The Heimdal Formation reservoir was encountered at 2,135 m TVD MSL with 61 m gross sand (56 m net). The sand had very good reservoir properties and was oil-bearing with undersaturated oil. Production from the nearby Heimdal field and Frigg field had caused depletion of the regional aquifer by approximately 18 bars. Based on the well results, the oil water contact (OWC) has been determined at various levels between 2,195 and 2,198 m TVD MSL, and the current OWC is expected to be influenced locally by depletion and production.

Reservoir

The Vilje field is a flat low-relief fan of Heimdal depositional system. The field has two separate structures; Vilje Main and Vilje South. The reservoir is a turbidite deposit, in the Heimdal Formation from the Paleocene at about 2,150 m TVD MSL. The reservoir interval is divided into three reservoir zones – R1, R2 and R3 – where R1 and R3 are clean sands while R2 is a fine-grained muddy layer which acts as a baffle to fluid flow.

Development

The Vilje field is a subsea development with three subsea horizontal producers tied back to the Alvheim FPSO. Vilje Main is drained by one single lateral well (VI1) and one bilateral well (VI2) with one branch above and one below the R2 shale. There is one single lateral well on Vilje South (VI3). The water depth in the area is approximately 120 m. The recovery mechanism is natural water drive from the regional underlying Heimdal aquifer.Status

The recoverable volumes in Vilje are classified as "Reserves; On Production" (SPE's classification system). After Skogul came on stream in March 2020, the main production strategy has been to optimise the combined Vilje and Skogul production in the pipeline. There is a commercial agreement between the Skogul and Vilje licenses, where Skogul compensates for deferred Vilje production. The actual production in 2022 from the Vilje reservoir, is lower than the 2P estimate for 2022 due to optimising the total Skogul + Vilje production. Well VI1 is responsible for approximately 80% of

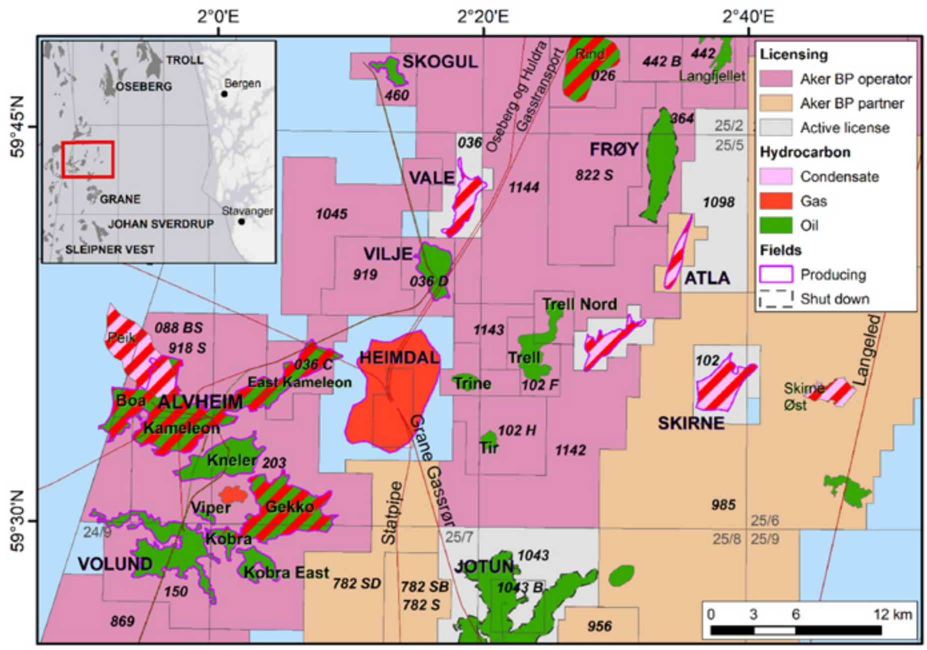


Figure 3.2 Vilje location map

Vilje production and produces on a continuous basis, while VI2 and VI3 are produced intermittently.

Aker BP holds a 46.904 percent interest in the licence and serves as operator. The other licence partners are DNO Norge, holding a 28.853 percent interest, and PGNiG Upstream Norway with a 24.243 percent interest.

3.1.3 Volund (PL150)

The Volund field is an oil field located 8 km south of the Alvheim field in block 24/9 licensed under PL150 in the North Sea, see Figure 3.3. The reservoir depth is about 1,900 m TVD MSL and the water depth in the area is about 120-130 m. Production started in April 2010.

Discovery

The Volund field was discovered in 1994 by well 24/9-5. The Intra Balder Formation sandstones were encountered with oil in the interval 2,011 m to 2,018 m TVD MSL (oil down to). The discovery was appraised by wells 24/9-6 and 24/9-7, confirming a field-wide OWC of 1995 m TVD MSL and a GOC of 1,891 m TVD MSL.

Reservoir

Volund is a massive injectite complex consisting of high-quality, Darcy quality sands which have been injected from the early Eocene Hermod Formation into overlying shales of the Sele, Balder and Hordaland formations. Dykes, termed “wings”, rise in three directions from a central lower sill which is mainly situated below the OWC. This results in a “bathtub” shape open to the west. Volund is unique in the sense that the entire hydrocarbon accumulation is contained in injected sands and with the majority within cross-cutting dykes.

Development

The field is developed with six production wells and one injection well as a subsea tie-back to the Alvheim FPSO. Initial development included three producing wells targeting the ~100 m oil column in the wings, supported by one water injector in the sill in addition to natural water drive. The first infill well started production in 2013. Another two infill wells started production in 2017. Two of the original producers have been sidetracked, one in 2019 and one in 2021.

Status

The recoverable volumes on Volund are classified as “Reserves; On Production” (SPE’s classification system). The actual production in 2022 was in line with the 2P estimate for 2022, but with a higher gas to oil ratio.

Aker BP is the operator and holds a 100 percent interest in Volund after the merger with Lundin Energy Norway AS.

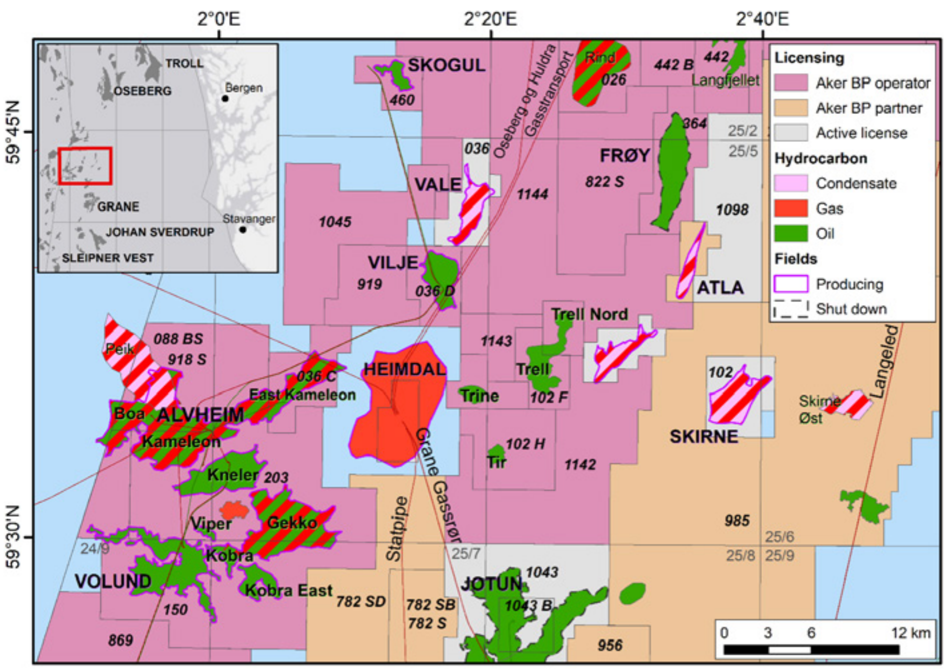


Figure 3.3 Volund location map

3.1.4 Bøyla (PL340)

The Bøyla field is an oil field located in PL340, block 24/9 in the central part of the North Sea, 15 km southwest of the Volund field. Water depth is 120 m and depth of reservoir is 2,000 m TVD MSL. Well M-01 BH, on the northwestern flank, started to produce on 19 January 2015 and has been the main contributor. The location of the Bøyla field is shown in Figure 3.4

Discovery

The Bøyla field was discovered in 2009 by well 24/9-9 S. The initial discovery name was "Marihøne A". The well proved undersaturated oil at normal pressure with an OWC at 2,071 m TVD MSL. Subsequent pilot and development wells have confirmed the OWC across the field.

Reservoir

The Bøyla structure is a flat low-relief Eocene turbidite fan deposit. The reservoir is within the Palaeocene/Eocene Hermod Sandstone Member, completely encased within Sele Formation shales. The Hermod Sandstone Member is interpreted as sediment gravity flows sourced from the East Shetland Platform, deposied in a basin floor setting. Hermod sandstones have presumably filled bathymetric lows created by the underlying Heimdal Member.

Two major depocenters have been recognised in the field, one in the west, and one in the east. Questions have been raised as to connectivity between these two parts of the reservoir.

The pre-drilled wells confirmed a consistent OWC. Injection testing of the single water injector has proved sufficient injectivity and interference between the injector (M3) and the western producer (M1). Production experience shows that communication between the injector and the eastern producer (M2) is not present on a production time scale.

Development

The Bøyla field is a four-slot subsea template development with two long horizontal producers and one deviated water injector. The fluid is transported through a 26-km pipe-in-pipe flowline to the Kneler A subsea template, which is further tied back to the Alvheim FPSO. Gas lift is required in the producers. The main recovery mechanism is water injection.

Status

The recoverable volumes in Bøyla are classified as "Reserves; On Production" (SPE's classification system). The actual production in 2022 was significantly lower than the 2P estimate for 2022. This was due to prioritising the Frosk test production well and equipment failure in the Bøyla water injector, leading to shut-in for a significant part of 2022. The injector is expected to be back online in 2023.

Aker BP is operator and holds an 80 percent interest in Bøyla. Aker BP increased its share from 65% to 80% after the merger with Lundin Energy Norway AS, leaving Vår Energi AS as the only partner (20% interest).

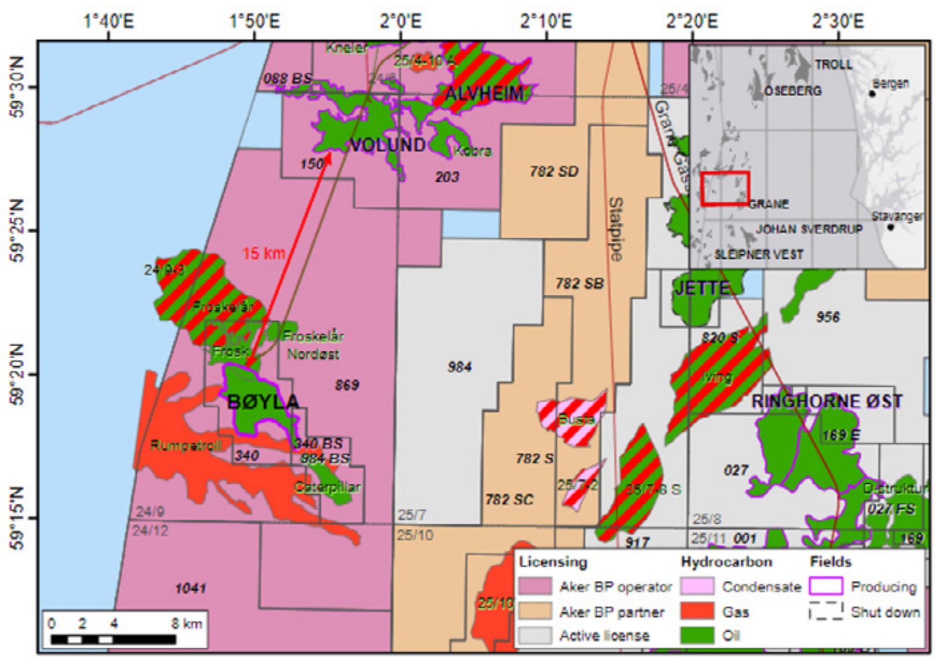


Figure 3.4 Bøyla location map

3.1.5 Frosk (PL340)

The Frosk field lies within Production Licence 340 and is located in block 24/9 of the Norwegian sector of the North Sea. Forty metres of oil-bearing injectite sand was penetrated within the Eocene Hordaland Group, located just above the Balder Formation. An OWC was penetrated, cored, and aligned with pressure data at 1,861.5 m TVDSS. The GOC was calculated to be 1,786 m TVDSS based on pressure data and supported by the measured PVT bubble point pressure. A gas-bearing thinner injectite was penetrated in the sidetrack, which constrained the depth of the GOC. The water depth at the discovery well is 119 m. Production from well 24/9-M4, the Frosk Test Producer, also called FTP, commenced in August 2019.

Discovery

Frosk was discovered in 2018 by the 24/9-12 S well and sidetrack 24/9-12 ST2. It was later appraised by wells 24/9-12 A / AT2 and 24/9-15 A. The wells penetrated a 40-m oil-bearing injectite sand complex from the Upper Paleocene to Lower Eocene in the Intra Hordaland Group. The reservoir was penetrated at 1800 m TVD MSL. The GOC was defined at 1786 m TVD MSL and OWC at 1861 m TVD MSL. The oil is biodegraded to a relatively low quality (21 °API and 6.7 cP)

Reservoir

The Frosk injectite sands are believed to have been injected into the Sele, Balder and Hordaland Formations from the underlying Gamma structure. Gamma is a 70-m thick sand body in the Balder Formation (24/9-3). Frosk consists of a dyke coming from the crest of Gamma and levelling out as a thick sill in the Hordaland Formation. Around the main Frosk injectite, we find several small dykes and sills, acting as "fingers". The injection process has enhanced the reservoir properties, with average porosity of 32 percent and permeabilities up to 10 Darcy. The main sill is very homogeneous, with a net-to-gross close to 100 percent. The behaviour of the Frosk reservoir outside the main seismic amplitude is uncertain, but the sands likely bifurcate into smaller sills and dykes as seen in Bøyla development pilot wells.

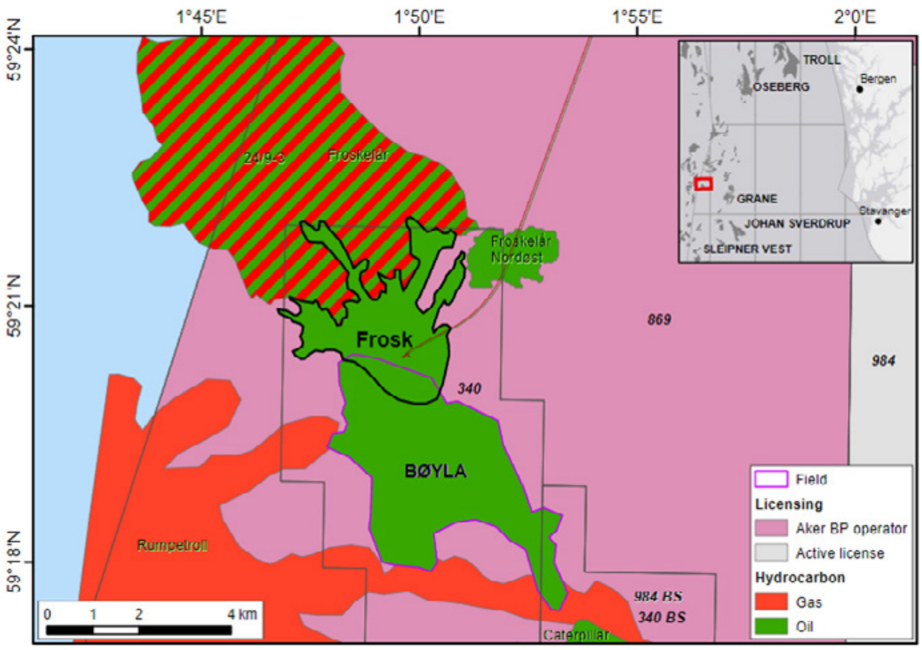


Figure 3.5 Frosk field location map

Development

Production from well 24/9-M4, the Frosk Test Producer, also called FTP, commenced in August 2019. The test production well is a horizontal bilateral well targeting Frosk Main injectite sands and Upper Zone. The main bore was permanently shut-in in March 2021 due to sand production. The well is producing through the Bøyla subsea system to the Alvheim FPSO.

The Frosk Development project represents two subsea production wells to drain the remaining areas of the field. Drilling was completed in December 2022. The development solution includes one horizontal production well (Frosk #2, 24/9-M-5H) targeting the northern dyke area and one horizontal bilateral producer (Frosk #3, 24/9-M-6 Y1H and Y2H) targeting the eastern and western areas of the Frosk Main injectite. The two new Frosk wells will be tied back to the Bøyla manifold and will have downhole gas lift. The well and completion design follow the current Alvheim and Frosk well designs, including standalone sand screens. Planned production start from the Frosk Development project is in 2023. The fluids are to be routed 26 km through the Bøyla pipeline via the Kneler A pipeline end manifold (PLEM) and manifold header, and then through the 2- km long flowline via the South Riser Base to the Alvheim FPSO for further processing.

Status

The recoverable volumes on Frosk Test are classified as “Reserves; On Production” (SPE’s classification system). The actual production in 2022 was lower than the 2P estimate for 2022. The well came back on stream after a well intervention in November 2021 due to massive sand production from the main bore (Y1H). The main bore has now been permanently shut-in and only branch (Y3H) is producing.

The recoverable volumes on Frosk Development are classified as “Reserves; Approved for Development” (SPE’s classification system). The Frosk Development project submitted a PDO in September 2021 and it was approved by the Ministry of Petroleum and Energy in July 2022. Planned production start is Q1 2023.

Aker BP is operator and holds an 80 percent interest in Frosk. Aker BP increased its share from 65% to 80% after the merger with Lundin Energy Norway AS, leaving Vår Energi AS as the only partner (20% interest).

3.1.6 Skogul

The Skogul oil field is located approximately 40 km north of Alvheim in block 25/1 under PL460 in the Central Viking Graben in the Norwegian North Sea, and consists of Eocene Balder and Frigg Formation deep marine deposited sandstones. Figure 3.6 shows the location of the discovery. The water depth is about 107 m in the area, and the crest of the structure is estimated to be at 2,097 m TVD MSL.

Discovery

The discovery well 25/1-11 R and the sidetrack well 25/1-11A were drilled in 2010 and proved a thin gas cap overlying a 20-m oil column with excellent reservoir quality in Upper Balder-Frigg Formation sandstones. Vertical well 25/1-11 R was drilled on a structural high with a strong amplitude anomaly, encountering a 13-m oil column and an oil-water contact (OWC) was proven at 2,126 mTVDSS. A deviated (29°) sidetrack well, 25/1-11 A, was subsequently drilled higher on the structure, but in an area with a dimmer amplitude anomaly. This well encountered a small gas cap with a gas-oil contact (GOC) at 2,106 m TVDSS and a 12-m oil column.

Reservoir

The reservoir consists of Eocene Upper Balder and Frigg Formation sandstones with good properties. The reservoir sandstones were derived from the East Shetland Platform to the West and deposited from deep marine turbidity currents as part of the Frigg submarine fans. Average NTG in the main producing intervals in the Skogul reservoir is high (~92%),

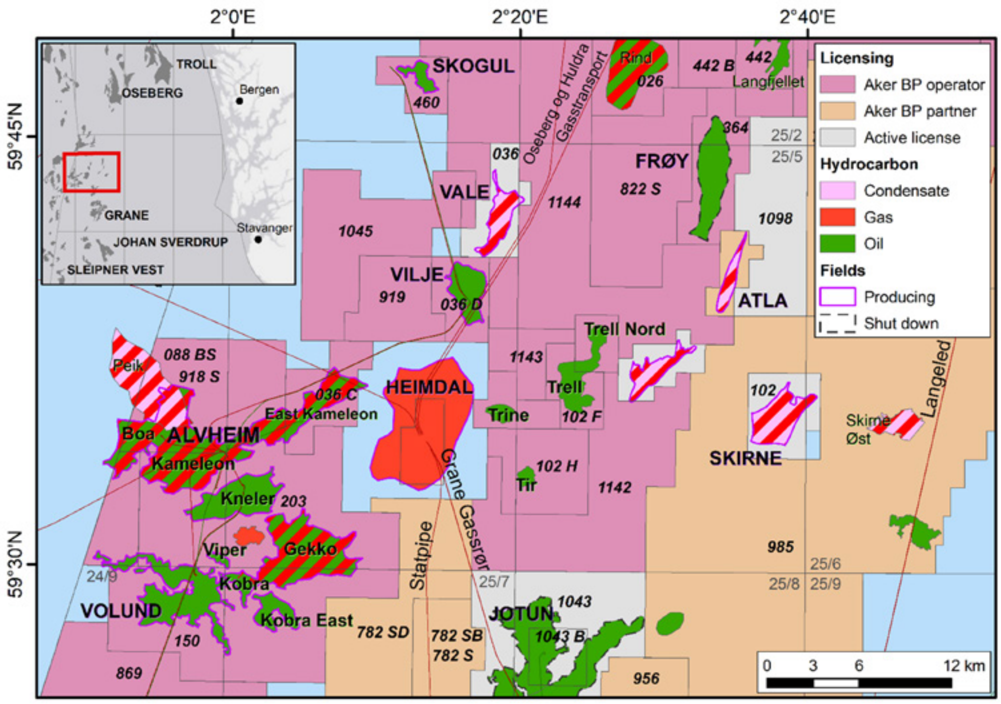


Figure 3.6 Skogul location map

average porosity is ~31% and permeabilities are around 1 D. The reservoir was depleted to 8% (~18 bar) below hydrostatic pressure at the time of discovery (2010). This is a result of the regional production history of which the Frigg field production and subsequent repressurisation are the most significant factors. Pressure measurements taken in the development wellbores (2019) show a uniformly increased pressure by ~3 bar since 2010. This provides a positive indication that an aquifer is present and gives pressure support to the Skogul reservoir.

