AkerBP

QUARTERLY REPORT

Q4 2021

FOURTH QUARTER 2021 SUMMARY

Aker BP reported total income of USD 1,849 (1,563) million and operating profit of USD 1,260 (849) million for the fourth quarter 2021. Net profit was USD 364 (206) million. The company paid a dividend of USD 150 million (USD 0.4165 per share) in the quarter. On 21 December 2021, the company announced a transaction agreement with Lundin Energy AB to acquire Lundin Energy's oil and gas related assets.

The company's net production in the fourth quarter was 207.0 (210.0) thousand barrels of oil equivalent per day (mboepd). The decrease was mainly driven by lower production from the Alvheim area and Skarv, partly offset by higher production from the Valhall area compared to the previous quarter. Net sold volume was 205.1 (224.8) mboepd. The average realised liquids price increased to USD 78.8 (71.5) per barrel, while the average realised price for natural gas increased to USD 169.5 (91.3) per barrel of oil equivalent (boe).

Production costs for the oil and gas sold in the quarter decreased to USD 202 (209) million due to lower volumes sold. The average production cost per produced unit was USD 10.1 (9.0) per boe, with the increase driven by lower production, higher power prices and well intervention costs in the Valhall area. Exploration expenses amounted to USD 83 (97) million. Depreciation was USD 219 (247) million, equivalent to USD 11.5 (12.8) per boe, while net impairments amounted to USD 79 million, mainly related to the Ula area.

This resulted in operating profit of USD 1,260 (849) million. After net financial expenses of USD 43 (47) million, profit before taxes ended at USD 1,218 (802) million. Tax expenses amounted to USD 854 (596) million, and net profit was USD 364 (206) million for the quarter.

The company continued progressing its portfolio of field development projects according to plan. During the fourth quarter, the development concept was decided for the NOAKA area development. In addition, development concepts were decided for Valhall NCP & King Lear and for Trine & Trell in the Alvheim area, and a PDO for Hanz in the Ivar Aasen area was submitted to the authorities. Capital expenditure amounted to USD 442 (378) million in the quarter, mainly related to development projects at the Alvheim and Valhall areas.

At the end of the quarter, Aker BP had total available liquidity of USD 5.4 (4.8) billion. Net interest-bearing debt was USD 1.7 (2.3) billion, including USD 0.1 (0.2) billion in lease debt.

In November, the company disbursed dividends of USD 150 million, equivalent to USD 0.4165 per share, reflecting an annualised dividend level of USD 600 million. During the fourth quarter, the Board resolved to further increase the dividend level by 14 percent to USD 0.475 per share per quarter, effective from 1 January 2022.

On 21 December 2021, the company announced a transaction agreement with Lundin Energy AB, pursuant to which Aker BP will acquire Lundin Energy's oil and gas related assets. The transaction is subject to approval by the shareholders of both companies at their respective general meetings, and approval by relevant authorities. Closing of the transaction is anticipated around mid-2022.

Forward-looking statements in this report reflect current views about future events and are, by their nature, subject to significant risks and uncertainties because they relate to events and depend on circumstances that may or may not occur in the future and may not be within our control. All figures are presented in USD unless otherwise stated, and figures in brackets apply to the previous quarter.

Financial summary

	UNIT	Q4 2021	Q3 2021	Q4 2020	FY 2021	FY 2020
Total income	USDm	1 849	1 563	834	5 669	2 979
EBITDA	USDm	1 559	1 250	623	4 541	2 128
Net profit/loss	USDm	364	206	129	851	45
Earnings per share (EPS)	USD	1.01	0.57	0.36	2.37	0.12
Capex	USDm	442	378	298	1 427	1 306
Exploration spend	USDm	95	109	80	434	246
Abandonment spend	USDm	16	27	105	204	178
Production cost	USD/boe	10.1	9.0	8.1	9.2	8.3
Taxes paid/refunded	USDm	160	98	(201)	223	(181)
Net interest-bearing debt	USDm	1 742	2 332	3 647	1 742	3 647
Leverage ratio		0.33	0.56	1.51	0.33	1.51
Dividend per share	USD	0.42	0.31	0.20	1.35	1.18
Average USDNOK exchange rate		8.72	8.77	9.02	8.60	9.41

Production summary

	UNIT	Q4 2021	Q3 2021	Q4 2020	FY 2021	FY 2020
Alvheim area	mboepd	43.4	46.6	54.7	46.5	55.4
Ivar Aasen	mboepd	15.2	15.3	18.7	16.7	20.1
Johan Sverdrup	mboepd	63.1	63.4	59.6	63.0	51.9
Skarv	mboepd	31.8	34.5	26.1	29.0	21.0
Ula area	mboepd	7.4	8.5	10.3	7.8	11.0
Valhall area	mboepd	46.1	41.5	53.6	46.4	50.7
Other	mboepd	0.1	0.2	0.0	0.1	0.5
Net production	mboepd	207.0	210.0	223.1	209.4	210.7
Over/underlift	mboepd	(1.9)	14.7	(9.3)	2.6	(0.5)
Net sold volume	mboepd	205.1	224.8	213.8	212.0	210.2
-Liquids	mboepd	165.4	183.6	175.7	173.8	176.4
-Natural gas	mboepd	39.7	41.2	38.1	38.2	33.8
Realised price liquids	USD/boe	78.8	71.5	44.2	69.2	40.0
Realised price natural gas	USD/boe	169.5	91.3	31.8	88.5	21.8

FINANCIAL REVIEW

Income statement

(USD MILLION)	Q4 2021	Q3 2021	Q4 2020	FY 2021	FY 2020
Total income	1 849	1 563	834	5 669	2 979
EBITDA	1 559	1 250	623	4 541	2 128
EBIT	1 260	849	278	3 315	433
Pre-tax profit	1 218	802	236	3 073	164
Net profit/loss	364	206	129	851	45
EPS (USD)	1.01	0.57	0.36	2.37	0.12

Total income in the fourth quarter 2021 amounted to USD 1,849 (1,563) million. The increase was driven by higher oil and gas prices. Sold volumes were 205.1 (224.8) mboepd in the quarter, following an underlift in the quarter of 1.9 mboepd compared to an overlift in the previous quarter of 14.7 mboepd. Realised prices for liquids increased by 10 percent, while realised prices for natural gas were up 86 percent compared to the previous quarter.

Production costs related to oil and gas sold in the quarter amounted to USD 202 (209) million. Production cost per produced unit amounted to USD 10.1 (9.0) per boe. See note 3 for further details on production costs.

Exploration expenses amounted to USD 83 (97) million, of which field evaluation costs were USD 31 (43) million. The latter includes costs related to finalising the concept for Valhall NCP & King Lear development project ahead of the concept select decision, Alve Nord in the Skarv area, as well as costs related to other future development projects. Dry well expenses were USD 33 (38) million and were mainly related to the Mugnetind and Lyderhorn exploration wells.

Depreciation amounted to USD 219 (247) million, corresponding to USD 11.5 (12.8) per barrel of oil equivalent. The change was driven by movements in reserves due to life extension of the Alvheim area and by variations in the relative share of production from different fields. Impairments amounted to USD 79 million, driven by revisions of future production and cost profiles for the Ula area, an impairment of the previously capitalised exploration costs related to the Liatårnet discovery, partly offset by a reversal of a previous impairment charge of the Trine & Trell discoveries as this project has now been further de-risked with selection of concept during the quarter (see note 5 for further details). Other operating expenses amounted to USD 6 (7) million.

Operating profit increased to USD 1,260 (849) million for the fourth quarter. Net financial expenses amounted to USD 43 (47) million.

Profit before taxes amounted to USD 1,218 (802) million. Tax expense was USD 854 (596) million. The effective tax rate was 70 percent. See note 9 for further details on tax.

This resulted in a net profit for the fourth quarter 2021 of USD 364 (206) million.

Statement of financial position

(USD MILLION)	Q4 2021	Q3 2021	Q4 2020
Total non-current assets	11 487	11 307	11 162
Total current assets	2 983	2 275	1 258
Total assets	14 470	13 582	12 420
Total equity	2 342	2 128	1 987
Bank and bond debt	3 577	3 595	3 969
Total abandonment provisions	2 757	2 716	2 806
Deferred taxes	3 323	3 142	2 642
Other liabilities	2 471	2 001	1 016
Total equity and liabilities	14 470	13 582	12 420
Net interest-bearing debt	1 742	2 332	3 647

At the end of the fourth quarter 2021, total assets amounted to USD 14,470 (13,582) million, of which current assets were USD 2,983 (2,275) million.

Equity amounted to USD 2,342 (2,128) million at the end of the quarter, corresponding to an equity ratio of 16 (16) percent.

Deferred tax liabilities amounted to USD 3,323 (3,142) million and total abandonment provisions amounted to USD 2,757 (2,716) million. Bank and bond debt totalled USD 3,577 (3,595) million. This was entirely made up of bond debt as the company's bank facilities were not drawn.

At the end of the fourth quarter, the company had total available liquidity of USD 5.4 (4.8) billion, comprising USD 1,971 (1,421) million in cash and cash equivalents, and USD 3.4 (3.4) billion in undrawn credit facilities.

Cash flow

(USD MILLION)	Q4 2021	Q3 2021	Q4 2020*	FY 2021	FY 2020*
Cash flow from operations	1 211	1 063	678	4 282	2 011
Cash flow from investments	(484)	(432)	(427)	(1 727)	(1 461)
Cash flow from financing	(180)	(184)	(533)	(1 123)	(119)
Net change in cash & cash equivalents	547	447	(281)	1 433	431
Cash and cash equivalents	1 971	1 421	538	1 971	538

* As described in note 1, the presentation of payment of borrowing costs in the statement of cash flows has been changed. As from first quarter 2021, these cash flows are presented as financing activities, while they previously were presented as operational activities. Comparative figures have been restated accordingly.

Net cash flow from operating activities was USD 1,211 (1,063) million in the quarter. Pre-tax profit increased in the quarter, driven by higher realised oil and gas prices. This was however partly offset by working capital changes and taxes paid.

Net cash used for investment activities was USD 484 (432) million, of which investments in fixed assets amounted to USD 422 (360) million for the quarter. Investments in capitalised exploration were USD 46 (49) million. Payments for decommissioning activities amounted to USD 16 (23) million.

