Lundin Petroleum

Q4

YEAR END REPORT 2016

Lundin Petroleum AB (publ)

company registration number 556610-8055

Highlights

Twelve months ended 31 December 2016 (31 December 2015)

- Production of 72.6 Mboepd (32.3 Mboepd)
- Revenue of MUSD 1,159.9 (MUSD 569.3)
- EBITDA of MUSD 902.6 (MUSD 384.7)
- Operating cash flow of MUSD 1,010.8 (MUSD 699.6)
- Net result of MUSD -499.3 (MUSD -866.3) including an after tax impairment charge of MUSD -548.6 (MUSD -296.3) and a net foreign exchange gain of MUSD 15.0 (loss of MUSD 507.3)
- Net debt of MUSD 4,075 (31 December 2015: MUSD 3,786)
- Annual record production of 72.6 Mboepd following the Edvard Grieg field start up in November 2015.
- Record low cost of operations per boe of USD 6.25 and cash operating costs per boe of USD 7.80 in 2016.
- In August 2016, the operator provided a guidance update on the Johan Sverdrup project announcing reduced capital costs to NOK 99 billion gross for Phase 1 and NOK 140-170 billion gross for Phase 1 and Phase 2 and an increased Phase 1 and Phase 2 production capacity of 660,000 bopd gross. The resource range increased to 1.9-3.0 billion boe.
- Secured new fully committed reserve-based lending facility of USD 5.0 billion.

Fourth quarter ended 31 December 2016 (31 December 2015)

- Production of 83.4 Mboepd (38.3 Mboepd)
- Revenue of MUSD 385.9 (MUSD 136.0)
- EBITDA of MUSD 317.9 (MUSD 93.6)
- Operating cash flow of MUSD 343.0 (MUSD 175.4)
- Net result of MUSD -739.1 (MUSD -493.7) including an after tax impairment charge of MUSD -548.6 (MUSD -296.3) and a net foreign exchange loss of MUSD -215.9 (MUSD -129.2).
- Quarterly record production of 83.4 Mboepd due to the exceptional performance and uptime of the producing assets.
- Record low cost of operations per boe of USD 5.38 and cash operating costs per boe of USD 6.51.

	1 Jan 2016- 31 Dec 2016 12 months	1 Oct 2016- 31 Dec 2016 3 months	1 Jan 2015- 31 Dec 2015 12 months	1 Oct 2015- 31 Dec 2015 3 months
Production in Mboepd	**72.6**	**83.4**	32.3	38.3
Revenue in MUSD	**1,159.9**	**385.9**	569.3	136.0
Net result in MUSD	**-499.3**	**-739.1**	-866.3	-493.7
Net result attributable to shareholders of the Parent Company in MUSD	**-356.7**	**-599.9**	-861.7	-492.5
Earnings/share in USD[1]	**-1.09**	**-1.76**	-2.79	-1.59
Earnings/share fully diluted in USD[1]	**-1.09**	**-1.76**	-2.79	-1.59
EBITDA in MUSD	**902.6**	**317.9**	384.7	93.6
Operating cash flow in MUSD	**1,010.8**	**343.0**	699.6	175.4

[1] Based on net result attributable to shareholders of the Parent Company.

Definitions

An extensive list of definitions can be found on www.lundin-petroleum.com under the heading “Definitions”.

Abbreviations

EBITDA	Earnings Before Interest, Tax, Depreciation and Amortisation
CAD	Canadian dollar
CHF	Swiss franc
EUR	Euro
NOK	Norwegian krona
RUR	Russian rouble
SEK	Swedish krona
USD	US dollar
TSEK	Thousand SEK
TUSD	Thousand USD
MSEK	Million SEK
MUSD	Million USD

Oil related terms and measurements

boe	Barrels of oil equivalents
boepd	Barrels of oil equivalents per day
bopd	Barrels of oil per day
Mbbl	Thousand barrels
Mboe	Thousand barrels of oil equivalents
Mboepd	Thousand barrels of oil equivalents per day
Mbopd	Thousand barrels of oil per day
Bn boe	Billion barrels of oil equivalents
Mcf	Thousand cubic feet

Letter to Shareholders

Dear fellow Shareholders,

A record breaking year

With 2016 now behind us we can confidently say that it is mission accomplished. 2016 has been an outstanding year for Lundin Petroleum. We have seen record production levels achieved with over 72,000 boepd produced for the year at a record low cash operating cost of USD 7.80 per barrel. This is primarily on the back of the excellent performance of the Edvard Grieg field that came onstream in November 2015, in addition to the continued robust performance from our operated assets in Malaysia and France that have delivered ahead of expectation. However, our net result for the year was impacted by a non-cash after tax impairment charge of MUSD 548.6 following the decision taken to remove the booked contingent resources associated with discoveries in Russia and in Malaysia. This impairment charge does not impact the cash flow generation of the Company.

In addition, we have seen the reserves in Edvard Grieg increasing from the original PDO estimate of 186 MMboe to 223 MMboe and we all know that big fields tend to get bigger. Already in the first quarter of 2017 we will be drilling one further appraisal well which has the potential to add further reserves.

The year was further marked by the acquisition of an additional 15 percent equity in Edvard Grieg from Statoil. This transaction not only increased our production and reserves but also strengthened our financial position further by improving an already very solid liquidity position following the signing of the USD 5.0 billion reserve-based lending facility earlier in the year.

At the same time, our largest development project Johan Sverdrup continues to deliver good news with lower project costs, higher increased production capacity and a reserves increase when compared to the original PDO estimates.

We have also seen our southern Barents Sea exploration strategy unfolding with the highly anticipated 23rd Licensing round awards. We were very pleased to be one of the most successful companies in this 23rd round and our ongoing 2017 exploration activity has the potential to add significant resources.

Outlook for 2017 and beyond

With the outlook for 2017 and beyond I am convinced that what lies ahead of us will be as equally exciting as 2016. In 2017 we will continue to see our production increasing while on the project development side, we will have the most active year ever with Johan Sverdrup Phase 1 project execution. It will also be the year when the concept will be selected for Phase 2 of the Johan Sverdrup project and we progress towards the execution phase.

In parallel, we will be drilling some world class exploration targets in the southern Barents Sea while continuing to work on an appraisal programme in our Alta and Gohta discoveries. Work towards development concept selection studies for Alta, Gohta and Luno II discoveries will be a priority.

In our “do nothing case” we will see our production level reach in excess of 120,000 boepd by the time Johan Sverdrup Phase 1 comes onstream. By the time Johan Sverdrup Phase 2 reaches plateau our production will reach in excess of 150,000 boepd. We also expect that we will do better with new developments in the pipeline and the new resources we will discover in the years to come.

Strong focus on HSE excellence

Our health, safety and environmental track record for 2016 has also been solid and we will continue to keep a strong focus on HSE excellence as the Company grows.

Such great results would not be possible without the enthusiasm, professionalism and entrepreneurship from my colleagues and the management team. My first year as the new CEO of Lundin Petroleum has been a very rewarding one and it is all down to the great team work and team spirit that exists within the Company.

To you, fellow shareholders, the Board, and the Lundin Petroleum team, I thank you for your continued support.

Yours Sincerely,

Alex Schneiter
President and CEO

Stockholm, 1 February 2017

OPERATIONAL REVIEW

Lundin Petroleum is an independent oil and gas exploration and production company with a principal focus on operations in Norway, with a portfolio of assets in Norway, Malaysia, France, the Netherlands and Russia. Norway represents the majority of Lundin Petroleum's operational activities with production for the financial year 2016 accounting for 82 percent of total production and with Norway representing 96 percent of Lundin Petroleum's total reserves as at 31 December 2016.

Reserves and Resources

Lundin Petroleum has 743.5 million barrels of oil equivalent (MMboe) of proved plus probable reserves as at 31 December 2016 as certified by an independent third party. Lundin Petroleum also has a number of discovered oil and gas resources which classify as contingent resources and are not yet classified as reserves. The best estimate contingent resources net to Lundin Petroleum amount to 267 MMboe as at 31 December 2016.

Production

Production for the year amounted to 72,600 barrels of oil equivalent per day (boepd) (compared to 32,300 boepd for 2015) and was thus in the upper end of the original production guidance of 65,000 to 75,000 boepd for the year and at the mid-point of the revised 2016 guidance of 70,000 to 75,000 boepd. The actual production was comprised as follows:

Production in Mboepd	**1 Jan 2016- 31 Dec 2016 12 months**	**1 Oct 2016- 31 Dec 2016 3 months**	1 Jan 2015- 31 Dec 2015 12 months	1 Oct 2015- 31 Dec 2015 3 months
Crude oil				
Norway	53.2	64.0	18.6	21.1
France	2.6	2.6	2.7	2.5
Malaysia	8.6	8.3	5.5	9.3
Total crude oil production	**64.4**	**74.9**	26.8	32.9
Gas				
Norway	6.1	7.1	2.1	2.3
Netherlands	1.6	1.4	1.8	1.7
Indonesia	0.5	–	1.6	1.4
Total gas production	**8.2**	**8.5**	5.5	5.4
Total production				
Quantity in Mboe	**26,559.6**	**7,676.9**	11,790.3	3,526.6
Quantity in Mboepd	**72.6**	**83.4**	32.3	38.3

Norway

Production

Production in Mboepd	WI [1]	**1 Jan 2016- 31 Dec 2016 12 months**	**1 Oct 2016- 31 Dec 2016 3 months**	1 Jan 2015- 31 Dec 2015 12 months	1 Oct 2015- 31 Dec 2015 3 months
Edvard Grieg	65%[2]	42.0	52.3	1.4	5.6
Alvheim	15%	10.0	12.5	7.8	7.2
Volund	35%	2.7	1.8	4.9	4.0
Bøyla	15%	1.7	1.6	2.1	2.0
Brynhild	90%	2.6	2.6	4.2	4.3
Gaupe	40%	0.3	0.3	0.3	0.3
		59.3	**71.1**	20.7	23.4

[1] Lundin Petroleum's working interest (WI)
[2] WI 50% up to 30 June 2016

Production from the Edvard Grieg field during the year was higher than forecast at 42,000 boepd due to better reservoir performance and uptime than forecast. During the fourth quarter of 2016 a fourth production well was successfully drilled and came onstream at planned production rates in December 2016, thus allowing the field to reach its projected daily flow-rate plateau production rate of 100,000 boepd gross. The production capacity from the first three wells has exceeded expectations and the reservoir pressure depletion rate has been more favourable than anticipated.

The first two water injection wells have also been successfully drilled during the year, with both wells encountering better than expected reservoir sands and pressure communication with the production wells. Both water injection wells are injecting at planned rates. The facilities uptime has also been exceptional with an average facilities uptime of 97 percent for the year. During the fourth quarter of 2016 the Edvard Grieg field was shut-in for a limited period for the tie-in of the Ivar Aasen field. The tie-in operation was successfully carried out in November 2016 and the Edvard Grieg platform commenced processing Ivar Aasen hydrocarbons on 24 December 2016.

The two water injection wells which have been drilled during the year have proven additional oil reserves in the western flank of the Edvard Grieg field. The first water injection well, which was drilled in the northwestern part of the field, encountered the top reservoir 23 metres shallow to prognosis with a 26 metres gross oil column. The second water injection well, drilled 1.4 km southwest of the first water injection well, also found the top reservoir shallow to prognosis by 13 metres with a 5 metres gross oil column. The results from these two water injection wells indicate more oil-in-place in the western flank of the field than originally foreseen and has resulted in the field's estimated gross ultimate recoverable reserves increasing by 17 MMboe with the field's total ultimate recoverable reserves increasing to 223 MMboe as at year end 2016, which is a 20 percent increase on the original PDO reserves estimate. In addition to the reserves upgrade from the two water injection wells a new appraisal well will spud during the first quarter of 2017 in the southwestern part of the field to target additional gross unrisked resources of up to 30 MMboe.

