Lundin Petroleum

Q1

Report for the THREE MONTHS ended 31 March 2017

Lundin Petroleum AB (publ)

company registration number 556610-8055

Highlights

On 13 February 2017, Lundin Petroleum announced its intention to spin-off its assets in Malaysia, France and the Netherlands (the IPC assets) into a newly formed company called International Petroleum Corporation (IPC) and to distribute the IPC shares, on a pro-rata basis, to Lundin Petroleum shareholders. The results of the IPC business are included in the Lundin Petroleum financial statements in the reporting period and are shown as discontinued operations. The spin-off occurred on 24 April 2017.

Continuing operations: three months ended 31 March 2017 (31 March 2016)

- Production of 82.6 Mboepd (47.9 Mboepd)
- Revenue of MUSD 421.5 (MUSD 145.1)
- EBITDA of MUSD 355.8 (MUSD 97.4)
- Operating cash flow of MUSD 365.9 (MUSD 133.4)
- Net result of MUSD 59.2 (MUSD 165.7) including a net foreign exchange gain of MUSD 20.4 (MUSD 188.3)
- Net debt of MUSD 4,029 (31 December 2016: MUSD 4,075)

- Net result from discontinued operations of MUSD 4.0 (MUSD -51.4)

Continuing operations	**1 Jan 2017– 31 Mar 2017 3 months**	1 Jan 2016 – 31 Mar 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Production in Mboepd	**82.6**	47.9	59.3
Revenue in MUSD	**421.5**	145.1	950.0
Net result in MUSD	**59.2**	165.7	-399.3
Net result attributable to shareholders of the Parent Company in MUSD	**60.5**	166.8	-256.7
Earnings/share in USD[1]	**0.18**	0.54	-0.79
Earnings/share fully diluted in USD[1]	**0.18**	0.54	-0.79
EBITDA in MUSD	**355.8**	97.4	752.5
Operating cash flow in MUSD	**365.9**	133.4	857.9

The numbers included in the table above are based on continuing operations (including 2016 comparatives)
[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
Mcf	Thousand cubic feet

Letter to Shareholders

Dear fellow Shareholders,

Following an outstanding year of performance in 2016, the first quarter of 2017 has continued this trend and delivered excellent results at or above expectations.

Increased production guidance for 2017

Lundin Petroleum's production for the first quarter was 82.6 Mboepd, which is at the upper end of our 2017 first quarter guidance with cash operating costs well below USD 5 per barrel, excluding the non-Norwegian producing assets that were spun-off to International Petroleum Corporation (IPC) in April. These results are mainly driven by the performance from our operated Edvard Grieg and our non-operated Alvheim fields. Edvard Grieg continues to outperform both at subsurface and facilities level. Also, during the first quarter of this year, an important milestone was achieved when the gross platform oil design capacity at the Edvard Grieg field was successfully raised from 126 to 145 Mbopd, a 15 percent increase. Facility uptime continues to exceed expectations while maintaining a very high safety performance. This outstanding performance has led us to revise Lundin Petroleum's full year production guidance to between 75 and 85 Mboepd and to reduce our cash operating cost guidance for the full year to USD 4.90 per barrel, excluding the IPC assets.

We also successfully completed the Edvard Grieg Southwest appraisal well during the first quarter. The well results were encouraging and will most likely lead to a further field reserves increase by year end.

Johan Sverdrup development on track

On the project development side, the world class Johan Sverdrup development continues to progress according to plan with the Phase 2 concept selection being agreed in the first quarter. We also continue to see significant cost reductions with the latest Phase 2 cost estimate down to between NOK 40 and 55 billion, approximately half of the estimate from when the plan of development was submitted.

Strategic exploration position in the southern Barents Sea

In parallel, our organic growth-led strategy is continuing to deliver with the recently announced Filicudi discovery located on the western flank of the Loppa High in the southern Barents Sea. The discovery has upgraded the overall prospectivity in the area and has established the Filicudi trend, where we will see further drilling activities in the near future. This in addition to the well-established Loppa High and the southeastern trends also located in the southern Barents Sea where the Børselv and the Korpfjell prospects will be drilled this year.

Focus on organic growth in Norway

Finally, the spin-off of the non-Norwegian assets into IPC was completed successfully in April. It now means that Lundin Petroleum will solely focus on its organic growth strategy in Norway while IPC will focus initially on its international assets with an acquisition driven strategy followed later on by both an acquisition and organic growth-led strategy. IPC is very well positioned to establish itself as a significant international exploration and production player and benefits from having a proven management team and Mike Nicholson as CEO. I wish IPC success for the coming years!

Back to Lundin Petroleum; we are firmly on track to meet our production growth targets while maintaining a strong focus on HSE excellence. Our organic growth story is as exciting as ever with significant future potential. This is particularly true for the southern Barents Sea area where we will see drilling activities continuing in the coming years.

Thanks to everyone in the Company who help us achieve these results, I am very proud to be part of this team!

A big thank you to the Board and the Lundin Family for your confidence and continued support and to you, fellow shareholders, I am grateful for your ongoing trust and support.

Yours Sincerely,

Alex Schneiter
President and CEO

Stockholm, 3 May 2017

Financial Report for the Three Months Ended 31 March 2017

OPERATIONAL REVIEW

Lundin Petroleum is an independent oil and gas exploration and production company with operations focused on Norway. The spin-off of Lundin Petroleum's non-Norwegian producing assets into the newly formed company International Petroleum Corporation (IPC) was completed on 24 April 2017 and the results from the assets in Malaysia, France and the Netherlands are reported as discontinued operations.

Continuing Operations
Norway

Reserves and Resources

Lundin Petroleum has 714.1 million barrels of oil equivalent (MMboe) of proved plus probable net 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 amounted to 249 MMboe as at 31 December 2016.