Net cash outflow from financing activities was USD 180 million, compared to an outflow of USD 184 million in the previous quarter. The main items were dividend disbursements of USD 150 (113) million, and payments of lease debt related to investments in fixed assets of USD 18 (16) million.

Risk management

The company is using various types of economic hedging instruments. Commodity derivatives are used to hedge the risk of oil price reduction. Aker BP currently has limited exposure towards fluctuations in interest rate, but generally manages such exposure by using interest rate derivatives. Foreign currency exchange derivatives are used to manage the company's exposure to currency risks, mainly costs in NOK, EUR, and GBP. These derivatives are marked to market with changes in market value recognized in the income statement.

The following table shows the company's inventory of oil put options at the time of this report:

OIL PUT OPTIONS	Q1 2022	Q2 2022	Q3 2022	Q4 2022
Share of oil production covered (after tax)	63 %	73 %	56 %	54 %
Average strike (USD/bbl)	45	45	45	45
Average premium (USD/bbl)	1.9	1.9	1.6	1.6

Dividends

At the Annual General Meeting in April 2021, the Board was authorised to approve the distribution of dividends based on the company's annual accounts for 2020 pursuant to section 8-2 (2) of the Norwegian Public Limited Companies Act.

During 2021, the company has disbursed dividends of USD 487.5 million, equivalent to USD 1.3537 per share.

On 21 December 2021, the Board resolved to increase the annualised dividend level from USD 600 million, corresponding to USD 1.666 per share, to USD 1.90 per share, effective from first quarter 2022. The first quarterly dividend payment of USD 0.475 (NOK 4.1782) is expected to be disbursed on or about 23 February 2022.

OPERATIONAL REVIEW

Aker BP's net production was 19.0 (19.3) mmboe in the fourth quarter of 2021, correspon-ding to 207.0 (210.0) mboepd. Net sold volume was 205.1 (224.8) mboepd. The average realised liquids price was USD 78.8 (71.5) per barrel, while the average realised gas price was USD 169.5 (91.3) per boe.

Alvheim Area

KEY FIGURES	AKER BP INTEREST	Q4 2021	Q3 2021	Q2 2021	Q1 2021	Q4 2020
Production, boepd						
Alvheim	65%	31 721	36 061	34 799	35 176	35 921
Bøyla (incl. Frosk)	65%	2 068	865	1 191	2 921	3 843
Skogul	65%	1 817	4 449	4 542	4 450	6 891
Vilje	46.904%	3 501	1 971	1 789	2 707	2 899
Volund	65%	4 275	3 264	3 602	4 892	5 192
Total production		43 382	46 610	45 923	50 147	54 746
Production efficiency		94 %	96 %	91 %	99 %	98 %

Fourth quarter production from the Alvheim area was 43.4 mboepd net to Aker BP. The reduction compared to the previous quarter was driven by natural decline and shut-in of wells to facilitate drilling of the Kameleon Infill West (KIW) well, partly offset by start-up of the Volund sidetrack and re-start of the Frosk Test production. Production efficiency was 94 (96) percent.

The Alvheim infill well program continued with good progress during the quarter, and the Volund single lateral side-track was put on production in late November, while drilling of the KIW well was completed in December. On the latter, mobilisation for the subsea tie-back campaign commenced early January, and the project is on track to achieve start of production in the first quarter 2022.

Preparations for project execution for the Kobra East & Gekko (KEG) and Frosk development projects are progressing acco-rding to plan. The drilling campaign for Frosk is scheduled to start in the third quarter 2022 with first oil planned in the first quarter 2023. For the KEG project, the main milestone in 2022 is the installation of a new pipeline in the third quarter.

Finally, the Trell and Trine (T&T) project passed the concept select decision gate (DG2) in the fourth quarter and is being matured towards a final investment decision around mid-2022. First oil is planned for first quarter 2025.

Ivar Aasen

KEY FIGURES	AKER BP INTEREST	Q4 2021	Q3 2021	Q2 2021	Q1 2021	Q4 2020
Production, boepd						
Total production	34.7862%	15 157	15 285	16 129	20 206	18 723
Production efficiency		81 %	86 %	89 %	90 %	90 %

Fourth quarter production from Ivar Aasen was 15.2 mboepd net to Aker BP, down one percent from the previous quarter. The reduction was mainly driven by a power outage at Edvard Grieg from 10 September to 14 November resulting in lower production efficiency of 81 (86) percent in the quarter. Additionally, a planned rig move at Edvard Grieg led to a temporary production shutdown, while a gas export constraint from 20 December resulted in a small production loss towards the end of the quarter.

The D-4 well, which was part of the increased oil recovery (IOR) campaign for 2021 came on stream in late October, slightly behind schedule due to the abovementioned power outage. Maturation of the IOR campaign for 2022 is ongoing, with planned sanctioning in the second quarter 2022. The Hanz project passed final investment decision in mid-December, and the PDO was submitted to Norwegian authorities. Total resources are estimated at approximately 20 mmboe (gross), with a break-even oil price of approximately USD 26 per boe. First oil from Hanz is expected in 2024.

Johan Sverdrup

KEY FIGURES	AKER BP INTEREST	Q4 2021	Q3 2021	Q2 2021	Q1 2021	Q4 2020
Production, boepd						
Total production	11.5733%	63 112	63 424	64 262	61 178	59 613

Johan Sverdrup produced at 535,000 barrels per day (gross) with high regularity through the fourth quarter of 2021, except for a short shutdown in November due to a power outage. The full year 2021 production efficiency was 97 percent.

Phase 2 of the Johan Sverdrup development progressed safely according to plan and cost, despite challenges caused by COVID-19. Hook-up and commissioning of the P2 platform (the second processing platform) made good progress at Aibel's construction site in Haugesund and offshore installation is on schedule for March 2022 by Allseas' heavy lift vessel Pioneering Spirit. All five Phase 2 subsea well templates have been installed in the fringe areas of the field and most of the in-field pipelines and umbilicals have been installed. Drilling of Phase 2 wells started in January with Odfjell Drilling's semi-submersible rig Deepsea Atlantic.

Skarv Area

KEY FIGURES	AKER BP INTEREST	Q4 2021	Q3 2021	Q2 2021	Q1 2021	Q4 2020
Production, boepd						
Total production	23.835 %	31 785	34 476	20 581	28 973	26 121
Production efficiency		88 %	97 %	58 %	84 %	98 %

Fourth quarter production from the Skarv Area was 31.8 mboepd net to Aker BP, a reduction of 8 percent from the previous quarter. Production losses driven by maintenance activities and a power outage at Kårstø resulted in reduced production efficiency of 88 (97) percent in the quarter. The power outage also restricted gas export through the Åsgard Transport System.

This was however partly offset by increased production from the Ærfugl wells. Ærfugl phase 2 came on stream 3 November, ahead of schedule and on budget. Following production start at Ærfugl phase 2 and resolution of the power outage situation, production efficiency was back at 98 percent in December.

Ula Area

KEY FIGURES	AKER BP INTEREST	Q4 2021	Q3 2021	Q2 2021	Q1 2021	Q4 2020
Production, boepd						
Ula	80 %	4 165	4 622	3 539	5 464	6 239
Tambar	55 %	1 915	2 725	1 927	1 413	1 092
Oda	15 %	1 297	1 192	930	1 865	2 959
Total production		7 376	8 539	6 396	8 741	10 290
Production efficiency		77 %	84 %	64 %	80 %	75 %

Production from the Ula area was 7.4 mboepd in the fourth quarter, a reduction of 14 percent compared to the previous quarter due to various technical issues and weather restrictions.

An impairment charge of USD 88 million was made in the fourth quarter, based on an updated assessment of future production and cost profiles for the Ula fields (see note 5 for further details)

The Ula Power Project continued to progress well during the quarter. The third and final generator has been installed and commissioning activities are ongoing.

Valhall Area

KEY FIGURES	AKER BP INTEREST	Q4 2021	Q3 2021	Q2 2021	Q1 2021	Q4 2020
Production, boepd						
Valhall	90%	45 623	40 983	44 699	52 526	52 881
Hod	90%	426	467	596	446	682
Total production		46 050	41 450	45 295	52 972	53 564
Production efficiency		84 %	76 %	81 %	91 %	90 %

Production from the Valhall area increased 11 percent quarter on quarter to 46.1 mboepd net to Aker BP, driven by higher production efficiency.

The Hod field development and integration activities between Hod B and the Valhall field centre progressed according to plan, and the subsea installation activities commenced in the fourth quarter. Production start from Hod was originally planned for first quarter 2022 but is now expected to be in second quarter due to late arrival of an installation vessel. The jack up rig Maersk Invisible completed drilling of four wells in the quarter, while the two final wells in the six-well program will be drilled in the first quarter 2022. Meanwhile, the Hod A plug and abandonment (P&A) project, which covers permanent P&A of eight wells, passed decision gate 2 (DG2), and a final investment decision is expected in the second quarter.

During the fourth quarter, a final investment decision was taken on an additional infill well on Valhall Flank West. The well will be drilled by the Maersk Invincible jack-up rig after finishing the six-well program at the Hod field development. The Maersk Reacher rig continued to support stimulation and intervention activity, bringing more wells up to their full production potential.

The Sulfate Removal Unit (SRU) reached the final investment decision in the fourth quarter. The objective of the SRU project is to provide high-quality injection water for Valhall, substantially reducing issues related to hydrogen sulphide and scaling. The project will have a positive effect on work environment, chemicals consumption (opex) and shut-in of production wells. Completion of the project is scheduled for the second quarter 2024.

Finally, the joint Valhall NCP & King Lear project passed DG2 in the fourth quarter and has entered the project maturing phase. The concept consists of a new process and wellhead platform (NCP) which will have a bridge connection to the Valhall field centre, and an unmanned platform on King Lear, located approximately 50 km from the field centre. New infrastructure will be laid on the seabed to connect the two fields. A total of 19 wells are planned, and the concept also includes considerable modification work on the Valhall field centre to facilitate recovery of additional barrels. The project will be connected to the existing power from shore solution at Valhall, resulting in close to zero emissions from operations.

