Annual report 2017

AKER BP ASA

Contents

HIGHLIGHTS 2017

5 JANUARY
1 BILLION BARRELS PRODUCED AT VALHALL

Valhall and Hod pass one billion barrels of oil equivalents produced. This is more than three times the volume expected at the opening of the field in 1982.

17 JANUARY
OFFERED 21 NEW LICENCES IN APA AWARD

Aker BP is offered interests in 21 new production licences in the Awards in pre-defined areas (APA) 2016. This includes 13 new operatorships. Of the 21 production licences, 16 are in the North Sea, 4 in the Norwegian Sea and 1 in the Barents Sea.

7 FEBRUARY
LOWER DEVELOPMENT COSTS ON JOHAN SVERDRUP

Statoil, operator for the Johan Sverdrup field, reports updated key figures. Aker BP is a partner in the giant development. The first phase is now estimated at NOK 97 billion, compared with NOK 123 billion in the Plan for Development and Operation (PDO). Current break-even is now below USD 20 per barrel for Phase 1, below USD 30 per barrel for Phase 2, and below USD 25 per barrel for the full field development project.

13 FEBRUARY
OIL DISCOVERY IN THE FILICUDI PROSPECT

The partners in PL533 (Aker BP 35 per cent working interest) make an oil and gas discovery in the main well 7219/12-1 in the southern Barents Sea. The well is located in PL533 approximately 40 km southwest of Johan Castberg and 30 km northwest of the Alta and Gohta discoveries on the Loppa High.

13 FEBRUARY
MINISTER SØVIKNES OPENS IVAR AASEN FIELD

The Ivar Aasen field in the North Sea is officially opened by Minister of Petroleum and Energy Terje Søviknes. "The development of Ivar Aasen represents significant values for the Norwegian society," said Søviknes. Oil production from the Aker BP-operated field started on 24 December 2016, four years after the Plan for Development and Operation (PDO) was submitted.

21 MARCH
PROCEEDING WITH PHASE 2 OF THE JOHAN SVERDRUP DEVELOPMENT

The Johan Sverdrup partnership has decided to proceed with Phase 2 of the Johan Sverdrup development. Phase 2 builds on the Phase 1 infrastructure, adding another processing platform to the field centre. The partners aim for submission of the Plan for Development and Operation (PDO) in the second half of 2018.

30 MARCH
TAMBAR RE-DEVELOPMENT APPROVED

The Tambar licence, with owners Aker BP and Faroe, approves Tambar re-development, consisting of two additional wells and gas lift. This is a major milestone for Tambar that extends the production period from about 2018 to 2028 with a potential upside. The expectation is that this will give 4-6000 new barrels a day over several years.

7 APRIL

AKER BP ENTERS INTO LONG-TERM FRAMEWORK AGREEMENTS

The framework agreements: Aker Solutions for engineering and procurement, Kværner for construction and hook-up, and both Siemens and ABB for electro, instrument, control and telecom. The intent of the agreements is that Aker BP will use an integrated project delivery model - a platform alliance - for each project.

Aker BP has also entered into a separate framework agreement with Heerema Marine Contractors for transport and installation of facilities offshore, including call-off for transport and installation on Valhall West Flank.

27 APRIL

AKER BP AWARDS FRAMEWORK CONTRACT TO SCHLUMBERGER

The framework contract covers acquisition of 4D seismic data. It has a duration of four years, with an option for 2+2 years. "With this framework contract, Aker BP is fortifying our position as an operator with significant ambitions for growth and value creation on the Norwegian Shelf," says SVP Reservoir, Ole-Johan Molvig.

28 MAY

PLUGGING WELLS ON VALHALL USING POWER FROM SHORE

Maersk Invincible is being supplied with electricity through the Valhall field. During the next years, the rig will permanently plug 18 wells from the Valhall DP platform. This is probably the first time a drilling rig has ever been powered fully from shore. Calculations show that electrification of the drilling rig will reduce local emissions by 15,200 tonnes of CO2 and 168 tonnes of NOx every year.

30 MAY

VALHALL QP REMOVAL CONTRACT AWARD

Allseas, via Excalibur Marine Contractors, is awarded a long-term framework agreement (6 years + 2 + 2) for transport, installation and removal services for Aker BP. A call-off for removal and disposal of the Valhall QP topsides and QP/DP bridge in 2019 is also awarded.

30 JUNE

GINA KROG STARTS PRODUCTION

Aker BP holds a 3.3 per cent interest in the Gina Krog field, operated by Statoil. It has been developed with a fixed platform with living quarters and processing facilities. Oil from Gina Krog will be exported to the markets with shuttle tankers while gas is exported via the Sleipner platform.

8 JULY

VOLUND INFILL WELL ON STREAM

The first of two new wells at the Volund field commenced production. The second followed on 11 August.

10 AUGUST

RIG CONTRACT TO ODFJELL DRILLING

Aker BP ASA awards a contract to Odfjell Drilling for lease of the semi-submersible drilling rig DeepSea Stavanger for a period of approximately nine months, with commencement in February 2018. The contract is for exploration and development drilling at various locations in the Norwegian Sea and the Barents Sea.

4 SEPTEMBER

FURTHER IMPROVEMENTS ON JOHAN SVERDRUP

Continued quality in project delivery and execution enables the partners in the Johan Sverdrup development to further reduce investment costs for Phase 1 by NOK 5 billion to NOK 92 billion. Since the Johan Sverdrup PDO was approved by Norwegian authorities, planned investments for Johan Sverdrup Phase 1 have been reduced by a total of NOK 31 billion.

24 OCTOBER
AKER BP ACQUIRES HESS NORGE

Aker BP ASA enters into an agreement to acquire Hess Norge AS. Through the transaction, Aker BP strengthens its production and resource base, and becomes the sole owner of the Valhall and Hod fields, where the company sees great value creation potential through increased oil recovery and flank developments.

26 OCTOBER
SUBSEA CONTRACT TO DEEPOCEAN

Aker BP ASA has awarded a contract to DeepOcean for subsea inspection, maintenance and repair (IMR) activities. The contract has a total market value of minimum NOK 300 million during the initial three years, with an option to continue the activities for an additional six years (2+2+2).

21 NOVEMBER
AKER BP FORMS TWO SEPARATE DRILLING & WELL ALLIANCES

Aker BP ASA enters into two separate alliance agreements - one with Maersk Drilling and Halliburton for jack-ups, and one with Odfjell Drilling and Halliburton for semi-submersibles. Both alliances are formed under the "one for all, all for one" collaboration model where the partners align around common goals to drive continuous improvement and create greater value for all.

4 DECEMBER
AKER BP ASA DIVESTS 10 PER CENT IN VALHALL/HOD

Aker BP ASA enters into an agreement with Pandion Energy AS to divest 10 per cent interest in the Valhall and Hod fields for an undisclosed cash sum. CEO of Aker BP, Karl Johnny Hersvik states in a comment: "Through this transaction, we gain a partner that shares our ambition of developing the upside potential in these fields".

7 DECEMBER
SERIOUS ACCIDENT ON THE MAERSK INTERCEPTOR DRILLING RIG AT TAMBAR

One person died following an accident on Maersk Interceptor. The deceased, a Norwegian citizen and employee of Maersk Drilling, fell into the sea during maintenance work on the rig. Another person, also an employee of Maersk Drilling, was injured during the accident. Maersk Interceptor was drilling wells on the Tambar field for Aker BP when the accident happened.

15 DECEMBER
AKER BP SUBMITS THREE PDOS

Aker BP ASA submits the Plans for Development and Operation (PDOs) for the Valhall Flank West, Ærfugl and Skogul fields to the Norwegian Ministry of Petroleum and Energy, on behalf of the respective partnerships. "This demonstrates our strong commitment to the Norwegian continental shelf as well as to the Norwegian society," says CEO Karl Johnny Hersvik.

18 DECEMBER
AKER BP INVESTS IN TECHNOLOGY FOR INCREASED RECOVERY

Aker BP invests in and acquires a 17 per cent stake in the company Fishbones AS. Fishbones is an unconventional stimulation technology applied to increase production rates in tight reservoirs. The technology will initially be applied at the Valhall field.

LETTER FROM THE CEO

MAXIMIZING SHAREHOLDER VALUE – YEAR AFTER YEAR

Aker BP continues to deliver outstanding results. We have demonstrated superior shareholder returns over the past three years. We distributed USD 250 million in dividends to our shareholders in 2017, and have now set our sights on even higher dividends in the coming years.

The last ten years has seen a steady growth in oil and gas demand globally. At the same time the oil market balance has changed rapidly. The oil market volatility calls for a resilient strategy. For Aker BP to succeed in becoming the leading independent offshore E&P company, we need to be cost leading. This is the foundation of our strategy.

The Norwegian Continental Shelf is still an attractive place to be. The resource base is huge, with more than 50 per cent of the estimated recoverable oil and gas still to be produced. Also from an environmental perspective, the NCS is highly competitive, with a low CO2 footprint per produced unit compared to the global average. We firmly believe that oil and gas will play a significant role in the global energy mix for many decades to come.

Going forward, we will continue our strategic focus on execution, improvement and growth as we have done over the past years. No strategy is better than the actions of an organization. We have worked with the entire Aker BP team to operationalize our strategy with clear goals and priorities to better drive performance management in the organization.

We had efficient operations with high operational uptime in 2017. The production from our assets was 160 mboepd, including the production from Hess. During the year, Aker BP increased its reserves (2P) by a net of 202 million barrels of oil equivalents (mmboe), to a total of 914 mmboe.

High HSE standards are the foundation for all our activities. Our operations should not cause any harm or injuries to personnel, the environment including climate and all assets. We failed to achieve our HSE objective in 2017. On 7 December 2017, one of our colleagues at Maersk Drilling passed away and another was seriously injured in an accident on the rig Maersk Interceptor on the Tambar field. The accident happened during maintenance work on the rig. We have cooperated closely with our alliance partner Maersk Drilling in this difficult situation. The measures we implement in the aftermath of this tragic accident extend far beyond Tambar and the Maersk Interceptor rig. I can ensure you that we will learn from this and use it to strengthen our HSE work going forward.

We concluded 2017 with the submission of three Plans for Development and Operation to the Norwegian Ministry of Petroleum and Energy. This demonstrates Aker BP's strong commitment to the NCS as well as to the Norwegian society at large. These investments are aiming to increase the value creation from existing core areas, and make up a vital part of our growth strategy. The planned Valhall Flank West, Ærfugl and Skogul developments will substantially strengthen Aker BP's reserves and production from our operated field centres at Valhall, Skarv and Alvheim.

These three field developments are being carried out through Aker BP's alliance model. In 2017, Aker BP entered into several long-term alliance agreements with key suppliers. The goal is to plan and execute field developments, drilling and well operations, and modifications in a safe and effective manner. Through the alliances, Aker BP and suppliers work in one integrated team with aligned incentives and shared upside and downside risk. We believe that the alliance execution model enables increased value creation and competitiveness for Aker BP, and thus gives us capacity to realize projects and resources that previously were off-limits.

The Volund infill wells to Alvheim was the first project completed using the subsea alliance. By delivering 30 per cent below target, it demonstrated the great improvement potential made possible through alliances. Aker BP is running a comprehensive improvement program to maximize flow efficiency and remove waste. The alliance model, together with a value chain based on LEAN, a flexible business model and digitalization are strategic pillars of this program.

Digitalization opens the door for massive improvements. A major strategic milestone for Aker BP was the establishment of a data platform in cooperation with Cognite. The strategy is to develop a world-class horizontal industrial data platform, making the vast amount of data a strategic asset in the industry's own terms. We are working in our business units and assets to develop use cases and to progress key digital initiatives. In order to fully exploit all the possibilities from digitalization, we must dare to share our progress and successes with the rest of the industry. This can further accelerate improvements.

Aker BP delivered significant growth in 2017, while simultaneously chasing cost per barrel produced. At the start of 2018, the company has a strong cash flow outlook and a robust balance sheet with a USD 2.9 billion liquidity reserve. This enables the company to increase dividends for 2018 to USD 450 million, thus fulfilling our overarching goal of maximizing value for our shareholders.

Aker BP has created a great platform for further growth. We pursue organic growth opportunities through a promising exploration portfolio, which ensures long-term reserve replacement and value creation from south to north on the NCS. In 2018, we will increase the exploration activity and are preparing for an exploration campaign of 12 wells. In 2017 we acquired Hess Norge, strengthening both our production and resource base. Aker BP has a proven M&A track record and we are targeting further selective inorganic growth.

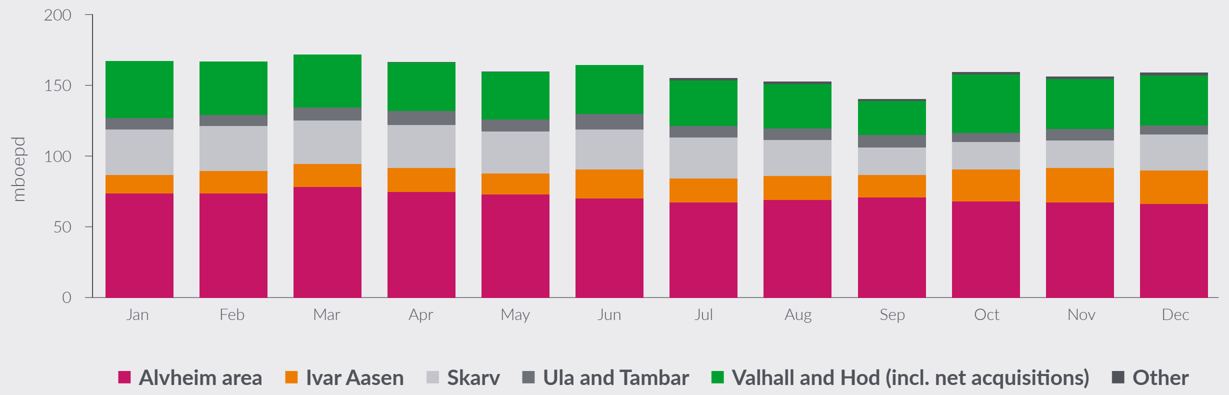
In 2018, Aker BP stands on an extremely solid foundation. During the last three years, we have built a company that delivered beyond all expectations. This is due to a series of smart and strategic transactions, good operational discipline, great execution capabilities, an impressive improvement agenda, and lastly, an organization whose willingness and capability to change is almost unbelievable!

We will continue with full force – as one team – towards becoming the leading independent offshore E&P company. I feel privileged to lead the Aker BP team!

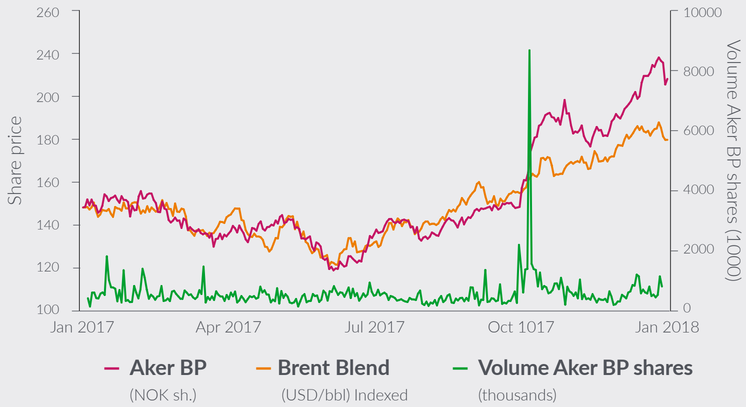
CEO Karl Johnny Hersvik

KEY NUMBERS 2017

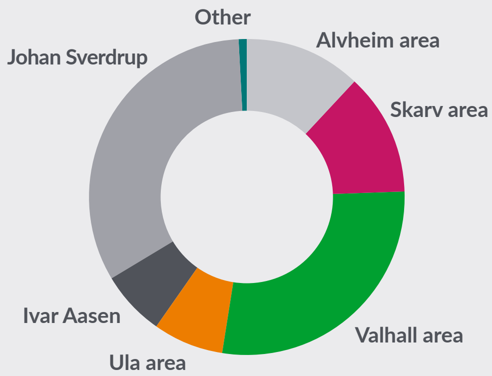
Production per month



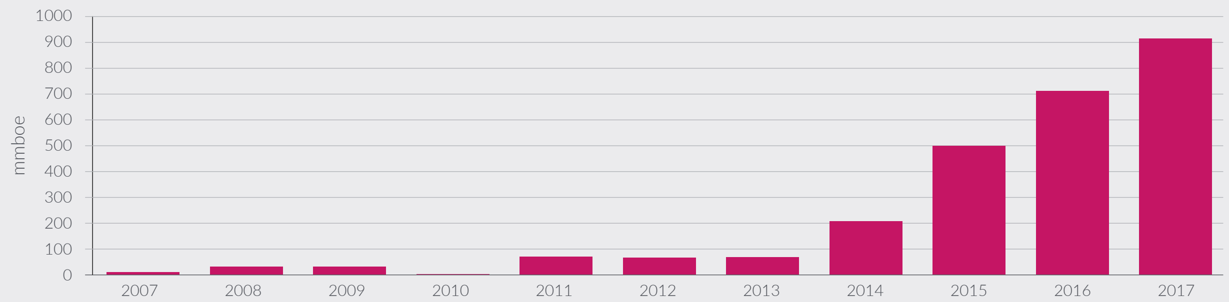
Share price



End 2017 P50 reserves



P50 reserves development



KEY NUMBERS 2017

Key numbers	Unit	Q1-17	Q2-17	Q3-17	Q4-17	2017	2016
SUMMARY OF FINANCIAL RESULTS							
Operating revenues	USDm	646	595	596	726	2 563	1 364
EBITDA	USDm	487	395	395	509	1 786	968
Net result	USDm	69	60	112	34	275	35
Earnings per share	USD	0,20	0,18	0,33	0,10	0,81	0,15
Production cost per barrel	USD/boe	9	9	11	12	10	8
Depreciation per barrel	USD/boe	14	14	14	15	14	18
Cash flow from operations	USDm	438	447	730	543	2 155	896
Cash flow from investments	USDm	- 270	- 312	- 285	- 2 192	- 3 059	- 705
Total assets	USDm	9 337	9 331	9 116	12 019	12 019	9 255
Net interest-bearing debt	USDm	2 330	2 302	1 941	3 156	3 156	2 425
Cash and cash equivalents	USDm	183	66	81	233	233	115
SUMMARY OF OPERATIONAL PERFORMANCE							
Alvheim (65%)	boepd	64 383	61 788	47 259	42 281	53 849	43 290
Bøyla (65%)	boepd	4 545	4 935	4 276	3 680	4 357	7 411
Gina Krog (3.3%)	boepd	-	-	1 453	1 712	798	-
Hod (37.5%)	boepd	568	580	500	472	530	150
Ivar Aasen (34.8%)	boepd	15 003	17 257	16 574	23 489	18 100	211
Skarv (23.8%)	boepd	31 608	29 326	24 518	21 403	26 680	7 551
Tambar/Tambar East (55%/46.2%)	boepd	2 059	2 621	2 145	949	1 941	520
Ula (80%)	boepd	6 183	7 232	6 468	5 982	6 466	1 271
Valhall (36.0%)	boepd	14 796	13 080	11 132	14 449	13 357	4 400
Vilje (46.9%)	boepd	5 604	5 795	5 063	4 767	5 304	6 599
Volund (65%)	boepd	526	4	12 316	16 292	7 342	5 027
Other (Atla, Enoch)	boepd	65	95	175	78	103	1 010
SUM	boepd	**145 338**	**142 713**	**131 880**	**135 554**	**138 825**	**77 441**
SUM (incl. net acquisitions)	boepd	**168 375**	**163 188**	**149 313**	**157 935**	**159 646**	**118 201**
Oil price	USD/bbl	54	51	55	65	56	47
Gas price	USD/scm	0,21	0,18	0,20	0,26	0,21	0,18

VISION: Creating the leading independent offshore E&P company

No strategy is better than the actions in an organisation

The strategy must be reflected in the targets we set and the results we deliver.

Aker BP should be leading on cost

Because: We do not control oil and gas prices. The competitive situation in Norway is getting tougher. Digitalisation is changing our industry.

Great savings possible – requires new way of thinking

Strategic alliances

Digitalisation

Lean operations

Flexible business model

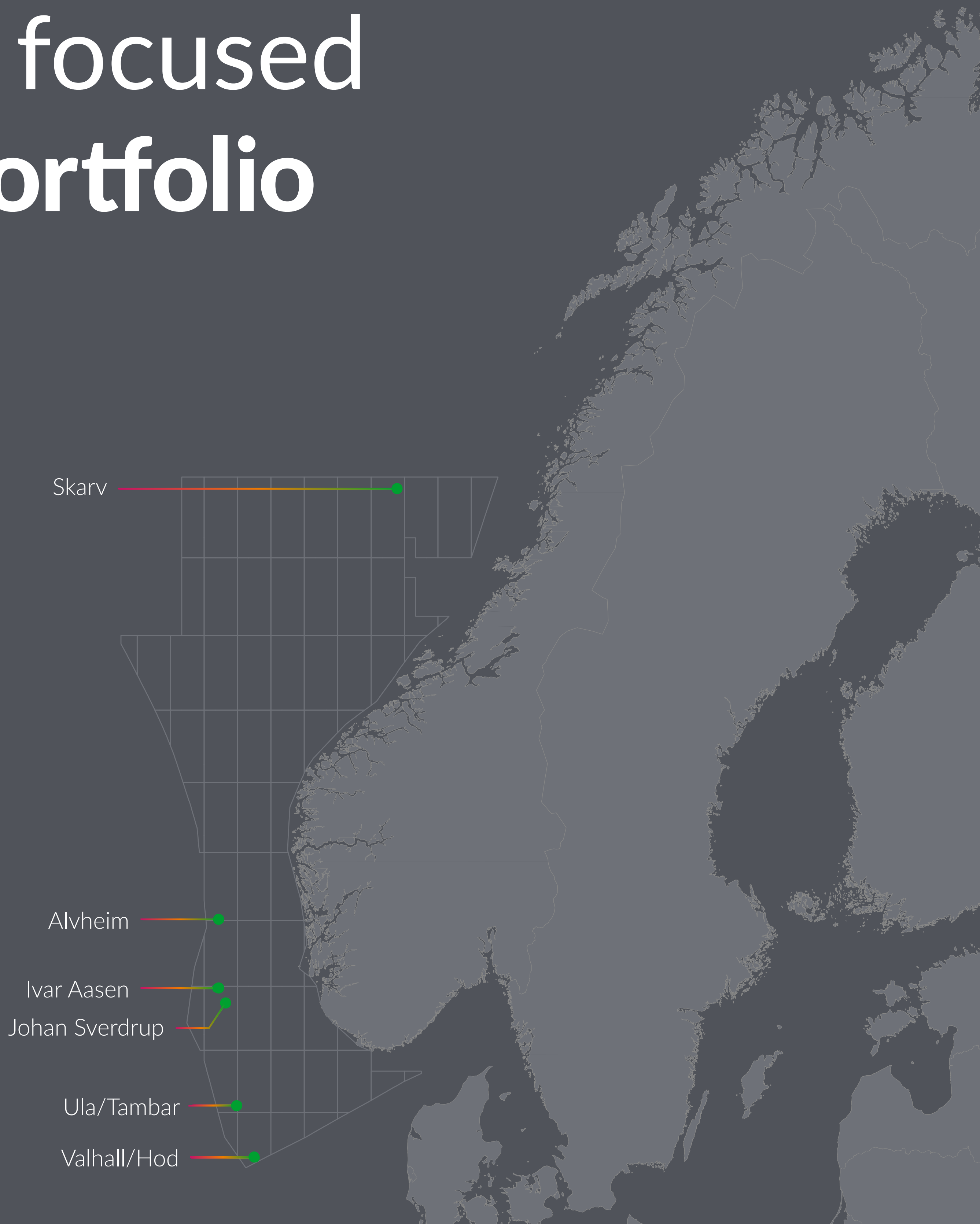
Target production cost below 7 USD/boe

Target full cycle break-even below 35 USD/bbl

Our values

S	A	F	E	R
Søkende	**Ansvarlig**	**Forutsigbar**	**Engasjert**	**Respektfull**
Enquiring	Responsible	Predictable	Committed	Respectful

A focused **portfolio**



THE VALHALL AREA

Key figures for Valhall and Hod 2017[1]

Production 2017: 34.7 mboepd (net)

End 2017 2P reserves (net): 257 mmboe

Production efficiency: 86 per cent

Seismic surveys: Ocean bottom seismic acquired May

1) pro forma, reflecting 90 per cent working interest

2017 was a year of very high activity in the Valhall area. In December, Aker BP submitted the Plan for Development and Operation (PDO) for Valhall Flank West, demonstrating the plan to proactively target upside potential in the area.

On 5 January 2017, Aker BP announced that Valhall and Hod passed one billion produced barrels of oil equivalents. This is more than three times the volume expected at the opening of the field in 1982. Aker BP still sees a great potential for value creation through increased oil recovery and flank developments in the Valhall area. The ambition now is to produce a further one billion barrels.

An essential delivery to realize the ambition is the Valhall Flank West. The project aims to continue the development of the Tor formation in Valhall on the western flank of the field, with start-up of operations in the fourth quarter 2019. Valhall Flank West will be developed from a new Normally Unmanned Installation (NUI), tied back to the Valhall field centre for processing and export. Recoverable reserves are estimated at around 60 million barrels of oil equivalents. Total investments for the development are estimated at NOK 5.5 billion in real terms.

Important to Aker BP's growth strategy was the acquisition of Hess Norge. The Ministry of Petroleum and Energy (MPE) approved the transaction on 22 December. At the same time, the MPE approved an agreement between Aker BP and Pandion Energy AS to divest a 10 per cent interest in the two fields for an undisclosed cash consideration. Aker BP gained a deeper exposure to one of its core areas. The new Valhall joint venture is set to pursue upsides in the area more aggressively going forward.

During 2017, two new wells were put on stream on Valhall. Drilling is carried out from Valhall IP. The rig commenced operations in March, after a two-year-long break following the dramatic fall in the oil price. The goal of the time-out was to optimize well design and work to increase efficiency of the drilling operations. The drilling has gotten off to an excellent start.

The world's largest jack-up rig Maersk Invincible arrived at the Valhall field in May. During the next years, the rig will permanently plug 18 wells from the Valhall DP platform. Maersk Invincible is supplied with electricity through the Valhall field. This is probably the first time a drilling rig has ever been powered fully from shore. Electrifying the drilling rig significantly cuts local CO2 and NOx emissions. At the end of 2017, 7 wells were completed. The plugging operations have progressed so well that it opens new opportunities of drilling further infill targets in the area.

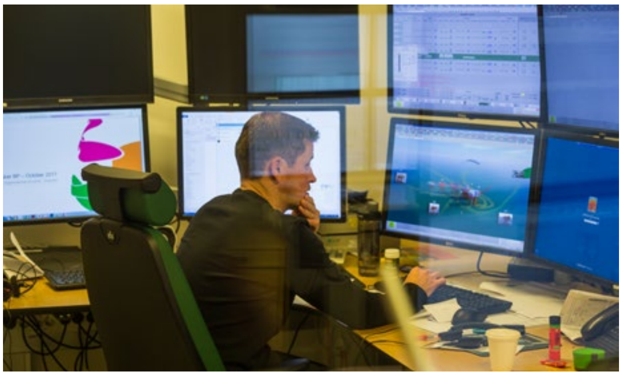
At the end of 2017, Aker BP invested in and acquired a 17 per cent stake in the company Fishbones AS. Fishbones is an unconventional stimulation technology applied to increase the production rates in tight reservoirs. It will initially be applied at the Valhall field, and Aker BP sees a potential for substantial cost savings and increased recovery by using this method.

Future outlook

The activity in the Valhall area will continue at full speed in 2018. A further three wells are set for completion during the year. The plugging of wells continues.

The construction in the Valhall Flank West project starts in the spring of 2018. A project covering the Valhall Flank North platform is also currently being matured. It aims to expand capability for water injection to the northern basin drainage area, thus securing the Valhall base production through enabling water injection to existing depleted producers and offering a potential for increased reserves recovery from Valhall of 6-8 mmboe gross. Opportunities for Flank South infill wells have also been identified.

Re-development of the Hod field has passed decision gate one. The project is looking into new wells, which will be tied in to the Valhall field centre. The concept will continue to mature in 2018 and a Hod appraisal well decision will be made.



Key facts for Valhall and Hod

Licence: PL006B, PL033, PL033B

Aker BP working interest: 90% (Valhall) 90% (Hod)

Partners: Pandion Energy AS (10% Valhall and 10% Hod)

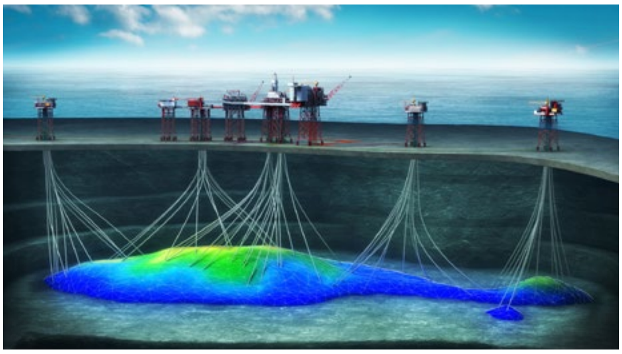
Discovered: Valhall 1975, Hod 1974

Production start: Valhall 1982, Hod 1990

The Valhall field centre consists of six separate steel platforms for living quarters, drilling, production, water injection, and a combined process and hotel platform. Two unmanned and remotely operated flank platforms (North and South) are located about 6 km north and south of the field centre.

The Hod field is developed with an unmanned wellhead platform, located 13 km south of Valhall, and is remotely operated from the Valhall field centre. All wells on the Hod platform are currently shut-in and awaiting plugging and abandonment. The Hod reservoir is now being produced from wells drilled from the Valhall South Flank platform.

Licence period: Valhall 2028, Hod 2021



THE ULA AREA

Key figures Ula, Tambar and Oda 2017

Production 2017:
8.4 mboepd (net)

End 2017 2P reserves (net): 66 mmboe

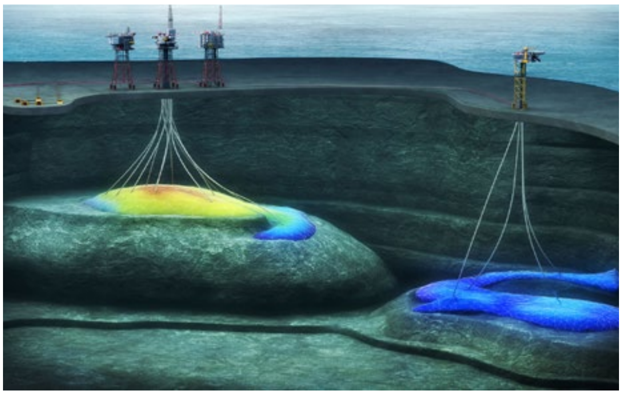
Production efficiency:
75 per cent

In the spring of 2017, the decision was made to give Ula's satellite field Tambar extended lifetime with two new wells and gas lift. Less than a year later the first well came into production. The Tambar re-development is just one of several initiatives to realize further value in the greater Ula area.

Maersk Interceptor spudded the Tambar South Infill well on 21 October. At the end of 2017, the drilling of a second new well at the Tambar field was progressing ahead of plan. The wells are part of the re-development project targeting gross reserves of 27 million barrels of oil equivalents.

The Tambar re-development is a robust project with a break-even price under USD 20 per barrel. It will extend the economic lifetime of the field until 2028 with a potential upside. The Tambar licence has already applied for a licence extension until 2028. With gross investments of around NOK 1.7 billion, the expectation is that the project will deliver gross 4-6000 new barrels a day over several years. The project also includes modifications at the Tambar platform and Ula that started in 2017.

Offshore modifications at the Ula facilities also started for the Oda tie-in project in 2017. Spirit Energy is the operator and is developing the Oda field with a subsea template, which will be tied back to Ula via the existing Oselvar infrastructure. The project involves two production wells and one water injector. Aker BP will perform the required facility modifications at the Ula platform.



First oil from Oda is expected in 2019. The Tambar and Oda development projects will deliver further import gas to Ula that will enable increased WAG oil production through new WAG wells at Ula. Aker BP's ambition is to drive down the high unit cost at Ula through further production growth and operational improvements.

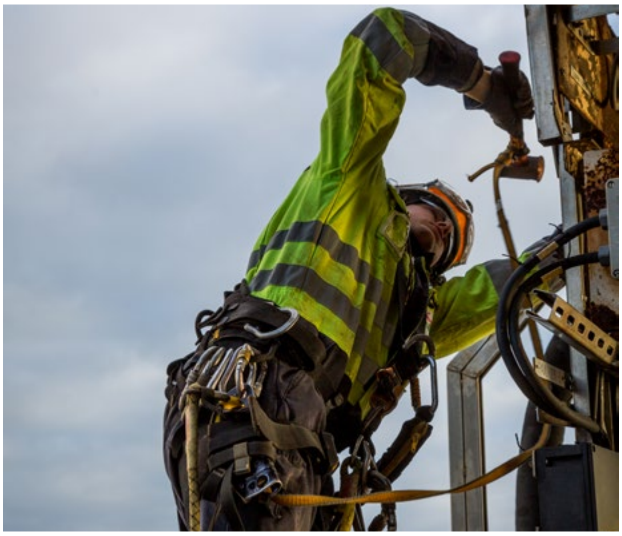
The activity has been high in the Ula area in 2017 and several modifications and upgrades will be ongoing throughout 2018 and beyond. Most lifeboats on the Ula field centre were replaced in 2017. The upgrade of the fire and gas system on Ula Q started in 2017, and the engineering and planning of a full replacement of the Ula power turbines also started during the year.

Future outlook

Aker BP believes there is a great remaining potential in the Ula area of interest. In the short-term, 2018 production will increase due to the new wells at Tambar. The first well started production at the beginning of March 2018. The second is expected to follow in Q2 2018. For the mid-to-longer term, the Ula licence has initiated studies to improve drilling efficiency at Ula, and Aker BP is currently maturing several infill well targets.

Aker BP will also initiate studies to investigate the opportunity for further technical lifetime extension of the Ula facilities until 2040 and beyond.

Finally, further development of Ula North and Ula Triassic will be considered. Aker BP also expects that the acreage awarded through the APA 2017 licensing round in the Ula area of interest will create future development opportunities which could benefit the Ula hub.



Key facts for Ula, Tambar and Oda

Licence: PL019 (Ula), PL065 (Tambar), PL300 (Tambar East), Tambar East Unit, PL405 (Oda)

Aker BP working interest: 80% (Ula), 55% (Tambar), 46.2% (Tambar East Unit), 15% (Oda)

Partners: Faroe (Ula and Tambar) Faroe, Repsol, INEOS, KUFPEC (Tambar East Unit), Spirit Energy, Suncore Energy and Faroe (Oda - with Spirit Energy as operator)

Discovered: Ula 1976, Tambar 1982, Tambar East 2007, Oda 2011

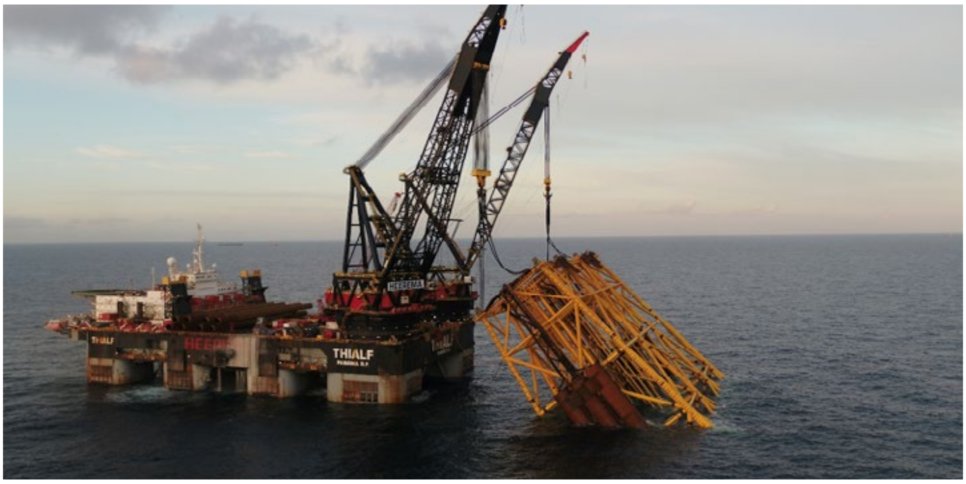
The Ula field is located in the southern part of the North Sea, and consists of three platforms. The field centre serves as an area hub for the satellite field Tambar. Tambar and Tambar East are tied back to the Ula facilities, together with the Repsol-operated Blane field and the Faroe-operated Oselvar field.

The Spirit-Energy-operated Oda field is developed with a subsea template, which will be tied back to Ula via the existing Oselvar infrastructure. The project involves two production wells and one water injector.

Production start: Ula 1986, Tambar 2001, Tambar East 2007, Oda expected in 2019

Licence period: Ula 2028, Tambar 2021, Tambar East 2021, Oda 2036

JOHAN SVERDRUP



Key figures
Johan Sverdrup 2017

End 2017 2P reserves (net): 300 mmboe

Construction completion: Approximately 80 per cent

Production start target: Q4 2019

In 2017, the first visible structure came in place on the Johan Sverdrup field. The 26,000-tonne jacket for the riser platform was launched and upended in a major offshore operation. Phase 1 of the giant development is progressing according to plan – targeting first oil in the fourth quarter of 2019.

At the end of the year, approximately 80 per cent of the Phase 1 facilities construction had been completed.

Phase 1 consists of a field centre with four fixed platforms, three subsea templates, oil and gas export pipelines, power from shore and 36 production and injection wells. Through 2017, engineering and construction was underway at more than 20 sites internationally.

Year of construction and pre-drilling

The first of four steel jackets was delivered by Kværner and installed offshore in July 2017. In September, three large modules constructed by Aibel in Thailand and Norway were lifted and integrated on a giant barge inshore in Klosterfjorden south of Stord. The drilling platform was then moved to Haugesund for final onshore hook-up and commissioning. The plan is to pick up the "drilling ready" topside using the heavy lift Allseas ship Pioneering Spirit and conduct a single lift installation offshore in the summer of 2018.

A four-well pilot and appraisal campaign for further improvement of reservoir definition was completed in February. Pre-drilling of eight production wells has successfully been completed. Nine water injectors are pre-drilled and completed.

Full field development

In March 2017, concept selection for Phase 2 was approved according to plan. Phase 2 includes 28 new production and injection wells in the peripheral parts of the Johan Sverdrup oil field. It increases the total number of wells from 36 to 64. Phase 2 also includes increased production capacity on a fifth platform, and increases the power from shore capacity that will also supply the surrounding fields Ivar Aasen, Edvard Grieg and Gina Krog with power. The front-end engineering and design (FEED) is nearly complete for the installations.

Future outlook

In 2018, the Johan Sverdrup activity will continue to be high. The pieces of the major puzzle are coming together on the field.

The riser platform modules are ready for transport from South Korea to Norway in February. Installation of three remaining jackets and the riser platform and drilling platform will take place in the period between April and September. Power cable and pipelines are set for installation. At the end of the year, the tieback of pre-drilled wells at the drilling platform will start.

The cost estimate for the Johan Sverdrup development continues on a positive downward trend. Twice during 2017, the operator Statoil reduced the investment cost figures. In February 2018, operator Statoil and the partnership announced a further cost reduction and increase in the value of the Johan Sverdrup field. This comes as a result of continued high quality in project execution, good drilling efficiency and further maturation of the resource base.

Total investments in Phase 1 of the project are currently estimated at NOK 88 billion (capex numbers in nominal terms based on fixed currency), which amounts to a reduction of NOK 35 billion or close to 30 per cent since the Plan for Development and operation (PDO) was approved in August 2015.

Break-even oil price is reduced to below USD 15 per barrel for the first phase of the Johan Sverdrup project.

Since the PDO for the first phase was submitted, the range of the full-field resource estimate has improved from 1.7 – 3.0 to now 2.1 – 3.1 billion barrels of oil equivalents.