The fifth production well is currently being drilled with a total of 14 development wells scheduled to be drilled as part of the Edvard Grieg development plan with drilling operations expected to continue into 2018. The total operating cost for the Edvard Grieg field was USD 7.20 per barrel during the year.

In May 2016, Lundin Petroleum announced that it had entered into an agreement to acquire an additional 15 percent working interest in the Edvard Grieg field from Statoil ASA. The effective date of the transaction is 1 January 2016 and the transaction completed on 30 June 2016. As a result of this transaction, Lundin Petroleum has increased its reserves by 29.5 MMboe. The additional production from this transaction has been accounted for from 1 July 2016. For more information, see the Financial Review section.

Production from the Greater Alvheim area during the year was better than forecast due to better than expected reservoir performance as well as a higher than expected Alvheim FPSO production efficiency of 97 percent, excluding planned shutdown of the Sage gas terminal in the United Kingdom. During August 2016, the terminal was shutdown for planned maintenance for 14 days and consequently the Alvheim FPSO was shut-in during this period. The total operating cost for the Greater Alvheim area was USD 5.10 per barrel during the year. The Greater Alvheim area partners signed a new contract for the Transocean Arctic rig which commenced an infill drilling campaign in the Greater Alvheim area in December 2016.

Net production from the Alvheim field during the year was better than forecast at 10,000 boepd. The reservoir performance continues to be excellent with the most recent infill well, the A5 three-branched production well, as well as the Viper and Kobra wells, which came onstream in November 2016, all producing significantly ahead of expectation. The gas processing capacity on the Alvheim FPSO has resulted in certain wells having been production constrained during the year, however this constraint has been alleviated through an upgrade of the Alvheim FPSO gas export compressor, resulting in increased gas handling capacity. Two infill wells are planned to be drilled at Alvheim during 2017 with production startup of these wells expected in 2018.

The Volund field net production during the year was below forecast at 2,700 boepd. Further infill opportunities have been identified on the Volund field and during the year the top holes of two infill wells were successfully drilled by the Transocean Winner rig before it went off hire at the end of July. These two wells will be completed by the Transocean Arctic rig which commenced the drilling of the first infill well in December 2016 with an expected production start-up in the second half of 2017. One exploration well is planned in 2017 targeting the Volund West prospect.

The Bøyla field net production during the year was slightly ahead of forecast at 1,700 boepd due to good reservoir performance with lower water cut in the wells than expected.

Net production from the Brynhild field during the year was lower than forecast at 2,600 boepd due to a temporary lower well capacity than forecast due to the water injection system being unavailable since August 2016. The water injection system is expected to recommence in early 2017 following repair of the pump. The Brynhild field achieved an uptime of 65 percent for the year, excluding the planned outage earlier this year. The Haewene Brim FPSO was shut-in for 20 days during the fourth quarter 2016 to undergo planned integrity and inspection work.

Despite no remaining reserves being attributed to the Gaupe field, the field is producing intermittently subject to favourable economic conditions and achieved net production of 300 boepd during the year.

Development

Licence	Field	WI	Operator	PDO Approval	Estimated gross reserves	Production start expected	Gross plateau production rate expected
Ivar Aasen Unit	Ivar Aasen	1.385%	Aker BP	May 2013	183 MMboe	Production start Dec 2016	67 Mboepd
Johan Sverdrup Unit	Johan Sverdrup	22.60%	Statoil	August 2015	1.9—3.0 Bn boe	Late 2019	660 Mboepd

Ivar Aasen

The Ivar Aasen field commenced production on 24 December 2016 and is currently ramping-up production from three wells. The field is expected to ramp-up production in accordance with the commercial arrangement with its host platform, Edvard Grieg, during 2017.

Johan Sverdrup

The Johan Sverdrup project is progressing on schedule with a majority of Phase 1 contracts now awarded, resulting in estimated total project costs being reduced compared to the original estimates. Phase 1 construction work commenced in 2015 with total project completion remaining on schedule.

Construction of three steel jackets has commenced at the Kværner yard on the west coast of Norway and of one jacket at the Dragados yard in Spain. Construction of the drilling platform and living quarters, through EPC contracts, is underway in Norway by Aibel and Kværner/KBR respectively and construction of the riser platform and processing platform commenced at Samsung Heavy Industries in Korea during the third quarter 2016 with Aker Solutions being contracted for the procurement and engineering of the riser platform and processing platform. In addition civil engineering works are underway on the onshore power system at Haugsneset in Norway. The pre-drilling of development wells commenced in March 2016 with eight development wells being completed to date, which is ahead of schedule.

The contract for the heavy lift installations for three of the topsides has been awarded to Allseas. Odfjell Drilling has been awarded contracts for drilling of the wells. Rosenberg WorleyParsons has been awarded the contracts for the construction of the three bridges linking the platforms and for the construction of two flare booms. In October 2016 the contract for modification work at the Mongstad oil terminal was awarded to Aker Solutions.

At the time of submitting the Phase 1 PDO in February 2015, the capital expenditure for Phase 1 was estimated at gross NOK 123 billion (nominal). With most of the major contracts now awarded, the latest cost estimate, as released by Statoil during the third quarter 2016, has been reduced to NOK 99 billion (nominal), a reduction of approximately 20 percent. This is based on a fixed project exchange rate of NOK 6 per USD and excludes additional foreign exchange rate savings in US dollar terms. The Phase 1 development is scheduled to start production in late 2019. The original gross production capacity for Phase 1 was estimated at 315,000 to 380,000 bopd. However, debottlenecking measures have concluded that the design processing capacity for Phase 1 will increase to 440,000 bopd with gas processing capacity in addition.

The PDO for Phase 1 also outlines certain concepts for the full field development involving an expected full field gross plateau production level of 660,000 bopd. Statoil provided an update on resources in the third quarter 2016 with gross resources increasing to between 1.9 and 3.0 billion boe with 95 percent of the resources being oil.

During the third quarter 2016, Statoil also revised down the full field development costs (Phase 1 and Phase 2) with the previous range of between NOK 160 and 190 billion being revised down to between NOK 140 and 170 billion (real 2016), due to market savings relating to Phase 1 and optimisation of the Phase 2 facilities concept. Phase 2 is expected to start production in 2022.

Appraisal

2016 appraisal well programme

Licence	Operator	WI	Well	Spud Date	Status
PL609	Lundin Petroleum	40%	Re-enter 7220/11-3 (Alta-3)	July 2016	Completed September 2016

During the year Lundin Petroleum successfully completed the drilling and testing of the Alta-3 appraisal well 7220/11-3A, which was a re-entry well from the suspended 7220/11-3 well drilled in 2015. The objective of the Alta-3 re-entry was to deepen the well to further assess the quality of the Permian carbonate reservoirs through water injection tests as well as to conduct a production test in the shallower gas zone. Two injection tests in the carbonate reservoir below the oil-water contact proved good to very good reservoir quality in the Falk and Ørn formations, respectively. A production test in the gas zone in the Lower Triassic reservoir section produced a maximum of 21 million cubic feet of gas per day through a 64/64 inch choke.

The original Alta-3 well encountered a gross hydrocarbon column of 120 metres and all three Alta wells drilled to date have proven pressure communication.

During the year Lundin Petroleum entered into a rig contract with Ocean Rig for the charter of the Leiv Eiriksson semi-submersible rig for an extended appraisal and exploration campaign in the southern Barents Sea. The contract encompasses five firm wells and multiple further well-slot options which can be called at Lundin Petroleum's election and the rig will carry out all of Lundin Petroleum operated wells in the southern Barents Sea for the 2017 drilling campaign.

The 2017 appraisal programme will consist of three appraisal wells with one well being drilled on the western flank of the Edvard Grieg field in PL338 (WI 65%) targeting gross resources of 30 MMboe. The remaining two wells will appraise the Alta/Gohta discoveries on the Loppa High in the southern Barents Sea with one well being drilled centrally on the Gohta discovery in PL492 (WI 40%) and one well being drilled centrally on the Alta discovery in PL609 (WI 40%).

Exploration

2016 exploration well programme

Licence	Well	Spud Date	Target	WI	Operator	Result
Utsira High						
PL544	16/4-10	January	Fosen	40%	Lundin Petroleum	Dry
Southern Barents Sea						
PL609	Re-enter 7220/6-2-R	October	Neiden	40%	Lundin Petroleum	Oil Discovery
PL533	7219/12-1	November	Filicudi	35%	Lundin Petroleum	Ongoing

In January 2016, the Lorry well in PL700 in the Norwegian Sea which was spudded in November 2015 was announced as dry. The well failed to encounter the prognosed reservoir.

In March 2016, the Fosen well in PL544 in the North Sea was announced as dry. The well, which was drilled just south of Luno II, encountered a 160 metres reservoir section but was water-wet with oil shows.

In November 2016 Lundin Petroleum announced a discovery on the Neiden prospect in PL609 in the southern Barents Sea. The well, which was drilled approximately 60 km northeast of the Alta discovery, encountered a Permian carbonate reservoir with a 31 metres hydrocarbon column of which 21 metres were oil and 10 metres gas. The discovery is estimated to contain between 25 and 60 MMboe of gross contingent resources.

Lundin Petroleum will drill five exploration wells offshore Norway in 2017. Three of the 2017 exploration wells will be drilled in the Barents Sea with the first well already underway in PL533 (WI 35%) targeting the Filicudi prospect. Two further wells are planned to be drilled in the southern Barents Sea with one well targeting the Børselv prospect in PL609 (WI 40%) located on-trend north of the Alta and Neiden discoveries, which is subject to partner approval. The second well will be targeting one segment of the shallower horizons within the multi-billion barrel gross prospective resource Korpfjell prospect in PL859 (WI 15%) in the eastern Barents Sea. One well will be drilled west of the Volund field in PL150 (WI 35%) and one well will be drilled on a potential northern extension of the Johan Sverdrup field (WI 22.6%).

Licence awards, transactions and relinquishments

In January 2016, the Ministry of Petroleum and Energy announced the licence awards in the 2015 APA licensing round. Lundin Petroleum was awarded four licences of which two as operator in PL815 and PL830 (both with WI 40%) in addition to two non-operated working interests in PL678SB and PL831 (both with WI 20%). In May 2016 the licence awards in the 23rd licensing round in the Barents Sea were announced and Lundin Petroleum was awarded five licences of which three as operator. Lundin Petroleum was awarded two operated licences, PL851 and PL609C (both with WI 40%) in the Loppa High area, one operated licence, PL853 (WI 60%) in the Hoop area and two non-operated licences, PL857 and PL859 (WI 20% and 15% respectively) in the eastern Barents Sea.

During the year, Lundin Petroleum relinquished PL438, PL519, PL544, PL555, PL631, PL673, PL674, PL708, PL741 and PL779.

In January 2017, the Ministry of Petroleum and Energy announced the licence awards in the 2016 APA licensing round. Lundin Petroleum was awarded four licences, of which two as operator in PL902 (WI 50%) and PL886 (WI 40%) in addition to two non-operated working interests in PL896 and PL869 (both with WI 20%).

South East Asia

Malaysia

Production

Production in Mboepd	WI	**1 Jan 2016- 31 Dec 2016 12 months**	**1 Oct 2016- 31 Dec 2016 3 months**	1 Jan 2015- 31 Dec 2015 12 months	1 Oct 2015- 31 Dec 2015 3 months
Bertam	75%	**8.6**	**8.3**	5.5	9.3

Peninsular Malaysia

Net production from the Bertam field on Block PM307 (WI 75%) during the year was ahead of forecast at 8,600 boepd with an uptime of 99 percent. The Bertam field has been producing from 11 wells as of mid-October 2015 with one additional well, the A15 well, commencing production in June 2016. The A15 well results were in line with expectations with production being constrained by facilities limitations. Overall field performance is better than forecast due to better than expected reservoir performance and this outperformance has been partially offset by the shut-in of two production wells during the year in relation to replacement of downhole electrical submersible pumps and for production shut-ins due to rig moves. The West Prospero drilling rig came off contract towards the end of May 2016. Due to the excellent reservoir performance on Bertam since production startup, the gross ultimate recoverable reserves have been increased from 16.9 MMboe to 19.6 MMboe.