The project will add new slots for further development of the Valhall area and secure development of the King Lear field. Gross resources are estimated to be above 200 mmboe, with a breakeven oil price of USD 25-30 per barrel of oil equivalent. The project is progressing towards a final investment decision in fourth quarter 2022, in time to be covered by the temporary tax scheme. First oil is scheduled for 2027.

North of Alvheim, Krafla and Fulla (NOAKA)

The NOAKA area is located between Oseberg and Alvheim in the Norwegian North Sea and consists of several oil and gas discoveries. The partners (Aker BP ASA, Equinor ASA and LOTOS Exploration & Production Norge AS) are planning for a coordinated development of the area, with Aker BP as the operator of North of Alvheim and Fulla (NOA Fulla), and with Equinor as the operator of Krafla.

The gross resource estimate amounts to around 600 million barrels of oil equivalent (gross), with further upside potential from future exploration in the area. Gross capex is currently estimated to be in the range of USD 10 billion, and the break-even oil price is estimated to be in line with Aker BP's investment criteria of USD 30 dollars per barrel. These estimates will be further refined before the final investment decision which is planned towards the end of 2022.

During the fourth quarter, a formal concept select decision was made for Krafla, following the final concept select decision for NOA Fulla during the third quarter 2021. This means that the concept for the full NOAKA area now is selected.

Krafla will be developed with an unmanned production platform and five subsea templates. The Krafla development will be tied back to the Aker BP-operated NOA PdQ for oil and produced water processing.

The NOA Fulla development concept includes a fixed platform at the Frigg Gamma Delta field, operated by Aker BP. The fixed platform, NOA PdQ, will function as an area hub, with processing, drilling, and living quarters. Further, the Frøy field will be re-developed with a normally unmanned installation, as a copy of the Valhall Flank West and the Hod B platforms. The development concept also includes robust and flexible subsea production systems with dual drilling layout for the Fulla, Langfjellet and Rind fields, all tied back to the NOA PdQ.

The NOAKA area will be powered from shore to ensure minimal carbon footprint. In October, the licence application for the power from shore solution was submitted to the Norwegian authorities.

EXPLORATION

Total exploration spend in the fourth quarter was USD 95 (109) million, while USD 83 (97) million was recognised as exploration expenses in the period, relating to dry well costs, seismic, area fees, field evaluation and G&G costs.

Field evaluation costs are driven by activities related to discoveries and projects which have not yet been sanctioned. In the fourth quarter, these costs amounted to USD 31 (43) million.

The drilling of the Mugnetind prospect in licence 906 was completed in the quarter and resulted in a minor oil discovery. Preliminary estimates place the size of the discovery between approximately 4-9 million barrels of oil equivalent. The discovery is not considered to be commercial.

Drilling of the Lyderhorn prospect in licence 1041 was also completed in the quarter. The wildcat well resulted in a small oil discovery. Preliminary estimates place the size of the discovery at approximately 5 million barrels of oil equivalent and is not considered to be commercial.

In January 2022, Aker BP was awarded 15 licences in the 2021 APA licensing round, of which seven as operator. Of the 15 production licences awarded to Aker BP, 10 are in the North Sea (5 as operator) and 5 are in the Norwegian Sea (2 as operator).

HEALTH, SAFETY, SECURITY AND THE 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.

KEY HSSE INDICATORS	UNIT	Q4 2021	Q3 2021	Q2 2021	Q1 2021	Q4 2020
Total recordable injury frequency (TRIF) L12M*	Per mill. exp. hours	1.9	1.6	1.2	1.4	1.2
Serious incident frequency (SIF) L12M	Per mill. exp. hours	0	0	0	0	0.2
Acute spill	Count	0	0	0	0	0
Process safety events Tier 1 and 2	Count	0	0	0	0	0
CO_2 emissions intensity L12M	Kg CO_2/boe	4.8	4.4	4.2	4.3	4.5

* Change in historical numbers for TRIF in 2021 due to updated exposure hours or re-classification of incident

The change in Total Recordable Injuries Frequency (TRIF) is mainly due to a slight increase in personal injuries, which is being addressed systematically in accordance with the company's governing processes. The company continues to monitor the trend closely and have mitigating actions in place.

The CO_2 emissions intensity for 2021 ended at 4.8 kg per boe, within the targeted level of 5 kg per boe. The increase from 2020 was mainly driven by higher emissions due to power outages at Ivar Aasen and process shutdowns at Valhall, in addition to lower production from the Ula and Alvheim areas.

The company continued working systematically to reduce emissions from its operated fields and through its drilling alliances, focusing on a wide range of measures to improve energy efficiency and reduce methane emissions. This resulted in an estimated reduction in annual emissions of approximately 23,000 tonnes of CO_2 equivalent.

Towards the end of the quarter, the company re-established some Covid-19 measures onshore and offshore due to the increasing infection rate. The company monitors the trend closely and will keep the measures in place for as long as necessary.

ACQUISITION OF LUNDIN ENERGY

On 21 December 2021, Aker BP announced a transaction agreement with Lundin Energy AB, pursuant to which Aker BP will acquire Lundin Energy's oil and gas related assets. In return, Lundin Energy's shareholders will receive approximately 0.95 shares in Aker BP plus a cash consideration of approximately USD 7.76 per share held in Lundin Energy. Lundin Energy's shareholders will retain shares in Lundin Energy AB, which is not being acquired.

The transaction is subject to approval by the shareholders of both companies at their respective general meetings, and approval by relevant authorities. The annual general meetings are scheduled for 31 March 2022 for Lundin Energy and 5 April 2022 for Aker BP. Aker, BP and Nemesia have provided irrevocable voting undertakings in favour of the merger and have agreed on a lock-up for six months on their Aker BP shares from closing of the transaction.

Closing of the transaction is anticipated around mid-2022.

OUTLOOK

Aker BP has a strong financial position and remains well positioned for future value creation. For 2022, the company's financial plan consists of the following key parameters [1]. The numbers relate to Aker BP's current portfolio only, and do not reflect any effects from the proposed Lundin transaction.

- Production of 210-220 mboepd
- Capex of around USD 1.6 billion
- Exploration spend of around USD 400 million
- Abandonment spend of around USD 100 million
- Production cost of around USD 10 per boe
- Dividends of USD 1.9 per share for the full year, to be paid in four quarterly instalments

1 Most of the company's cost elements (both capex and production cost) are denominated in NOK. The estimated USD amounts are based on an USDNOK exchange rate of 8.5.

FINANCIAL STATEMENTS WITH NOTES

INCOME STATEMENT

(USD 1 000)	Note	Q4 2021	Q3 2021	Group Q4 2020	01.01.-31.12. 2021	2020
Petroleum revenues		1 820 879	1 558 228	830 098	5 639 990	2 868 153
Other income		28 201	4 447	3 410	28 757	111 110
Total income	2	**1 849 080**	**1 562 675**	**833 508**	**5 668 747**	**2 979 263**
Production costs	3	202 374	208 798	142 068	745 313	627 975
Exploration expenses	4	82 620	97 477	41 722	353 034	174 099
Depreciation	6	219 312	246 846	289 408	964 083	1 121 818
Impairments	5,6	79 016	153 881	55 302	262 554	573 128
Other operating expenses		5 536	6 534	27 028	29 261	49 457
Total operating expenses		**588 858**	**713 537**	**555 528**	**2 354 245**	**2 546 477**
Operating profit/loss		**1 260 222**	**849 138**	**277 980**	**3 314 502**	**432 786**
Interest income		1 441	342	89	2 481	3 763
Other financial income		31 041	33 449	49 203	116 171	170 865
Interest expenses		26 072	27 018	47 640	139 533	181 677
Other financial expenses		49 093	54 218	43 965	220 836	262 052
Net financial items	8	**-42 683**	**-47 444**	**-42 313**	**-241 718**	**-269 101**
Profit/loss before taxes		**1 217 539**	**801 694**	**235 667**	**3 072 785**	**163 685**
Tax expense (+)/income (-)	9	853 509	595 860	106 200	2 222 080	118 970
Net profit/loss		**364 030**	**205 834**	**129 467**	**850 704**	**44 715**
Weighted average no. of shares outstanding basic and diluted		359 787 854	359 336 759	360 100 643	359 642 622	359 808 121
Basic and diluted earnings/loss USD per share		1.01	0.57	0.36	2.37	0.12

STATEMENT OF COMPREHENSIVE INCOME

(USD 1 000)	Note	Q4 2021	Q3 2021	Group Q4 2020	01.01.-31.12. 2021	2020
Profit/loss for the period		364 030	205 834	129 467	850 704	44 715
Items which will not be reclassified over profit and loss (net of taxes)						
Actuarial gain/loss pension plan		-	-	9	-	9
Total comprehensive income/loss in period		**364 030**	**205 834**	**129 477**	**850 704**	**44 724**

STATEMENT OF FINANCIAL POSITION

(USD 1 000)	Note	31.12.2021	Group 30.09.2021	31.12.2020
ASSETS				
Intangible assets				
Goodwill	6	1 647 436	1 647 436	1 647 436
Capitalized exploration expenditures	6	256 535	404 515	521 922
Other intangible assets	6	1 407 551	1 374 238	1 521 311
Tangible fixed assets				
Property, plant and equipment	6	7 976 308	7 666 727	7 266 137
Right-of-use assets	6	94 177	105 248	132 735
Financial assets				
Long-term receivables		73 346	73 975	29 086
Other non-current assets		30 304	32 553	30 210
Long-term derivatives	12	1 375	2 765	12 841
Total non-current assets		**11 487 032**	**11 307 457**	**11 161 678**
Inventories				
Inventories		126 442	123 430	112 704
Receivables				
Trade receivables		366 785	412 195	297 880
Other short-term receivables	10	500 154	307 293	286 817
Short-term derivatives	12	18 577	10 860	23 212
Cash and cash equivalents				
Cash and cash equivalents	11	1 970 906	1 420 783	537 801
Total current assets		**2 982 863**	**2 274 561**	**1 258 414**
TOTAL ASSETS		**14 469 895**	**13 582 017**	**12 420 091**