Production

Production for the three month period ending 31 March 2017 (reporting period) amounted to 82.6 thousand barrels of oil equivalent per day (Mboepd) (compared to 47.9 Mboepd for the same period in 2016) which was 6 percent above the mid-point production guidance for the reporting period and at the top of the production guidance range. This performance is due to strong facilities and reservoir performance at both the Edvard Grieg field and the Alvheim area during the reporting period and based on this strong performance Lundin Petroleum is increasing its full year 2017 production guidance to between 75 to 85 Mboepd from between 70 to 80 Mboepd. Total cash operating cost, including netting off tariff income, was USD 4.04 per barrel during the reporting period and is forecast to be USD 4.90 per barrel for the year. The production during the reporting period was comprised as follows:

Production in Mboepd	**1 Jan 2017– 31 Mar 2017 3 months**	1 Jan 2016 – 31 Mar 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Norway			
Crude oil	74.6	43.0	53.2
Gas	8.0	4.9	6.1
Total production	**82.6**	47.9	59.3
Quantity in Mboe	**7,430.4**	4,356.7	21,701.4

Production in Mboepd	WI[1]	**1 Jan 2017– 31 Mar 2017 3 months**	1 Jan 2016 – 31 Mar 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Edvard Grieg	65%[2]	63.5	30.2	42.0
Ivar Aasen	1.385%	0.6	–	0.0
Alvheim	15%	14.6	8.8	10.0
Volund	35%	0.3	3.5	2.7
Bøyla	15%	1.2	2.1	1.7
Brynhild	90%	2.2	3.1	2.6
Gaupe	40%	0.2	0.2	0.3
		82.6	47.9	59.3

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

Net production from the Edvard Grieg field during the reporting period was higher than forecast at 63.5 Mboepd due to increased facilities capacity, continued high production efficiency and good reservoir performance. During the first quarter of 2017 a fifth production well was successfully drilled and came onstream at planned production rates. The production capacity from the first five production wells exceeds expectations and the reservoir depletion rate continues to be more favourable than anticipated.

The total operating cost for the Edvard Grieg field was USD 4.67 per barrel during the reporting period and is forecast to be USD 5.00 per barrel for the year.

The sixth Edvard Grieg production well is currently drilling with a further three development wells planned during 2017. To date, seven out of a total of 14 development wells have been completed with drilling operations expected to continue into 2018.

In April 2017 Lundin Petroleum announced the completion of the Edvard Grieg Southwest appraisal well 16/1-27 which encountered a 15 metre gross oil column in high quality reservoirs that were better than prognosis. While the top reservoir was encountered deeper than prognosed, the oil water contact was also encountered 9 metres deeper than the established contact for the Edvard Grieg field and pressure data confirms communication with the Edvard Grieg field. The well results confirm a preliminary gross resource upside for this part of the Edvard Grieg field in the range of 10 to 30 MMboe. The final implication for the total reserves for the Edvard Grieg field will be quantified in the 2017 year end reserves update. The impact on the development drilling programme due to this additional resource upside in the field is currently being assessed.

The Ivar Aasen field which produces through the Edvard Grieg facilities commenced production in December 2016 and after a short period of commissioning instability the combined fields have been producing with a high level of reliability. The Edvard Grieg production efficiency during the reporting period was 95 percent which is ahead of expectations.

During the reporting period capacity testing of the Edvard Grieg facilities confirmed that the facilities are able to produce at rates 15 percent above design levels of 100 Mboepd. The current production fully utilizes this higher facilities capacity whilst also honouring the contractual allocation of facilities capacity between the Edvard Grieg and Ivar Aasen fields and is before any impact of facilities downtime. The contractual allocation of facilities capacity between the Edvard Grieg and Ivar Aasen fields changes through time, the details of which are reflected in Lundin Petroleum's quarterly production guidance for 2017.

Net production from the Ivar Aasen field during the reporting period was in line with forecast at 0.6 Mboepd. Production continues to ramp-up with five production wells on line and the water injection system is expected to start-up during the second quarter of 2017.

Production from the Alvheim area during the reporting period was ahead of forecast due to better than expected reservoir performance as well as higher than expected Alvheim FPSO production efficiency of 97 percent. Additionally, production has been optimised between the fields within the Alvheim area to maximise production through the Alvheim FPSO. The total operating cost for the Alvheim area was USD 3.24 per barrel during the reporting period and is forecast to be USD 4.20 per barrel for the year.

Net production from the Alvheim field during the reporting period was significantly better than forecast at 14.6 Mboepd. The reservoir performance continues to be excellent with the most recent infill well A5 as well as the Viper and Kobra wells, which came onstream in November 2016, all producing significantly ahead of expectation. Additionally, Alvheim field production has been prioritised over Volund production to maximise facilities throughput. Two infill wells are planned to be drilled at Alvheim during 2017 with production startup of these wells expected in 2018.

Net production from the Volund field during the reporting period was below forecast at 0.3 Mboepd. Cutback of Volund production is required during the first half of 2017 while two infill wells are being drilled on the field and additionally an arrangement has been agreed to maximise total production through the Alvheim FPSO by further cutting back Volund field production and prioritising Alvheim field production until the new Volund infill wells start-up. The Volund West infill well was completed during the reporting period with results in line with expectations. The three-branch Volund South infill well is ongoing, with a third branch having been added due to good results from two pilot holes drilled as part of the drilling programme. Both wells are expected to come onstream in the third quarter of 2017.

Net production from the Bøyla field during the reporting period was marginally below forecast at 1.2 Mboepd.

Net production from the Brynhild field during the reporting period was higher than forecast at 2.2 Mboepd. The water injection system was re-instated in February 2017 but continuing operational issues are impacting stable injection rates. The Brynhild field achieved an uptime of 55 percent for the reporting period.

Despite no remaining reserves being attributed to the Gaupe field, the field is producing intermittently subject to favourable economic conditions and net production during the reporting period was in line with forecast at 0.2 Mboepd.