At year end 2016 Lundin Petroleum decided to remove the booked contingent resources associated with the Tembakau gas discovery on PM307 from its books. The net contingent resources removed amounted to 28.9 MMboe. For more information, see the Financial Review section.

During the year, Lundin Petroleum relinquished PM308A and PM319.

Sabah, East Malaysia

Lundin Petroleum completed the drilling of the Imbok well on Block SB307/308 (WI 65%) in early January 2016. The well encountered only oil shows in Miocene sands and was plugged and abandoned as dry. Following the Imbok well, the rig was moved to drill the Bambazon prospect, also on Block SB307/308, which encountered 15 metres of net reservoir pay with oil shows. However, no moveable oil was recovered from sampling and the well was plugged and abandoned as dry. The West Prospero rig subsequently moved to the Maligan prospect on Block SB307/308 and whilst gas shows were encountered, the well was plugged and abandoned as dry.

At year end 2016 Lundin Petroleum decided to remove the booked contingent resources associated with the gas discoveries on SB303 (WI 55%) from its books. The net contingent resources removed amounted to 31.8 MMboe.

Farm-out agreements

Lundin Petroleum signed a farm-out agreement with Dyas in December 2015 whereby Lundin Petroleum has transferred a 20 percent working interest in Block SB307/308 (WI 65% after farm-out) and a 20 percent working interest in Block SB303 (WI 55% after farm-out), located offshore Sabah, East Malaysia. In addition, Dyas acquired from Lundin Petroleum a 15 percent working interest in Block PM328 (WI 35% after farm-out), located offshore Peninsular Malaysia.

Termination of the FPSO sale

Lundin Petroleum announced on 22 January 2016 that it had entered into an agreement to sell the FPSO Bertam to M3nergy Investment Ltd (M3nergy), a wholly owned subsidiary of M3nergy Berhad of Malaysia. The transaction was subject to M3nergy securing financing within a certain timeframe. However, M3nergy was unable to secure the required financing and the agreement to sell the FPSO was subsequently terminated.

Indonesia

Production

Production in Mboepd	WI	**1 Jan 2016- 31 Dec 2016 12 months**	**1 Oct 2016- 31 Dec 2016 3 months**	1 Jan 2015- 31 Dec 2015 12 months	1 Oct 2015- 31 Dec 2015 3 months
Singa	25.9%	**0.5**	–	1.6	1.4

In April 2016, Lundin Petroleum completed the sale of the business in Indonesia to PT Medco Energi Internasional TBK for a cash consideration of MUSD 22, with an effective date of 1 October 2015. The Indonesian assets sold to Medco include the non-operated interest in the producing Singa gas field. Lundin Petroleum may become entitled to certain contingent payments in respect of the future production from the Singa gas field. Lundin Petroleum ceased reporting the production contribution from Singa as of 28 April 2016.

Continental Europe

Production

Production in Mboepd	WI	**1 Jan 2016- 31 Dec 2016 12 months**	**1 Oct 2016- 31 Dec 2016 3 months**	1 Jan 2015- 31 Dec 2015 12 months	1 Oct 2015- 31 Dec 2015 3 months
France					
– Paris Basin	100%[1]	2.2	2.1	2.3	2.2
– Aquitaine	50%	0.4	0.5	0.4	0.3
Netherlands	Various	1.6	1.4	1.8	1.7
		4.2	**4.0**	4.5	4.2

[1] Working interest in the Dommartin Lettree field 42.5 percent.

France
Net production during the year from France was slightly above forecast at 2,600 boepd. Good production performance has been achieved from the Vert La Gravelle field (WI 100%) in the Paris Basin and the fields in the Aquitaine Basin have also performed well during the year.

The Netherlands
Net production for the year from the Netherlands was ahead of forecast at 1,600 boepd.

The Langezwaag-3 (WI 7.75%) well, on the Gorredijk licence, was drilled during the third quarter 2016 and put on production in November 2016.

The drilling of the K5-F3 development well has been completed and the well was put on production in the third quarter of 2016. The F3-B106 side-track well commenced drilling in December 2016 and is currently drilling ahead. During the fourth quarter 2016 the installation of compression on the E17a platform was completed and successfully started up.

In 2017, the planned activity involves the drilling of the A6 development well on the offshore E17a-A field (WI 1.2%) and the Nieuwehorne-1 exploration well in the onshore Gorredijk licence (WI 7.75%).

Russia
During the year the exploration area of the Lagansky block surrounding the Morskaya field (WI 70%) was relinquished.

At year end 2016 Lundin Petroleum decided to remove the booked contingent resources associated with the Morskaya oil discovery from its books. The net contingent resources removed amounted to 110.1 MMboe. For more information, see the Financial Review section.

Corporate Responsibility

During the year, Lundin Petroleum recorded five incidents among contractors, resulting in a year to date Lost Time Incident Rate (LTIR) of 0.72 per million hours worked and a Total Recordable Incident Rate (TRIR) of 2.53, a clear improvement over 2015 with an LTIR of 1.76 and a TRIR of 3.71. In February 2016, a tragic fatal accident took place offshore Malaysia when a contractor undertook repair work on the FPSO export hose. A thorough investigation was undertaken and follow-up measures were implemented. Two minor lost time incidents were recorded in France in February and April 2016 and two restricted work incidents in France and Norway in November.

In May 2016, Lundin Petroleum issued its first sustainability report based on the Global Reporting Initiative, GRI G4 guidance, providing more qualitative and quantitative sustainability data. This report is available on www.lundin-petroleum.com.

In June 2016, Lundin Petroleum reported to the Carbon Disclosure Project (CDP) on its climate change strategy and 2015 emissions performance.

FINANCIAL REVIEW

Result

The net result for the financial year ended 31 December 2016 amounted to MUSD -499.3 (MUSD -866.3). The loss for the year was mainly driven by an after tax impairment charge of MUSD 548.6. The net result attributable to shareholders of the Parent Company for the year amounted to MUSD -356.7 (MUSD -861.7) representing earnings per share of USD -1.09 (USD -2.79).

Earnings before interest, tax, depletion and amortisation (EBITDA) for the year amounted to MUSD 902.6 (MUSD 384.7) representing EBITDA per share of USD 2.77 (USD 1.24). Operating cash flow for the year amounted to MUSD 1,010.8 (MUSD 699.6) representing operating cash flow per share of USD 3.10 (USD 2.26).

Changes in the Group

On 28 April 2016, Lundin Petroleum completed the sale of its Indonesia business, including the non-operated Singa gas field.

Edvard Grieg transaction

The transaction to acquire an additional 15 percent working interest in the Edvard Grieg field and interests in the associated pipeline assets from Statoil ASA with an effective date of 1 January 2016, completed on 30 June 2016. In consideration for the acquisition of the assets, Lundin Petroleum issued 27,580,806 new shares in Lundin Petroleum AB based upon an agreed share price of SEK 138 per share and a SEK/USD exchange rate of 8.098, which equates to a consideration of MUSD 470.0 as at 1 January 2016. The transaction was accounted for at closing in accordance with IFRS3 Business Combinations as required by the amended IFRS11 Joint Arrangements which provides guidance on the accounting for acquisitions of interests in joint operations in which the activity constitutes a business. The production and financial results from the additional working interest are being reflected from 1 July 2016.

A summary of the net assets acquired at closing is shown in the table below:

Expressed in MUSD	30 June 2016
Assets	
Oil and gas properties	456.1
Goodwill	128.1
Cash	25.9
Total Assets Acquired	**610.1**
Liabilities	
Deferred tax	111.0
Site restoration provision	24.2
Working capital	10.4
Total Liabilities Acquired	**145.6**
Net Assets Acquired	**464.5**

Note: the numbers in the table above are subject to finalisation adjustments

In accordance with the Norwegian Petroleum Tax Act, the consideration paid is on an after tax basis and the remaining tax balances were transferred from Statoil ASA to Lundin Petroleum. Lundin Petroleum is therefore not entitled to a tax deduction for the consideration paid over and above the tax values transferred. In accordance with IAS12 Income Taxes, a deferred tax liability for an amount of MUSD 128.1 was recognised on the difference between the assigned fair values and the related tax base as at 30 June 2016, and the offsetting accounting entry is to goodwill. The goodwill forms part of the impairment testing of the Edvard Grieg field going forward.

In addition, Lundin Petroleum transferred 2 million treasury shares and issued 1,735,309 new shares to Statoil ASA in exchange for a cash consideration of MSEK 544.1 (MUSD 64.1).

Revenue
Revenue for the year amounted to MUSD 1,159.9 (MUSD 569.3) and was comprised of net sales of oil and gas, change in under/over lift position and other revenue as detailed in Note 1.

Net sales of oil and gas for the year amounted to MUSD 1,166.5 (MUSD 521.0). The average price achieved by Lundin Petroleum for a barrel of oil equivalent amounted to USD 42.40 (USD 50.71) and is detailed in the following table. The average Dated Brent price for the year amounted to USD 43.73 (USD 52.39) per barrel.

Net sales of oil and gas for the year are detailed in Note 3 and were comprised as follows:

Sales Average price per boe expressed in USD	**1 Jan 2016- 31 Dec 2016 12 months**	**1 Oct 2016- 31 Dec 2016 3 months**	1 Jan 2015- 31 Dec 2015 12 months	1 Oct 2015- 31 Dec 2015 3 months
Crude oil sales				
Norway				
– Quantity in Mboe	20,654.5	7,036.6	5,939.4	999.5
– *Average price per boe*	*43.61*	*49.63*	*52.97*	*43.63*
France				
– Quantity in Mboe	907.0	187.7	971.4	203.0
– *Average price per boe*	*43.98*	*51.44*	*52.07*	*36.00*
Netherlands				
– Quantity in Mboe	1.2	–	1.2	–
– *Average price per boe*	*33.54*	–	*50.20*	–
Malaysia				
– Quantity in Mboe	2,787.8	793.9	1,455.6	612.8
– *Average price per boe*	*45.13*	*51.01*	*48.92*	*44.01*
Total crude oil sales				
– Quantity in Mboe	**24,350.5**	**8,018.2**	8,367.6	1,815.3
– Average price per boe	***43.80***	***49.81***	*52.16*	*42.91*
Gas and NGL sales				
Norway				
– Quantity in Mboe	2,352.1	658.5	745.7	176.0
– *Average price per boe*	*30.94*	*37.41*	*44.21*	*36.23*
Netherlands				
– Quantity in Mboe	580.4	141.2	633.3	159.4
– *Average price per boe*	*27.04*	*31.11*	*38.88*	*33.60*
Indonesia				
– Quantity in Mboe	178.2	–	527.7	115.0
– *Average price per boe*	*52.02*	–	*50.99*	*51.49*
Total gas and NGL sales				
– Quantity in Mboe	**3,110.7**	**799.7**	1,906.7	450.4
– Average price per boe	***31.42***	***36.29***	*44.31*	*39.19*
Total sales				
– Quantity in Mboe	**27,461.2**	**8,817.9**	10,274.3	2,265.7
– Average price per boe	***42.40***	***48.58***	*50.71*	*42.17*

The table above excludes 47,449 barrels of crude oil purchased from outside the Group by Lundin Petroleum Marketing SA and sold to the market.