Final investment decision and PDO for Phase 2 of Johan Sverdrup are scheduled for the second half of 2018. Production start is expected in 2022. Further maturation has reduced the estimated investment costs for phase 2 to below NOK 45 billion.

With this, the break-even oil price for the full-field development of Johan Sverdrup has been improved to below USD 20 per barrel. Aker BP expects the cost estimates for Johan Sverdrup to decrease even more. This will further strengthen the robustness of the project and increase the value generated by the project for the owners and society.

Facts about Johan Sverdrup

Licence: PL265, PL501, PL502

Aker BP working interest: 11.5733%

Partners: Statoil (operator), Lundin Norway, Petoro and Maersk Oil

Year of discovery: 2010

With expected resources of between 2.1 – 3.1 billion barrels of oil equivalents, it will be one of the most important industrial projects in Norway over the next 50 years. Johan Sverdrup is developed in several phases.

Phase 1 is expected to start up in late 2019 with production capacity estimated at 440,000 barrels of oil per day.

Phase 2 is expected to start up in 2022, with full field production estimated at 660,000 barrels of oil per day. Peak production on Johan Sverdrup will be equivalent to 25% of all Norwegian petroleum production.

IVAR AASEN

Key figures for Ivar Aasen 2017

Production 2017: 18.1 mboepd (net)

End 2017 2P reserves (net): 59 mmboe

Production efficiency: 90.4 per cent

Ivar Aasen can look back at a fantastic first year in production. The field reached a daily production of 60,000 barrels of oil equivalents this autumn – way ahead of schedule.

Minister of Petroleum and Energy Terje Søviknes officially opened the Ivar Aasen field in the North Sea on 13 February 2017. "The development of Ivar Aasen is an important milestone for the oil industry, and represents significant values for the Norwegian society," said Søviknes at the opening ceremony.

During the first 12 months, Ivar Aasen ended up with a net production of 18.1 mboepd. The facilities delivered excellent production performance with high uptime. The operational availability was more than 97 per cent in 2017. The activity has been extremely high. The Ivar Aasen team delivered the activities without any serious HSE incidents.

The production saw a steady ramp-up through the year according to the processing agreement with Edvard Grieg. Water injection started in May. In October, Ivar Aasen reached a new production record of 60,000 barrels of oil equivalents per day. This means that the field reached plateau production one year ahead of schedule.

On August 6, the Maersk Interceptor rig sailed from Ivar Aasen. The last of the 13 wells in the plan for development and operation (PDO) was delivered. The drilling and well operations on Ivar Aasen were delivered twice as quickly as planned and with 500 rig days saved compared with the PDO plan.

Modern technology contributes to maximum efficiency in operation of the Ivar Aasen field. The organisation on board the platform is closely integrated with the onshore organisation via modern communication solutions. An operations centre in Trondheim gives maintenance and engineering support, and expert analysis is based on the same condition monitoring data seen in the offshore control room. The functions monitored include electrical and rotating equipment, valves, process control, automation, instruments, telecom and safety.

Future outlook

The Ivar Aasen team continues to work to reduce costs and improve regularity using digitalisation, new technology and LEAN work processes. The field will serve as a laboratory for operational improvements across the Aker BP portfolio.

The drilling of two water injectors is planned in 2018. Hanz is a possible subsea tie-back to Ivar Aasen and an appraisal well will be drilled in Hanz in 2018. Several area infill drilling opportunities have been identified, and the first campaign is planned for 2019.

The regularity from Ivar Aasen is expected to increase further with power from shore. Ivar Aasen will receive power from shore from the Johan Sverdrup development from 2022. An investment decision will be taken during 2018.

Key facts Ivar Aasen

Licence: PL001B, PL338BS, PL242, PL457B (Ivar Aasen Unit), PL 028B (Hanz)

Aker BP working interest: 34.786% (Ivar Aasen Unit), 35% (Hanz)

Partners: Statoil, Spirit Energy, Wintershall, VNG, Lundin, OKEA (Ivar Aasen Unit), Statoil , Spirit Energy (Hanz)

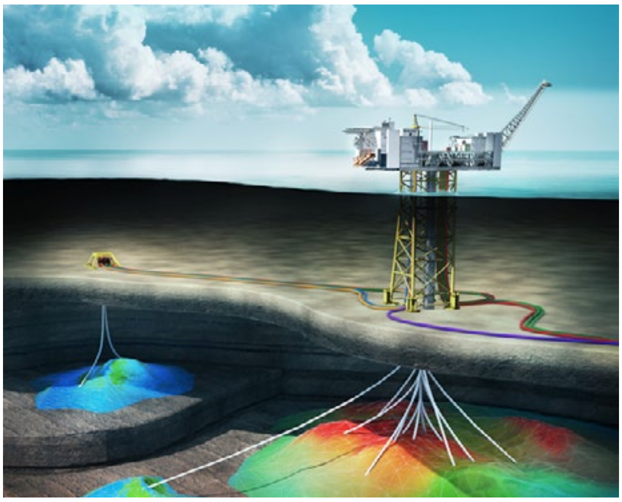
Year of discovery: 2008

Production start: December 2016

The Ivar Aasen field lies in the northern part of the North Sea, approximately 175 km west of Karmøy. The field contains about 200 million barrels of oil equivalents, including Hanz. Hanz will be developed in phase two of the Ivar Aasen development.

The Ivar Aasen field is a coordinated development with the Edvard Grieg field, which is located 10 km further southeast, and the export solutions are coordinated with this field. The gas is exported via the SAGE pipeline to St Fergus in the UK. The oil from the two fields is exported through a new pipeline from the Edvard Grieg field to the Grane oil pipeline, and further on to the Sture terminal. Ivar Aasen receives power from the Edvard Grieg platform.

Licence period: 2036



THE GREATER ALVHEIM AREA

Key figures for greater Alvheim area 2017

Production 2017: 70.9 mboepd (net)

End 2017 2P reserves (net): 111 mmboe

Production efficiency: 97.3 per cent

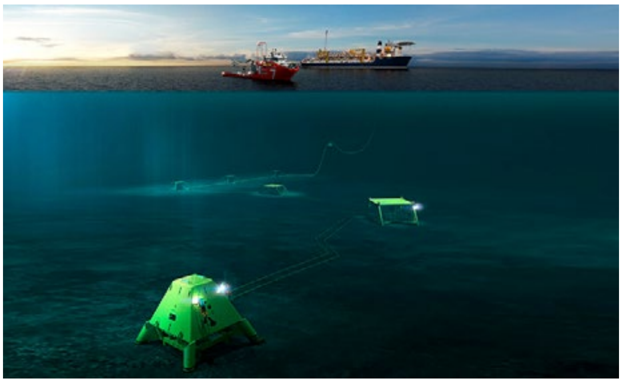
Seismic surveys: A repeat 4D survey was acquired over the entire area in 2017

Alvheim has delivered outstanding results in 2017. A stable and high production throughout the year represents a solid foundation for Aker BP's total value creation.

The production efficiency in 2017 was 97.3 per cent. At the end of the year, the Alvheim FPSO had delivered a net production for Aker BP of 70.9 mboepd. This accounts for 51 per cent of Aker BP's total net production.

The Alvheim production got off to a very good start in 2017. The satellite field Viper Kobra came on stream in November 2016, and excellent well performance as well as a win-win arrangement between the Volund and Alvheim groups contributed to increased production from the Alvheim area.

The Transocean Artic rig drilled and completed the Volund West infill well and Volund South tri-lateral infill well in the first half of the year. The wells, which produce through the Volund infrastructure, came on stream on 8 July and 11 August. The oil production in the Volund pipeline was maximized through optimizing the Volund and Viper Kobra production in the Volund flowline.



Volund Infill was the first project to be completed in the Subsea Alliance between Aker BP, Subsea 7 and Aker Solutions. The tie-in of the new wells was completed in record time – with an estimated accelerated schedule of nine months for the subsea scope. The alliance could also point to a significantly reduced cost compared to a traditional tie-in project, demonstrating the effect of Aker BP's alliance strategy.

The year concluded with Aker BP submitting the Plan for Development and Operation (PDO) for the Skogul field to the Norwegian Ministry of Petroleum and Energy. The Skogul field, formally known as Storklakken, is located 30 kilometres north of Alvheim FPSO. It will be developed as a subsea tieback to Alvheim via Vilje. Recoverable reserves are estimated at around 10 million barrels of oil equivalents and total investments at NOK 1.5 billion in real terms. Production start is planned for the first quarter of 2020.

The production well at Skogul will be subsea production well number 35 in the Alvheim area. It represents Aker BP's continuous effort to maximize value in the area and extend economical field life.

Future outlook

In second half of 2017, Transocean Arctic drilled BOA infill West and South. The Subsea Alliance completed the installation scope and the wells started production to the Alvheim FPSO in February 2018. This will help arrest the production decline on Alvheim.

From July 2018, the Kamelon infill South well will be drilled. This trilateral well, with a combined reservoir length of ten kilometres in lateral sections, is a highly complex well. It will help to drain the remaining oil above existing wells and the flanks in this area of the field.

The Gekko appraisal well is planned for 2018/2019 to de-risk the development of this field in the Alvheim licence and to determine the potential for an oil and/or gas development. Near-infrastructure exploration will take place with the drilling of Frosk which was spudded before the end of 2017. In February 2018, the well proved oil. Preliminary analysis indicates a discovery size of 30-60 million barrels of oil equivalents (mmboe), which is significantly more than the company's pre-drill estimates of 3-21 mmboe. Rumpetroll and Deep Alvheim will follow in the years to come. Further ILX exploration prospects are also being matured.

More infill wells are being matured to optimize the recovery from each substructure and to arrest the production decline and minimize the unit production cost. A repeat of the 4D seismic survey was shot in 2017 and will be used to de-risk and identify some of these infill opportunities. In addition to the Skogul development, the discoveries Gekko/Kobra East and Caterpillar are being matured, targeting production start in 2021.

Key Facts greater Alvheim area

Licence: PL203, PL088BS, PL036C, PL036D, PL150, PL340, PL460

Aker BP working interests: 65% (Alvheim), 65% (Bøyla), 46.9% (Vilje), 65% (Volund), 65% (Skogul)

Partners: ConocoPhillips (PL203 PL088BS and PL036C), Lundin (PL203 PL088BS, PL036C, PL150 and PL340), Point (PL340), Statoil, (PL036D), PGNiG (PL036D and PL460), Verus (Boa Unit)

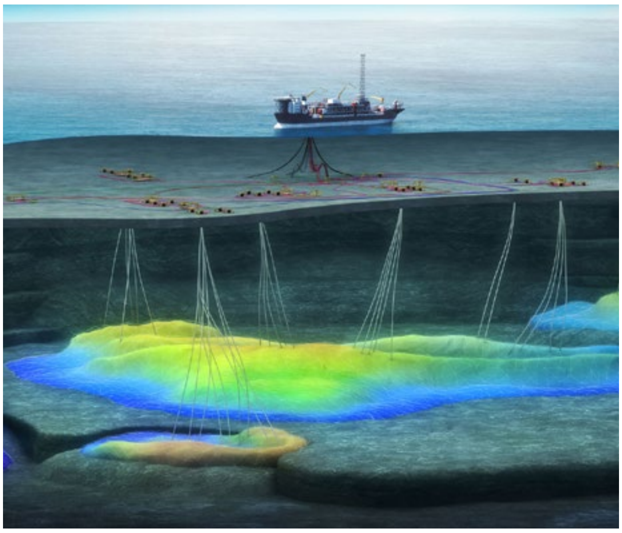
Discovered: 1998

Production start: 2008

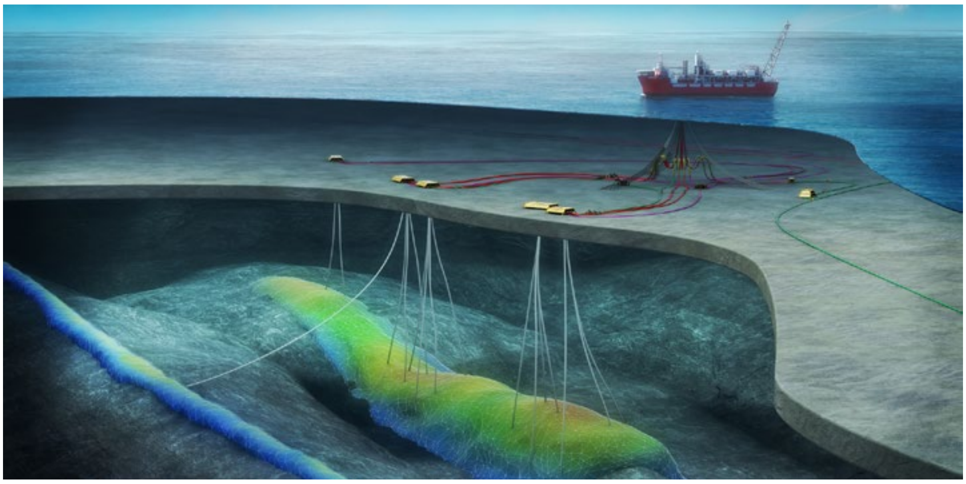
The greater Alvheim area is located in the central part of the North Sea, close to the UK sector. It consists of the main field Alvheim, and the satellite fields Bøyla, Vilje and Volund. The volumes are produced via the Alvheim FPSO.

The main field Alvheim (PL088BS, PL203, PL036C) consists of the Kneler, Boa, Kameleon, East Kameleon, Viper-Kobra structures and the Kobra East and Gekko discoveries. Viper-Kobra came on stream during Q4, 2016. Bøyla (PL340), Vilje (PL036C) and Volund (PL150) are satellites which are smaller discoveries and tied into the Alvheim FPSO. Skogul (PL460) is currently under development and will be tied-back to Alvheim via Vilje in 2020

Licence period: 2032 (PL203)



THE SKARV AREA



Key figures for Skarv 2017

Production 2017: 26.7 mboepd (net)

End 2017 2P reserves (net): 114 mmboe

Production efficiency: 93 per cent

Seismic surveys: Shot over Ærfugl and Skarv in the summer of 2017

2017 concluded with the submission of the Ærfugl Plan for Development and Operation (PDO). The development, formerly known as Snadd, adds significant new resources and extends the economic life of the Skarv FPSO, again allowing for increased recovery from the Skarv field itself.

Ærfugl is a unique gas condensate field, nearly 60 km long and just 2-3 km wide, situated close to the Skarv FPSO. The PDO covers the full-field development and includes the resources in both the Ærfugl and Snadd Outer fields, which are planned for development in two phases. The first phase includes three new production wells in the southern part of the field tied into the Skarv FPSO via a trace heated pipe-in-pipe flowline, in addition to the existing A-1 H well. Production start is planned in late 2020.

Ærfugl will be organised and executed as a part of Aker BP's alliance model. It is a highly attractive and robust development with a break-even price of 18.5 USD/boe for the full-field development. The total remaining reserves for the full-field development are estimated at approximately 275 million barrels of oil equivalents. Total investments in the Ærfugl project are estimated at NOK 8.5 billion (real terms) with NOK 4.5 billion in the first phase.

Stable and high production

During 2017, the Skarv area, including the Skarv producing field and the production from the Ærfugl test producer, delivered high and stable production. Facility performance has been exemplary.

At the beginning of the year, a successful intervention on well A04 brought it back from a hydraulic leakage. This contributed to the good production rate in the first quarter. In mid-2017, two wells at Skarv were shut in due to technical issues in addition to the A03 producer, which has been shut in since 2015. However, ample capacity from the other wells softened the negative impact of the shut-ins.

During the autumn, well intervention work was carried out from the rig Songa Enabler. Good cooperation between key stakeholders and quick decisions made the rig period possible at Skarv. It took just three months from the well B-08 was shut in until workover started. In December, well B-08 came on stream again.

A successful shutdown to test the emergency shutdown valves was carried out in the autumn. The process system was converted to use MEG instead of methanol. This ensures faster ramp-up time after shutdowns in the future. The integrity of pipelines was successfully tested in pigging campaigns during the year.

Future outlook

In January 2018, Aker BP won two new licences in the Skarv area in the predefined defined areas round. This opens up for future possible tie-ins to the Skarv FPSO. The next few years will see a step-up in exploration activity to appraise attractive area resource potential and utilize significant spare oil capacity. The drilling of KvitungenTumler, an attractive cretaceous target, starts in the first quarter of 2018. Follow-on exploration drilling is expected in 2019.

The maturing of near-field and infill drilling opportunities to increase oil production and optimize production continues. 4D seismic shot in the summer of 2017 is being processed. Reservoir work is ongoing on the Gråsel discovery. Completion techniques to increase recovery in the low-permeability. Tilje formation are also being assessed.

The work to re-instate production from two shut-in wells continues. Well intervention on B06 picks up in the first quarter of 2018 with the rig DeepSea Stavanger.

An improvement program targeting Skarv FPSO production cost is ongoing. It aims for a target of less than 7USD/boe when Ærfugl reaches plateau production.

In the Ærfugl development, construction to the subsea umbilical riser flowline and the subsea production system will start in 2018. Some modifications must be carried out to the Skarv FPSO in connection with Ærfugl. Engineering started in the end of 2017, and offshore work is set for start-up in January 2019.

The second phase of Ærfugl is subject to further maturation. The reference case includes two additional wells in the northern part of the field and one in Snadd Outer tied into the Skarv FPSO. Estimated production start is late 2023.

Key facts for Skarv

Licence Skarv Unit: PL159, PL212, PL212B and PL262

Aker BP working interest: 23.84%

Partners: Statoil, DEA, PGNiG

Discovered: 1998

The Skarv field is located in the northern part of the Norwegian Sea, and is Aker BP's northernmost producing field. The field is developed with a production ship with storage and offloading capacity (FPSO), and has one of the world's largest gas processing plants offshore. Subsea wells are tied back to the FPSO from subsea templates.

Ærfugl is part of Skarv Unit. Snadd Outer, to be developed as part of phase 2 of the Ærfugl development, is in licence PL212E. The partners in this licence are the same as the Skarv Unit, but with different interests.

Production start: December 2012

Licence period: 2033

BOARD OF DIRECTORS

CHAIRMAN

ØYVIND ERIKSEN

Øyvind Eriksen (born 1964) is President and CEO of Aker ASA and holds a law degree from the University of Oslo.

He joined the law firm BA-HR in 1990, where he became a partner in 1996 and director/chairman from 2003. Mr. Eriksen is chairman of Aker Solutions ASA and Aker Kværner Holding AS, and director of several companies, including The Resource Group TRG AS, TRG Holding AS and Reitangruppen AS. Mr. Eriksen is a Norwegian citizen.

DEPUTY CHAIR

ANNE MARIE CANNON

Anne Marie Cannon (born 1957) has over 30 years' experience in the oil and gas sector. From 2000 to 2014, she was Sr. Advisor to the Natural Resources Group with Morgan Stanley, focusing on upstream M&A. She has previously held positions with J Henry Schroder Wagg, Shell UK E&P and with Thomson North Sea.

Ms. Cannnon was an executive director on the boards of Hardy Oil and Gas and British Borneo. She has served on the Board of Directors of Aker ASA. She is a non-executive director of Premier Oil and of STV Group plc. She holds a BSc Honours Degree from Glasgow University. Ms. Cannon is a British citizen.

BOARD MEMBER

KJELL INGE RØKKE

Kjell Inge Røkke (born 1958) is an entrepreneur and industrialist, and has been a driving force in the development of Aker since the 1990s.

Mr. Røkke owns 67.8 per cent of Aker ASA through The Resource Group TRG AS and subsidiaries, which he co-owns with his wife. He is Chairman of Aker ASA and a member on the boards of Aker Solutions ASA, Kværner ASA, Akastor ASA, Aker BP ASA and Ocean Yield ASA. He holds no shares in Aker BP ASA, and has no stock options. Mr. Røkke is a Norwegian citizen.

BOARD MEMBER

BERNARD LOONEY

Bernard Looney is the Upstream Chief Executive for BP plc., where he is responsible for exploration, development and production within the Upstream segment.

Mr. Looney joined BP in 1991 as a Drilling Engineer. He has extensive management experience in the oil and gas business, having worked in a variety of locations, including the North Sea, Vietnam, Gulf of Mexico and Alaska. He was appointed to the role of Chief Executive for BP's Upstream Segment in February 2016, is a member of the BP Group Executive Committee and is also a director of several BP Group companies. Mr. Looney is an Irish citizen.

BOARD MEMBER

KATE THOMSON

Kate Thomson is Group Treasurer for the BP Group, having previously held the position of Group Head of Tax. In her current role, Kate has responsibility for the central financing of the BP Group, providing liquidity to its businesses and optimising value through the management of financial risks at the group level.

Since joining BP in 2004, Thomson has held a variety of roles within the Tax function, giving her a deep understanding of the oil and gas industry. As Group Head of Tax, Thomson led a global team of tax professionals, developing BP's response to an increasingly challenging fiscal and regulatory environment. Prior to joining BP, Thomson qualified as a chartered accountant with Deloitte. She moved into international tax with Charter plc where she became Head of Tax in 1998, before joining EY in 2001 in M&A tax. Thomson is also a director of several BP Group companies. Thomson is a British citizen.

BOARD MEMBER

TROND BRANDSRUD

Trond Brandsrud (born 1958) is CFO in Lindorff, and holds a master's degree from the Norwegian School of Economics.

Until 2015, Mr. Brandsrud was CFO of Aker ASA, he has been CFO in Seadrill, and he has held several leading financial positions in Shell, both in Norway and globally. Mr. Brandsrud has experience as director of several privately-held and listed companies. He is a Norwegian citizen.

BOARD OF DIRECTORS

BOARD MEMBER

GRO KIELLAND

Gro Kielland (born 1959) holds an MSc in Mechanical Engineering from the Norwegian University of Science and Technology (NTNU). Ms. Kielland has held a number of leading positions in the oil and gas industry both in Norway and abroad, among others as CEO of BP Norway. Her professional experience includes work related to both operations and field development, as well as HSE.

Ms. Kielland currently serves as an Operational Partner with HitecVision. In addition to her duties and responsibilities at the non-executive level for HitecVision, she also serves as a non-executive Chairman and Director for several other companies. Ms Kielland is a Norwegian citizen.

BOARD MEMBER

TERJE SOLHEIM

Terje Solheim (born 1962) is General Manager of Aker BP's Harstad office. He has been with Aker BP since 2013 and has held several positions.

Solheim has an extensive background from the Norwegian Armed Forces, and was one of the founders of Norwegian Petro Services (NPS). He came to Det norske from Det Norske Veritas (DNV). Mr. Solheim is a Norwegian citizen.

BOARD MEMBER

LONE OLSTAD

Lone Olstad (born 1977) is alliance Project Manager in subsea projects. She has been with Aker BP since 2006.

Ms. Olstad has broad experience within the oil industry and in positions including reservoir engineer, production engineer, project engineer in operation, project manager for performance improvement project completed in 2012, and project services manager in subsea projects. Olstad has participated in 'Female Future' where board competency was part of the program. Olstad has an MSc from NTNU (2001) and is a Norwegian citizen.

BOARD MEMBER

BJØRN THORE RIBESEN

Bjørn Thore Ribesen (born 1970) is Offshore Installation Manager on Ivar Aasen. He has been with Aker BP since 2007. Mr. Ribesen has held several positions in the drilling department, including Drilling and Well Manager for exploration drilling and Ivar Aasen.

Mr. Ribesen graduated with a BEng Honours Degree from University of Newcastle upon Tyne (1996). Before he joined Aker BP he was in Schlumberger (1996-2007), where he held a variety of positions. Ribesen is a Norwegian citizen.

BOARD MEMBER

ØRJAN HOLSTAD

Ørjan Holstad (born 1989) is trained as an Instrument Technician and has been an employee of BP Norge AS, now Aker BP, since 2010. Has been a fulltime employee representative since 2014.

EXECUTIVE MANAGEMENT TEAM

CHIEF EXECUTIVE OFFICER

KARL JOHNNY HERSVIK

Karl Johnny Hersvik (born 1972) has been CEO of Aker BP since May 2014. Prior to joining Aker BP, he served as head of research for Statoil. Mr. Hersvik has held a number of specialist and executive positions with Norsk Hydro and StatoilHydro. He holds a number of directorships whose objective is to promote cooperation between industry and academia.

Mr. Hersvik holds a Cand. Scient. (second cycle) degree in Industrial Mathematics from the University of Bergen.

CHIEF FINANCIAL OFFICER

ALEXANDER KRANE

Alexander Krane (born 1976) took up the position of CFO with Aker BP in 2012. Prior to joining Aker BP, he held the position of Corporate Controller with Aker ASA. He has also worked as a public accountant with KPMG, both in Norway and in the US.

Mr. Krane holds a Bachelor of Commerce degree ("siviløkonom") from Bodø Graduate School of Business and an MBA degree from the Norwegian School of Economics in Bergen. He is also a state-authorized public accountant in Norway.

SPECIAL ADVISOR

ØYVIND BRATSBERG

Øyvind Bratsberg (born 1959) joined Aker BP in 2008 as Chief Operating Officer. He has 30 years' experience from several companies in the areas of marketing, business development and operations. Before taking up his position with Det norske (Aker BP), he was responsible for early-phase field development on the Norwegian Continental Shelf for StatoilHydro.

Mr. Bratsberg holds an MSc degree in Mechanical Engineering from NTH, now the Norwegian University of Science and Technology, NTNU.

SVP EXPLORATION

GRO GUNLEIKSRUD HAATVEDT

Gro Gunleiksrud Haatvedt (born 1957) joined Aker BP in 2014. She came from the position of SVP Exploration for the Norwegian Continental Shelf with Statoil ASA, where she also served as country manager in Libya.

She has held several positions with Norsk Hydro (head of Geology, Technology and Competence). She has been responsible for business development and exploration in Iran, and VP Exploration for NCS.

Ms. Haatvedt holds a Cand. Scient degree in Applied Geophysics from the University of Oslo.

SVP PROJECTS

OLAV HENRIKSEN

Olav Henriksen (born 1956) joined Aker BP in January 2015. Prior to joining Aker BP, Mr. Henriksen has been working with large development projects in ConocoPhillips since 1990. He has extensive work experience from both Kværner Installasjon and ConocoPhillips, including work with large projects such as Ekofisk, Statfjord, Gullfaks, Oseberg and Eldfisk.

Mr. Henriksen has a degree in engineering from Møre og Romsdal Ingeniørhøyskole (the Møre and Romsdal college of engineering).

SVP IMPROVEMENT

PER HARALD KONGELF

Per Harald Kongelf (born 1959) is responsible for Aker BP's improvement program. Prior to joining Aker BP, Per Harald Kongelf served as head of the Norwegian operations in Aker Solutions.

Mr. Kongelf holds an MSc degree from NTNU in Trondheim and has more than 25 years of industrial experience through numerous technical and management positions in Aker Solutions.

EXECUTIVE MANAGEMENT TEAM

SVP HSE

JORUNN KVÅLE

Jorunn Kvaale (born 1963) comes from the position of Engineering Services Manager, BP Norge. She has extensive experience in the oil and gas industry, including from Amoco and as OIM for BP Norway.

Ms. Kvaale is an engineer in Telecommunications and holds a master's degree from BI.

SVP OPERATIONS

ELDAR LARSEN

Eldar Larsen (born 1960) comes from the position of SVP Operations, BP Norge. He has extensive experience from large industrial operations on fields such as Gullfaks, Sleipner, Snorre, Ormen Lange, Ula, Valhall and Skarv.

Mr. Larsen holds a master's degree in chemical industry from NTNU in Trondheim.

SVP RESERVOIR

OLE JOHAN MOLVIG

Ole Johan Molvig (born 1972) comes from the position of VP Subsurface, Det norske. He has long experience in the oil and gas industry, mainly from ExxonMobil, Statoil and Marathon Oil.

Mr. Molvig holds a master's degree from NTNU in Trondheim.

SVP DRILLING AND WELL

TOMMY SIGMUNDSTAD

Tommy Sigmundstad (born 1971) comes from the position of Vice President Wells BP Asia Pacific. Sigmundstad has broad experience within the oil and gas industry from companies such as Baker Hughes and Philips, before joining BP in 2000. Within BP, Sigmundstad has held different operational, engineering and management positions in Norway, the United Kingdom, Azerbaijan and Indonesia.

Mr. Sigmundstad holds a master's degree in petroleum engineering from Stavanger University.

Board of Directors´ **Report**

BOARD OF DIRECTORS' REPORT

2017 was another year of progress for Aker BP. The financial and operational performance was strong, and the oil and gas reserves increased significantly driven by both organic growth and acquisitions. Moreover, the company's improvement program is showing tangible results. In sum, Aker BP is well positioned to deliver profitable growth and increasing shareholder value in the future.

Aker BP carries out significant operations related to exploration and production of oil and gas on the Norwegian Continental Shelf ("NCS"). In addition, the company's development projects involve workers from a wide range of contractors. Health, Safety, Security and Environment ("HSSE") and Corporate Social Responsibility ("CSR") are of paramount importance to the Board of Directors of Aker BP. Accordingly, the Board recognizes its responsibility to the safety of people and the environment, and is devoted to spending time and resources to meet all regulations and adhere to the highest HSSE standards in the oil industry.

In 2017, one person from a contractor lost his life in a tragic accident in one of Aker BP's operations. Aker BP is following up the causes of this accident to ensure that the learnings are implemented and shared with the industry, to prevent similar accidents in the future.

To meet the challenges of an uncertain macro environment and to strengthen its long-term competitiveness, Aker BP has established a strong platform for further value creation. The company leverages an effective business model built on lean principles, strong technological competence and industrial cooperation to ensure safe and efficient operations.

Aker BP has a comprehensive improvement agenda with four focus areas. The aim is to reduce cost and improve efficiency across all disciplines to enable sanctioning of new stand-alone projects at break-even prices below 35 USD/boe. The focus areas include 1) reorganization of the value chain with strategic partnerships and alliances to remove waste and increase productivity, 2) digitalization of the Exploration & Production ("E&P") business model, 3) changing the management systems and culture to build on "Lean" by prioritizing flow efficiency over resource efficiency and 4) to bring these together inside one organization and one business model that balances volatility and flexibility to sustain growth.

In 2017 the company acquired Hess Norge AS, which was the only partner in the Aker BP operated fields Valhall and Hod. After a subsequent divestment of a 10 per cent interest, Aker BP currently owns 90 per cent in the two fields (up from 36 per cent and 37.5 per cent respectively). These transactions had economic effect from 1 January 2017 but were completed towards the end of the year. For accounting purposes, the transactions were recorded per year-end 2017.

Aker BP's net production in 2017 was 160 thousand barrels of oil equivalents per day ("mboepd"), including the full-year effect of the increased interest in Valhall and Hod. More than 99 per cent of the production came from the five operated production hubs; The Alvheim area, Ivar Aasen, the Valhall area, Skarv and the Ula area.

In 2017 the company submitted Plans for Development and Operations ("PDO") for three new field developments, all operated by Aker BP; Ærfugl, Valhall Flank West and Skogul. These projects are expected to contribute significantly to the company's production and profitability in the years to come.

The Johan Sverdrup project continued to move forward according to plan in 2017 and cost estimates were further reduced. The Gina Krog development was completed during the year, and production started in June.

The exploration results for 2017 were disappointing, with only one small discovery made in the Filicudi prospect in the Barents Sea.

Looking forward, the company has a visible organic growth path to a production more than 330 mboepd after 2023, of which around 200 mboepd is expected to come from existing fields and projects already sanctioned. The total organic growth represents a compound annual growth rate of approximately 13 per cent from 2017.

P50 net reserves at year-end 2017 were estimated to 914 mmboe, an increase of 29 per cent from the previous year. The main drivers for the increase was the booking of reserves related to the three PDOs, and the increased interest in Valhall and Hod. The P50 contingent resources grew by 28 per cent to 769 mmboe through a combination of organic and inorganic growth.

The company has a robust and diversified capital structure with USD 2.9 billion in available liquidity as at 31 December 2017. The company paid four dividends in 2017, totaling USD 250 million. This will increase to USD

450 million in 2018, and the Board's stated intention is to increase the annual dividends by another USD 100 million per year until 2021.

Aker BP is well positioned to participate in future growth on the NCS. The Board is conscious of the risks associated with project execution and the changing market conditions in which the company operates. The Board is prioritizing capital discipline and mitigation of risk wherever possible throughout the organization.

Share price performance and ownership structure

In 2017, the share price for Aker BP ended at NOK 201.90 per share, compared to NOK 154.50 per share at the end of 2016. At the end of the year, 360.1 million shares were issued, compared to 337.7 million shares at the end of 2016. Aker ASA remains the largest owner with 40 per cent, while BP plc controls 30 per cent of the shares. The remaining 30 per cent were split among more than 7,000 shareholders. Aker BP is listed on the Oslo Stock Exchange under the ticker symbol "AKERBP".

Business description

Description of the company

Aker BP is a fully-fledged E&P company with exploration, development and production activities on the NCS. Aker BP holds no oil or gas assets outside Norway. All activities are thus within the Norwegian offshore tax regime, and to the extent the company has overseas activities, these are related to construction and engineering of field developments.

Aker BP is active in all three main petroleum provinces on the NCS. The company remains convinced that the NCS offers attractive opportunities for oil and gas exploration and development. This is supported by the NPD's latest undiscovered resources estimates. The company plans to continue to be an active industry player in the coming years.

The company's registered address is at Lysaker in Bærum municipality. The company also has offices in Harstad, Sandnessjøen, Stavanger and Trondheim. Karl Johnny Hersvik is Chief Executive Officer.

At the end of 2017, the company had 1,371 (1,371) employees. As operator for 62 (53) licenses and partner in an additional 46 (48) licenses, the company is a major license holder on the NCS.

Production

As of 31 December 2017, Aker BP had production from 13 fields: Alvheim (65 per cent and operator), Atla (10 per cent and partner), Bøyla (65 per cent and operator), Enoch (2 per cent and partner), Gina Krog (3.3 per cent and partner), Hod (90 per cent and operator), Ivar Aasen (34.786 per cent and operator), Skarv (23.834 per cent and operator), Tambar/Tambar East (55/46.2 per cent and operator), Ula (80 per cent and operator), Valhall (90 per cent and operator), Vilje (46.9 per cent and operator) and Volund (65 per cent and operator).

Production in 2017 averaged 159.6 mboepd, including the full-year effect of the increased interest in the Valhall and Hod fields to 90 per cent following the acquisition of Hess Norge and subsequent sale of 10 per cent interest in both fields to Pandion Energy. Approximately 79 per cent of the production was liquids and 21 per cent was gas. This represents a substantial increase compared to the 2016 production of 118.2 mboepd (including the full-year production from the BP Norge assets), driven by the increased interest in Valhall, the ramp-up of production from Ivar Aasen and the contribution from new wells at Alvheim and Volund.

Alvheim (65 per cent, operator) is an oil and gas field operated by Aker BP and is located in the North Sea at a water depth between 120 and 130 metres. The field consists of the Kneler, Boa, Kameleon, East Kameleon, Viper and Kobra structures as well as the Gekko discovery. The Boa reservoir straddles the Norway-UK median line, and is unitized with Verus Petroleum, who is the owner on the UK side. The productive reservoir of the Alvheim field is the middle to late Palaeocene/early Eocene Heimdal and Hermod Formation sandstones, which exist at a depth of approximately 2,100 metres.

Alvheim has been developed using a floating production, storage and offloading (FPSO) vessel, and production started in 2008. The development provides for the transport of oil by shuttle tanker and transportation of gas to the SAGE system. The Alvheim FPSO is also a production host for the satellite fields Volund, Vilje and Bøyla, and for Skogul which is currently under development.

Net production from Alvheim, including Boa, averaged 53.8 mboepd in 2017. Production from the Alvheim field is estimated to end in 2033, with subsequent abandonment between 2033 and 2034. Year-end 2017 P50 reserves for Alvheim are estimated at 73.3 mmboe net to Aker BP.

The **Volund** field (65 per cent, operator) is located approximately eight km south of Alvheim, and was the second field developed as a subsea tieback to Alvheim. The field started producing in 2009 with four production wells and one water injection well. Two additional infill wells were completed and started production in 2017.

Net production at Volund averaged 7.3 mboepd in 2017. Production from the Volund field is expected to last until 2033, with subsequent abandonment between 2033 and 2034. Year-end 2017 P50 reserves are estimated at 16.6 mmboe net to Aker BP.

The **Vilje** field (46.9 per cent, operator) is located northeast of Alvheim at a water depth of 120 metres. The productive reservoir of the Vilje field is the middle to late Palaeocene Heimdal Formation sandstone at a depth of approximately 2,100 metres. The field is tied back to the Alvheim FPSO. Production commenced in 2008.

Net production from Vilje averaged 5.3 mboepd in 2017. Production from the Vilje field is expected to cease in 2033, with subsequent abandonment scheduled to take place from 2033 to 2034, which coincides with the expected cessation of production from the Alvheim area. Year-end 2017 P50 reserves are estimated at 8.7 mmboe net to Aker BP.

The **Bøyla** field (65 per cent, operator) is located 28 km south of Alvheim at a water depth of 120 metres. The productive reservoir of the Bøyla field is within the Hermod sandstone member, which is a deep marine, channelized submarine fan system at a depth of approximately 2 100 metres. The field is tied back to the Alvheim FPSO. Production commenced in January 2015. The field is developed with two horizontal production wells and one water injection well.

Net production from Bøyla averaged 4.4 mboepd in 2017. Production from the Bøyla field is expected to cease in 2033, with subsequent abandonment scheduled to take place between 2033 to 2034, which coincides with the expected cessation of production from the Alvheim area. Year-end 2017 P50 reserves are estimated at 6.0 mmboe net to Aker BP.

The **Valhall** field (90 per cent, operator) is located in the southern part of the Norwegian North Sea at water depth of 70 metres. The reservoir consists of chalk in the Upper Cretaceous Tor and Hod Formations. Reservoir depth is approximately 2,400 metres.

The field was originally developed with three facilities for accommodation, drilling and processing, and started production in 1982. The Valhall complex consists today of six separate steel platforms for living quarters, drilling, wellheads, production, water injection, combined process- and hotel platform respectively. These platforms are bridge-connected. In addition, the field has two unmanned flank platforms, one in the south and one in the north. Liquids are routed via pipeline to Ekofisk and further to Teesside in the UK. Gas is sent via Norpipe to Emden in Germany.

Net production from Valhall averaged 33.4 mboepd in 2017. The Valhall concession period currently expires in 2028. The resource potential extends beyond the concession period, and it is common in the industry to achieve extensions to concessions, and the cessation of production will be subject to the technical life of the facilities and the economic cut-off. The current design life for the new Production-Hotel platform (PH) is 2049, 2033 for the Injection Platform (IP) and the Flank North and South, and the Wellhead Platform (WP) has been granted life extension until 2028. Year-end 2017 P50 reserves are estimated at 253.6 mmboe net to Aker BP.

The **Hod** field (90 per cent, operator) is located in the southern part of the North Sea. The field was discovered in 1974 and is located 13 kilometres south of Valhall. The water depth in the area is 72 metres. The reservoir lies in chalk in the lower Paleocene Ekofisk Formation, and the Upper Cretaceous Tor and Hod Formations. The reservoir depth is approximately 2,700 metres. The field is developed with a normally unmanned platform, tied back to and remotely operated form Valhall. Hod started producing in 1990.

Net production from Hod averaged 1.3 mboepd in 2017. Hod currently produces from wells drilled from the Valhall Flank South platform. All wells on the Hod platform are currently shut in and awaiting plug and abandon operations. Year-end 2017 P50 reserves are estimated at 3.7 mmboe net to Aker BP.

The **Ula** field (80 per cent, operator) is located in the southern part of the North Sea. The water depth in the area is 70 metres. The main reservoir is at a depth of 3 345 metres in the Upper Jurassic Ula Formation.

The development consists of three conventional steel facilities for production, drilling and accommodation, connected by bridges. The field started producing in 1986. The field's gas capacity was upgraded in 2008 with a new gas processing and injection module. The oil is exported via Ekofisk to Teeside and all gas is reinjected into the reservoir to enhance recovery. Ula acts as a third-party host for the Oselvar and Blane fields via subsea tie-backs.