Development
Skogul is developed as a tie-back to the Alvheim FPSO via the Vilje template and pipeline. A bilateral producer was drilled and completed between July 2019 and January 2020. It is tied to a two-slot subsea template. The drive mechanism is depletion and natural aquifer support.

Status
Skogul field recoverable volumes are classified as "Reserves; Approved " (SPE's classification system). After Skogul came on stream in March 2020, the main production strategy has been to optimise the combined Vilje and Skogul production in the pipeline. There is a commercial agreement between the Skogul and Vilje licences, where Skogul compensates for deferred Vilje production. The actual production in 2022 was higher than the 2P estimate for 2022, mainly due to prioritising Skogul production by shutting in cyclical wells on Vilje.

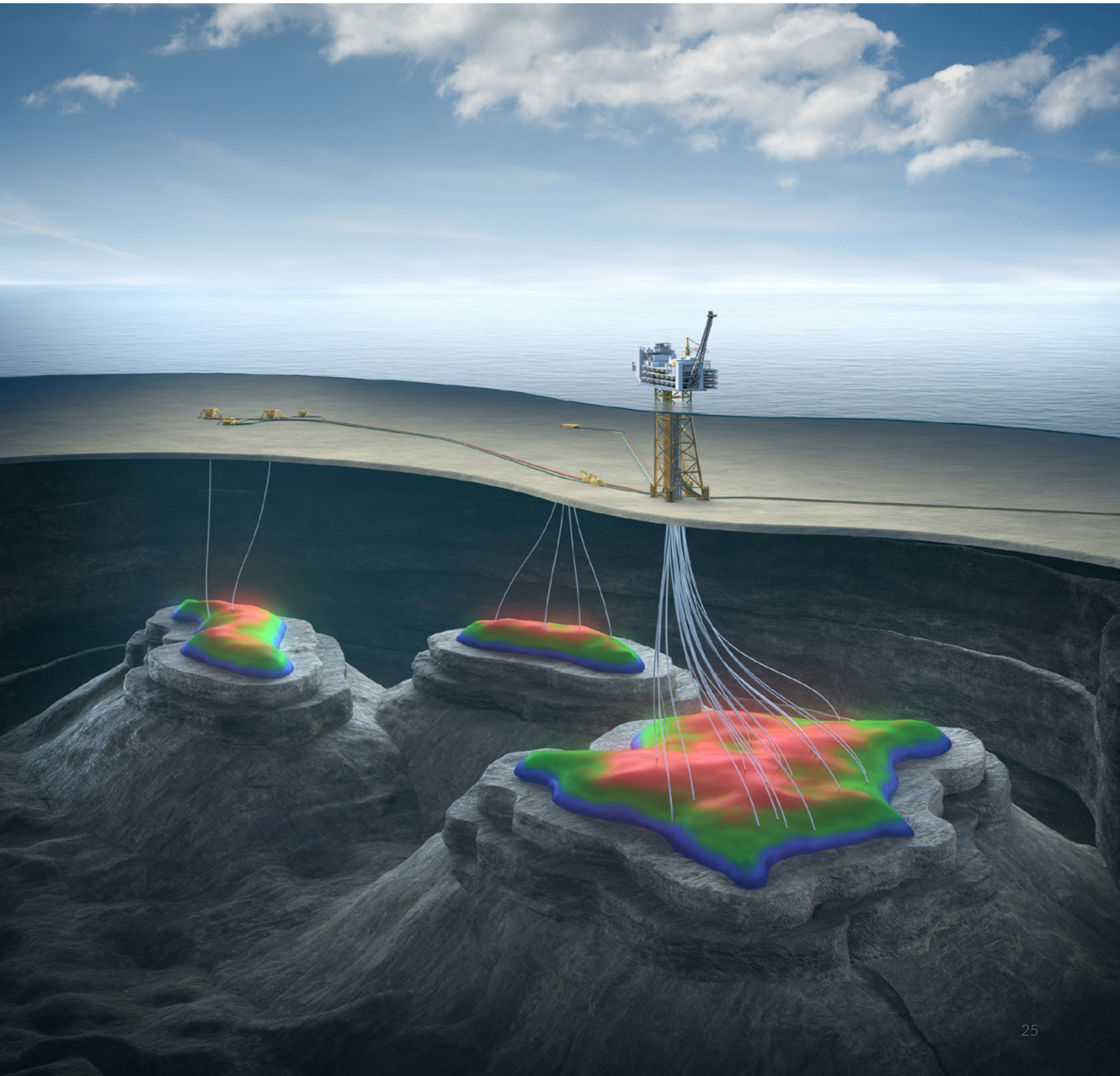
Aker BP is operator and holds 65 percent interest in the Skogul field. The remaining 35 percent is held by PGNiG Upstream Norway AS.

3.1.7 Ivar Aasen Unit and Hanz (PL001B, PL028B, PL242, PL338BS, PL457)

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. The field contains both oil and free gas. The Ivar Aasen field includes two accumulations: Ivar Aasen and West Cable, Figure 3.7. The accumulations cover several licences and have been unitised into the Ivar Aasen Unit. Ivar Aasen commenced production on 24 December 2016. The water depth in the area is approximately 110 m and the main reservoir at Ivar Aasen is found at about 2,400 m TVD MSL reservoir depth.

Discovery

Ivar Aasen was discovered with well 16/1-9 in 2008, proving oil and gas in Jurassic and Triassic sandstones. An earlier exploration well, 16/1-2 in 1976, within the structural closure was initially classified as dry but was after a re-examination reclassified as an oil discovery. West Cable was discovered with well 16/1-7 in 2004, proving oil in Jurassic sandstones.



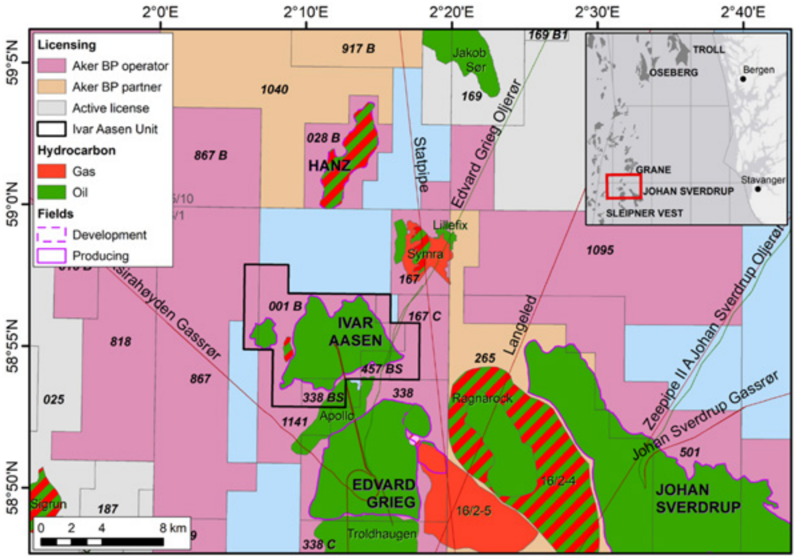


Figure 3.7 Ivar Aasen Unit and Hanz location map

Reservoir
The two accumulations are located at the Gudrun Terrace between the Southern Viking Graben and the Utsira High. The reservoir sands are fluvial and shallow marine deposits from the late Triassic to late Jurassic. The reservoir sands in the Ivar Aasen structure are complex and heterogeneous while the reservoir at West Cable is more homogeneous. The Ivar Aasen structure contains saturated oil and two gas caps while the West Cable structure contains undersaturated oil.

Development
The drainage strategy for the Ivar Aasen structure assumes water injection for pressure maintenance. West Cable is produced by natural depletion where the major driving force is aquifer drive. A total of eleven producers (ten targeting the Ivar Aasen structure and one in West Cable) and eight water injectors (in the Ivar Aasen structure) have been drilled in the Ivar Aasen field. The production wells are completed with mechanical sand control and ICD completions while the injectors have cemented perforated liners, except two horizontal injector with screens. In Phase 2 of the development, the Hanz discovery will be developed with two subsea wells tied-back to the Ivar Aasen platform. The current plan is production start-up from Hanz in 2024. The Hanz development is discussed in Chapter 3.2.1.

The Ivar Aasen field is developed with a steel jacket including living quarters and process facilities located at a water depth of 110 m with dry wellheads on the platform. The wells are drilled from a jack-up rig. The wellstream is partly processed on the platform before transportation through pipelines to the Edvard Grieg installation for final stabilisation and export. Edvard Grieg also supplied Ivar Aasen with power until a joint solution for power from shore was established in December 2022.

Status
The PDO for the Ivar Aasen area was approved in early 2013. The field development went according to plan and the field came on stream on 24 December 2016

All initially planned wells have been drilled in the Ivar Aasen and West Cable structures. The development wells on Ivar Aasen Main Field came in roughly as expected. Two new water injection wells were drilled in 2018, named D-6 and D-7. In 2019, two new producers were drilled: D-18 in the underlying Alluvial Fan formation and one branched Skagerrak 2 producer in the East (D-15). In Q1 2021, two new producers came on stream; D-17 in Alluvial Fan and D-20 in Skagerrak 2. Well D-13 was also drilled, targeting the Braid Plane reservoir zone. This well was considered dry as the permeability, hence productivity, was too low. One injector supporting drainage in Skagerak 2 (D-4A) commenced injection in Q3 2021. West Cable ceased production in June 2022. West Cable oil volumes recovered has been 0.15 MSm^3. Slot D-09 will be used for production on Ivar Aasen commencing in 2023. D-13 was drilled to the Sleipner and Skagerak 2 Formations, and commenced production in mid-December 2022. D-08 was re-drilled to to the Skagerak 2 Formation, commencing injection in 2023.

Net production at Ivar Aasen averaged 12.4 mboepd in 2022. This was about 21% lower than expected mainly because of compressor failure on EG and lower production efficiency. Delayed effect of D-4A injector and choking of D-19 due to high reservoir outtake and lower pressure than expected contributed to lower production in 2022 than expected. Cessation of production (CoP) from the Ivar Assen field is expected EOY 2035.

The recoverable volumes on Ivar Aasen are classified as “Reserves; On Production”» (SPE’s classification system).

Aker BP holds 36.1712 percent interest in the Ivar Aasen Unit. The other licensees are Equinor (41.4730), Sval Energi AS (12.3173 percent), OKEA ASa (9.2385 percent) and MVest Energy AS (0.8 percent).

3.1.8 Edvard Grieg (PL338)

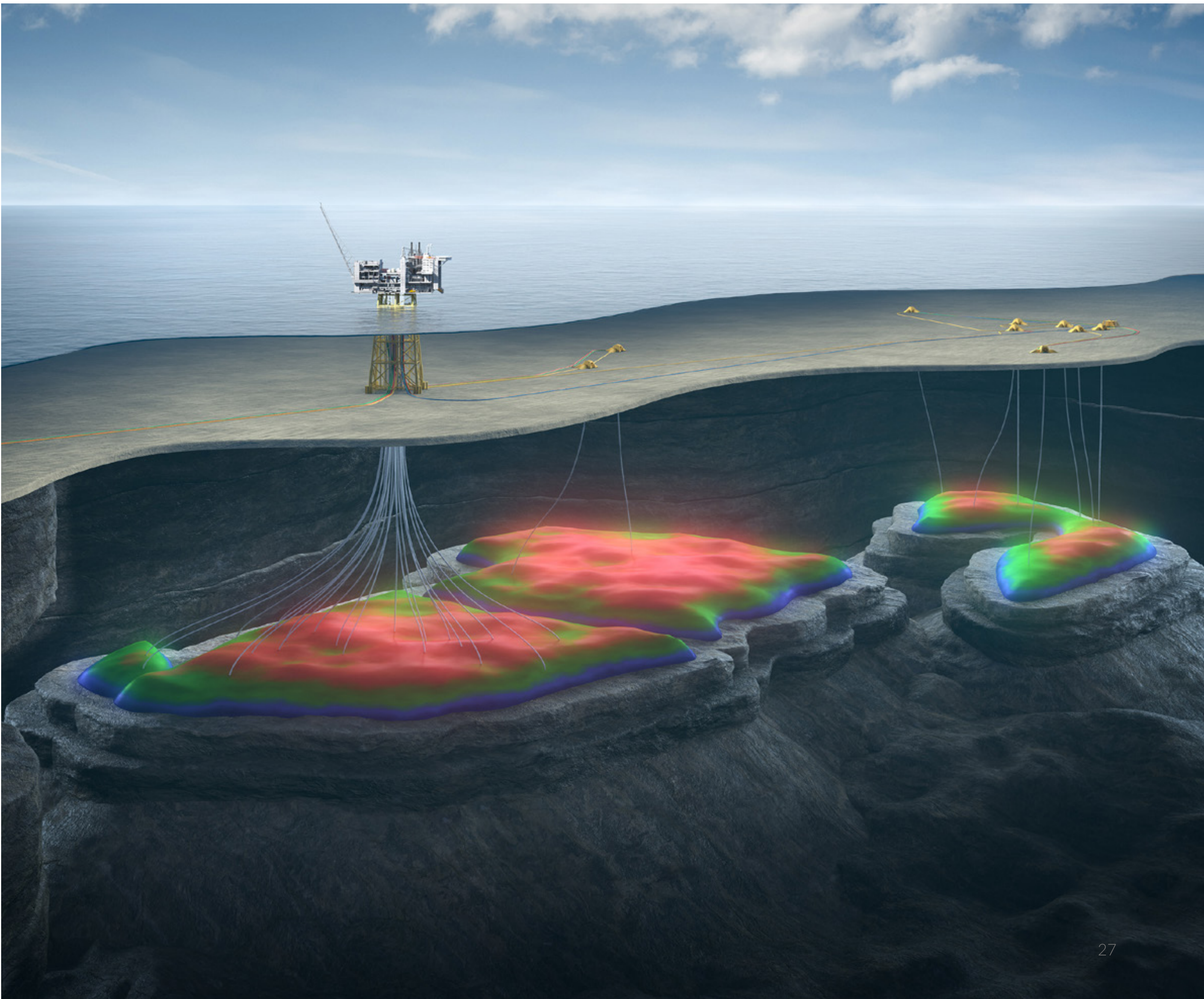
The Edvard Grieg field is located in Block 16/1, PL338, on the western side of the Utsira High. The field is approximately 180 km west of Stavanger, with a water depth around 109 m. Top reservoir is at ~1850 mTVD MSL. The PDO for Edvard Grieg (former LUNO) was approved in 2012 with production starting in November 2015. Edvard Grieg is new to the Aker BP portfolio and was part of the acquisition of Lundin Energy in 2022.

Discovery

Edvard Grieg was discovered with well 16/1-8, which proved oil in aeolian sandstone and conglomerates. The field was further appraised by 16/1-10 and 16/1-13. Two DSTs were performed showing good productivity and improving properties/thickness away from the wells. In 2011 16/1-15 proved oil on the Tellus high consisting of lower Cretaceous sandstone of excellent reservoir quality overlaying a porous and fractured basement section. The production test proved very good productivity in both formations. Production history shows that the Tellus High and Luno basin are in very good communication. Five more appraisal wells have been drilled on Edvard Grieg, of which three have targeted the eastern conglomerates, one has targeted the sands to the west and the last proving oil in fractured/weathered basement on Tellus East

Reservoir

The Edvard Grieg field is a combined structural and stratigraphic trap in which light and slightly undersaturated oil is found within a variety of reservoirs. These include: bioclastic shallow marine sandstones; aeolian sandstones; fluvial and alluvial sandstones and conglomerates; and weathered granitic basement. The sandstones generally exhibit excellent reservoir quality whereas the conglomerates exhibit moderate to poor properties. The basement reservoir is mainly found to the north of the field on the Tellus high and exhibits extreme variability in reservoir quality.



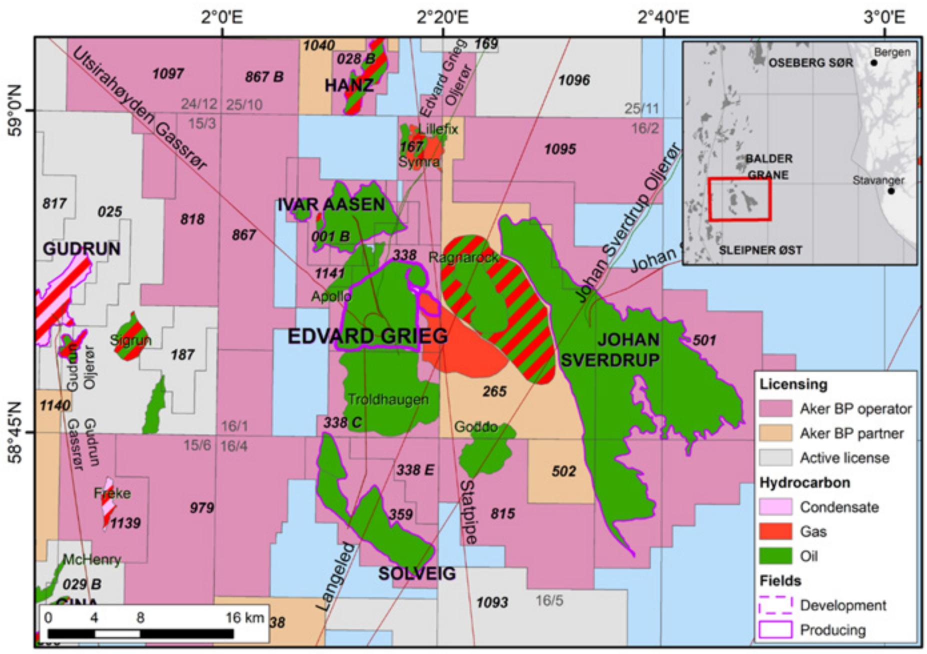


Figure 3.8: Edvard Grieg location map.

Development
The Edvard Grieg field is developed as a PDQ jacket solution, with a total of 20 well slots. A full processing facility is installed on the platform. The Edvard Grieg platform is connected to Oseberg Transport System (OTS) through the EdvardGrieg Oil Pipeline (EGOP) and Grane Oil Pipeline (GOP) and to the Scottish Area Gas EvacuationSystem (SAGE) through the Utsira High Gas Pipeline (UHGP). Ivar Aasen, Solveig and Troldhaugen EWT are currently tied back to Edvard Grieg.

The main drainage strategy on Edvard Grieg is injection by voidage to ensure pressure maintenance. A total of 13 producers and 4 injectors have been drilled, including the IOR 2023 campaign. The majority of the wells are completed using screens and two wells have the Fishbones technology installed. Three of the injectors have cemented liners, while the last, a converted producer, is completed using screens. Three of the wells have zonal control using ODIN valves, while a fourth well is completed with sliding sleeves. One of the wells is a dual-branched MLT with branch control.

The first IOR compaign was completed in 2021, consisting of three (3) infill production wells.

The platform was fully electrified in December 2022.

In addition to the existing tie backs to Edvard Grieg, Solveig Phase 2, Troldhaugen Full field, Hanz and Symra are planned tie-backs in the future. Hanz and Symra will go through Ivar Aasen prior to Edvard Grieg. The development projects are discussed in a later section.

Status
Production on Edvard Grieg started in November 2015. Two production wells were available at the time of startup. Injection started 7 months after production start. The field has performed significantly better than expected, mainly because of higher volumes, delayed water breakthrough and more optimal sweep, confirmed by 4D seismic. The estimated reserves at PDO were produced in 2021 while the field was still on plateau. Three new producers came on stream in 2021 as part of the IOR 2021 campaign, with results in line with or better than expectations.

The field is still producing at plateau with a gradually increasing water cut in most of the wells. Net production from Edvard Grieg in 2022 was 75 mboepd, which is in line with the forecast.

The recoverable volumes on Edvard Grieg are classified as "Reserves; On Production" (SPE's classification system).

The estimate is slightly reduced for the base profile. However, due to the sanctioning of the IOR 2023 campaign consisting of three new producers, the total estimate is increased during 2022.

The partnership on Edvard Grieg consists of Aker BP (operator) with 65 percent, OMV (Norge) with 20 percent and Wintershall Dea with 15 percent.

3.1.9 Solveig (PL359)

The Solveig field is an oil and gas discovery located on the Utsira High, 190 km west of Stavanger. The distance to the Edvard Grieg field to the north is 15 km. Water depth at the location is around 109 m. Top reservoir is at appox. 1890 mTVD MSL. The PDO for Solveig Phase 1 was approved in 2019, followed by first oil Q3 2021. The field was part of the acquisition of Lundin Energy in 2022 and is therefore new to Aker BP's portfolio.

Discovery & Appraisal

PL359 was awarded on 6 January 2006 (APA 2005). The first well in the licence, 16/4-5 (2010), was dry but proved oil shows in faulted/fractured but tightly cemented, granitic basement. The Solveig discovery was made by the second well in the licence, 16/4-6 S (drilled in 2013), and was further appraised by the wells 16/5-5 (late 2013), 16/4-8 S (2014), 16/4-9S (2015) and 16/4-11 (2018) before submittal of the Solveig PDO in late 2018. Post-PDO, well16/4-13 ST2 appraised Segment D in 2021. Figure 3.10 shows the different segments in the Solveig field.