Sales of oil and gas are recognised when the risk of ownership is transferred to the purchaser. Sales quantities in a period can differ from production quantities as a result of permanent and timing differences. Permanent differences arise as a result of paying royalties in kind as well as the effects from production sharing agreements. Timing differences can arise due to under/over lift of entitlement, inventory, storage and pipeline balances effects.

The change in under/over lift position amounted to a charge of MUSD 28.9 (credit of MUSD 25.6) in the year due to the timing of the cargo liftings compared to production.

Other revenue amounted to MUSD 22.3 (MUSD 22.7) for the year and included Bertam FPSO lease income, a quality differential compensation on Alvheim blended crude, tariff income from France and the Netherlands and income for maintaining strategic inventory levels in France.

Production costs

Production costs including inventory movements for the year amounted to MUSD 227.5 (MUSD 150.3) and are detailed in the table below.

Production costs	1 Jan 2016- 31 Dec 2016 12 months	1 Oct 2016- 31 Dec 2016 3 months	1 Jan 2015- 31 Dec 2015 12 months	1 Oct 2015- 31 Dec 2015 3 months
Cost of operations				
– In MUSD	166.0	41.2	121.1	32.8
– In USD per boe	*6.25*	*5.38*	*10.27*	*9.31*
Tariff and transportation expenses				
– In MUSD	37.9	8.0	11.8	3.7
– In USD per boe	*1.43*	*1.03*	*1.00*	*1.05*
Royalty and direct production taxes				
– In MUSD	3.3	0.8	3.5	0.9
– In USD per boe	*0.12*	*0.10*	*0.29*	*0.25*
Cash operating costs				
– In MUSD	**207.2**	**50.0**	136.4	37.4
– In USD per boe	***7.80***	***6.51***	*11.56*	*10.61*
Change in inventory position				
– In MUSD	-1.8	2.2	-12.6	-6.8
– In USD per boe	*-0.07*	*0.30*	*-1.07*	*-1.94*
Other				
– In MUSD	22.1	6.1	26.5	5.1
– In USD per boe	*0.83*	*0.80*	*2.25*	*1.46*
Total production costs				
– In MUSD	**227.5**	**58.3**	150.3	35.7
– In USD per boe	***8.56***	***7.61***	*12.74*	*10.13*

Note: USD per boe is calculated by dividing the cost by total production volume for the period.

The total cost of operations for the year was MUSD 166.0 (MUSD 121.1). The increase compared to the same period last year is mainly due to the contribution of the Edvard Grieg field which commenced production in November 2015. The total cost of operations excluding operational projects amounted to MUSD 151.7 (MUSD 102.7).

The cost of operations per barrel for the year amounted to USD 6.25 (USD 10.27) including operational projects and USD 5.71 (USD 8.71) excluding operational projects. This was below guidance given at the third quarter of USD 6.50 including operational projects and USD 5.85 excluding operational.

Tariff and transportation expenses for the year amounted to MUSD 37.9 (MUSD 11.8). The increase compared to the same period last year is mainly due the impact of the Edvard Grieg field.

Other costs amounted to MUSD 22.1 (MUSD 26.5) and mainly related to the operating cost share arrangement on the Brynhild field whereby the amount of operating cost varies with the oil price until mid-2017. This arrangement is being marked-to-market against the oil price curve and due to the low oil price curve at the end of 2015 an asset was recognised as at 31 December 2015. This asset is being charged to the income statement over the remaining term of the arrangement.

Depletion and decommissioning costs

Depletion and decommissioning costs amounted to MUSD 471.4 (MUSD 260.6) and are detailed in Note 3. The depletion costs associated with oil and gas properties amounted to MUSD 473.9 (MUSD 258.0) at an average rate of USD 17.84 (USD 21.88) per barrel. The higher depletion costs for the year compared to last year are due to the depletion charge associated with the Edvard Grieg field, partly offset by a lower Brynhild field depletion rate following the impairment of the carrying value at the end of 2015. Decommissioning costs released to the income statement in the year amounted to MUSD 2.5 (MUSD 2.6 charge) and related to the reduction in the site restoration estimate for the Gaupe field, Norway.

Depletion of other assets amounted to MUSD 31.1 (MUSD 23.7) for the year and related to the Bertam FPSO which was depreciated from April 2015.

Exploration costs
Exploration costs expensed in the income statement for the year amounted to MUSD 116.1 (MUSD 184.1) and are detailed in Note 3. Exploration and appraisal costs are capitalised as they are incurred. When exploration drilling is unsuccessful, the capitalised costs are expensed. All capitalised exploration costs are reviewed on a regular basis and are expensed where their recoverability is considered highly uncertain.

During the year, exploration costs relating to Norway of MUSD 101.9 were expensed and mainly related to the uncommercial exploration wells that were drilled in PL700 (Lorry), PL544 (Fosen) and PL609 (Neiden). In addition, exploration costs were expensed relating to Malaysia of MUSD 13.1 following the drilling of the unsuccessful Bambazon and Maligan wells in SB307/308.

Impairment costs
Non-cash impairment costs charged to the income statement for the year amounted to MUSD 632.1 (MUSD 737.0) following a decision to remove the contingent resources associated with the gas discoveries in the Sabah region offshore East Malaysia and the Tembakau gas discovery in PM307 offshore Peninsular Malaysia, as well as the Morskaya oil discovery in the Russian Caspian Sea. Management deems that it is unlikely that any of these discoveries will be developed in the foreseeable future. A pre-tax impairment cost of MUSD 506.1 was charged to the income statement in respect of Russia with a deferred tax credit of MUSD 83.5, giving a net after tax charge of MUSD 422.6. The impairment cost for Malaysia charged to the income statement was MUSD 126.0 with no associated tax credit.

Other cost of sales
Other cost of sales for the year amounted to MUSD 2.1 (MUSD –) and related to the purchase of crude oil from a third party and marketed by the Group along with its own crude.

Sale of assets
Sale of assets amounted to a charge of MUSD 3.5 (MUSD –) for the year. The reported charge related to the disposal of the Indonesian business which completed on 28 April 2016. The effective date of the deal was 1 October 2015 for a cash consideration of MUSD 22.

General, administrative and depreciation expenses
The general administrative and depreciation expenses for the year amounted to MUSD 31.9 (MUSD 39.5) which included a charge of MUSD 4.6 (MUSD 7.1) in relation to the Group’s long-term incentive plans (LTIP), see also Remuneration section below. Fixed asset depreciation expenses for the year amounted to MUSD 4.3 (MUSD 5.2).

Finance income
Finance income for the year amounted to MUSD 22.6 (MUSD 7.4) and is detailed in Note 4.

The net foreign currency exchange gain for the year amounted to MUSD 15.0 (loss of MUSD 507.3). Foreign exchange movements occur on the settlement of transactions denominated in foreign currencies and the revaluation of working capital and loan balances to the prevailing exchange rate at the balance sheet date where those monetary assets and liabilities are held in currencies other than the functional currencies of the Group’s reporting entities. Lundin Petroleum has hedged certain foreign currency operational expenditure amounts against the US Dollar and for the year, the net realised exchange loss on settled foreign exchange hedges amounted to MUSD 29.1 (MUSD 132.7).

In the fourth quarter of 2016, the net foreign currency exchange loss amounted to MUSD 215.9 (MUSD 129.2) following the strengthening of the US Dollar against the Euro and Norwegian Krone, which principally reversed the year to date foreign currency exchange gain recognised at the end of the previous quarter.

Finance costs
Finance costs for the year amounted to MUSD 225.4 (MUSD 617.9) and are detailed in Note 5.

Interest expenses for the year amounted to MUSD 137.3 (MUSD 71.4) and represented the portion of interest charged to the income statement. An additional amount of interest of MUSD 23.4 (MUSD 40.2) associated with the funding of the Norwegian development projects was capitalised in the year. The total interest expense has increased compared to last year mainly due to the increased borrowings to fund the capital expenditure. The result on interest rate hedge settlements amounted to a loss of MUSD 19.5 (MUSD 6.9) and increased compared to last year due to the higher fixed interest rate that was hedged in 2016 compared to 2015.

The amortisation of the deferred financing fees amounted to MUSD 43.2 (MUSD 12.4) for the year and related to the expensing of the fees incurred in establishing the new group financing facility and the Norwegian exploration refund facility over the period of usage of the facilities. In addition, the unamortised portion of the capitalised financing fees incurred in establishing the previous financing facilities and the short term revolving credit facility were expensed during the second quarter of 2016 and amounted to MUSD 22.3.

Tax

The overall tax credit for the year amounted to MUSD 59.3 (MUSD 570.1).

The current tax credit for the year amounted to MUSD 80.6 (MUSD 280.6) which included MUSD 78.9 (MUSD 283.3) relating to the tax refund on Norwegian exploration and appraisal expenditure.

The deferred tax charge for the year amounted to MUSD 21.3 (credit of MUSD 289.5) and included a deferred tax charge of MUSD 98.5 relating to Norway, primarily on the difference in depletion for tax and accounting purposes. A deferred tax credit of MUSD 83.5 in relation to the Russian impairment charge was also recognised in the fourth quarter of 2016.

The Group operates in various countries and fiscal regimes where corporate income tax rates are different from the regulations in Sweden. Corporate income tax rates for the Group vary between 20 and 78 percent. The effective tax rate for the year is affected by items which do not receive a full tax credit such as the reported impairment charges and Malaysian exploration costs, and by the uplift allowance applicable in Norway for development expenditures against the offshore tax regime.

Non-controlling interest

The net result attributable to non-controlling interest for the year amounted to MUSD -142.6 loss (loss of MUSD -4.6) and related mainly to the non-controlling interest's share in a Russian subsidiary which is fully consolidated.

Balance Sheet

Non-current assets

Oil and gas properties amounted to MUSD 4,376.4 (MUSD 4,015.4) and are detailed in Note 7.
Development and exploration and appraisal expenditure incurred for the year was as follows:

Development expenditure in MUSD	**1 Jan 2016- 31 Dec 2016 12 months**	**1 Oct 2016- 31 Dec 2016 3 months**	1 Jan 2015- 31 Dec 2015 12 months	1 Oct 2015- 31 Dec 2015 3 months
Norway	877.1	258.0	880.7	219.0
Malaysia	15.2	-0.2	130.1	-4.6
France	2.8	0.9	16.9	1.0
Netherlands	2.5	0.4	2.7	0.7
Indonesia	0.1	–	-1.1	-0.5
	897.7	**259.1**	1,029.3	215.6

An amount of MUSD 877.1 (MUSD 880.7) of development expenditure was incurred in Norway during the year, primarily on the Johan Sverdrup and Edvard Grieg field developments. In Malaysia, MUSD 15.2 (MUSD 130.1) was incurred during the year primarily on the Bertam field A15 development well.

Exploration and appraisal expenditure in MUSD	**1 Jan 2016- 31 Dec 2016 12 months**	**1 Oct 2016- 31 Dec 2016 3 months**	1 Jan 2015- 31 Dec 2015 12 months	1 Oct 2015- 31 Dec 2015 3 months
Norway	142.1	51.8	370.2	101.5
Malaysia	14.2	-6.4	33.3	25.8
France	0.3	–	0.4	–
Russia	1.4	0.5	5.3	1.2
Indonesia	0.3	0.3	3.1	–
Netherlands	0.1	–	1.5	0.1
	158.4	**46.2**	413.8	128.6

Exploration and appraisal expenditure of MUSD 142.1 (MUSD 370.2) was incurred in Norway during the year, primarily on the Neiden in PL609 and the Filicudi in PL533 exploration wells in the fourth quarter of 2016, the Alta-3 appraisal well in PL609, the Fosen well in PL544 and the Lorry well in PL700. In Malaysia, MUSD 14.2 (MUSD 33.3) was incurred during the year mainly on the Bambazon and Maligan wells in SB307/308. The credit to expenditure in Malaysia in the fourth quarter of 2016 mainly relates to a farm-out payment received.