Development

Licence	Field	WI	Operator	PDO Approval	Estimated gross reserves	Production start expected	Gross plateau production rate expected
Johan Sverdrup Unit	Johan Sverdrup	22.6%	Statoil	August 2015	2.0—3.0 billion boe	Late 2019	660 Mbopd

Johan Sverdrup

Phase 1 of the Johan Sverdrup project is approximately 40 percent completed and is on schedule. With all the major project contracts awarded and the good progress on the project, Phase 1 costs continue to be reduced. Due to improved reservoir understanding the resource range for the field has again been increased. Additionally, concept selection (DG2) for Phase 2 of the project was concluded during the reporting period.

Construction on all elements of Phase 1 of the project have commenced with work ongoing at 22 construction sites around the world and with the project having increased manning to peak levels of approximately 3 million man-hours per month. Construction of three steel jackets is underway at the Kværner yard on the west coast of Norway and 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 is ongoing at Samsung Heavy Industries in Korea 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 first jacket to be installed offshore is for the riser platform and the installation is on schedule for August 2017. The remainder of the offshore facilities are scheduled for installation in 2018 and 2019.

The pre-drilling of development wells commenced in March 2016 with eight production wells and two water injection wells having been completed to date ahead of schedule and with well results in line with expectations. In addition, three pilot wells have been drilled during the reporting period to assist with the placement of the development wells with results in line or better than prognosis.

At the time of submitting the Phase 1 Plan of Development and Operation (PDO) in February 2015, the capital expenditure for Phase 1 was estimated at gross NOK 123 billion (nominal). The latest cost estimate, as released by Statoil in early 2017, has been reduced to NOK 97 billion (nominal), a reduction of approximately 21 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 gross production capacity for Phase 1 of the project is estimated at 440 Mbopd and is scheduled to start production in late 2019.

During the reporting period, the Johan Sverdrup partnership decided to proceed with concept selection (DG2) for Phase 2 of the project. This will involve the installation of an additional processing platform bridge linked to the Phase 1 field centre and additional facilities to allow the tie-in of 28 additional wells to access the Avaldsnes, Kvitsøy and Geitungen satellite areas of the field. These additional facilities will take the full field gross plateau level to 660 Mbopd. Phase 2 costs are estimated at NOK 40 to 55 billion (nominal) and represent approximately 50 percent reduction compared to the estimate in the original PDO for Phase 1, which is due to a combination of the market conditions and optimisation of the Phase 2 facilities concept. Front End Engineering Design (FEED) contracts in connection with Phase 2 of the project have been awarded to Aker Solutions for the processing platform, Kværner for the jacket and Siemens for the expansion of the power from shore facilities. The PDO for Phase 2 is scheduled in the second half of 2018 and Phase 2 is scheduled to come onstream in 2022.

During the reporting period, Statoil provided an update on resources for the Johan Sverdrup field with gross resources increasing to between 2.0 and 3.0 billion boe with 95 percent of the resources being oil.

The full field development costs (Phase 1 and Phase 2) are revised down from the original PDO total of NOK 207 billion to between NOK 137 and 152 billion (real 2016). Full field breakeven oil price is now estimated at below 25 USD per barrel.

Appraisal

2017 appraisal well programme

Licence	Operator	WI	Well	Spud Date	Status
PL265	Statoil	22.6%	16/2-22S (Johan Sverdrup - Tonjer)	January 2017	Completed February 2017
PL338	Lundin Petroleum	65%	16/1-27 (Edvard Grieg Southwest)	March 2017	Completed April 2017
PL492	Lundin Petroleum	40%	7120/1-5 (Gohta-3)	March 2017	Ongoing
PL609	Lundin Petroleum	40%	7220/11-4 (Alta-4)	June 2017	

In February 2017, the 16/2-22S Tonjer well testing a possible northern extension of the Johan Sverdrup field was announced to have encountered an oil column of 16 metres in moderate to poor quality Draupne reservoirs of lower quality compared to the main Johan Sverdrup reservoir. This result has no impact on the Johan Sverdrup development or the resources and the partnership will assess the results of the well as regards to possible future development.

In April 2017, Lundin Petroleum announced the completion of the Edvard Grieg Southwest appraisal well 16/1-27 and the results have been reported in the Production section above.

Lundin Petroleum will drill a further two appraisal wells offshore Norway during 2017 with a well on the Gohta discovery in PL492 (WI 40%) and a well on the Alta discovery in PL609 (WI 40%) both located on the Loppa High in the southern Barents Sea. The Gohta-3 appraisal well is currently ongoing.

Lundin Petroleum has a rig contract with Ocean Rig for the charter of the Leiv Eiriksson semi-submersible rig for a flexible term with multiple well option slots that can be called at Lundin Petroleum's election. This rig is currently planned to carry out all of Lundin Petroleum's operated wells in the southern Barents Sea for the 2017 drilling campaign.

Exploration

2017 exploration well programme

Licence	Well	Spud Date	Target	WI	Operator	Result
Southern Barents Sea						
PL533	7219/12-1	November 2016	Filicudi	35%	Lundin Petroleum	Oil and gas discovery
PL609	7220/6-3	August 2017	Børselv	40%	Lundin Petroleum	
PL859	7435/12-1	August 2017	Korpfjell	15%	Statoil	
PL533	7219/12-2	October 2017	Hufsa	35%	Lundin Petroleum	
Alvheim Area						
PL150B	24/9-11S	May 2017	Volund West	35%	Aker BP	

In February 2017, Lundin Petroleum announced a discovery on the Filicudi prospect in PL533 in the southern Barents Sea. The well, which was drilled approximately 40 km southwest of the Johan Castberg discovery, encountered a 129 metre hydrocarbon column, with 63 metres of oil and 66 metres of gas, in high quality Jurassic and Triassic sandstone reservoirs. A sidetrack well was drilled that also confirmed the reservoir and hydrocarbon column. The discovery is estimated to contain between 35 and 100 MMboe of gross resources. Significant additional prospectivity is mapped along trend with the Filicudi discovery in PL533 and plans are being progressed for follow-up drilling in 2017.