STATEMENT OF FINANCIAL POSITION

(USD 1 000)	Note	31.12.2021	Group 30.09.2021	31.12.2020
EQUITY AND LIABILITIES				
Equity				
Share capital		57 056	57 056	57 056
Share premium		3 637 297	3 637 297	3 637 297
Other equity		-1 352 462	-1 566 492	-1 707 071
Total equity		**2 341 891**	**2 127 860**	**1 987 281**
Non-current liabilities				
Deferred taxes	9	3 323 213	3 142 033	2 642 461
Long-term abandonment provision	15	2 656 358	2 637 470	2 650 263
Long-term bonds	14	3 576 735	3 594 939	3 968 566
Long-term derivatives	12	2 370	2 006	-
Long-term lease debt	7	91 835	95 772	131 856
Total non-current liabilities		**9 650 511**	**9 472 221**	**9 393 146**
Current liabilities				
Trade creditors		147 366	166 599	113 517
Accrued public charges and indirect taxes		28 147	25 203	25 761
Tax payable	9	1 497 291	990 482	163 352
Short-term derivatives	12	35 082	27 675	3 539
Short-term abandonment provision	15	100 863	78 750	155 244
Short-term lease debt	7	44 378	61 869	83 904
Other current liabilities	13	624 366	631 358	494 346
Total current liabilities		**2 477 493**	**1 981 937**	**1 039 664**
Total liabilities		**12 128 004**	**11 454 157**	**10 432 810**
TOTAL EQUITY AND LIABILITIES		**14 469 895**	**13 582 017**	**12 420 091**

STATEMENT OF CHANGES IN EQUITY - GROUP

(USD 1 000)	Share capital	Share premium	Other equity: Other paid-in capital	Other comprehensive income: Actuarial gains/losses	Other comprehensive income: Foreign currency translation reserves[1)]	Accumulated deficit	Total other equity	Total equity
Equity as of 31.12.2019	**57 056**	**3 637 297**	573 083	-85	-115 491	-1 784 274	**-1 326 767**	**2 367 585**
Dividend distributed	-	-	-	-	-	-354 167	-354 167	-354 167
Profit/loss for the period	-	-	-	-	-	-84 752	-84 752	-84 752
Purchase of treasury shares[2)]	-	-	-	-	-	-28	-28	-28
Equity as of 30.09.2020	**57 056**	**3 637 297**	573 083	-85	-115 491	-2 223 221	**-1 765 714**	**1 928 638**
Dividend distributed	-	-	-	-	-	-70 833	-70 833	-70 833
Profit/loss for the period	-	-	-	-	-	129 467	129 467	129 467
Other comprehensive income for the period	-	-	-	9	-	-	9	9
Equity as of 31.12.2020	**57 056**	**3 637 297**	573 083	-76	-115 491	-2 164 587	**-1 707 071**	**1 987 281**
Dividend distributed	-	-	-	-	-	-337 500	-337 500	-337 500
Profit/loss for the period	-	-	-	-	-	486 674	486 674	486 674
Net purchase of treasury shares[2)]	-	-	-	-	-	-8 595	-8 595	-8 595
Equity as of 30.09.2021	**57 056**	**3 637 297**	573 083	-76	-115 491	-2 024 008	**-1 566 492**	**2 127 860**
Dividend distributed	-	-	-	-	-	-150 000	-150 000	-150 000
Profit/loss for the period	-	-	-	-	-	364 030	364 030	364 030
Other comprehensive income for the period	-	-	-		-	-		
Equity as of 31.12.2021	**57 056**	**3 637 297**	573 083	-76	-115 491	-1 809 977	**-1 352 462**	**2 341 891**

1) The amount arose mainly as a result of the change in functional currency in 2014.

2) The treasury shares are purchased/sold for use in the group's share saving plan.

STATEMENT OF CASH FLOW

				Group		
		Q4	Q3	Q4	01.01.-31.12.	
				Restated		Restated
(USD 1 000)	Note	2021	2021	2020	2021	2020
CASH FLOW FROM OPERATING ACTIVITIES						
Profit/loss before taxes		1 217 539	801 694	235 667	3 072 785	163 685
Taxes paid	9	-198 475	-97 680	-16 556	-296 155	-145 286
Taxes refunded	9	38 350	-	217 373	72 989	326 208
Depreciation	6	219 312	246 846	289 408	964 083	1 121 818
Impairment	5,6	79 016	153 881	55 302	262 554	573 128
Accretion expenses	8,15	28 815	28 624	29 298	113 748	116 947
Total interest expenses (excluding amortized loan costs)	8	23 034	23 975	44 559	117 073	161 863
Changes in derivatives	2,8	1 444	13 295	-43 728	50 015	-15 999
Amortized loan costs	8	3 038	3 043	3 081	22 460	19 813
Expensed capitalized dry wells	4,6	33 243	37 603	6 071	98 827	56 626
Changes in inventories, trade creditors and receivables		23 164	-27 388	-199 547	-48 794	-161 027
Changes in other current balance sheet items		-257 771	-121 030	57 211	-147 428	-206 423
NET CASH FLOW FROM OPERATING ACTIVITIES		**1 210 710**	**1 062 862**	**678 138**	**4 282 157**	**2 011 353**
CASH FLOW FROM INVESTMENT ACTIVITIES						
Payment for removal and decommissioning of oil fields		-16 123	-23 241	-85 508	-172 512	-150 306
Disbursements on investments in fixed assets (excluding capitalized interest)		-421 862	-359 969	-297 219	-1 376 879	-1 238 601
Disbursements on investments in capitalized exploration		-45 656	-48 562	-43 774	-177 464	-127 283
Cash received from sale of licenses		-	-	-	-	54 747
NET CASH FLOW FROM INVESTMENT ACTIVITIES		**-483 642**	**-431 772**	**-426 501**	**-1 726 855**	**-1 461 443**
CASH FLOW FROM FINANCING ACTIVITIES						
Net drawdown/repayment/fees related to revolving credit facility		-	-	-	-7 675	-1 451 550
Repayment of bonds		-	-	-406 000	-1 282 503	-618 553
Net proceeds from bond issue		-	-	-	899 334	2 718 248
Receipt/payment upon settlement of derivatives related to financing		-	-	-	-	-56 804
Interest paid (including interest element of lease payments)		-8 444	-54 766	-35 966	-151 085	-184 068
Payments on lease debt related to investments in fixed assets		-18 125	-15 580	-971	-44 805	-57 885
Payments on other lease debt		-3 071	-5 850	-18 873	-39 810	-43 709
Paid dividend		-150 000	-112 500	-70 833	-487 500	-425 000
Net purchase/sale of treasury shares		-	4 223	-	-8 595	-28
NET CASH FLOW FROM FINANCING ACTIVITIES		**-179 640**	**-184 473**	**-532 642**	**-1 122 640**	**-119 348**
Net change in cash and cash equivalents		**547 429**	**446 617**	**-281 006**	**1 432 662**	**430 562**
Cash and cash equivalents at start of period		1 420 783	975 360	818 547	537 801	107 104
Effect of exchange rate fluctuation on cash held		2 694	-1 195	259	443	134
CASH AND CASH EQUIVALENTS AT END OF PERIOD	11	**1 970 906**	**1 420 783**	**537 801**	**1 970 906**	**537 801**

NOTES
(All figures in USD 1 000 unless otherwise stated)

These condensed consolidated interim financial statements ("interim financial statements") have been prepared in accordance with the International Financial Reporting Standards as adopted by the EU ("IFRS") IAS 34 "Interim Financial Reporting", thus the interim financial statements do not include all information required by IFRS and should be read in conjunction with the group's 2020 annual financial statements. The interim financial statements reflect all adjustments which are, in the opinion of management, necessary for a fair statement of the financial position, results of operations and cash flows for the dates and interim periods presented. Interim period results are not necessarily indicative of results of operations or cash flows for an annual period. These interim financial statements have not been subject to review or audit by independent auditors.

These interim financial statements were authorised for issue by the company’s Board of Directors on 9 February 2022.

Note 1 Accounting principles

The accounting principles used for this interim report are consistent with the principles used in the group's 2020 annual financial statements, except for a change in presentation of payment of borrowing costs in the statement of cash flows. From Q1 2021, the group presents these cash flows as financing activities, while they prior to 2021 were presented as operational and investment activities. The reason behind the change is that borrowing costs are directly linked to the group's financing activities, and are thus deemed more relevant to include under financing activities. Comparative figures have been restated accordingly and the impact on relevant previous periods is included in the table below.

Breakdown of restating impact on Statetment of Cash Flow (USD 1 000)	**Q4 2020**	**01.01.-31.12. 2020**
NET CASH FLOW FROM OPERATING ACTIVITIES		
- Prior to restating	645 014	1 857 053
- After restating	678 138	2 011 353
Change	33 124	154 300
NET CASH FLOW FROM INVESTMENT ACTIVITIES		
- Prior to restating	-435 343	-1 500 710
- After restating	-426 501	-1 461 443
Change	8 842	39 267
NET CASH FLOW FROM FINANCING ACTIVITIES		
- Prior to restating	-490 677	74 219
- After restating	-532 642	-119 348
Change	-41 966	-193 568
Impact on net change in cash and cash equivalents	**0**	**0**

In preparing these interim financial statements, management has made judgements, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets and liabilities, income and expense. Actual results may differ from these estimates.

The significant judgements made by management in applying the group’s accounting policies and the key sources of estimation uncertainty are in all material respects the same as those that applied in the group's 2020 annual financial statements.