Net production from Ula averaged 6.5 mboepd in 2017. The Ula concession period expires in 2028. The resource potential extends beyond the concession period, and it is common in the industry to achieve extensions to concessions, and the cessation of production will be subject to the technical life of the facilities and the economic cut-off Year-end 2017 P50 reserves are estimated at 44.0 mmboe net to Aker BP.

The **Tambar** and **Tambar East** field (55.0/46.2 per cent, operator) is located 16 kilometres southeast of the Ula field in the southern part of the North Sea. The water depth in the area is 68 metres. 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 metres.

The field has been developed with a remotely controlled wellhead facility without processing equipment, and started production in 2001. In 2017, a re-development project was initiated to extend the lifetime of Tambar with two new wells and gas lift, and an application for a license extension to 2028 was submitted.

Net production from Tambar averaged 1.9 mboepd in 2017. Year-end 2017 P50 reserves are estimated at 14.7 mmboe net to Aker BP.

The **Skarv** field (23.8 per cent, operator) is located about 200 kilometres west of Sandnessjøen in the northern part of the Norwegian Sea. The water depth in the area is 350-450 metres. The reservoirs in Skarv contain gas and condensate in Middle and Lower Jurassic sandstones in the Garn, Ile and Tilje Formations. There is also an underlying oil zone in the Skarv deposit in the Garn and Tilje Formations. The reservoirs lie at a depth of 3,300-3,700 metres.

Skarv is developed with a production ship with storage and offloading capacity (FPSO) anchored to the seabed. The FPSO has a life expectancy of 25 years. Production started in 2012.

Net production from Skarv, including test production from Ærfugl, averaged 26.7 mboepd in 2017. The Skarv concession period currently expires in 2033 and the original Skarv FPSO design life is 2035. Year-end 2017 P50 reserves are estimated at 45.4 mmboe net to Aker BP.

The **Ivar Aasen** field (34.8 per cent, operator) is located in the northern part of the North Sea, about 30 kilometres south of the Grane and Balder fields, and consists of the discoveries Ivar Aasen and West Cable. The water depth is 110 metres. The Ivar Aasen reservoir is of Late Triassic to Middle Jurassic age, and contains oil at a depth of around 2,400 metres. Parts of the reservoir have an overlying gas cap. The reservoir in West Cable is in the Middle Jurassic Sleipner Formation, and contains oil at a depth of around 2,950 metres.

The development comprises a production, drilling and quarters (PDQ) platform with a steel jacket and a separate jack-up rig for drilling and completion. The platform has spare slots for possible additional wells. The platform is prepared for tie-in of a subsea template planned for the development of the Hanz field, and for possible development of other nearby discoveries. First stage processing is carried out on the Ivar Aasen field, and the partly processed fluids are transported to the Edvard Grieg field for final processing and export. Production started in December 2016.

Average daily production net to Aker BP in 2017 amounted to 18.1 mboepd, and net reserves are estimated at 58.5 mmboe.

The partner operated fields **Atla** (10 per cent), **Enoch** (2 per cent) and **Gina Krog** (3.3 per cent) produced an average of 0.9 mboepd net to Aker BP in 2017. Year-end 2017 P50 reserves net to Aker BP for these fields are estimated at 6.8 mmboe, of which Gina Krog amounts to 6.7 mmboe.

Development Projects

In 2017, Aker BP participated in several field development projects. The Johan Sverdrup and Oda projects continued throughout the year, while the Gina Krog development was completed. Aker BP also submitted Plans for Development and Operations (PDO) for three new field developments; Ærfugl, Valhall Flank West and Skogul.

Johan Sverdrup

Johan Sverdrup (11.5733 per cent participating interest in unit, partner) is the largest oil discovery on the Norwegian shelf since the 1980s and is located on the Utsira High, 155 km west of Stavanger. The operator currently estimates the field's recoverable volumes at between 2.1 and 3.1 billion boe, with a break-even oil price for phase 1 below 15 USD/boe and below 20 USD/boe for the full field development.

The PDO for phase 1 was approved by the Norwegian parliament in August 2015. The project was approximately 70 per cent complete at the end of 2017, and production is expected to commence late 2019. The development plan accounts for 50 years of production, and the project is of high socio-economic importance in Norway.

The Johan Sverdrup oil field is planned to be developed in two phases. In phase 1 a field centre is established consisting of four bridge-linked platforms (processing platform, drilling platform, riser platform and living quarter), in addition to three subsea water injection templates. The oil will be transported via a dedicated pipeline to the Mongstad terminal, whereas the gas will be transported via the Statpipe system to Kårstø for processing and export.

The capital expenditures for phase 1 were estimated in the PDO at NOK 123 billion (nominal value, based on project FX). The estimated capital expenditure includes drilling, power from shore and export of oil and gas, as well as contingencies and allowances for market adjustments. As a consequence of the macro environment and project improvements, the operator's estimate of capital expenditures has been reduced several times, most recently to NOK 88 billion (nominal value, based on project FX), which implies a reduction of almost 30 per cent.

The projected cost of phase 2 (the full field development) has also been reduced significantly, now below NOK 45 billion (nominal, based on project FX) which implies a reduction of around 50 per cent since the preliminary estimate in the phase 1 PDO in 2015. The PDO for phase 2 is scheduled to be submitted during the second half of 2018 and start-up of production is expected in 2022.

The ambition is a recovery rate of 70 per cent, taking into account proven technology for increased/enhanced oil recovery (IOR/EOR) in future phases. In the PDO, the planned production capacity for phase 1 was 315 to 380 mbopd, however debottlenecking measures have increased the planned phase 1 production capacity to 440 mbopd. Fully developed, the production capacity is expected to be 660 mbopd.

At the end of 2017, Aker BP has booked 300 mmboe as net P50 reserves for the Johan Sverdrup full field development, representing 33 per cent of Aker BP's total P50 reserves.

The partnership consists of Statoil (operator), Lundin Norway, Petoro, Aker BP and Maersk Oil.

Oda (15 per cent, partner) is being developed with a subsea template tied back to the Ula field center via the Oselvar infrastructure. Recoverable reserves are estimated at 48 mmboe (gross) and the project is planned to be developed with two production wells and one water injector well, with first oil planned for 2019. The PDO for Oda was submitted in 2016, with total investments estimated at NOK 5.4 billion.

Gina Krog (3.3 per cent, partner) has been developed with a steel jacket platform and a floating storage and offloading vessel, with gas exports via the Sleipner platform. The produced oil is shipped by shuttle tankers. Production started in June 2017. Aker BP has booked 7 mmboe as net P50 reserves for Gina Krog.

Ærfugl (23.8 per cent, operator) is a unique gas condensate field, nearly 60 km long and just 2-3 km wide, situated close to the Aker BP-operated Skarv FPSO. Ærfugl was previously named Snadd.

The PDO covers the full-field development and includes the resources in both the Ærfugl and Snadd Outer fields, which are planned to be developed in two phases. The first phase includes three new production wells in the southern part of the field tied into the Skarv FPSO via a trace heated pipe-in-pipe flowline, in addition to the existing A-1 H well. Production from the three new wells is expected to begin in 2020.

The second phase is subject to further maturation, but the reference case includes two additional wells in the northern part of the field and one in Snadd Outer, also tied into the Skarv FPSO, with an estimated production start late 2023. Other alternatives will also be taken into consideration before selecting the optimized concept.

The gross remaining reserves for the full-field development are estimated at approximately 275 million barrels of oil equivalents. Total investments in the project are estimated at NOK 8.5 billion in real terms, of which NOK 4.5 billion in the first phase. Aker BP has booked 69 mmboe as net P50 reserves for Ærfugl.

Valhall Flank West (90 per cent, operator) is a project that aims to continue the development of the Tor formation in Valhall on the western flank of the field, with planned startup of operation in fourth quarter 2019.

Valhall Flank West will be developed from a new Normally Unmanned Installation (NUI), tied back to the Valhall field centre for processing and export. Six production wells are planned, with an option to convert two of these wells into water injectors at a later stage. The NUI is going to be fully electrified, and will be designed to minimize the need for maintenance activities. The platform will be remotely operated from the Valhall field centre.

Aker BP has booked 54 mmboe as net P50 reserves for Valhall Flank West.

Skogul (65 per cent, operator) was previously named Storklakken, and is located 34 kilometres north of Alvheim at a water depth of 110 metres. The productive reservoir is within the Eocene Balder and Frigg formation deep marine deposited sandstone members at a depth of approximately 2,100 metres. The PDO was submitted in 2017, and the field will be developed as a subsea tieback to Alvheim via Vilje with one horizontal production well and one cross-flow water injection well. Production is expected to commence early 2020. Aker BP has booked 6 mmboe as net P50 reserves for Skogul.

Exploration

Aker BP's ambition is to be the leading exploration player on the Norwegian continental shelf and to discover 250 mmboe net to Aker BP in the period from 2016 to 2020. This follows the ambition of long-term reserve replacement and value creation by establishing new core areas with operated production. The company strives to exceed this goal by continuously seeking additional prospect opportunities and improving the available data and technology to create a competitive edge.

In 2017, Aker BP participated in a total of 11 exploration wells, including two sidetracks, a slight decrease from 14 wells in 2016.

The exploration activity is grouped in three categories; Exploration near own producing fields (ILX), exploration for growth, and exploration in frontier areas. Over time, the company is seeking a balance between ILX, growth and frontier exploration targets. In 2017, Aker BP focused on exploring near existing or planned infrastructure.

Exploration drilling was concentrated on the Loppa High in the Barents Sea, in the Alvheim area, in the NOAKA area and adjacent to the Johan Sverdrup and Gina Krog fields. Except for the Filicudi discovery, the results were disappointing. The entire NCS experienced few new discoveries in 2017, but Aker BP still sees the long-term exploration results as satisfactory, and the ambition to discover 250 mmboe net to Aker BP in the period from 2016 to 2020 remains within reach.

On the Loppa High in the Barents Sea, the Filicudi discovery in PL 533 north of the Gohta discovery was made in late 2016 to early 2017. The in-place volumes are estimated to be in the range of 79 to 108 million barrels of oil, while recoverable volumes will depend on the development solution.

Aker BP was awarded 14 operated licenses and 9 new partner licenses through Awards in Predefined Areas (APA) 2017 in January 2018. Most of these licenses are located close to the company's existing core areas.

In 2017, total investments in exploration amounted to USD 262 (258) million. Exploration expenses in the Income statement amounted to USD 226 (147) million, including expensed capitalized dry wells of USD 75 (52) million, while new capitalized exploration expenditures amounted to USD 112 (181) million.

The annual accounts

(All figures in brackets refer to 2016. For accounting purposes, the transactions with Hess Norge and Pandion are recorded at transaction date 22 December 2017.)

The group prepares its financial statements in accordance with the International Financial Reporting Standards (IFRS) as adopted by EU and the Norwegian Accounting Act.

Changes in accounting standards

The applied accounting principles are in all material respect the same as for the previous financial year. There were no new standards effective as of 1 January 2017, and none of the amended standards and interpretations effective as of 1 January 2017 had significant impact for the group. Some accounting standards have been issued but not entered into as of 31 December 2017 (IFRS 9, IFRS 15 and IFRS 16) and the potential impact on the accounts are described in note 1.

There are no material changes in the presentation in the income statement for 2017 compared to 2016.

Income statement

The group's total income amounted to USD 2,563 (1,364) million. Petroleum production amounted to 50.7 (28.3) mmboe. The average realized oil price was 56 USD/boe, which represents an increase of around 20 per cent compared to 2016.

Exploration expenses amounted to USD 226 (147) million and were mainly related to dry and non-commercial wells, seismic data and general exploration activities.

Depreciation amounted to USD 727 (509) million, which corresponds to a depreciation per barrel of oil equivalent of USD 14.3.

Net impairments amounted to USD 52 (71) million, related to technical goodwill and to the Gina Krog field. The main reason for the Gina Krog impairment was lower long-term oil price assumptions as detailed in note 14. The technical goodwill from acquisitions has limited lifetime as it is tested for impairment at the cash generating unit ("CGU") level, and not at the corporate level (which would include assets such as Johan Sverdrup and Ivar Aasen). In practice, this means that the technical goodwill from the acquisitions will be impaired over the lifetime of the respective fields. A breakdown of the impairment charges is included in Note 14 to the financial statements.

Other operating expenses amounted to USD 28 (22) million. The majority of other operating expenses are relating to preparation for operation, non-license related costs, IT costs and consultants.

The company reported an operating profit of USD 1,007 (387) million.

The pre-tax profit amounted to USD 811 (290) million, and the tax expense on the ordinary profit amounted to USD 536 (255) million. The tax rules and tax calculations are described in Notes 1 and 11 to the financial statements. The effective tax rate was significantly impacted by foreign exchange differences as a result of the statutory requirement to calculate the tax in NOK, while the group's functional currency is USD.

The after-tax profit was USD 275 (35) million.

Statement of financial position

Total assets at year-end amounted to USD 12,019 (9,255) million.

Equity increased by USD 539 million to USD 2,989 million comprising new share capital issued in connection with the acquisition of Hess Norge AS and net profit for the period, minus dividends paid. At year-end, equity amounted to approximately 24.9 (26.5) per cent of total assets.

At 31 December 2017, total interest-bearing debt amounted to USD 3,389 (2,541) million, consisting of the DETNOR02 bond of USD 230 million, Senior USD Notes of USD 392 million, the drawn amount on the RBL of USD 1,271 million and the Bridge facility related to the Hess Norge acquisition of USD 1,496 million (all figures are net of unamortized loan fees). The available borrowing base on the RBL is USD 4.0 billion. For information about terms on the credit facilities, see Note 25.

Cash and cash equivalents totaled USD 233 (115) million at the end of the year.

Cash flow and liquidity

Net cash flow from operating activities amounted to USD 2,155 (896) million. This included tax refunds excluding interest of USD 405 (213) million.

Net cash flow used in investment activities amounted to USD 3,059 (705) million. The main items were investments in fixed assets of USD 977 (936) million, and net payments of USD 1,884 million related to the acquisition of Hess Norge and the asset sale to Pandion Energy.

At the end of 2017, financial covenants for the company's debt instruments were comfortably within applicable thresholds. The company has a robust balance sheet with USD 2.9 billion in available liquidity, providing the company with ample financial flexibility. The company is continuously working to improve the efficiency and effectiveness of its capital and debt structure.

Hedging

The company seeks to reduce the risk related to foreign exchange rates, interest rates and commodity prices through hedging instruments.

For 2017, the company had put options in place for a volume equivalent to approximately 15 per cent of its oil production. At year-end 2017, the company had purchased oil put options with strike prices of 50-55 USD/bbl for around 13 per cent of its expected 2018 oil production. Subsequent to year-end 2017, the company has purchased put options for an additional 7 per cent of its expected 2018 oil production at a strike price of 60 USD/bbl.

The going concern assumption

Pursuant to the Norwegian Accounting Act section 3-3a, the Board of Directors confirms that the requirements of the going concern assumption are met and that the annual accounts have been prepared on that basis. The Board considers the financial position and the liquidity of the company to be good. The company is continuously considering various sources of funding to facilitate the expected growth of the company. Cash flow from operations, combined with available liquidity of USD 2.9 billion is expected to be more than sufficient to finance the company's commitments in 2018.

In the Board of Directors' view, the annual accounts give a true and fair view of the company's assets and liabilities, financial position and results. The Board of Directors is not aware of any factors that materially affect the assessment of the company's position as of 31 December 2017, or the result for 2017, other than those presented in the Board of Directors' Report or that otherwise follow from the financial statements.

Resource accounts

Aker BP complies with guidelines from Oslo Børs and the Society of Petroleum Engineers' (SPE) classification system for quantification of petroleum reserves and contingent resources. Total net P90/1P reserves are estimated at 692 (529) mmboe, while net P50/2P reserves amounted to 914 (711) mmboe at year-end 2017. See Note 31 for a more detailed review of the resource accounts. The reserves have been certified by an independent third party.

Profit for the year

The Board of directors proposes that the profit for the year is transferred to other equity.

HSSE and organization

Health, Safety, Security and Environment ("HSSE") is always the number one priority in all of Aker BP's activities. The company strives to ensure that all its operations, drilling campaigns and projects are carried out under the highest HSSE standards.

Health, safety and the environment in Aker BP's operations

2017 has been a year characterized by a high activity level and major achievements for Aker BP, but also by a tragic fatality on the Maersk Interceptor in December. During maintenance work involving installation of a sea water lift pump, a wire sling broke and a person fell to sea and was fatally injured. Another person was also seriously injured during the incident. Aker BP is following up the causes of this accident to ensure that the learnings are implemented and shared with the industry, to prevent similar accidents in the future.

The Total Recordable Injuries Frequency ("TRIF") for 2017 was 2.94, up from 2.6 in 2016. Six personal injuries were classified as serious.

During 2017, Aker BP had two incidents with high potential – both involving dropped objects that resulted in material damage. All events during the year were investigated according to procedures, and the lessons learned were implemented. The improvement activities in the company's 2017 HSSE program have been completed and new HSSE programs for 2018 have been issued for each asset.

The Petroleum Safety Authority ("PSA") carried out a total of 16 audits of Aker BP's activities. Other authorities like the Norwegian Environmental Agency, the Norwegian Petroleum Directorate and the Norwegian Radiation Protection Agency conducted eight audits of Aker BP's activities. Aker BP did not receive any orders from the PSA related to the company's operations in 2017. Aker BP has responded to all audits in a timely manner.

Aker BP works actively to reduce the environmental footprint of its operations. This includes energy efficiency initiatives as well as chemicals substitution. The average emission of CO_2 from Aker BP's operated fields in 2017 was 7.2 kg/boe (54 kg CO2/tons oe). This is lower than the average for NCS in 2016 (61 kg CO2/tons oe) and significantly below the global average for the industry in 2016 (129 kg CO2/ tons oe).

To support the Paris climate agreement of the 2°C limit and the KonKraft initiative (CO_2 reduction target for the Norwegian Petroleum Industry), Aker BP has committed to reduce CO_2 emissions by 140 000 tons per year from 2020 to 2030. An energy forum has been established to follow up the company's part of the KonKraft initiative. The company's goal is to minimize emissions from its activities on the NCS through the choice of energy efficient solutions and operations. New projects need to perform feasibility studies for power from shore or power transmission. In cases where new energy intensive equipment is purchased, the equipment must be as energy efficient as possible and be of low-emission technology. Aker BP also strives to reduce the amount of waste from its operations.

The Carbon Disclosure Project ("CDP") is a global non-profit organization that focuses on investors, companies and cities to take urgent action to build a sustainable economy by measuring and understanding their environmental impact. Aker BP's score was improved from a C in 2016 to a B in 2017. Aker BP is satisfied with this score, which is the highest score realistically achievable for an offshore E&P company.

Employees and working conditions

Recruitment

Aker BP recruited 99 new employees and 12 apprentices in 2017. The company also gained 11 employees through the acquisition of Hess Norge.

Aker BP has a long-standing collaboration with graduate schools and universities to recruit talent as well as cooperation with regards to student internships.

Status of employees

At year-end 2017, the company had 1371 (1371) employees.

Equal opportunities

The company endeavors to maintain a working environment with equal opportunities for all based on qualifications, irrespective of gender, ethnicity, sexual orientation or disability.

In December 2017, women held 20 per cent of the positions in the company. The share of women on the Board of directors was 40 per cent. The share of women in the executive management team was 20 per cent and in the middle management it was 20.5 per cent.

Men and women with the same jobs, with equal professional experience who perform equally well, shall receive the same pay in Aker BP. The complexity of the job, discipline area and number of years of work experience affect the pay level of individual employees.

At year-end, 8.3 per cent of the employees were of non-Norwegian origin.

The working environment

Aker BP has a working environment committee (AMU) as described in the Norwegian Working Environment Act. The committee plays an important role in monitoring and improving the working environment and in ensuring that the company complies with laws and regulations in this area.

The company is committed to maintaining an open and constructive dialogue with the employee representatives and has arranged meetings on a regular basis throughout the year. Four local trade unions are registered as being represented in the company; Tekna, Lederne, SAFE and Industri Energi.

In the Board's view, the working environment in Aker BP during 2017 was good. This was confirmed by an organizational survey conducted in September 2017.

Sickness absence

In 2017, sickness absence in Aker BP was 3.9 per cent for offshore personnel and 2.2 per cent for onshore personnel. The total sickness absence was 2.7 per cent.

Ethics

Aker BP's code of ethics sets out requirements for good business conduct and personal conduct for all employees of Aker BP and members of its governing bodies. The code also applies to hired personnel, consultants and others who act on behalf of Aker BP.

Corporate social responsibility (CSR), ethics and anti-corruption

Targeted and systematic work

In the HSSE field, emphasis has been placed on improving safety, ensuring a safe working environment, strengthening the emergency response organization, avoiding discharges to sea, reducing the use of substances hazardous to health and the environment, and reducing emissions to air. A new management system has been established, as well as a new model for managing risk.

Systematic work to reduce emissions/discharges to air and sea

Aker BP is continuously focusing on reducing the company's impact on the climate and the environment. The company complies with laws and regulations and is following the guiding principles of ISO 14001 for environmental management. The company also participates in relevant research and development to continuously improve operations and reduce its environmental footprint.

Ecosystem vulnerability and biodiversity are factors taken into consideration in all of Aker BP's operations. Environmental analyses are performed to assess the risks in the area, both in terms of birds, fish, marine mammals, seabed disturbances and marine fauna. Acceptance criteria are set per group of species and a risk-based approach is used to finalize the environmental impact assessment. In 2017 a visual survey of corals was performed along the proposed Ærfugl pipeline route, a tie-in field to Skarv, to ensure coral reefs remain protected and are not affected by the pipeline. A similar approach is used for anchor patterns to protect sensitive seabed and resources.

Aker BP worked to reduce discharges to sea throughout 2017. Ivar Aasen started up the produced water reinjection system at the end of 2017.

Environmental measures to support the efforts to reduce emissions (CO_2, NO_X) and environmental risk include:

- The Valhall field has had electrical power from shore since 2012. The Ivar Aasen field is supplied with power from Edvard Grieg, which will be supplied with power from shore from 2022 as part of the Utsira High.
- Tambar is supplied with power from the Ula field, and Valhall Flank South and North are supplied with power from the Valhall field centre.
- The drilling rig Maersk Invincible, used for plugging wells at Valhall, was supplied with power from Valhall in 2017. Electrification of the rig resulted in an annual reduction of 186 tons NOx and 16 000 tons CO2. The project has received NOK 38 million in financial support from the NOX fund.
- The continuous flaring on Valhall ceased by the end of 2015. Ivar Aasen ceased flaring at the end of 2017.
- Both Skarv and Alvheim have ceased flaring and are using low-NOX turbines with heat recovery.
- An Energy forum has been initiated in Aker BP to focus on energy management and energy efficiency in operations and projects. The goal is to map energy usage across the assets and implement actions to reduce CO2 emissions to deliver on the KonKraft commitments.

	Valhall	Ula	Skarv	Alvheim	Ivar Aasen	Total (avg)
Produced water oil concentration, mg/ltr	9.9	17.8	8.2	32.5	11	19.4
Acute discharges to sea (number > 1 bbl)	2	3	2	1	0	8
Produced water reinjection %	N/A	0	N/A	91.2	99	60
CO_2 per produced b.o.e.	0.7	33.7	10.1	5.4	1.3	7.2
Gas flaring mill. Sm3	1.5	6.2	2.9	4.7	1.5	16.8
Waste segregation %	73	83	82	88	68	

Corporate social responsibility also applies to suppliers

In 2017, Aker BP has ensured that the company's Corporate Social Responsibility and Code of Conduct requirements are communicated to all its suppliers by mandating these requirements in all new contracts. In addition, the requirements are published on the company's website, together with its standard Terms & Conditions, which is a common method of publishing CSR related requirements to ensure these become public knowledge.

Taking responsibility for the surrounding society

Aker BP's goal is to have good relations with its surrounding society. This applies both at the national level and in the local communities where the company operates. The company is supporting schools and education, and sponsoring projects such as Det Norske Teatret, the football club Viking, ice hockey team Stavanger Oilers, the Nidaros Cathedral Boys Choir, the Bakgårds festival and several other local events.

The company's collaboration with the Department of Mathematics at the University of Oslo and the website www.matematikk.org continued in 2017 and will be continued in 2018. Motivating school pupils, and particularly girls, to choose an education in the fields of science and technology is an important task that the company will continue with. The company has a multi-year cooperation agreement with Helgeland Knowledge Park to which it contributes financially and by participating in career fairs, career days and by providing information for school career advisers etc. The company is also collaborating with various voluntary organizations that help people in need in Norway and abroad.

The company has emphasized providing accurate information in interim reports, capital market days and through direct dialogue with relevant authorities.

Research and development

Aker BP continues to pursue a Research and Development (R&D) strategy that supports the overall strategy of Aker BP to become the leading independent offshore E&P company. The total spending on R&D projects in 2017 was NOK 193 million, and the R&D portfolio is comprised of projects from all company business units. Two key strategic priorities and focus areas for the R&D portfolio in 2017 has been (i) increased understanding of subsurface and (ii) digitalization. In addition, the portfolio is comprised of projects that support securing a license to operate in new areas and to carry out operations efficiently at a high HSSE standard and with state-of-the-art technology, and topics related to unmanned facilities and improved field development solutions for the future.

The company's R&D projects within digitalization aim to build fully digital and seamless work processes from discovery to production, and to utilize machine learning to assist in concept selection and detailed engineering. Aker BP is continuously identifying new areas where digital technologies demonstrate significant improvement potential, and expects digitalization to remain an important topic on the R&D agenda also going forward.

Aker BP also sees a large improvement potential within subsurface disciplines, especially within imaging using advanced seismic acquisition and processing. The company is cooperating with vendors, universities and research institutions, and is leveraging obtained knowledge and insight across new exploration opportunities.

Selected highlights from Aker BP's R&D portfolio include:

- Development of a platform for acquisition, processing and storage of data from industrial sensors, meeting Big Data, robotics and machine learning challenges
- New approach to field development with fully integrated digital thread from early phase initial design to fabrication, including automated specification and equipment selection, full cost estimation, and schedule integration
- Automated Reservoir Management through pre-processing of subsurface information to develop an automated and stochastic ranking of opportunities
- Regional program on safety and emergency preparedness preparations and scenario testing for the Barents Sea

Corporate governance

Aker BP believes that good corporate governance with a clear distribution of roles and responsibility between the owners, the Board and executive personnel is crucial in order to deliver value to its shareholders.

The Board of Aker BP is responsible for maintaining the highest corporate governance standards. The Board carries out an annual review of the company's principles. The company complies with relevant rules and regulations for corporate governance, including the most recent version of the Norwegian Code of Conduct for Corporate Governance, published on 30 October 2014, unless otherwise specified.

An account of corporate governance is provided in a separate section of the annual report and on the company's website www.akerbp.com.

Reporting of payments to governments

Aker BP has prepared a report on government payments in accordance with the Norwegian Accounting Act § 3-3 d) and the Norwegian Securities Trading Act § 5-5a. It states that companies engaged in activities within the extractive industries shall annually prepare and publish a report containing information about their payments to governments at country and project level. The report is provided in a separate section of the annual report and on the company's website www.akerbp.com.

Risk factors

Risks relating to the oil and gas industry

Aker BP's business, results of operations, cash flow and financial condition depend significantly on the level of oil and gas prices and market expectations to these, and may be adversely affected by volatile oil and gas prices and by the general global economic and financial market situation.

The company's profitability is determined in large part by the difference between the income received from the oil and gas produced and the operational costs, taxation costs relating to recovery (which are assessable irrespective of sales), as well as costs incurred in transporting and selling the oil and gas. Lower prices for oil and gas may thus reduce the amount of oil and gas that the company is able to produce economically. This may also reduce the economic viability of the production levels of specific wells or of projects planned or in development to the extent that production costs exceed anticipated revenue from such production.

The economics of producing from some wells and assets may also result in a reduction in the volumes of the company's reserves. Aker BP might also elect not to produce from certain wells at lower prices. These factors could result in a material decrease in net production revenue, causing a reduction in oil and gas acquisition and development activities. In addition, certain development projects could become unprofitable because of a decline in price and could result in the company having to postpone or cancel a planned project, or if it is not possible to cancel the project, carry out the project with negative economic impact.

In addition, a substantial material decline in prices from historical average prices could reduce the company's ability to refinance its outstanding credit facilities and could result in a reduced borrowing base under credit facilities available to the company, including the RBL facility. Changes in the oil and gas prices may thus adversely affect the company's business, results of operations, cash flow, financial condition and prospects.

Exploration, development and production operations involve numerous safety and environmental risks and hazards that may result in material losses or additional expenditures

Developing oil and gas resources and reserves into commercial production involves risk. Aker BP's exploration operations are subject to all the risks common in the oil and gas industry. These risks include, but are not limited to, encountering unusual or unexpected rock formations or geological pressures, geological uncertainties, seismic shifts, blowouts, oil spills, uncontrollable flows of oil, natural gas or well fluids, explosions, fires, improper installation or operation of equipment and equipment damage or failure. Given the nature of offshore operations, Aker BP's exploration, operating and drilling facilities are also subject to the hazards inherent in marine operations, such as capsizing, sinking, grounding and damage from severe storms or other severe weather conditions, as well as loss of containment, fires or explosions.

The market in which Aker BP operates is highly competitive

The oil and gas industry is very competitive. Competition is particularly intense in the acquisition of (prospective) oil and gas licenses. Aker BP's competitive position depends on its geological, geophysical and engineering expertise, financial resources, the ability to develop its assets and the ability to select, acquire, and develop proven reserves.

Climate change regulation could have negative effect on the company

The company's business and results of operations could be adversely affected by climate change and the adoption of new climate change laws, policies and regulations. Growing concerns about climate change and greenhouse gas emissions have led to the adoption of various regulations and policies, including the Paris Agreement negotiated at the 2015 United Nations Conference on Climate Change ("COP 21"), which requires participating nations to reduce carbon emissions every five years beginning in 2023. Multiple plans have also been proposed in the Norwegian parliament to reduce carbon emissions from companies operating in certain sectors, including the oil and gas industry, and create a carbon trading system linked to the European Union's emissions trading scheme.

The emission reduction targets and other provisions of the recent Norwegian climate change law, the Paris Agreement, or similar legislative or regulatory initiatives enacted in the future, could adversely impact the company's business by imposing increased costs in the form of taxes or for the purchase of emission allowances, limiting the company's ability to develop new oil and gas reserves, decreasing the value of its assets, or reducing the demand for hydrocarbons and refined petroleum products.

Additionally, some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. Aker BP's offshore operations are particularly at risk from severe climatic events. If any such climate changes were to occur, they could have an adverse effect on the company's financial condition and results of operations.

Risks relating to the business of the company

Aker BP's current production and expected future production is concentrated in a few fields

Aker BP's production of oil and gas comes from a limited number of offshore fields. If mechanical or technical problems, storms or other events or problems affect the production on one of these offshore fields, it may have direct and significant impact on a substantial portion of the company's production. Also, if the actual reserves associated with any one of these fields are less than the estimated reserves, the company's results from operations and financial condition could be materially adversely affected.

There are risks related to redetermination of unitized petroleum deposits

Unitization agreements relating to production licenses may include a redetermination clause, stating that the apportionment of the deposit between licenses can be adjusted within certain agreed time periods. Any such redetermination of interest in any of the company's licenses may have a negative effect on its interest in the unitized deposit, including its tract participation and cash flow from production. No assurance can be made that any such redetermination will be satisfactorily resolved, or will be resolved within reasonable time and without incurring significant costs. Any redetermination negatively affecting the company's interest in a unit may have a material adverse effect on its business, results of operations, cash flow, financial condition and prospects.

Development projects are associated with risks relating to delays and costs

Aker BP's ongoing development projects involve advanced engineering work, extensive procurement activities and complex construction work to be carried out under various contract packages at different locations onshore. Furthermore, the company (together with its license partners), must carry out drilling operations, install, test and commission offshore installations and obtain governmental approval to take them into use prior to commencement of production. The complexity of such development projects makes them very sensitive to circumstances that may affect the planned progress or sequence of the various activities, as this may result in delays or cost increases.

Although Aker BP believes that the development projects will be completed on schedule in accordance with all license requirements and within the estimated budgets, the current or future projected target dates for production may be delayed and cost overruns may incur.

Furthermore, estimated exploration costs are subject to a number of assumptions that may not prove to be correct. Any such inability to explore, appraise or develop petroleum operations or incorrect assumptions regarding exploration costs may have a material adverse effect on the company's growth ambitions, future business and revenue, operating results, financial condition and cash flow.

Aker BP is subject to third-party risk in terms of operators and partners

Where Aker BP is not the operator of a license, although it may have consultation rights or the right to withhold consent in relation to significant operational matters depending on the level of its interest in such license (as most decisions by the management committee only require a majority vote), the company has limited control over management of the assets and mismanagement by the operator or disagreements with the operator as to the most appropriate course of action may result in significant delays, losses or increased costs to Aker BP.

Aker BP is subject to third-party risk in terms of contractors

Market conditions may impair the liquidity situation of contractors and consequently their ability to meet its obligations towards Aker BP. This may in turn impact both project timelines and cost.

Oil and gas production could vary significantly from reported reserves and resources

Aker BP's reserve evaluations have been prepared in accordance with existing guidelines. These evaluations include many assumptions relating to factors such as initial production rates, recovery rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and gas, operating costs, and royalties and other government levies that may be imposed over the producing life of the reserves and resources. Actual production and cash flows will vary from these evaluations, and such variations could be material. Hence, although the company understands the life expectancy of each of its assets, the life of an asset may be shorter than anticipated. Among other things, evaluations are based, in part, on the assumed success of exploration activities intended to be undertaken in future years. The reserves, resources and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploration activities do not achieve the level of success assumed in the evaluations, and such reductions may have a material adverse effect on the company's business, results of operations, cash flow and financial condition.

Aker BP may become a target of cyber-attacks

The company could be a target of cyber-attacks designed to penetrate the security of its network or internal systems, misappropriate proprietary information, commit financial fraud and/or cause interruptions to the company's activities, including a reduction or halt in production. Such attacks could include hackers obtaining access to company systems, the introduction of malicious computer code or denial of service attacks. Such actual or perceived breaches of network security could adversely affect the company's business or reputation, and may create exposure to the loss of information, litigation and possible liability.

Changes in taxation and regulations for the petroleum industry

Aker BP has built up a significant tax balance that can be utilized against future production revenues. There is no assurance that future political conditions in Norway will not result in the government adopting different policies for petroleum taxation. In the event there are changes to this tax regime, it could lead to new investments being less attractive and prevent further growth of the company.

Furthermore, the amounts of taxes could also change significantly as a result of new interpretations of the relevant tax laws and regulations or changes to such laws and regulations. In addition, tax authorities could review and question the company's tax returns leading to additional taxes and tax penalties which could be material.

The Norwegian Government is currently implementing a tax reform in Norway. The tax reform has, inter alia, led to a reduction in the general corporate tax rate, while the special petroleum tax rate has been increased. The overall effect of the rate changes for the petroleum sector is that the total marginal tax rate of 78 per cent has remained unchanged. Further tax reform may result in changes in the Norwegian tax system (which may include changes in the tax treatment of interest costs and to withholding taxes) that may affect our current and future tax positions, net income after tax and financial condition.

Separately, within the current tax regime the Norwegian tax authorities may take a different view from the company as to whether costs qualify as deductible exploration costs eligible for a tax refund or the law may change as to what costs qualify as deductible exploration costs or whether a tax refund may be obtained in respect of such costs. In that event, the company may not be able to claim tax refunds for all of its exploration costs.

Financial risks

The company may require additional capital in the future, which may not be available on favorable terms, or at all

The company's future capital requirements depend on many factors, including whether the company's cash flow from operations is sufficient to fund the company's business plans. The company may need additional funds in the longer term in order to further develop exploration and development programs or to acquire assets or shares of other companies. In particular, the development projects require significant capital expenditures in the years to come. Even though the company has taken measures to ensure a solid financial basis for the development projects, the company cannot assure that it will be able to generate or obtain sufficient funds to finance the projects. In particular, given the extensive scope of the projects, any unforeseen circumstances or actions to be dealt with that is not accounted for, may result in a substantial gap between estimated and actual costs. Thus, the actual costs necessary to carry out the projects may be considerably higher than currently estimated. These investments, along with the company's ongoing operations, may be financed partially or wholly with debt, which may increase the company's debt levels above industry standards.

The company may also have to manage its business in a certain way so as to service its debt and other financial obligations. Should the financing of the company not be sufficient to meet its financing needs, the company may, among other things, be forced to reduce or delay capital expenditures or research and development expenditures or sell assets or businesses at unanticipated times and/or at unfavorable prices or other terms, or to seek additional equity capital or to restructure or refinance its debt. There can be no assurance that such measures would be successful or would be adequate to meet debt and other obligations as they come due, or would not result in the company being placed in a less competitive position.

The general financial market conditions, stock exchange climate, interest level, the investors' interest in the company, the share price of the company, as well as a number of other factors beyond the company's control, may restrict the company's ability to raise necessary funds for future growth and/or investments. Thus, additional funding may not be available to the company or, if available, may not be available on acceptable terms. If the company is unable to raise additional funds as needed, the scope of its operations may be reduced and, as a result, the company may be unable to fulfil its long-term development program, or meet its obligations under its contracts, which may ultimately be withdrawn or terminated for non-compliance. The company may also have to forfeit or forego various opportunities, curtail its growth and/or reduce its assets. This could have a material adverse effect on the company's business, prospects, financial condition, results of operations and cash flows, and on the company's ability to fund the development of its business.

The company is exposed to interest rate and liquidity risk associated with its borrowing portfolio and fluctuations in underlying interest rates

The company's long-term debt is primarily based on floating interest rates. An increase in interest rates can therefore materially adversely affect the company's cash flows, operating results and financial condition and make it difficult to service its financial obligations. The company has, and will in the future have, covenants related to its financial commitments. Failure to comply with financial obligations, financial covenants and other covenants may entail several material adverse consequences, including the need to refinance, restructure, or dispose of certain parts of, the company's businesses in order to fulfil the company's financial obligations and there can be no assurances that the company in such event will be able to fulfil its financial obligations.

Changes in foreign exchange rates may affect the company's results of operations and financial position

The company is exposed to market fluctuations in foreign exchange rates due to the fact that the company reports profit and loss and the balance sheet in USD. Revenues are in USD for oil and in GBP and EUR for gas, while operational costs and investments are in several other currencies in addition to USD. Moreover, taxes are calculated and paid in NOK. The company actively manages its foreign currency exposure through a mix of forward contracts and options, however significant fluctuations in exchange rates between USD and NOK could adversely affect the liquidity position of the company. The company expects to maintain its foreign exchange hedging activity in 2018.

The company is exposed to risk of counterparties being unable to fulfil their financial obligations

The company's partners and counterparties consist of a diverse group of companies with no single material source of credit risk. However, a general downturn in financial markets and economic activity may result in a higher volume of late payments and outstanding receivables, which may in turn adversely affect the company's business, operating results, cash flows and financial condition.

Events after the year-end closing of the accounts

On 16 January 2018, Aker BP was offered 23 new licenses, including 14 operatorships in the in the Awards in Predefined Areas (APA) 2017 licensing round.

On 7 February 2018, Aker BP announced that development costs for Johan Sverdrup had been further reduced.

On 14 February 2018, Aker BP disbursed USD 112.5 million in dividends to shareholders.

On 19 February 2018, Aker BP announced an oil discovery in the Frosk exploration well located in production license 340 near Alvheim. The preliminary estimated size of the discovery was 30-60 mmboe. Aker BP is the operator of the license with a 65 per cent working interest.