Lundin Petroleum will drill a further four exploration wells offshore Norway during 2017 targeting net unrisked prospective resources of over 500 MMboe. The remaining 2017 exploration programme consists of three wells 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. 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 southeastern Barents Sea. The third well will be targeting the Hufsa prospect in PL533 along trend with the Filicudi discovery, which is subject to partner approval. Additionally, one well will be drilled west of the Volund field in PL150 (WI 35%). In addition, a large high-specification 3D seismic survey will be acquired over the Alta, Gohta and Filicudi discoveries and associated prospectivity.

Licence awards, transactions and relinquishments

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

During the reporting period, a licence exchange was completed with Engie to swap 10 percent of Lundin Petroleum's working interest in PL778 for Engie's 20 percent working interest in both PL715 and PL722. In addition, acquisition of Shell's 20 percent working interest in PL715 was agreed during the reporting period which is subject to government approval. Also, Lundin Petroleum farmed out its 20 percent licence interest in PL685 to Wellesley Petroleum.

During the reporting period, Lundin Petroleum relinquished PL410, PL625, PL653, PL678, PL694, PL734, PL736S, PL765 and PL766.

Russia

At year end 2016, Lundin Petroleum removed the contingent resources from its books associated with the Morskaya oil discovery and wrote down the entire book value of the asset. Management is reviewing options for the Morskaya asset. The terms of the Morskaya production licence require agreement on an appraisal plan with the Russian licensing authority, Rosnedra, which is being progressed in order to maintain the licence in good standing while options for the asset are being reviewed.

Discontinued Operations
Non-Norwegian Producing Assets

Reserves and Resources

The non-Norwegian producing assets spun-off to IPC had 29.4 MMboe of proved plus probable reserves as at 31 December 2016 as certified by an independent third party.

Production

Production for the non-Norwegian producing assets being spun-off to IPC during the reporting period amounted to 11.5 Mboepd (14.5 Mboepd) and was above the midpoint of the production guidance for the reporting period. The production during the reporting period was comprised as follows:

Production in Mboepd	**1 Jan 2017– 31 Mar 2017 3 months**	1 Jan 2016 – 31 Mar 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Crude oil			
France	2.5	2.6	2.6
Malaysia	7.6	8.5	8.6
Total crude oil production	**10.1**	11.1	11.2
Gas			
Netherlands	1.4	1.7	1.6
Indonesia	–	1.7	0.5
Total gas production	**1.4**	3.4	2.1
Total production	**11.5**	14.5	13.3
Quantity in Mboe	**1,036.0**	1,317.6	4,858.2

South East Asia

Malaysia

Production in Mboepd	WI	**1 Jan 2017– 31 Mar 2017 3 months**	1 Jan 2016 – 31 Mar 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Bertam	75%	**7.6**	8.5	8.6

Peninsular Malaysia

Net production from the Bertam field on Block PM307 (WI 75%) during the reporting period was in line with forecast at 7.6 Mboepd. Reservoir performance for the Bertam field was in line with expectation and facilities uptime for the reporting period was in excess of 99 percent.

Applications regarding Block PM307 for relinquishment of the exploration areas and for granting of a gas holding area over the Tembakau gas discovery have been submitted, subject to approval from Petronas.

An extension to the drill or drop decision on exploration Block PM328 has been submitted to extend the decision by six months until September 2017, subject to approval from Petronas.

Sabah, East Malaysia

During the reporting period applications for relinquishment of the exploration Blocks SB307 and SB308 have been submitted and are awaiting approval from Petronas.

No commitments are outstanding on any Blocks in Malaysia.

Indonesia

Production in Mboepd	WI	**1 Jan 2017– 31 Mar 2017 3 months**	1 Jan 2016 – 31 Mar 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Singa	25.9%	–	1.7	0.5

The Indonesian assets were sold to PT Medco Energi International TBK effective April 2016 and thus there was no production during the reporting period.

Continental Europe

Production in Mboepd	WI	**1 Jan 2017– 31 Mar 2017 3 months**	1 Jan 2016 – 31 Mar 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
France				
– Paris Basin	100%[1]	2.1	2.2	2.2
– Aquitaine	50%	0.4	0.4	0.4
Netherlands	Various	1.4	1.7	1.6
		3.9	4.3	4.2

[1] Working interest in the Dommartin Lettree field 43 percent.

France

Net production during the reporting period from France was slightly above forecast at 2.5 Mboepd. 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 reporting period.

The Netherlands

Net production for the reporting period from the Netherlands was ahead of forecast at 1.4 Mboepd.

The F3-B106 side-track well commenced drilling in December 2016 and has been successfully drilled and completed. The well was put on production in March 2017.

The Nieuwehorne-1 exploration well in the onshore Gorredijk licence (WI 7.75%) is expected to be drilled during the second quarter 2017 and the A6 development well on the offshore E17a-A field (WI 1.2%) is expected to be drilled in the fourth quarter of 2017. During the first half of 2017 a new pipeline from the Total operated L4 field to the K6 field, is being installed with first gas expected by mid-2017.

Corporate Responsibility

During the reporting period, one medical treatment incident occurred in Malaysia, resulting in a Lost Time Incident Rate (LTIR) of 0.00 and a Total Recordable Incident Rate (TRIR) of 1.38 per million hours worked for the Group. No reportable incidents occurred in Norway during the reporting period.

FINANCIAL REVIEW

Result

The operating profit from continuing operations for the reporting period amounted to MUSD 219.8 (MUSD -33.9). The operating profit for the reporting period was driven by the increased production in Norway and the higher oil prices compared to last year.

The net result from continuing operations for the reporting period amounted to MUSD 59.2 (MUSD 165.7). The net result from continuing operations in the reporting period was lower compared to the first quarter of 2016 due to the largely non-cash foreign exchange gain reported in the first quarter of 2016.

The net result from continuing operations attributable to shareholders of the Parent Company for the reporting period amounted to MUSD 60.5 (MUSD 166.8) or MUSD 64.5 (MUSD 115.4) including discontinued operations representing earnings per share from continuing operations of USD 0.18 (USD 0.54) or USD 0.19 (USD 0.37) including discontinued operations.