In addition, MUSD 456.1 was added to the oil and gas properties at 30 June 2016 and related to the additional 15 percent of the Edvard Grieg field acquired from Statoil.

Other tangible fixed assets amounted to MUSD 166.1 (MUSD 204.3) and included the accounting book value of the Bertam FPSO.

Goodwill associated with the accounting for the Edvard Grieg transaction amounted to MUSD 128.1 (MUSD —) and is described in the section Edvard Grieg transaction above.

Financial assets amounted to MUSD 9.4 (MUSD 10.7) and are detailed in Note 8. Other shares and participations amounted to MUSD 8.9 (MUSD 4.1) and related to the shares held in ShaMaran Petroleum which are reported at market value with any change in value being recorded in other comprehensive income.

Deferred tax assets amounted to MUSD 13.5 (MUSD 13.4) and are mainly related to Malaysia following the impairment of the Bertam field at year end 2015 resulting in the depreciable tax pool value being higher than the accounting book value.

Derivative instruments amounted to MUSD 17.0 (MUSD —) and related to the marked-to-market gain on the outstanding interest rate hedge contracts due to be settled after twelve months.

Current assets
Inventories amounted to MUSD 54.9 (MUSD 45.6) and included both hydrocarbon inventories and well and operational supplies mainly held in Norway and Malaysia.

Trade and other receivables amounted to MUSD 288.9 (MUSD 159.3) and are detailed in Note 9. Trade receivables, which are all current, amounted to MUSD 193.4 (MUSD 35.2). Underlift amounted to MUSD 28.9 (MUSD 26.5) and was mainly attributable to a net underlift position on the Norwegian producing fields, Edvard Grieg and Brynhild. Joint operations debtors relating to various joint venture receivables amounted to MUSD 31.2 (MUSD 48.4). Prepaid expenses and accrued income amounted to MUSD 29.4 (MUSD 29.5) and represented prepaid operational and insurance expenditure. Brynhild operating cost share amounted to MUSD 3.0 (MUSD 14.7) and related to marked-to-market valuation of the arrangement where the share of the Brynhild field operating cost varies with the oil price. Other current assets amounted to MUSD 3.0 (MUSD 5.0) and included VAT and other miscellaneous receivable balances.

Derivative instruments amounted to MUSD 0.8 (MUSD —) and related to the marked-to-market gain on outstanding interest rate hedge contracts due to be settled within twelve months.

Current tax assets amounted to MUSD 77.5 (MUSD 264.7) of which MUSD 76.9 related to the Norwegian corporate tax refund in respect of 2016 which will be received in the fourth quarter of 2017.

Cash and cash equivalents amounted to MUSD 69.5 (MUSD 71.9). Cash balances are held to meet ongoing operational funding requirements.

Non-current liabilities
Financial liabilities amounted to MUSD 4,048.3 (MUSD 3,834.8) and are detailed in Note 10. Bank loans amounted to MUSD 4,145.0 (MUSD 3,858.0) and related to the outstanding loan under the Group's reserve-based lending facility. Capitalised financing fees relating to the establishment costs of the financing facilities amounted to MUSD 96.7 (MUSD 23.2) and are being amortised over the period of usage of the financing facilities.

Provisions amounted to MUSD 420.0 (MUSD 379.9) and are detailed in Note 11. The provision for site restoration amounted to MUSD 407.1 (MUSD 368.2) and related to future decommissioning obligations. The provision has increased during the year due to additions relating to the Norwegian development projects and by MUSD 24.2 relating to the additional 15 percent of the Edvard Grieg field acquired at 30 June 2016. Farm-in payment amounted to MUSD 5.5 (MUSD 4.6) and related to a provision for payments towards historic costs based on production milestones on the Bertam field, Malaysia.

Deferred tax liabilities amounted to MUSD 669.3 (MUSD 542.6) of which MUSD 621.3 (MUSD 407.9) related to Norway and included a net deferred tax liability of MUSD 111.0 related to the additional 15 percent of Edvard Grieg. The provision mainly arises on the excess of book value over the tax value of oil and gas properties. Deferred tax assets are netted off against deferred tax liabilities where they relate to the same jurisdiction.

Derivative instruments amounted to MUSD 29.8 (MUSD 48.4) and related to the marked-to-market loss on outstanding interest rate and currency hedge contracts due to be settled after twelve months.

Other non-current liabilities amounted to MUSD 33.8 (MUSD 32.2) and related to the full consolidation of a subsidiary in which the non-controlling interest entity has made funding advances in relation to LLC PetroResurs, Russia.

Current liabilities
Trade and other payables amounted to MUSD 308.4 (MUSD 349.9) and are detailed in Note 12. Overlift amounted to MUSD 29.9 (MUSD -) and was mainly attributable to a net overlift position on the Greater Alvheim area producing fields. Joint operations creditors and accrued expenses amounted to MUSD 238.8 (MUSD 271.5) and related mainly to the development and drilling

activity in Norway. Other accrued expenses amounted to MUSD 16.9 (MUSD 23.7) and other current liabilities amounted to MUSD 9.5 (MUSD 11.4).

Derivative instruments amounted to MUSD 37.6 (MUSD 66.1) and related to the marked-to-market loss on outstanding interest rate and currency hedge contracts due to be settled within twelve months.

Current provisions amounted to MUSD 6.9 (MUSD 4.8) and related to the current portion of the provision for Lundin Petroleum's Unit Bonus Plan.

Parent Company

The business of the Parent Company is investment in and management of oil and gas assets. The net result for the Parent Company amounted to MSEK -103.3 (MSEK -78.1) for the year.

The result included general and administrative expenses of MSEK 106.6 (MSEK 89.6) and net finance costs of MSEK 0.5 (net finance income of MSEK 2.8).

On 30 June 2016, following 2016 EGM resolutions, Lundin Petroleum AB issued 27,580,806 new shares to Statoil ASA as part of the Edvard Grieg transaction. In addition, the Company also issued 1,735,309 new shares and transferred 2 million treasury shares held to Statoil ASA in exchange for a cash consideration of MSEK 544.1 based upon a share price of SEK 145.66 per share. These three share transactions increased the share capital/premium of the Company by an amount of MSEK 4,533.8.

Following the sale of the 2 million treasury shares to Statoil ASA, the Company does not hold any own shares at 31 December 2016.

Pledged assets of MSEK 6,740.3 (MSEK 3,569.7) relate to the accounting value of the pledge of the shares in respect of the financing facility entered into by its fully-owned subsidiary Lundin Petroleum BV, see also the Liquidity section below.

Related Party Transactions

During the year, the Group has entered into transactions with related parties on a commercial basis as described below.

Since 30 June 2016, the Group has sold oil and related products to the Statoil group on an arm's-length basis amounting to MUSD 155.0.

The Group received MUSD 0.3 (MUSD 0.5) from related parties for the provision of office and other services. The Group paid MUSD 0.4 (MUSD 0.2) to related parties in respect of services received.

Liquidity

In February 2016, Lundin Petroleum replaced its existing USD 4.0 billion lending facility, which was due to reduce in availability from June 2016 and mature in 2019, with a committed seven year senior secured reserve-based lending facility of up to USD 5.0 billion, with an initial committed amount of USD 4.3 billion. The committed amount has subsequently been increased to USD 5.0 billion. The financing facility is a reserve-based lending facility secured against certain cash flows generated by the Group. The amount available under the facility is recalculated every six months based upon the calculated cash flow generated by certain producing fields and fields under development at an oil price and economic assumptions agreed with the banking syndicate providing the facility. The facility is secured by a pledge over the shares of certain Group companies and a charge over some of the bank accounts of the pledged companies. The pledged amount at 31 December 2016 was MUSD 743.8 (MUSD 422.9) equivalent and represented the accounting value of net assets of the Group companies whose shares are pledged as described in the Parent Company section above.

In April 2015, Lundin Petroleum entered into a NOK 4.5 billion Norwegian exploration refund facility with ten international banks. The facility is secured against the tax refunds generated from Lundin Norway's exploration and appraisal activities on the Norwegian Continental Shelf and extends until the end of 2016. Following the receipt of the 2014 Norwegian exploration tax refund in December 2015, the facility size was reduced to NOK 2.15 billion. As at 31 December 2016, the facility was cancelled after the outstanding balance was repaid in November 2016 from the 2015 exploration tax refund receipt.

In March 2016, Lundin Petroleum entered into a six month revolving credit facility (RCF) of MUSD 300 with the option to extend by a further three months. Following the increased commitments under the Group's USD 5.0 billion reserve-based lending facility and the completion of the Edvard Grieg transaction, the RCF was cancelled effective 30 June 2016.

Lundin Petroleum has, through its subsidiary Lundin Malaysia BV, entered into Production Sharing Contracts (PSC) with Petroliam Nasional Berhad, the oil and gas company of the Government of Malaysia (Petronas). Bank guarantees have been issued in support of the work commitments and other related costs in relation to certain of these PSCs and the outstanding amount of the bank guarantees at 31 December 2016 was MUSD 10.3.

Subsequent Events

In January 2017, Lundin Petroleum acquired a further 17.8 million shares in ShaMaran Petroleum as part of the private placement of 360 million shares by the company at CAD 0.10 per share.

Share Data

Lundin Petroleum AB's issued share capital amounted to SEK 3,478,713 represented by 340,386,445 shares with a quota value of SEK 0.01 each (rounded off).

The Board of directors will propose to the AGM that no dividend will be paid to the shareholders for the financial year 2016.

Remuneration

Lundin Petroleum's principles for remuneration and details of the long-term incentive plans are provided in the Company's 2015 Annual Report and in the materials provided to shareholders in respect of the 2016 AGM, available on www.lundin-petroleum.com.

Unit Bonus Plan

The number of units relating to the awards made in 2014, 2015 and 2016 under the Unit Bonus Plan outstanding as at 31 December 2016 were 117,433, 277,928 and 360,099 respectively.

Performance Based Incentive Plan

The AGM 2016 resolved a long-term performance based incentive plan in respect of Group management and a number of key employees. The plan is effective from 1 July 2016 and the 2016 award is accounted for from the second half of 2016. The total outstanding number of awards at 31 December 2016 is 512,595 and the awards vest over three years from 1 July 2016 subject to certain performance conditions being met. Each award was fair valued at the date of grant at SEK 89.30 using an option pricing model.

The 2015 plan is effective from 1 July 2015 and the total outstanding number of awards at 31 December 2016 is 684,372 which vest over three years from 1 July 2015 subject to certain performance conditions being met. Each award was fair valued at the date of grant at SEK 91.40.

The 2014 plan is effective from 1 July 2014 and the total outstanding number of awards at 31 December 2016 is 602,554 which vest over three years from 1 July 2014 subject to certain performance conditions being met. Each award was fair valued at the date of grant at SEK 81.40.

Accounting Policies

This interim report has been prepared in accordance with International Accounting Standard (IAS) 34, Interim Financial Reporting, and the Swedish Annual Accounts Act (SFS 1995:1554).

The accounting policies adopted are in all other aspects consistent with those followed in the preparation of the Group's annual financial statements for the year ended 31 December 2015.

The financial reporting of the Parent Company has been prepared in accordance with accounting principles generally accepted in Sweden, applying RFR 2 Reporting for legal entities, issued by the Swedish Financial Reporting Board and the Annual Accounts Act (SFS 1995:1554).

Under Swedish company regulations it is not allowed to report the Parent Company results in any other currency than Swedish Krona or Euro and consequently the Parent Company's financial information is reported in Swedish Krona and not the Group's reporting currency of US Dollar.