Note 2 Income

Breakdown of petroleum revenues (USD 1 000)	Q4 2021	Q3 2021	Group Q4 2020	01.01.-31.12. 2021	2020
Sales of liquids	1 199 242	1 208 591	714 514	4 392 625	2 581 776
Sales of gas	618 441	345 849	111 431	1 233 314	270 404
Tariff income	3 195	3 788	4 154	14 051	15 973
Total petroleum revenues	**1 820 879**	**1 558 228**	**830 098**	**5 639 990**	**2 868 153**
Sales of liquids (boe 1 000)	15 216	16 892	16 165	63 447	64 549
Sales of gas (boe 1 000)	3 649	3 787	3 507	13 935	12 384

Other income (USD 1 000)					
Realized gain/loss (-) on oil derivatives	-6 638	-6 638	-7 611	-19 362	55 328
Unrealized gain/loss (-) on oil derivatives	3 432	4 094	1 718	-5 449	-1 734
Gain on license transactions	-	-	-	-	5 417
Other income[1]	31 407	6 991	9 302	53 568	52 099
Total other income	**28 201**	**4 447**	**3 410**	**28 757**	**111 110**

[1] Mainly related to insurance settlement received in Q4 2021

Note 3 Production costs

Breakdown of production cost (USD 1 000)	Q4 2021	Q3 2021	Group Q4 2020	01.01.-31.12. 2021	2020
Cost of operations	139 544	114 051	108 169	472 791	435 366
Shipping and handling	41 874	46 173	47 990	179 579	168 824
Environmental taxes	10 428	14 199	9 190	47 637	35 922
Production cost based on produced volumes	**191 845**	**174 422**	**165 349**	**700 007**	**640 111**
Adjustment for over/underlift (-)	10 529	34 376	-23 281	45 306	-12 137
Production cost based on sold volumes	**202 374**	**208 798**	**142 068**	**745 313**	**627 975**
Total produced volumes (boe 1 000)	19 042	19 322	20 525	76 439	77 101
Production cost per boe produced (USD/boe)	10.1	9.0	8.1	9.2	8.3

Note 4 Exploration expenses

Breakdown of exploration expenses (USD 1 000)	Q4 2021	Q3 2021	Group Q4 2020	01.01.-31.12. 2021	2020
Seismic	3 079	3 953	1 627	23 138	25 522
Area fee	7 067	3 926	3 877	18 891	15 272
Field evaluation	31 218	43 423	21 308	176 969	44 718
Dry well expenses[1]	33 243	37 603	6 071	98 827	56 626
Other exploration expenses	8 012	8 571	8 839	35 208	31 961
Total exploration expenses	**82 620**	**97 477**	**41 722**	**353 034**	**174 099**

[1] Dry well expenses in Q4 2021 are mainly related to the wells Mugnetind and Lyderhorn

Note 5 Impairments

Impairment testing

Impairment tests of individual cash-generating units are performed when impairment/reversal triggers are identified, and goodwill is tested for impairment at least annually. In Q4 2021, two categories of impairment tests have been performed:

- Impairment test of fixed assets and related intangible assets, including technical goodwill
- Impairment test of residual goodwill

Impairment is recognized when the book value of an asset or a cash-generating unit, including associated goodwill, exceeds the recoverable amount. Correspondingly, a reversal of impairment is recognized when the recoverable amount exceeds the book value. Prior period impairment of goodwill is not subject to reversal. The recoverable amount is the higher of the asset's fair value less cost to sell and value in use. The impairment testing for Q4 has been performed in accordance with the fair value method (level 3 in fair value hierarchy) and 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.

For producing licenses and licenses 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 2021.

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 and gas prices are therefore based on the forward curve from the beginning of Q1 2022 to the end of Q4 2024. From Q1 2025, the oil and gas prices are based on the company's long-term price assumptions. Long-term oil price assumption is unchanged from year-end 2020.

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

Year	USD/BOE
2022	75.8
2023	71.0
2024	67.9
From 2025 (in real 2021 terms)	65.0

The nominal gas prices applied in the impairment test are as follows:

Year	GBP/therm
2022	1.64
2023	1.03
2024	0.66
From 2025 (in real 2021 terms)	0.48

Oil and gas reserves

Future cash flows are calculated on the basis of expected production profiles and estimated proven and probable remaining reserves.

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 post tax nominal discount rate used is 7.6 percent. This represents a change from 8.1 percent applied in previous quarters in 2021.

Currency rates

Year	USD/NOK
2022	8.87
2023	8.92
2024	8.95
From 2025	8.00

Inflation

The long-term inflation rate is assumed to be 2.0 percent.

Impairment testing of assets including technical goodwill

The technical goodwill recognized in previous business combinations is allocated to each CGU for the purpose of impairment testing. Hence, the impairment test of technical goodwill is included in the impairment testing of assets, and the technical goodwill is written down before the asset. The carrying value of the assets is the sum of tangible assets, intangible assets and technical goodwill as of the assessment date. In line with the methodology described in the annual report, deferred tax (from the date of acquisitions) reduces the net carrying value prior to the impairment charges. When deferred tax liabilities from the acquisitions decreases as a result of depreciation, more goodwill is as such exposed for impairment. This may lead to future impairment charges even though other assumptions remain stable.

Below is an overview of the impairment charge and the carrying value per cash generating unit where impairment has been recognized in Q4 2021:

Cash-generating unit (USD 1 000)	**Ula/Tambar**
Net carrying value	487 176
Recoverable amount	398 753
Impairment/reversal (-)	**88 422**
Allocated as follows:	
Technical goodwill	-
Other intangible assets/license rights	-
Tangible fixed assets	88 422

The main reasons for the Ula impairment charge are the effect of updated cost and production profiles.

For details of the allocation of the impairment/reversal to tangible fixed assets and intangible assets, see note 6.

Sensitivity analysis

The table below shows how the impairment or reversal of impairment of assets and technical goodwill would be affected by changes in the various assumptions, given that the remaining assumptions are constant. The CGU's impacted are Ula/Tambar, Ivar Aasen and Valhall.

		Change in impairment after	
Assumption (USD 1 000)	**Change**	**Increase in assumptions**	**Decrease in assumptions**
Oil and gas price forward period	+/- 50 %	-231 316	613 846
Oil and gas price long-term	+/- 20 %	-124 607	145 421
Production profile (reserves)	+/- 5 %	-55 798	55 798
Discount rate	+/- 1 % point	-4 342	7 048
Currency rate USD/NOK	+/- 2.0 NOK	-183 672	304 906
Inflation	+/- 1 % point	-35 937	32 739

Exploration assets

During the quarter, a net impairment reversal of USD 9.1 million has been recognized, mainly related to an impairment of Liatårnet of USD 47.6 million, and an impairment reversal of USD 60.0 million related to Trell & Trine. The reversal was triggered by an updated impairment assessment in relation to the project being included in the Alvheim CGU after concept selection was made towards the end of the fouth quarter. The impairment charge and reversal of prior period impairment have been allocated between other intangible assets and capitalized exploration expenditures with USD -50.7 million (net reversal) and USD 41.6 million (net impairment) respectively.

Residual goodwill

Residual goodwill is allocated across all CGUs for impairment testing. The combined recoverable amount exceeds the carrying amount by a substantial margin.

Climate related risks

The climate related risk assessment is generally described in the company's sustainability reporting. For financial reporting, the transition risk (market, regulatory, reputation, technical and operational) is deemed as the most important, and this has been integrated in the economic assumptions used for impairment testing. This includes a step up of CO2 tax/fees from current levels to approximately NOK 2 100 per tonn (2021 real) in 2030.

In addition, various scenarios from International Energy Agency have been included in a separate sensitivity test which includes the six producing CGU's in the company. The price assumptions in those senarios have been provided by IEA at 2030 and 2050 in 2020 real terms, and for the sensitivity calculation a linear development between average actual 2021 and to 2030, as well as between 2030 and 2050 have been applied. The table below summarizes how the impairment charge would increase (+) or decrease (-) using the oil and gas price assumptions in the following scenarios (2030 and 2050 prices in brackets):

		Change in impairment				
IEA Scenario (USD 1 000 000)		**Valhall/Hod**	**Ula/Tambar**	**Alvheim**	**Ivar Aasen**	**Total**
Net Zero	(Oil 36 - 24 USD/bbl, Gas 3.9 - 3.6 USD/mmbtu)	1 047	210	15	118	1 390
Sustainable Development	(Oil 56 - 50 USD/bbl, Gas 4.2 - 4.5 USD/mmbtu)	-	47	-	-	47
Announced Pledges	(Oil 67 - 64 USD/bbl, Gas 6.5 - 6.5 USD/mmbtu)	-	-43	-	-	-43
Stated Policies	(Oil 77 - 88 USD/bbl, Gas 7.7 - 8.3 USD/mmbtu)	-	-125	-	-	-125

The estimated impairment charge on the CGU's Johan Sverdrup and Skarv would not be impacted by any of the scenarios above. Ula/Tambar is the only CGU where there is previous impairment charge that could be reversed going forward. The estimated headroom in the impairment test on all six CGU's would increase by approximately USD 1.5 billion in the Stated Policies scenario, compared to the oil and gas prices applied in the impairment testing.

Note 6 Tangible fixed assets and intangible assets

TANGIBLE FIXED ASSETS - GROUP

Property, plant and equipment (USD 1 000)	**Assets under development**	**Production facilities including wells**	**Fixtures and fittings, office machinery**	**Total**
Book value 31.12.2020	**1 088 754**	**6 062 384**	**114 999**	**7 266 137**
Acquisition cost 31.12.2020	**1 088 754**	**9 886 875**	**241 304**	**11 216 933**
Additions	574 535	393 998	9 525	978 058
Disposals/retirement	-	-	-	-
Reclassification	-171 688	365 060	2 519	195 891
Acquisition cost 30.09.2021	**1 491 601**	**10 645 933**	**253 348**	**12 390 882**
Accumulated depreciation and impairments 31.12.2020	**-**	**3 824 491**	**126 305**	**3 950 795**
Depreciation	-	644 150	32 714	676 864
Impairment/reversal (-)	-	96 495	-	96 495
Disposals/retirement depreciation	-	-	-	-
Accumulated depreciation and impairments 30.09.2021	**-**	**4 565 136**	**159 018**	**4 724 154**
Book value 30.09.2021	**1 491 601**	**6 080 797**	**94 329**	**7 666 727**
Acquisition cost 30.09.2021	**1 491 601**	**10 645 933**	**253 348**	**12 390 882**
Additions	239 874	226 780	3 225	469 880
Disposals/retirement	-	-	-	-
Reclassification[1)]	63 961	63 376	-124	127 213
Acquisition cost 31.12.2021	**1 795 436**	**10 936 089**	**256 449**	**12 987 974**
Accumulated depreciation and impairments 30.09.2021	**-**	**4 565 136**	**159 018**	**4 724 154**
Depreciation	-	188 618	10 726	199 344
Impairment/reversal (-)	-	88 168	-	88 168
Disposals/retirement depreciation	-	-	-	-
Accumulated depreciation and impairments 31.12.2021	**-**	**4 841 922**	**169 744**	**5 011 666**
Book value 31.12.2021	**1 795 436**	**6 094 167**	**86 705**	**7 976 308**

1) The reclassifications are mainly related to the Krafla project (included in the NOAKA development) transferred from capitalized exploration to assets under development, as well as parts of Ærfugl phase 2 and wells on Valhall entering production phase during Q4 2021.