Earnings before interest, tax, depletion and amortisation (EBITDA) from continuing operations for the reporting period amounted to MUSD 355.8 (MUSD 97.4) representing EBITDA per share of USD 1.05 (USD 0.32). Operating cash flow from continuing operations for the reporting period amounted to MUSD 365.9 (MUSD 133.4) representing operating cash flow per share of USD 1.07 (USD 0.43).

Changes in the Group

On 13 February 2017, Lundin Petroleum announced its intention to spin-off its assets in Malaysia, France and the Netherlands (the IPC assets) into a newly formed company called International Petroleum Corporation (IPC) and to distribute the IPC shares, on a pro-rata basis, to Lundin Petroleum shareholders. The results of the IPC business are included in the Lundin Petroleum financial statements for the reporting period and are shown as discontinued operations. The spin-off of IPC occurred on 24 April 2017. For more detail refer to Note 14.

Revenue

Revenue for the reporting period amounted to MUSD 421.5 (MUSD 145.1) 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 reporting period amounted to MUSD 381.2 (MUSD 149.3). The average price achieved by Lundin Petroleum for a barrel of oil equivalent from own production amounted to USD 51.14 (USD 32.33) and is detailed in the following table. The average Dated Brent price for the reporting period amounted to USD 53.69 (USD 33.94) per barrel.

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

Sales from own production Average price per boe expressed in USD	**1 Jan 2017– 31 Mar 2017 3 months**	1 Jan 2016 – 31 Mar 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Crude oil sales			
Norway			
– Quantity in Mboe	6,266.8	4,205.1	20,654.5
– *Average price per boe*	*52.63*	*32.42*	*43.60*
Gas and NGL sales			
Norway			
– Quantity in Mboe	813.6	405.4	2,352.1
– *Average price per boe*	*39.62*	*31.38*	*30.94*
Total sales from continuing operations			
– Quantity in Mboe	**7,080.4**	4,610.5	23,006.6
– Average price per boe	***51.14***	*32.33*	*42.31*

The table above excludes 369,743 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. 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 an income of MUSD 35.6 (cost of MUSD 5.1) in the reporting period due to the timing of the cargo liftings compared to production.

Other revenue amounted to MUSD 4.7 (MUSD 0.9) for the reporting period and included a quality differential compensation on Alvheim blended crude and tariff income of MUSD 4.2 (MUSD -) which is due to net income from Ivar Aasen tariffs paid to Edvard Grieg.

Production costs

Production costs including inventory movements for the reporting period amounted to MUSD 36.1 (MUSD 41.6) and are detailed in Note 2. The total production cost per barrel of oil equivalent produced is detailed in the table below.

Production costs from continuing operations	**1 Jan 2017– 31 Mar 2017 3 months**	1 Jan 2016 – 31 Mar 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Cost of operations			
– In MUSD	26.4	27.1	113.1
– In USD per boe	*3.56*	*6.21*	*5.21*
Tariff and transportation expenses			
– In MUSD	7.7	8.6	33.9
– In USD per boe	*1.03*	*1.98*	*1.56*
Cash operating costs			
– In MUSD	**34.1**	35.7	147.0
– In USD per boe [1]	***4.59***	*8.19*	*6.77*
Change in inventory position			
– In MUSD	-0.6	-0.3	-0.7
– In USD per boe	*-0.08*	*-0.07*	*-0.04*
Other			
– In MUSD	2.6	6.2	22.1
– In USD per boe	*0.35*	*1.43*	*1.02*
Production costs from continuing operations			
– In MUSD	**36.1**	41.6	168.4
– In USD per boe	***4.86***	*9.55*	*7.75*

Note: USD per boe is calculated by dividing the cost by total production volume for the period.
[1] The numbers in this table are excluding tariff income netting. Lundin Petroleum's cash operating costs for the reporting period of USD 4.59 per barrel is reduced to USD 4.04 per barrel when tariff income is netted off.

The total cost of operations for the reporting period amounted to MUSD 26.4 (MUSD 27.1). The decrease compared to the same period last year is mainly due to lower operational project cost for the Brynhild field. The total cost of operations excluding operational projects amounted to MUSD 24.9 (MUSD 25.0).

The cost of operations per barrel amounted to USD 3.56 (USD 6.21) including operational projects and USD 3.36 (USD 5.73) excluding operational projects. The cost of operations per barrel amounts are lower than the guidance provided in February 2017.

Tariff and transportation expenses for the reporting period amounted to MUSD 7.7 (MUSD 8.6). The main reason for the reduction per barrel is due to the increased volumes in the Oseberg transportation system that the Edvard Grieg pipeline is part of.

Other costs amounted to MUSD 2.6 (MUSD 6.2) 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.

Depletion and decommissioning costs

Depletion and decommissioning costs amounted to MUSD 131.1 (MUSD 75.9) at an average rate of USD 17.64 (USD 17.42) per barrel and are detailed in Note 3. The higher depletion costs for the reporting period compared to the same period last year is due to the depletion charge associated with the Edvard Grieg field as a result of the higher production levels achieved.

Exploration costs
Exploration costs expensed in the income statement for the reporting period amounted to MUSD 4.2 (MUSD 54.5) 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 reporting period, exploration costs relating to Norway of MUSD 3.8 were expensed relating to relinquished licences.

Other costs of sales
Other cost of sales for the reporting period amounted to MUSD 19.3 (MUSD -) and related to oil purchased from outside the Group by Lundin Petroleum Marketing SA.

General, administrative and depreciation expenses
The general administrative and depreciation expenses for the reporting period amounted to MUSD 11.0 (MUSD 7.0) which included a charge of MUSD 1.1 (MUSD 1.1) in relation to the Group's long-term incentive plans (LTIP), see also Remuneration section below. Fixed asset depreciation expenses for the reporting period amounted to MUSD 0.6 (MUSD 0.9).