BOARD OF DIRECTORS' – signature page

The Board of Directors of Aker BP ASA
Akerkvartalet, 8 March 2018

Øyvind Eriksen, Chairman of the Board	Anne Marie Cannon, Deputy Chair
Bernard Looney, Board member	Kjell Inge Røkke, Board member
Trond Brandsrud, Board member	Kate Thomson, Board member
Gro Kielland, Board member	Lone Olstad, Board member
Bjørn Thore Ribesen, Board member	Terje Solheim, Board member
Ørjan Holstad, Board member	Karl Johnny Hersvik, Chief Executive Officer

REPORTING OF PAYMENTS TO GOVERNMENTS

This report is prepared in accordance with the Norwegian Accounting Act Section § 3-3 d) and Securities Trading Act § 5-5 a). It states that companies engaged in activities within the extractive industries shall annually prepare and publish a report containing information about their payments to governments at country and project level. The Ministry of Finance has issued a regulation (F20.12.2013 nr 1682 – "the regulation") stipulating that the reporting obligation only apply to reporting entities above a certain size and to payments above certain threshold amounts. In addition, the regulation stipulates that the report shall include other information than payments to governments, and it provides more detailed rules applicable to definitions, publication and group reporting.

This report contains information for the activity in the whole fiscal year 2017 for Aker BP AS (previously Hess Norge AS), including the period before it became part of the Aker BP group.

The management of Aker BP has applied judgment in the interpretation of the wording in the regulation with regard to the specific type of payment to be included in this report, and on what level it should be reported. When payments are required to be reported on a project-by-project basis, it is reported on a field-by-field basis. Only gross amounts on operated licences are reported, as all payments within the licence performed by non-operators will normally be cash calls transferred to the operator and will as such not be payments to the government. Aker BP's activities within the extractive industries, are in all material respects located on the Norwegian Continental Shelf. Hence, the main part of the reported payments below is to the Norwegian government. However, part of the Ivar Aasen project has been conducted in Singapore and in 2017 there was a tax payment to Singapore Tax Authorities which is deemed to be in scope for this reporting.

Reporting of payments

The regulation's Section 2 no. 5 defines the different types of payments subject to reporting. In the following sections, only those applicable to Aker BP will be described.

Income tax

Norway

The income tax is calculated and paid on corporate level and is therefore reported for the whole company rather than licence-by-licence. The tax payments in 2017 of NOK 817 013 072 (including interest) are mainly related to tax instalments for the income year 2017. This number excludes tax refunds received in 2017.

Singapore

The tax payment related to the activity in the Singapore Branch for 2017 amounted to 302 586 Singapore Dollar.

CO2 tax

CO2 tax is to some extent included in the fuel price/rig rental paid to external rig companies. The CO2 tax paid on the Alvheim field includes the fields tied in to the Alvheim FPSO (Vilje, Volund and Bøyla) as Alvheim performs the payment and charges the other fields via opex share.

NOx

The company is member of the NOx fund and all NOx payments are made to this fund rather than to the government.

NAME OF FIELD/ LICENCE	CO2 TAX PAID IN 2017 (NOK)
Alvheim	93,963,871
Ivar Aasen	8,642,850
Hod	146,687
Valhall	4,213,571
Ula	74,571,816
Skarv	164,544,979
Total CO2 paid	**346,083,774**

Area fee

The table below specifies the area fee paid by Aker BP on behalf of the different licences in 2017. Licences of which the company has received net refund of area fee are not included in the figures.

NAME OF FIELD/ LICENCE	AREA FEE PAID IN 2017 (NOK)
Alvheim	12,022,849
Bøyla	4,110,000
Hod	2,200,000
Skarv	33,702,000
Tambar	4,110,000
Ula	4,053,315
Valhall	7,056,874
Vilje	760,000
Volund	685,000
PL 019C	1,284,218
PL 027D	983,325
PL 103B	527,332
PL 150B	105,096
PL 169C	983,325
PL 212B	3,151,000
PL 212E	5,754,000
PL 242	2,192,000
PL 261	9,316,000
PL 364	4,384,000
PL 442	13,010,000
PL 460	1,040,825
PL 504	764,808
	112,195,966

Other information required to be reported

When companies are required to report payments as the above, it is also mandatory to report on investments, sales income, production volumes and purchases of goods and services in the country in which companies have activities within the extractive industries. As mentioned above, Aker BP operates on the Norwegian Continental Shelf only. This reporting requirement is therefore deemed to be met by the financial statements as specified below:

- Total net investments amounted to USD 3 058 994 thousand, as specified in the cash flow analysis in the financial statements. This includes cash payments related to the acquisition of Hess Norge AS.

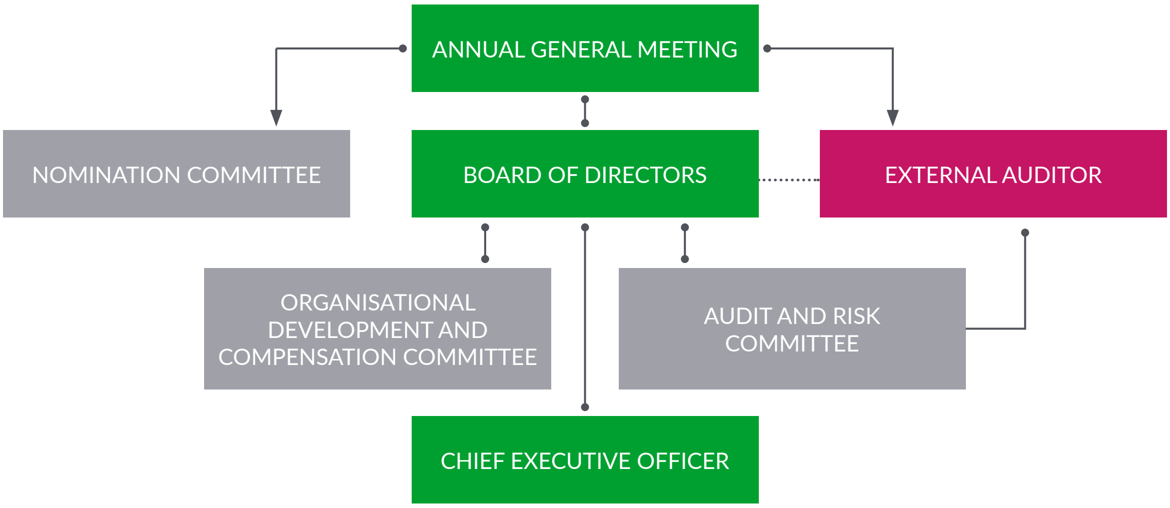
- Sales income (Petroleum revenues) in 2017 amounted to USD 2 575 654 thousand, as specified in Note 7 to the financial statements

- Total production in 2017 was 50 671 230 barrels of oil equivalents, see Note 7 to the financial statements

- For information about purchases of goods and services, reference is made to the Income Statement and the related notes

1. The board of directors' report on corporate governance

Aker BP ASA ('Aker BP') aims to ensure the greatest possible value creation to the shareholders and society over time in a safe and prudent manner. A good management and control model with a clear division of responsibility and roles between the owners, represented by the shareholders in the General Meeting, the Board of Directors and the corporate management is crucial to achieve this.



2. Implementation and reporting on corporate governance

The Board of Aker BP is responsible for actively adhering to sound corporate governance standards.

Aker BP is a Norwegian public limited liability company (ASA), listed on the Oslo Børs and established under Norwegian laws. In accordance with the Norwegian Accounting Act, section 3-3b, Aker BP includes a description of principles for corporate governance as part of the Board of Directors' Report in the annual report or alternatively makes a reference to where this information can be found.

The Norwegian Corporate Governance Board (NCGB) has issued the Norwegian Code of Practice for Corporate Governance ("the Code"). The Code can be found on www.nues.no. Adherence to the Code is based on the "comply or explain" principle, which means that a company must comply with all the recommendations of the Code or explain why it has chosen an alternative approach to specific recommendations.

Oslo Børs requires listed companies to publish an annual statement of their policy on corporate governance in accordance with the Code in force at the time. Continuing obligations for companies listed at Oslo Børs is available at www.oslobors.no.

Aker BP complies with applicable laws and regulations. Aker BP complies with the current edition of the Code, issued on 30 October 2014, unless otherwise specifically stated. The following statement on corporate governance is structured the same way as the Code, thus following the 15 chapters included in the Code.

The vision for Aker BP is "Creating the leading independent offshore E&P (Exploration & Production) company". The following values are adopted by the company:

- ENQUIRING - We are curious and aiming for new and better solutions.
- RESPONSIBLE - We put safety first and strive to create value for our owners and for society.
- PREDICTABLE - We build trust and reputation through reliability and consistent behaviour.
- COMMITTED - We are committed to each other, the company and society.
- RESPECTFUL - We have high ethical standards. We have respect for those we work with and value diversity.

The company has adopted a Code of Conduct to ensure that employees, hired personnel, consultants and others acting on behalf of Aker BP, do so in a consistent manner with respect to ethics and good business practice. The Code of Conduct clarifies the company's fundamental ethical values including corporate social responsibility and is a guideline for those making decisions on behalf of the company.

The company shall demonstrate responsibility through actions, the quality of its work, the projects and products and all its activities. The company's ambition is that business activities shall integrate social, ethical and environmental goals and measures. As a minimum, Aker BP will comply with laws, regulations and conventions in the areas where the company operates, but the established set of ethical guidelines extends beyond such compliance. Established procurement procedures secure non-discrimination and transparency in the procurement processes. It is also stated in the Code of Conduct that any form of corruption is not tolerated.

In addition, the company has a sponsorship programme to promote the company and its activities. Guidelines for the use of sponsorships are included in the Code of Conduct. Aker BP supports measures that are directly related to the company's business as an oil company, measures that provide significant exposure and measures that can be for the benefit of the employees. Information about ongoing sponsorships are available on the website: http://www.akerbp.com/en/about-us/csr/sponsorships/.

The company shall achieve its goals in accordance with the adopted Code of Conduct, which is available on the website http://www.akerbp.com/en/about-us/code-of-conduct/.

Deviations to the code: None

3. Business

According to Aker BP's Articles of Association article 3, its objective is "to carry out exploration for and recovery of petroleum and activities related thereto, and, by subscribing for shares or by other means, to participate in corresponding businesses or other business, alone or in cooperation with other enterprises and interests". Further information about the Articles of Association is available at: http://www.akerbp.com/en/investor/corporate-governance/articles-of-association/.

Through an annual strategy process, the Board defines and evaluates the company's goals and main strategies. Together with the company's financial status, these goals are communicated to the market.

It is Aker BP's objective to create the leading independent offshore E&P company. In order to achieve this objective, the company will take part in exploration, development and production activities and be opportunistic in its approach to M&A, including buying and selling interests in companies, fields and discoveries.

Deviations to the code: None

4. Equity and dividends

The Board seeks to optimize the company's capital structure by balancing risk, return on equity against lenders' security and liquidity requirements. The company aims to have a good reputation in all debt and equity markets. The Board continuously evaluates the company's capital structure, ensuring an optimal and diversified capital and debt structure. This is a key priority for the Board. This involves monitoring available funding sources and related cost of capital.

At year-end 2017, the company's book equity was USD 2.99 billion, which represents 25 per cent of the balance sheet total of USD 12.02 billion. The market value of the company's equity was USD 8.86 billion (NOK 72.71 billion) on 31 December 2017. The company's equity was strengthened during 2017 following a NOK 4.1 billion (USD 500 million) equity issue and a net profit of USD 275 million for the full year 2017.

It is the company's goal that over time, Aker BP's shareholders shall receive a competitive return on their investment through increase in the share price and cash dividend. In 2017, the company paid USD 250 million (0.74 per share) in dividends to shareholders. For 2018, the company plans to pay USD 450 million in dividends, and the ambition is to increase this by USD 100 million per year until 2021.

The financial liquidity is considered to be good. At 31 December 2017, the company's cash and cash equivalents were USD 233 million. In addition, available undrawn amount on committed credit facilities were about USD 2.7 billion.

In April 2017, the Annual General Meeting (AGM) authorized the Board to increase the share capital by a maximum of NOK 16,886,853, representing up to five per cent of the total share capital at the time of such meeting. As of 31 December 2017, the mandate had not been used.

The AGM in April 2017 provided the Board a mandate to re-purchase company shares equivalent to up to five per cent of the total share capital at the time of such meeting. The mandate is valid until the AGM meeting in 2018. As of 31 December 2017, the mandate has not been used.

Deviations to the code: None

5. Equal treatment of shareholders and transactions with closely related parties

The company has one class of shares, and all shares carry the same rights.

When the company considers it to be in the best interest of shareholders to issue new equity there is a clear objective to limit the level of dilution. Aker BP will carefully consider alternative financing options, its overall capital structure, the purpose and need for new equity, the timing of such an offering, the offer share price, the financial market conditions and the need for compensating existing shareholders in the event that pre-emption rights are waived. Arguments for waiving pre-emption rights will be clearly stated.

In the event that the Board decides to use its current authorization to re-purchase company shares, the transactions will be carried out through the stock exchange or at prevailing stock exchange prices if carried out in any other way.

In October 2017, Aker BP entered into an agreement to acquire Hess Norge AS. As part of the transaction, Aker BP issued 22,376,438 shares at NOK 184 per share (including NOK 1.5 per share as payment for the associated rights to a cash dividend). The subscription price was set at an all-time high, with no discount to the market close prior to the announcement of the equity issue.

The equity issue was carried out as a private placement. The Board considered a private placement to be in the best interests of the company and its shareholders as the company was able to raise capital more quickly, with no discount to the trading price and with lower transaction costs and transaction risk than through a rights issue.

As per 31 December 2017, Aker Capital AS owned 40.0 per cent of Aker BP. Aker Capital AS is a wholly-owned subsidiary of Aker ASA. Following the merger with BP Norge AS in 2016, Aker ASA de-consolidated Aker BP and started to account for Aker BP in accordance with the equity method.

Aker BP is committed to equal treatment of all shareholders. The Board is of the view that it is positive for Aker BP that Aker ASA and BP plc assume the role of active owners and are actively involved in matters of major importance to Aker BP and to all shareholders. The cooperation with Aker ASA and BP plc offers Aker BP access to expertise- and resources within upstream business activities, technology, strategy, transactions and funding. It may be necessary to offer Aker ASA and BP plc special access to commercial information in connection with such cooperation. Any information disclosed to Aker ASA's and BP plc's representatives in such a context will be disclosed in compliance with the laws and regulations governing the stock exchange and the securities market.

Applicable accounting standards and regulations require Aker ASA and BP plc to prepare their consolidated financial statements to include accounting information of Aker BP. Aker BP is considered an associate of Aker ASA and BP plc under the applicable accounting standard. In order to comply with these accounting standards, Aker ASA and BP plc have in the past received, and will going forward receive, unpublished accounting information of Aker BP. Such distribution of unpublished accounting information from Aker BP to Aker ASA and BP plc is executed under strict confidentiality and in accordance with applicable regulations on the handling of inside information.

The Board recognizes Aker ASA's and BP plc's contribution as active shareholders. Investor communication seeks to ensure that any shareholders are able to contribute, and management will actively seek the views of shareholders. Investor activities are also directed at promoting higher stock liquidity to balance a shareholder structure with many long-term investors.

Aker BP has no related parties, as defined in the Public Limited Liability Company Act ("Almennaksjeloven"). The company has nevertheless established procedures for transactions with such parties and also extended these to include Aker ASA. The Board of Directors and executive management are nevertheless very conscious that all relations with Aker ASA and BP p.l.c, its subsidiaries and other companies in which Aker ASA or BP p.l.c have ownership interests or entities they have significant control over, shall be premised on commercial terms and are entered into on an arm's-length basis. Transactions with Aker and BP controlled companies are described in the financial statements' disclosure about transactions with related parties.

The company's employees are prohibited from engaging in financial activities of a potentially competitive nature in relation to Aker BP. The company's Code of Conduct provides clear guidelines as to how employees and representatives of the company's governing bodies should act in situations where there is a risk of conflicts of interest and partiality.

Deviations to the code: None

6. Freely negotiable shares

Aker BP's shares are freely negotiable securities, and the company's Articles of Association do not impose any form of restriction on their negotiability.

The company's shares are listed on the Oslo Børs and the company works actively to attract the interest of new shareholders, both Norwegian and foreign investors. Strong liquidity in the company's shares is essential if the company is to be viewed as an attractive investment and thus achieve a low cost of capital.

Deviations to the code: None

7. General meetings

The General Meeting of shareholders is the company's highest authority. The Board strives to ensure that the General Meeting is an effective forum for communication between the shareholders and the Board, and encourages shareholders to participate in the meetings.

The Board can convene an extraordinary General Meeting at any time. A shareholder or a group holding at least five per cent of the company's shares, can request an extraordinary General Meeting. The Board is then obliged to hold the meeting within one month of receiving the request.

Preparation for General Meetings

The AGM is normally held before the end of April each year, and no later than the end of June, which is the latest date permitted by the Public Limited Liability Companies Act. The date of the next AGM is normally included in the financial calendar.

The notice of a General Meeting is sent to the shareholders and published on the company's website and the stock exchange no later than 21 days prior to the meeting.

Article 7 in the company's Articles of Association, about the General Meeting, stipulates that documents concerning matters to be considered by the General Meeting, will be made available to the shareholders on the company's website. This also applies to documents that are required by law to be included in or enclosed with the notice of the General Meeting.

The supporting documentation provides the necessary information for shareholders to form a view on the matters to be considered.

Participation in a General Meeting

According to Article 7 in the Articles of Association, the right to attend and vote at the General Meeting can only be exercised when the share transaction is introduced in the shareholder register no later than the fifth business day prior to the General Meeting (registration date).

Shareholders who are unable to attend a General Meeting are encouraged to vote by proxy. A form for the appointment of a proxy, which allows separate voting instructions to be given for each matter to be considered by the meeting are included in the notice. The deadline for registration is set as close as possible to the date of the meeting, normally the day before.

Conduct of a General Meeting and agenda for AGM

The Board proposes the agenda for the AGM. The main agenda items are determined by the requirements of the Public Limited Liability Companies Act and Article 7 in the company's Articles of Association.

At the AGM in April 2018, the Board will nominate a person who can vote on behalf of the shareholders as their authorized representative. Shareholders may cast their votes in writing, including by means of electronic communication, in a given period prior to the General Meeting. Appropriate arrangements are made for shareholders to vote separately on candidates nominated for election to the company's corporate bodies.

Aker BP's General Meetings are normally chaired by the Chairman of the Board, or a person appointed by the Chairman of the Board. If there is reason to perceive the Chairman of the Board as being personally conflicted in respect of any matters then another person will be appointed to chair the meeting.

The Code states that it is appropriate that all members of the Board should attend General Meetings. Representatives from the Board, the nomination committee, the auditor and the executive management will attend the AGM. However, given the geographic distribution of the people, it is normal that some of these bodies may not be able to attend the AGM.

Minutes of General Meetings are published on the company's website and through a stock exchange announcement.

Deviations from the code: The code recommends that all members of the Board are present at the General Meeting and that all members of the Nomination Committee should attend the AGM. Due to the nature of discussions at General Meetings, Aker BP has not deemed it necessary to require all Board members and nomination committee members to be present.

8. Nomination committee

Article 8 in the company's Articles of Association stipulates that the Nomination Committee shall consist of three members elected by the General Meeting. It also stipulates that the majority of the members shall be independent of the Board and the executive management and that the members shall be elected for a period of two years at a time. The committee's remuneration is determined by the General Meeting.

At the AGM in April 2016, Finn Haugan and Hilde Myrberg were re-elected as members of the Nomination Committee for two years. Arild Støren Frick was re-elected as the Chair of the Nomination Committee in 2017. No members of the committee are members of executive management or the Board of Aker BP.

The Nomination Committee should be composed in such a way that it represents a wide range of shareholders' interests. It should also be strived for both genders being represented in the committee. The Nomination Committee's duties are also stated by Article 8 in the Articles of Association. The committee shall propose candidates for - and remuneration to - the Board of Directors and the Nomination Committee and justify its recommendation.

Shareholders have an opportunity to submit proposals to the committee. The electronic mailbox for submitting proposals to the committee, with deadlines for submitting proposals where such apply, is accessible through our website at http://www.akerbp.com/proposecandidate/.

Deviations from the code: None

9. Board of directors: composition and independence

The Board of Aker BP consisted of eleven members as of 31 December 2017. The company's Articles of Associations, Article 5, stipulates that the Board shall consist of between five and eleven members and the members shall be elected for a period of up to two years.

Among the shareholder-elected Board members, two (Kjell Inge Røkke and Øyvind Eriksen) are affiliated with the company's largest shareholder Aker ASA. Deputy Chair Anne Marie Cannon is a member of the Board of Directors for Aker ASA. Among the shareholder-elected Board members, two (Bernard Looney and Kate Thomson) are affiliated with the company's second largest shareholder BP plc. All other Board members are considered independent of the company's two main shareholders, as well as of the company's material business contacts. All Board members are considered independent of the company's executive personnel.

In 2017, the Board has conducted a total of 10 Board meetings. Participation was 95 percent.

The Board composition ensures alignment of interests with all shareholders and members of the Board are encouraged to own shares in the company. It is the Board's view that the Board collectively meets the need for expertise, capacity and diversity. Board members possess strong experience from banking and finance, oil and gas sector in general, and reservoir engineering, exploration and field development in particular.

An overview of the expertise of the Board members is available on the website:
http://www.akerbp.com/en/about-us/board-of-directors/.

The Corporate Assembly was abolished in the third quarter 2017. This was based on a suggestion by employees, and a subsequent referendum among the employees in which the majority voted in favour of such abolishment.

Deviations from the code: None

10. The work of the board of directors

The Board has adopted a yearly plan for its activities. The Board has authority over and is responsible for supervising the company's business operations and management. The Board handles matters of major importance, or of an extraordinary nature and may in addition require management to refer any matter to it. The Board's objectives are to create value for the company's shareholders in both the short and long term and to ensure that Aker BP fulfils its obligations at all times. An important task for the Board is to appoint the CEO and while the CEO is responsible for the day-to-day management of the company's business activities, the Board acknowledges its responsibility for the overall management of the company. The Board is responsible for:

A. Drawing up strategic plans and supervising these through regular reporting and reviewing,

B. Identifying significant risks to Aker BP's activities and establishing appropriate systems to monitor and manage such risks,

C. Ensuring that shareholders have access to timely and correct information about financial circumstances and important business-related events in accordance with relevant legislation, and

D. Ensuring the establishment and securing the integrity of the company's internal control and management systems.

The Board recognizes the significant risks associated with the operations. Consequently, the Board has dedicated significant resources and time to understand and discuss not only general risks facing an E&P company, but also inherent risks connected to organization, culture and leadership. For a company like Aker BP, the Board views the risks in taking on an operated development project and meeting the required financing for its entire portfolio as well as taking on operated assets, to be among the most significant risks. Accordingly, this is where the mitigating efforts are concentrated.

The work of the Board is based on the rules of procedure describing the Board's responsibility including division of roles between the Board and the CEO. There are specific instructions to guide the work of the CEO. The CEO, CFO and the company secretary attend all Board meetings. Other members of the company's executive management attend the Board meetings per invitation and as necessary due to specific matters. If the Chair of the Board has been personally involved in matters of a material character, the Deputy Chair takes over the tasks of the chair directing the Board's work in the specific matter.

Considering the size of the company and the scope of its activities, the Board finds it appropriate to keep all Board members informed about all Board matters, except for cases where Board members may have conflicting interests with the company. The Board carried out a self-evaluation of its own performance for 2017 also comprising an evaluation of the Board's competence and potential areas for strengthening this competence.

Audit and Risk Committee

The Board has established an Audit and Risk Committee consisting of the following Board members:

- Trond Brandsrud, Chair
- Anne Marie Cannon
- Kate Thomson

All members are independent of the company's executive management. Anne Marie Cannon sits on the Board of Directors in Aker ASA, the largest shareholder in Aker BP and Kate Thomson is Group Treasurer with BP plc.

The Chair of the Audit and Risk Committee is considered to have experience and formal background qualifying as "financial expert" according to the requirement stated in the Public Limited Liability Company Act. Trond Brandsrud is Group Executive Officer at RemCo. Until 2015, he was the Chief Financial Officer of Aker ASA, he has been Chief Financial Officer in Seadrill, and he has held several leading financial positions in Shell for 20 years, both in Norway and globally. The Audit and Risk Committee holds regular meetings and reviews the quality of all interim and annual reports before they are reviewed by the Board of Directors and then published. In 2017, the committee held nine meetings. The company's auditor works closely with the Audit and Risk Committee on a regular basis. The committee also oversees the company's financial risk management and monitors and reviews the company's business risk. The management and the Audit and Risk Committee evaluate the risk management on financial reporting and the effectiveness of established internal controls. Identified risks and effects of financial reporting are discussed on a quarterly basis. Oversight of HSE and operational risks is retained directly by the Board.

All meetings in conjunction with quarterly reporting and accounts have taken place together with the company's auditor. It is the view of the committee that cooperation between the auditor and executive management is good. The Audit and Risk Committee has worked together with executive management and the auditor to improve the internal control environment according to the COSO (Committee of Sponsoring Organizations of the Treadway Commission) framework over the last years.

Compensation and Organizational Development Committee

Also, the Board has a Compensation and Organizational Development Committee consisting of the following three Board members:

- Øyvind Eriksen, Chair
- Gro Kielland
- Terje Solheim

The Compensation and Organizational Development Committee is established to ensure that remuneration arrangements support the strategy of the business and enable the recruitment, succession planning and leadership development, and motivation and retention of senior executives. It needs to comply with the requirements of regulatory and governance bodies, satisfy the expectations of shareholders and remain consistent with the expectations of the wider employee population. Further, the committee shall ensure that the overall organizational structure is set up to deliver on the company's strategy going forward.

In addition to the Audit and Risk Committee and Compensation and Organizational Development Committee, the Board may appoint various ad hoc sub-committees when required, with a limited timeframe and scope. The sub-committees' authority is limited to prepare items and make recommendations to the Board.

Deviations from the code: None

11. Risk management and internal control

Risk Management

Appropriate internal control and risk management contributes to the transparency and quality reporting for the benefit of the company, shareholders' long-term interests and the operational challenges as an operator on the Norwegian Continental Shelf.

The company continuously and systematically operates a robust and transparent risk management process vertically and horizontally throughout the organisation.

The company's operational activities are limited to Norway and are subject to Norwegian regulations. All activities taking place in a production license are subject to supervision and audits from governmental bodies (e.g. the Petroleum Safety Authority Norway (Norwegian PSA) and the Norwegian Environment Agency), and license partners.

The Board considers risk in the context of growing a sustainable business while meeting governance, safety and accountability expected by stakeholders. The Board and the Audit and Risk Committee (ARC) regularly review major risks identified and reported through the company Enterprise Risk Management process

The Business Management System (BMS) is formed by a cultural framework and a structural framework. The structural framework consists of twelve common governing models, the asset value chain and a set of technical support and business support process areas. The Risk Governance model was updated in 2017 to better integrate barrier management in our risk management operations. The purpose of the process is to enable the company to maximise opportunities, minimise threats and optimise achievements of business objectives. We address and manage risk across silos throughout the asset value chain. One common way of working supported by a common infrastructure enables holistic risk management at all levels.

The company has identified specific areas for further improvements in 2018 to ensure full integration of the risk management system in the way we conduct our business. These improvement initiatives are stated in the company's Health, Safety and Environment (HSE) plan.

Risk management priorities for 2018 include improving performance and risk management integration alongside further embedding of the Enterprise Risk Management process in the organisation. This will be coupled with further maturing the overall risk management capability.

The company's risk response includes monitoring of emerging risks through continuous analysis and engagement with operational management. The company may consult external advisors to find the most appropriate and balanced risk response.

Internal control for financial reporting

Aker BP has established a framework for Internal Control for Financial Reporting based on COSO (Committee of Sponsoring Organizations of the Treadway Commission) and is operationalized as follows:

- Internal Control Environment
- Objective setting
- Event Identification and Risk Assessment
- Risk Response and Control Activities
- Information and communication
- Monitoring

The established framework is an integrated part of the company's management system. The company's internal control environment is characterized by clearly defined responsibilities and roles between the Board of Directors, Audit and Risk committee and management. The implemented procedure for financial reporting is integrated with the company's management system, including ethical guidelines that describe how the representatives of the company must act.

The company has established processes, procedures and controls for financial reporting, which are appropriate for an exploration and production company. The company's documented procedures enable:

- Effective and appropriate identification of risks
- Measurement of compliance against procedures
- Sufficient segregation of duties
- Provision of relevant, timely and reliable financial reporting that provides a fair view of Aker BP's business
- Prevention of manipulation/fraud of reported figures
- Compliance with all relevant requirements of IFRS

A risk assessment related to financial reporting is performed and documented by the management. Risk assessments are monitored by the Audit and Risk Committee on a quarterly basis as part of the quarterly reporting process. The Board of Directors approves the overall risk assessment related to financial reporting on an annual basis. In 2017, the following main risk areas were identified related to financial reporting:

- Business combination with Hess Norge AS – Complexity in purchase price allocation following the acquisition
- Impairment of goodwill, tangible and intangible assets – There is a risk that fair value declines are not identified and recorded in an appropriate manner
- Tax – Complexity in tax regulations and calculation entail risk of error in financial reporting
- Transformation to become an even larger exploration and production company – There is a risk that the company does not have adequate procedures and systems for financial and reserves reporting
- Asset retirement obligation - There is a risk of errors in the estimates and calculations during the ARO process

The company seeks to communicate transparently on its activities and its financial reporting which is made after significant interaction with management responsible for exploration, development and production activities in the business.

Key events that may affect the financial reporting are identified and monitored continuously. An "Issue list" is established to address possible accounting and tax effects of events and activities. Both the auditor and the Audit and Risk committee review the "Issue list" at least on a quarterly basis.

The Finance Department monitors the compliance with established procedures and reports any material deviations to the Audit and Risk Committee. It also identifies actions to improve procedures and conducts a self-assessment of its performance against objectives, which are then presented and discussed with the Audit and Risk committee. 2017 has been a transitional year following the merge with BP Norge AS. A new Business Management system which describes all key controls have been implemented in 2017. Further, a project has been ongoing in 2017 to develop a new accounting system and fully integrate the previous BP Norge AS in this system and maintain the best of internal control environment from both companies. The new accounting system went live in January 2018.

In 2018, Aker BP will continue to focus on improvements of internal controls and further develop the new accounting system. The internal control environment will be evaluated and strengthened as part of the new SAP solution for Aker BP.

Deviations from the code: None

12. Remuneration of the board of directors

The remuneration of the Board members is not performance-based, but based on a fixed annual fee. None of the shareholder-elected Board members have pension schemes or termination payment agreements with the company. Information about all remuneration paid to individual Board members is provided in Note 9 to the annual accounts.

The General Meeting decides the remuneration of the Board and the sub-committees. The Nomination Committee proposes the remuneration of the Board to the General Meeting and ensures that it reflects the responsibility of its members and the time spent on Board work. The Board must approve any Board member's consultancy work for the company and remuneration for such work. No such work was carried out during 2017.

Deviations from the code: None

13. Executive remuneration

The Board makes guidelines for executive remuneration, including the CEO's remuneration and other terms and conditions of employment. Note 9 to the annual accounts contain details about the remuneration of the Board and Executive Management Team, including payroll, bonus payments and pension expenses.

The bonus for employees except EMT varies from max 10% to 30% based on internal job grade. From 2017 all employees have the bonus determined on the Company-wide key performance indicators (KPIs) and priorities.

Members of EMT have individual maximum bonus potential varying from 60 per cent to 100 per cent of their base salary. In addition, certain members of the EMT participate in a one-off, three-year incentive program started in 2015 linked to the relative performance of the Aker BP share price versus a benchmark index consisting of the average of the Oslo Stock Exchange Energy Index and the Stoxx 600 Europe Oil & Gas index. Total payment in 2018 is capped at 60 per cent of the executive manager's annual base salary or a monetary amount.

The pension scheme continued to be a defined contribution plan capped at twelve times the National Insurance scheme basic amount (12G) for all employees including the executive management.

Deviations from the code: None

14. Information and communication

Aker BP maintains a proactive dialogue with analysts, investors and other stakeholders of the company. The company strives to continuously publish relevant information to the market in a timely, effective and non-discriminatory manner, and has a clear goal to attract both Norwegian and foreign investors and to promote higher stock liquidity.

All stock exchange announcements are made available on the Oslo Børs website, www.newsweb.no, as well as the company's website (www.akerbp.com) at the same time. The announcements are also distributed to news agencies and other online services.

Aker BP publishes its preliminary annual accounts by the end of February, as part of its fourth quarter report. The complete annual report, including approved and audited accounts and the Board of Directors' Report, is available no later than three weeks before the AGM. Information sent to shareholders is published on the web site simultaneously.

The company's financial calendar for the coming year is published as a stock exchange announcement and made available on the company's website no later than 31 December each year, in accordance with the continuing obligations for companies listed at the Oslo Børs.

Aker BP holds open presentations in connection with the publication of the company's quarterly results in addition to an annual capital markets day. The presentations are webcasted for the benefit of investors who are prevented from attending or do not wish to attend the presentations. At the presentations, the executive management review and comment on the published results, market conditions and the company's future activities.

The company's management gives high priority to communication with the investor market. Individual meetings are organized for a wide range of existing and potential new investors and analysts. The company also attends relevant industry and investor conferences.

Aker BP will reduce its contacts with analysts, investors and journalists in the final two weeks before publication of its results. During this period, the company will give no comments to the media or other parties about the company's results and future outlook. This is to ensure that all interested parties in the market are treated equally.

Deviations from the code: None

15. Takeovers

The Board has established a separate set of guidelines for how it will act in the event of a takeover bid, as recommended by the Code. The overriding principle for review of a takeover bid is equal treatment of the shareholders. The principles are based on the Board of Directors and management having an independent responsibility for fair and equal treatment of the shareholders in a takeover process, and that the day-to-day operations of the company are not unnecessarily disturbed. It is management's responsibility to ensure that the Board of Directors is made aware of any potential takeover bid, while the Board of Directors is responsible for ensuring that shareholders are kept informed and are given reasonable time to consider the offer.

Unless the Board of Directors has particular reason, it will not take steps to prevent or obstruct a takeover bid for the company's shares, nor hinder the progress of the bid without approval from the shareholders.

If an offer is made for Aker BP's shares, the Board of Directors should make a statement to the shareholders that contains an assessment of the bid, the Board of Directors' recommendations and the reason for the recommendation. If the Board of Directors is unable to make a recommendation to the shareholders, the Board of Directors shall explain its reasoning for this.

Transactions that have the effect of a sale of the company or a major part of it must be decided on by the shareholders at shareholders' meeting.

Deviations from the code: None

16. Auditor

The AGM elects the auditor and approves the auditor's fee. The Board of Directors will meet with the auditor annually without representatives of the company management being present, to review internal control procedures and discuss any weaknesses and proposals for improvement. The auditor participates in the Board meetings to discuss the annual accounts.

The auditor participates in all meetings with the Audit and Risk Committee and meets the Audit and Risk Committee without the company's management being present. The auditor submits the main features of the plan for the annual audit of the company to the Audit and Risk Committee annually. The auditor's independence in relation to the company is evaluated annually. A complete auditor evaluation for 2017 has been performed by the audit committee. The auditor may carry out certain audit related or non-audit services for the company, providing these are not in conflict with its duties as auditor. The company has established an audit and non-audit service policy.

In the annual financial statements, the auditor's remuneration is split between the audit fee and fees for other services. In the presentation to the AGM, the chair presents the breakdown between the audit fee and fees for other services.