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.

Right-of-use assets

(USD 1 000)	Drilling Rigs	Vessels and Boats	Office	Other	Total
Book value 31.12.2020	**41 864**	**57 395**	**31 525**	**1 950**	**132 735**
Acquisition cost 31.12.2020	**47 963**	**62 016**	**46 427**	**2 303**	**158 709**
Additions	-	-	5 989	-	5 989
Allocated to abandonment activity	-11 518	-1 821	-	-	-13 339
Disposals/retirement	-	-	-	-	-
Reclassification	-10 646	-1 615	-	-	-12 260
Acquisition cost 30.09.2021	**25 800**	**58 580**	**52 416**	**2 303**	**139 099**
Accumulated depreciation and impairments 31.12.2020	**6 099**	**4 620**	**14 902**	**353**	**25 974**
Depreciation	-	1 556	6 189	132	7 877
Impairment/reversal (-)	-	-	-	-	-
Disposals/retirement depreciation	-	-	-	-	-
Accumulated depreciation and impairments 30.09.2021	**6 099**	**6 176**	**21 091**	**485**	**33 851**
Book value 30.09.2021	**19 701**	**52 404**	**31 325**	**1 818**	**105 248**
Acquisition cost 30.09.2021	**25 800**	**58 580**	**52 416**	**2 303**	**139 099**
Additions	-	-	-	-	-
Allocated to abandonment activity[1)]	-	-122	-	-	-122
Disposals/retirement	-	-	-	-	-
Reclassification[2)]	-7 388	-1 021	-	-	-8 409
Acquisition cost 31.12.2021	**18 412**	**57 436**	**52 416**	**2 303**	**130 567**
Accumulated depreciation and impairments 30.09.2021	**6 099**	**6 176**	**21 091**	**485**	**33 851**
Depreciation	-	520	1 975	44	2 540
Impairment/reversal (-)	-	-	-	-	-
Disposals/retirement depreciation	-	-	-	-	-
Accumulated depreciation and impairments 31.12.2021	**6 099**	**6 696**	**23 066**	**530**	**36 390**
Book value 31.12.2021	**12 313**	**50 740**	**29 350**	**1 774**	**94 177**

[1)] This represents the share of right-of-use assets used in abandonment activity, and thus booked against the abandonment provision.

[2)] Reclassified to tangible fixed assets in line with the activity of the right-of-use asset.

Right-of-use assets are depreciated linearly over the lifetime of the related lease contract.

INTANGIBLE ASSETS - GROUP

(USD 1 000)	Other intangible assets: Licenses etc.	Other intangible assets: Software	Total	Capitalized exploration expenditures	Goodwill
Book value 31.12.2020	**1 521 311**	**-**	**1 521 311**	**521 922**	**1 647 436**
Acquisition cost 31.12.2020	**2 368 985**	**7 501**	**2 376 486**	**668 029**	**2 726 583**
Additions		-		131 808	-
Disposals/retirement/expensed dry wells	-	-	-	65 584	-
Reclassification	-	-	-	-183 630	-
Acquisition cost 30.09.2021	**2 368 985**	**7 501**	**2 376 486**	**550 622**	**2 726 583**
Accumulated depreciation and impairments 31.12.2020	**847 674**	**7 501**	**855 175**	**146 107**	**1 079 146**
Depreciation	60 031	-	60 031	-	-
Impairment/reversal (-)	87 042	-	87 042	-	-
Disposals/retirement depreciation	-	-	-	-	-
Accumulated depreciation and impairments 30.09.2021	**994 747**	**7 501**	**1 002 248**	**146 107**	**1 079 146**
Book value 30.09.2021	**1 374 238**	**-**	**1 374 238**	**404 515**	**1 647 436**
Acquisition cost 30.09.2021	**2 368 985**	**7 501**	**2 376 486**	**550 622**	**2 726 583**
Additions		-		45 656	-
Disposals/retirement/expensed dry wells	-	7 501	7 501	33 243	-
Reclassification[1]	-	-	-	-118 804	-
Acquisition cost 31.12.2021	**2 368 985**	**-**	**2 368 985**	**444 232**	**2 726 583**
Accumulated depreciation and impairments 30.09.2021	**994 747**	**7 501**	**1 002 248**	**146 107**	**1 079 146**
Depreciation	17 428	-	17 428	-	-
Impairment/reversal (-)	-50 741	-	-50 741	41 589	-
Disposals/retirement depreciation	-	-7 501	-7 501	-	-
Accumulated depreciation and impairments 31.12.2021	**961 434**	**-**	**961 434**	**187 696**	**1 079 146**
Book value 31.12.2021	**1 407 551**	**-**	**1 407 551**	**256 535**	**1 647 436**

[1] The reclassification is mainly related to the Krafla project (included in the NOAKA development), which passed concept select during Q4 2021.

Licenses include both planned and producing projects on various fields. The producing projects are depreciated in line with the unit-of-production method for the applicable field.

	Group				
Depreciation in the income statement (USD 1 000)	**Q4 2021**	**Q3 2021**	**Q4 2020**	**01.01.-31.12. 2021**	**01.01.-31.12. 2020**
Depreciation of tangible fixed assets	199 344	225 148	262 720	876 207	1 004 395
Depreciation of right-of-use assets	2 540	2 444	2 156	10 416	19 350
Depreciation of other intangible assets	17 428	19 255	24 532	77 459	98 073
Total depreciation in the income statement	**219 312**	**246 846**	**289 408**	**964 083**	**1 121 818**
Impairment in the income statement (USD 1 000)					
Impairment/reversal of tangible fixed assets	88 168	149 630	57 607	184 664	67 099
Impairment/reversal of other intangible assets	-50 741	4 251	-2 305	36 301	294 549
Impairment/reversal of capitalized exploration expenditures	41 589	-	-	41 589	146 107
Impairment of goodwill	-	-	-	-	65 373
Total impairment in the income statement	**79 016**	**153 881**	**55 302**	**262 554**	**573 128**

Note 7 Leasing

The incremental borrowing rate applied in discounting of the nominal lease debt is between 2.71 percent and 6.71 percent, dependent on the duration of the lease and when it was intially recognized.

	Group		
	2021		2020
(USD 1 000)	Q4	01.01.-30.09.	01.01.-31.12.
Lease debt as of beginning of period	**157 641**	**215 760**	**313 256**
New lease debt recognized in the period	-	5 989	16 834
Payments of lease debt[1]	-23 564	-72 609	-118 224
Lease debt derecognized in the period	-	-	-12 767
Interest expense on lease debt	2 368	9 190	16 629
Currency exchange differences	-233	-688	32
Total lease debt	**136 213**	**157 641**	**215 760**
Short-term	44 378	61 869	83 904
Long-term	91 835	95 772	131 856
[1] **Payments of lease debt split by activities** (USD 1 000):			
Investments in fixed assets	20 150	30 273	67 125
Abandonment activity	203	31 512	27 660
Operating expenditures	2 032	5 467	18 075
Exploration expenditures	227	1 631	874
Other income	952	3 725	4 489
Total	**23 564**	**72 609**	**118 224**
Nominal lease debt maturity breakdown (USD 1 000)**:**			
Within one year	51 010	69 417	95 124
Two to five years	68 602	69 980	99 809
After five years	42 837	46 880	57 464
Total	**162 448**	**186 276**	**252 397**

The identified leases have no significant impact on the group`s financing, loan covenants or dividend policy. The group does not have any residual value guarantees. Extension options are included in the lease liability when, based on management's judgement, it is reasonably certain that an extension will be exercised.

Note 8 Financial items

			Group		
	Q4	Q3	Q4	01.01.-31.12.	
(USD 1 000)	2021	2021	2020	2021	2020
Interest income	**1 441**	**342**	**89**	**2 481**	**3 763**
Realized gains on derivatives	5 524	3 640	7 193	27 392	16 821
Change in fair value of derivatives	-	-	42 010		74 537
Net currency gains	25 517	29 810	-	88 779	79 507
Total other financial income	**31 041**	**33 449**	**49 203**	**116 171**	**170 865**
Interest expenses	33 221	30 611	49 869	145 651	184 501
Interest on lease debt	2 368	2 708	3 531	11 558	16 629
Capitalized interest cost, development projects	-12 555	-9 344	-8 842	-40 136	-39 267
Amortized loan costs	3 038	3 043	3 081	22 460	19 813
Total interest expenses	**26 072**	**27 018**	**47 640**	**139 533**	**181 677**
Net currency loss	-	-	5 501	-	-
Realized loss on derivatives	15 010	8 205	9 121	23 249	125 791
Change in fair value of derivatives	4 876	17 389	-	44 565	-
Accretion expenses	28 815	28 624	29 298	113 748	116 947
Other financial expenses	392	1	45	39 274	19 314
Total other financial expenses	**49 093**	**54 218**	**43 965**	**220 836**	**262 052**
Net financial items	**-42 683**	**-47 444**	**-42 313**	**-241 718**	**-269 101**

Note 9 Tax

Tax for the period (USD 1 000)	Q4 2021	Q3 2021	Group Q4 2020	01.01.-31.12. 2021	01.01.-31.12. 2020
Current year tax payable/receivable	667 609	500 466	25 836	1 526 236	-333 104
Change in current year deferred tax	181 180	94 625	79 900	684 723	448 393
Prior period adjustments	4 720	769	463	11 122	3 680
Tax expense (+)/income (-)	**853 509**	**595 860**	**106 200**	**2 222 080**	**118 970**

Calculated tax payable (-)/tax receivable (+) (USD 1 000)	Group 2021 Q4	2021 01.01.-30.09.	2020 01.01.-31.12.
Tax payable/receivable at beginning of period	-990 482	-163 352	-361 157
Current year tax payable/receivable	-667 609	-858 627	333 104
Tax payable/receivable related to acquisitions/sales	-	-	-3 855
Net tax payment/refund	160 125	63 041	-180 922
Prior period adjustments and change in estimate of uncertain tax positions	-4 720	-52 445	-10 425
Currency movements of tax payable/receivable	5 395	20 902	59 903
Net tax payable (-)/receivable (+)	**-1 497 291**	**-990 482**	**-163 352**
Tax receivable included as current assets (+)	-	-	-
Tax payable included as current liabilities (-)	-1 497 291	-990 482	-163 352