Finance income
Finance income for the reporting period amounted to MUSD 20.6 (MUSD 188.7) and is detailed in Note 4.

The net foreign currency exchange gain for the reporting period amounted to MUSD 20.4 (MUSD 188.3). 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 period, the net realised exchange loss on settled foreign exchange hedges amounted to MUSD 2.5 (MUSD 17.9).

The US Dollar weakened against the Euro during the reporting period resulting in a net foreign currency exchange gain on the US Dollar denominated external loan which is borrowed by a subsidiary using Euro as functional currency. In addition, the Norwegian Krone weakened against the Euro in the reporting period, generating a net foreign currency exchange loss on an intercompany loan balance denominated in Norwegian Krone.

Finance costs
Finance costs for the reporting period amounted to MUSD 45.3 (MUSD 47.7) and are detailed in Note 5.

Interest expenses for the reporting period amounted to MUSD 28.6 (MUSD 34.2) and represented the portion of interest charged to the income statement. An additional amount of interest of MUSD 12.2 (MUSD 3.1) associated with the funding of the Norwegian development projects was capitalised in the reporting period. The total interest expense has increased compared to the same period last year due to the higher borrowings. The result on interest rate hedge settlements amounted to a loss of MUSD 6.0 (MUSD 4.3) and increased compared to the comparative period due to the higher fixed interest rate that was hedged in 2017.

The amortisation of the deferred financing fees amounted to MUSD 4.3 (MUSD 5.4) for the reporting period and related to the expensing of the fees incurred in establishing the financing facilities, including the Norwegian exploration refund facility, over the period of usage of the facilities.

Loan facility commitment fees for the reporting period amounted to MUSD 2.8 (MUSD 1.2) with the increase compared to the same period last year being due to the increased available borrowing amounts under the Group's reserve-based lending facility.

Tax
The overall tax charge for the reporting period amounted to MUSD 135.9 (credit of MUSD 58.6) and is detailed in Note 6.

The current tax charge for the reporting period amounted to MUSD 0.3 (credit MUSD 30.0) which included a tax credit of MUSD - (MUSD 30.1) relating to the Norway exploration tax refund.

The deferred tax charge for the reporting period amounted to MUSD 135.6 (credit of MUSD 28.6) which predominantly related to Norway. The deferred tax amount arises primarily where there is a difference in depletion for tax and accounting purposes.

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 reporting period is affected by items which do not receive a full tax credit such as the reported net foreign currency exchange gain, Norwegian financial items 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 reporting period amounted to MUSD -1.3 (MUSD -1.1) and related mainly to the non-controlling interest's share in a Russian subsidiary which is fully consolidated.

Discontinued operations

The net result from discontinued operations amounted to MUSD 4.0 (MUSD -51.4) and is detailed in Note 14.

Balance Sheet

Non-current assets

Oil and gas properties amounted to MUSD 4,277.6 (MUSD 4,376.4) and are detailed in Note 7. The oil and gas properties does not include any amount for the IPC business as at 31 March 2017 as they have been reclassified as assets held for distribution and appear within the current assets and are detailed in Note 14.

Development and exploration and appraisal expenditure incurred for the reporting period was as follows:

Development expenditure in MUSD	**1 Jan 2017– 31 Mar 2017 3 months**	1 Jan 2016 – 31 Mar 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Norway	257.0	168.4	877.1
Development expenditures from continuing operations	**257.0**	168.4	877.1

An amount of MUSD 257.0 (MUSD 168.4) of development expenditure was incurred in Norway during the reporting period, primarily on the Johan Sverdrup, Edvard Grieg and Volund field developments.

Exploration and appraisal expenditure in MUSD	**1 Jan 2017– 31 Mar 2017 3 months**	1 Jan 2016 – 31 Mar 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Norway	54.1	40.9	142.1
Russia	0.4	0.3	1.4
Exploration and appraisal expenditure from continuing operations	**54.5**	41.2	143.5

Exploration and appraisal expenditure of MUSD 54.1 (MUSD 40.9) was incurred in Norway during the reporting period, primarily on the Filicudi exploration well in PL533, the appraisal well Edvard Grieg Southwest in PL338 and the Gotha-3 appraisal well in PL492.

Other tangible fixed assets amounted to MUSD 13.9 (MUSD 166.1). Other tangible fixed assets does not include any amount for the IPC business as at 31 March 2017 as they have been reclassified as assets held for distribution and appear within the current assets and are detailed in Note 14.

Goodwill associated with the accounting for the Edvard Grieg transaction during 2016 amounted to MUSD 128.1 (MUSD 128.1).

Financial assets amounted to MUSD 10.1 (MUSD 9.4) and are detailed in Note 8. Other shares and participations amounted to MUSD 9.6 (MUSD 8.9) 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.

Derivative instruments amounted to MUSD 16.6 (MUSD 17.0) 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 30.2 (MUSD 54.9) and included both well supplies and hydrocarbon inventories. Inventories does not include any amount for the IPC business as at 31 March 2017 as they have been reclassified as assets held for distribution and appear within the current assets and are detailed in Note 14.

Trade and other receivables amounted to MUSD 165.4 (MUSD 288.9) and are detailed in Note 9. Trade and other receivables does not include any amount for the IPC business as at 31 March 2017 as they have been reclassified as assets held for distribution and appear within the current assets and are detailed in Note 14.

Trade receivables, which are all current, amounted to MUSD 84.1 (MUSD 193.4) and included invoiced cargoes. Underlift amounted to MUSD 33.1 (MUSD 28.9) and was attributable to a net underlift position on the Norwegian producing fields, mainly Edvard Grieg and Alvheim. Joint operations debtors relating to various joint venture receivables amounted to MUSD 10.3 (MUSD 31.2). Prepaid expenses and accrued income amounted to MUSD 33.1 (MUSD 29.4) and represented mainly prepaid operational and insurance expenditure. Brynhild operating cost share amounted to MUSD 1.6 (MUSD 3.0) and related to the mark-to-market valuation of the arrangement where the share of the operating cost varies with the oil price. Other current assets amounted to MUSD 3.2 (MUSD 3.0) and included VAT and other miscellaneous receivable balances.