Risks and Risk Management

The objective of Business Risk Management is to identify, understand and manage threats and opportunities within the business on a continual basis. This objective is achieved by creating a mandate and commitment to risk management at all levels of the business. This approach actively addresses risk as an integral and continual part of decision making within the Group and is designed to ensure that all risks are identified, fully acknowledged, understood and communicated well in advance. The ability to manage and or mitigate these risks represents a key component in ensuring that the business aim of the Company is achieved. Nevertheless, oil and gas exploration, development and production involve high operational and financial risks, which even a combination of experience, knowledge and careful evaluation may not be able to fully eliminate or which are beyond the Company's control.

A detailed analysis of Lundin Petroleum's strategic, operational, financial and external risks and mitigation of those risks through risk management is described in Lundin Petroleum's 2015 Annual Report.

Derivative financial instruments

Lundin Petroleum has entered into forward currency hedges to meet part of its future NOK capital requirements relating to the Johan Sverdrup field development. At 31 December 2016, Lundin Petroleum had outstanding currency hedges as summarised below:

Buy	Sell	Average contractual exchange rate	Settlement period
MNOK 3,492.6	MUSD 423.6	NOK 8.25:USD 1	Jan 2017 – Dec 2017
MNOK 3,493.0	MUSD 424.2	NOK 8.23:USD 1	Jan 2018 – Dec 2018
MNOK 1,672.4	MUSD 200.4	NOK 8.35:USD 1	Jan 2019 – Dec 2019

In the fourth quarter of 2016, Lundin Petroleum entered into additional interest rate hedge contracts and at 31 December 2016, had outstanding interest rate hedge contracts as follows:

Borrowings expressed in MUSD	Fixing of floating LIBOR average rate per annum	Settlement period
2,000	1.94%	Jan 2017 – Dec 2017
2,000	2.02%	Jan 2018 – Dec 2018
2,000	1.18%	Jan 2019 – Dec 2019

Under IAS 39, subject to hedge effectiveness testing, all of the hedges are treated as effective and changes to the fair value are reflected in other comprehensive income.

Exchange Rates

For the preparation of the financial statements for the year, the following currency exchange rates have been used.

	31 Dec 2016		31 Dec 2015	
	Average	Period end	Average	Period end
1 USD equals NOK	8.4014	8.6200	8.0637	8.8090
1 USD equals Euro	0.9037	0.9487	0.9012	0.9185
1 USD equals Rouble	67.0692	60.9999	61.2881	74.1009
1 USD equals SEK	8.5610	9.0622	8.4303	8.4408

Consolidated Income Statement

Expressed in MUSD	Note	**1 Jan 2016-31 Dec 2016 12 months**	**1 Oct 2016-31 Dec 2016 3 months**	1 Jan 2015-31 Dec 2015 12 months	1 Oct 2015-31 Dec 2015 3 months
Revenue	1	**1,159.9**	**385.9**	569.3	136.0
Cost of sales					
Production costs	2	-227.5	-58.3	-150.3	-35.7
Depletion and decommissioning costs		-471.4	-136.5	-260.6	-84.0
Depletion of other assets		-31.1	-7.7	-23.7	-7.2
Exploration costs		-116.1	-45.8	-184.1	-67.8
Impairment costs of oil and gas properties		-632.1	-632.1	-737.0	-737.0
Other cost of sales		-2.1	–	–	–
Gross profit/loss	3	**-320.4**	**-494.5**	-786.4	-795.7
Sale of assets		-3.5	–	–	–
General, administration and depreciation expenses		-31.9	-10.6	-39.5	-8.3
Operating profit/loss		**-355.8**	**-505.1**	-825.9	-804.0
Net financial items					
Finance income	4	22.6	-209.1	7.4	5.7
Finance costs	5	-225.4	-48.0	-617.9	-162.7
		-202.8	**-257.1**	-610.5	-157.0
Profit/loss before tax		**-558.6**	**-762.2**	-1,436.4	-961.0
Income tax	6	59.3	23.1	570.1	467.3
Net result		**-499.3**	**-739.1**	-866.3	-493.7
Attributable to:					
Shareholders of the Parent Company		-356.7	-599.9	-861.7	-492.5
Non-controlling interest		-142.6	-139.2	-4.6	-1.2
		-499.3	**-739.1**	-866.3	-493.7
Earnings per share – USD[1]		-1.09	-1.76	-2.79	-1.59
Earnings per share fully diluted – USD[1]		-1.09	-1.76	-2.79	-1.59

[1] Based on net result attributable to shareholders of the Parent Company.

Consolidated Statement of Comprehensive Income

Expressed in MUSD	**1 Jan 2016- 31 Dec 2016 12 months**	**1 Oct 2016- 31 Dec 2016 3 months**	1 Jan 2015- 31 Dec 2015 12 months	1 Oct 2015- 31 Dec 2015 3 months
Net result	**-499.3**	**-739.1**	-866.3	-493.7
Items that may be subsequently reclassified to profit or loss:				
Exchange differences foreign operations	13.8	-8.2	-81.7	-14.7
Cash flow hedges	64.3	-45.2	6.9	5.6
Available-for-sale financial assets	5.3	3.5	-3.7	-0.9
Other comprehensive income, net of tax	**83.4**	**-49.9**	-78.5	-10.0
Total comprehensive income	**-415.9**	**-789.0**	-944.8	-503.7
Attributable to:				
Shareholders of the Parent Company	-278.2	-650.8	-934.8	-499.6
Non-controlling interest	-137.7	-138.2	-10.0	-4.1
	-415.9	**-789.0**	-944.8	-503.7

Consolidated Balance Sheet

Expressed in MUSD	Note	31 December 2016	31 December 2015
ASSETS			
Non-current assets			
Oil and gas properties	7	4,376.4	4,015.4
Other tangible fixed assets		166.1	204.3
Goodwill		128.1	–
Financial assets	8	9.4	10.7
Deferred tax assets		13.5	13.4
Derivative instruments	13	17.0	–
Total non-current assets		**4,710.5**	4,243.8
Current assets			
Inventories		54.9	45.6
Trade and other receivables	9	288.9	159.3
Derivative instruments	13	0.8	–
Current tax assets		77.5	264.7
Cash and cash equivalents		69.5	71.9
Total current assets		**491.6**	541.5
TOTAL ASSETS		**5,202.1**	4,785.3
EQUITY AND LIABILITIES			
Equity			
Shareholders' equity		-238.6	-498.2
Non-controlling interest		-113.6	24.1
Total equity		**-352.2**	-474.1
Liabilities			
Non-current liabilities			
Financial liabilities	10	4,048.3	3,834.8
Provisions	11	420.0	379.9
Deferred tax liabilities		669.3	542.6
Derivative instruments	13	29.8	48.4
Other non-current liabilities		33.8	32.2
Total non-current liabilities		**5,201.2**	4,837.9
Current liabilities			
Trade and other payables	12	308.4	349.9
Derivative instruments	13	37.6	66.1
Current tax liabilities		0.2	0.7
Provisions	11	6.9	4.8
Total current liabilities		**353.1**	421.5
Total liabilities		**5,554.3**	5,259.4
TOTAL EQUITY AND LIABILITIES		**5,202.1**	4,785.3

Consolidated Statement of Cash Flows

Expressed in MUSD	**1 Jan 2016-31 Dec 2016 12 months**	**1 Oct 2016-31 Dec 2016 3 months**	1 Jan 2015-31 Dec 2015 12 months	1 Oct 2015-31 Dec 2015 3 months
Cash flows from operating activities				
Net result	-499.3	-739.1	-866.3	-493.7
Adjustments for:				
Exploration costs	116.1	45.8	184.1	67.8
Depletion, depreciation and amortisation	509.2	147.5	286.9	90.2
Impairment of oil and gas properties	632.1	632.1	737.0	737.0
Current tax	-80.6	-15.5	-280.6	-75.1
Deferred tax	21.3	-7.6	-289.5	-392.2
Long-term incentive plans	15.6	6.3	15.2	3.6
Foreign currency exchange	-44.1	218.1	374.6	105.0
Interest expense	137.3	30.5	71.3	24.3
Capitalised financing fees	43.2	5.1	12.4	3.1
Other	21.3	0.3	28.5	3.4
Interest received	2.3	1.8	6.1	5.7
Interest paid	-153.7	-39.2	-110.1	-32.8
Income taxes paid / received	278.4	274.2	335.6	335.4
Changes in working capital	-220.9	-267.8	-193.7	-112.6
Total cash flows from operating activities	**778.2**	**292.5**	311.5	269.1
Cash flows from investing activities				
Investment in oil and gas properties	-1,055.7	-304.9	-1,443.3	-344.4
Investment in other fixed assets	0.6	-0.7	-36.0	-1.5
Investment in subsidiaries	–	–	-0.1	–
Investment in other shares and participations	–	–	-3.7	–
Decommissioning costs paid	-10.7	-0.6	-10.6	-1.0
Disposal of fixed assets[1]	23.7	–	–	–
Other[2]	25.8	-5.1	-0.5	–
Total cash flows from investing activities	**-1,016.3**	**-311.3**	-1,494.2	-346.9
Cash flows from financing activities				
Changes in long-term liabilities	288.7	40.6	1,171.0	95.6
Financing fees paid	-114.3	–	-3.3	-0.1
Issuance of shares/Sale of treasury shares[3]	64.1	–	–	–
Total cash flows from financing activities	**238.5**	**40.6**	1,167.7	95.5
Change in cash and cash equivalents	0.4	21.8	-15.0	17.7
Cash and cash equivalents at the beginning of the period	71.9	48.8	80.5	53.0
Currency exchange difference in cash and cash equivalents	-2.8	-1.1	6.4	1.2
Cash and cash equivalents at the end of the period	**69.5**	**69.5**	71.9	71.9

1 Cash received on the sale of the Indonesian business on closing including settlement of net working capital.
2 Cash received on closing of the Edvard Grieg transaction with Statoil ASA.
3 Cash received on the additional sale of newly issued and treasury shares to Statoil ASA.

Consolidated Statement of Changes in Equity

Expressed in MUSD	Share capital	Additional paid-in-capital/Other reserves	Retained earnings	Total	Non-controlling interest	Total equity
	Attributable to owners of the Parent Company					
At 1 January 2015	**0.5**	**8.8**	**422.2**	**431.5**	**34.2**	**465.7**
Comprehensive income						
Net result	–	–	-861.7	-861.7	-4.6	-866.3
Other comprehensive income	–	-73.1	–	-73.1	-5.4	-78.5
Total comprehensive income	**–**	**-73.1**	**-861.7**	**-934.8**	**-10.0**	**-944.8**
Transactions with owners						
Value of employee services	–	–	–	–	-0.1	-0.1
Investment in subsidiaries	–	–	5.1	5.1	–	5.1
Total transactions with owners	**–**	**–**	**5.1**	**5.1**	**-0.1**	**5.0**
At 31 December 2015	**0.5**	**-64.3**	**-434.4**	**-498.2**	**24.1**	**-474.1**
Comprehensive income						
Net result	–	–	-356.7	-356.7	-142.6	-499.3
Other comprehensive income	–	78.5	–	78.5	4.9	83.4
Total comprehensive income	**–**	**78.5**	**-356.7**	**-278.2**	**-137.7**	**-415.9**
Transactions with owners						
Issuance of shares / Sale of treasury shares	–	534.1	–	534.1	–	534.1
Value of employee services	–	–	3.7	3.7	–	3.7
Total transaction with owners	**–**	**534.1**	**3.7**	**537.8**	**–**	**537.8**
At 31 December 2016	**0.5**	**548.3**	**-787.4**	**-238.6**	**-113.6**	**-352.2**