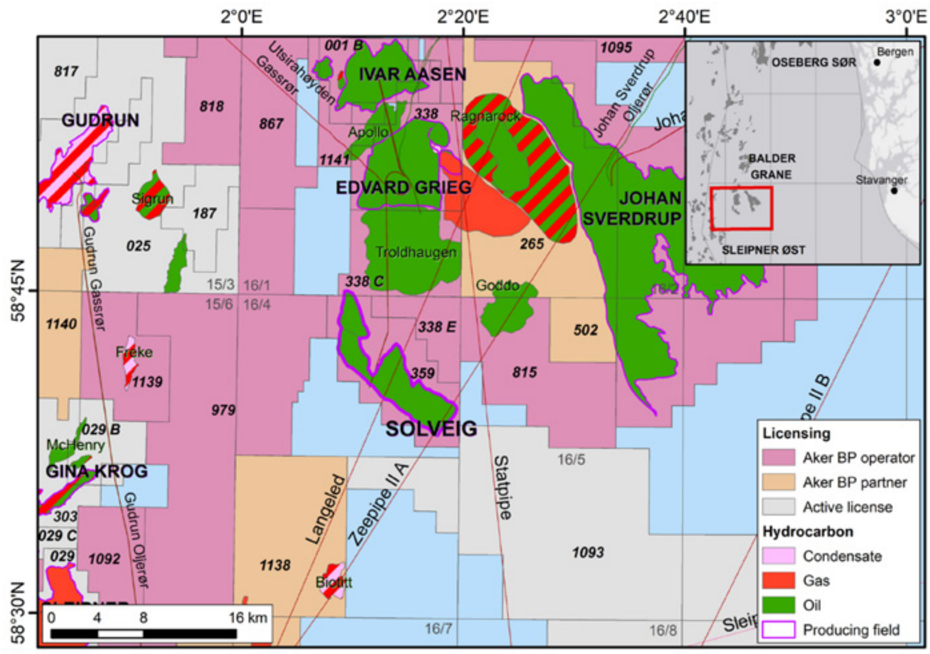


Figure 3.9: Solveig location map

Reservoir

The Solveig field includes two main reservoir intervals, "Outer Wedge" and "Synrift", separated by a major, regional unconformity. Both reservoirs are dominated by continental red-bed sandstones with a scarcity of age-diagnostic fossils. The Outer Wedge reservoir is dated late-Permian Rotliegendes Group and the Synrift reservoir is of (late) Devonian (Buchan Equivalent) age. The current understanding of the Solveig field is that the large-scale stratigraphic architecture is controlled by three major, regional unconformities.

Both the Outer Wedge and the Synrift reservoir varies from coarse-grained alluvial fan conglomerates, sandy desert or alluvial plaines and mature aoeolian and fluvial systems. Synrift has a somewhat poorer reservoir quality than the Outer Wedge, but both are changing as a function of sediment maturity.

Development

Phase 1 of this development was finished in February 2022 after drilling and completing three oil producers and two water injectors. All the Phase 1 wells are single satellites which are commingled and tied back to the Edvard Grieg platform. The oil and gas is processed at Edvard Grieg before export. The Edvard Grieg platform is connected to Oseberg Transport System (OTS) through the Edvard Grieg Oil Pipeline (EGOP) and Grane Oil Pipeline (GOP) and to the Scottish Area Gas Evacuation System (SAGE) through the Utsira High Gas Pipeline (UHGP).

Production start-up was during Q3 2021. The Phase 1 development focusses on the Outer Wedge reservoir unit in Segments B and C, with a test production of the Synrift reservoir in Segment B through one of the development wells. The Phase 2 development is described further under the Development Project section.

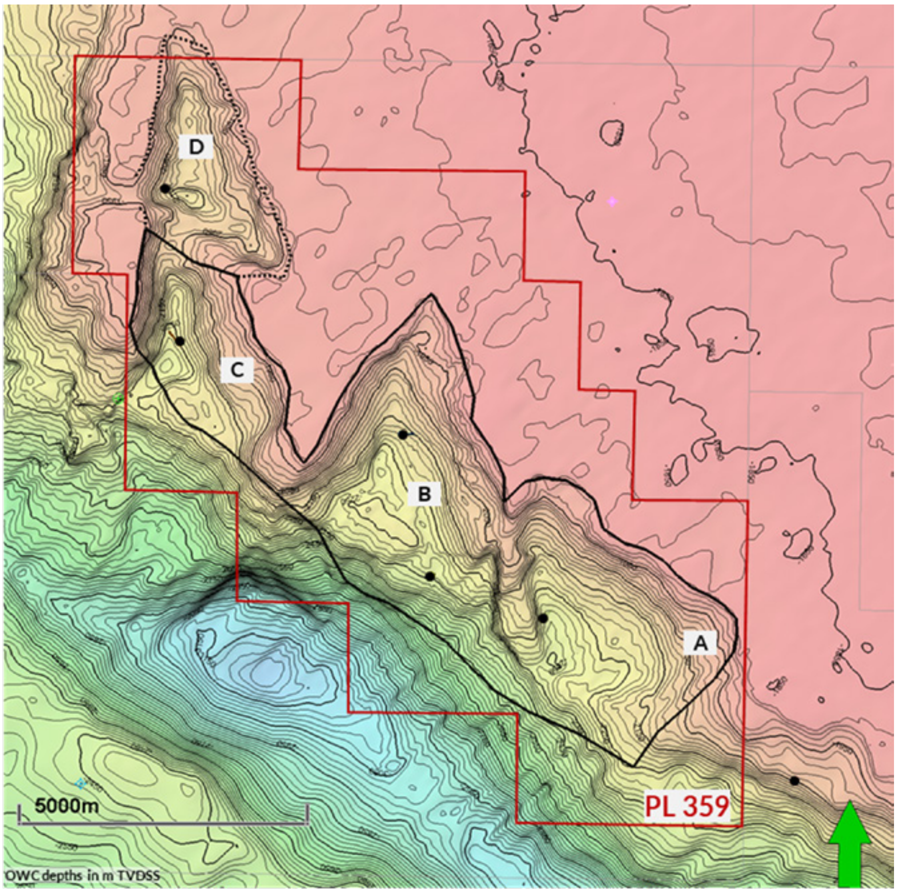


Figure 3.10: Segment overview Solveig

Status
Solveig came on stream in Q3 2021, producing back to the Edvard Grieg platform. In 2021 the reserves for Solveig were increased to account for the positive drilling results from the development wells in Phase 1, which is also supported by the first year of production.

The drainage strategy on Solveig has been to gain as much production experience as possible to mature the Phase 2 development. Segment B Synrift has therefore been prioritised. Pressure maintenance is the primary injection strategy. The Solveig field has been operated with the aim of maximising production from the Edvard Grieg and Ivar Aasen Hub.

Net production from Solveig in 2022 amounted to ~6.7 mboed

The recoverable volumes on Solveig Phase 1 remain unchanged for 2022 and are classified as “Reserves; On Production” (SPE’s classification system).

The current PL359 licensees are Aker BP ASA (operator) 65 percent, OMV (Norge) AS 20 percent, Wintershall Dea Norge AS 15 percent.

3.1.10 Troldhaugen (PL338C)

Troldhaugen (previously Rolvsnes) is a field located in the PL338C/PL338E licences on the Utsira High in the Norwegian sector (blocks 16/1 and 16/4) of the North Sea. Ownership in the licences is aligned with Aker BP ASA holding 80 percent (operator) and OMV (Norge) AS 20 percent. This alignment of ownership allows for development optimisation for the two licences.

Discovery

The first two wells drilled in PL338C, the discovery well 16/1-12 (2009) and the appraisal well 16/1-25 S (2015), proved an oil column of approximately 30 m. A third well, 16/1-28 ST2 (2018), was drilled horizontally through 2550 metres of weathered and fractured basement. Since August 2021, this well has been used for the ongoing Troldhaugen (Rolvsnes) Extended Well Test (EWT), tied to the Edvard Grieg platform, and has been renamed 16/1-CA-1 H. There is currently no other dedicated production from weathered basement reservoirs on the Norwegian Continental Shelf.

In licence PL338E, only one well has been drilled, 16/4-5 (2010). At this location, basement was tight. However, significant variability in basement reservoir quality has been observed among the around 30 wells that have penetrated basement in the Utsira High area, even wells that are relatively close to each other. This is also consistent with expected geological variability in weathered basements, suggesting that this well may not be representative for the entire PL338E licence.

Reservoir

The reservoir consists of fractured and weathered basement. The original mineralogy is mainly granite and granodiorite of Ordovician/Silurian age. Utsira High was exposed for tropical weathering during much of the Mesozoic. Weathering takes place by interactions between meteoric water and rocks along the fluid pathways. The degree of weathering depends on several factors such as exposure time, rock mineralogy, fractures, (paleo-)climate and (paleo-)topography. A relatively slow erosion rate is a requirement for subsequent preservation of the weathered zone. This is typically the case in relatively flat areas within a tectonically stable region, like in much of present-day Australia or the African Savannah. Weathered zones can become fully protected against further erosion by being flooded and buried under sediments.

Development

Troldhaugen is a subsea tie-back to Edvard Grieg via the Troldhaugen EWT infrastructure consisting of one production pipeline, umbilical and gas lift.

Status

The EWT production started on 7 August 2021. Increasing water cut was observed after a couple of weeks but has since stabilised. The test performance and significant data acquisition has formed the basis for the current understanding of dynamic reservoir performance.

The reserves on Troldhaugen include EWT production, only, until the earliest end date for the test production period which is 1 March 2023. These volumes are classified as "Reserves; On Production" (SPE's classification system).

Remaining volumes in Troldhaugen are classified as contingent resources, see Chapter 4.

Aker BP holds 80 percent and OMV (Norge) AS the remaining 20 percent.

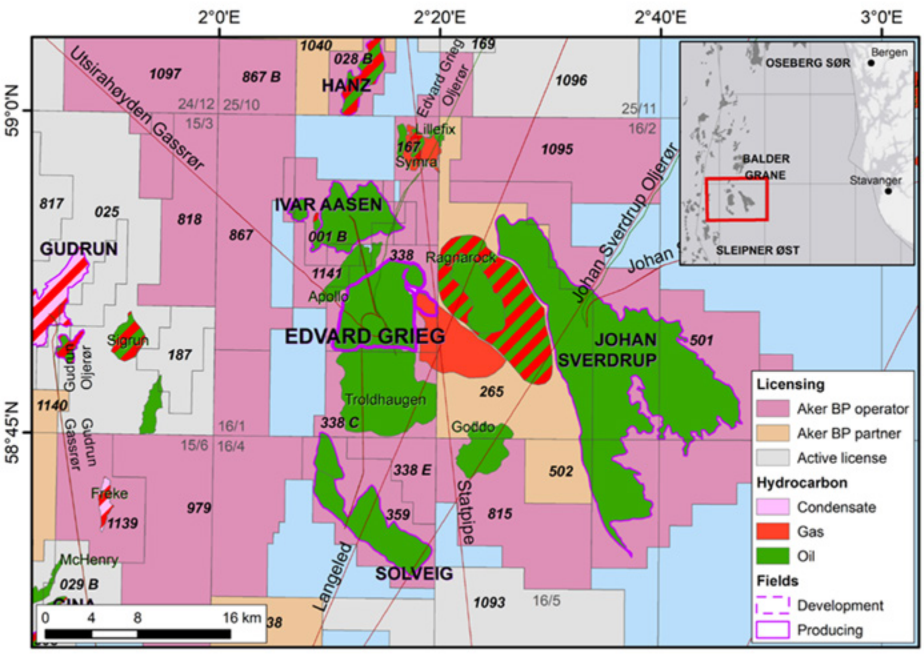
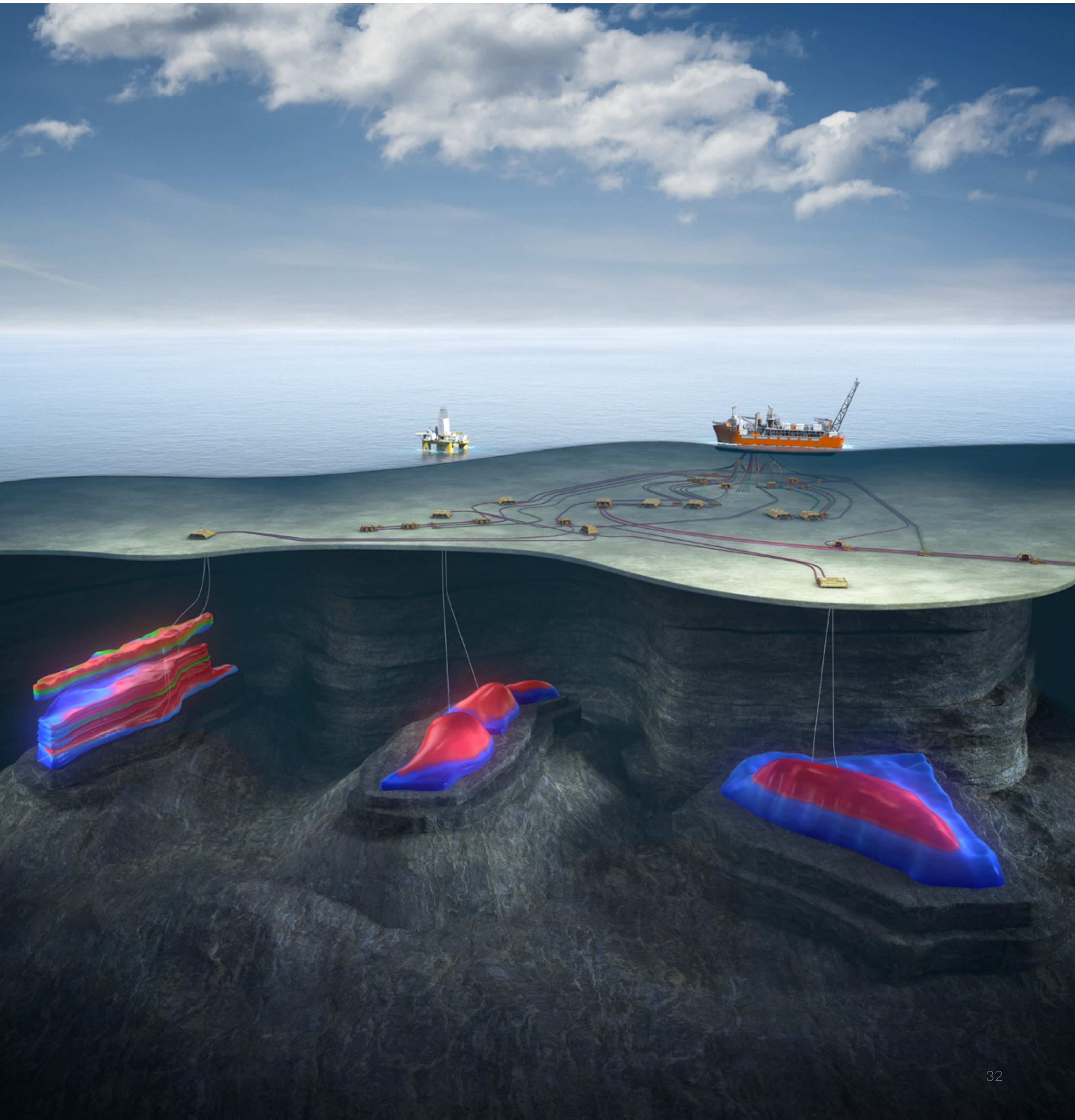


Figure 3.11: Troldhaugen location map

3.1.11 Skarv Unit (PL262, PL159, PL212B, PL212)

Skarv/Idun is an oil and gas field located about 35 km southwest of the Norne field in the northern part of the Norwegian Sea in the Skarv Unit in blocks 6507/2, 6507/3, 6507/5 and 6507/6. Water depth in the area is 350-450m, see Figure 3.10. The Skarv unit is a joint development of the Skarv and Idun, Gråsel and Ærfugl fields (formerly known as Snadd). Note that the northern part of the Ærfugl discovery (Ærfugl Nord, formerly known as Snadd Outer) is not a part of the Skarv Unit, Figure 3.12, but is described here together with Ærfugl.



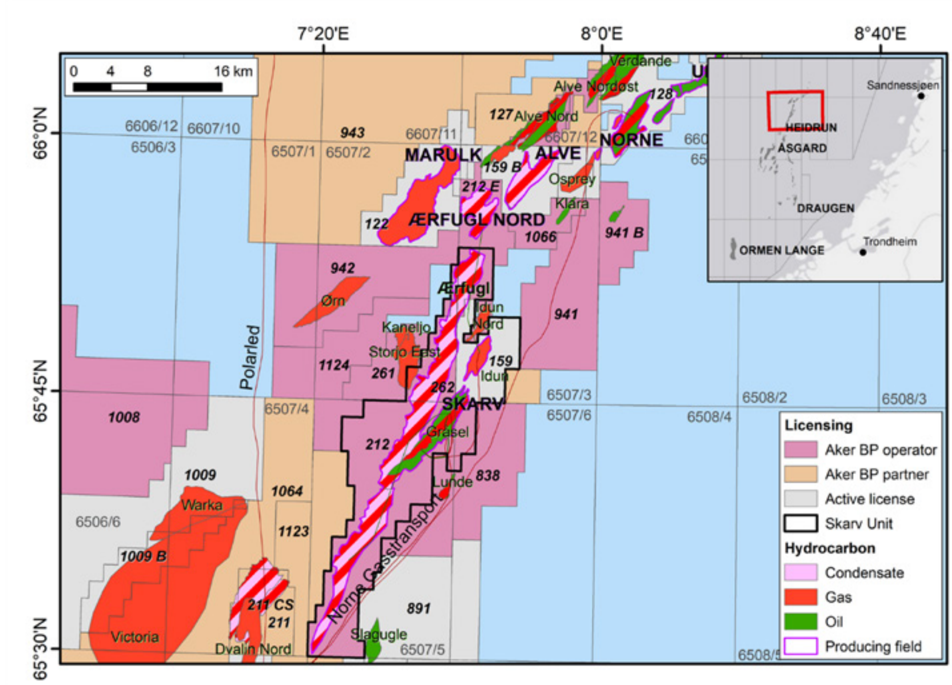


Figure 3.12: Skarv and Ærfugl location map

3.1.12 Skarv

Discovery

Gas and oil were discovered in the Skarv A segment by 6507/5-1 in 1998. The field was later appraised and gas with an oil column was found in the Skarv B and C segments. Dry gas was discovered in Idun by well 6507/3-3 in 1999.

Development

The development concept is a production, storage and offloading vessel (FPSO) above the Skarv field tied to five subsea templates with 23 wells. Distribution between the well types is: six oil producers, five gas producers, two gas injectors in Skarv/Idun, (two gas injectors are temporarily shut-in as gas blowdown on the Skarv B and C segments has started). In addition, there is one oil producer and a commingled injector in Gråsel and seven Ærfugl gas producers. Gråsel and Ærfugl are described in separate sections in this chapter. A new gas producer in Idun Tunge was drilled from the Skarv A template in 2022.

The oil is exported by a shuttle tanker. The gas is exported in an 80-km pipeline connected to the Åsgard Transport System. Capacity in Gassled is secured through the Gassco booking system.

Reservoir

The Skarv structure is defined by three segments - the A, B and C segments, separated by faults. However, production experience indicates that the fault between the B and C segments may be leaking. Idun (East and West) is a separate, gas filled structure with no communication to the Skarv A, B, C segments. The segments are close to hydrostatic pressure. Each segment constitutes Jurassic Garn, Ile and Tilje formations.

The Garn Formation is a high-quality reservoir and the deeper Ile and Tilje Formations are more heterogeneous with poorer reservoir quality.

The Skarv/Idun field contains both oil and gas. The production strategy is oil production in combination with gas injection, keeping the pressure constant, followed by gas blowdown. Gas blowdown started in the Skarv B and C segments in March 2022. The gas-filled segments are produced by depletion.

Status

Skarv/Idun production started on 31 December 2012. To date, approximately two-thirds of the estimated ultimate recovery has been produced. Two gas wells are currently producing in Garn A. The two Idun wells are shut in due to back pressure from Ærfugl wells. The plan is to restart production when Ærfugl production moves over to the low pressure separator, currently projected to be in 2024. All gas wells are on decline.

Gas blowdown started in the B and C segments in March 2022. The two gas injectors were shut-in and the four oil producers continue to produce with increasing GOR. The reservoir pressure is falling at 6 bar/month. The two oil wells in the Tilje Formation in the A segment continued to produce with slightly increasing gas rates throughout 2022.

There is very little formation water production seen from Skarv.

Net production from Skarv plus Idun Tunge averaged 10.9mboepd in 2022. In total, Skarv, Gråsel, Idun Tunge, Ærfugl and Ærfugl Nord produced 38.4mboepd. This is above expected production due to start of blowdown.

Economic cut-off (CoP) for the Skarv-area is estimated to be 2036 for the 2P-case.

The recoverable volumes on Skarv and Idun, including Gråsel, Idun Tunge, Ærfugl and Ærfugl Nord, are classified as "Reserves; On Production" (SPE's classification system).

Aker BP is the operator and holds 23.835 percent interest in the Skarv Unit. The remaining interest is held by Equinor (36.165 percent), Wintershall DEA Norge AS (28.0825 percent) and PGNiG Upstream International AS (11.9175 percent).

3.1.13 Gråsel

The Skarv discovery well, 6507/5-1, also found oil in Cretaceous sandstones from the Cromer Knoll Group in the Lange Formation, which is the Gråsel discovery.

Reservoir
The Gråsel discovery is situated stratigraphically above the Skarv field. Shallow marine sandstones from the Late Cretaceous, Lange Formation, form the main reservoir. The field exhibits high reservoir porosity and permeability (approx. 1-5 D). The Gråsel field is defined by a combined structural and stratigraphic trap, pinching out to the northeast with dip-closure in all other directions. The reservoir is tecturally complex sandstone with thin argillaceous layers, crossbedding and bioturbation.

Development
The Gråsel reservoir is developed with one oil producer (B-7 AH) and one gas injector commingled with Skarv Tilje (J-3 H), tied back to the FPSO.