Derivative instruments amounted to MUSD 3.4 (MUSD 0.8) and related to the marked-to-market gain on the outstanding interest rate hedge contracts due to be settled within twelve months.

Current tax assets amounted to MUSD 77.4 (MUSD 77.5) of which MUSD 77.3 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 56.3 (MUSD 69.5). Cash balances are held to meet ongoing operational funding requirements.

Non-current liabilities

Financial liabilities amounted to MUSD 4,000.6 (MUSD 4,048.3) and are detailed in Note 10. Bank loans amounted to MUSD 4,085.0 (MUSD 4,145.0) and related to the outstanding loan under the Group's reserve-based lending facility. Capitalised financing fees relating to the establishment costs of the Group's financing facility amounted to MUSD 84.4 (MUSD 96.7) and are being amortised over the expected life of the facility.

Provisions amounted to MUSD 344.3 (MUSD 420.0) and are detailed in Note 11. Provisions does not include any amount for the IPC business as at 31 March 2017 as they have been reclassified as Liabilities held for distribution and appear within the current liabilities and are detailed in Note 14. The provision for site restoration amounted to MUSD 336.4 (MUSD 407.1) and related to future decommissioning obligations. The site restoration provision related to Norway amounted to MUSD 336.4 (MUSD 316.1). The increase in Norway reflects the additional liability for Edvard Grieg and Volund production drilling and for the Johan Sverdrup development project.

Deferred tax liabilities amounted to MUSD 758.2 (MUSD 669.3). 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 19.4 (MUSD 29.8) 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 34.2 (MUSD 33.8) and mainly represent 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 658.6 (MUSD 308.4) and are detailed in Note 12. Joint operations creditors and accrued expenses amounted to MUSD 216.4 (MUSD 238.8) and related to activity in Norway. Proposed dividends amounted to MUSD 410.0 (MUSD -) and related to the approved distribution of the IPC shares, on a pro-rata basis, to Lundin Petroleum shareholders. Other accrued expenses amounted to MUSD 7.9 (MUSD 16.9) and other current liabilities amounted to MUSD 2.6 (MUSD 9.5).

Derivative instruments amounted to MUSD 32.0 (MUSD 37.6) 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 7.7 (MUSD 6.9) and related to the current portion of the provision for Lundin Petroleum's Unit Bonus Plan.

Assets and liabilities held for distribution

The net assets held for distribution amounted to MUSD 398.1 (MUSD —) and are detailed in Note 14.

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 -29.8 (MSEK -12.4) for the reporting period.

The result included general and administrative expenses of MSEK 30.6 (MSEK 13.1) and net finance costs of MSEK 0.2 (MSEK 0.3).

Current liabilities amounted to MSEK 3,667.5 (MSEK 17.6) and included proposed dividends amounting to MSEK 3,655.6 (MSEK –) relating to the approved distribution of the IPC shares, on a pro-rata basis, to Lundin Petroleum shareholders.

Pledged assets of MSEK 7,457.3 (MSEK 6,740.3) 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 reporting period, the Group has entered into transactions with related parties on a commercial basis as described below.

The Group received MUSD 0.1 (MUSD 0.1) from related parties for the provision of office and other services.

The Group has sold oil and related products to the Statoil group on an arm's-length basis amounting to MUSD 40.

Liquidity

In February 2016, Lundin Petroleum entered into a committed seven year senior secured reserve-based lending facility of 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 March 2017 is MUSD 836.4 (MUSD 743.8) equivalent and represents the accounting value of net assets of the Group companies whose shares are pledged as described in the Parent Company section above.

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 March 2017 was MUSD 10.1.

Subsequent Events

The reorganisation of the Lundin Petroleum Group to spin-off its assets in Malaysia, France and the Netherlands into IPC was completed on 7 April 2017. The distribution and first day of trading of IPC's shares on the TSX and Nasdaq First North occurred on 24 April 2017.

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).

Remuneration

Lundin Petroleum's principles for remuneration and details of the long-term incentive plans are provided in the Company's 2016 Annual Report and in the materials provided to shareholders in respect of the 2017 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 March 2017 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 March 2017 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 March 2017 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 March 2017 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 2016.

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 2016 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 March 2017, Lundin Petroleum had outstanding currency hedges as summarised below:

Buy	Sell	Average contractual exchange rate	Settlement period
MNOK 2,618.0	MUSD 317.4	NOK 8.25:USD 1	Apr 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 first quarter of 2017, Lundin Petroleum entered into additional interest rate hedge contracts and at 31 March 2017 had outstanding interest rate hedge contracts as follows:

Borrowings expressed in MUSD	Fixing of floating LIBOR average rate per annum	Settlement period
3,000	1.66%	Apr 2017 – Dec 2017
3,000	1.87%	Jan 2018 – Dec 2018
3,000	1.42%	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 reporting period, the following currency exchange rates have been used.

	31 Mar 2017		31 Mar 2016		31 Dec 2016	
	Average	Period end	Average	Period end	Average	Period end
1 USD equals NOK	8.4380	8.5757	8.6486	8.2692	8.4014	8.6200
1 USD equals Euro	0.9392	0.9354	0.9076	0.8783	0.9037	0.9487
1 USD equals Rouble	58.7208	56.4147	74.8552	67.0225	67.0692	60.9999
1 USD equals SEK	8.9272	8.9161	8.4646	8.1030	8.5610	9.0622