Deviations from the code: None

Financial Statements 2017

FINANCIAL STATEMENTS WITH NOTES

OVERVIEW OF THE FINANCIAL STATEMENTS AND NOTES

INCOME STATEMENT

(USD 1 000)	Note	Group 2017	Group 2016	Parent 2017	Parent 2016
Petroleum revenues	7	2 575 654	1 260 803	2 575 654	1 129 939
Other income	7	-12 721	103 326	-12 721	-12 242
Total income		**2 562 933**	**1 364 129**	**2 562 933**	**1 117 697**
Exploration expenses	5	225 702	147 453	225 702	138 878
Production costs		523 379	226 818	523 379	166 219
Depreciation	13	726 670	509 027	726 670	495 876
Impairments	13, 14	52 349	71 375	52 349	71 375
Other operating expenses	9	27 606	21 993	27 582	24 549
Total operating expenses		**1 555 705**	**976 665**	**1 555 682**	**896 897**
Operating profit/loss		**1 007 228**	**387 464**	**1 007 252**	**220 800**
Interest income		7 716	5 795	7 012	5 516
Other financial income		75 507	42 871	116 401	64 068
Interest expenses		103 627	82 161	123 171	89 438
Other financial expenses		175 696	63 515	176 052	81 101
Net financial items	10	**-196 100**	**-97 011**	**-175 810**	**-100 955**
Profit/loss before taxes		**811 128**	**290 453**	**831 441**	**119 844**
Taxes (+)/tax income (-)	11	536 340	255 482	531 487	84 874
Net profit/loss		**274 787**	**34 971**	**299 955**	**34 971**
Weighted average no. of shares outstanding basic and diluted	12	340 189 283	236 582 807	340 189 283	236 582 807
Basic and diluted earnings/loss(-) USD per share	12	0.81	0.15	0.88	0.15

STATEMENT OF COMPREHENSIVE INCOME

(USD 1 000)	Note	Group 2017	Group 2016	Parent 2017	Parent 2016
Profit/loss for the period		274 787	34 971	299 955	34 971
Items which will not be reclassified over profit and loss (net of taxes)					
Actuarial gain/loss pension plan		-1	-	-1	-
Items which may be reclassified over profit and loss (net of taxes)					
Currency translation adjustment		25 167	-59	-	-59
Total comprehensive income in period		**299 953**	**34 911**	**299 953**	**34 911**

STATEMENT OF FINANCIAL POSITION

		Group		Parent	
(USD 1 000)	Note	31.12.2017	31.12.2016	31.12.2017	31.12.2016
ASSETS					
Intangible assets					
Goodwill	13	1 860 126	1 846 971	1 860 126	1 846 971
Capitalized exploration expenditures	13	365 417	395 260	365 417	395 260
Other intangible assets	13	1 617 039	1 332 813	1 617 039	1 332 813
Tangible fixed assets					
Property, plant and equipment	13	5 582 493	4 441 796	5 582 493	4 441 796
Financial assets					
Long-term receivables		40 453	47 171	40 453	47 171
Long-term derivatives	22	12 564	-	12 564	-
Other non-current assets	17	8 398	12 894	1 594 404	1 932 014
Total non-current assets		**9 486 491**	**8 076 905**	**11 072 497**	**9 996 025**
Inventories					
Inventories	6	75 704	69 434	75 704	69 434
Receivables					
Accounts receivable	15	99 752	170 000	99 752	170 000
Tax receivables	11	1 586 006	400 638	-	139 443
Other short-term receivables	16	535 518	422 932	535 518	422 932
Short-term derivatives	22	2 585	-	2 585	-
Cash and cash equivalents					
Cash and cash equivalents	18	232 504	115 286	232 504	115 286
Total current assets		**2 532 069**	**1 178 290**	**946 063**	**917 096**
TOTAL ASSETS		**12 018 560**	**9 255 196**	**12 018 560**	**10 913 121**

STATEMENT OF FINANCIAL POSITION

		Group		Parent	
(USD 1 000)	Note	31.12.2017	31.12.2016	31.12.2017	31.12.2016
EQUITY AND LIABILITIES					
Equity					
Share capital	19	57 056	54 349	57 056	54 349
Share premium		3 637 297	3 150 567	3 637 297	3 150 567
Other equity		-705 756	-755 709	-705 756	-755 709
Total equity		**2 988 596**	**2 449 207**	**2 988 596**	**2 449 207**
Non-current liabilities					
Deferred taxes	11	1 307 148	1 045 542	1 307 148	1 045 542
Long-term abandonment provision	21	2 775 622	2 080 940	2 775 622	2 080 940
Provisions for other liabilities	23	152 418	218 562	152 418	218 562
Long-term bonds	20	622 039	510 337	622 039	510 337
Long-term derivatives	22	13 705	35 659	13 705	35 659
Other interest-bearing debt	24	1 270 556	2 030 209	1 270 556	2 030 209
Current liabilities					
Trade creditors		32 847	88 156	32 847	88 156
Accrued public charges and indirect taxes		27 949	39 048	27 949	39 048
Tax payable	11	351 156	92 661	351 156	92 661
Short-term derivatives	22	7 691	5 049	7 691	5 049
Short-term abandonment provision	21	268 262	75 981	268 262	75 981
Short-term interest-bearing debt	24	1 496 374	-	1 496 374	-
Other current liabilities	25	704 197	583 844	704 197	2 241 770
Total liabilities		**9 029 964**	**6 805 988**	**9 029 964**	**8 463 914**
TOTAL EQUITY AND LIABILITIES		**12 018 560**	**9 255 196**	**12 018 560**	**10 913 121**

The Board of Directors and the CEO of Aker BP ASA
Akerkvartalet, 8 March 2018

Øyvind Eriksen, Chair of the Board

Kjell-Inge Røkke, Board member

Anne Marie Cannon, Deputy Chair

Trond Brandsrud, Board member

Gro Kielland, Board member

Bernard Looney, Board member

Bjørn Thore Synsvoll Ribesen, Board member

Terje Solheim, Board member

Lone Margrethe Olstad, Board member

Kate Thomson, Board member

Karl Johnny Hersvik, Chief Executive Officer

Ørjan Holstad, Board member

STATEMENT OF CHANGES IN EQUITY - GROUP AND PARENT

			Other equity					
				Other comprehensive income				
(USD 1 000)	**Share capital**	**Share premium**	Other paid-in capital	Actuarial gains/(losses)	Foreign currency translation reserves*	Retained earnings	**Total other equity**	**Total equity**
Equity as of 31.12.2015	**37 530**	**1 029 617**	573 083	-88	-115 491	-1 185 625	**-728 121**	**339 026**
Private placement	16 820	2 120 950	-	-	-	-	-	2 137 769
Dividend distributed	-	-	-	-	-	-62 500	-62 500	-62 500
Profit/loss for the period	-	-	-	-	-	34 971	34 971	34 971
Other comprehensive income for the period	-	-	-	-	-59	-	-59	-59
Equity as of 31.12.2016	**54 349**	**3 150 567**	573 083	-88	-115 550	-1 213 154	**-755 709**	**2 449 207**
Private placement	2 706	486 729	-	-	-	-	-	489 436
Dividend distributed	-	-	-	-	-	-250 000	-250 000	-250 000
Profit/loss for the period	-	-	-	-	-	274 787	274 787	274 787
Other comprehensive income for the period	-	-	-	-1	25 167	-	25 166	25 166
Equity as of 31.12.2017 (Group)	**57 056**	**3 637 297**	573 083	-89	-90 383	-1 188 366	**-705 756**	**2 988 596**
Parent adjustment								
Profit/loss for the period	-	-	-	-	-	25 167	25 167	25 167
Other comprehensive income for the period	-	-	-	-	-25 167	-	-25 167	-25 167
Equity as of 31.12.2017 (Parent)	**57 056**	**3 637 297**	573 083	-89	-115 550	-1 163 199	**-705 756**	**2 988 596**

* The main part of the foreign currency translation reserve arose as a result of the change in functional currency in Q4 2014

STATEMENT OF CASH FLOW

(USD 1 000)	Note	Group 2017	Group 2016	Parent 2017	Parent 2016
CASH FLOW FROM OPERATING ACTIVITIES					
Profit/loss before taxes		811 128	290 453	831 441	119 844
Taxes paid during the period		-101 115	-1 419	-101 115	-1 419
Tax refund during the period		404 704	212 944	140 913	208 036
Depreciation	13	726 670	509 027	726 670	495 876
Net impairment losses	13, 14	52 349	71 375	52 349	71 375
Accretion expenses	10, 21	129 619	47 977	129 619	33 473
Interest expenses	10	156 704	160 808	176 248	168 084
Interest paid		-145 940	-161 634	-145 940	-161 634
Changes in derivatives	7, 10	-34 461	10 408	-34 461	10 408
Amortized loan costs	10	36 900	17 915	36 900	17 915
Gain on change of pension scheme	7	-	-115 616	-	-
Amortization of fair value of contracts		11 728	-	11 728	-
Expensed capitalized dry wells	5, 13	75 401	51 669	75 401	51 669
Changes in inventories, accounts payable and receivables		-7 583	-317 488	-7 583	-317 488
Changes in abandonment liabilities through income statement		-27	-1 131	-27	-3 373
Changes in other current balance sheet items		39 414	120 365	-444	198 631
NET CASH FLOW FROM OPERATING ACTIVITIES		**2 155 491**	**895 652**	**1 891 700**	**891 397**
CASH FLOW FROM INVESTMENT ACTIVITIES					
Payment for removal and decommissioning of oil fields	21	-85 733	-12 237	-85 733	-9 995
Disbursements on investments in fixed assets	13	-977 462	-935 755	-977 462	-934 410
Acquisitions of Hess Norge AS / BP Norge AS (net of cash acquired)	2	-2 055 033	423 990	-2 055 033	-27 507
Acquisition of Premier Oil Norge AS (net of cash acquired)		-	-	-	11 300
Cash received from sale of licenses		170 959	-	170 959	-
Disbursements on investments in capitalized exploration expenditures and other intangible assets	13	-111 724	-181 492	-111 724	-180 825
Dividend from BP Norge AS		-		263 791	451 497
NET CASH FLOW USED IN INVESTMENT ACTIVITIES		**-3 058 994**	**-705 494**	**-2 795 203**	**-689 940**
CASH FLOW FROM FINANCING ACTIVITIES					
Repayment of long-term debt	24	-777 911	-612 825	-777 911	-612 825
Repayment of bond (DETNOR03)	10, 20	-330 000	-	-330 000	-
Net cash received from issuance of new shares	19	489 436	-	489 436	-
Net proceeds from issuance of debt	20, 24	1 886 885	512 013	1 886 885	512 013
Paid dividend		-250 000	-62 500	-250 000	-62 500
NET CASH FLOW FROM FINANCING ACTIVITIES	28	**1 018 410**	**-163 312**	**1 018 410**	**-163 312**
Net change in cash and cash equivalents		**114 906**	**26 846**	**114 906**	**38 145**
Cash and cash equivalents at start of period		115 286	90 599	115 286	79 299
Effect of exchange rate fluctuation on cash held		2 312	-2 158	2 312	-2 158
CASH AND CASH EQUIVALENTS AT END OF PERIOD	18	**232 504**	**115 286**	**232 504**	**115 286**
SPECIFICATION OF CASH EQUIVALENTS AT END OF PERIOD					
Bank deposits and cash		231 506	106 369	231 506	106 369
Restricted bank deposits		998	8 917	998	8 917
CASH AND CASH EQUIVALENTS AT END OF PERIOD	18	**232 504**	**115 286**	**232 504**	**115 286**

NOTES TO THE ACCOUNTS

General information

Aker BP ASA (Aker BP or the company) is an oil company involved in exploration, development and production of oil and gas on the Norwegian Continental Shelf (NCS).

The company is a public limited liability company registered and domiciled in Norway. Aker BP's shares are listed on Oslo Stock Exchange (Oslo Børs) under the ticker AKERBP. The company's registered business address is Oksenøyveien 10, 1366 Lysaker, Norway.

Aker BP's group consolidated financial statements consist of the parent company Aker BP ASA and the subsidiaries BP Norge AS and Aker BP AS (previously Hess Norge AS) which has been consolidated from the acquisition date 22 December 2017. The acquisition of Hess Norge AS has been accounted for as a business combination in accordance with IFRS 3. Immediately after the acquisition of the shares, all assets and liabilities in Hess Norge AS, except for tax loss carried forward, were transferred to Aker BP. The subsidiary BP Norge AS was liquidated during 2017. For more information regarding subsidiaries, see Note 3.

The financial statements were approved by the Board of Directors on 8 March 2018 and will be presented for approval at the Annual General Meeting on 11 April 2018.

Note 1 – Summary of IFRS accounting principles

1.1 Basis of preparation

The group consolidated and the company's financial statements have been prepared in accordance with the Norwegian Accounting Act and International Financial Reporting Standards (IFRS) as adopted by the EU.

The financial statements have been prepared on a historical cost basis with the exception of the following accounting items which are measured on an alternative basis on each reporting date:

- Financial instruments at fair value through profit or loss.
- Loans, receivables and other financial liabilities, which are recognized at amortized cost.

The financial statements have been prepared using uniform accounting principles for equivalent transactions and events taking place on otherwise equal terms.

All amounts have been rounded to the nearest thousand unless otherwise stated. As a result of rounding adjustments, the figures in one or more rows or columns included in the financial statements and notes may not add up to the total of that row or column.

1.2 Functional currency and presentation currency

The functional currency of Aker BP ASA and the presentation currency of the group is USD.

1.3 Important accounting judgments, estimates and assumptions

The preparation of financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions that have an effect on the application of accounting principles and on recognized amounts relating to assets and liabilities, to provide information relating to contingent assets and liabilities on the date of the Statement of financial position, and to report revenues and expenses in the course of the accounting period.

The important judgments management has made on the application of accounting principles relate to the following:

Goodwill allocation and methodology for impairment testing: For the purpose of impairment testing, goodwill is allocated to cash-generating unit (CGU), or groups of cash-generating units, that are expected to benefit from the synergies of the business combination from which it arose. The appropriate allocation of goodwill requires management's judgment and may impact the subsequent impairment charge significantly. Although not an IFRS term, “technical goodwill” is used by Aker BP to describe a category of goodwill arising as an offsetting account to deferred tax recognised in business combinations, as described in Section 1.8 below. There are no specific IFRS guidelines pertaining the allocation of technical goodwill, and management has therefore applied the general guidelines for allocating goodwill for the purpose of impairment testing. In general, technical goodwill is allocated to CGU level for impairment testing purposes, while residual goodwill may be allocated across all CGUs based on facts and circumstances in the business combination.

When performing the impairment test for technical goodwill, deferred tax recognized in relation to the acquired licences reduces the net carrying value prior to the impairment charges. This is done to avoid an immediate impairment of all technical goodwill. When deferred tax from the initial recognition decreases, more goodwill is as such exposed for impairment. Going forward, depreciation of values calculated in the purchase price allocation will result in decreased deferred tax liability.

On selling a licence where the company historically has recognized deferred tax and goodwill in a business combination, both goodwill and deferred taxes from the acquisition are included when calculating gain/loss. When recording impairment of such licences as a result of impairment testing, the same assumptions are applied when measuring the impairment. This avoids a gross up of the impairment with tax, in that the impairment charged to the Income statement will not be higher than the original post-tax amount paid in the business combination.

Accounting estimates are used to determine reported amounts, including the possibility of realizing certain assets, the expected useful life of tangible and intangible assets, the tax expense, etc. Even though these estimates are based on management’s best judgment and assessment of previous and current events and actions, the actual results may deviate from the estimates. The estimates and underlying assumptions are reviewed regularly. Changes to the estimates are recognized when new estimates can be determined with sufficient certainty. Changes to accounting estimates are recognized in the period when they arise. The main sources of uncertainty when using estimates for the company relate to the following:

Proven and probable oil and gas reserves: Oil and gas reserves are estimated by the company’s experts in accordance with industry standards. The estimates are based on Aker BP’s own assessment of internal information and information received from the operators. In addition, reserves are certified by an independent third party. Proven and probable oil and gas reserves consist of the estimated quantities of crude oil, natural gas and condensates shown by geological and technical data to be recoverable with reasonable certainty from known reservoirs under existing economic and operational conditions, i.e. on the date that the estimates are prepared. Current market prices are used in the estimates, except for existing contractual future price changes.

Proven and probable reserves and production volumes are used to calculate the depreciation of oil and gas fields by applying the unit-of-production methodology. Reserve estimates are also used as basis for impairment testing of licence-related assets. Changes in petroleum prices and cost estimates may change reserve estimates and accordingly economic cut-off, which may impact the timing of assumed decommissioning and removal activities. Changes to reserve estimates can also be caused by updated production and reservoir information. Future changes to proven and probable oil and gas reserves can have a material effect on depreciation, life of field, impairment of licence-related assets, and operating results.

Successful Effort Method - exploration: Aker BP’s accounting policy is to temporarily recognize expenses relating to the drilling of exploration wells in the Statement of financial position as capitalized exploration expenditures, pending an evaluation of potential oil and gas discoveries. If resources are not discovered, or if recovery of the resources is considered technically or commercially unviable, the costs of exploration wells are expensed. Decisions as to whether this expenditure should remain capitalized or be expensed during the period, may materially affect the operating result for the period.

Acquisition costs: Expenses relating to the acquisition of exploration licences are capitalized and assessed for impairment if there are indications of impairment. See Items 1.11 and 1.12 for further details.

Fair value measurement: From time to time, the fair values of non-financial assets and liabilities are required to be determined, e.g. when the entity acquires a business, determines allocation of purchase price in an asset deal or where an entity measures the recoverable amount of an asset or CGU at fair value less cost to sell. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest.

A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset in its highest and best use or by selling it to another market participant that would use the asset in its highest and best use. The group uses valuation techniques that are appropriate in the circumstances and for which sufficient data are available to measure fair value, maximizing the use of relevant observable inputs and minimizing the use of unobservable inputs. The fair value of oil fields in production and development phase is normally based on discounted cash flow models, where the determination of the different input in the model requires significant judgment from management, as described in the section below regarding impairment.

Impairment/reversal of impairment: Aker BP has significant investments in long-lived assets. Changes in the expected future value/cash flow of individual assets can result in the book value of some assets being impaired to estimated recoverable value. Impairment losses other than those relating to goodwill must be reversed if the conditions for the impairment are no longer present. Considerations regarding whether an asset is actually impaired or whether the impairment losses should be reversed can be complicated and are based on judgement and assumptions. The complexity of the issue can, for example, relate to the modelling of relevant future cash flows to determine the asset’s value in use, decide on measurement units and establish the asset’s net sales value.

The evaluation of impairment requires long-term assumptions concerning a number of often volatile economic factors, including future oil prices, oil production, currency exchange rates and discount rates. Such assumptions require the estimation of relevant factors such as forward price curves (oil), long-term price assumptions, the level of capex and opex, production estimates and residual asset values. Likewise, establishing an asset’s net sales value requires careful assessment unless information about net sales value can be obtained from an actual observable market. See Note 13 ’ Tangible fixed assets and intangible assets’ and Note 14 ’Impairments’ for details about impairment.

Decommissioning and removal obligations: The company has considerable obligations relating to decommissioning and removal of offshore installations at the end of the production period. Obligations associated with decommissioning and removal of long-term assets are recognized at present value of future expenditures on the date they are incurred. At the initial recognition of an obligation, the estimated cost is capitalized as production plant and depreciated over the useful life of the asset (typically by unit-of-production). It is difficult to estimate the costs for decommissioning and removal at initial recognition as these estimates are based on currently applicable laws and regulations, and are dependent on technological developments. Many decommissioning and removal activities will take place in the distant future, and the technology and related costs are constantly changing. The estimates include costs based on expected removal concepts based on known technology and estimated costs of maritime operations, hiring of heavy-lift barges and drilling rigs. As a result, the initial recognition of the obligation in the accounts, the related costs capitalized in the Statement of financial position for decommissioning and removal and subsequent adjustment of these items, involve careful consideration. Based on the described uncertainty, there may be significant adjustments in estimates of liabilities that can affect future financial results. See Note 21 for further details about decommissioning and removal obligations.

Income tax: The company may incur significant amounts of income tax payable or receivable, and recognizes significant changes to deferred tax or deferred tax assets. These figures are based on management’s interpretation of applicable laws and regulations, and on relevant court decisions. The quality of these estimates is highly dependent on management’s ability to properly apply a complex set of rules and identify changes to the existing legal framework. See Note 11 for details about the deferred tax and taxes payable.

1.4 Foreign currency transactions

Transactions and balances

Transactions in foreign currencies are translated using the exchange rate on the transaction date. Monetary items in foreign currencies in the Statement of financial position are translated using the exchange rates at the end of the period. Foreign exchange gains and losses are recognized on an ongoing basis in the accounting period. Non-monetary items that are measured in terms of historical costs in a foreign currency are translated using the exchange rates on the dates of the initial transactions. Non-monetary items measured at fair value in a foreign currency are translated using the exchange rates on the date when the fair value is determined.

Group companies

The results and financial position of group companies that have a functional currency different from the presentation currency are translated into the presentation currency as follows:

(i) Assets and liabilities for each balance sheet presented are translated based on the exchange rates at the balance sheet date.

(ii) Revenues and expenses for each Income statement presented are translated at average exchange rate for the period. However, if this average is not a reasonable approximation of the cumulative effect on the prevailing rates on the actual transaction dates, revenues and expenses are translated using the foreign exchange rates on the specific transaction date.

(iii) Equity transactions are translated at the exchange rate on the transaction date.

All resulting exchange rate differences are recognized in other comprehensive income. The same method has been used for translating the parent company financial statements to USD as presentation currency for periods prior to the change in functional currency to USD.

1.5 Revenue recognition

Revenues from petroleum products in which the company has an interest with other producers are recognized on the basis of the company's proportionate share of production during the period, regardless of actual sales (entitlement method).

This is achieved by applying the following approach in dealing with imbalances between actual sales and entitlements:

The excess of product sold during the period over the participant's ownership share of production from the property is recognized by the overlift party as a liability (deferred revenue) and not as revenue. Conversely, the underlift party would recognize an underlift asset (receivable) and report corresponding revenue.

Differences between oil lifted and sold: petroleum overlifts are presented as current liabilities, while petroleum underlifts are presented as short-term receivables. The value of overlift/underlift is set at the estimated sales value, minus estimated sales costs.

Other revenues are recognized when the goods or services are delivered and material risk and control are transferred. Gain on asset disposals as described in Section 1.9 is included in other operating income.

Tariff revenue from processing of oil and gas is recognized as earned in line with underlying agreements.

Revenue is presented net of customs and excise taxes on petroleum products.

Dividends are recognized when the shareholders' dividend rights are approved by the Annual General Meeting.

Interest is taken to income based on the effective interest method as it is earned.

1.6 Interests in joint arrangements

IFRS defines a joint arrangement as an arrangement over which two or more parties have joint control. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities (being those that significantly affect the returns of the arrangement) require unanimous consent of the parties sharing control.

The company has interests in licences on the Norwegian Continental Shelf. Under IFRS 11 Joint Arrangements, a joint operation is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets and obligations for the liabilities, relating to the arrangement. The company recognizes investments in joint operations (oil and gas licences) by reporting its share of related revenues, expenses, assets, liabilities and cash flows under the respective items in the company's financial statements.

For those licences that are not deemed to be joint arrangements pursuant to the definition in IFRS 11 as there is no joint control, the company recognizes its share of related expenses, assets, liabilities and cash flows on a line-by-line basis in the financial statements in accordance with applicable IFRSs.

1.7 Classification in statement of financial position

Current assets and current liabilities include items that fall due for payment less than a year from the end of the reporting period and items relating to the business cycle. Next year's instalments on long-term liabilities are classified as current liabilities. Financial investments in shares are classified as current assets, while strategic investments are classified as non-current assets.

1.8 Business combinations and goodwill

In order to consider an acquisition as a business combination, the acquired asset or groups of assets must constitute a business (an integrated set of operations and assets conducted and managed for the purpose of providing a return to the investors). The combination consists of inputs and processes applied to these inputs that have the ability to create output.

Acquired businesses are included in the financial statements from the transaction date. The transaction date is defined as the date on which the company achieves control over the financial and operating assets. This date may differ from the actual date on which the assets are transferred.

Comparative figures are not adjusted for acquired, sold or liquidated businesses.

For accounting purposes, the acquisition method is used in connection with the purchase of businesses. Acquisition cost equals the fair value of the assets used as consideration, including contingent consideration, equity instruments issued and liabilities assumed in connection with the transfer of control. Acquisition cost is measured against the fair value of the acquired assets and liabilities. Identifiable intangible assets are included in connection with acquisitions if they can be separated from other assets or meet the legal contractual criteria. If the acquisition cost at the time of the acquisition exceeds the fair value of the acquired net assets (when the acquiring entity achieves control of the transferring entity), goodwill arises.

If the fair value of the net identifiable assets acquired exceeds the acquisition cost on the acquisition date, the excess amount is taken to the Income statement immediately.

Goodwill is allocated to the CGUs or groups of CGUs that are expected to benefit from synergy effects of the acquisition. The allocation of goodwill may vary depending on the basis for its initial recognition.

The main part of the company's goodwill is related to the requirement to recognize deferred tax for the difference between the assigned fair values and the related tax base ("technical goodwill"). The fair value of of the company’s licences, all of which are located on the Norwegian Continental Shelf, are based on cash flows after tax. This is because these licences are only sold in an after-tax market based on decisions made by the Norwegian Ministry of Finance pursuant to the Petroleum Taxation Act Section 10. The purchaser is therefore not entitled to a tax deduction for the consideration paid over and above the seller’s tax values. In accordance with IAS 12 paragraphs 15 and 24, a provision is made for deferred tax corresponding to the difference between the acquisition cost and the transferred tax depreciation basis. The offsetting entry to this deferred tax is goodwill. Hence, goodwill arises as a technical effect of deferred tax. Technical goodwill is tested for impairment separately for each CGU which give rise to the technical goodwill. A CGU may be individual oil fields, or a group of oil fields that are connected to the same infrastructure/production facilities.

The estimation of fair value and goodwill may be adjusted up to 12 months after the takeover date if new information has emerged about facts and circumstances that existed at the time of the takeover and which, had they been known, would have affected the calculation of the amounts that were included from that date.

Acquisition-related costs, except costs to issue debt or equity securities, are expensed as incurred.

1.9 Acquisitions, sales and licence swaps

On acquisition of a licence that involves the right to explore for and produce petroleum resources, it is considered in each case whether the acquisition should be treated as a business combination (see Item 1.8) or an asset purchase. Generally, purchases of licences in a development or production phase will be regarded as a business combination. Other licence purchases regarded as asset purchases are described below.

Oil and gas production licences
For licences in the development phase, the acquisition cost is allocated between capitalized exploration expenses, licence rights and production plant.

When entering into agreements regarding the purchase/swap of assets, the parties agree on an effective date for the takeover of the net cash flow (usually 1 January in the calendar year which would also normally be the effective date for tax purposes). In the period between the effective date and the completion date, the seller will include its sold share of the licence in the financial statements. In accordance with the purchase agreement, there is a settlement with the seller of the net cash flow from the asset in the period from the effective date to the completion date (pro & contra settlement). The pro & contra settlement will be adjusted to the seller’s losses/gains and to the assets for the purchaser, in that the settlement (after a tax reduction) is deemed to be part of the consideration in the transaction. Revenues and expenses from the relevant licence are included in the purchaser’s Income statement from the completion date, as defined in 1.8 above.

For tax purposes, the purchaser will include the net cash flow (pro & contra) and any other income and costs as from the effective date.

When acquiring licences that are defined as asset acquisitions, no provision is made for deferred tax.

Farm-in agreements
Farm-in agreements are usually entered into in the exploration phase and are characterised by the transferor waiving future financial benefits in the form of reserves, in exchange for reduced future financing obligations. For example, a licence interest is taken over in return for a share of the transferor’s expenses relating to the drilling of a well. In the exploration phase, the company normally accounts for farm-in agreements on a historical cost basis, as the fair value is often difficult to determine.

Swaps
Swaps of assets are calculated at the fair value of the asset being surrendered, unless the transaction lacks commercial substance, or neither the fair value of the asset received, nor the fair value of the asset surrendered, can be effectively measured. In the exploration phase, the company normally recognizes swaps based on historical cost, as the fair value often is difficult to measure.

1.10 Unitizations

According to Norwegian law, a unitization is required if a petroleum deposit extends over several production licences and these production licences have a different ownership representation. Consensus must be achieved with regard to the most rational coordination of the joint development and ownership distribution of the petroleum deposit. A unitization agreement shall be approved by the Ministry of Petroleum and Energy.

The company recognizes unitizations in the exploration phase based on historical cost, as the fair value often is difficult to measure. For unitizations involving licences outside the exploration phase, it has to be considered whether the transaction has commercial substance. If so, the unitization is recognized at fair value.

1.11 Tangible fixed assets and intangible assets

General
Tangible fixed assets are recognized on a historical cost basis. Depreciation of assets other than oil and gas fields is calculated using the straight-line method over estimated useful lives and adjusted for any impairment or change in residual value, if applicable.

The book value of tangible fixed assets consists of acquisition cost after deduction of accumulated depreciation and impairment losses. Expenses relating to leased premises are capitalized and depreciated over the remaining lease period if the recognition criteria for an asset have been met.

The expected useful lives of tangible fixed assets are reviewed annually, and in cases where these differ significantly from previous estimates, the depreciation period is changed accordingly. Changes to estimates are included prospectively in that the change is recognized in the period in which it occurs, and in future periods if the change affects both.

The residual value of an asset is the estimated amount that the company would obtain from disposal of the asset, after deduction of the estimated costs of disposal, if the asset was already of the age and in the condition expected at the end of its useful life.

Ordinary repair and maintenance costs relating to day-to-day operations are charged to the Income statement in the period in which they are incurred. The costs of major repairs and maintenance are included in the asset's book value.

Gains and losses relating to the disposal of assets are determined by comparing the selling price with the book value, and are included in other operating income/expenses. Assets held for sale are reported at the lower of the book value and the fair value less cost to sell.

Operating assets related to petroleum activities

Exploration and development costs relating to oil and gas fields
Capitalized exploration expenditures are classified as intangible assets and reclassified to tangible assets at the start of the development. For accounting purposes, the field is considered to enter the development phase when the technical feasibility and commercial viability of extracting hydrocarbons from the field are demonstrable, normally at the time of concept selection. All costs relating to the development of commercial oil and/or gas fields are recognized as tangible assets. Pre-operational costs are expensed as they are incurred.

The company employs the 'successful efforts' method to account for exploration and development costs. All exploration costs (including seismic shooting, seismic studies and 'own time'), with the exception of acquisition costs of licences and drilling costs for exploration wells, are expensed as incurred. When exploration drilling is ongoing in a period after a reporting date and the result of the drilling is subsequently not successful, the capitalized exploration cost as of the reporting date is expensed if the evaluation of the well is completed before the date when the financial statement is authorized for issue.

Drilling cost for exploration wells are temporarily capitalized pending the evaluation of potential discoveries of oil and gas resources. Such costs can remain capitalized for more than one year. The main criteria are that there must be plans for future activity in the licence or that a development decision is expected in the near future. If no resources are discovered, or if recovery of the resources is considered technically or commercially unviable, expenses relating to the drilling of exploration wells are charged to expense.

Acquired licence rights are recognized as intangible assets at the time of acquisition. Acquired licence rights related to fields in the exploration phase remain as intangible assets also when the related fields enter the development or production phase.

Depreciation of oil and gas fields
Capitalized exploration and evaluation expenditures, development expenditures from construction, installation or completion of infrastructure facilities such as platforms, pipelines and production wells, and field-dedicated transport systems for oil and gas are capitalized as production facilities and are depreciated using the unit-of-production method based on proven and probable developed reserves expected to be recovered from the area during the concession or contract period. Acquired assets used for the recovery and production of petroleum deposits, including licence rights, are depreciated using the unit-of-production method based on proven and probable reserves. The reserve basis used for depreciation purposes is updated at least once a year. Any changes in the reserves affecting unit-of-production calculations are reflected prospectively.

1.12 Impairment

Tangible fixed assets and intangible assets
Tangible fixed assets and intangible assets (including licence rights, exclusive of goodwill) with a finite useful life will be assessed for potential loss in value when events or changes in the circumstances indicate that the book value of the assets is higher than the recoverable amount.

The valuation unit used for assessment of impairment will depend on the lowest level at which it is possible to identify cash inflows that are independent of cash inflows from other groups of fixed assets. For oil and gas assets, this is carried out at the field or licence level. The loss in value for capitalized exploration costs is assessed for each well. Impairment is recognized when the book value of an asset or a CGU exceeds the recoverable amount. The recoverable amount is the higher of the asset's fair value less cost of disposal and value in use. When assessing the value in use, the expected future cash flow is discounted to the net present value by applying a discount rate after tax that reflects the current market valuation of the time value of money and the specific risk related to the asset. The discount rate is derived from the Weighted Average Cost of Capital (WACC).

For producing licences and licences in a development phase, the recoverable amount is calculated by discounting future cash flows after tax. Future cash flows are determined in the various licences based on the production profile compared to estimated proven and probable remaining reserves. The lifetime of the field for the purpose of impairment testing, is normally determined by the point in time when the operating cash flow from the field becomes negative.

For acquired exploration licences, an initial assessment as described in Section 1.11 above is performed – an assessment of whether plans for further activities have been established or, if applicable, an evaluation of whether development will be decided on in the near future.

A previously recognized impairment can only be reversed if changes have occurred in the estimates used for the calculation of the recoverable amount. However, the reversal cannot be to an amount that is higher than it would have been if the impairment had not previously been recognized. Such reversals are recognized in the Income statement. After a reversal, the depreciation amount is adjusted in future periods in order to distribute the asset's revised book value, minus any residual value, on a systematic basis over the asset's expected remaining life.

Goodwill
Goodwill is tested for impairment annually or more frequently if events or changes in circumstances indicate that the value may be impaired.

Impairment is recognized if the recoverable amount of the CGU (or group of CGUs) to which the goodwill is related is less than the book value, including associated goodwill and deferred tax as described in Section 1.8. Losses relating to impairment of goodwill cannot be reversed in future periods. The company performs its annual impairment test of goodwill in the fourth quarter.

On selling a licence where the company historically has recognized deferred tax and goodwill in a business combination, both goodwill and deferred taxes from the acquisition are included when calculating gain/loss. When recording impairment of such licences as a result of impairment testing, the same assumptions are applied when measuring the impairment. This avoids gross up of the impairment with tax, in that the impairment charged to the Income statement will not be higher than the original post tax amount paid in the business combination.

1.13 Financial instruments

The company has classified the financial instruments into the following categories of financial assets and liabilities:

- Financial assets at fair value designated as such upon initial recognition
- Cash and receivables
- Financial liabilities at fair value designated as such upon initial recognition
- Financial liabilities measured at amortized costs

Financial assets with fixed or determinable cash flows that are not quoted in an active market are classified as loans and receivables.

Financial liabilities that do not form part of the "held for trading purposes" category and which have not been designated as being at fair value with changes in value through profit or loss are classified as other financial liabilities.

For financial instruments not traded in an active market, the fair value is determined using appropriate valuation techniques. Such techniques may include using recent arm's length market transaction; reference to the current fair value of other instruments that is substantially the same; discounted cash flow analysis or other valuation models.

An analysis of fair values of financial instruments and further details as to how they are measured are provided in Note 28.

1.14 Impairment of financial assets

Financial assets that are assessed at amortized cost are impaired when, based on objective evidence, it is likely that the instrument's cash flows have been negatively affected by one or more events that have occurred after the initial recognition of the instrument. In addition, the loss event must have an impact on estimated future cash flows that can be reliably estimated. The impairment is recognized in the Income statement. Should the reason for the impairment subsequently cease to exist, and this can be objectively linked to an event taking place after the impairment of the asset, the previous impairment shall be reversed. The reversal shall not cause the book value of the financial asset to exceed the amount that the amortized cost would have been if the impairment had not been recognized at the time when the impairment was reversed. Reversals of previous impairments are presented on the same line item as the impairment.

1.15 Research and development

Research consists of original, planned studies carried out with a view to achieving new scientific or technical knowledge or understanding. Development consists of the application of information gained through research, or of other knowledge, to a plan or design for the production of new or significantly improved materials, facilities, products, processes, systems or services before commercial production or use commences.

The licence system on the Norwegian Continental Shelf stimulates research and development activities. The company is mainly involved in research and development through projects financed by participants in the licences.

1.16 Presentation of payroll and administration costs

The company presents its payroll and operating costs based on the functions in development, operational and exploration activities respectively, based on allocation of registered hours worked. As a basis, the company uses gross payroll and operating expenses reduced by the amounts already invoiced to operated licences.

1.17 Lease agreements

Financial lease agreements
Lease agreements in which the company accepts the main risk and returns incidental to ownership of the assets are financial lease agreements. At the start of the lease period, financial lease agreements are calculated at an amount corresponding to the lowest of the fair value and the minimum present value of the lease. When calculating the lease agreement's net present value, the implicit interest rate in the lease agreement is used provided that it can be calculated; otherwise, the company's incremental borrowing rate is used. Direct costs in connection with the establishment of the lease agreement are included in the asset's cost price.

Financial lease agreements are treated as tangible fixed assets in the Statement of financial position and have the same depreciation period as the company's other depreciable assets. If it cannot be assumed with reasonable certainty that the company will take over ownership of the asset after the expiry of the lease, the asset is depreciated over whichever is the shorter of the contract period of the lease agreements and the asset's expected useful life.

Operating lease agreements
Lease agreements in which the main risk and returns associated with the ownership of the asset are not transferred, are classified as operating lease agreements. Rental payments are classified as operating expenses and are recognized on a straight-line basis over the contract period.

1.18 Trade debtors

Trade debtors are recognized in the Statement of financial position at nominal value after a deduction for the provision for bad debt. The provision for bad debt is calculated on the basis of an individual valuation of each trade debtor. Known losses on receivables are expensed as incurred.

1.19 Borrowing costs

Borrowing costs that can be directly ascribed to procurement, processing or production of a qualifying asset shall be capitalized as part of the asset's acquisition cost. Borrowing cost is only capitalized during the development phase. Other borrowing costs are expensed in the period in which they are incurred.

A qualifying asset is one that necessarily takes a substantial period of time to be made ready for its intended use or sale. Qualifying assets are generally those that are subject to major development or construction projects.

1.20 Inventories

The inventory mainly consists of equipment for the drilling of exploration and production wells and are valued at the lower of cost price (based on weighted average cost) and net realizable value. Costs include raw materials, freight and direct production costs in addition to some indirect costs.

1.21 Cash and cash equivalents

Cash and cash equivalents include cash, bank deposits, and other short-term highly liquid investments with an original due date of three months or less. Bank overdrafts are included in the Statement of financial position as short-term loans.

1.22 Interest-bearing debt

All borrowings are initially recognized at transaction price, which equals the fair value of the amount received minus issuing costs relating to the loan.

Subsequently, interest-bearing borrowings are valued at amortized cost using the effective interest method; the difference between the transaction price (after transaction costs) and the face value is recognized in the Income statement during the period until the loan falls due. Amortized costs are calculated by considering all issue costs and any discount or premium on the settlement date.

1.23 Tax

General
Tax payable/tax receivable for the current and previous periods is based on the amounts receivable from or payable to the tax authorities.

Tax consists of tax payable and changes in deferred tax. Deferred tax/tax benefits are calculated on the basis of the differences between book value and tax basis values of assets and liabilities, with the exception of temporary differences on acquisition of licences that is defined as asset purchase.

The book value of deferred tax benefits is assessed and reduced insofar as it is no longer probable that future earnings or current tax regulations will make it possible to utilise the benefit. Deferred tax benefits that are not capitalized will be re-evaluated on each date of Statement of financial position and capitalized insofar as it is probable that future earnings or current tax regulations will make it possible to utilise the benefit.

Deferred tax and tax benefits are measured using the expected tax rate when the tax benefit is realised or the tax liability is met, based on tax rates and tax regulations that have been enacted or substantively enacted by the end of the reporting period.

Tax payable and deferred tax is recognized directly against equity or other comprehensive income insofar as the tax items are related to equity transactions or items of other comprehensive income.

Deferred tax and tax benefits are presented net, where netting is legally permitted and the deferred tax benefit and liability are related to the same tax subject and are payable to the same tax authorities.

Functional currency

The company’s functional currency is USD, while it is a statutory requirement to calculate the current tax based on NOK functional currency. This may impact the tax rate when the exchange rate between NOK and USD varies. The revaluation of tax receivable and payable is presented as foreign exchange gain/loss, while the impact on deferred tax from revaluation of tax balances is presented as tax expense / income.

Petroleum taxation
As a production company, Aker BP is subject to the special provisions of the Petroleum Taxation Act. Revenues from activities on the Norwegian Continental Shelf are liable to ordinary company tax and special tax. The tax rate for general corporate tax was 25 per cent in 2016, and was changed to 24 per cent in 2017. The rate for special tax was 53 and 54% correspondingly. From 1 January 2018, the corresponding rates have changed to 23 and 55 per cent, which has impacted the deferred tax calculation in 2017.

Tax depreciation
Pipelines and production facilities can be depreciated by up to 16 2/3 per cent annually, i.e., using the straight-line method over six years. Depreciation can be started when the expenses are incurred. When the field stops producing, the remaining cost price can be included as a deduction in the final year.

Uplift
Uplift is a special income deduction in the basis for calculation of special tax. The uplift is calculated on the basis of investments in pipelines and production facilities, and can be regarded as an extra depreciation deduction in the special tax basis. The uplift constituted until 5 May 2013, 7.5 per cent per year over a period of four years, totalling 30 per cent of the investment. From 5 May 2013, the rate is 5.5 per cent per year (5.4 per cent from 2017 and 5.3 per cent from 2018) over a period of four years, totalling 22 per cent of the investment (21.6 per cent from 2017, and 21.2 per cent from 2018). Transition rules apply for some of the company's fields in development phase, which allows for the old 7.5 per cent rate until the year of production start. Uplift is recognized in the year in which it is deducted in the companies' tax returns, and thus has a similar effect on the tax for the period as a permanent difference.

Financial items
Interest on debt with associated currency losses/gains (net financial expenses on interest-bearing debt) is distributed between the offshore and onshore tax jurisdictions. The offshore interest deduction is calculated as the net financial costs of interest-bearing debt multiplied by 50 per cent of the ratio between net asset value for tax purposes allocated to the offshore tax jurisdictions as of 31 December in the income year and the average interest-bearing debt through the income year.

Remaining financial expenses, currency losses and all interest income as well as currency gains are allocated to the onshore jurisdiction.

Uncovered losses in the onshore tax jurisdictions resulting from the distribution of net financial items can be allocated to the offshore tax jurisdictions and deducted from regular income.

Only 50 per cent of other losses in the onshore tax jurisdictions are permitted to be reallocated to the offshore tax jurisdictions as deductions in regular income.

Exploration expenses
Companies may claim a refund from the State for the tax value of exploration expenses incurred insofar as these do not exceed the year’s tax-related loss allocated to the offshore activities. The refund is included under ‘Tax receivable’ in the Statement of financial position.

Tax loss
Companies subject to special tax may, without time limitations, carry forward losses with the addition of interest. A corresponding rule also applies to unused uplift. The tax position can be transferred on realisation of the company or merger. Alternatively, disbursement of the tax value can be claimed from the State if the company ceases petroleum activities. The tax loss will thus be reclassified from deferred tax to current tax at the time the petroleum activity ceases, or is transferred to another company.

1.24 Employee benefits

Pension schemes
The company is required to have an occupational pension scheme in accordance with the Norwegian law on required occupational pension ("lov om obligatorisk tjenestepensjon"). The company's pension scheme meets the requirements of that law.

Gains and losses on curtailment or settlement of a defined-benefit pension scheme are included in the Income statement when the curtailment or settlement occurs. The company is making contributions to the pension plan for full-time employees equal to 7 per cent for salary up to 7.1 G and 25.1 per cent between 7.1 and 12 G. The pension premiums are charged to expenses as they are incurred.

An early retirement scheme (AFP) has been introduced for all employees. The scheme is a multi-employer defined benefit plan, but is accounted for as a defined contribution pension, and premiums are expensed as incurred.

1.25 Provisions

A provision is recognized in the accounts when the company incurs a commitment (legal or self-imposed) as a result of a past event and it is probable that financial settlement will take place as a result of this commitment, and the amount can be reliably calculated. Provisions are evaluated at each period end and are adjusted to reflect the best estimate.

An onerous contract is a contract in which the unavoidable costs of meeting the obligations under the contract exceed the economic benefits expected to be received under it. A provision for onerous contracts is measured at the present value of the lower of the expected cost of terminating the contract and the expected net cost of continuing with the contract.