Status
B-7 AH started producing in June 2021 with oil rates around 2000 Sm^3/d. First injection in Gråsel (J-3H) was September 2021 and producer-injector communication was confirmed after 3 months. During 2022, the oil rate has fallen as the GOR has increased.

Gråsel net production averaged 1.0 mboepd in 2022, in line with expectations.

3.1.14 Ærfugl

Ærfugl is a gas condensate field located about 35 km southwest of the Norne field in the northern part of the Norwegian Sea in the Skarv Unit in blocks in 6507/2, 6507/3, 6507/5 and 6507/6, see Figure 3.12. Water depth in the area is 350-450 m and the reservoir depth is about 2,800 m TVD MSL. The field was tested through one producer tied into the Skarv facilities for four years prior to the field development decision. The PDO was submitted in December 2017.

Discovery
The Ærfugl field was discovered in 2000 with well 6507/5-3. It was appraised in 2010/2011 by wells 6507/5-6 S, 6507/5 A-1 H, 6507/5 B-5, and in 2012 by well 6507/3-9 S for Ærfugl Nord (previously called Snadd Outer).

Development
The Ærfugl field is produced through the existing facilities on Skarv and developed with seven highly deviated subsea wells tied into the Skarv FPSO with heated flowlines. In addition to the original A-1H test producer, three wells were drilled on Ærfugl South and came on stream in November 2020. A second drilling phase included three wells towards the north. The first well was drilled from the Idun template and came on stream in 2020, while the two remaining wells came onstream end 2021. One of these wells, G-1H, is located in the Ærfugl Nord licence.

Status
The A-1H test producer in Ærfugl started gas production in February 2013 and continues to produce. Early production from this well provided excellent data which helped to significantly de-risk the Ærfugl development. The Idun template well, D-4H, experienced water breasthrough earlier than expected. Two of the Southern wells, L-1H and M-1H, have also experienced water breakthrough. The two northern wells, H-1H and Ærfugl Nord (G-1AH) have not seen water yet.

A successful water shut-off was performed on well L-1H in 2021. The water shut-off in D-4 H was not as successful, but the water production rate has stabilised. The well will presumably stop producing by end 2023. A successful water shut-off was performed on well M-1H in 2022.

The latest model update on Ærfugl includes the most important new data from drilling the two recent wells in the north. The updated model ensemble has on average 15% less GIIP overall and 25% less GIIP in Ærfugl Nord with new structural realisations being the largest contributor. Pressure mapping is also showing more complex connectivity. Based on this, the overall Ærfugl reserves have been reduced by 18% .

Net production in 2022 from Ærfugl was approximately 20.2mboepd. Ærfugl Nord production was approximately 6.3mboepd, in line with expectations.

The Ærfugl field is in the Skarv Unit. Aker BP holds a 23.835 percent share in the Unit. The northern extension, Ærfugl Nord is in licence PL212E, where Aker BP holds a share of 30 percent.

3.1.15 Ula (PL019)

Ula is an oil field in the southern part of the Norwegian sector of the North Sea in block 7/12 in PL019, Figure 3.13. The water depth in the area is about 70 m and the reservoir depth is about 3,500 m TVD MSL.

Discovery

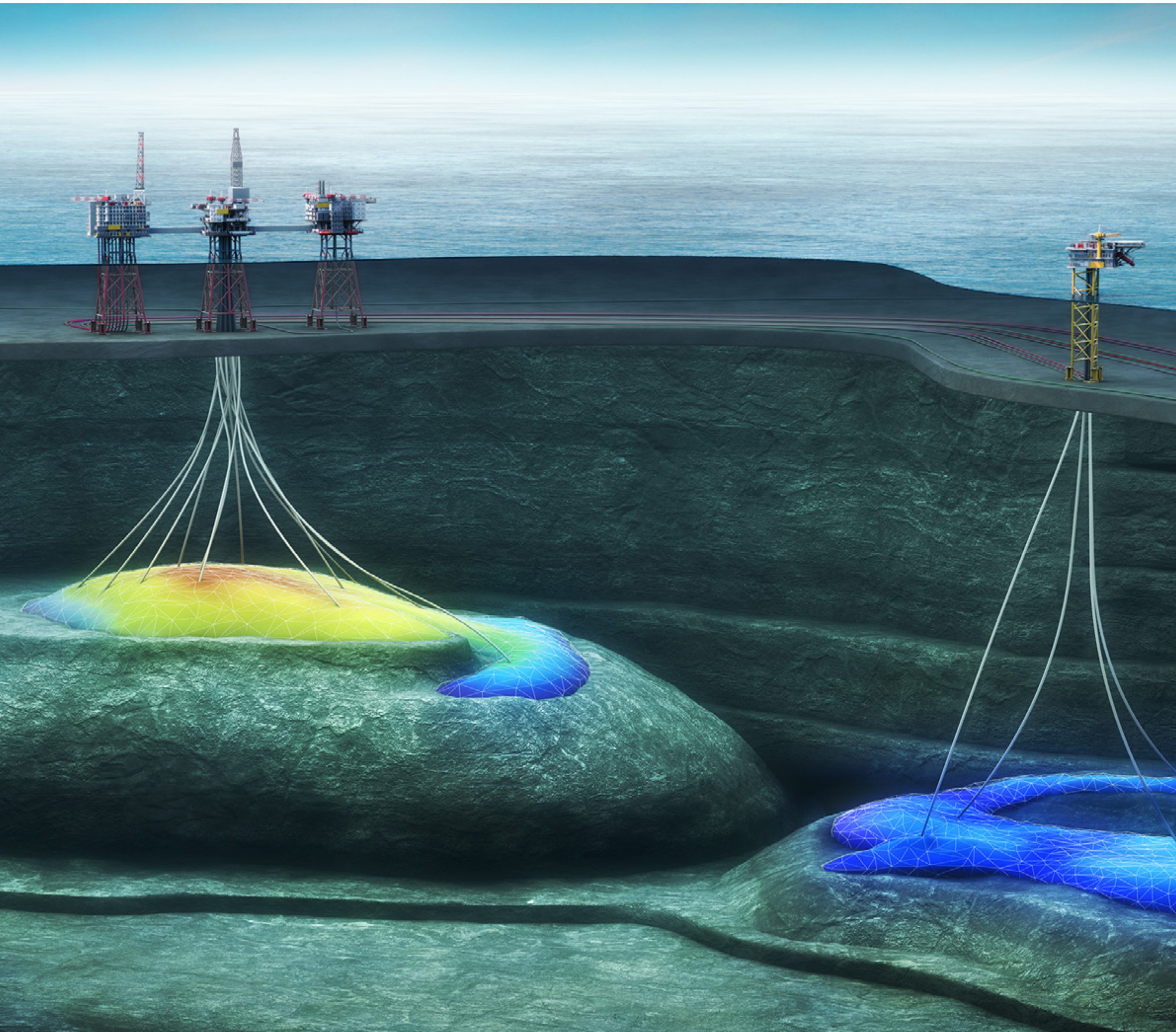
Ula was discovered by well 7/12-2 in 1976. The well penetrated a major Late Jurassic reservoir (Ula Formation) and was terminated within a Triassic hydrocarbon-bearing sequence of poor quality sands and interbedded shales. Core analysis and log interpretation indicate an Ula Formation sandstone reservoir, of 128 m net thickness with porosities ranging from 14 percent to 28 percent, permeabilities from a few mD to over 2 D and water saturations from 5 percent to over 50 percent. The Ula Formation was oil-bearing from top to base at 3,532 m in an oil down-to setting.

Reservoir

The main reservoir is at a depth of 3,345 metres in the Upper Jurassic Ula Formation. The Jurassic reservoir consists of two production intervals with water and gas injection in the deeper layer. A separate Triassic reservoir underlies the main reservoir.

Development

The Ula development consists of three conventional steel facilities for production, drilling and accommodation, which are connected by bridges. The gas capacity at Ula was upgraded in 2008 with a new gas processing and gas injection module (UGU) that doubled the capacity. Ula is the processing facility for Oda, Tambar and Blane. The oil is transported by pipeline via Ekofisk to Teesside in the UK. All gas is reinjected into the reservoir to increase oil recovery.



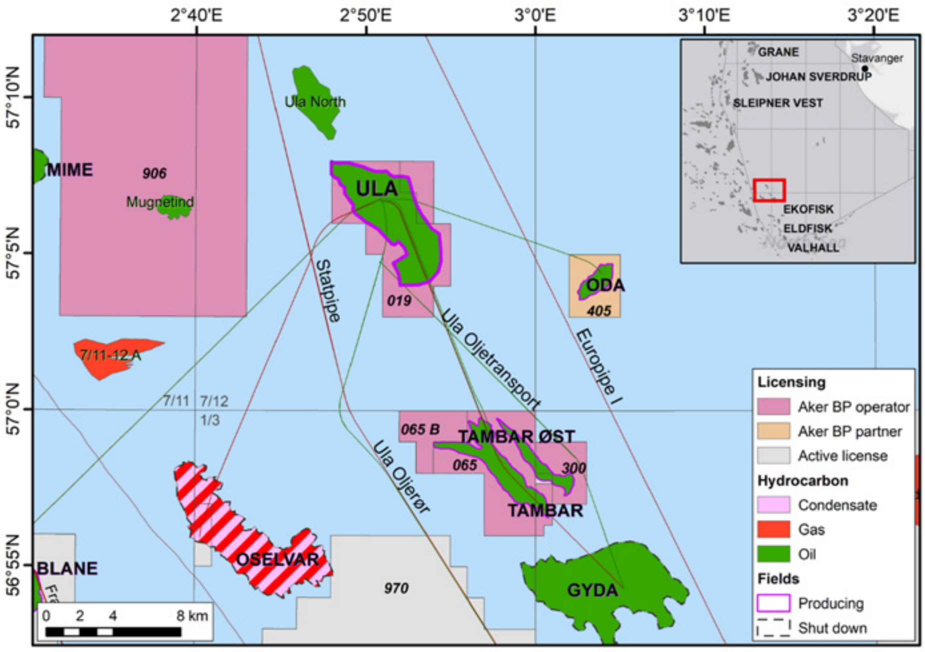


Figure 3.13: Ula location map

Oil was initially recovered by pressure depletion, but after a period of time, water injection was implemented to improve recovery. Water alternating gas (WAG) injection started in 1998. The WAG program has been extended with gas from Tambar (2001), Blane (2007), Oda (2019) and Oselvar (2012, now ceased). Gas lift is used in the shallowest reservoir interval.

Status
49 wells have been drilled on Ula since start-up, of which nine wells are currently producing and four are injecting.

The planned CoP of the Ula field has changed from 2032 to 2028. The calculated economic cut-off on the 2P/P50 production profiles is end-2022. Hence, the Ula production does not meet the requirements to be defined as PRMS reserves. The Ula Management Committee has decided to plan for continued production from Ula until 2028. This will allow production from the tie-in fields.

Injection of additional import gas has been evaluated, but found non-economic.

Net production to Aker BP averaged approximately 3.0 mboepd in 2022. Ula production was lower than expected in 2022 due to well issues.

Aker BP is the operator and holds an 80 percent interest in the Ula field. The remaining 20 percent share is held by DNO Norge AS.

3.1.16 Tambar (PL065)

Tambar is an oil field about 16 kilometres southeast of the Ula field in the southern part of the Norwegian sector of the North Sea, Figure 3.14. The water depth in the area is 68 metres.

Discovery

Tambar was discovered in 1983 by well 1/3-3.

Reservoir

The reservoir consists of Upper Jurassic sandstones in the Ula Formation, deposited in a shallow marine environment. The reservoir lies at a depth of 4,100-4,200 m and the reservoir characteristics are generally very good. The field is produced by pressure depletion, with natural gas expansion combined with aquifer support as the main reservoir drive mechanisms.

Development

The field has been developed with a remotely-controlled wellhead facility without processing equipment. The oil is transported to Ula through a pipeline. After processing at Ula, the oil is exported in the existing pipeline system via Ekofisk to Teesside in the UK, while the gas is injected into the Ula reservoir to improve oil recovery.

Status

A total of six producers have been drilled on Tambar since start-up, of which three wells are currently producing.

Major challenges restricting production are the wells' ability to lift with ever-decreasing reservoir pressure combined with increased water cut. Infill producer K-2B was drilled in 2021 to replace K-2A in the northern area of the field. However, this well has struggled with lack of sufficient reservoir pressure, similar to the previous K-2A. The Tambar team continues to evaluate potential production optimisitaion initiatives.

The planned Tambar field CoP is 2028, but current economic cut-off is in 2025.

The recoverable volumes on Tambar are classified as "Reserves; On Production" (SPE's classification system).

Net 2022 production to Aker BP from Tambar averaged approximately 1.2 mboepd.

Aker BP is operator and holds 55 percent interest in the Tambar field. The remaining 45 percent share is held by DNO Norge AS.

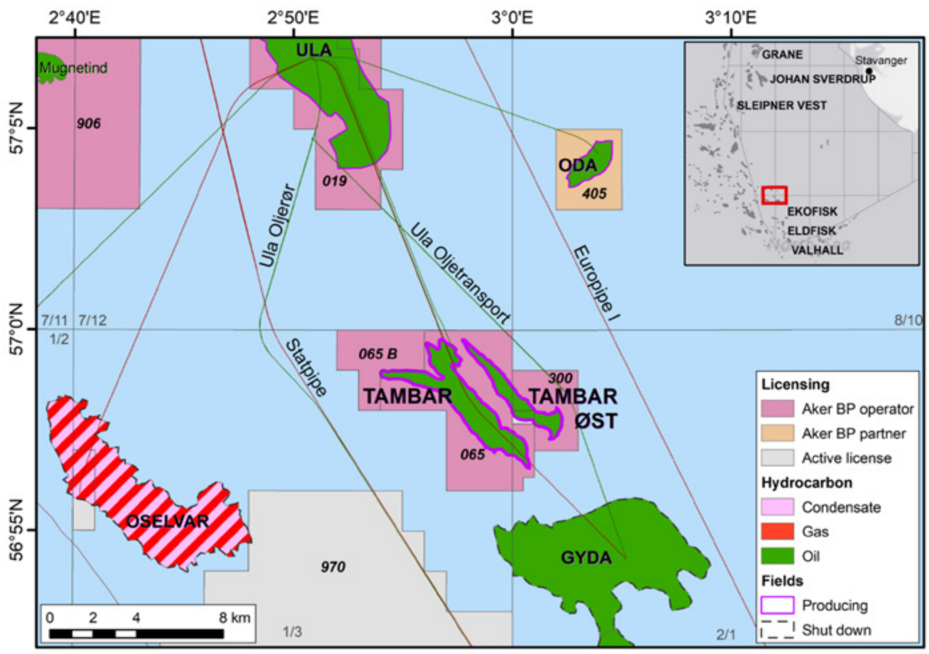


Figure 3.14: Tambar and Tambar East location map

3.1.17 Tambar East (PL065, PL300, PL019B)

Tambar East (Tambar Øst) is a minor oil field located east of Tambar, see Figure 3.14.

Discovery

Tambar East was discovered in 2007 by well 1/3-K-5.

Reservoir

The reservoir consists of Late Jurassic sandstones, deposited in a shallow marine environment. The reservoir lies at a depth of 4,050-4,200 metres and the quality varies but is generally poorer than the Tambar main field. The field is produced by pressure depletion, and the reservoir is believed to be compartmentalised.

Development

Tambar East is an oil field in the North Sea developed with one production well drilled from the Tambar facility. The field location is shown in Figure 3.14. The oil is transported to Ula via Tambar. After processing at Ula, the oil is exported in the existing pipeline system via Ekofisk to Teesside in the UK. The gas is used for gas injection in the Ula reservoir to improve oil recovery.

Status

In RNB submissions, cessation of production was assumed in 2017. The well was temporarily shut down in November 2017. The base assumption is that well K-5A will be restarted in 2024 when back pressure has declined, and local reservoir pressure has increased. However, the team is also looking into alternatives, such as a deep sidetrack to the existing producer. This work has recently been kicked off and is still at an early stage.

There was no production from Tambar East in 2022.

In the absence of a firm plan to re-start Tambar East-production, reserves are reported as zero as of 31 December 2022.

Aker BP is the operator and holds 46.2 percent interest in the Tambar East Unit. The remaining shares are held by DNO Norge AS (37.8 percent), Repsol Norge AS (9.76 percent), INEOS (5.44 percent) and KUFPEC Norway AS (0.80 percent).

3.1.18 Valhall (PL006B, PL033B)

Valhall is an oil field in the southern part of the Norwegian sector of the North Sea in PL006B and PL033B (unitised into the Valhall Unit) in blocks 2/8 and 2/11, Figure 3.15. The water depth is about 70 m.

Discovery

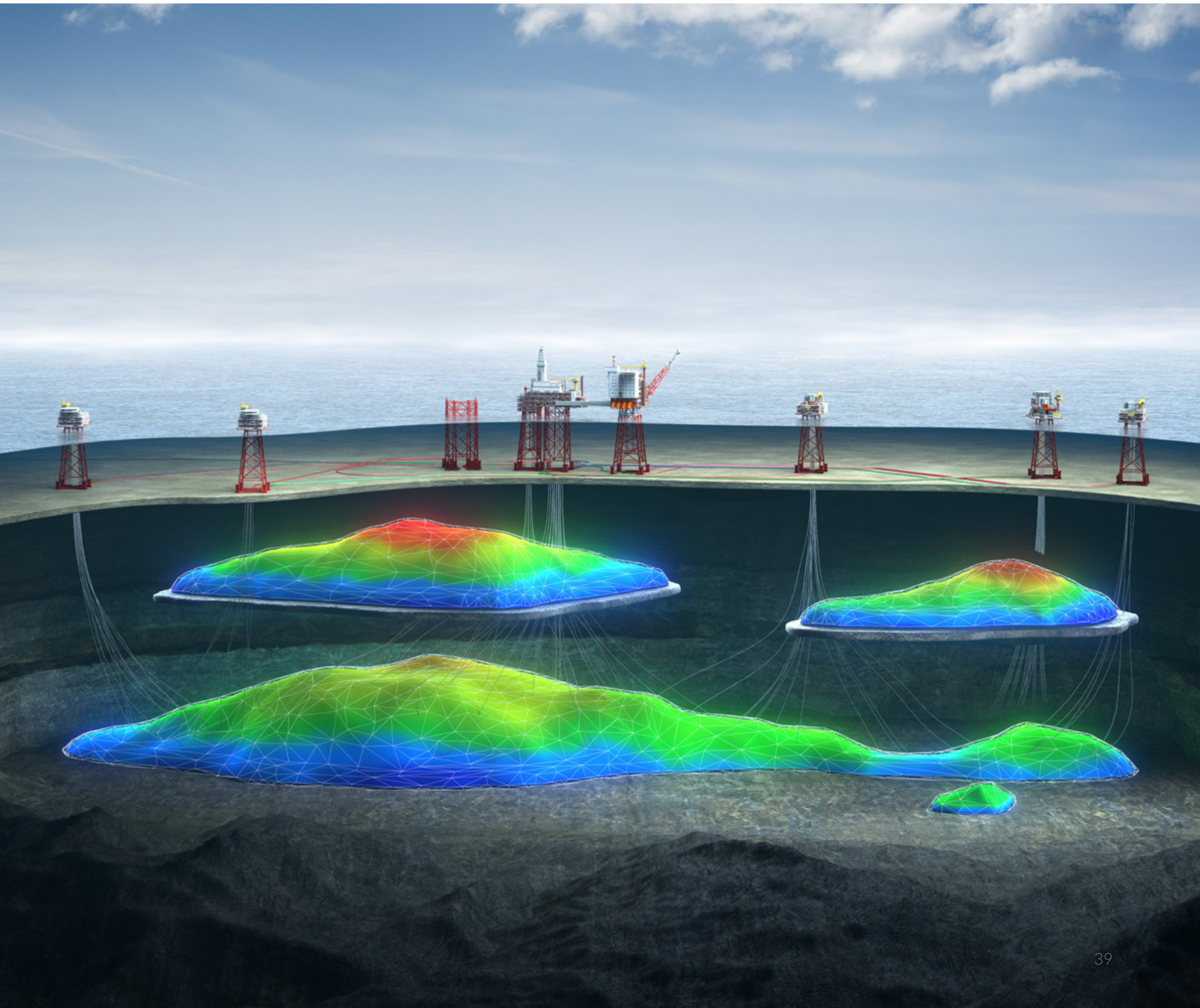
The Valhall field was discovered in 1975 by exploration well 2/8-6. Production started in 1982.

Reservoir

The reservoir consists of chalk in the Upper Cretaceous Tor and Hod Formations. Reservoir depth is approximately 2,400 metres. The Tor Formation chalk is fine-grained and soft; with high porosity (up to 50 percent). Matrix permeability is in the 1-10 mD range. There are areas with natural fractures with high permeability conduits. The Hod Formation porosity is 30 percent-38 percent with permeability 0.1-1mD.

The Valhall field is subdivided into eight reservoir units: (a) North Flank, (b) Northern Basin, (c) East Flank, (d) West Flank, (e) South Flank, (f) Central Crest, (g) Southern Crest, (h) Lower Hod Formation. Seven of the units are located within the Tor formation. The eighth unit is in the underlying Lower Hod formation.

The field has produced with pressure depletion and a very effective compaction drive since 1982. As a result of the pressure depletion the chalk has compacted, and the seabed subsided. Water injection in the centre of the field started in 2004. This has reduced pressure depletion and hence subsidence. Gas lift is used to optimise production in most of the producers as a remedy to avoid oscillating production and premature dying of wells.