Notes to the Consolidated Financial Statements

Note 1 – Revenue MUSD	**1 Jan 2016- 31 Dec 2016 12 months**	**1 Oct 2016- 31 Dec 2016 3 months**	1 Jan 2015- 31 Dec 2015 12 months	1 Oct 2015- 31 Dec 2015 3 months
Crude oil	1,068.8	399.4	436.5	77.9
Condensate	14.7	4.9	0.6	0.2
Gas	83.0	24.1	83.9	17.5
Net sales of oil and gas	**1,166.5**	**428.4**	521.0	95.6
Change in under/over lift position	-28.9	-48.3	25.6	33.3
Other revenue	22.3	5.8	22.7	7.1
Revenue	**1,159.9**	**385.9**	569.3	136.0

Note 2 – Production costs MUSD	**1 Jan 2016- 31 Dec 2016 12 months**	**1 Oct 2016- 31 Dec 2016 3 months**	1 Jan 2015- 31 Dec 2015 12 months	1 Oct 2015- 31 Dec 2015 3 months
Cost of operations	166.0	41.2	121.1	32.8
Tariff and transportation expenses	37.9	8.0	11.8	3.7
Direct production taxes	3.3	0.8	3.5	0.9
Change in inventory position	-1.8	2.2	-12.6	-6.8
Other	22.1	6.1	26.5	5.1
	227.5	**58.3**	150.3	35.7

Note 3 – Segment information MUSD	**1 Jan 2016- 31 Dec 2016 12 months**	**1 Oct 2016- 31 Dec 2016 3 months**	1 Jan 2015- 31 Dec 2015 12 months	1 Oct 2015- 31 Dec 2015 3 months
Norway				
Crude oil	901.0	349.2	314.6	43.6
Condensate	14.3	4.9	–	–
Gas	58.5	19.8	33.0	6.4
Net sales of oil and gas	**973.8**	**373.9**	347.6	50.0
Change in under/over lift position	-29.1	-48.6	25.9	33.6
Other revenue	1.5	0.6	2.0	0.4
Revenue	**946.2**	**325.9**	375.5	84.0
Production costs	-168.4	-39.8	-104.5	-23.4
Depletion and decommissioning costs	-386.2	-116.1	-158.9	-49.6
Exploration costs	-101.9	-44.1	-146.5	-31.2
Impairment costs of oil and gas properties	–	–	-526.0	-526.0
Gross profit/loss	**289.7**	**125.9**	-560.4	-546.2

Note 3 – Segment information cont. MUSD	1 Jan 2016- 31 Dec 2016 12 months	1 Oct 2016- 31 Dec 2016 3 months	1 Jan 2015- 31 Dec 2015 12 months	1 Oct 2015- 31 Dec 2015 3 months
France				
Crude oil	39.9	9.7	50.6	7.3
Net sales of oil and gas	**39.9**	**9.7**	50.6	7.3
Change in under/over lift position	0.4	0.2	-0.2	-0.2
Other revenue	1.2	0.3	1.5	0.4
Revenue	**41.5**	**10.2**	51.9	7.5
Production costs	-20.5	-4.0	-25.1	-6.3
Depletion and decommissioning costs	-14.4	-3.7	-15.5	-3.5
Exploration costs	-0.1	-0.1	-0.6	–
Gross profit/loss	**6.5**	**2.4**	10.7	-2.3
Netherlands				
Crude oil	–	–	0.1	–
Condensate	0.4	–	0.6	0.2
Gas	15.2	4.3	24.0	5.2
Net sales of oil and gas	**15.6**	**4.3**	24.7	5.4
Change in under/over lift position	-0.2	0.1	-0.1	-0.1
Other revenue	1.7	0.4	1.8	0.5
Revenue	**17.1**	**4.8**	26.4	5.8
Production costs	-9.9	-2.2	-12.0	-3.0
Depletion and decommissioning costs	-9.7	-1.9	-10.7	-2.5
Exploration costs	-1.3	-1.3	-0.7	-0.3
Gross profit/loss	**-3.8**	**-0.6**	3.0	–
Malaysia				
Crude oil	125.8	40.5	71.2	27.0
Net sales of oil and gas	**125.8**	**40.5**	71.2	27.0
Other revenue	15.1	3.8	10.8	3.8
Revenue	**140.9**	**44.3**	82.0	30.8
Production costs	-27.3	-12.3	-4.4	-1.3
Depletion and decommissioning costs	-61.1	-14.8	-66.4	-28.4
Depletion of other assets	-31.1	-7.7	-23.7	-7.2
Exploration costs	-13.1	–	-36.3	-36.3
Impairment costs of oil and gas properties	-126.0	-126.0	-191.8	-191.8
Gross profit/loss	**-117.7**	**-116.5**	-240.6	-234.2
Indonesia				
Gas	9.3	–	26.9	5.9
Net sales of oil and gas	**9.3**	**–**	26.9	5.9
Other revenue	–	–	–	–
Revenue	**9.3**	**–**	26.9	5.9
Production costs	-1.4	–	-4.3	-1.7
Depletion and decommissioning costs	–	–	-9.1	–
Exploration costs	-0.3	-0.3	–	–
Impairment costs of oil and gas properties	–	–	-19.2	-19.2
Gross profit/loss	**7.6**	**-0.3**	-5.7	-15.0

Note 3 – Segment information cont. MUSD	1 Jan 2016- 31 Dec 2016 12 months	1 Oct 2016- 31 Dec 2016 3 months	1 Jan 2015- 31 Dec 2015 12 months	1 Oct 2015- 31 Dec 2015 3 months
Other				
Crude oil	2.1	–	–	–
Net sales of oil and gas	**2.1**	**–**	–	–
Other revenue	2.8	0.7	6.6	2.0
Revenue	**4.9**	**0.7**	6.6	2.0
Exploration costs	0.6	–	–	–
Impairment costs of oil and gas properties[1]	-506.1	-506.1	–	–
Other cost of sales	-2.1	–	–	–
Gross profit/loss	**-502.7**	**-505.4**	6.6	2.0

[1] The impairment costs of oil and gas properties relates to Russia

Total				
Crude oil	1,068.8	399.4	436.5	77.9
Condensate	14.7	4.9	0.6	0.2
Gas	83.0	24.1	83.9	17.5
Net sales of oil and gas	**1,166.5**	**428.4**	521.0	95.6
Change in under/over lift position	-28.9	-48.3	25.6	33.3
Other revenue	22.3	5.8	22.7	7.1
Revenue	**1,159.9**	**385.9**	569.3	136.0
Production costs	-227.5	-58.3	-150.3	-35.7
Depletion and decommissioning costs	-471.4	-136.5	-260.6	-84.0
Depletion of other assets	-31.1	-7.7	-23.7	-7.2
Exploration costs	-116.1	-45.8	-184.1	-67.8
Impairment costs of oil and gas properties	-632.1	-632.1	-737.0	-737.0
Other cost of sales	-2.1	–	–	–
Gross profit/loss	**-320.4**	**-494.5**	-786.4	-795.7

Within each segment, revenues from transactions with a single external customer amount to ten percent or more of revenue for that segment.

Note 4 – Finance income MUSD	1 Jan 2016- 31 Dec 2016 12 months	1 Oct 2016- 31 Dec 2016 3 months	1 Jan 2015- 31 Dec 2015 12 months	1 Oct 2015- 31 Dec 2015 3 months
Foreign currency exchange gain, net	15.0	-215.9	–	–
Interest income	2.3	1.8	6.1	5.6
Guarantee fees	0.4	0.2	0.7	–
Other	4.9	4.8	0.6	0.1
	22.6	**-209.1**	7.4	5.7

Note 5 – Finance costs MUSD	**1 Jan 2016- 31 Dec 2016 12 months**	**1 Oct 2016- 31 Dec 2016 3 months**	1 Jan 2015- 31 Dec 2015 12 months	1 Oct 2015- 31 Dec 2015 3 months
Interest expense	137.3	30.5	71.4	24.4
Foreign currency exchange loss, net	–	–	507.3	129.2
Result on interest rate hedge settlement	19.5	4.7	6.9	1.6
Unwinding of site restoration discount	15.2	4.5	10.0	2.5
Amortisation of deferred financing fees	43.2	5.1	12.4	3.1
Loan facility commitment fees	9.3	2.9	7.7	1.0
Other	0.9	0.3	2.2	0.9
	225.4	**48.0**	617.9	162.7

Note 6 – Income tax MUSD	**1 Jan 2016- 31 Dec 2016 12 months**	**1 Oct 2016- 31 Dec 2016 3 months**	1 Jan 2015- 31 Dec 2015 12 months	1 Oct 2015- 31 Dec 2015 3 months
Current tax	-80.6	-15.5	-280.6	-75.1
Deferred tax	21.3	-7.6	-289.5	-392.2
	-59.3	**-23.1**	-570.1	-467.3

Note 7 – Oil and gas properties MUSD	**31 Dec 2016**	31 Dec 2015
Norway	4,055.7	2,987.5
Malaysia	130.6	301.6
France	171.0	187.0
Netherlands	19.1	31.5
Russia	–	490.2
Indonesia	–	17.6
	4,376.4	4,015.4

Note 8 – Financial assets MUSD	**31 Dec 2016**	31 Dec 2015
Other shares and participations	8.9	4.1
Brynhild operating cost share	–	5.5
Other	0.5	1.1
	9.4	10.7

Note 9 – Trade and other receivables MUSD	**31 Dec 2016**	31 Dec 2015
Trade receivables	193.4	35.2
Underlift	28.9	26.5
Joint operations debtors	31.2	48.4
Prepaid expenses and accrued income	29.4	29.5
Brynhild operating cost share	3.0	14.7
Other	3.0	5.0
	288.9	159.3

Note 10 – Financial liabilities

MUSD	31 Dec 2016	31 Dec 2015
Non-current:		
Bank loans	4,145.0	3,858.0
Capitalised financing fees	-96.7	-23.2
	4,048.3	3,834.8

Note 11 – Provisions

MUSD	31 Dec 2016	31 Dec 2015
Non-current:		
Site restoration	407.1	368.2
Long-term incentive plans	3.2	2.2
Farm-in payment	5.5	4.6
Other	4.2	4.9
	420.0	379.9
Current:		
Long-term incentive plans	6.9	4.8
	6.9	4.8
	426.9	384.7

Note 12 – Trade and other payables

MUSD	31 Dec 2016	31 Dec 2015
Trade payables	13.3	23.1
Overlift	29.9	–
Deferred revenue	–	20.2
Joint operations creditors and accrued expenses	238.8	271.5
Other accrued expenses	16.9	23.7
Other	9.5	11.4
	308.4	349.9

Note 13 – Financial instruments
MUSD

For financial instruments measured at fair value in the balance sheet, the following fair value measurement hierarchy is used:

– Level 1: based on quoted prices in active markets;
– Level 2: based on inputs other than quoted prices as within level 1, that are either directly or indirectly observable;
– Level 3: based on inputs which are not based on observable market data.

Based on this hierarchy, financial instruments measured at fair value can be detailed as follows:

31 December 2016 MUSD	Level 1	Level 2	Level 3
Assets			
Other shares and participations	8.9	–	–
Derivative instruments – non-current	–	17.0	–
Derivative instruments – current	–	0.8	–
	8.9	**17.8**	**–**
Liabilities			
Derivative instruments – non-current	–	29.8	–
Derivative instruments – current	–	37.6	–
	–	**67.4**	**–**

31 December 2015 MUSD	Level 1	Level 2	Level 3
Assets			
Other shares and participations	4.1	–	–
	4.1	–	–
Liabilities			
Derivative instruments – non-current	–	48.4	–
Derivative instruments – current	–	66.1	–
	–	114.5	–

There were no transfers between the levels during the year.

The fair value of the financial assets is estimated to equal the carrying value. The fair value of the Derivative instruments, is calculated using the forward interest rate curve and the forward exchange rate curve respectively for the interest rate swap and the currency hedging contracts. The hedge counterparties are all banks which are party to the loan facility agreement.