If the time effect is considerable, the provisions are discounted using a discount rate before tax that reflects the market's pricing of the time value of the amount and the risk specifically associated with the commitment. On discounting, the book value of the provisions is increased in each period to reflect the change in time relative to the due date of the commitment. The increase is expensed as an accretion expense.

Decommissioning and removal costs:

In accordance with the licence terms and conditions for the licences in which the company participates, the Norwegian State can require licence owners to remove the installation in whole or in part when production ceases or the licence period expires.

In the initial recognition of the decommissioning and removal obligations, the company provides for the net present value of future costs related to decommissioning and removal. A corresponding asset is capitalized as a tangible fixed asset and depreciated using the unit-of-production method. Changes in the time value (net present value) of the obligation related to decommissioning and removal accretion are charged to income as financial expenses and increase the balance-sheet liability related to future decommissioning and removal expenses. Changes in the best estimate for expenses related to decommissioning and removal are recognized in the Statement of financial position. The discount rate used in the calculation of the fair value of the decommissioning and removal obligation is the risk-free rate with the addition of a credit risk element.

1.26 Segment

Since its formation, the company has conducted its entire business in one and the same segment, defined as exploration for and production of petroleum in Norway. The company conducts its activities on the Norwegian Continental Shelf, and management follows up the company at this level. The financial information relating to geographical distribution and large customers is presented in Note 4.

1.27 Earnings per share

Earnings per share are calculated by dividing the ordinary profit/loss attributable to ordinary equity holders of the parent entity by the weighted average number of the total outstanding shares. Shares issued during the year are weighted in relation to the period in which they have been outstanding. Diluted earnings per share is calculated as the profit/loss for the year divided by the weighted average number of outstanding shares during the period, adjusted for the dilution effect of any share options.

1.28 Contingent liabilities and assets

Except for in the event of a business combination, neither contingent liabilities nor contingent assets are recognized.

A contingent liability is a possible obligation that arises from past events and whose existence will be confirmed only by the occurrence or non-occurrence of one or more uncertain future events not wholly within the control of the entity; or a present obligation that arises from past events but is not recognized because it is not probable that an outflow of resources embodying economic benefits will be required to settle the obligation or the amount of the obligation cannot be measured with sufficient reliability.

Contingent liabilities are disclosed with the exception of contingent liabilities where the probability of the liability having to be settled is remote.

Contingent assets are possible asset that arises from past events and whose existence will be confirmed only by the occurrence or non-occurrence of one or more uncertain future events not wholly within the control of the entity. Information about such contingent assets is provided if inflow of economic benefits is probable.

1.29 Changes to accounting standards and interpretations that:

Have entered into force:

The accounting policies applied are consistent with those of the previous financial year, and none of the new and amended standards and interpretations effective as of 1 January 2017 had significant impact for the group.

Have been issued but have not entered into force:

A number of standards and interpretations are issued, but not yet effective as of 31 December 2017. Those that may have an impact on the group are disclosed below. The company has adopted the standards effective from 1 January 2018 and will adopt the standards with effective date beyond 2018 when they become effective, provided that the standards are endorsed by the EU before publication of the annual report.

IFRS 9 Financial instruments

IFRS 9 Financial Instruments, which replaces IAS 39 Financial Instruments: Recognition and Measurement, was issued in July 2014. The standard introduces new requirements for classification and measurement, impairment, and hedge accounting. IFRS 9 is effective for annual periods beginning on or after 1 January 2018, with early application permitted. Except for hedge accounting, retrospective application is required, but comparative information is not compulsory. For hedge accounting, the requirements are generally applied prospectively, with some limited exceptions. Based on the group's financial instruments and the related accounting treatment as of 31 December 2017, the adoption of IFRS 9 does not have any significant impact on the group financial statements.

IFRS 15 Revenue from contracts with customers

IFRS 15 Revenue from Contracts with Customers was issued in May 2014 and establishes a new five-step model that will apply to revenue arising from contracts with customers. Under IFRS 15, revenue is recognized at an amount that reflects the consideration to which an entity expects to be entitled in exchange for transferring goods or services to a customer.

The new revenue standard will supersede all current revenue recognition requirements under IFRS, including IAS 18 *Revenue*. Either a full or modified retrospective application is required for annual periods beginning on or after 1 January 2018 with early adoption permitted. The company plans to apply the modified retrospective approach.

Under IFRS 15, revenue will be recognised when the customer obtains control of the liquids or gas, which will ordinarily be at the point of delivery when title passes. The changes in over/underlift balances currently included in revenues under the company's entitlement method do not meet the IFRS 15 definition of revenue from contracts with customers, and so will be classified as 'Other revenues'. These 'Other revenues' will be aggregated with the IFRS 15 revenues from contract with customers and presented as a single line item 'Petroleum Revenues' in the Income Statement, with details provided in the note disclosures.

Hence, there will be no changes to reported 'Petroleum Revenues' in the Income Statement following the implementation of IFRS 15. There is also no impact on the profit, cash flows or equity of Aker BP as a result of the adoption of IFRS 15.

IFRS 16 Leases

IFRS 16 Leases was issued in January 2016 and replaces the current lease accounting standard, IAS 17 Leases, including related interpretations. The new standard changes introduce a single on-balance sheet accounting model for all leases, which will result in the recognition of a lease liability and a right of use asset in the balance sheet. The standard is effective from 1 January 2019, and was endorsed by EU in Q4 2017. The impact on Aker BP is likely to be significant, depending upon the number and materiality of contracts active at the date of implementation and which are classified as operating leases under the current lease accounting standard.

The company is in the process of assessing the impact of IFRS 16, including a quantitative assessment, which has not yet been finalized. Some of the lease contracts may already be effectively recognized in the Statement of financial position for instance because a leased rig will be used for abandonment activity which is already included in the abandonment provision. For lease contracts that are entered into on behalf of a license, the company intends to recognize its net share of the related right-of-use assets and leasing liability.

The company plans to apply the modified retrospective approach with no restatement of comparative figures. The lease liability at the date of initial application will thus be measured at the present value of the remaining lease payments, discounted using an incremental borrowing rate.

Note 2 Business combination

On 22 December 2017, Aker BP finalized the acquisition of 100 per cent of the shares in Hess Norge AS. The transaction was announced on 24 October 2017, and was financed by the issuance of USD 0.5 billion in new share capital and a new loan facility of USD 1.5 billion. The main reason for the acquisition was to give Aker BP a deeper exposure to one of its core areas.

For tax purposes, the effective date was 1 January 2017. The acquisition is regarded as a business combination and has been accounted for using the acquisition method of accounting in accordance with IFRS 3. A purchase price allocation (PPA) has been performed as of the acquisition date 22 December 2017 to allocate the consideration to fair value of assets and liabilities of Hess Norge AS.

Each identifiable asset and liability is measured at its acquisition date fair value based on guidance in IFRS 13. The standard defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. This definition emphasizes that fair value is a market-based measurement, not an entity-specific measurement. When measuring fair value, the group uses the assumptions that market participants would use when pricing the asset or liability under current market conditions, including assumptions about risk. Acquired property, plant and equipment as well as intangible assets (value of licenses) have been valued using the income approach.

Accounts receivable are recognized at gross contractual amounts due, as they relate to large and credit-worthy customers. Historically, there has been no significant uncollected accounts receivable in Hess Norge AS.

The recognized amounts of assets and liabilities assumed as at the date of the acquisition were as follows:

(USD 1 000)	**31.12.2017**
Other intangible assets	507 640
Deferred tax assets	699
Property, plant and equipment	1 076 337
Inventories	15 377
Accounts receivable	41 673
Other short-term receivables	65 077
Tax receivables	1 558 574
Cash and cash equivalents	21 231
Total assets	**3 286 608**
Long-term abandonment provision	1 004 232
Provisions for other liabilities*	85 963
Trade creditors	6 575
Accrued public charges and indirect taxes	3 869
Tax payable	17 518
Short-term abandonment provision	182 806
Other current liabilities	91 311
Total liabilities	**1 392 274**
Total identifiable net assets at fair value	1 894 334
Consideration paid on acquisition	2 076 264
Goodwill arising on acquisition**	**181 930**

* The amount arises from a committed rig contract where the contractual terms were different from the current market terms at the time of acquisition at 22 December 2017. The fair value is based on the difference between market price and contract price.

** No part of the goodwill will be deductible for tax purposes.

The entire amount of goodwill recognized in the transaction relates to the requirement to recognize deferred tax assets and liabilities for the difference between the assigned fair values and the tax bases of assets acquired and liabilities assumed in a business combination. Licences under development and licences in production can only be sold in a market after tax, based on a decision made by the Norwegian Ministry of Finance pursuant to the Petroleum Taxation Act Section 10. The assessment of fair value of such licences is therefore based on cash flows after tax. Nevertheless, in accordance with IAS 12 Sections 15 and 19, a provision is made for deferred tax corresponding to the tax rate multiplied by the difference between the acquisition cost and the tax base. The offsetting entry to this deferred tax is goodwill. Hence, goodwill arises as a technical effect of deferred tax ("technical goodwill").

The above valuation is based on currently available information about fair values as of the acquisition date. If new information becomes available within 12 months from the acquisition date, the group may change the fair value assessment in the PPA, in accordance with guidance in IFRS 3.

If the acquisition had taken place at the beginning of 2017, year to date revenue would have increased by USD 455 million while net profit would have decreased by USD 62 million.

Parent company

On 22 December 2017, the same date as the completion of the purchase of the shares in Hess Norge AS, all assets and liabilities previously held in Hess Norge AS were transferred to Aker BP. The distribution was based on group continuity based on the PPA described above. The only remaining asset in Hess Norge AS subsequent to the transfer, is tax loss carried forward as of 1 January 2017. The tax loss carried forward is classified as a tax receivable in the Group financial statements as it is expected to be refunded by the Norwegian tax authorities. In the separate financial statements of Aker BP ASA, the value of the shares in Hess Norge AS corresponds to the nominal value of the tax loss carried forward.

Note 3 Overview of subsidiaries

Hess Norge AS was acquired 22 December 2017 and is consolidated in the group accounts as described in Note 2. Immediately after the completion of the share transaction, Hess Norge AS changed name to Aker BP AS. In addition, Aker BP ASA has three subsidiaries which are not consolidated in the group accounts in 2017 due to materiality considerations:

Det norske oljeselskap AS (100 per cent)

Det norske oljeselskap AS, previously Marathon Oil Norge AS, was acquired by Aker BP in October 2014. All activity was transferred to Aker BP on 31 October 2014. As of year-end 2017, the only remaining asset in this company is cash equivalents reflecting the share capital amounting to USD 1.0 million.

Alvheim AS (65 per cent)

The sole purpose of Alvheim AS is to act as legal owner of MST Alvheim, the floating production facility which is used to produce oil and gas from the Alvheim fields. The costs of and benefits from operating the MST Alvheim will be carried by the partners in the Alvheim field. Hence, Alvheim AS only has the formal ownership rather than the actual value of the production facilities. Aker BP has a 65 per cent share in Alvheim AS, which corresponds to the ownership in the Alvheim field.

Sandvika Fjellstue AS (100 per cent)

Sandvika Fjellstue AS owns a conference centre used by Aker BP, located in Sandvika in Verdal.

The activity in BP Norge AS was transferred to Aker BP in 2016, and BP Norge AS was liquidated on 13 July 2017.

For additional information regarding subsidiaries, see Note 17.

Note 4 Segment information

The group's business is entirely related to exploration for and production of petroleum in Norway. The company's activities are considered to have a homogeneous risk and return profile before tax, and the business is located in the geographical area Norway. The company operates within a single operating segment which matches the internal reporting to the company's executive management. The two main customers in 2017 (i.e. exceeding 10 per cent of total sales) accounted for USD 1 147 million and USD 757 million respectively (group and parent). In 2016, four customers exceeded the treashold of 10 per cent, and accounted for USD 441 million, USD 276 million, USD 272 million and USD 157 million for the group. For the parent, the corresponding numbers were USD 317 million, USD 276 million, USD 272 million, USD 157 million.

Note 5 Exploration expenses

Breakdown of exploration expenses (USD 1 000)	**Group**		**Parent**	
	2017	**2016**	**2017**	**2016**
Seismic	53 283	29 321	53 283	29 304
Area fee	16 589	13 291	16 589	13 076
Dry well expenses	75 401	51 669	75 401	51 669
Other exploration expenses	80 429	53 171	80 429	44 828
Total exploration expenses	**225 702**	**147 453**	**225 702**	**138 878**

Note 6 Inventories

The inventory mainly consists of equipment for the drilling of exploration and production wells.

Inventory value (USD 1 000)	Group		Parent	
	2017	**2016**	**2017**	**2016**
Inventories - measured at cost	94 436	82 795	94 436	82 795
Write-down to net realisable value	18 732	13 361	18 732	13 361
Book value of inventories	**75 704**	**69 434**	**75 704**	**69 434**

The write-down to net realisable value is based on an assessment of obsolete equipment as of year end.

Note 7 Income

Breakdown of petroleum revenues (USD 1 000)	Group		Parent	
	2017	**2016**	**2017**	**2016**
Recognized income liquids	2 183 069	1 120 094	2 183 069	1 021 551
Recognized income gas	369 694	128 436	369 694	96 879
Tariff income	22 891	12 274	22 891	11 509
Total petroleum revenues	**2 575 654**	**1 260 803**	**2 575 654**	**1 129 939**
Breakdown of produced volumes (barrels of oil equivalent) (unaudited)				
Liquids	39 634 824	23 830 388	39 634 824	21 645 073
Gas	11 036 406	4 512 648	11 036 406	3 343 534
Total produced volumes	**50 671 230**	**28 343 036**	**50 671 230**	**24 988 607**
Other income (USD 1 000)				
Realized gain/loss (-) on oil derivatives	-7 440	30 199	-7 440	30 199
Unrealized gain/loss (-) on oil derivatives	-6 510	-46 399	-6 510	-46 399
Other income*	1 230	119 526	1 230	3 958
Total other income	**-12 721**	**103 326**	**-12 721**	**-12 242**

* For 2017 the amount is mainly related to sale of licenses, while for 2016 it mainly relates to gain on settlement of defined benefit scheme in BP Norge AS.

Refer to note 22 and 28 for further details regarding commodity derivatives.

Note 8 Remuneration and guidelines for remuneration of senior executives and the Board of Directors, and total payroll expenses

	Group		Parent	
Breakdown of payroll expenses (USD 1 000)	**2017**	**2016**	**2017**	**2016**
Payroll expenses	252 889	142 383	252 889	117 835
Pension*	20 469	-79 648	20 469	8 654
Social security tax	38 692	22 645	38 692	17 739
Other personnel costs	4 280	3 541	4 280	2 310
Total payroll expenses	**316 330**	**88 920**	**316 330**	**146 538**

* The negative pension cost in 2016 is mainly related to change in pension scheme for employees in BP Norge AS.

Employee share program

In 2017, the company started an annual share purchase program for all employees, including senior executives. The shares in the program are offered at a 20 per cent discount and are subject to a three-year lock-up during which employees will not be allowed to sell the shares. In connection with the share purchase program, all employees are also offered an interest free loan of 60% of the basic amount in the National Insurance scheme ("G"), which will be repaid within one year. In total, employees subscribed for approximately USD 11.3 million.

	Group		Parent	
Number of full time equivalents employed during the year	**2017**	**2016**	**2017**	**2016**
Europe	1 341	742	1 341	602
Southeast Asia	-	15	-	15
Total	**1 341**	**757**	**1 341**	**616**

Remuneration of senior executives in 2017* (USD 1 000)	**Salary**	**Bonus [2)]**	**Payments in kind**	**Other**	**Total remuneration**	**Pension costs**	**Total number of shares****	**Owning interest**
Karl Johnny Hersvik (Chief Executive Officer) [1)]	721	1 183	2	11	1 917	19	1 416	0.0 %
Øyvind Bratsberg (Special Advisor) [1)]	427	331	2	4	763	19	53 848	0.0 %
Alexander Krane (Chief Financial Officer) [1)]	412	297	6	-	716	19	16 248	0.0 %
Gro G. Haatvedt (SVP Exploration) [1) 3)]	442	446	2	6	896	76	10 832	0.0 %
Olav Henriksen (SVP Projects) [1)]	447	453	2	-	902	84	354	0.0 %
Per Harald Kongelf (SVP Improvement)	365	186	2	-	553	19	-	-
Tommy Sigmundstad (SVP D&W)	323	165	2	-	490	19	-	-
Ole Johan Molvig (SVP Reservoir Development)	341	165	2	19	526	19	3 894	0.0 %
Jorunn Kvåle (SVP HSSE)	266	128	2	18	414	19	-	-
Eldar Larsen (SVP Operations) [3)]	367	174	2	25	568	19	1 416	0.0 %
Total remuneration of senior executives in 2017	**4 113**	**3 526**	**21**	**84**	**7 745**	**316**	**88 008**	**0.0 %**

[1)] Bonus includes estimated LTI commitments during 2017.
[2)] Numbers represent actual bonus earned in 2017. From the total amount in this column, USD 1 171 thousand relates to LTI program.
[3)] A loan in connection with the employee share program has been provided and will be repaid during 2018.

* All remuneration to senior executives is paid in NOK and converted to USD using a yearly average USD/NOK-rate at 8.263.
** These shares have been purchased by the individuals and are not part of the remuneration.

Remuneration of senior executives in 2016* (USD 1 000)	**Salary**	**Bonus [2)]**	**Payments in kind**	**Other**	**Total remuneration**	**Pension costs**	**Total number of shares****	**Owning interest**
Karl Johnny Hersvik (Chief Executive Officer)	575	880	2	-	1 457	17	-	-
Øyvind Bratsberg (Special Advisor) [1)]	450	249	2	4	704	17	49 105	0.0 %
Alexander Krane (Chief Financial Officer)	383	254	8	1	647	17	12 000	0.0 %
Gro G. Haatvedt (SVP Exploration)	409	387	2	6	804	72	8 000	0.0 %
Olav Henriksen (SVP Projects)	390	393	2	-	785	72	-	-
Geir Solli (SVP Operations) [2)]	386	229	6	50	670	17	25 000	0.0 %
Leif G. Hestholm (SVP HSE) [3)]	270	76	2	16	364	17	-	-
Per Harald Kongelf (SVP Improvement) [4)]	125	57	1	120	302	6	-	-
Tommy Sigmundstad (SVP D&W) [5)]	136	51	1	185	373	7	-	-
Ole Johan Molvig (SVP Reservoir Development) [6)]	285	41	2	19	347	17	-	-
Jorunn Kvåle (SVP HSE) oct-dec [7)]	52	8	-	-	60	-	-	-
Eldar Larsen (SVP Operations) oct-dec [8)]	84	13	1	1	99	-	-	-
Total remuneration of senior executives in 2016	**3 546**	**2 637**	**26**	**401**	**6 609**	**261**	**94 105**	**0.0 %**

[1)] Acting SVP D&W until 31 July 16.
[2)] SVP Operations until 30 November 16.
[3)] SVP HSE until 30 November 16.
[4)] Joined the Company 5 September 16. Other includes sign-on fee.
[5)] Joined the Company 1 August 16. Other includes sign-on fee.
[6)] New position in EMT from 1 December 16.
[7)] Payroll amounts from 30 September 2016, SVP HSE from 1 December 2016.
[8)] Payroll amounts from 30 September 2016, SVP Operations from 1 December 16.
[9)] Numbers represent estimated bonus for 2016, not actual bonus payment. From the total amount in this column, USD 980 thousand relates to a long term incentive program.

* All remuneration to senior executives is paid in NOK and converted to USD using a yearly average USD/NOK-rate at 8.399.

** Number of shares as of year end, and have been purchased by the individuals and are not part of the remuneration.

The tables below include regular fees to the Board and fees for participation in the Board's subcommittees. The fees to the nomination committee are also included. Fees to Board members employed in Aker ASA or BP plc groups will be paid to the companies, not to the Board member in person. Some Board members have shares in the company. The table also includes the number of shares and owning interest in Aker BP ASA held directly or indirectly through related parties. Indirect ownership through other companies is included as a whole where the owning interest is 50 per cent or more.

Fees in 2017* **Name**	**Comments**	**Fee** (USD 1 000)	**Total number of shares**	**Owning interest**
Øyvind Eriksen	Chairman of the Board from 11 March 2016. Chairman of the Compensation committee.	106	-	-
Anne Marie Cannon	Deputy Chair from 17 April 2013. Member of the Audit & Risk committee.	78	6 308	0.0 %
Bernard Looney	Board member from 30 September 2016.	-	-	-
Kjell Inge Røkke [1)]	Board member from 17 April 2013.	46	-	-
Trond Brandsrud	Board member from 11 March 2016. Chairman of the Audit & Risk committee from 28 April 2016.	47	-	-
Kate Thomson	Board member from 30 September 2016. Member of the Audit & Risk committee from 4 October 2016.	-	-	-
Gro Kielland	Board member from 20 March 2014. Member of the Compensation committee.	48	-	-
Terje Solheim	Employee representative from 20 March 2014. Member of the Compensation committee from 28 April 2016.	28	1 906	0.0 %
Lone Margrethe Olstad	Employee representative from 11 March 2016.	24	-	-
Bjørn Thore Ribesen	Employee representative from 11 March 2016.	24	22 747	0.0 %
Ørjan Holstad	Employee representative from 1 November 2017.	3	1 062	0.0 %
Emil Brustad-Nilsen	Deputy board member from 11 March 2016.	11	-	-
Murray Auchincloss	Deputy board member from 1 April 2017.	-	-	-
Kristin Gjertsen (2.deputy)	Deputy employee representative from 11 March 2016.	8	-	-
Ifor Roberts (3.deputy)	Deputy employee representative from 11 March 2016.	5	10 644	0.0 %
Martine Midtsand Hovland	Deputy employee representative from 1 November 2017.	-	1 713	0.0 %
Arild Støren Frick	Chairman of the Nomination committee from 13 April 2015.	4	-	-
Finn Haugan	Member of the Nomination committee.	6	-	-
Hilde Myrberg	Member of the Nomination committee.	6	-	-
Members until 30 June 2017				
Aage Ertsgaard (1.deputy)	Deputy employee representative from 11 March 2016 to 30 June 2017.	2	6 508	0.0 %
Total		**447**	**50 888**	**0.0 %**

[1)] Mr. Røkke owns and controls The Resource Group AS, which owns 68.2 per cent of Aker ASA, which through a subsidiary owns 40.0 per cent of Aker BP.

* Fee to board members are paid in NOK and converted to USD using a yearly average USD/NOK-rate at 8.263.

Fees in 2016 Name	Comments	Fee (USD 1 000)	Total number of shares	Owning interest
Øyvind Eriksen	Chairman of the Board from 11 March 2016. Chairman of the Compensation committee.	89	-	-
Anne Marie Cannon	Deputy Chair from 17 April 2013. Member of the Audit & Risk committee.	76	6 308	0.0 %
Gro Kielland	Board member from 20 March 2014. Member of the Audit & Risk committee/Compensation committee.	57	-	-
Kjell Inge Røkke [1)]	Board member from 17 April 2013.	45	-	-
Trond Brandsrud	Board member from 11 March 2016. Chairman of the Audit & Risk committee from 28 April 2016.	45	-	-
Emil Brustad-Nilsen	Deputy Board member from 11 March 2016.	4	-	-
Terje Solheim	Employee representative from 20 March 2014. Member of the Compensation committee from 28 April 2016.	24	1 198	0.0 %
Bjørn Thore Ribesen	Employee representative from 11 March 2016.	15	20 000	0.0 %
Lone Margrethe Olstad	Employee representative from 11 March 2016.	15	-	-
Aage Ertsgaard (1.deputy)	Deputy employee representative from 11 March 2016.	2	6 508	0.0 %
Kristin Gjertsen (2.deputy)	Deputy employee representative from 11 March 2016.	2	6 321	0.0 %
Ifor Sellevoll Roberts (3.deputy)	Deputy employee representative from 11 March 2016.	4	7 887	0.0 %
Bernard Looney	Board member from 30 September 2016.	-	-	-
Kate Thomson	Board member from 30 September 2016. Member of the Audit & Risk committee from 4 October 2016.	-	-	-
Arild Støren Frick	Chairman of the Nomination committee from 13 April 2015.	4	-	-
Finn Haugan	Member of the Nomination committee.	2	-	-
Hilde Myrberg	Member of the Nomination committee.	2	-	-
Members until 11 March 2016				
Kristin Gjertsen	Employee representative until 11 March 2016.	9	6 321	0.0 %
Sverre Skogen	Chairman of the Board from 17 April 2013 to 11 March 2016. Chairman of the Compensation committee until 11 March 2016.	41	-	-
Jørgen C Arentz Rostrup	Board member from 17 April 2013 to 11 March 2016. Chairman of the Audit & Risk committee until 11 March 2016.	37	4 320	0.0 %
Gudmund Evju	Employee representative from 20 March 2014 to 11 March 2016.	7	88 895	0.0 %
Camilla Oftebro	Deputy employee representative from 20 March 2014 to 11 March 2016	1	-	-
Tormod Førland	Deputy employee representative from 20 March 2014 to 11 March 2016	1	36 315	0.0 %
Kristin Alne	Deputy employee representative from 18 April 2015 to 11 March 2016	1	-	-
Members until 30 September 2016				-
Kitty Hall (Kat. J. Martin)	Board member from 17 April 2013 to 30 September 2016.	45	-	-
Kjell Pedersen	Board member from 18 April 2015 to 30 September 2016. Member of the Organizational Development and Compensation committee.	38	500	0.0 %
Total fee		**566**	**184 573**	**0.1 %**

[1)] Mr. Røkke owns and controls The Resource Group AS, which owns 68.2 per cent of Aker ASA, which through a subsidiary owns 40.0 per cent of Aker BP.

Guidelines and adherence to the guidelines in 2017

In 2017, the company's remuneration policy has been in accordance with the guidelines described in the Board of Directors' Report for 2016 and submitted to the annual general meeting for an advisory vote in April 2017.

Guidelines for 2018

The Board has established guidelines for 2018 for salaries and other remuneration to the Chief Executive Officer and other senior executives. The guidelines will be reviewed at the company's annual general meeting in 2018.

Senior executives receive a basic salary, adjusted annually. The company's senior executives participate in the general arrangements applicable to all the company's employees as regards bonus programme (see below), pension plans and other payments in kind such as free internet connection at home and subsidized fitness centre fees. In special cases, the company may offer other benefits in order to recruit personnel, including to compensate for bonus rights earned in previous employment.

For bonus arrangements for executive management, reference is made to the section Executive Remuneration in the Board of Directors Report. Estimated amount incurred in 2017 for the different bonus arrangements, including the three year incentive program, is included in the bonus column in the table above.

Adjustment of the CEO's base salary is decided by the Board. Adjustment of the base salaries for other senior executives is decided by the CEO within the wage settlement framework adopted by the Board.

It is up to the Board to decide whether to pay bonuses, based on the previous year’s performance. For 2017, the bonus will be disbursed in Q1 2018.

Note 9 Auditors fee

(USD 1 000)	Group 2017	Group 2016	Parent 2017	Parent 2016
Fees for statutory audit services - KPMG (excluding VAT)	618	630	618	575
Fees for other attestations - KPMG (excluding VAT)	349	64	349	64
Total auditor's fees	**967**	**694**	**967**	**639**

Note 10 Financial items

(USD 1 000)	Group 2017	Group 2016	Parent 2017	Parent 2016
Total interest income	**7 716**	**5 795**	**7 012**	**5 516**
Realized gains on derivatives	18 428	3 138	18 428	3 138
Change in fair value of derivatives	40 971	35 991	40 971	35 991
Net currency gains	16 107	3 742	16 107	24 939
Other financial income*	-	-	40 894	-
Total other financial income	**75 507**	**42 871**	**116 401**	**64 068**
Interest expenses	156 704	160 808	176 248	168 084
Capitalized interest cost, development projects	-89 977	-96 562	-89 977	-96 562
Amortized loan costs	36 900	17 915	36 900	17 915
Total interest expenses	**103 627**	**82 161**	**123 171**	**89 438**
Realised loss on derivatives	9 331	7 675	9 331	7 675
Accretion expenses	129 619	47 977	129 619	33 473
Other financial expenses*	36 746	7 864	37 102	39 953
Total other financial expenses	**175 696**	**63 515**	**176 052**	**81 101**
Net financial items	**-196 100**	**-97 011**	**-175 810**	**-100 955**

* The parent company number includes the group continuity adjustment (for BP Norge AS), as well as other adjustments to the value of shares in subsidiaries.

The rate (weighted average interest rate) used to determine the amount of borrowing cost eligible for capitalisation in 2017 is 8.06 per cent. The corresponding rate for 2016 was 6.33 per cent.

Note 11 Taxes

Breakdown of the current year's tax income (-)/tax expense (+) (USD 1 000)	Group 2017	Group 2016	Parent 2017	Parent 2016
Calculated current year tax/exploration tax refund	332 092	-131 488	327 238	-130 663
Prior periods' adjustments to current tax	4 516	-2 747	4 516	-1 519
Current tax income (-)/expense (+)	**336 608**	**-134 235**	**331 754**	**-132 182**
Prior periods' adjustments to deferred tax	-2 982	15 100	-2 982	5 226
Change in deferred tax	202 715	374 617	202 715	211 830
Deferred tax income (-)/expense (+)	**199 733**	**389 717**	**199 733**	**217 055**
Net tax income (-)/tax expense (+)	**536 340**	**255 482**	**531 487**	**84 874**
Effective tax rate in %	**66%**	**88 %**	**64%**	**71 %**

Reconciliation of tax income (-)/tax expense (+) (USD 1 000)	Tax rate	Group 2017	Group 2016	Parent 2017	Parent 2016
78% tax rate on profit before tax	78%	632 680	226 553	648 524	93 479
Tax effect of uplift	54%	-123 057	-103 313	-123 057	-99 890
Change in tax rates*		-1 894	-2 888	-1 894	-2 888
Permanent difference on impairment	78%	22 813	62 053	22 813	62 053
Foreign currency translation of NOK monetary items	78%	-12 955	2 163	-12 955	-594
Foreign currency translation of USD monetary items	78%	120 113	55 692	120 113	51 381
Tax effect of financial and other 24%/25% items	54%	-19 592	-21 335	-8 671	-19 729
Revaluation of tax balances**	78%	-84 676	28 901	-84 676	-9 730
Other permanent differences and prior period adjustment	78%	2 908	7 656	-28 710	10 791
Total taxes (+)/tax income (-)		**536 340**	**255 482**	**531 487**	**84 874**

* The tax rate for general corporation tax changed from 24 to 23 per cent from 1 January 2018. The rate for special tax changed from the same date from 54 to 55 per cent.

** Tax balances are in NOK and converted to USD using the period end currency rate. When NOK weakens against USD, the tax rate increases as there is less remaining tax depreciation measured in USD (vice versa).

Breakdown of tax effect of temporary differences and tax losses carry forward (USD 1 000)	Group 2017	Group 2016	Parent 2017	Parent 2016
Tangible fixed assets	-2 339 675	-1 775 189	-2 339 675	-1 775 189
Capitalized exploration cost	-285 025	-308 303	-285 025	-308 303
Other intangible assets	-1 151 969	-932 700	-1 151 969	-932 700
Abandonment provision	2 354 228	1 674 332	2 354 228	1 674 332
Financial instruments	1 597	9 776	1 597	9 776
Other provisions	113 696	157 183	113 696	157 183
Tax losses carry forward 23% / 24%	-	9 542	-	9 542
Tax losses carry forward 55% / 54%	-	119 815	-	119 815
Total deferred tax liability (-)/deferred tax asset (+)	**-1 307 148**	**-1 045 542**	**-1 307 148**	**-1 045 542**

Reconciliation of change in deferred tax (-)/deferred tax asset (+) (USD 1 000)	Group 2017	Group 2016	Parent 2017	Parent 2016
Deferred tax/ deferred tax assets as of 1.1	-1 045 542	-1 356 114	-1 045 542	-1 444 386
Change in deferred taxes in Income statement	-202 715	-374 617	-202 715	-211 830
Reclassification of loss carry forward to tax receivable	-	-238 866	-	84 368
Deferred tax related to acquisitions/sales	-61 877	942 611	-61 877	535 893
Prior period adjustments	2 982	-18 555	2 982	-9 587
Deferred tax charged to OCI and equity	5	-1	5	-1
Total deferred tax liability (-)/deferred tax asset (+)	**-1 307 148**	**-1 045 542**	**-1 307 148**	**-1 045 542**

Reconciliation of change in tax receivable (+)/tax payable (-) (USD 1 000)	Group 2017	Group 2016	Parent 2017	Parent 2016
Tax receivable/payable at 1.1	307 977	126 391	46 783	108 393
Current year tax in Income statement	-332 092	131 488	-327 238	130 663
Tax receivable/payable related to acquisitions/sales	1 523 512	255 873	-35 062	-71 071
Tax payment/tax refund	-303 589	-211 525	-39 798	-123 102
Prior period adjustments	9 502	-1 681	9 502	-1 545
Revaluation of tax payable	29 540	7 430	-5 343	3 444
Tax receivable (+)/tax payable (-)	**1 234 850**	**307 977**	**-351 156**	**46 783**
Tax receivable	1 586 006	400 638	-	139 443
Tax payable	-351 156	-92 661	-351 156	-92 661

Note 12 Earnings per share

Earnings per share is calculated by dividing the year's profit/loss attributable to ordinary equity holders of the parent entity, which was USD 275 million (USD 35 million in 2016) by the year's weighted average number of outstanding ordinary shares, which was 340.2 million (236.6 million in 2016). There are no option schemes or convertible bonds in the company. This means that there is no difference between the ordinary and diluted earnings per share.

	Group	
(USD 1 000)	2017	2016
Profit/loss for the year attributable to ordinary equity holders of the parent entity	274 787	34 971
The year's average number of ordinary shares (in thousands)	340 189	236 583
Earnings per share in USD	**0.81**	**0.15**

Note 13 Tangible fixed assets and intangible assets

TANGIBLE FIXED ASSETS - GROUP AND PARENT

(USD 1 000)	Assets under development	Production facilities including wells	Fixtures and fittings, office machinery	Total
Book value 31.12.2015	**1 493 795**	**1 470 881**	**14 758**	**2 979 434**
Acquisition cost 31.12.2015	**1 505 779**	**2 514 487**	**35 506**	**4 055 772**
Acquisition of BP Norge AS	-	921 081	-	921 081
Additions	752 795	177 144	12 603	942 542
Disposals	-	-	4 001	4 001
Reclassification***	-1 349 900	1 337 853	12 028	-19
Acquisition cost 31.12.2016	**908 674**	**4 950 566**	**56 137**	**5 915 377**
Accumulated depreciation and impairments 31.12.2015	**11 984**	**1 043 606**	**20 748**	**1 076 338**
Depreciation	-	411 400	6 491	417 891
Impairment	-10 418	-6 191	-	-16 609
Retirement/disposals/transfer depreciations	-	-156	-3 882	-4 038
Accumulated depreciation and impairments 31.12.2016	**1 566**	**1 448 659**	**23 357**	**1 473 582**
Book value 31.12.2016	**907 108**	**3 501 908**	**32 779**	**4 441 796**
Acquisition cost 31.12.2016	**908 674**	**4 950 566**	**56 137**	**5 915 377**
Acquisition of Hess Norge AS	-	1 076 337	-	1 076 337
Additions*	794 809	-129 338	43 401	708 873
Disposals**	33 329	88 913	1 531	123 773
Reclassification***	-189 466	249 149	6 339	66 021
Acquisition cost 31.12.2017	**1 480 689**	**6 057 801**	**104 346**	**7 642 835**
Accumulated depreciation and impairments 31.12.2016	**1 566**	**1 448 659**	**23 357**	**1 473 582**
Depreciation	-	622 179	13 384	635 563
Impairment	-6	21 111	128	21 232
Retirement/disposals/transfer depreciations**	-1 560	-66 944	-1 531	-70 035
Accumulated depreciation and impairments 31.12.2017	**-**	**2 025 004**	**35 338**	**2 060 342**
Book value 31.12.2017	**1 480 689**	**4 032 797**	**69 007**	**5 582 493**

* The negative addition is mainly caused by decreased abandonment provision during the year, amounting to USD 276.3 million.

** The disposal is mainly related to the sale of 10 per cent share in Valhall/Hod.

*** The reclassifiations are mainly related to the Ivar Aasen and Gina Krog fields which entered into the production phase in during 2016 and 2017 respectively.

Capitalized exploration expenditures are reclassified to "Fields under development" when the field enters into the development phase. If development plans are subsequently re-evaluated, the associated costs remain in assets under development and are not reclassified back to exploration assets. Fields under development are reclassified to "Production facilities" from the start of production. Production facilities, including wells, are depreciated in accordance with the Unit of Production Method. Office machinery, fixtures and fittings etc. are depreciated using the straight-line method over their useful life, i.e. 3 - 5 years. Removal and decommissioning costs are included as production facilities or fields under development.

See note 14 for information regarding impairment charges.

INTANGIBLE ASSETS - GROUP AND PARENT

(USD 1 000)	Other intangible assets Licences etc.	Software	Total	Exploration wells	Goodwill
Book value 31.12.2015	**646 487**	**1 543**	**648 030**	**289 980**	**767 571**
Acquisition cost 31.12.2015	**789 316**	**9 149**	**798 465**	**289 980**	**1 561 880**
Acquisition of BP Norge AS	759 962	-	759 962	-	1 158 954
Additions	25 519	-1 383	24 137	157 337	-
Disposals/expensed dry wells	-	265	265	51 669	-
Reclassification	406	-	406	-388	
Acquisition cost 31.12.2016	**1 575 203**	**7 501**	**1 582 705**	**395 260**	**2 720 835**
Accumulated depreciation and impairments 31.12.2015	**142 829**	**7 606**	**150 435**	**-**	**794 309**
Depreciation	91 254	-118	91 136	-	-
Impairment	8 429	-	8 429	-	79 555
Retirement/disposals/transfer depreciations	157	-265	-108	-	-
Accumulated depreciation and impairments 31.12.2016	**242 670**	**7 223**	**249 892**	**-**	**873 864**
Book value 31.12.2016	**1 332 534**	**279**	**1 332 813**	**395 260**	**1 846 971**
Acquisition cost 31.12.2016	**1 575 203**	**7 501**	**1 582 705**	**395 260**	**2 720 835**
Acquisition of Hess Norge AS	507 640	-	507 640	-	181 930
Additions	156	-	156	111 569	
Disposals/expensed dry wells*	149 747	-	149 747	75 401	163 791
Reclassification	-11	-	-11	-66 011	-
Acquisition cost 31.12.2017	**1 933 241**	**7 501**	**1 940 742**	**365 417**	**2 738 973**
Accumulated depreciation and impairments 31.12.2016	**242 670**	**7 223**	**249 892**	**-**	**873 864**
Depreciation	90 863	245	91 107	-	
Impairment	1 956	-	1 956	-	29 161
Retirement/disposals/transfer depreciations*	-19 252	-	-19 252	-	-24 177
Accumulated depreciation and impairments 31.12.2017	**316 236**	**7 467**	**323 703**	**-**	**878 847**
Book value 31.12.2017	**1 617 005**	**34**	**1 617 039**	**365 417**	**1 860 126**

* The disposal is mainly related to the sale of 10 per cent share in Valhall/Hod.

Licenses related to fields in production are depreciated using the Unit of Production method. Software is depreciated over its useful life (three years, using a straight-line method).

Depreciation in the Income statement (USD 1 000)	Group 2017	Group 2016	Parent 2017	Parent 2016
Depreciation of tangible fixed assets	635 563	417 891	635 563	404 740
Depreciation of intangible assets	91 107	91 136	91 107	91 136
Total depreciation in the Income statement	**726 670**	**509 027**	**726 670**	**495 876**

Impairment in the Income statement (USD 1 000)	Group 2017	Group 2016	Parent 2017	Parent 2016
Impairment/reversal of tangible fixed assets	21 232	-16 609	21 232	-16 609
Impairment/reversal of intangible assets	1 956	8 429	1 956	8 429
Impairment of goodwill	29 161	79 555	29 161	79 555
Total impairment in the Income statement	**52 349**	**71 375**	**52 349**	**71 375**

See note 14 for information regarding impairment charges.