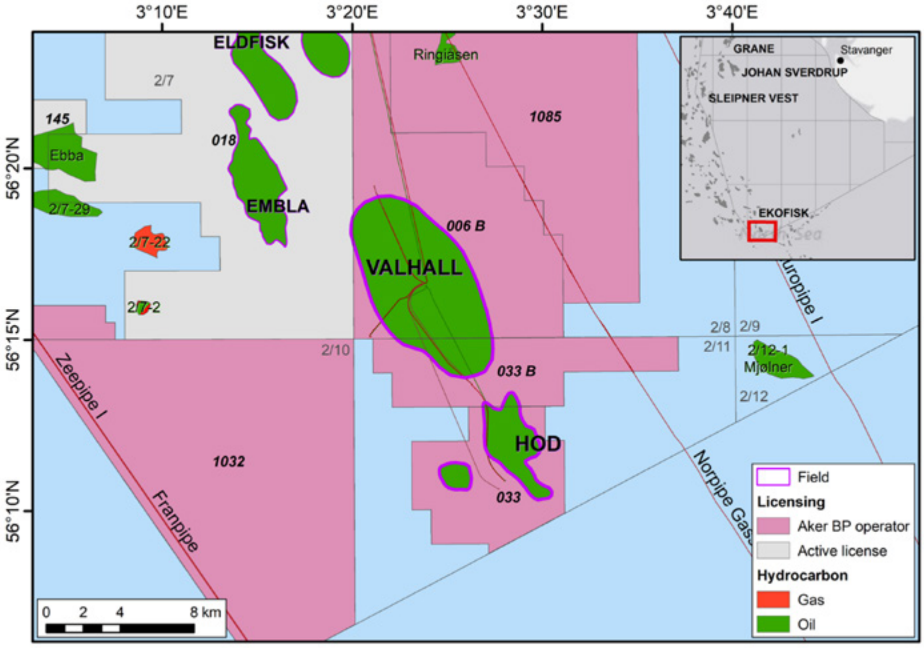


Figure 3.15: Valhall and Hod location map

Development

The plan for development and operation (PDO) for Valhall was approved in 1977. The field was originally developed with three platforms: accommodation, drilling and processing (QP, DP & PCP). The PDO for a Valhall wellhead platform was approved in 1995, and the platform (WP) was installed in 1996. A PDO for a water injection project was approved in 2000, and an injection platform (IP) was installed in 2003 next to WP. Two satellite wellhead platforms (SF & NF) were installed in 2003 with 16 slots each, drilling targets to the South and North Flanks of the field. In 2013, a new integrated Production and Hotel Platform (PH), bridge linked to the IP Platform was put to use. A satellite wellhead platform (WF) with 12 well slots was sanctioned in 2017, drilling targets to the West Flank. The original PCP, QP and DP platforms have been decommissioned.

Oil and NGL are routed via pipeline to Ekofisk and further to Teesside in the UK. Gas is routed via Norpipe to Emden in Germany.

Status

Valhall currently has 57 active producers and nine active injectors.

During 2022, Valhall drilled one new well on West Flank (V-11) that was started producing in 2022. The recoverable volumes for Valhall Base are classified as “Reserves; On Production”.

The Valhall PWP (Production and Wellhead Platform) project delivered a PDO in 2022. Valhall PWP consists of a joint development for the Valhall and Fenris fields (Fenris development is described in Chapter 3.2). Valhall PWP will be bridge-linked to Valhall PH and will include the following functions:

- 24 new wells slots for Valhall drilling.
- Riser for gas export to Emden. This function is currently located on Valhall WP. The plan is to decommission Valhall WP by the end of 2028.
- Riser for gas lift pipelines to satellite platforms (currently located on Valhall WP).
- Upgrade of the Valhall produced water treatment facility (currently located on Valhall PH).
- Facilities to process production from Fenris.

The Valhall PWP PDO describes a plan to use 15 of the 24 well slots, leaving nine slots available for future developments. 14 new development wells and one waste injector. The plan is to install the PWP jacket and wellbay in 2025 with the ability to pre-drill wells, with final commissioning and first oil from Valhall PWP and Fenris planned in 2027. The 14 Valhall development wells will target both the Tor and Hod Formations, with expansion of the waterflood in both formations. The recoverable volumes for Valhall PWP have been classified as “Reserves; Justified for Development”.

The 2P/P50 production profile indicates an economic cut-off (CoP) in 2049. Net production to Aker BP averaged 39 mboepd in 2022, below expectations primarily due to well issues.

Aker BP holds 90 percent interest in the Valhall field, with Pandion holding the remaining 10 percent.

3.1.19 Hod (PL033)

Hod is an oil field 13 km south of the Valhall field in the southern part of the Norwegian sector in the North Sea (PL033 in block 2/11), see Figure 3.15. The water depth is approximately 70 m and the reservoir depth is about 2,700 m TVD MSL.

Discovery

The Hod field was discovered in 1974 by exploration well 2/11-2. Production started in 1990.

Reservoir

The reservoir lies in chalk in the lower Palaeocene Ekofisk Formation, and the Upper Cretaceous Tor and Hod formations. The field consists of three structures: Hod West, Hod East and Hod Saddle.

The field has been produced by pressure depletion. Gas lift has been used in some wells to increase production and lift performance.

Development

The field was initially developed with an unmanned production wellhead platform (Hod A) which was remotely controlled from Valhall. Since 2012, there has been no production from Hod A. The Hod Saddle reservoir is currently produced through four wells drilled from Valhall Flank South. In 2021, a new unmanned wellhead platform (Hod B) was installed with 12 well slots. Six new wells were drilled in 2021 and 2022, and production from all these wells started in 2022. The initial Hod facility (Hod A) awaits decommissioning and disposal.

Transport of oil and NGL from Valhall is routed via pipeline to Ekofisk and further to Teesside in the UK. Gas from Valhall is sent via Norpipe to Emden in Germany.

Status

Hod field is currently produced from six Hod B wells and four wells drilled from the Valhall South Flank platform that extends into the Hod licence. The equity split between the Valhall and Hod licences is based on 'length of well' in respective licences. Wells on the Hod A facility are awaiting final P&A.

Hod field CoP is estimated to be 2049, same as for the Valhall field.

Net production to Aker BP averaged 6 mboepd in 2022, below plan due to late start-up of Hod-B production..

The recoverable volumes for Hod Base are classified as "Reserves; On Production".

Aker BP has a 90 percent interest in the Hod field, with Pandion holding the remaining 10 percent.

3.1.20 Johan Sverdrup (PL265, PL501, PL502, PL501B)

Johan Sverdrup is a major oil field extending over four licences (PL265, PL501, PL502 and PL501B), and the plan for development and operation (PDO) was approved in 2015. The field is located in a half-graben on the Utsira High in the North Sea, approximately 160 km west of Stavanger in blocks 16/2, 16/3 and 16/5; see Figure3.16. The water depth in the area is 110 - 120 m and the reservoir depth is about 1,900 m TVD MSL.

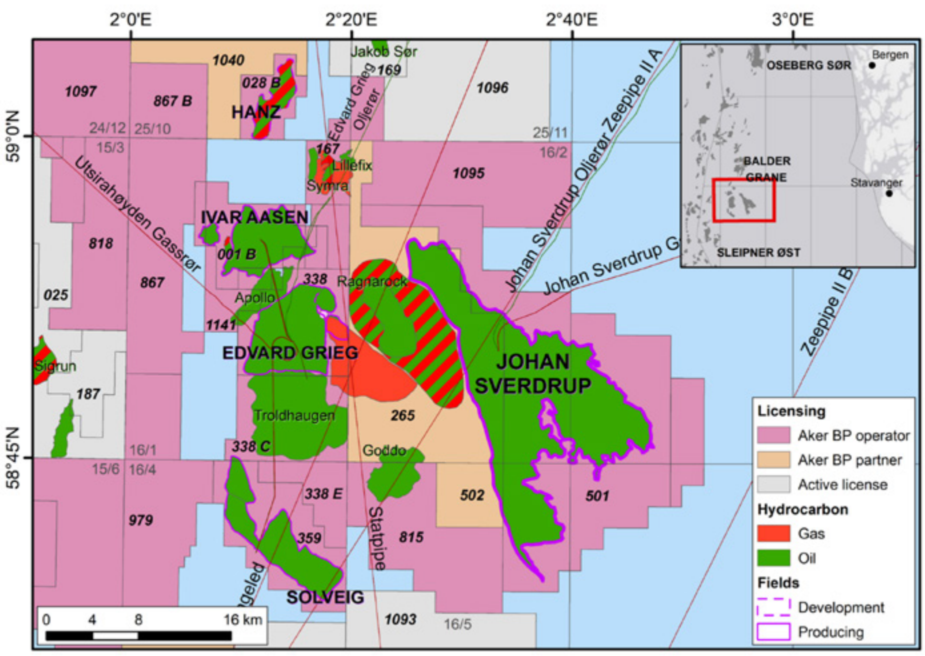


Figure 3.16: Johan Sverdrup location map

Figure 3.17: Johan Sverdrup field centre

Discovery
The discovery well 16/2-6 was drilled in 2010 on the Avaldsnes High. The well proved oil in Jurassic and pre-Jurassic sandstones. A large number of wells have been drilled since then to appraise the discovery.

Reservoir
The reservoir consists of late to middle-early Jurassic sediments in Draupne sandstone and in the older Statfjord and Vestland Groups. The reservoirs are characterised by excellent reservoir properties. The apex of the field is located at approximately 1,840 m TVD MSL and the free water levels (FWL) encountered are in the range of 1,922 – 1,934 m TVD MSL. Top reservoir is generally regular and gently dipping towards the east and the south, whereas the base is an unconformity and has an irregular character. Gross reservoir thickness varies from up to ~90 m in the central/western parts of the field to less than 10 m in the fringes, with a large part of the field having thin reservoir below seismic resolution.

The reservoir fluid is highly undersaturated oil with a low GOR ranging between 40 and 80 Sm^3/Sm^3 and with a viscosity of approximately 2 cP.

Generally, the Phase 1 field development is based on producers located in the central/western thicker parts of the field, with water injection located down dip in the water zone in the eastern and southern parts of the field.

Development
The PDO for Phase 1 was approved by the authorities in August 2015. The Phase 1 development plan includes a field centre with four platforms: a processing platform (P1), a drilling platform (DP), a riser and export platform (RP) and a living quarters and utilities platform (LQ), see Figure 3.17. The platforms are installed on steel jackets linked by bridges. Phase 1 also includes 18 oil production and 16 water injection wells and three subsea water injection templates. Production from Phase 1 commenced on 5 October 2019.

Phase 2 (the full field development) develops the reserves in the fringe areas of the field as well as enables acceleration of production from the Phase 1 area. The PDO for Phase 2 was submitted in August 2018 and approved by the authorities in the spring of 2019. Production start was on 15 December 2022. The Phase 2 development includes an additional processing platform (P2) located next to the riser platform at the field centre, Figure3.17. The fringe areas will be developed with subsea templates tied back to the riser platform. The wells will be a mixture of subsea wells and additional wells drilled from the central drilling platform.

Phase 1 and Phase 2 PDOs include 62 oil production and water injection wells on Johan Sverdrup. Before start-up of Phase 2, the field was producing at a plateau of 535 000 bbl/d oil. After Phase 2 start-up, the oil production plateau production is expected to be at least 720 000 bbl/d.

The oil and gas are transported to shore via dedicated pipelines. The oil is transported to the Mongstad terminal and the gas is transported via the Statpipe system to Kårstø for processing and onward transportation.

Status
Production from Phase 1 started on 5 October 2019. After a very successful ramp-up, the field has produced with high regularity. The oil production capacity was increased to a production level of 535 000 bbl/d (approximately 180 000 boe/d net to Aker BP) from 19 producers, supported by 15 water injection wells (December 2022).

The PDO for Phase 2 was submitted in August 2018 and approved in early 2019. Production from Phase 2 started on 15 December 2022. The production level is being ramped up to the expected new plateau rate of at least 720 000 bbl/d in the first quarter of 2023.

Aker BP has included reserves assuming a full field development of the field in the reserve base (both Phase 1 and Phase 2), including volumes from the WAG-project (which has been approved by the licence).

The volumes related to the Phase 1 and Phase 2 development are classified as "Reserves; On Production", whereas the volumes related to WAG are classified as "Reserves; Approved" (SPE's classification system).

Several IOR/EOR techniques have been identified which may increase the reserves on Johan Sverdrup. The most promising is infill drilling. In 2022, two infill well targets have been approved by the partnership, adding to the reserves base. The volumes related to the two infill wells are classified as "Reserves; Approved" (SPE's classification system).

Estimated economic cut-off (CoP) for the Johan Sverdrup field is in the 2P-case year-end 2058.

Net production to Aker BP averaged ~116 mboepd in 2022, below plan due to later start-up of Phase 2 than expected.

The unit agreement gives Aker BP a 31.5733 percent share of the field. The remaining shares are held by Equinor Energy (42.6267 percent, operator), Petoro (17.3600 percent) and TotalEnergies (8.4400 percent).

3.1.21 Oda (PL405)

The Oda field is located ~14 km east of the Ula field in Block 8/10, PL405, on the eastern side of the Central Graben in the Norwegian North Sea (Figure 3.18). The water depth is about 66 m. The crest of the structure is estimated at approx. 2,300 m TVD MSL. The PDO was approved by the authorities in May 2017. Production commenced in March 2019.

Discovery

The discovery well, 8/10-4 S, was drilled in 2011 in the northwestern part of a salt-induced structure. The well proved an oil-down-to situation in the Ula Fm. A water gradient in a downflank sidetrack suggests FWL at 2,985 m TVD MSL. The east and southwest segments of the structure were drilled dry in 2014.

Reservoir

The Oda reservoir consists of the Upper Jurassic Ula Formation; a sandstone reservoir with high-quality properties, on the western flank of the steeply dipping salt diapir. The oil column is about 485 m of high-quality, light crude oil.

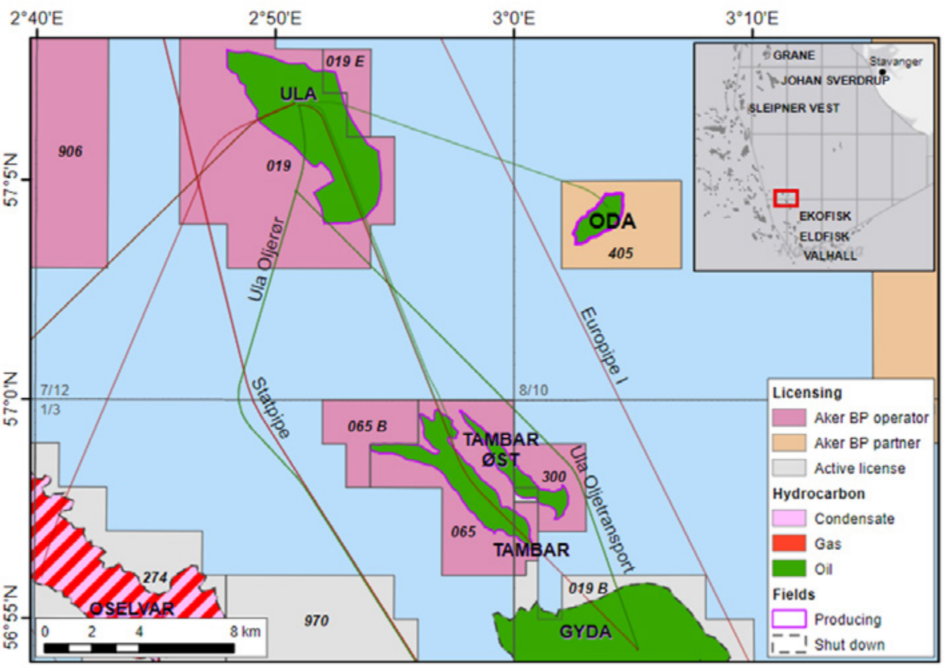


Figure 3.16: Oda location map

Development
The development concept is a subsea tie-in to the Aker BP-operated Ula Platform with re-usage of the Oselvar facility and separator at Ula. The Oda reservoir is drained by two producers supported by one water injection well. All the wells have been drilled from an integrated subsea template.

Status
Oda production started in March 2019, five months ahead of plan. The field was produced without pressure support during the first ~7 months due to damage in the water injection pipeline, and technical problems during water injection start up, October 2019. With pressure support, the wells delivered the planned 35mboepd with B-1 H as the main producer. B-3 AH did not deliver as expected, likely a consequence of reduced reservoir thickness and reservoir properties because the well was drilled into a fault.

During 2022, a sidetrack to the well B-1 H was decided and successfully drilled in a fast-track project. The sidetrack is placed updip of the donor well and started production in May 2022. The well produced 21% more oil in 2022 than the DG3 estimate for the well.

In 2022, Oda net production of 2.7 mboepd was 100% higher than 2021 due to the successful sidetrack of B-1AH.

Oda recoverable volumes are classified as “Reserves; On Production” (SPE’s classification system).

Estimated economic cut-off (CoP) for the Oda field is in the 2P-case year-end 2026

Aker BP holds 15 percent interest in Oda. The remaining shares are held by Sval Energi AS (70 percent, operator) and DNO ASA (15 percent).

3.1.22 Alta (PL102C)

Atla is a small gas/condensate field in the central part of the North Sea, with a water depth of 119 metres.

Discovery
The Atla field was discovered in 2010 by well 25/5-7.

Reservoir
The reservoir contains gas/condensate in sandstones in the Brent Group from the Middle Jurassic at a depth of about 2,700 metres.

Development
The field produces with a subsea installation tied back to the existing pipeline between the Heimdal and Skirne fields. Production started two years after the discovery in October 2010.

Status
During 2022, Atla production has fluctuated due to low reservoir pressure, and COP is planned for June 2023, together with the host Heimdal. The reserve estimates reflect reallocation at Heimdal,

Net production in 2021 was very low as expected.

The recoverable volumes are classified as “Reserves; On Production” (SPE’s classification system).

Aker BP holds 10 percent interest in the licence. Total E&P Norge AS is the operator holding a 40 percent interest while Petoro AS holds 30 percent interest and Lotos Exploration and Production Norge AS holds the remaining 20 percent interest.

3.2 DEVELOPMENT PROJECTS

3.2.1 Hanz

Hanz is an oil and gas accumulation discovered by well 25/10-8 in 1997, 12 km north of the Ivar Aasen PDQ. Hanz consists of Draupne formation sandstones, see Figure3.7.

Discovery

The Hanz discovery was made by exploration well 25/10-8 in 1997 by Exxon. A production test (DST) was performed on the discovery well. The Hanz reservoir was further appraised by wells 25/10-16 S, 25/10-16 A and 25/10-16 C by Aker BP in the 2018 appraisal campaign.

Reservoir

The Hanz discovery consists of Upper Jurassic Draupne sandstones at a depth of about 2400 m. The depositional environment is gravity flow turbidites originating from the Utsira High to the east. The reservoir has several overlying thin sands, each with a thickness of 1-7 metres, separated by thin shale layers. Both DST, core samples and logs show excellent reservoir quality with highly porous multi-Darcy sandstone. The reservoir pressure is slightly below hydrostatic. Vertical communication between sand bodies is believed to be poor. Lateral communication is in general good, but barriers might exist.

The Hanz Heimdal aquifer reservoir is about 350 m above the Hanz Draupne reservoir. The Heimdal reservoir is a highly porous multi-Darcy homogeneous sand package of about 60 m thickness and extends over a very large area of the North Sea. The reservoir pressure is slightly below hydrostatic.

Development

Hanz will be produced through a 14-km pipeline to Ivar Aasen. The drainage strategy is pressure support by a cross-flow water injector taking water from the Heimdal aquifer reservoir located about 350 m above the Hanz Draupne reservoir. Both the producer and the cross-flow water injector will have an approx. 2000 m horizontal well reservoir section in the Draupne reservoir. The wells will be about 700 m apart and aim to penetrate all major hydrocarbon sands on the Draupne Horst structure. The wells will be drilled as satellites in July 2023 and the plan is to bring them om stream in 1Q 2024.

Status

The Hanz development was sanctioned by the licence in December 2021. The recoverable volumes on Hanz are classified as “Reserves; Approved” (SPE’s classification system).

Aker BP holds 35 percent in Hanz. The remaining shares are held by Equinor (50 percent) and Sval Energi (15 percent).

3.2.2 Kobra East and Gekko (KEG)

The KEG discoveries are located approximately 10 km southeast of the Alvheim FPSO.

Discovery

The Gekko oil and gas discovery was made in 1974 by well 25/4-3 in the Heimdal Formation. Kobra East was discovered in 2016 through drilling an extension of the Kobra well 24/9-P-8 AY1H.

Reservoir

The Gekko reservoir consists of Heimdal Formation sands, in a submarine fan system south of and analogous to the Alvheim reservoir. Gekko is defined by two subtle four-way closures, Gekko South with blocky stacked sandy turbidites and high net/gross and Gekko North with channel sands interbedded with more fine-grained deposits. The reservoir is all-over in pressure communication within Heimdal and to the large aquifer. The Kobra East reservoir is analogous to Viper and Kobra and consists of a main injection sill overlain by dykes and wings. The reservoir properties are excellent.

Development

The KEG field development plan is based on a subsea tie back via the Kneler B manifold to the Alvheim FPSO. The plan for Gekko is to have a four-slot manifold in the south and a two-slot manifold in the north. The drainage strategy is to produce oil from three trilateral wells (two into Gekko South and one into Gekko North), followed by a gas blowdow phase produced through two sidetracks. The main drainage mechanism for the oil phase is natural pressure depletion, with a strong aquifer drive and some gas cap expansion. To achieve good drainage of the 6-7 m oil column, each of the 9 laterals will have aplanned completion length of about 4000 m (with AICDs) and will be placed about 2 m below the gas-oil contact. Kobra East is to be developed by a trilateral well drilled from the same four-slot template as Gekko South. Pressure support is provided by the large Heimdal aquifer. The Kobra East well will be able to continue production during Gekko gas blowdown.