Deferred tax liability (-)/asset (+) (USD 1 000)	Group 2021 Q4	2021 01.01.-30.09.	2020 01.01.-31.12.
Deferred tax liability/asset at beginning of period	-3 142 033	-2 642 461	-2 235 357
Change in current year deferred tax	-181 180	-503 543	-448 393
Deferred tax related to acquisitions/sales	-	-	37 727
Prior period adjustments	-	3 971	3 595
Deferred tax charged to OCI and equity	-	-	-33
Net deferred tax liability (-)/asset (+)	**-3 323 213**	**-3 142 033**	**-2 642 461**

Reconciliation of tax expense (USD 1 000)	Q4 2021	Q3 2021	Group Q4 2020	01.01.-31.12. 2021	01.01.-31.12. 2020
78 % tax rate on profit/loss before tax	949 681	625 321	183 820	2 396 772	127 674
Tax effect of uplift	-79 880	-69 449	-61 301	-270 454	-268 564
Permanent difference on impairment	-39 691	4 149	1 497	-36 862	169 670
Foreign currency translation of monetary items other than USD	-19 768	-22 772	3 026	-68 575	-62 040
Foreign currency translation of monetary items other than NOK	14 950	-18 432	229 697	16 508	129 042
Tax effect of financial and other 22 % items	8 971	44 088	-107 953	114 038	37 761
Currency movements of tax balances[1)]	8 441	27 840	-153 368	43 332	-30 321
Other permanent differences, prior period adjustments and change in estimate of uncertain tax positions	10 805	5 115	10 782	27 321	15 748
Tax expense (+)/income (-)	**853 509**	**595 860**	**106 200**	**2 222 080**	**118 970**

[1)] 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 (and vice versa).

In accordance with statutory requirements, the calculation of current tax is required to be based on NOK functional currency. This may impact the effective tax rate as the group's functional currency is USD.

Note 10 Other short-term receivables

(USD 1 000)	Group 31.12.2021	30.09.2021	31.12.2020
Prepayments	45 429	41 535	59 635
VAT receivable	13 354	7 683	6 770
Underlift of petroleum	36 944	21 741	53 537
Accrued income from sale of petroleum products	290 254	145 465	49 441
Other receivables, mainly balances with license partners	114 172	90 869	117 433
Total other short-term receivables	**500 154**	**307 293**	**286 817**

Note 11 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 31.12.2021	30.09.2021	31.12.2020
Bank deposits	1 970 906	1 420 783	537 801
Cash and cash equivalents	**1 970 906**	**1 420 783**	**537 801**
Unused RCF facility	3 400 000	3 400 000	4 000 000

The RCF is undrawn as at 31 December 2021 and the remaining unamortized fees of USD 15.9 million related to the facility are therefore included in other non-current assets.

The senior unsecured Revolving Credit Facility (RCF) was established in May 2019, with the Working Capital facility amended and extended in April 2021. The Working Capital Facility has a committed amount of USD 1.4 billion and is due in 2024, with options for up to two years extension. The Liquidity facility is due in 2026, and has a committed amount of USD 2.0 billion until 2025 and then reduces to USD 1.65 billion for the final year. The interest rate is LIBOR plus a margin of 1.25 percent for the Working Capital Facility and 1.00 percent for the Liquidity Facility. In addition, a utilization fee is applicable for the Liquidity Facility. A commitment fee of 35 percent of applicable margin is paid on the undrawn facility. The financial covenants are as follows:

- Leverage Ratio: Total net debt divided by EBITDAX shall not exceed 3.5 times
- Interest Coverage Ratio: EBITDA divided by Interest expenses shall be a minimum of 3.5 times

The financial covenants are calculated on a 12 months rolling basis. As at 31 December 2021 the Leverage Ratio is 0.33 and Interest Coverage Ratio is 27.3 (see APM section for further details), which are well within the thresholds mentioned above. Based on the group's current business plans and applying oil and gas price forward curves at end of Q4 2021, the group’s estimates show that the financial covenants will continue to be within the thresholds by a substantial margin.

The financial covenants in the group's current debt facilities exclude the effects from IFRS 16, and therefore cannot be directly derived from the group's financial statements. See reconciliations of Alternative Performance Measures for detailed information.

Note 12 Derivatives

(USD 1 000)	31.12.2021	Group 30.09.2021	31.12.2020
Unrealized gain currency contracts	1 375	2 765	12 841
Long-term derivatives included in assets	**1 375**	**2 765**	**12 841**
Unrealized gain on currency contracts	18 577	10 860	23 212
Short-term derivatives included in assets	**18 577**	**10 860**	**23 212**
Total derivatives included in assets	**19 952**	**13 625**	**36 053**
Unrealized losses currency contracts	2 370	2 006	-
Long-term derivatives included in liabilities	**2 370**	**2 006**	**-**
Unrealized losses commodity derivatives	8 989	12 420	3 539
Unrealized losses currency contracts	26 094	15 255	-
Short-term derivatives included in liabilities	**35 082**	**27 675**	**3 539**
Total derivatives included in liabilities	**37 452**	**29 681**	**3 539**

The group has various types of economic hedging instruments. Commodity derivatives are used to hedge the risk of oil price reduction. The group currently has limited exposure towards fluctuations in interest rate, but generally manages such exposure by using interest rate derivatives. Foreign currency exchange derivatives are used to manage the company's exposure to currency risks, mainly costs in NOK, EUR and GBP. These derivatives are marked to market with changes in market value recognized in the income statement. The nature of the instruments and the valuation method is consistent with the disclosed information in the annual financial statements as at 31 December 2020.

The company established its Euro Medium Term Note ('EMTN') programme in April 2021 and issued EUR 750 million Senior Notes in May 2021. As these Senior Notes bonds are EUR denominated there are currency risks associated with the translation to the company's USD functional currency and the cash payments of interest and principle amounts, though EUR denominated gas sales mitigate the risks associated with payments. The company has not entered any foreign currency exchange derivatives related to the EUR Senior Notes.

Note 13 Other current liabilities

Breakdown of other current liabilities (USD 1 000)	31.12.2021	Group 30.09.2021	31.12.2020
Balances with license partners	48 456	77 026	20 915
Share of other current liabilities in licenses	311 694	357 849	245 158
Overlift of petroleum	40 044	14 312	11 331
Payroll liabilities, accrued interest and other provisions	224 173	182 171	216 942
Total other current liabilities	**624 366**	**631 358**	**494 346**

Note 14 Bonds

Senior unsecured bonds (USD 1 000)	Maturity	Group 31.12.2021	30.09.2021	31.12.2020
AKERBP – USD Senior Notes 4.750% (19/24)	Jun 2024	-	-	743 329
AKERBP – USD Senior Notes 3.000% (20/25)	Jan 2025	497 295	497 075	496 417
AKERBP – USD Senior Notes 5.875% (18/25)	Mar 2025	-	-	495 523
AKERBP – USD Senior Notes 2.875% (20/26)	Jan 2026	497 103	496 926	496 394
AKERBP – EUR Senior Notes 1.125% (21/29)	May 2029	843 995	862 939	-
AKERBP – USD Senior Notes 3.750% (20/30)	Jan 2030	993 622	993 424	992 764
AKERBP – USD Senior Notes 4.000% (20/31)	Jan 2031	744 720	744 575	744 139
Long-term bonds - book value		**3 576 735**	**3 594 939**	**3 968 566**
Long-term bonds - fair value		**3 752 778**	**3 823 194**	**4 191 375**

Interest is paid on a semi annual basis, except for the EUR Senior Notes which is paid on an annual basis. None of the bonds have financial covenants.

Note 15 Provision for abandonment liabilities

(USD 1 000)	2021 Q4	Group 2021 01.01.-30.09.	2020 01.01.-31.12.
Provisions as of beginning of period	2 716 220	2 805 507	2 788 218
Change in abandonment liability due to asset sales	-	-	-13 122
Incurred removal cost	-16 246	-169 727	-162 741
Accretion expense	28 815	84 933	116 947
Impact of changes to discount rate	-340 973	-	20 554
Change in estimates and provisions relating to new drilling and installations[1)]	369 405	-4 493	55 650
Total provision for abandonment liabilities	**2 757 221**	**2 716 220**	**2 805 507**
Short-term	100 863	78 750	155 244
Long-term	2 656 358	2 637 470	2 650 263

[1)] The change in estimates are mainly driven by increased future service rates and new wells

Estimates are 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 2.0 percent and a nominal discount rate before tax of between 3.7 percent and 5.2 percent. For previous quarters in 2021 and year end 2020 the inflation rate was 2.0 percent and the discount rate was between 3.1 percent and 4.6 percent. The credit margin included in the discount rate is 3.3 percent. For previous quarters in 2021 and year end 2020 the credit margin was 3.0 percent.

Note 16 Contingent liabilities and assets

During the normal course of its business, the group will be involved in disputes, including tax disputes. The group 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.

Note 17 Subsequent events

On 2 February 2022, it was announced that Aker BP sold its 7,4% interest in Cognite AS to Saudi Aramco. The company expects to recognize a gain of approximately USD 90 million when the transaction is complete, which is expected to occur in Q1 2022.