Note 14 Impairments

Impairment testing

Impairment tests of individual cash-generating units are performed when impairment triggers are identified, and for goodwill impairment is tested at least annually. In 2017, two categories of impairment tests have been performed:

- Impairment test of fixed assets and related intangible assets, other than goodwill
- Impairment test of goodwill

Impairment is recognized when the book value of an asset or a cash-generating unit, including associated goodwill, exceeds the recoverable amount. The recoverable amount is the higher of the asset's fair value less cost to sell and value in use. For assets and goodwill in the Group prior to the acquisition of BP Norge AS, the impairment testing has been based on value in use, consistent with the impairment testing prior to the acquisition of BP Norge AS. For assets and goodwill recognized in relation to the acquisition of BP Norge AS and Hess Norge AS, the impairment testing has been based on fair value (level 3 in fair value hierarchy). For both value in use and fair value, the impairment testing is performed based on discounted cash flows. The expected future cash flow is discounted to the net present value by applying a discount rate after tax that reflects the current market valuation of the time value of money, and the specific risk related to the asset. The discount rate is derived from the weighted average cost of capital (WACC) for a market participant. Cash flows are projected for the estimated lifetime of the fields, which may exceed periods greater than five years. If not specifically stated otherwise, the same assumptions have been applied for value in use and fair value testing.

For producing licences and licences in the development phase, recoverable amount is estimated based on discounted future after tax cash flows. Below is an overview of the key assumptions applied for impairment testing purposes as of 31 December 2017.

Oil and gas prices

Future price level is a key assumption and has significant impact on the net present value. Forecasted oil and gas prices are based on management's estimates and available market data. Information about market prices in the near future can be derived from the futures contract market. The information about future prices is less reliable on a long-term basis, as there are fewer observable market transactions going forward. In the impairment test, the oil price is therefore based on the forward curve from the beginning of 2018 to the end of 2020. From 2021, the oil price is based on the company's long-term price assumptions.

The nominal oil prices applied in impairment test are as follows:

Year	USD/BOE
2018	65.2
2019	60.2
2020	56.3
From 2021 (in real terms)	65.0

For value in use testing, the long term price assumption at year end 2016 and Q1 - Q3 2017 was USD 75 per boe, while it was 65 for fair value testing.

Oil and gas reserves

Future cash flows are calculated on the basis of expected production profiles and estimated proven and probable remaining reserves. The recoverable amount is sensitive to changes in reserves. For more information about the determination of the reserves, reference is made to note 1, section 1.3, and to note 30.

Future expenditure

Future capex, opex and abandonment cost are calculated based on the expected production profiles and the best estimate of the related cost.

Discount rate

The discount rate is derived from the company's weighted average cost of capital ("WACC"). The capital structure considered in the WACC calculation is derived from the capital structures of an identified peer group and market participants with consideration given to optimal structures. The cost of equity is derived from the expected return on investment by the company's investors. The cost of debt is based on the interest-bearing borrowings on debt specific to the assets acquired. The beta factors are evaluated annually based on publicly available market data about the identified peer group.

For value in use testing, the post tax nominal discount rate used is 7.5 per cent (unchanged from previous quarters in 2017 and from year end 2016). For fair value, the discount rate used is 10.0 per cent, which is a change from 7.5 per cent applied in previous quarters in 2017 and year end 2016. The difference between the discount rate applied for fair value and value in use testing reflects the additional risk in the cash flows used in fair value testing.

Currency rates

Year	USD/NOK
2018	8.10
2019	8.00
2020	7.92
From 2021	7.75

Inflation

The long-term inflation rate is assumed to be 2.5 per cent.

Impairment testing of assets other than goodwill

The impairment test of assets other than goodwill has been performed prior to the quarterly goodwill impairment test. If these assets are found to be impaired, their carrying value will be written down before the impairment test of goodwill. The carrying value of the assets is the sum of tangible assets and intangible assets as of the assessment date.

Below is an overview of the impairment charge and the carrying value per cash generating unit where impairment has been recognized in 2017. The main reason for the impairment on Gina Krog is the decreased long term price assumptions for value in use testing.

	Impairment charged/reversal		Recoverable amount/
Cash generating unit (USD 1 000)	**Intangible**	**Tangible**	**carrying value**
Gina Krog	-	19 732	126 401
Other CGU's	1 956	1 500	-
Total	**1 956**	**21 232**	**126 401**

Impairment testing of technical goodwill

For the purpose of impairment testing, goodwill acquired through business combinations have, before any impairment charges in 2017, been allocated as follows:

Goodwill allocation (USD 1 000)	
Remaining technical goodwill from business combinations in previous years	1 383 605
Residual goodwill	505 768
Total goodwill	**1 889 373**

Technical goodwill has been allocated to individual CGUs for the purpose of impairment testing. The residual goodwill is allocated to group of CGUs including all fields acquired together with all existing Aker BP's fields, as this mainly relates to tax and workforce synergies and the ability to capture synergies from managing a portfolio of both acquired and existing fields on the NCS.

The carrying value of the CGUs consists of the carrying values of the oilfield assets plus associated technical goodwill. In the impairment test performed, carrying value is adjusted by the remaining part of deferred tax from which the technical goodwill arose, to avoid an immediate impairment of all technical goodwill.

The CGU's Valhall/Hod and Ula/Tambar were impaired in Q1 2017, applying the assumptions described in Q1 2017. The impairment charge was as follows:

(USD 1 000)	Ula/Tambar	Valhall/Hod
Net carrying value	242 635	1 096 104
Recoverable amount	229 588	1 079 904
Impairment charge	**13 047**	**16 200**

As described above, deferred tax (from the date of acquisitions) reduces the net carrying value prior to the impairment charges. When deferred tax from the acquisitions decreases, more goodwill is as such exposed for impairment. This may lead to future impairment charges even though other assumptions remain stable. In Q1 2017, the reduced deferred tax together with decreased forward prices were the main reasons for the impairment.

Sensitivity analysis

After the impairment charge in Q1 2017, there have been several updates in the assumptions and the production profiles. The sensitivity below shows how the impairment of technical goodwill would have been affected by changes in assumptions, using the assumptions and production profiles at year end. The only impacted CGU within the ranges set forth below, is Ula/Tambar.

		Change in goodwill impairment after	
Assumption (USD 1 000)	**Change**	**Increase in assumption**	**Decrease in assumption**
Long term oil price	+/- 20%	-	48 987
Production profiles (reserves)	+/- 5%	-	-
Discount rate	+/- 1% point	-	-
Currency rate USD/NOK	+/- 1.0 NOK	-	-
Inflation	+/- 1% point	-	-

Impairment testing of residual goodwill

As mentioned above, residual goodwill is allocated across all CGUs for impairment testing. The combined recoverable amount exceeds the carrying amount by a substantial margin. Based on this, no impairment of residual goodwill has been recognized.

Impairment testing in 2016

In 2016, the impairment charge was in all material respect related to technical goodwill from acquisitions. The methodology for impairment testing was the same as in 2017 as described in this Note.

The following assumptions were applied for the impairment testing at year end 2016:
- discount rate of 7.5 per cent nominal after tax (WACC)
- a long-term inflation of 2.5 per cent
- a long-term exchange rate of NOK/USD 7.00 (forward curve first three years)
- a long-term oil price assumption of 75 USD/barrel (value in use) and 65 USD/barrel (fair value), using forward curve first three years

Summary of impairment/reversal of impairments

The following impairments/(reversals) have been recorded:

	Group and parent	
(USD 1 000)	**2017**	**2016**
Impairment of other intangible assets/licence rights	1 956	8 429
Impairment of tangible fixed assets	21 232	-16 608
Impairment of technical goodwill	29 161	79 555
Total impairments	**52 349**	**71 375**

Note 15 Accounts receivable

The company's customers are large, financially sound oil companies. Accounts receivable consist of receivables related to the sale of oil and gas.

	Group		Parent	
(USD 1 000)	31.12.2017	31.12.2016	31.12.2017	31.12.2016
Receivables related to the sale of petroleum	99 752	170 000	99 752	170 000
Total accounts receivable	**99 752**	**170 000**	**99 752**	**170 000**

Age distribution of accounts receivable as of 31 December for the group was as follows:

Year (USD 1 000)	Total	Not due	<30d	30-90d	>90d
2017	99 752	99 752	-	-	-
2016	170 000	134 928	34 413	659	-

Note 16 Other short-term receivables

	Group		Parent	
(USD 1 000)	31.12.2017	31.12.2016	31.12.2017	31.12.2016
Prepayments	59 100	40 730	59 100	40 730
VAT receivable	10 856	7 913	10 856	7 913
Underlift of petroleum	118 012	70 003	118 012	70 003
Accrued income from sale of petroleum products	105 670	86 429	105 670	86 429
Other receivables, mainly from licenses	241 879	217 857	241 879	217 857
Total other short-term receivables	**535 518**	**422 932**	**535 518**	**422 932**

Note 17 Other non-current assets

	Group		Parent	
(USD 1 000)	31.12.2017	31.12.2016	31.12.2017	31.12.2016
Shares in Alvheim AS	10	10	10	10
Shares in Det norske oljeselskap AS	1 021	1 021	1 021	1 021
Shares in Sandvika Fjellstue AS	1 814	1 814	1 814	1 814
Shares in BP Norge AS	-	-	-	1 919 120
Shares in Aker BP AS	-	-	1 586 006	-
Investment in subsidiaries	**2 845**	**2 845**	**1 588 851**	**1 921 965**
Tenancy deposit	2 027	1 553	2 027	1 553
Other non-current assets	3 526	8 496	3 526	8 496
Total other non-current assets	**8 398**	**12 894**	**1 594 404**	**1 932 014**

Alvheim AS, Det norske oljeselskap AS (previously Marathon Oil Norge AS) and Sandvika Fjellstue AS have been deemed immaterial for consolidation purposes. For more information regarding shares in subsidiaries, see Note 3.

The acquisition of Hess Norge AS (renamed to Aker BP AS post transaction) was completed at 22 December 2017 and the company is consolidated in the group numbers as outlined in Note 2. BP Norge AS was liquidated during Q3 2017.

Note 18 Cash and cash equivalents

The item 'Cash and cash equivalents' consists of bank accounts and short-term investments that constitute parts of the group's transaction liquidity.

Breakdown of cash and cash equivalents (USD 1 000)	Group		Parent	
	31.12.2017	**31.12.2016**	**31.12.2017**	**31.12.2016**
Bank deposits	231 506	106 369	231 506	106 369
Restricted funds (tax withholdings)*	998	8 917	998	8 917
Cash and cash equivalents	**232 504**	**115 286**	**232 504**	**115 286**
Unused revolving credit facility (see note 24)	-	550 000	-	550 000
Unused reserve-based lending facility (see note 24)	2 670 000	1 805 000	2 670 000	1 805 000

* During 2017, the company established a bank guarantee related to withheld payroll tax of NOK 300 million (equivalent to USD 35.9 million). The main part of the restricted funds was thus released.

Note 19 Share capital and shareholders

(USD 1 000)	Parent	
	31.12.2017	**31.12.2016**
Share capital	57 056	54 349
Total number of shares (in 1 000)	360 114	337 737
Nominal value per share in NOK	1.00	1.00

The group completed a private placement in Q4 2017, increasing the number of outstanding shares by 22.4 million to 360.1 million shares. The additional shares have a nominal value of NOK 1 and a share premium value of NOK 181.5 per share. There is only one single class of shares in the company and all shares carry a single voting right.

Overview of the 20 largest shareholders registered as of 31 December 2017	**No. of shares** (in 1 000)	**Owning interest**
AKER CAPITAL AS	144 049	40.00%
BP GLOBAL INVESTMENTS LIMITED	108 021	30.00%
FOLKETRYGDFONDET	15 650	4.35%
STATE STREET BANK AND TRUST COMP	2 950	0.82%
VERDIPAPIRFONDET DNB NORGE (IV)	2 835	0.79%
BROWN BROTHERS HARRIMAN (LUX.) SCA	2 668	0.74%
JPMORGAN CHASE BANK, N.A., LONDON	1 679	0.47%
STATE STREET BANK AND TRUST COMP	1 624	0.45%
STATE STREET BANK AND TRUST COMP	1 571	0.44%
KLP AKSJENORGE	1 524	0.42%
JPMORGAN CHASE BANK, N.A., LONDON	1 508	0.42%
STATE STREET BANK AND TRUST COMP	1 422	0.39%
JPMORGAN CHASE BANK, N.A., LONDON	1 372	0.38%
JPMORGAN CHASE BANK, N.A., LONDON	1 354	0.38%
DANSKE INVEST NORSKE INSTIT. II.	1 299	0.36%
CLEARSTREAM BANKING S.A.	1 169	0.32%
THE BANK OF NEW YORK MELLON SA/NV	1 168	0.32%
RBC INVESTOR SERVICES BANK S.A.	1 067	0.30%
VERDIPAPIRFONDET ALFRED BERG GAMBA	1 055	0.29%
VPF NORDEA AVKASTNING	1 034	0.29%
OTHER	65 093	18.08%
Total	**360 114**	**100.00%**

Note 20 Bonds

	Group		Parent	
(USD 1 000)	**31.12.2017**	**31.12.2016**	**31.12.2017**	**31.12.2016**
DETNOR02 Senior unsecured bond [1]	230 375	214 827	230 375	214 827
DETNOR03 Subordinated PIK toggle bond [2]	-	295 510	-	295 510
AKERBP – Senior Notes 2017 (17/22) [3]	391 664	-	391 664	-
Long-term bonds	**622 039**	**510 337**	**622 039**	**510 337**

[1] The loan is denominated in NOK and runs from July 2013 to July 2020 and carries an interest rate of 3 month NIBOR + 6.5 per cent. The principal falls due on July 2020 and interest is paid on a quarterly basis. The loan is unsecured. The loan has been swapped into USD using a cross currency interest rate swap whereby the group pays LIBOR + 6.81 per cent quarterly. In connection with the RBL amendment described in note 24, the financial covenants in this bond have been adjusted to be consistent with the RBL.

[2] During 2017, the group notified the DETNOR 03 Bondholders that it exercised its early redemption right under a Replacing Capital Event, and repaid the entire bond at 110 per cent of par value. The early redemption premium, and the remaining unamortized fees related to this bond issue were thus expensed in 2017.

[3] The bond was established in July 2017 and carries an interest of 6 per cent. The principal falls due on July 2022 and interest is paid on a semi annual basis. The loan is senior unsecured and has no financial covenants.

Note 21 Provision for abandonment liabilities

	Group and parent	
(USD 1 000)	**31.12.2017**	**31.12.2016**
Provisions as of 1 January	2 156 921	423 325
Abandonment liability from acquisitions	1 315 181	1 680 206
Change in abandonment liability due to asset sales	-207 516	-
Incurred cost removal	-74 005	-12 237
Accretion expense - present value calculation	129 619	47 977
Changed net present value from changed discount rate	511 330	45 642
Change in estimates and incurred liabilities on new drilling and installations*	-787 646	-27 992
Total provision for abandonment liabilities	**3 043 884**	**2 156 921**
Break down of the provision to short-term and long-term liabilities		
Short-term	268 262	75 981
Long-term	2 775 622	2 080 940
Total provision for abandonment liabilities	**3 043 884**	**2 156 921**

* The change in estimates are mainly a result of increased experience and learning from P&A activities, offset by decreased discount rates.

The estimate is based on executing a concept for abandonment in accordance with the Petroleum Activities Act and international regulations and guidelines. The calculations assume an inflation rate of 2.5 per cent and a nominal discount rate before tax of between 3.44 per cent and 4.42 per cent. The discount rate in 2016 was between 4.14 per cent and 6.35 per cent.

Note 22 Derivatives

(USD 1 000)	Group and parent 31.12.2017	31.12.2016
Unrealized gain currency contracts	12 564	-
Long-term derivatives included in assets	**12 564**	**-**
Unrealized gain currency contracts	2 585	-
Short-term derivatives included in assets	**2 585**	**-**
Total derivatives included in assets	**15 149**	**-**
Unrealized losses currency contracts	-	5 073
Unrealized losses interest rate swaps	13 705	30 586
Long-term derivatives included in liabilities	**13 705**	**35 659**
Unrealized losses currency contracts	-	3 868
Unrealized losses commodity derivatives	7 691	1 181
Short-term derivatives included in liabilities	**7 691**	**5 049**
Total derivatives included in liabilities	**21 396**	**40 708**

The group has different types of economic hedging instruments. The commodity derivatives are used to hedge the risk of oil price reduction. The group manages its interest rate exposure using interest rate derivatives, including a cross currency interest rate swap. Foreign currency exchange derivatives are used to manage the company's exposure to currency risks, mainly NOK, EUR and GBP. These derivatives are mark to market with changes in market value recognized in the Income statement. In the Income statement, impacts from commodity derivates are presented as other income, while impacts from other derivatives are presented as financial items.

Note 23 Provisions for other liabilities

Breakdown of provisions for other liabilities (USD 1 000)	Group and parent 31.12.2017	31.12.2016
Fair value of contracts assumed in acquisitions*	149 031	202 874
Other long term liabilities	3 387	15 688
Total provisions for other liabilities	**152 418**	**218 562**

* The negative contract values are related to rig contracts entered into by the acquirees, which were different from current market terms at the time of the acquisitions. The fair value is based on the difference between market price and contract price at the time of the acquisitions. The balance is split between current and non-current liabilities based on the cash flow in the contracts, and amortized over the lifetime of the contracts.

Note 24 Other interest-bearing debt

(USD 1 000)	Group and parent 31.12.2017	31.12.2016
Reserve-based lending facility	1 270 556	2 030 209
Long-term interest-bearing debt	**1 270 556**	**2 030 209**
Bridge facility	1 496 374	-
Short-term interest-bearing debt	**1 496 374**	**-**

The RBL facility was established in 2014 and is a senior secured seven-year facility. The facility was originally USD 3.0 billion, with an additional uncommitted accordion option of USD 1.0 billion. In connection with the acquisition of BP Norge AS in 2016, the facility size was increased to USD 4.0 billion. In addition a new, uncommitted, accordion option of USD 1.0 billion was added to the facility.

After certain amendments made to the RBL facility in 2017, the borrowing base under the amended facility is set annually based on the company's certified 2P reserves. Current availability under the RBL is USD 4 billion. The financial covenants are as follows:

- Leverage Ratio shall be maximum 4 untill the production start of Johan Sverdrup, thereafter maximum 3.5
- Interest Coverage Ratio shall be minimum 3.5

The interest rate is from 1 - 6 months LIBOR plus a margin of 2 - 3 per cent based on drawn amount. In addition, a commitment fee is paid on unused credit.

The lenders have security in the form of pledge in all licenses (development and producing assets), insurance policies and hedging proceeds.

As part of the amendment process of the RBL facility, the revloving credit facility ("RCF") of USD 550 million was cancelled during the year.

In relation to the acquisition of Hess Norge AS, the company obtained a new USD 1.5 billion bank facility ("Bridge facility"). The facility has a duration of 18 months, carries an interest of Libor + 1.5 per cent (the margin increases to 2.0 per cent after nine months), and is secured by a pledge in the shares of Aker BP AS (previously Hess Norge AS). The company expects the tax losses from Aker BP AS to be settled during 2018. Such settlement would trigger a mandatory repayment of the USD 1.5 billion bank facility. The financial covenants in this facility are consistent with the RBL.

Note 25 Other current liabilities

Breakdown of other current liabilities (USD 1 000)	Group 31.12.2017	Group 31.12.2016	Parent 31.12.2017	Parent 31.12.2016
Current liabilities related to overcall in licences	81 223	81 686	81 223	81 686
Share of other current liabilities in licences	409 387	360 222	409 387	360 222
Overlift of petroleum	9 610	20 000	9 610	20 000
Fair value of contracts assumed in acquisitions*	62 097	36 199	62 097	36 199
Other current liabilities**	141 880	85 737	141 880	1 743 662
Total other current liabilities	**704 197**	**583 844**	**704 197**	**2 241 770**

* The negative contract values are related to rig contracts entered into by the acquirees, which were different from current market terms at the time of the acquisitions. The fair value is based on the difference between market price and contract price at the time of the acquisitions. The balance is split between current and non-current liabilities based on the cash flow in the contracts, and amortized over the lifetime of the contracts.

** Other current liabilities include unpaid wages and vacation pay, accrued interest and other provisions.

Note 26 Lease agreements, capital commitments, contractual obligations, guarantees and contingent liabilities

Lease agreements

The company has entered into different operating leases for rig contracts, other licence related commitments and office premises. The leases do not contain any restrictions on the company's dividend policy or financing. The company has not had any material contingent rent for the years presented below. To the extent the lease has been approved and committed by the partners in the relevant Aker BP operated licenses, the committments disclosed represent Aker BP share only.

Rig lease - operated by Aker BP

On behalf of the partners in Ivar Aasen, the company signed an agreement in 2013 with Maersk Drilling for the delivery of a jack-up rig for the development project on the Ivar Aasen field. The rig has drilled production wells on the Ivar Aasen field, but has been partly subleased to other licenses for the remaining lease period. The initial contract period expires in December 2019, with an additional two years option period.

The company has on behalf of the partners in Valhall entered into a new lease agreement for the Maersk Invincible which was delivered in May 2017. The rig will mainly be used for plug and abandonment (P&A) activities on the Valhall area. Hence, the contractual obligation is already reflected in the Statement of financial position. The contract period is five years, with an additional two years option period.

In August 2017, the company entered into a lease agreement with Odfjell Drilling for the rig Deepsea Stavanger with an estimated lease period of 9 months in 2018. In December 2017, a new lease agreement for the same rig was entered into. This lease period is estimated to 12 months, starting in Q2 2019.

The leased rig Transocean Arctic is currently finalizing the drilling activities on the Alvheim Area, with an estimated completion in March 2018.

Other licence related leases

The company has also entered into other operating lease agreements as rental of supply and standby vessels. In addition the company has lease commitments pertaining to its ownership in partner operated oil and gas fields.

Office premises

The company entered into a new rental agreement for office premises in Oslo in 2016, which expires in 2027. The company has two rental agreements for office space in Trondheim (both will expire in 2020) and one in Harstad (expires in 2020). The company has also entered into a new rental agreement for office premises in Stavanger, which expires in 2023. As a result of the acquisition with BP Norge AS, the company entered into further rental agreement for office premises in Stavanger, which expires in 2021.

The operating lease expenses recognized in the Income statement were as follows:

	Group		**Parent**	
(USD 1 000)	**2017**	**2016**	**2017**	**2016**
Rig lease payments	113 674	109 547	113 674	109 547
Other licence related lease payments	52 347	30 178	52 347	27 161
Office premises	10 496	16 261	10 496	15 644
Payments received on subleases	-	-100	-	-100
Total	**176 517**	**155 885**	**176 517**	**152 252**

Future minimum lease payments under non-cancellable operating leases are as follows:*

	Group		Parent	
(USD 1 000)	31.12.2017	31.12.2016	31.12.2017	31.12.2016
Rigs				
Within one year	202 080	96 030	202 080	96 030
One to five years	602 029	295 510	602 029	295 510
After five years	-	17 499	-	17 499
Total rigs	**804 108**	**409 039**	**804 108**	**409 039**
Other licence related				
Within one year	62 871	36 268	62 871	36 268
One to five years	69 856	81 047	69 856	81 047
After five years	72 045	56 185	72 045	56 185
Total other licence related	**204 772**	**173 500**	**204 772**	**173 500**
Office premises				
Within one year	11 087	50 210	11 087	50 210
One to five years	36 612	42 329	36 612	42 329
After five years	14 397	12 173	14 397	12 173
Total office premises	**62 096**	**104 712**	**62 096**	**104 712**
Total future minimum lease payments	**1 070 976**	**687 251**	**1 070 976**	**687 251**
Subleases expected to be received				
Within one year	19 219	-	19 219	-
One to five years	4 000	16 002	4 000	16 002
After five years	-	-	-	-
Total subleases expected to be received	**23 220**	**16 002**	**23 220**	**16 002**
Total net future minimum lease payments	**1 047 757**	**671 250**	**1 047 757**	**671 250**

* Future minimum lease payments comprise payments over the lease term that the company is or can be required to make, excluding contingent rent, costs for services and taxes to be paid by and reimbursed to the company, in accordance with IAS 17.

Capital commitments and other contractual obligations

The company has future capital commitments of USD 330 million on non-operated licences (USD 520 million in 2016). Aker BP has entered into agreements for transport of petroleum products and other contractual obligations related to operation of offshore installations of USD 927 million (USD 633 million in 2016).

Nominal capital commitments and contractual obligations are as follows:

(USD 1 000)*	31.12.2017	31.12.2016
Within one year	387 754	336 748
One to five years	631 476	490 583
After five years	237 459	325 886
Total	**1 256 689**	**1 153 216**

* Represents Aker BP`s interest in the licences as the commitments have been fully allocated to licences for the expected periods.

Guarantees

In connection with the booking of capacity in the infrastructure on the Norwegian Continental Shelf, the operator of the infrastructure (Gassco) requires a guarantee covering the transportation cost in the coming two years. During 2017, this guarantee has been increased to NOK 900 million.

During 2017, the company established a bank guarantee related to withheld payroll tax of NOK 300 million.

Prior to the acquisition of BP Norge AS, the company had a loan scheme whereby permanent employees could borrow up to 30 per cent of their gross annual salary at the prescribed interest rate for tax purposes. The company covered the difference between the market interest rate and the prescribed interest rate for tax purposes at any time and and the company guaranteed for the employees' loans. Remaining guarantees furnished by the company for employees totalled USD 1.1 million at 31 December 2017.

Contingent liabilities

During the normal course of its business, the company will be involved in disputes, including tax disputes. Potential tax claims related to previous taxable income of acquired companies can to some extent be reimbursed from the sellers. The company has made accruals for probable liabilities related to litigation and claims based on management's best judgment and in line with IAS 37 and IAS 12.

As for other licences on the NCS, the company has unlimited liability for damage, including pollution damage. The company has insured its pro rata liability on the NCS on a par with other oil companies. Installations and liability are covered by an operational liability insurance policy.

Note 27 Transactions with related parties

Transactions with related parties

At year-end 2017, Aker (Aker Capital AS) and BP Global Investments Limited are the two major shareholders in Aker BP, with ownership interest of 40.00 and 30.00 per cent respectively. An overview of the 20 largest shareholders is provided in Note 19.

Transactions with related parties are carried out on the basis of the "arm’s length" principle.

Related party (USD 1 000)	**Receivables (+) / liabilities (-)**	**Group**		**Parent**	
		31.12.2017	**31.12.2016**	**31.12.2017**	**31.12.2016**
Aker Solutions	Trade creditors	21	3 205	21	3 205
BP Shipping	Trade creditors	-	458	-	458
Other Aker Group Companies	Trade creditors	20	182	20	182
Other BP Group Companies	Trade creditors	-	123	-	123
BP Gas Marketing	Trade debtors	-	16 136	-	16 136
BP Oil International Ltd.	Trade debtors	57 003	141 415	57 003	141 415
Other BP Group Companies	Trade debtors	-	221	-	221

Related party (USD 1 000)	**Revenues (-) / expenses (+)**	**Group**		**Parent**	
		2017	**2016**	**2017**	**2016**
Aker ASA	Board remuneration etc.	373	230	373	230
Aker Geo (First Geo AS)	Exploration expenses	3 234	758	3 234	758
Aker Kværner	Other operating expenses	829	133	829	133
Aker Solutions	Development costs	30 658	25 433	30 658	18 131
Aker Solutions Holding	Other operating expenses	493	327	493	327
Aker Subsea Solutions	Development costs	156	835	156	835
AKOFS Offshore Operations AS	Development costs	-	334	-	334
Other Aker Group Companies	Other operating expenses	493	662	493	662
BP Exploration Operating Company Ltd.	Other operating expenses	-62	5 308	-62	948
BP International Ltd.	Other operating expenses	-	9 990	-	2
BP Shipping	Other operating expenses	-	916	-	458
Other BP Group Companies	Other operating expenses	-	823	-	128
BP Gas Marketing	Sales of Gas	32 724	46 207	32 724	17 504
BP Oil International	Sales of Oil and NGL	468 566	242 593	468 566	149 075
Cognite AS	Other operating expenses	2 488	-	2 488	-
Fornebuporten Holding AS	Other operating expenses	793	1 260	793	1 260
Fornebuporten Næring 3 AS	Other operating expenses	751	454	751	454
Frontica Advantage AS	Other operating expenses	-	752	-	752
OCY Alexandra	Platform supply vessel leases	3 315	-	3 315	-

Except for the sale of petroleum products, the majority of transactions with BP Group companies listed above are in connection with transitional services. Following the acquisition of BP Norge in 2016, the BP Group continued to provide transitional support to Aker BP in areas such as IT infrastructure and systems, engineering and petro-technical consultancy, hydrocarbon sales and marketing.

Note 28 Financial instruments

Capital structure and equity

The main objective of the company's management of the capital structure is to maximize return to the owners by ensuring competitive conditions for both the company's own capital and borrowed capital.

The size of the company's resource and reserve base is very important in relation to access to capital and borrowing terms. The increase in resources, reported reserves and equity ratio as a result of large acquisitions in the recent years has significantly strengthened the company's ability to obtain attractive terms and conditions for its debt portfolio. The company seeks to optimize its capital structure by balancing return on equity against liquidity requirements.

The company monitors changes in financing needs, risk, assets and cash flows, and evaluates the capital structure continuously. To maintain the desired capital structure, the company considers various types of capital transactions, including refinancing of its debt, purchase or issue new shares or debt instruments, sell assets or pay back capital to the owners.

Unless specified otherwise, the numbers below apply both to the group and the parent.

Categories of financial assets and liabilities

The company has the following financial assets and liabilities: financial assets and liabilities recognized at fair value through profit or loss, cash and receivables, and other liabilities. The latter two are recognized in the accounts at amortized cost, while the first item is recognized at fair value.

Categories of financial assets and financial liabilities - Group*

31.12.2017	Financial assets at fair value designated as such upon initial recognition	Cash and receivables	Financial liabilities at fair value designated as such upon initial recognition	Financial liabilities measured at amortized costs	Total
Assets					
Accounts receivable	-	99 752	-	-	99 752
Tax receivable	-	1 586 006	-	-	1 586 006
Other short-term receivables**	-	442 600	-	-	442 600
Cash and cash equivalents	-	232 504	-	-	232 504
Derivatives	15 149	-	-	-	15 149
Total financial assets	**15 149**	**2 360 862**	**-**	**-**	**2 376 012**
Liabilities					
Derivatives	-	-	21 396	-	21 396
Trade creditors	-	-	-	32 847	32 847
Bonds	-	-	-	622 039	622 039
Other interest bearing debt	-	-	-	2 766 930	2 766 930
Other short-term liabilities	-	-	-	704 197	704 197
Total financial liabilities	**-**	**-**	**21 396**	**4 126 012**	**4 147 408**

* The table above presents group figures. The parent figures are identical except for tax receivable which is held by Aker BP AS subsidiary and thus not included in the table above.

** Prepayments are not included in other short-term receivables, as they do not meet the definition of financial instruments.

31.12.2016	Financial assets at fair value designated as such upon initial recognition	Loan and receivables	Financial liabilities at fair value designated as such upon initial recognition	Financial liabilities measured at amortized costs	Total
Assets					
Accounts receivable	-	170 000	-	-	170 000
Other short-term receivables*	-	382 202	-	-	382 202
Cash and cash equivalents	-	115 286	-	-	115 286
Total financial assets	**-**	**667 488**	**-**	**-**	**667 488**
Liability					
Derivatives	-	-	40 708	-	40 708
Trade creditors	-	-	-	88 156	88 156
Bonds	-	-	-	510 337	510 337
Reserve-based lending facility	-	-	-	2 030 209	2 030 209
Other short-term liabilities	-	-	-	622 893	622 893
Total financial liabilities	**-**	**-**	**40 708**	**3 251 595**	**3 292 303**

* Prepayments are not included in other short-term receivables, as they do not meet the definition of financial instruments.

Financial risk

The company has financed its activities with reserve-based lending, a bridge facility (see Note 24) and two bonds (see Note 20). In addition, the company has financial instruments such as accounts receivable, trade creditors etc., directly related to its day-to-day operations. For hedging purposes, the company has different types of economic hedging instruments, but no hedge accounting is applied. Commodity derivatives are used to hedge the risk of oil price reduction. Foreign currency exchange contracts and options are used in order to reduce currency risk related to cash flows. The company manages a portion of its interest rate exposure with a cross currency interest rate swap and interest rate derivatives.

The most important financial risks which the company is exposed to relate to oil and gas prices, foreign exchange rates, interest rates and access to competitively priced funding.

The company's risk management, including financial risk management, is designed to ensure identification, analysis and systematic and cost-efficient handling of risk. Established management procedures provide a good basis for reporting and monitoring of the company's financial risk exposure.

(i) Commodity price risk

Aker BP's revenues are derived from the sale of petroleum products, and the revenue flow is therefore exposed to oil and gas price fluctuations. The company is continuously evaluating and assessing opportunities for hedging as part of a prudent financial risk management process. In 2017 the company entered into new commodity hedges for 2018. These are put options with a strike price of 50 and 55 USD/bbl. for approximately 13 per cent of estimated 2018 oil production, corresponding to approximately 45 per cent of the after tax value. Subsequent to the end of 2017, the company has bought put options at a strike price of USD 60 per barrel for an additional 7 per cent of estimated oil production for 2018. This increases the total hedging volume to 20 per cent of estimated oil production for 2018, corresponding to approximately 70 per cent of the undiscounted after-tax value.

In 2017 the company had put options in place with a strike of USD 50/bbl. for approximately 15 per cent of the 2017 oil production.

The following table summarizes the sensitivity of the commodity derivatives to a reasonably possible change in the forward oil price as of 31 December 2017, with all other variables held constant. As the company has not hedged production after 2018, the calculation is based on 2018 forward curve only. The impact presented below is on the fair value of the commodity derivatives only, and does not include other Income statement effects from changes in oil prices.

(USD 1 000)	Increase/decrease in oil price	31.12.2017	31.12.2016
Effect on pre-tax profit/loss:	+ 30%	-2 676	-6 613
	- 30%	29 204	28 750

(ii) Currency risk

Revenues from sale of petroleum and gas are mainly in USD, EUR and GBP, while expenditures are mainly in NOK, USD, EUR and GBP. Sales and expenses in the same currency contribute to mitigating some of the currency risk. Currency derivatives may be used to further reduce this risk.

The table below shows the company's exposure in NOK as of 31 December:

Exposure relating to (USD 1 000)	**31.12.2017**	**31.12.2016**
Tax receivables, cash and cash equivalents, other short-term receivables and deposits	2 122 165	867 226
Trade creditors, tax payable and other short-term liabilities	-1 058 283	-604 001
Bonds	-230 375	-
Net exposure to NOK	**833 507**	**263 225**

The amounts above does not include tax balances in NOK, as they are not deemed to be financial instruments.The company's management of currency risk takes into account the USD values of non-USD assets, liabilities, opex and investments over time, including those exposures arising from the requirement to perform the tax calculation in NOK while the company's functional currency is USD.

The company is also exposed to change in other exchange rates such as GBP/USD and EUR/USD, but the amounts are deemed immaterial.

The table below shows the impact on profit/loss from changes in USD/NOK exchange rate. Other currencies are not included as the exposure is deemed immaterial.

(USD 1 000)	**Change in exchange rate**	**31.12.2017**	**31.12.2016**
Effect on pre-tax profit/loss:	+ 10%	-85 631	-35 467
	- 10%	153 499	38 465

The sensitivity above includes the impact from currency derivatives. It has been significantly impacted by the large NOK denominated tax receivable as of 31 December 2017. Subsequent to year end 2017, the company has entered into new currency hedges that would have decreased the exposure to currency fluctuations disclosed above.

(iii) Interest-rate risk

The company is exposed to interest-rate risk to borrowings and cash deposits. Floating-interest loans involve risk exposure for the company's future cash flows. As of 31 December 2017, the company's total loan liabilities exposed to interest risk amounted to approximately USD 3.1 billion, distributed between long-term bonds, the bridge facility and the reserve-based lending facility. The corresponding loan liabilities as of 31 December 2016 amounted to approximately USD 2.2 billion.

The terms of the company's loans are described in Notes 20 and 24. The interest-rate risk relating to cash and cash equivalents is relatively limited. The following table shows the company's sensitivity to potential changes in interest rates which is reasonably possible:

Change in interest rate level in basis points (USD 1 000)		**31.12.2017**	**31.12.2016**
Effect on pre-tax profit/loss:	+ 100 points	-18 213	-9 844
	- 100 points	15 462	9 089

In order to calculate sensitivity of interest rate changes, floating interest rates have been changed by + / - 100 basis points.

The table presents the annual effect on profit and loss for the financial instruments exposed to interest risk at the balance sheet date. Any changes in interest rates will impact the fair value of interest-rate swaps, as the floating rate interest received on the interest rate swaps is associated with a corresponding floating rate interest payment on a bond or a loan. A change in fair value on the interest rate swaps has reduced the exposure to interest-rate risk by USD 12.4 million in the sensitivity presented.

(iv) Liquidity risk/liquidity management

The company's liquidity risk is the risk that it will not be able to meet its financial obligations as they fall due.

Short-term (12 months) and long-term (five years) forecasts are prepared on a regular basis to plan the company's liquidity requirements. These plans are updated regularly for various scenarios and form part of the decision basis for the company's management and Board of Directors.

Excess liquidity is defined as a portfolio consisting of liquid assets other than the funds deposited in regular operational bank accounts and unused credit facilities. For excess liquidity, the requirement for low liquidity risk (i.e. the risk of realization on short notice) is generally more important than maximizing the return.

The company's objective for the placement and management of excess capital is to maintain a low risk profile and good liquidity.

The company's liquid assets as of 31 December 2017 are mainly deposited in bank accounts. As of 31 December 2017, the company had cash reserves of USD 233 million (2016: USD 115 million). Revenues and expenses are carefully managed on a day-to-day basis for liquidity risk management purposes.

The table below shows the payment structure for the company's financial commitments, based on undiscounted contractual payments:

		Contract related cash flow				
31.12.2017	**Book value**	**Less than 1 year**	**1-2 years**	**2-5 years**	**over 5 years**	**SUM**
Non-derivative financial liabilities:						
Bonds	622,039	41,367	41,367	717,907	-	800,642
Other interes bearing debt	2,766,930	1,574,001	47,751	1,357,855	-	2,979,608
Trade creditors and other liabilities	711,049	711,049	-	-	-	711,049
Derivative financial liabilities						
Derivatives	21,396	7,691	-	13,705	-	21,396
Total as of 31.12.2017	**4,121,414**	**2,334,109**	**89,119**	**2,089,467**	**-**	**4,512,694**

		Contract related cash flow				
31.12.2016	**Book value**	**Less than 1 year**	**1-2 years**	**2-5 years**	**over 5 years**	**SUM**
Non-derivative financial liabilities:						
Bonds	510,337	48,221	48,221	354,929	312,642	764,013
Reserve-based lending facility	2,030,209	108,072	108,072	2,400,949	-	2,617,093
Trade creditors and other liabilities	88,156	88,156	-	-	-	88,156
Derivative financial liabilities						
Derivatives	40,708	5,052	3,699	31,956	-	40,708
Total as of 31.12.2016	**2,669,410**	**249,501**	**159,992**	**2,787,834**	**312,642**	**3,509,970**

(v) Credit risk

The risk of counterparties being financially incapable of fulfilling their obligations is regarded as minor as there have not historically been any losses on accounts receivable. The company's customers and licence partners are large and credit worthy oil companies, and it has thus not been necessary to make any provision for bad debt.

In the management of the company's liquid assets, low credit risk is prioritized. Liquid assets are generally placed in bank deposits that represent a low credit risk.

The maximum credit risk exposure corresponds to the book value of financial assets. The company deems its maximum risk exposure to correspond with the book value of accounts receivable and other short-term receivables, see notes 15 and 16.