Status

The KEG field development passed DG3 and submitted the PDO in June 2021, which was approved by the Ministry of Petroleum and Energy in February 2022. KEG phase 1 (first oil) is scheduled for January 2024, while KEG phase 2 (first gas) is scheduled for Q4 2030 - Q1 2031.The recoverable volumes on KEG are classified as “Reserves; Approved “ (SPE’s classification system).

- Aker BP is the operator of KEG with an 80 percent working interest. Aker BP increased its share from 65% to 80% after the merger with Lundin Energy Norway AS, leaving ConocoPhillips Skandinavia AS as the only partner (20%).

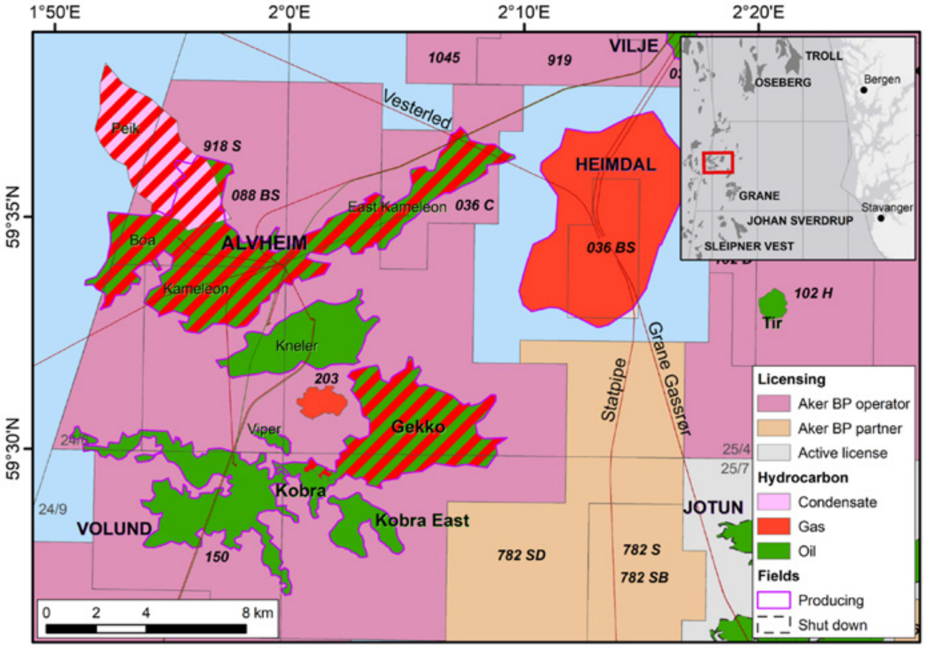


Figure 3.19: Kobra East and Gekko (KEG) location map

3.2.3 Tyrving

The Tyrving field consists of the two discoveries Trell and Trine. Trell is located in block 25/5, production licence PL102F. Trine is located in block 25/4, production licence PL036E/F. Tyrving is situated in the central part of the Norwegian sector in the North Sea, east of the Heimdal field. Tyrving is unitised. A location map is shown in Figure 3.20. Water depth in the area is 119 m and the reservoir is located between 2100 - 2200 m TVD MSL. The PDO for Tyrving was submitted to the Ministry of Petroleum and Energy in August 2022.

Discovery

The Trine discovery well, 25/4-2, was drilled in 1973. The well discovered oil in Late Paleocene sandstone (Heimdal Member in the Lista Formation) at a depth of 2133.5 m TVD MSL. A nine-metre-thick oil column was found from top of the reservoir down to an OWC at 2142.5 m TVD MSL. The Trell discovery well, 25/5-9, was drilled in 2014. This well discovered a 21-m oil column in the Heimdal Formation with an OWC at 2178 m TVD MSL.

Reservoir

The Tyrving field consist of two relatively small four-way closures filled with oil, 4 - 5 km apart. The reservoir is from the Late Paleocene in the Heimdal Member within the Lista Formation, and consists of turbidite sandstones with excellent reservoir properties; NTG above 90%, porosity of 26% and permeabilities above 1D. The Heimdal sandy sequence in the Tyrving area comprises a 300 to 400-m thick package and the oil accumulations are connected to a large aquifer.

Development

The plan calls for Tyrving to start production in 2025. The development consists of one three-branch well in Trell, and one bilateral well in Trine. The completions are open hole wire wrap ICD screens. Potential value of using AICDs is being evaluated. Production from each branch will be hydraulically controlled with inflow valves. A prospect called Trell North, not included in the reserves estimates, will also be explored via a drillhole from the Trell well. Each field will have a 2-slot template, and they will be produced through a 15-km long pipeline to the East Kameleon Pipeline End Manifold (PLEM), from which they also have gas for downhole gaslift. Tyrving will share pipeline capacity with the East Kameleon field connected to the Alvheim FPSO. Oil production is expected to be supported by water drive from the Heimdal aquifer. This has been successful for most fields in the area. The plan is to drill well branches at maximal distance to the oil-water contact, minimum 7 m standoff. Downhole gas lift, pressure and temperature gauges and downhole watercut metering will be implemented. Reservoir pressure has been measured slightly above 200 bar and temperature is around 70oC. The pressure may still be increasing due to regional aquifer equilibration after Heimdal field shut-in. Oil bubble point is very low for both fields and gas-oil ratios are slightly below 40 Sm^3/Sm^3. Oil viscosities are 0.9 cP (Trell) and 2.0 cP (Trine).

Status

The PDO was submitted 2022. Production start-up is planned in 2025 with an average oil rate of 2900 Sm^3/d the first year.

The recoverable volumes on Tyrving are classified as "Reserves; Justified for development" (SPE's classification system).

Aker BP holds 61.26 percent interest in the licence and serves as operator. The other licence partners are Petoro AS, holding a 26.84 percent interest, and Lotos Exploration and Production Norge AS with an 11.90 percent interest.

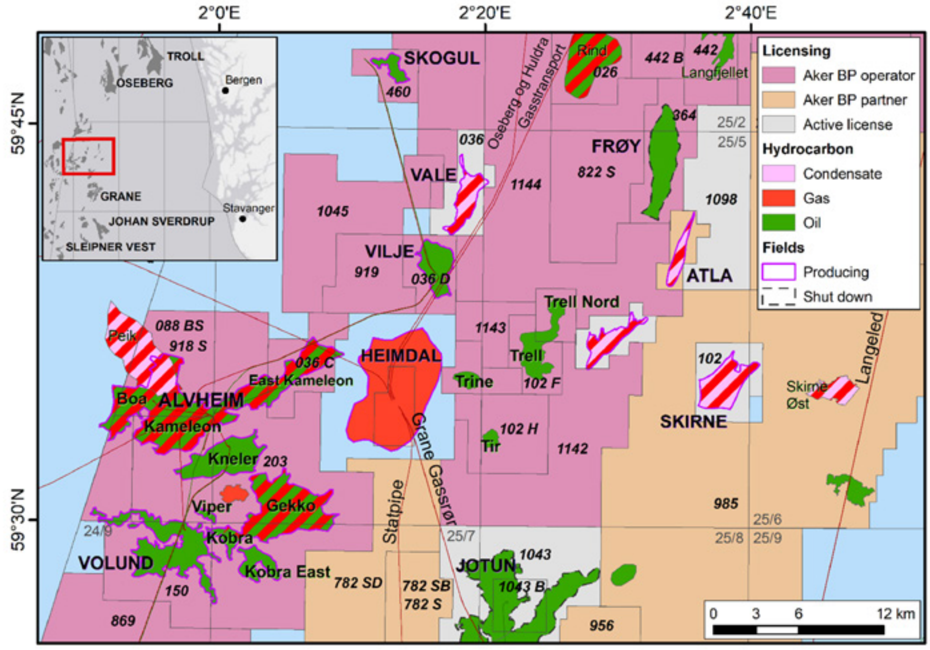


Figure 3.20: Tyrving location map

3.2.4 Skarv Satellite Project (SSP)

The Skarv satellite project consists of the development of the Ørn, Alve Nord and Idun Nord fields, tied back to the Skarv FPSO, see Figure 3.21.

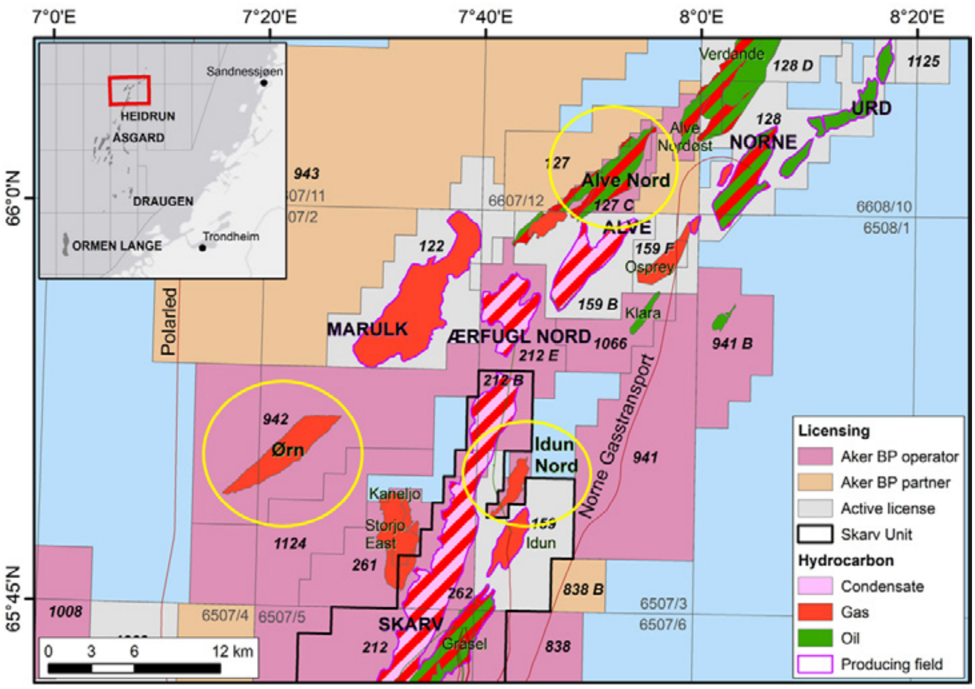


Figure 3.21: Skarv satellites location map

3.2.5 Ørn

Discovery
Ørn is a gas/condensate discovery made in 2019 with well 6507/2-5 S.

Reservoir
The Ørn reservoir is of moderate quality sandstones of the Middle Jurassic Garn Formation. The reservoir is significantly overpressured (667 bar reservoir pressure).

Development
Ørn will be developed by depletion from two production wells, one inclined and one near horizontal, drilled from a new four-slot subsea template. The template will be connected to a new central manifold which is connected to the Skarv FPSO via a new riser. Ørn will utilise spare processing capacity at the Skarv FPSO.

Status
The PDO was submitted in December 2022. The planned start of production is 2027.

The recoverable volumes on Ørn are classified as "Reserves; Justified" (SPE's classification system).

Aker BP holds 30 percent in Ørn. The remaining shares are held by PGNiG Upstream Norway AS 40% and Equinor Energy AS 30%.

3.2.6 Alve Nord

Discovery
Alve Nord was discovered by well 6607/12-2 S drilled in 2011. It is made up of two main reservoir intervals: The sand-rich gravity flows of the Cretaceous Lange Formation and shallow to marginal marine deposits in the Jurassic.

Reservoir
The reservoir quality in the Jurassic is poor to moderate. The Cretaceous Lange interval reservoir quality is moderate to good. The main target is gas.

Development
Alve Nord will be drained by depletion by two production wells, one horizontal producer in the Cretaceous and one high-angle well in the Jurassic, drilled from a new four-slot subsea template. The template will be connected to a new central manifold which is connected to the Skarv FPSO via a new riser. The planned start of production is 2027.

Status
The PDO was submitted to Norwegian authorities in December 2022. The planned start of production is 2027.

The recoverable volumes on Alve Nord are classified as "Reserves; Justified " (SPE's classification system).

Aker BP holds 68.0825 percent in Alve Nord. The remaining shares are held by PGNiG Upstream Norway AS 11.9175 % and Wintershall DEA Norge AS 20 %.

3.2.7 Idun Nord

Discovery
Idun Nord was discovered by well 6507/3-7 drilled in 2009. It found gas/condensate in the Garn Formation from the Middle Jurassic.

Reservoir
The reservoir quality in the Jurassic Garn Formation is very good. The reservoir consists of 2 main segments, only one segment is proven and reported as reserves. The reservoir is over-pressured with 473 bar pressure at 3523 mTVDMSL.

Development
Idun Nord will be drained by depletion and some aquifer support by two production wells drilled from a new four-slot subsea template. A low-angle production well will be drilled into each segment. The template will be connected to a new central manifold which is connected to the Skarv FPSO via a new riser. The planned start of production is 2027.

Status
The PDO was submitted to Norwegian authorities in December 2022. The planned start of production is 2027.

The recoverable volumes on Idun Nord are classified as "Reserves; Justified" (SPE's classification system).

Aker BP holds 23.835 percent in Idun Nord. The remaining shares are held by Equinor Energy AS 36.165% and Wintershall DEA Norge AS 40%.

3.2.8 Fenris

The plan is develop the Fenris reservoir from a new eight-slot unmanned platform through new process facilities located at Valhall PWP (Production and Wellhead Platform). Valhall PWP development of the Valhall field is described in Chapter 3.1.18.

Discovery

The Fenris gas condensate discovery was made in 1989 by well 2/4-14 in the Farsund Formation, and further appraised by wells 2/4-18, 2/4-21, 2/4-21 A and 2/4-23 S. The Ula Formation accumulation was discovered in 2015 by well 2/4-23 S.

Reservoir

Fenris is a gas-condensate field consisting of two Upper Jurassic reservoirs lying at about 5000 m depth. The depositional environment is turbidites for the Farsund Formation, and shallow marine sandstones for the Ula Formation. The accumulation has high pressure (950-1050 bar) and high temperature (165-185ºC). Well 2/4-14 experienced an underground blowout lasting for 7-11 months. Wells 2/4-21 (2012) and 2/4-23 S (2015) encountered a reservoir depleted by the 2/4-14 blowout, proving lateral communication within the Farsund Formation. In the Ula Formation, a mini-DST was acquired in well 2/4-23 S proving flow.

Development

Fenris is planned as an eight-slot unmanned installation with a 50-km pipeline to Valhall, where gas and condensate will be processed for export. The drainage strategy is depletion. Two vertical wells are planned in each formation. The wells will be drilled in 2024/2025, and production start-up is planned in September 2027.

Status

The Fenris development passed DG3 and submitted a PDO in December 2022. The recoverable volumes on Fenris are classified as "Reserves; Justified" (SPE's classification system).

Aker BP holds 77.8 percent in Fenris. The remaining shares are held by PGNiG (22.2 percent).

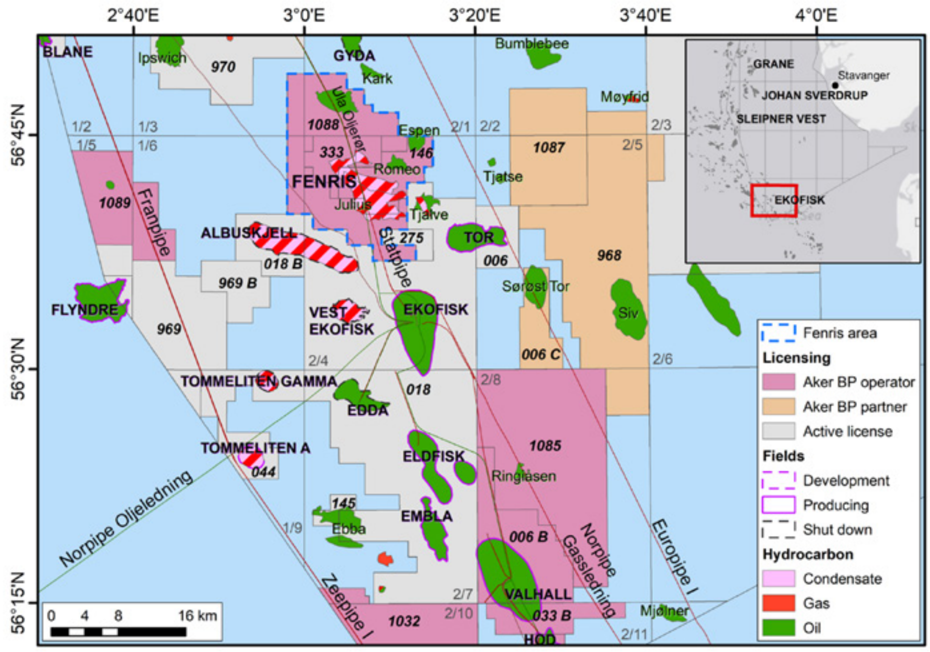
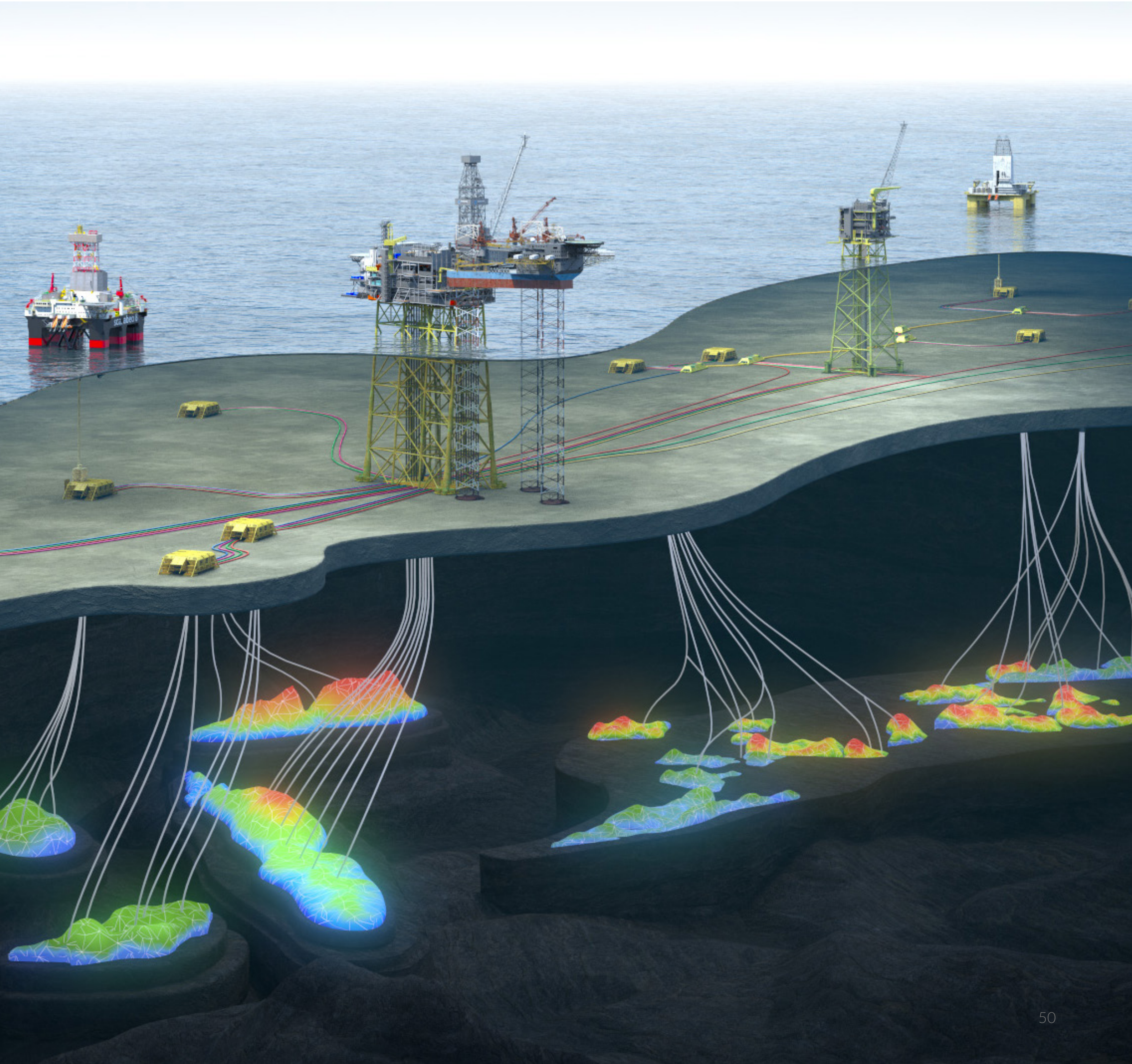


Figure 3.22.4: Fenris location map

3.2.9 Yggdrasil

The Yggdrasil area includes ten discoveries over a 60-km long trend, south of Oseberg and northeast of Alvheim, see Figure 3.23. The area consists of the Hugin fields (renamed from NOA fields), the Fulla field and the Munin fields (renamed from Krafla). The NOA fields include the Frøy field, the Frigg Gamma Delta field, the Langfjellet field and the Rind field. DG3s for Hugin, Full and and Munin were passed 12 December 2022 and the PDOs/POI were submitted to MPE for approval on 16 December 2022.

Aker BP is operator for the entire area, except the oil and gas export pipelines which are operated by Equinor. The development of the Yggdrasil area consists of a PDQ platform, Hugin A, located centrally on the Frigg Gamma Delta field, a NUI wellhead platform, Hugin B on Frøy and an unmanned processing platform, Munin on the Krafla field and a total of nine subsea templates. Oil export is via a new pipeline to Grane Oil Pipeline and further to Oseberg Transportation System (Sture). Gas transport is via a new gas export pipeline with entry from both Hugin A and Munin to Statpipe Area A. Power will be supplied from shore with a cable from Samnanger via a compensation station on Fitjar.