Note 18 Investments in joint operations

Total number of licenses	31.12.2021	30.09.2021
Aker BP as operator	80	80
Aker BP as partner	44	44

Changes in production licenses in which Aker BP is the operator:			Changes in production licenses in which Aker BP is a partner:		
License:	**31.12.2021**	**30.09.2021**	**License:**	**31.12.2021**	**30.09.2021**
PL 026[1)]	87.700%	92.130 %	PL 006C[3)]	35.000%	15.000 %
PL 026B[1)]	87.700%	90.260 %	PL 533B[5)]	0.000%	35.000 %
PL 036E[2)]	48.420%	58.000 %	PL 943[3)]	10.000%	0.000 %
PL 036F[2)]	48.420%	58.000 %	PL 1064[3)]	20.000%	30.000 %
PL 102F[2)]	48.420%	44.000 %			
PL 102G[2)]	48.420%	44.000 %			
PL 261[3)]	60.000%	50.000 %			
PL 364[1)]	87.700%	90.260 %			
PL 442[1)]	87.700%	90.260 %			
PL 442B[1)]	87.700%	90.260 %			
PL 442C[1)]	87.700%	90.260 %			
PL 867[3)]	80.000%	100.000 %			
PL 867B[3)]	80.000%	100.000 %			
PL 873[1)]	47.700%	40.000 %			
PL 874[1)]	87.700%	90.260 %			
PL 906[3)]	50.000%	60.000 %			
PL 942[4)]	30.000%	30.000 %			
PL 1008[3)]	90.000%	100.000 %			
PL 1085[3)]	55.000%	60.000 %			
Total	**19**	**19**	**Total**	**3**	**3**

[1)] NOAKA transactions with Lotos

[2)] Unitization Trell & Trine

[3)] License transactions Q4

[4)] Operatorship attained

[5)] Relinquished license or Aker BP has withdrawn from the license

Note 19 Selected historical interim information

(USD 1 000)	2021 Q4	2021 Q3	2021 Q2	2021 Q1	2020 Q4
Total income	**1 849 080**	**1 562 675**	**1 123 754**	**1 133 238**	**833 508**
Production costs	202 374	208 798	158 235	175 906	142 068
Exploration expenses	82 620	97 477	102 020	70 917	41 722
Depreciation	219 312	246 846	240 372	257 554	289 408
Impairments	79 016	153 881	-	29 656	55 302
Other operating expenses	5 536	6 534	8 965	8 225	27 028
Total operating expenses	**588 858**	**713 537**	**509 592**	**542 258**	**555 528**
Operating profit/loss	**1 260 222**	**849 138**	**614 162**	**590 980**	**277 980**
Net financial items	-42 683	-47 444	-61 744	-89 846	-42 313
Profit/loss before taxes	**1 217 539**	**801 694**	**552 418**	**501 134**	**235 667**
Tax expense (+)/income (-)	853 509	595 860	398 607	374 104	106 200
Net profit/loss	**364 030**	**205 834**	**153 811**	**127 029**	**129 467**

(boe 1 000)	2021 Q4	2021 Q3	2021 Q2	2021 Q1	2020 Q4
Sold volumes					
Liquids	15 216	16 892	14 871	16 468	16 165
Gas	3 649	3 787	2 879	3 620	3 507

(USD 1 000)	2021 Q4	2021 Q3	2021 Q2	2021 Q1	2020 Q4
Assets					
Goodwill	1 647 436	1 647 436	1 647 436	1 647 436	1 647 436
Other intangible assets	1 664 086	1 778 753	1 873 199	1 878 702	2 043 233
Property, plant and equipment	7 976 308	7 666 727	7 630 389	7 392 321	7 266 137
Right-of-use asset	94 177	105 248	115 705	126 861	132 735
Receivables and other assets	1 116 982	963 070	833 760	803 603	792 750
Cash and cash equivalents	1 970 906	1 420 783	975 360	392 276	537 801
Total assets	**14 469 895**	**13 582 017**	**13 075 850**	**12 241 198**	**12 420 091**
Equity and liabilities					
Equity	2 341 891	2 127 860	2 030 304	1 988 993	1 987 281
Other provisions for liabilities incl. P&A (long)	2 658 728	2 639 476	2 680 537	2 665 343	2 650 263
Deferred tax	3 323 213	3 142 033	3 050 315	2 781 602	2 642 461
Bonds and bank debt	3 576 735	3 594 939	3 614 833	3 474 328	3 968 566
Lease debt	136 213	157 641	178 980	200 346	215 760
Other current liabilities incl. P&A	935 825	929 586	923 494	678 456	792 407
Tax payable	1 497 291	990 482	597 387	452 131	163 352
Total equity and liabilities	**14 469 895**	**13 582 017**	**13 075 850**	**12 241 198**	**12 420 091**

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.

Abandonment spend (abex) is payment for removal and decommissioning of oil fields[1)]

Capex is disbursements on investments in fixed assets[1)]

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

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

Exploration spend (expex) is exploration expenses plus additions to capitalized exploration wells less dry well expenses[1)]

Interest coverage ratio is calculated as twelve months rolling EBITDA, divided by interest expenses, excluding any impacts from IFRS 16.

Leverage ratio is calculated as Net interest-bearing debt divided by twelve months rolling EBITDAX, excluding any impacts from IFRS 16

Net interest-bearing debt is book value of current and non-current interest-bearing debt less cash and cash equivalents

Operating profit/loss is short for earnings/loss before interest and other financial items and taxes

Production cost per boe is production cost basd on produced volumes, divided by number of barrels of oil equivalents produced in the corresponding period (see note 3)

[1)] Includes payments of lease debt as disclosed in note 7.

(USD 1 000)	Note	Q4 2021	Q3 2021	Q4 2020	01.01.-31.12. 2021	01.01.-31.12. 2020
Abandonment spend						
Payment for removal and decommissioning of oil fields		16 123	23 241	85 508	172 512	150 306
Payments of lease debt (abandonment activity)	7	203	3 357	19 003	31 715	27 660
Abandonment spend		**16 326**	**26 598**	**104 511**	**204 227**	**177 966**
Depreciation per boe						
Depreciation	6	219 312	246 846	289 408	964 083	1 121 818
Total produced volumes (boe 1 000)	3	19 042	19 322	20 525	76 439	77 101
Depreciation per boe		**11.5**	**12.8**	**14.1**	**12.6**	**14.6**
Dividend per share						
Paid dividend		150 000	112 500	70 833	487 500	425 000
Number of shares outstanding		359 788	359 337	360 101	359 643	359 808
Dividend per share		**0.42**	**0.31**	**0.20**	**1.36**	**1.18**
Capex						
Disbursements on investments in fixed assets (excluding capitalized interest)		421 862	359 969	297 219	1 376 879	1 238 601
Payments of lease debt (investments in fixed assets)	7	20 150	17 549	1 144	50 423	67 125
CAPEX		**442 012**	**377 518**	**298 363**	**1 427 302**	**1 305 727**
EBITDA						
Total income	2	1 849 080	1 562 675	833 508	5 668 747	2 979 263
Production costs	3	-202 374	-208 798	-142 068	-745 313	-627 975
Exploration expenses	4	-82 620	-97 477	-41 722	-353 034	-174 099
Other operating expenses		-5 536	-6 534	-27 028	-29 261	-49 457
EBITDA		**1 558 550**	**1 249 865**	**622 690**	**4 541 139**	**2 127 731**
EBITDAX						
Total income	2	1 849 080	1 562 675	833 508	5 668 747	2 979 263
Production costs	3	-202 374	-208 798	-142 068	-745 313	-627 975
Other operating expenses		-5 536	-6 534	-27 028	-29 261	-49 457
EBITDAX		**1 641 170**	**1 347 342**	**664 412**	**4 894 173**	**2 301 830**
Equity ratio						
Total equity		2 341 891	2 127 860	1 987 281	2 341 891	1 987 281
Total assets		14 469 895	13 582 017	12 420 091	14 469 895	12 420 091
Equity ratio		**16%**	**16%**	**16%**	**16%**	**16%**
Exploration spend						
Disbursements on investments in capitalized exploration expenditures		45 656	48 562	43 774	177 464	127 283
Exploration expenses	4	82 620	97 477	41 722	353 034	174 099
Dry well	4	-33 243	-37 603	-6 071	-98 827	-56 626
Payments of lease debt (exploration expenditures)	7	227	578	310	1 858	874
Exploration spend		**95 260**	**109 013**	**79 735**	**433 529**	**245 629**

(USD 1 000)	Note	Q4 2021	Q3 2021	Q4 2020	01.01.-31.12. 2021	01.01.-31.12. 2020
Interest coverage ratio						
Twelve months rolling EBITDA	19	4 541 139	3 605 280	2 127 731	4 541 139	2 127 731
Twelve months rolling EBITDA, impacts from IFRS 16	7	-14 035	-14 052	-23 438	-14 035	-23 438
Twelve months rolling EBITDA, excluding impacts from IFRS 16		*4 527 104*	*3 591 228*	*2 104 293*	*4 527 104*	*2 104 293*
Twelve months rolling interest expenses	8	145 651	162 300	184 501	145 651	184 501
Twelve months rolling amortized loan cost	8	22 460	22 502	19 813	22 460	19 813
Twelve months rolling interest income	8	2 481	1 128	3 763	2 481	3 763
Net interest expenses		*165 630*	*183 674*	*200 552*	*165 630*	*200 552*
Interest coverage ratio		**27.3**	**19.6**	**10.5**	**27.3**	**10.5**
Leverage ratio						
Long-term bonds	14	3 576 735	3 594 939	3 968 566	3 576 735	3 968 566
Cash and cash equivalents	11	1 970 906	1 420 783	537 801	1 970 906	537 801
Net interest-bearing debt excluding lease debt		*1 605 829*	*2 174 157*	*3 430 766*	*1 605 829*	*3 430 766*
Twelve months rolling EBITDAX	19	4 894 173	3 917 416	2 301 830	4 894 173	2 301 830
Twelve months rolling EBITDAX, impacts from IFRS 16	7	-12 177	-12 111	-22 564	-12 177	-22 564
Twelve months rolling EBITDAX, excluding impacts from IFRS 16		*4 881 996*	*3 905 305*	*2 279 266*	*4 881 996*	*2 279 266*
Leverage ratio		**0.33**	**0.56**	**1.51**	**0.33**	**1.51**
Net interest-bearing debt						
Long-term bonds	14	3 576 735	3 594 939	3 968 566	3 576 735	3 968 566
Long-term lease debt	7	91 835	95 772	131 856	91 835	131 856
Short-term lease debt	7	44 378	61 869	83 904	44 378	83 904
Cash and cash equivalents	11	1 970 906	1 420 783	537 801	1 970 906	537 801
Net interest-bearing debt		**1 742 042**	**2 331 798**	**3 646 526**	**1 742 042**	**3 646 526**

Operating profit/loss see Income Statement

Production cost per boe see note 3

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