Parent Company Income Statement

Expressed in MSEK	**1 Jan 2016-31 Dec 2016 12 months**	**1 Oct 2016-31 Dec 2016 3 months**	1 Jan 2015-31 Dec 2015 12 months	1 Oct 2015-31 Dec 2015 3 months
Revenue	**3.8**	**0.9**	8.7	0.3
General and administration expenses	-106.6	-49.4	-89.6	-21.7
Operating profit/loss	**-102.8**	**-48.5**	-80.9	-21.4
Net financial items				
Finance income	3.5	0.8	4.6	0.9
Finance costs	-4.0	0.2	-1.8	-1.7
	-0.5	**1.0**	2.8	-0.8
Profit/loss before tax	**-103.3**	**-47.5**	-78.1	-22.2
Income tax	—	—	—	—
Net result	**-103.3**	**-47.5**	-78.1	-22.2

Parent Company Comprehensive Income Statement

Expressed in MSEK	**1 Jan 2016-31 Dec 2016 12 months**	**1 Oct 2016-31 Dec 2016 3 months**	1 Jan 2015-31 Dec 2015 12 months	1 Oct 2015-31 Dec 2015 3 months
Net result	**-103.3**	**-47.5**	-78.1	-22.2
Other comprehensive income	—	—	—	—
Total comprehensive income	**-103.3**	**-47.5**	-78.1	-22.2
Attributable to:				
Shareholders of the Parent Company	-103.3	-47.5	-78.1	-22.2
	-103.3	**-47.5**	-78.1	-22.2

Parent Company Balance Sheet

Expressed in MSEK	31 December 2016	31 December 2015
ASSETS		
Non-current assets		
Shares in subsidiaries	12,256.6	7,871.8
Other tangible fixed assets	–	0.2
Total non-current assets	**12,256.6**	7,872.0
Current assets		
Receivables	20.7	17.5
Cash and cash equivalents	3.2	0.4
Total current assets	**23.9**	17.9
TOTAL ASSETS	**12,280.5**	7,889.9
SHAREHOLDERS´EQUITY AND LIABILITIES		
Shareholders´ equity including net result for the period	12,212.9	7,782.4
Non-current liabilities		
Provisions	0.6	0.4
Payables to group companies	49.4	100.7
Total non-current liabilities	**50.0**	101.1
Current liabilities		
Current liabilities	17.6	6.4
Total current liabilities	**17.6**	6.4
Total liabilities	**67.6**	107.5
TOTAL EQUITY AND LIABILITIES	**12,280.5**	7,889.9
Pledged assets	**6,740.3**	3,569.7

Parent Company Cash Flow Statement

Expressed in MSEK	1 Jan 2016-31 Dec 2016 12 months	1 Oct 2016-31 Dec 2016 3 months	1 Jan 2015-31 Dec 2015 12 months	1 Oct 2015-31 Dec 2015 3 months
Cash flow from operations				
Net result	-103.3	-47.5	-78.1	-22.2
Adjustment for non-cash related items	24.6	9.1	0.3	0.2
Changes in working capital	7.4	6.5	-23.8	-79.9
Total cash flow from operations	**-71.3**	**-31.9**	-101.6	-101.9
Cash flow from financing				
Change in long-term liabilities	-467.5	30.6	100.4	100.4
Proceeds from share issues /treasury shares	544.1	–	–	–
Total cash flow from financing	**76.6**	**30.6**	100.4	100.4
Change in cash and cash equivalents	5.3	-1.3	-1.2	-1.5
Cash and cash equivalents at the beginning of the period	**0.4**	**4.5**	1.8	1.9
Currency exchange difference in cash and cash equivalents	-2.5	–	-0.2	–
Cash and cash equivalents at the end of the period	**3.2**	**3.2**	0.4	0.4

Parent Company Statement of Changes in Equity

Expressed in MSEK	Restricted equity		Unrestricted equity			
	Share capital	Statutory reserve	Other reserves	Retained earnings	Total	Total equity
Balance at 1 January 2015	**3.2**	**861.3**	**2,295.3**	**4,700.7**	**6,996.0**	**7,860.5**
Total comprehensive income	**–**	**–**	**–**	**-78.1**	**-78.1**	**-78.1**
Balance at 31 December 2015	**3.2**	**861.3**	**2,295.3**	**4,622.6**	**6,917.9**	**7,782.4**
Total comprehensive income	**–**	**–**	**–**	**-103.3**	**-103.3**	**-103.3**
Transactions with owners						
Issuance of shares / sale of treasury shares	0.3	–	4,533.5	–	4,533.5	**4,533.8**
Total transactions with owners	**0.3**	**–**	**4,533.5**	**–**	**4,533.5**	**4,533.8**
Balance at 31 December 2016	**3.5**	**861.3**	**6,828.8**	**4,519.3**	**11,348.1**	**12,212.9**

Key Financial Data

Lundin Petroleum discloses alternative performance measures as part of its financial statements prepared in accordance with ESMA's (European Securities and Markets Authority) guidelines. Definitions of the performance measures are provided under the key ratio definitions below.

Financial data (MUSD)	1 Jan 2016- 31 Dec 2016 12 months	1 Oct 2016- 31 Dec 2016 3 months	1 Jan 2015- 31 Dec 2015 12 months	1 Oct 2015- 31 Dec 2015 3 months
Revenue	1,159.9	385.9	569.3	136.0
EBITDA	902.6	317.9	384.7	93.6
Net result	-499.3	-739.1	-866.3	-493.7
Operating cash flow	1,010.8	343.0	699.6	175.4
Data per share (USD)				
Shareholders' equity per share	-0.70	-0.70	-1.61	-1.61
Operating cash flow per share	3.10	1.01	2.26	0.57
Cash flow from operations per share	2.39	0.86	1.01	0.87
Earnings per share	-1.09	-1.76	-2.79	-1.59
Earnings per share - fully diluted	-1.09	-1.76	-2.79	-1.59
EBITDA per share	2.77	0.93	1.24	0.30
EBITDA per share — fully diluted	2.76	0.93	1.24	0.30
Dividend per share	—	—	—	—
Number of shares issued at period end	340,386,445	340,386,445	311,070,330	311,070,330
Number of shares in circulation at period end	340,386,445	340,386,445	309,070,330	309,070,330
Weighted average number of shares for the period	325,808,486	340,386,445	309,070,330	309,070,330
Weighted average number of shares for the period fully diluted	326,738,233	341,316,192	310,019,890	310,019,890
Share price				
Share price at period end (SEK)	198.10	198.10	122.60	122.60
Key ratios				
Return on equity (%) [1]	121	179	—	—
Return on capital employed (%)	-12	-14	-26	-22
Net debt/equity ratio (%) [1]	—	—	—	—
Equity ratio (%)	-7	-7	-10	-10
Share of risk capital (%)	6	6	1	1
Interest coverage ratio	-3	-15	-11	-31
Operating cash flow/interest ratio	6	10	9	7
Yield	n/a	n/a	n/a	n/a

[1] As the equity at 31 December 2015 and 2016 was negative, these ratios have not been calculated.

Key Ratio Definitions

EBITDA (Earnings Before Interest, Taxes, Depreciation and Amortisation): Operating profit before depletion of oil and gas properties, exploration costs, impairment costs, depreciation of other tangible assets and gain on sale of assets.

Operating cash flow: Revenue less production costs and less current taxes.

Shareholders' equity per share: Shareholders' equity divided by the number of shares in circulation at period end.

Operating cash flow per share: Operating cash flow divided by the weighted average number of shares for the period.

Cash flow from operations per share: Cash flow from operations in accordance with the consolidated statement of cash flow divided by the weighted average number of shares for the period.

Earnings per share: Net result attributable to shareholders of the Parent Company divided by the weighted average number of shares for the period.

Earnings per share fully diluted: Net result attributable to shareholders of the Parent Company divided by the weighted average number of shares for the period after considering the dilution effect of the awards outstanding under the Group's performance based incentive plan.

EBITDA per share: EBITDA divided by the weighted average number of shares for the period.

EBITDA per share fully diluted: EBITDA divided by the weighted average number of shares for the period after considering the dilution effect of the awards outstanding under the Group's performance based incentive plan.

Weighted average number of shares for the period: The number of shares at the beginning of the period with changes in the number of shares weighted for the proportion of the period they are in issue.

Weighted average number of shares for the period fully diluted: The number of shares at the beginning of the period with changes in the number of shares weighted for the proportion of the period they are in issue after considering the dilution effect of the awards outstanding under the Group's performance based incentive plan.

Return on equity: Net result divided by average total equity.

Return on capital employed: Income before tax plus interest expenses plus/less currency exchange differences on financial loans divided by the average capital employed (the average balance sheet total less non-interest bearing liabilities).

Net debt/equity ratio: Bank loan less cash and cash equivalents divided by shareholders' equity.

Equity ratio: Total equity divided by the balance sheet total.

Share of risk capital: The sum of the total equity and the deferred tax provision divided by the balance sheet total.

Interest coverage ratio: Result after financial items plus interest expenses plus/less currency exchange differences on financial loans divided by interest expenses.

Operating cash flow/interest ratio: Revenue less production costs and less current taxes divided by the interest expense for the period.

Yield: dividend per share in relation to quoted share price at the end of the financial period.

Stockholm, 1 February 2017

Ian H. Lundin Chairman	Alex Schneiter President and CEO	Peggy Bruzelius
C. Ashley Heppenstall	Lukas H. Lundin	Grace Reksten Skaugen
Magnus Unger	Cecilia Vieweg	

Financial Information

The Company will publish the following reports:

- The three month report (January — March 2017) will be published on 3 May 2017.
- The six month report (January — June 2017) will be published on 2 August 2017.
- The nine month report (January — September 2017) will be published on 1 November 2017.

The AGM will be held on 4 May 2017 in Stockholm, Sweden.

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This information is information that Lundin Petroleum AB is required to make public pursuant to the EU Market Abuse Regulation and the Securities Markets Act. The information was submitted for publication, through the contact persons set out above, at 07.00 CET on 1 February 2017.

Forward-Looking Statements

Certain statements made and information contained herein constitute "forward-looking information" (within the meaning of applicable securities legislation). Such statements and information (together, "forward-looking statements") relate to future events, including the Company's future performance, business prospects or opportunities. Forward-looking statements include, but are not limited to, statements with respect to estimates of reserves and/or resources, future production levels, future capital expenditures and their allocation to exploration and development activities, future drilling and other exploration and development activities. Ultimate recovery of reserves or resources are based on forecasts of future results, estimates of amounts not yet determinable and assumptions of management.

All statements other than statements of historical fact may be forward-looking statements. Statements concerning proven and probable reserves and resource estimates may also be deemed to constitute forward-looking statements and reflect conclusions that are based on certain assumptions that the reserves and resources can be economically exploited. Any statements that express or involve discussions with respect to predictions, expectations, beliefs, plans, projections, objectives, assumptions or future events or performance (often, but not always, using words or phrases such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions) are not statements of historical fact and may be "forward-looking statements". Forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. No assurance can be given that these expectations and assumptions will prove to be correct and such forward-looking statements should not be relied upon. These statements speak only as on the date of the information and the Company does not intend, and does not assume any obligation, to update these forward-looking statements, except as required by applicable laws. These forward-looking statements involve risks and uncertainties relating to, among other things, operational risks (including exploration and development risks), productions costs, availability of drilling equipment, reliance on key personnel, reserve estimates, health, safety and environmental issues, legal risks and regulatory changes, competition, geopolitical risk, and financial risks. These risks and uncertainties are described in more detail under the heading "Risks and Risk Management" and elsewhere in the Company's annual report. Readers are cautioned that the foregoing list of risk factors should not be construed as exhaustive. Actual results may differ materially from those expressed or implied by such forward-looking statements. Forward-looking statements are expressly qualified by this cautionary statement.

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