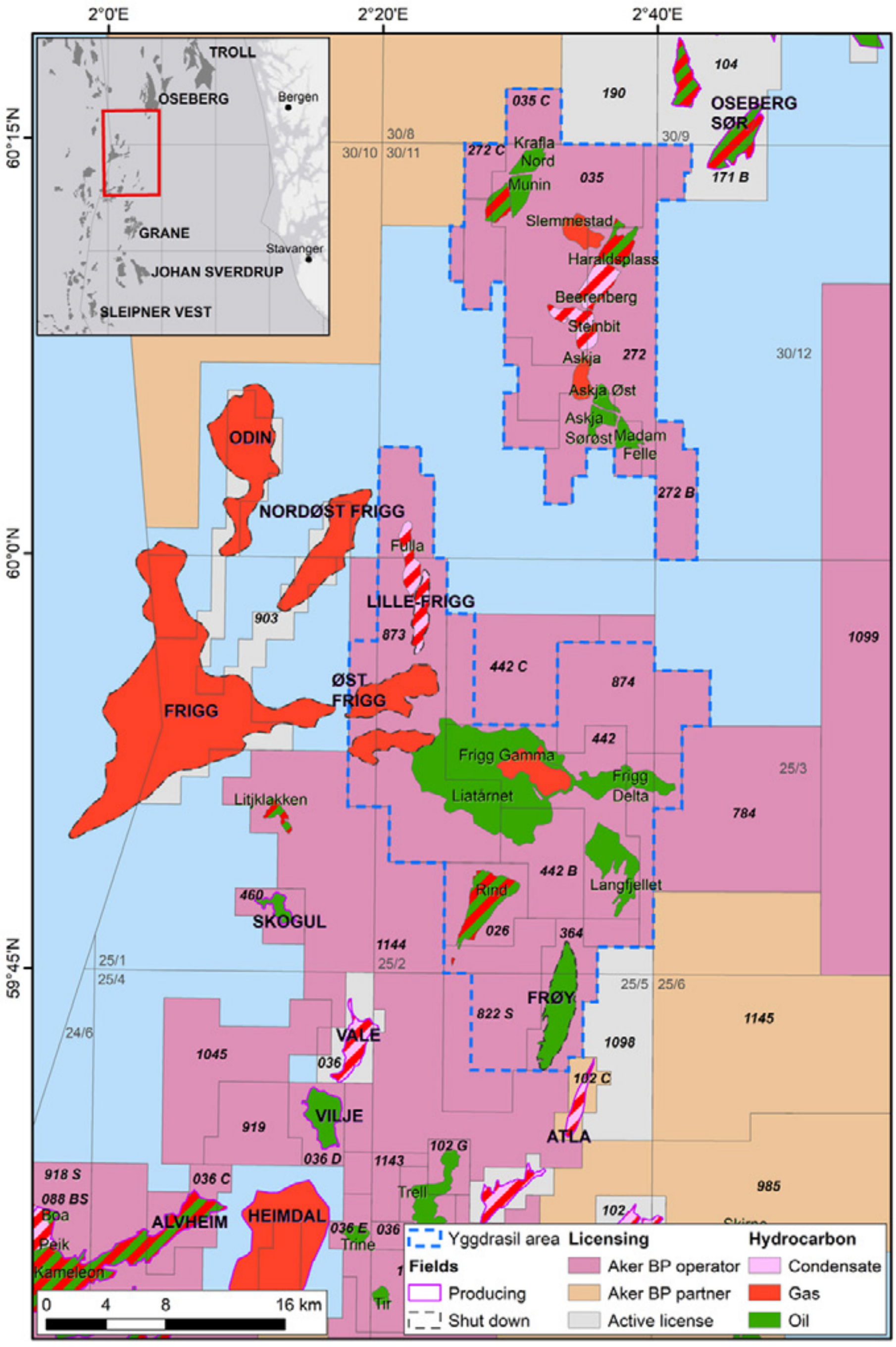


Figure 3.23: The Yggdrasil area

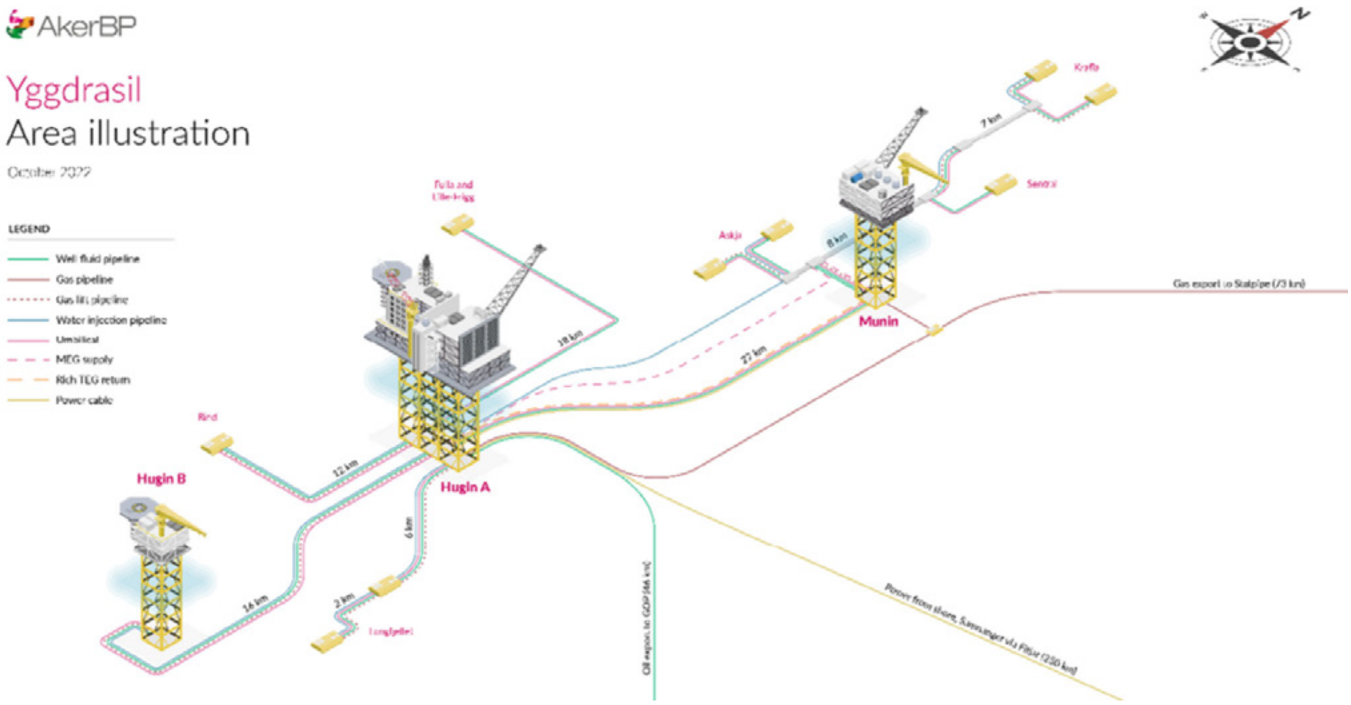


Figure 3.24: Yggdrasil Area Development

3.2.10 Frøy (PL364)

Discovery

Frøy field was discovery by well 25/5-1 in 1987 followed up by appraisal well 25/5-2 in 1989. The Frøy development was approved in May 1992 and was in production from 1995 to 2001 with Elf as the operator. Early water breakthrough and increasing water cut; subsequently increasing gas-oil ratio and a drop in well pressures were experienced and led to the decision to abandon the field in 2001 after producing 5.9 MSm^3 of oil and 1.7 GSm^3 of gas.

Reservoir

The Frøy re-development consists of Middle Jurassic Hugin and Sleipner Formations, which were deposited in a range of fluvial to marginal marine environments with variable tidal influence. The resulting reservoir shows a complex architecture and highly variable reservoir properties, with marked contrasts in flow properties between zones.

Development

The Frøy re-development consists of a 12-slot normally unmanned installation, the Hugin B platform, tied-back to the Hugin A platform. Frøy will have 6 producers (slanted/horizontal) and 2 water injectors. Based on pilot results, an optional producer can be drilled in the Frøy NE prospect. The drainage strategy is pressure support through water injection supplied by the Hugin A platform.

Status

The Plan for Development and Operation (PDO) was submitted in December 2022. The recoverable volumes on Frøy are classified as "Reserves; Justified" (SPE's classification system).

Aker BP holds 87.7percent in Frøy. The remaining shares are held by LOTOS 12.3 percent.

3.2.11 Frigg Gamma Delta (PL442)

Discovery

The Frigg Gamma discovery well, 25/2-10 S, was drilled in 1986 with an appraisal well, 25/2-11, in 1987 which showed gas with a 14-m thick oil column. The Frigg Delta discovery well, 25/2-17. was drilled in 2009 and found oil with no gas cap.

Reservoir

The Frigg Formation comprises gravity-driven deep marine sediments, both classical turbidites, debrites and slumps, which are stacked in lobe complexes. The depositional lobes consist mostly of sandstones, but shaly interbeds can occur within the lobes.

The two different structures, Frigg Gamma and Frigg Delta, are connected through a common aquifer. Frigg Gamma has a thin oil column of 14 m with an overlaying gas cap and an underlying strong aquifer. Frigg Delta contains undersaturated oil column with higher viscosity compared to Frigg Gamma.

Development

The Frigg Gamma Delta development includes 6 trilateral horizontal producers and 2 water injectors drilled from the Hugin A platform. The development strategy for Frigg Delta is oil production with pressure support from the aquifer, Frigg Gamma will rely on pressure support from the gas cap. The water injector's primary purpose is to dispose of produced water from the Hugin A platform.

Status
The Plan for Development and Operation (PDO) was submitted in December 2022. The recoverable volumes on Frigg Gamma Delta are classified as "Reserves; Justified" (SPE's classification system).

Aker BP holds 87.7percent in Frigg Gamma Delta. The remaining shares are held by LOTOS 12.3 percent.

3.2.12 Langfjellet (PL442)

Discovery
Langfjellet was discovered by exploration well 25/2-18 with three entry points into the reservoir (A, C and S) in 2016, drilled by Aker BP. The well proved oil in sandstones of the Hugin Formation and condensate in the Sleipner Formation.

Reservoir
Variable sedimentary environments during its deposition and subsequent deep burial, has resulted in a reservoir characterised by contrasting and mostly marginal reservoir properties. Each of the Langfjellet discovery wells show variable oil pressures, water pressures and variations in oil gradients. The data shows that both vertical and lateral barriers are present, creating multiple compartments.

Development
Langfjellet will be developed with two 6-slot subsea templates that are tied-back to the Hugin A platform. Three producers, two water injectors and an infill (depending on result of a pilot well) well are initially planned, leaving six spare slots for future use. The producers are U-shaped or sinus-shaped wells with two or more deviated cuts across the oil-bearing stratigraphy, to mitigate any barriers in the reservoir.

Status
The Plan for Development and Operation (PDO) was submitted in December 2022. The recoverable volumes on Langfjellet are classified as "Reserves; Justified" (SPE's classification system).

Aker BP holds 87.7 percent in Langfjellet. The remaining shares are held by LOTOS 12.3 percent.

3.2.13 Rind (PL442, 25/2-5)

Discovery
The exploration well, 25/2-5, was drilled by Elf on the Rind Horst in 1976 and proved oil in Hugin Formation and Statfjord Group, and gas-condensate in the Sleipner Formation. An appraisal well, 25/2-13, targeting the western segment was drilled in 1990 and proved similar hydrocarbon types in the same formations.

Reservoir
The Hugin reservoir is approxa. 100 m thick and consists of shallow- to marginal marine strata. The Sleipner reservoir is approximately 50 m thick and comprises fluvio-deltaic and coal-bearing paralic strata. The deeper Statfjord reservoir is approximately 200 m thick and consists of fluvial to marginal marine strata. Due to its channelised nature and dominantly low permeability, the reservoir is assumed to have a comparatively low degree of connectivity. The Statfjord reservoir is separated from Hugin/Sleipner by a ~150m thick Dunlin shale.

Development
Rind will be developed with a 6-slot subsea template tied-back to the Hugin A platform. One producer will be a multilateral horizontal well, the other two producers will be single horizontal wells. The Statfjord producer will be completed with a Fishbone completion to mitigate the lower permeability. The two water injectors will give pressure support to the field

Status
The Plan for Development and Operation (PDO) was submitted in December 2022. The recoverable volumes on Rind are classified as "Reserves; Justified" (SPE's classification system).

Aker BP holds 87.7 percent in Rind. The remaining shares are held by LOTOS 12.3 percent.

3.2.14 Fulla and Lille-Frigg (PL873)

Discovery
Well 30/11-7, drilled by Statoil in 2008 on the Fulla structure, proved a lean gas-condensate in sandstones of the Ness Formation. The sidetrack, 30/11-7 A, proved the main gas-condensate accumulation in the Tarbert Formation.

Lille-Frigg was discovered in 1975 by Elf Aquitaine Norge, and the Plan for Development and Operation (PDO) was approved in 1991. The field was developed with a subsea installation with three production wells tied-back to the Frigg field Centre. Production started in 1994 but was stopped prematurely in 1999 due to water breakthrough and risk of hydrate formation in the pipelines. 2.3 GSm^3 of gas and 1.2 MSm^3 of condensate were produced. The installation was removed in 2001.

Reservoir
The Fulla & Lille-Frigg area consists of the Tarbert Formation which is mostly characterised by delta front and estuarine depositional environments.

The Tarbert Formation on both Fulla and Lille-Frigg is generally very sand-prone, with the best reservoir properties found in fluvial and/or deltaic distributary channel deposits.

Development
Fulla Lille-Frigg will be developed through a 6-slot subsea template with a tie-back to the Hugin A platform. Both fields will be drained by natural pressure depletion through two slanted producers on Fulla and a horizontal producer in Lille-Frigg.

Status
The Plan for Development and Operation (PDO) was submitted in December 2022. The recoverable volumes on Fulla and Lille-Frigg are classified as “Reserves; Justified” (SPE’s classification system).

Aker BP holds 47.7 percent in Fulla & Lille-Frigg. The remaining shares are held by LOTOS 12.3 percent and Equinor 40.0

3.2.15 Munin (PL272, PL035, PL035C)

Discovery
The Munin field was discovered in 1997 with well 30/11-5 followed up by numerous appraisal/exploration wells, making the total number of wells 11 plus 6 sidetracks. The Munin field now consists of 11 oil and gas discoveries in the Brent group, in the Tarbert Formation. The reservoirs are found in Upper and Middle Tarbert and Etive/Ness.

Reservoir
The Brent group was deposited as a major delta system comprising sandstone, siltstones, shale, calcite and coals. Deposition of the Tarbert Formation has occurred in the retrogradational phase of the Brent delta, generally in marginal marine estuarine environment or shallow marine environments, during early rift initiation.

Munin is divided into three areas: Krafla, Sentral and Askja.

Krafla has 3 proven segments: Krafla Vest, Krafla Midt, and Krafla Nord. Varying pressures, fluid phases and contacts have been observed across these compartments.

Sentral has 3 proven segments: Beerenberg, Slemmestad and Haraldsplass. There are different fluid types and contacts observed in these segments.

Askja has 4 proven segments: Askja Vest, Askja Øst, Askja Sørøst and Madam Felle. Askja Vest is separated from Askja Øst based on difference in fluid phase (gas/oil) and different pressures across a fault. Askja Øst is separated from Askja Sørøst by a likely sealing fault.

Development
The development will be with subsea templas at the Krafla, Sentral and Askja areas and tied-back to the Munin platform. There is two-phase separation on the platform. The gas is exported to Kårstø via Statpipe, and the liquid phases are pumped to the Hugin A platform at Frigg Gamma Delta.

In total, there will be 21 producers and 3 water injectors.

Status
The Plan for Development and Operation (PDO) was submitted in December 2022. The recoverable volumes on Munin are classified as “Reserves; Justified” (SPE’s classification system).

Aker BP holds 50.0 percent in Munin. The remaining shares are held by Equinor 50.0 percent.

3.2.16 Solveig Phase 2 (PL359)

Discovery

The discovery and appraisal history of Solveig is described in Chapter 3.1.9.

Reservoir

The Phase 2 development will focus on the Synrift reservoir with additional wells in Segment B, plus the inclusion of Segment A and Segment D into the development. Phase 2 will also target the Outer Wedge reservoir interval in Segment D. The reservoirs are described in Chapter 3.1.9.

Development

Solveig Phase 2 is a subsea tie-back to Edvard Grieg via the Solveig Phase 1 infrastructure. The tie-in connection points are the Solveig Phase 1 Pipeline End Manifold (PLEMs), which all have tie-in points for future expansion. The development consists of two drill centres, one is a single satellite and the other is a template drill centre. The Solveig Phase 2 reservoir development is shown in Figure 3.25 5, with two MLT producers and one water injector.

Status

The Solveig Phase 2 development was santcioned in December 2022. Development drilling will start in Q4 2025, with first oil planned for Q2 2026.

The recoverable volumes on Solveig Phase 2 are classified as "Reserves; Justified" (SPE's classification system).

Aker BP holds 65 percent in Solveig. The remaining shares are held by OMV (Norge) AS 20 percent and Wintershall Dea Norge AS 15 percent.

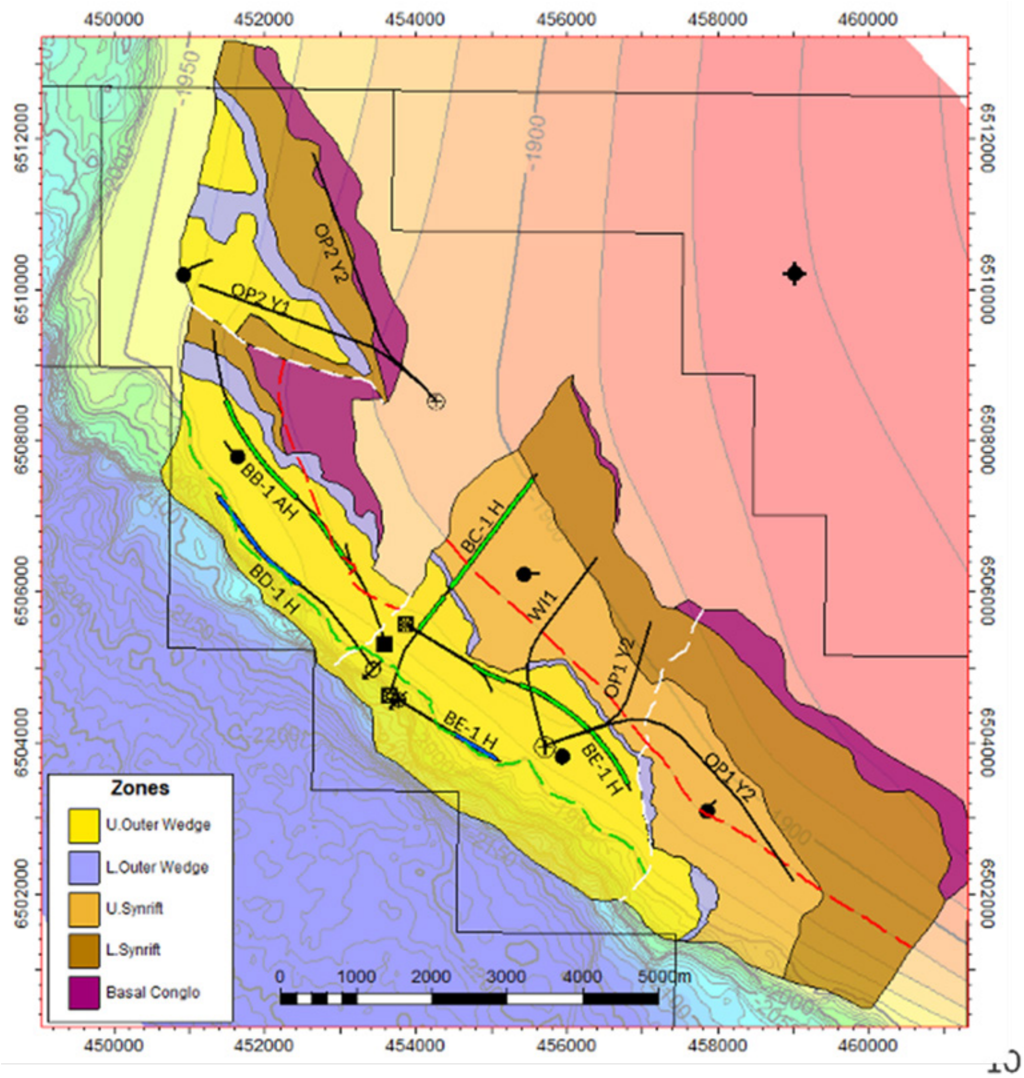


Figure 3.25.5: Solveig Phase 2 development wells shown in black

3.2.17 Symra (PL167 & PL167C)

Discovery

Lundin Energy entered the licence as partner in 2004, gaining operatorship in 2021. The current PL167 / PL167C licensees are Aker BP (operator 50%), Equinor Energy AS (30%) and Sval Energi AS (20%). Symra (previously Lille-Prinsen) was discovered by the 16/1-6S (2003) well and appraised by 16/1-29 ST2 (2018). Appraisal well 16/1-34A (2021) confirmed oil in Zechstein carbonates, and a well test (DST) proved good reservoir connectivity/continuity. The upper Jurassic sandstones on the western flank of the high, also called "Outer Wedge" were discovered by appraisal well 16/1-30S (and geological sidetrack 16/1-30A) in 2019.

Reservoir

In PL167, the Symra structure includes several segments and reservoirs of different ages including Heather Formation sandstones, the Zechstein Formation carbonates and basement reservoirs.

The Heather Formation is penetrated by wells 16/1-30 S and 16/1-30 A in the Outer Wedge segment consisting of variable reservoir quality sandstone. The Zechstein carbonates were part of an extensive carbonate platform, which was eroded over most of the basement high. Basement is the largest reservoir in terms of bulk volume in the Symra area. It is included in the reservoir model given the commercial success of production from basement wells further south.