Determination of fair value

The fair value of forward exchange contracts is determined using the forward exchange rate at the end of the reporting period. The fair value of commodity derivatives is determined using the forward Brent blend curve at the end of the reporting period. The fair value of interest rate swaps and cross currency interest rate swaps is determined by using the expected floating interest rates at the end of the period and is confirmed by external market sources. See Note 22 for detailed information about the derivatives.

The following of the company's financial instruments have not been valued at fair value: trade debtors, other short-term receivables, other long-term receivables, short-term loans and other short-term liabilities, bonds and other interest bearing liabilities.

The carrying amount of cash and cash equivalents is approximately equal to fair value, since these instruments have a short term to maturity. Similarly, the carrying amount of accounts receivable, other receivables, trade creditors and other short-term liabilities is virtually the same as their fair value as they are entered into on ordinary terms and conditions.

The bond issued September 2013 is listed on Oslo Børs, and the fair value for disclosure purposes is determined using the quoted value as of 31 December 2017.
The USD 6% Senior Notes are listed on The International Stock Exchange, and the fair value for disclosure purposes is determined using the quoted value as of 31 December 2017. For the RBL and bridge facility, the fair value is assessed to equal the book value.

The following is a comparison between the book value and fair value of the company's financial instruments, except those where the carrying amount is a reasonable approximation of fair value (such as short-term trade receivables and payables in addition to instruments measured to fair value).

	31.12.2017		31.12.2016	
Fair value of financial instruments (USD 1 000)	**Book value**	**Fair value**	**Book value**	**Fair value**
Financial liabilities measured at amortized cost:				
Bonds	622 039	691 189	510 337	584 400
Other interest-bearing debt	2 766 930	2 766 930	2 030 209	2 030 209
Total financial liabilities	**3 388 969**	**3 458 119**	**2 540 546**	**2 614 609**

Fair value hierarchy

The company classifies fair value measurements by employing a value hierarchy that reflects the significance of the input used in preparing the measurements. The fair value hierarchy consists of the following levels:

Level 1 - input in the form of listed (unadjusted) prices in active markets for identical assets or liabilities.

Level 2 - input other than listed prices of assets and liabilities included in Level 1 that is observable for assets or liabilities, either directly (i.e. as prices) or indirectly (i.e. derived from prices).
Level 3 - input for assets or liabilities for which there is no observable market data (non-observable input).

The company has no assets or liabilities in Level 3.

31.12.2017 **Financial instruments recognized at fair value** (USD 1 000)	**Level 1**	**Level 2**	**Level 3**
Financial assets or liabilities measured at fair value with changes in value recognized through profit or loss			
Derivatives	-	6 247	-

31.12.2016 **Financial instruments recognized at fair value** (USD 1 000)	**Level 1**	**Level 2**	**Level 3**
Financial assets or liabilities measured at fair value with changes in value recognized through profit or loss			
Derivatives	-	40 708	-

In the course of the reporting period, there were no changes in the fair value measurements that involved any transfers between levels.

Reconciliation of liabilities arising from financing activities

The table below shows a reconciliation between the opening and the closing balances in the statement of financial position for liabilities arising from financing activities.

			Non-cash changes			
	31.12.2016	Cash flows	Amortization	Currency	Other fin exp*	31.12.2017
Long-term interest-bearing debt	2 030 209	-777 168	17 516	-	-	1 270 556
Short-term interest-bearing debt	-	1 496 193	180	-	-	1 496 374
Bonds	510 337	59 949	10 551	10 982	30 220	622 039
Net cash received from issuanse of new shares	-	489 436	-	-	-	-
Paid dividend	-	-250 000	-	-	-	-
Totals	**2 540 546**	**1 018 410**	**28 247**	**10 982**	**30 220**	**3 628 405**

			Non-cash changes			
	31.12.2015	Cash flows	Amortization	Currency	Other fin exp*	31.12.2016
Long-term interest-bearing debt	2 118 935	-99 825	11 099	-	-	2 030 209
Bonds	503 440	-987	3 899	3 985	-	510 337
Paid dividend	-	-62 500	-	-	-	
Totals	**2 622 375**	**-163 312**	**14 998**	**3 985**	**-**	**2 478 046**

* Other financial expenses represents the early redemption fee related to the repayment of DETNOR03.

Note 29 Investments in joint operations

Fields operated:	31.12.2017	31.12.2016
Alvheim	65.000 %	65.000 %
Bøyla	65.000 %	65.000 %
Hod**	90.000 %	37.500 %
Ivar Aasen Unit	34.786 %	34.786 %
Jette Unit	70.000 %	70.000 %
Valhall**	90.000 %	35.953 %
Vilje	46.904 %	46.904 %
Volund	65.000 %	65.000 %
Tambar	55.000 %	55.000 %
Tambar Øst	46.200 %	46.200 %
Ula	80.000 %	80.000 %
Skarv	23.835 %	23.835 %

Fields non-operated:	31.12.2017	31.12.2016
Atla	10.000 %	10.000 %
Enoch	2.000 %	2.000 %
Gina Krog	3.300 %	3.300 %
Johan Sverdrup	11.5733 %	11.5733 %
Jotun**	0.000 %	7.000 %
Oda	15.000 %	15.000 %
Varg	5.000 %	5.000 %

Production licences in which Aker BP is the operator:

Licence:	31.12.2017	31.12.2016
PL 001B	35.000 %	35.000 %
PL 006B**	90.000 %	35.833 %
PL 019	80.000 %	80.000 %
PL 019C	80.000 %	46.000 %
PL 026B	90.260 %	90.260 %
PL 027D	100.000 %	100.000 %
PL 028B	35.000 %	35.000 %
PL 033**	90.000 %	37.500 %
PL 033B**	90.000 %	37.500 %
PL 036C	65.000 %	65.000 %
PL 036D	46.904 %	46.904 %
PL 065	55.000 %	55.000 %
PL 088BS	65.000 %	65.000 %
PL 103B*	0.000 %	70.000 %
PL 150	65.000 %	65.000 %
PL 150B	65.000 %	65.000 %
PL 169C	50.000 %	50.000 %
PL 203	65.000 %	65.000 %
PL 203B	65.000 %	65.000 %
PL 212	30.000 %	30.000 %
PL 212B	30.000 %	30.000 %
PL 212E	30.000 %	30.000 %
PL 242	35.000 %	35.000 %
PL 261	50.000 %	50.000 %
PL 262	30.000 %	30.000 %
PL 300	55.000 %	55.000 %
PL 340	65.000 %	65.000 %
PL 340BS	65.000 %	65.000 %
PL 364**	90.260 %	100.000 %
PL 407*	0.000 %	50.000 %
PL 442	90.260 %	90.260 %
PL 442B***	90.260 %	0.000 %
PL 460**	65.000 %	100.000 %
PL 504	47.593 %	47.593 %
PL 626	50.000 %	50.000 %
PL 659	50.000 %	35.000 %
PL 677	60.000 %	60.000 %
PL 715*	0.000 %	40.000 %
PL 724	40.000 %	40.000 %
PL 724B	40.000 %	40.000 %
PL 736S*	0.000 %	65.000 %
PL 748	50.000 %	30.000 %
PL 748B***	50.000 %	0.000 %
PL 762	20.000 %	20.000 %
PL 777	40.000 %	40.000 %
PL 777B	40.000 %	40.000 %
PL 777C***	40.000 %	0.000 %
PL 784	40.000 %	40.000 %
PL 790	30.000 %	30.000 %
PL 814	40.000 %	40.000 %
PL 818	40.000 %	40.000 %
PL 821	60.000 %	60.000 %
PL 821B***	60.000 %	0.000 %
PL 822S	60.000 %	60.000 %
PL 839	23.835 %	23.835 %
PL 843	40.000 %	40.000 %
PL 858	40.000 %	40.000 %
PL 861***	50.000 %	0.000 %
PL 867***	40.000 %	0.000 %
PL 868***	60.000 %	0.000 %
PL 869***	40.000 %	0.000 %
PL 872***	40.000 %	0.000 %
PL 873***	40.000 %	0.000 %
PL 874***	90.260 %	0.000 %
PL 893***	60.000 %	0.000 %
PL 895***	60.000 %	0.000 %
Number	**62**	**53**

Production licences in which Aker BP is a partner:

Licence:	31.12.2017	31.12.2016
PL 006C	15.000 %	15.000 %
PL 018DS	13.338 %	13.338 %
PL 026	30.000 %	30.000 %
PL 029B	20.000 %	20.000 %
PL 035	50.000 %	50.000 %
PL 035C	50.000 %	50.000 %
PL 038	5.000 %	5.000 %
PL 048D	10.000 %	10.000 %
PL 102C	10.000 %	10.000 %
PL 102D	10.000 %	10.000 %
PL 102F	10.000 %	10.000 %
PL 102G	10.000 %	10.000 %
PL 220**	15.000 %	0.000 %
PL 265	20.000 %	20.000 %
PL 272	50.000 %	50.000 %
PL 405	15.000 %	15.000 %
PL 457BS	40.000 %	40.000 %
PL 492	60.000 %	60.000 %
PL 502	22.222 %	22.222 %
PL 507*	0.000 %	45.000 %
PL 533	35.000 %	35.000 %
PL 554	30.000 %	30.000 %
PL 554B	30.000 %	30.000 %
PL 554C	30.000 %	30.000 %
PL 610*	0.000 %	37.500 %
PL 613*	0.000 %	20.000 %
PL 627	20.000 %	20.000 %
PL 627B	20.000 %	20.000 %
PL 650*	0.000 %	25.000 %
PL 653*	0.000 %	30.000 %
PL689*	0.000 %	20.000 %
PL 689B*	0.000 %	20.000 %
PL 694*	0.000 %	20.000 %
PL 719	20.000 %	20.000 %
PL 721	40.000 %	20.000 %
PL 722	20.000 %	20.000 %
PL 778*	0.000 %	20.000 %
PL 782S	20.000 %	20.000 %
PL 782SB	20.000 %	20.000 %
PL 782SC***	20.000 %	0.000 %
PL 797*	0.000 %	25.000 %
PL 804*	0.000 %	30.000 %
PL 810**	30.000 %	0.000 %
PL 811	20.000 %	20.000 %
PL 813	3.300 %	3.300 %
PL 838	30.000 %	30.000 %
PL 842	30.000 %	30.000 %
PL 844	20.000 %	30.000 %
PL 852	40.000 %	20.000 %
PL 857	20.000 %	40.000 %
PL 862***	50.000 %	0.000 %
PL 863***	40.000 %	0.000 %
PL 864***	20.000 %	0.000 %
PL 871***	20.000 %	0.000 %
PL 891***	30.000 %	0.000 %
PL 892***	30.000 %	0.000 %
PL 902***	30.000 %	0.000 %
Number	**46**	**47**

* Relinquished licences or Aker BP has withdrawn from the licence.

** Acquired/changed through licence transactions or licence splits.

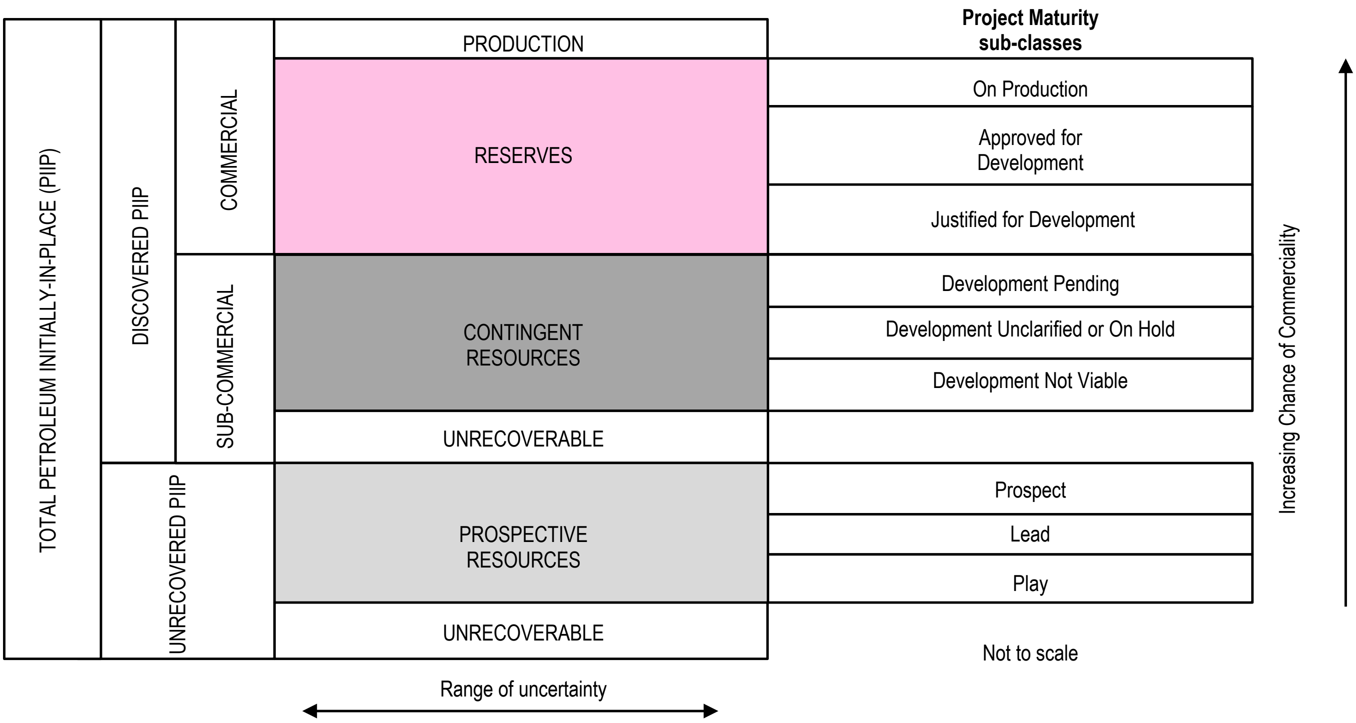
*** Interest awarded in the APA Licensing round (Application in Predefined Areas) in 2016. The awards were announced in 2017.

Note 30 Classification of reserves and contingent resources (unaudited)

Classification of reserves and contingent 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 Børs requirements for the disclosure of hydrocarbon reserves and contingent resources. The framework of the classification systme is illustrated in Figure 1.

Figure 1 - SPE's classification system used by Aker BP ASA



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 simulations models in combination with decline analysis has been used for profile generation.

Note that an independent third party, AGR Reservoir Services, has certified all reserves except for the minor assets Atla and Enoch, representing approximately 0.004 per cent of total 2P reserves.

Aker BP ASA has a working interest in 28 fields/projects containing reserves, see Table 1 and 2. Out of these fields/projects, 13 are in the sub-class "On Production"/Developed, eight are in the sub-class "Approved for Development"/Undeveloped and seven are in the sub-class "Justified for Development"/Undeveloped. Note that the several fields have reserves in more than one reserve sub-class.

Table 1 - Aker BP fields - Developed reserves

Field/project	Investment share	Operator	Resource class
Alvheim (Norwegian part, including Kameleon, Kneler, Boa and Viper/Kobra)	65.00 %	Aker BP	On production
Vilje	46.90 %	Aker BP	On production
Volund	65.00 %	Aker BP	On production
Bøyla	65.00 %	Aker BP	On production
Atla	10.00 %	Total	On production
Ula	80.00 %	Aker BP	On production
Tambar	55.00 %	Aker BP	On production
Tambar Øst	46.20 %	Aker BP	On production
Valhall	90.00 %	Aker BP	On production
Hod	90.00 %	Aker BP	On production
Skarv	23.84 %	Aker BP	On production
Ivar Aasen	34.79 %	Aker BP	On production
Gina Krog (Production start 2017. Moved from Approved for Development)	3.30 %	Statoil	On production
Enoch (No reserves reported in 2016 due to well integrity uncertainties)	2.00 %	Repsol Sinopec	On production

Table 2 - Aker BP fields - Undeveloped reserves

Field/project	Investment share	Operator	Resource class
Johan Sverdrup	11.57 %	Statoil	Approved for development
Hanz	34.79 %	Aker BP	Approved for development
Alvheim Kameleon Gas Cap Blow Down	65.00 %	Aker BP	Approved for development
Alvheim Boa Infill South	65.00 %	Aker BP	Approved for development
Alvheim Boa Infill North	65.00 %	Aker BP	Approved for development
Alvheim Kameleon Infill South	65.00 %	Aker BP	Approved for development
Valhall IP Drilling Program	90.00 %	Aker BP	Approved for development
Ula WAG from Tambar and Oda	80.00 %	Aker BP	Approved for development
Tambar Development	55.00 %	Aker BP	Approved for development
Skarv A-03 Workover	23.84 %	Aker BP	Approved for development
Oda	15.00 %	Spirit Energy	Approved for development
Ærfugl	23.84 %	Aker BP	Justified for development
Skogul	65.00 %	Aker BP	Justified for development

Total net proven reserves (1P/P90) as of 31 December 2017 to Aker BP ASA are estimated at 692 million barrels of oil equivalents. Total net proven plus probable reserves (2P/P50) are estimated at 914 million barrels of oil equivalents. The split between liquid and gas and between the different subcategories are given in table 3 and 4.

Table 3 - Reserves by field and area

	1P / P90 (low estimate)					2P / P50 (best estimate)				
31.12.2017	Gross oil (mmboe)	Gross NGL (mmboe)	Gross gas (mmboe)	Gross oil equival. (mmboe)	Net oil equival. (mmboe)	Gross oil/cond. (mmboe)	Gross NGL (mmboe)	Gross gas (mmboe)	Gross oil equival. (mmboe)	Net oil equival. (mmboe)
Alvheim	56.5	-	18.4	74.9	47.2	82.7	-	33.4	116.1	73.2
Volund	15.9	-	0.5	16.5	10.7	23.5	-	2.1	25.6	16.6
Vilje	14.4	-	-	14.4	6.7	18.5	-	-	18.5	8.7
Bøyla	6.5	-	0.1	6.6	4.3	9.0	-	0.2	9.2	6.0
Skogul	5.7	-	0.7	6.4	4.1	8.6	-	1.0	9.7	6.3
Alvheim Area	**99.0**	**-**	**19.7**	**118.7**	**73.1**	**142.3**	**-**	**36.8**	**179.0**	**110.8**
Ula	36.3	1.1	-	37.4	29.9	53.3	1.7	-	55.0	44.0
Tambar	10.5	0.5	2.6	13.6	7.5	20.2	1.0	5.1	26.4	14.5
Tambar East	-	-	-	-	-	0.4	0.0	0.0	0.4	0.2
Ula Area	**46.8**	**1.7**	**2.6**	**51.0**	**37.4**	**74.0**	**2.8**	**5.1**	**81.9**	**58.7**
Valhall	187.3	7.4	28.7	223.4	201.0	234.2	9.8	37.9	281.8	253.7
Hod	2.5	0.1	0.3	2.9	2.6	3.6	0.1	0.5	4.1	3.7
Valhall Area	**189.8**	**7.5**	**29.0**	**226.3**	**203.6**	**237.7**	**9.9**	**38.3**	**286.0**	**257.4**
Ivar Aasen	87.2	6.0	16.1	109.3	38.0	122.6	7.6	20.4	150.5	52.4
Hanz	12.0	0.6	1.7	14.3	5.0	14.4	0.9	2.3	17.6	6.1
Ivar Aasen Area	**99.2**	**6.6**	**17.8**	**123.6**	**43.0**	**137.0**	**8.4**	**22.7**	**168.1**	**58.5**
Ærfugl	26.5	28.4	133.2	188.1	45.7	37.4	41.7	195.4	274.6	68.7
Skarv	32.4	23.2	108.9	164.5	39.2	37.8	26.8	125.7	190.3	45.4
Skarv Area	**58.9**	**51.7**	**242.1**	**352.7**	**84.9**	**75.2**	**68.5**	**321.1**	**464.9**	**114.0**
Johan Sverdrup	**1 961.8**	**50.1**	**63.4**	**2 075.3**	**240.2**	**2 452.1**	**62.6**	**79.2**	**2 593.9**	**300.2**
Atla	0.1	0.4	0.0	0.6	0.1	0.1	0.6	0.1	0.8	0.1
Enoch	0.2	-	-	0.2	0.0	0.3	-	-	0.3	0.0
Gina Krog	75.4	26.6	47.5	149.5	4.9	101.1	36.9	66.1	204.1	6.7
Oda	28.3	-	1.3	29.6	4.4	45.2	-	2.2	47.4	7.1
Other	**104.1**	**27.0**	**48.8**	**179.9**	**9.4**	**146.7**	**37.5**	**68.4**	**252.6**	**13.9**
Total					**691.7**					**913.5**

Table 4 - Reserves by project and reserve class

On production 31.12.2017	Interest %	1P / P90 (low estimate)					2P / P50 (best estimate)				
		Gross oil/cond. (mmboe)	Gross NGL (mmboe)	Gross gas (mmboe)	Gross oil equival. (mmboe)	Net oil equival. (mmboe)	Gross oil (mmboe)	Gross NGL (mmboe)	Gross gas (mmboe)	Gross oil equival. (mmboe)	Net oil equival. (mmboe)
Alvheim	65.0 %	37.2	-	2.0	39.2	25.5	53.7	-	7.3	61.0	39.6
Boa	57.6 %	9.5	-	0.8	10.4	6.0	13.9	-	1.7	15.6	9.0
Vilje	46.9 %	14.4	-	-	14.4	6.7	18.5	-	-	18.5	8.7
Volund	65.0 %	15.9	-	0.5	16.5	10.7	23.5	-	2.1	25.6	16.6
Bøyla	65.0 %	6.5	-	0.1	6.6	4.3	9.0	-	0.2	9.2	6.0
Atla	10.0 %	0.1	0.4	0.0	0.6	0.1	0.1	0.6	0.1	0.8	0.1
Ula	80.0 %	27.4	0.9	-	28.3	22.6	38.6	1.2	-	39.8	31.8
Tambar	55.0 %	-	-	-	-	-	0.1	0.0	0.0	0.1	0.1
Tambar East	46.2 %	-	-	-	-	-	0.4	0.0	0.0	0.4	0.2
Valhall	90.0 %	103.0	3.9	15.2	122.1	109.9	134.6	5.2	20.1	160.0	144.0
Hod	90.0 %	2.5	0.1	0.3	2.9	2.6	3.6	0.1	0.5	4.1	3.7
Skarv	23.8 %	32.4	23.2	108.9	164.5	39.2	37.2	26.2	122.6	186.0	44.3
Ivar Aasen	34.8 %	87.2	6.0	16.1	109.3	38.0	122.6	7.6	20.4	150.5	52.4
Gina Krog	3.3 %	75.4	26.6	47.5	149.5	4.9	101.1	36.9	66.1	204.1	6.7
Enoch	2.0 %	0.2	-	-	0.2	0.0	0.3	-	-	0.3	0.0
Total						**270.6**					**363.2**

Approved for development 31.12.2017	Interest %	1P / P90 (low estimate)					2P / P50 (best estimate)				
		Gross oil (mmboe)	Gross NGL (mmboe)	Gross gas (mmboe)	Gross oil equival. (mmboe)	Net oil equival. (mmboe)	Gross oil/cond. (mmboe)	Gross NGL (mmboe)	Gross gas (mmboe)	Gross oil equival. (mmboe)	Net oil equival. (mmboe)
Johan Sverdrup	11.6 %	1 961.8	50.1	63.4	2 075.3	240.2	2 452.1	62.6	79.2	2 593.9	300.2
Hanz	34.8 %	12.0	0.6	1.7	14.3	5.0	14.4	0.9	2.3	17.6	6.1
Alvheim Kam. Gas Cap Blow Down	65.0 %	-	-	12.6	12.6	8.2	-	-	20.2	20.2	13.2
Alvheim Boa Infill South	57.6 %	3.3	-	1.1	4.3	2.5	5.5	-	1.5	7.0	4.0
Alvheim Boa Infill North	57.6 %	3.5	-	1.6	5.0	2.9	5.2	-	2.3	7.5	4.3
Alvheim Kameleon Infill South	65.0 %	3.0	-	0.3	3.3	2.2	4.4	-	0.5	4.8	3.1
Valhall IP Drilling Program	90.0 %	41.8	1.5	5.8	49.2	44.3	44.5	2.0	7.8	54.3	48.9
Ula WAG from Tambar and Oda	80.0 %	8.8	0.3	-	9.1	7.3	14.7	0.5	-	15.2	12.2
Tambar Development	55.0 %	10.5	0.5	2.6	13.6	7.5	20.1	1.0	5.1	26.3	14.5
Oda	15.0 %	28.3	-	1.3	29.6	4.4	45.2	-	2.2	47.4	7.1
Skarv A-03 Workover	23.8 %	-	-	-	-	-	0.6	0.7	3.1	4.3	1.0
Total						**324.4**					**414.6**

Justified for development 31.12.2017	Interest %	1P / P90 (low estimate)					2P / P50 (best estimate)				
		Gross oil/cond. (mmboe)	Gross NGL (mmboe)	Gross gas (mmboe)	Gross oil equival. (mmboe)	Net oil equival. (mmboe)	Gross oil/cond. (mmboe)	Gross NGL (mmboe)	Gross gas (mmboe)	Gross oil equival. (mmboe)	Net oil equival. (mmboe)
Ærfugl Phase 1	23.8 %	18.6	18.3	85.8	122.7	29.2	23.7	23.1	108.4	155.3	37.0
Ærfugle Phase 2	23.8 %	6.1	8.0	37.6	51.7	12.3	8.0	10.4	48.7	67.1	16.0
Ærfugl Outer	30.0 %	1.8	2.1	9.9	13.7	4.1	5.7	8.2	38.3	52.2	15.6
Valhall Flank West Project	90.0 %	37.0	1.9	7.3	46.2	41.5	48.2	2.5	9.5	60.2	54.2
Valhall North Flank Injector	90.0 %	5.5	0.1	0.3	5.9	5.3	6.9	0.1	0.4	7.4	6.6
Skogul	65.0 %	5.7	-	0.7	6.4	4.1	8.6	-	1.0	9.7	6.3
Total						**96.7**					**135.7**

Total reserves 31.12.2017	**691.7**	**913.5**
Total reserves 31.12.2016	**529.0**	**711.1**

Changes from 2016 reserve report are summarized in Table 5. The main reason for increased net reserve estimate are the new Valhall development project Valhall Flank West, the new Ærfugl development project and increased equity of 90 per cent on Valhall and Hod (from 36.0 and 37.5 respectively).

An oil price of 58.0 USD/bbl (2018) and 66.6 USD/bbl (following years) has been used for reserve estimation. Sensitivities with a spread of +25 per cent have also been performed. This had only minor effect on the reserve estimates. The low price resulted in total net proven (1P/P90) reserves of 666 mmboe and net proven plus probable (2P/P50) reserves of 902 mmboe. The high oil price resulted in 697 mmboe and 914 mmboe for proven (1P/P90) and proven plus probably (2P/P50) respectively.

Table 5 - Aggregated reserves, production, developments, and adjustments

Net attributed million barrels of oil equivalent	**On production**		**Approved for devlop.**		**Justified for devlop.**		**Total**	
(mmboe)	1P/P90	2P/P50	1P/P90	2P/P50	1P/P90	2P/P50	1P/P90	2P/P50
Balance as of 31.12.2016	**215.9**	**302.9**	**290.4**	**372.3**	**22.7**	**35.9**	**529.0**	**711.1**
Production	-58.3	-58.3	-	-	-	-	-58.3	-58.3
Transfer	25.4	33.9	-13.1	-11.0	-12.3	-22.9	-	-
Revisions	22.5	-0.6	8.7	-1.7	-	-	31.1	-2.3
IOR	-	-	9.1	14.1	-	-	9.1	14.1
Discovery and extensions	-	-	-	-	86.4	122.9	86.4	122.9
Acquisition and sale	65.0	85.2	29.3	40.8	-	-	94.3	126.1
Balance as of 31.12.2017	**270.4**	**363.0**	**324.4**	**414.6**	**96.8**	**135.9**	**691.7**	**913.5**
Delta	54.5	60.1	34.1	42.3	74.1	100.0	162.6	202.4

Note 31 Events after the balance sheet date

15 January 2018, the company announced its decision of increasing the dividend level for 2018 to USD 450 million. In February 2018 a quarterly dividend of USD 0.3124 per share was disbursed, reflecting this increased dividend level.

STATEMENT BY THE BOARD OF DIRECTORS AND CHIEF EXECUTIVE OFFICER

Pursuant to the Norwegian Securities Trading Act section § 5-5 with pertaining regulations, we hereby confirm that, to the best of our knowledge, the company's and the group's financial statements for 2017 have been prepared in accordance with IFRS, as provided for by the EU, and in accordance with the requirements for additional information provided for by the Norwegian Accounting Act. The information presented in the financial statements gives a true and fair picture of the company's liabilities, financial position and results overall.

To the best of our knowledge, the Board of Directors' Report gives a true and fair picture of the development, performance and financial position of the company, and includes a description of the principal risk and uncertainty factors facing the company and the group. Additionally, we confirm to the best of our knowledge that the report 'Payment to governments' as provided in a separate section in this annual report has been prepared in accordance with the requirements in the Norwegian Securities Trading Act Section 5-5a with pertaining regulations.

The Board of Directors of Aker BP ASA

Akerkvartalet, 8 March 2018

Øyvind Eriksen, Chair of the Board

Anne Marie Cannon, Deputy Chair

Gro Kielland, Board member

Bjørn Thore Synsvoll Ribesen, Board member

Lone Margrethe Olstad, Board member

Karl Johnny Hersvik, Chief Executive Officer

Kjell Inge Røkke, Board member

Trond Brandsrud, Board member

Bernard Looney, Board member

Terje Solheim, Board member

Kate Thomson, Board member

Ørjan Holstad, Board member

Alternative performance measures

Aker BP may disclose alternative performance measures as part of its financial reporting as a supplement to the financial statements prepared in accordance with IFRS. Aker BP believes that the alternative performance measures provide useful supplemental information to management, investors, security analysts and other stakeholders and are meant to provide an enhanced insight into the financial development of Aker BP's business operations and to improve comparability between periods.

Depreciation per boe is depreciation divided by number of barrels of oil equivalents produced in the corresponding period

Dividend per share (DPS) is dividend paid in the quarter divided by number of shares outstanding

EBIT is short for earnings before interest and other financial items and taxes

EBITDA is short for earnings before interest and other financial items, taxes, depreciation and amortisation and impairments

EBITDAX is short for earnings before interest and other financial items, taxes, depreciation and amortisation, impairments and exploration expenses

Equity ratio is total equity divided by total assets

Net interest-bearing debt is book value of current and non-current interest-bearing debt less cash and cash equivalents

Production cost per boe is production cost divided by number of barrels of oil equivalents produced in the corresponding period

KPMG AS
Sørkedalsveien 6
Postboks 7000 Majorstuen
0306 Oslo

Telephone +47 04063
Fax +47 22 60 96 01
Internet www.kpmg.no
Enterprise 935 174 627 MVA

To the General Meeting of Aker BP ASA

Independent Auditor's Report

Report on the Audit of the Financial Statements

Opinion

We have audited the financial statements of Aker BP ASA. The financial statements comprise:

- The financial statements of the parent company Aker BP ASA (the Company), which comprise the statement of financial position as at 31 December 2017, and income statement, statement of comprehensive income, statement of changes in equity, cash flow for the year then ended, and notes to the financial statements, including a summary of significant accounting policies, and

- The consolidated financial statements of Aker BP ASA and its subsidiaries (the Group), which comprise the statement of financial position as at 31 December 2017, and income statement, statement of comprehensive income, statement of changes in equity, cash flow for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In our opinion:

- The financial statements are prepared in accordance with the law and regulations.

- The accompanying financial statements give a true and fair view of the financial position of the Company as at 31 December 2017, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards as adopted by the EU.

- The accompanying consolidated financial statements give a true and fair view of the financial position of the Group as at 31 December 2017, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards as adopted by the EU.

Basis for Opinion

We conducted our audit in accordance with laws, regulations, and auditing standards and practices generally accepted in Norway, including International Standards on Auditing (ISAs). Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of our report. We are independent of the Company and the Group as required by laws and regulations, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Key Audit Matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the financial statements for the current period. These matters were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

Abandonment provisions

Refer to financial statement Note 1.3 (Important accounting judgments, estimates and assumptions), Note 1.25 (Provisions) and Note 21 (Provision for abandonment liabilities).

The key audit matter	*How the matter was addressed in our audit*
Management's estimate of abandonment provisions requires significant judgment due to: • the technically challenging nature of the decommissioning work which may be performed over several years; • applying experiences and data from actual decommissioning projects (e.g. number of days required to plug wells) to estimates of future decommissioning activities; • uncertainties over current market costs for decommissioning work (e.g. rig rates) and future cost escalation; • factors outside the control of the Group which may impact the costs and timing of decommissioning work (e.g. weather conditions); and • the relatively limited number of decommissioning projects completed by the Group and the wider industry which can act as benchmarks. As a result of these uncertainties, there are typically a wide range of possible abandonment provision estimates for each licence. Significant auditor judgment is therefore required when evaluating the abandonment provisions, and to determine whether there is sufficient evidence available to support the estimates and judgments made.	For each licence with a potentially significant abandonment liability, we critically assessed management's estimate of the decommissioning costs, including: • well count and relevant technical details of facilities and infrastructure with reference to publicly available information and licence reporting; • assumptions for the number of days required for plugging and abandonment activities, with reference to benchmark data where available; • plug and abandonment costs for drilled wells, including rig costs, with reference to benchmark data; • facilities removal and decommissioning costs with reference to benchmark data and third party reports where available; and • foreign currency, inflation and cost escalation assumptions with reference to market and industry data. For non-operated licences where the Group uses the operator company estimates, we assessed the amounts against reports from the operator company. In addition, we assessed the assumed economic cut-off date with reference to licence forecasts, including an assessment of the consistency with the forecasts and assumptions used in impairment testing and other audit work. We assessed the mathematical accuracy of management's discounting model to confirm the year-end present values of decommissioning cost estimates and accretion recognised during the year, and the discount rate applied with reference to industry practice and market data.

Hess Norge acquisition

Refer to Board of Directors' report and financial statement Note 1.3 (Important accounting judgments, estimates and assumptions), Note 1.8 (Business combinations and goodwill) and Note 2 (Business combination).

The key audit matter	*How the matter was addressed in our audit*
On 22 December 2017 the company completed the acquisition of Hess Norge AS in a business combination. The purchase price allocation and the determination of fair values adopted required a number of estimates and judgments to be applied, including: • estimates of oil and gas reserves, forecast production profiles and prices; • forecast operating, capital, abandonment and tax expenditures;	We read the transaction agreements and traced payments to bank statements. The Company had an existing interest in, and operatorship of, the significant licences acquired, and we assessed the reasonableness of management's valuation and identification of assets and liabilities with reference to data sources used in impairment testing and estimate of abandonment provisions as per separate Key Audit Matters, in addition to third party reserves certifications.

• expected future foreign exchange rates; • identification and valuation of intangible assets and contingent liabilities; • assessment of disputed tax positions; • discount rates to be applied; and • allocation of goodwill balances to cash generating units. In addition, the calculation of fair values requires financial modelling of the cash flows relating to each asset or liability, including tax effects, which can be complex and may require additional assumptions to be made. As such, the purchase price allocation requires significant attention during the audit and is subject to a high degree of auditor judgment.	We also evaluated the resulting fair values of licences with reference to the divestment of an interest in the same licences. We involved KPMG valuation specialists to assess the mathematical and methodological integrity of management's valuation models. We assessed the discount rates applied with reference to market data and evaluated the adequacy of the business combination related disclosures in Note 2 of the financial statements.

Impairment of licence assets and associated goodwill

Refer to Board of Directors' report and financial statement Note 1.3 (Important accounting judgments, estimates and assumptions), Note 1.12 (Impairment accounting policy) and Note 14 (Impairments).

The key audit matter	*How the matter was addressed in our audit*
The recoverable amounts of licence assets and the associated goodwill are sensitive to changes in market assumptions, in particular oil and gas prices, discount rate and forecast operational performance including the volumes of oil and gas to be produced and licence related expenditures. Any negative developments in these assumptions and forecasts, may be an impairment trigger, even if other factors have moved favourably. In addition, the goodwill balances allocated to licence cash generating units will be subject to impairment charges as the related oil and gas reserves are produced. Management's determination of the recoverable amounts of licence assets and associated goodwill requires a number of estimates and assumptions relating to operational and market factors, and involves a high degree of judgment. In addition, the calculation of recoverable amounts requires complex financial modelling of the cash flows of each cash generating unit. Significant auditor judgment is required when evaluating whether the recoverable amounts, and the assumptions which drive the underlying cash flow estimates, are reasonable and supportable.	We assessed management's identification of impairment triggers with reference to asset specific attributes and market conditions. For each cash generating unit with material asset values where an impairment trigger was identified, we critically assessed the key elements of the cash flow forecasts, including: • production profiles with reference to reserves estimates prepared by the Company's reservoir engineers and third party reserves reports; • three year oil and gas prices with reference to forward curve data and the Company's long term oil price assumptions against benchmark data from analysts, consultancies and other publicly available sources; • opex and capex expenditures with reference to historical forecasts, approved licence budgets and management forecasts; and • abandonment expenditures with reference to our audit work on the abandonment provision (refer Abandonment provisions Key Audit Matter). In addition, KPMG valuation specialists assessed the mathematical and methodological integrity of management's impairment models, including the modelling of tax related cash flows. We also assessed the reasonableness of the discount rate applied with reference to market data and considered whether the disclosures regarding key assumptions and sensitivities adequately reflected the underlying impairment assessments.

Other information

Management is responsible for the other information. The other information comprises information included in the Annual report , but does not include the financial statements and our auditor's report thereon.

Our opinion on the financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of the Board of Directors and the Chief Executive Officer for the Financial Statements

The Board of Directors and the Chief Executive Officer (Management) are responsible for the preparation and fair presentation of the financial statements in accordance with International Financial Reporting Standards as adopted by the EU, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's and the Group's ability to continue as a going concern, disclosing, as applicable, matters related to going concern. The financial statements of the Company use the going concern basis of accounting insofar as it is not likely that the enterprise will cease operations. The financial statements of the Group use the going concern basis of accounting unless management either intends to liquidate the Group or to cease operations, or has no realistic alternative but to do so.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with laws, regulations, and auditing standards and practices generally accepted in Norway, including ISAs, will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with laws, regulations, and auditing standards and practices generally accepted in Norway, including ISAs, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error. We design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's or the Group's internal control.

- evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's or the Group's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company or the Group to cease to continue as a going concern.

- evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Group to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

We communicate with the Board of Directors regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit

We also provide the Board of Directors with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

From the matters communicated with the Board of Directors, we determine those matters that were of most significance in the audit of the financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

Report on Other Legal and Regulatory Requirements

Opinion on the Board of Directors' report

Based on our audit of the financial statements as described above, it is our opinion that the information presented in the Board of Directors' report including the statements on Corporate Governance and Corporate Social Responsibility concerning the financial statements, the going concern assumption, and the proposal for the allocation of the profit is consistent with the financial statements and complies with the law and regulations.

Opinion on Registration and Documentation

Based on our audit of the financial statements as described above, and control procedures we have considered necessary in accordance with the International Standard on Assurance Engagements *(ISAE) 3000, Assurance Engagements Other than Audits or Reviews of Historical Financial Information*, it is our opinion that management has fulfilled its duty to produce a proper and clearly set out registration and documentation of the Company's accounting information in accordance with the law and bookkeeping standards and practices generally accepted in Norway.

Oslo, 8 March 2018
KPMG AS

Mona I. Larsen

Mona Irene Larsen
State Authorised Public Accountant

Bilder: Kjetil Eide/Statoil, Øyvind Sætre/Aibel and Aker BP
Design: Tania Goffredo Design

AKER BP ASA

Fornebuporten, Building B
Oksenøyveien 10
1366 Lysaker

Post: Postboks 65,
1324 Lysaker

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

www.akerbp.com