Development

The Symra field is planned as a subsea development, with tie-back to the host platform at Ivar Aasen (distance approximately 7.5 km). Final processing of the Symra oil and gas will occur at Edvard Grieg with export through the existing EG (and IA) oil and gas downstream transport system. The selected concept for the subsea layout is one 4-slot ITS/ template and drill centre, with the SURF scope covering pipelines for oil, gas lift, water injection and umbilical. A defined upgrade scope is to be carried out at Ivar Assen, consisting of a new water injection pump and chemical injection skid, among other things. The reference case drainage strategy consists of 4 oil producers (3 pre-drilled), Two of the oil producers can be converted to injectors (OWS and OW wells) and the Outer Wedge South well is converted into a water injector, 18 months post first oil

Status

The PDO was submitted in December 2022 and first oil is expected in Q1 2027.

The recoverable volumes on Symra are classified as "Reserves; Justified" (SPE's classification system).

Licence partners are Aker BP as operator with 50 percent, Equinor Energy with 30 percent and Sval Energi with 20 percent.

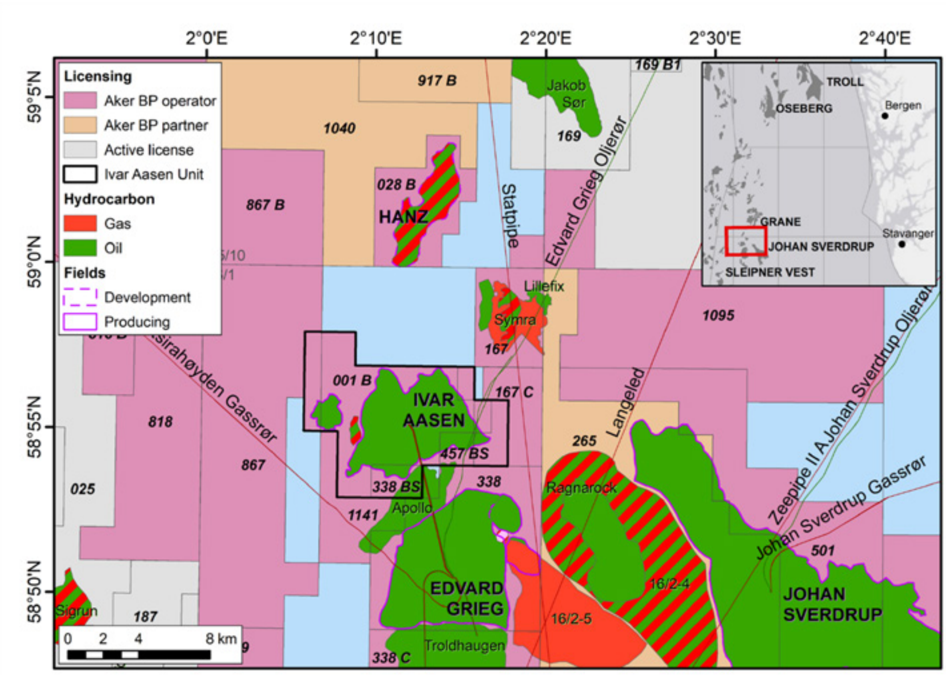


Figure 3.26: Symra location

3.2.18 Verdande

Discovery

The Verdande discovery well 6608/10-17S was drilled in 2017 and encountered an oil column with a gas cap in two levels in the Cretaceous Lange Formation. The upper-level reservoir sandstone contained a 8-m oil column while the lower reservoir contained 5-m oil with a 13-m gas column. The field was further appraised in 2018 and 2020.

Reservoir

The field consists of two accumulations: Cape Vulture and Alve Nord Øst. It is positioned on the Dønna Terrace and has three reservoir units. The porosity ranges from 15% to 19% and permeability is 117 to 1561mD. The main uncertainties are poor connectivity and/or not optimal well placement.

Development

The field will be developed using three long horizontal oil producers drilled from a new four-slot template tied back to the Norne FPSO. The drainage strategy is a combination of pressure support from gas cap expansion and natural depletion.

Status

The PDO was submitted in December 2022. The planned start of production is 2025.

The recoverable volumes on Verdande are classified as "Reserves; Justified" (SPE's classification system).

Aker BP holds 7 percent in the Verdande Unit. The remaining shares are held by Equinor Energy AS 59.2682%, PGNiG 0.8272%, Petoro 22.4067% and Vår Energi 10.4979%.

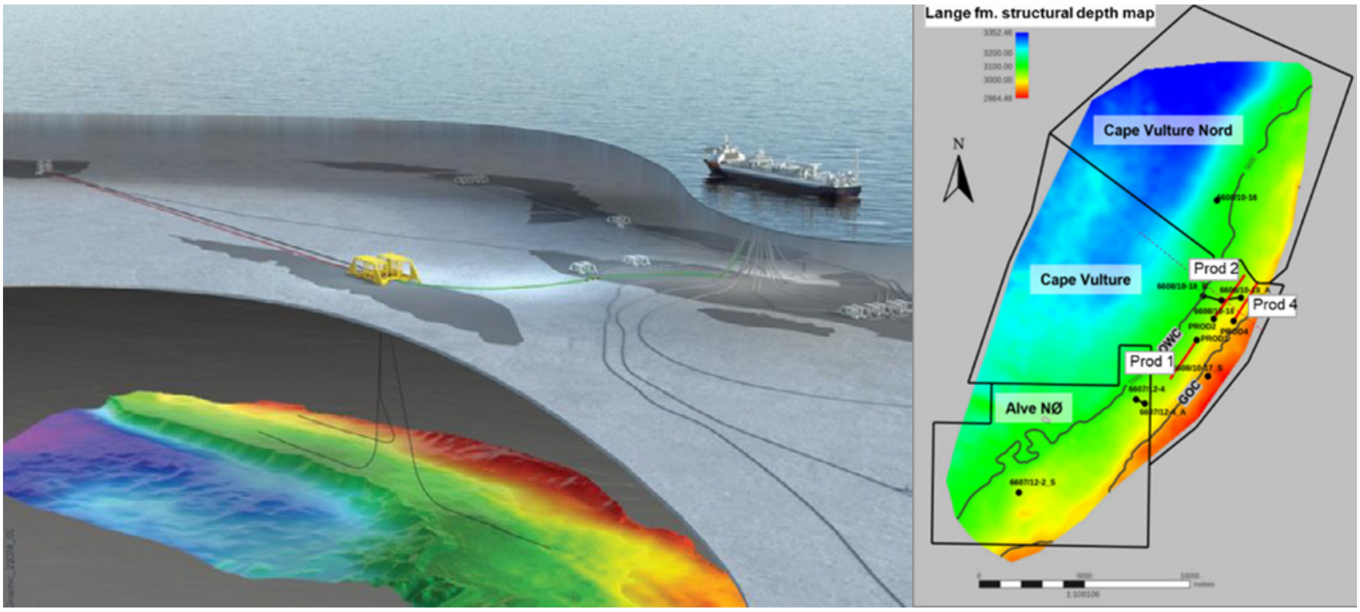


Figure 3.27: Outline of the Verdande project and placement of the 3 development wells

4. CONTINGENT RESOURCES

Aker BP has contingent resources in a wide range of assets and at different stages of maturation. The total net contingent resources estimates reported here include volumes as defined in Figure 1.1. Discoveries that need more data acquisition to define the way forward, such as Rondeslottet and Liatårnet, are not included.

The contingent resources range from 373 mmboe to 1,022 mmboe, with a 2C volume of 744 mmboe. Approximately 2/3 of this is associated with further development of the fields containing reserves described in 3 Description of Reserves.

The most important contributors to the contingent resources are the discoveries in the Yggdrasil area (North of Alvheim and Askja/Krafla), the King Lear volumes and volumes in the Valhall area.

The following is a short description of the most important projects within the company's core areas containing contingent resources.

4.1 CONTINGENT RESOURCES BY AREA

4.1.1 Alvheim Area

The contingent resources in resource category 4 and 5("Development Pending" and "Development not Clarified or on Hold") in the Alvheim area are:

- Trell Nord
- Froskelår development
- Froskelår North East
- Several resource category 7 projects exist as well, among them Caterpillar, Rumpetroll and Kneler NE.
- The combined net contingent resource potential for the Alvheim Area ranges from 25 to 103 mmboe.

The Alvheim Area is actively being worked to add additional infill and development opportunities from resource category 7 and maintain a focused exploration strategy for potential prospect opportunities.

4.1.2 Edvard Grieg Area

Troldhaugen (PL338C & PL338E)

Troldhaugen (previously Rolvsnes) is a field located in the PL338C/PL338E licences on the Utsira High in the Norwegian sector (blocks 16/1 and 16/4) of the North Sea. Ownership in the licences is aligned with Aker BP ASA holding 80 percent (operator) and OMV (Norge) AS 20 percent. This alignment of ownership allows for optimising development of the two licences.

See Chapter 3.1.10 for more details.

Discovery and reservoir

The Troldhaugen appraisal history and reservoir description is provided in Chapter 3.1.10.

Development

In addition to the existing CA-1H (EWT) well, the full field development consists of two additional oil producers:v

- OP-2 bilateral well in PL338C, Y-1 ~4km and Y-2 ~2.5 km long with branch control
- OP-3 4 km long single branch well in PL338E with three zones hydraulic smart completion

The two wells are drilled through an Integrated Template Structure (ITS). The ITS also provides two spare slots for future expansion of the development. The ITS is tied back to Edvard Grieg via the Troldhaugen EWT infrastructure 6 km to the north.

Status

A PDO was submitted in December 2022 with first oil planned for Q1 2026. The execution of the project was however conditional upon the performance of the extended well test. Since the PDO was submitted, the experience from the well test has resulted in a reduction in the expected recoverable volume for the project, and Aker BP therefore decided not to accede to the PDO.

No volumes from the full field development have been booked as reserves in 2022.

Aker BP holds 80 percent and OMV (Norge) AS the remaining 20 percent.

Several other projects have been identified in the Edvard Grieg area. The combined net contingent resource potential in the Edvard Grieg Area ranges from 44 - 115 mmboe.

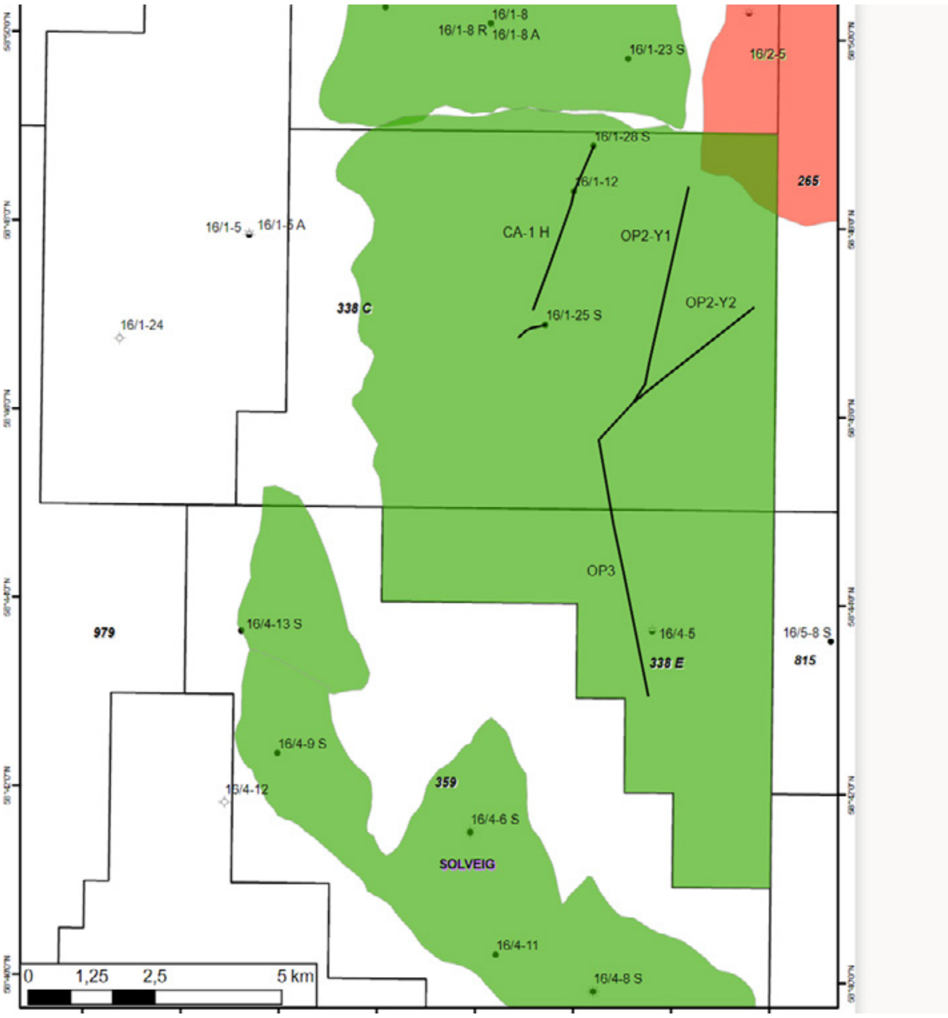


Figure 7 4.1: Troldhaugen well locations map

4.1.3 The Ivar Aasen Area

Symra Area

The Paleocene Heimdal prospectivity in PL167 is a distal pinchout of the Heimdal basin floor fan system, a stratigraphically trapped Heimdal sandstone within the Lista Formation shales. The Paleocene Heimdal reservoirs have been encountered in the following wells: 16/1-6 S, 16/1-6 A, 16/1-29 S and most recently in 16/1-34 S and 16/1-34 A.

The Verdandi discovery, made in 16/1-6 S (2003), comprises gas within the Heimdal Member. The sidetrack 16/1-6 A encountered a water-up-to in the same formation. The Verdandi discovery was appraised in well 16/1-29 ST2 (2018) where samples were taken suggesting an oil leg present in Heimdal. The discovery was further appraised in 16/1-34 S (2021), which proved an oil column. These prospects will be further matured as part of the Symra development.

The Grid oil and gas discovery (2003 - 2021) within PL167, has been confirmed in several wells in the area. The discovery is comprised of oil and gas in thin, injected sandstones. Eocene Grid prospectivity 16/1-6 S (2003) discovered oil in the Grid Formation, while the Grid Formation sandstone in the sidetrack (16/1-6 A) was reported as dry. As for the Heimdal discovery, Grid will be further matured as part of the Symra development.

Licence partners are Aker BP as operator with 50%, Equinor Energy with 30% and Sval Energi with 20%.

Several other projects have been identified in the Ivar Aasen-area. The combined net contingent resource potential in the Ivar Aasen Area ranges from 11 - 46 mmboe.

4.1.4 The Yggdrasil Area (renamed from NOAKA - North of Alvheim Krafla Askja)

The contingent resources in Yggdrasil are spread over five fields as outlined below. The resources at Langfjellet and Frøy will be targeted by geo-pilot wells and the resources at Krafla, Sentral and Askja will drilled as keeper wells, i.e. completed as a producer if a discovery is made. There is no need for additional infrastructure to produce the contingent resources.

Contingent resources in Yggdrasil:

- Langfjellet 4b/5
- Frøy infill (NE & LP)
- Krafla
  - Eldfjel
- Sentral
  - Haukeland
  - Samantha
- Askja
  - Askja Nord
  - Magdalena
  - Katarina

The combined net contingent resource potential in the Yggdrasill Area ranges from 43 - 167 mmboe.

4.1.5 The Valhall Area

Several projects have been identified which may significantly increase the reserves from the Valhall and Hod fields. The following is a list of projects included in the resource classes 4 and 5 ("Development Pending" and "Development not Clarified or on Hold"), Figure 1.1.

- Valhall Flank North Infill N-11
- Valhall Flank North Infill N-14
- Valhall Flank West Waterflood
- Valhall PWP Technology Upside
- Valhall Redrills and Late Sidetracks
- Valhall Extended Production
- Valhall Diatomite Test Producer
- Hod field Development Expansion
- Fenris Infill Wells

Some of these projects are expected to be approved by the end of 2023, while others will need further maturing prior to sanction.

Several projects in resource category 7 have also been identified, including further development of the diatomite reservoir, infill drilling and extended waterflood, EOR, etc. Pending further maturation, these projects are at present not included in the Valhall area contingent resources estimate below.

Aker BP holds 90 percent interest in all Valhall and Hod projects and 77.8 percent in Fenris.

The combined net resource potential in resource categories 4 and 5 for Aker BP in the Valhall Area ranges from 70 - 258 mmboe.

4.1.6 Skarv Area

The contingent resources in resource category 3 and 5("Development Pending" and "Development not Clarified or on Hold") in the Skarv area are:

- Lunde
- Dvalin Nord (Adriana/Sabina)
- Ærfugl Infill

The Skarv Area is actively being worked to add additional infill and development opportunities from resource category 7 and maintain a focused exploration strategy for potential prospect opportunities. These include:

- Infill wells in Tilje segments A & C
- Extension of the FPSO technical lifetime beyond 2036.

The combined net contingent resource potential for the Skarv Area ranges from 8 to 19 mmboe.

4.1.7 Ula Area

At present no contingent volumes are recorded in the Ula and Tambar fields.

4.1.8 Partner-Operated Assets

Garantiana (PL554)

The Garantiana discovery is an elongated structure with a gross ~100 m thick Early Jurassic / Cook Formation / medium quality reservoir (200-400 mD) located at a depth of approximately 3,600 m TVD MSL in the northern North Sea. The reservoir is high pressure (630 bar) with somewhat challenging fluid characteristics (high pour point temperature, unstable asphaltene and H2S content).

Garantiana was discovered by 34/6-2S and 2A in 2012 (central area) and appraised by 24/6-3S in 2014 (southern area). The southern area has proven good reservoir properties through drill stem tests, the middle area has poorer characteristics, and the northern area is not appraised.

Updated volume estimates indicate a net resource potential ranging from 12 to 25 mmboe to Aker BP. The discovery will most likely be developed as a subsea tie-back to Snorre B. Current plans indicate production start in 2029.

An exploration well was drilled in Q2 2021 in the Garantiana West segment. This is an oil discovery in the Cook formation with good reservoir quality. There is an improved fluid type observed at Garantiana West. Volume estimates indicate a net resource potential ranging from 2 to 5 mmboe to Aker BP. Garantiana West will most likely be developed as a satellite structure tie-in to Garantiana.

Equinor is the operator and Aker BP holds 30 percent share in PL554

Wisting (PL537 and PL537B)

The Wisting field includes oil discoveries in the Wisting Central and Hanssen compartments; located in the Hoop Fault complex, in the Barents Sea. Oil has been proven in the late Triassic to Middle Jurassic sediments in Realgrunnen Sub-group, the Stø, Nordmela and Fruholmen Formations. The main reservoir (Stø Formation) gross thickness is ~25m and it is characterised by excellent reservoir properties (2-4D). The apex of the field is estimated to be approximately 600 m TVD MSL, and the free water levels (FWL) encountered are in the range of 690 - 698 m TVD MSL. The Wisting reservoir has normal pressure (~70 bar) and low temperature (~17 °C).

The 7324/8-1 (Wisting Central) and 7324/7-2 (Hanssen) discoveries were made in September 2013 and July 2014. The appraisal well, well 7324/7-3 S (Wisting Central II) was drilled in April 2016 and well 7324/8-3 (Wisting Central III) was drilled in September 2017. A total of six wells have been drilled in the Wisting Area. The water depth is approximately 400 m.

Volume estimates indicate a net resource potential ranging from 126 to 196 mmboe to Aker BP. The discovery will most likely be a stand-alone development with an FPSO (Floating Production Storage and Offloading vessel).

Equinor is the operator and Aker BP holds a 35 percent share in PL537 and PL537B.

4.1.9 Other

Other resources classified as contingent resources include development of the Newt, Nidhogg and Storjo East discoveries. Volumes estimates range from 24 to 70 mmboe.

5. MANAGEMENT'S DISCUSSION AND ANALYSIS

The assessment of reserves and resources is carried out by experienced professionals in Aker BP based on input from operators, partners and in-house evaluations. The responsibility for carrying out the evaluation lies with the business projects. The reserves and resource accounting is coordinated and quality-controlled by a small group of professionals, led by a reservoir engineer with more than 30 years of experience in such assessments.

Additionally, all volumes within the reserve category (except for the minor Enoch and Atla) have been certified by an independent third-party consultancy (AGR Petroleum Services AS). All production and cost profiles are included in AGR's certification report for completeness and assessment of economic cut-off with Aker BP SPE PRMS price assumptions.

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 based on expected production profiles and estimated proven and probable reserves. Cut-off time for the reserves in a field or project is set at the time when the maximum cumulative net cashflow for each project occurs. The company has used a long-term inflation assumption of 2.0 percent, a long-term exchange rate of 8.0 NOK/USD (8.5 and 8.25 in 2023 and 2024, respectively), and a long-term oil price of 65 USD/bbl (real 2022 terms), down from a 2023 oil price estimate of 80 USD/bbl and 2024 estimate of 70 USD/bbl.

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 estimate reflects our high confidence volumes. 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. Therefore, there is a remaining risk that actual results may be lower than the 1P/P90. A significant change in oil prices may also impact the reserves. Low oil prices may force the licensees to shut down producing fields early and lead to lower production. Higher oil prices may extend the life of the fields beyond current assumptions.

Karl Johnny Hersvik
CEO

AkerBP

Aker BP ASA

Fornebuporten, Building B
Oksenøyveien 10
1366 Lysaker

Postal address:
P.O. Box 65
1324 Lysaker, Norway

Telephone: +47 51 35 30 00
E-mail: post@akerbp.com

www.akerbp.com

Design: Headspin