Consolidated Income Statement

Expressed in MUSD	Note	**1 Jan 2017– 31 Mar 2017 3 months**	1 Jan 2016 – 31 Mar 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
		Continuing operations	Continuing operations	Continuing operations
Revenue	1	**421.5**	145.1	950.0
Cost of sales				
Production costs	2	-36.1	-41.6	-168.4
Depletion and decommissioning costs		-131.1	-75.9	-386.2
Exploration costs		-4.2	-54.5	-101.9
Impairment costs of oil and gas properties		–	–	-506.1
Other cost of sales		-19.3	–	-2.1
Gross profit/loss	3	**230.8**	-26.9	-214.7
General, administration and depreciation expenses		-11.0	-7.0	-30.0
Operating profit/loss		**219.8**	-33.9	-244.7
Net financial items				
Finance income	4	20.6	188.7	2.7
Finance costs	5	-45.3	-47.7	-221.5
		-24.7	141.0	-218.8
Profit/loss before tax		**195.1**	107.1	-463.5
Income tax	6	-135.9	58.6	64.2
Net result from continuing operations		**59.2**	165.7	-399.3
Discontinued operations				
Net result - IPC	14	4.0	-51.4	-100.0
Net result		**63.2**	114.3	-499.3
Attributable to:				
Shareholders of the Parent Company		64.5	115.4	-356.7
Non-controlling interest		-1.3	-1.1	-142.6
		63.2	114.3	-499.3
Earnings per share – USD[1]				
From continuing operations		0.18	0.54	-0.79
From discontinued operations		0.01	-0.17	-0.30
Earnings per share fully diluted – USD[1]				
From continuing operations		0.18	0.54	-0.79
From discontinued operations		0.01	-0.17	-0.30

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

Consolidated Statement of Comprehensive Income

Expressed in MUSD	1 Jan 2017– 31 Mar 2017 3 months	1 Jan 2016 – 31 Mar 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Net result	**63.2**	114.3	-499.3
Items that may be subsequently reclassified to profit or loss:			
Exchange differences foreign operations	1.9	7.7	13.8
Cash flow hedges	18.7	49.1	64.3
Available-for-sale financial assets	-0.8	4.8	5.3
Other comprehensive income, net of tax	**19.8**	61.6	83.4
Total comprehensive income	**83.0**	175.9	-415.9
Attributable to:			
Shareholders of the Parent Company	84.2	174.7	-278.2
Non-controlling interest	-1.2	1.2	-137.7
	83.0	175.9	-415.9

Consolidated Balance Sheet

Expressed in MUSD	Note	31 March 2017	31 December 2016
ASSETS			
Non-current assets			
Oil and gas properties	7	4,277.6	4,376.4
Other tangible fixed assets		13.9	166.1
Goodwill		128.1	128.1
Financial assets	8	10.1	9.4
Deferred tax assets		–	13.5
Derivative instruments	13	16.6	17.0
Total non-current assets		**4,446.3**	4,710.5
Current assets			
Assets held for distribution	14	566.5	–
Inventories		30.2	54.9
Trade and other receivables	9	165.4	288.9
Derivative instruments	13	3.4	0.8
Current tax assets		77.4	77.5
Cash and cash equivalents		56.3	69.5
Total current assets		**899.2**	491.6
TOTAL ASSETS		**5,345.5**	5,202.1
EQUITY AND LIABILITIES			
Equity			
Shareholders´ equity		-563.4	-238.6
Non-controlling interest		-114.8	-113.6
Total equity		**-678.2**	-352.2
Liabilities			
Non-current liabilities			
Financial liabilities	10	4,000.6	4,048.3
Provisions	11	344.3	420.0
Deferred tax liabilities		758.2	669.3
Derivative instruments	13	19.4	29.8
Other non-current liabilities		34.2	33.8
Total non-current liabilities		**5,156.7**	5,201.2
Current liabilities			
Liabilities held for distribution	14	168.4	–
Trade and other payables	12	658.6	308.4
Derivative instruments	13	32.0	37.6
Current tax liabilities		0.3	0.2
Provisions	11	7.7	6.9
Total current liabilities		**867.0**	353.1
Total liabilities		**6,023.7**	5,554.3
TOTAL EQUITY AND LIABILITIES		**5,345.5**	5,202.1

Consolidated Statement of Cash Flows

Expressed in MUSD	**1 Jan 2017– 31 Mar 2017 3 months**	1 Jan 2016 – 31 Mar 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
	Continuing operations	Continuing operations	Continuing operations
Cash flows from operating activities			
Net result	59.2	165.7	-399.3
Adjustments for:			
Exploration costs	4.2	54.5	101.9
Depletion, depreciation and amortisation	131.7	76.8	391.7
Impairment of oil and gas properties	–	–	506.1
Current tax	0.3	-30.0	-78.4
Deferred tax	135.6	-28.6	14.2
Long-term incentive plans	3.3	3.8	15.6
Foreign currency exchange loss	-22.8	-205.8	-24.9
Interest expense	28.6	34.2	137.3
Capitalised financing fees	4.3	5.4	38.9
Other	2.7	5.4	12.6
Interest received	0.1	0.3	2.3
Interest paid	-40.6	-37.0	-153.7
Income taxes paid / received	–	-0.2	273.5
Changes in working capital	34.1	31.2	-169.1
Total cash flows from operating activities	**340.7**	75.7	668.7
Cash flows from investing activities			
Investment in oil and gas properties	-311.5	-209.6	-1,020.6
Investment in other fixed assets	-0.6	-0.4	-1.1
Investment in other shares and participations	-1.3	–	–
Decommissioning costs paid	0.2	-0.5	-1.0
Other payments [1]	–	–	25.8
Total cash flows from investing activities	**-313.2**	-210.5	-996.9
Cash flows from financing activities			
Changes in long-term liabilities	-59.5	232.6	288.7
Financing fees paid	–	-87.2	-104.0
Cash funded from / to discontinued operations	31.7	-6.8	92.5
Issuance of shares/Sale of treasury shares [2]	–	–	64.1
Total cash flows from financing activities	**-27.8**	138.6	341.3
Change in cash and cash equivalents	-0.3	3.8	13.1
Cash and cash equivalents at the beginning of the period	56.1	42.4	42.4
Currency exchange difference in cash and cash equivalents	0.5	-0.4	0.6
Cash and cash equivalent of discontinued operations [3]	–	22.3	13.4
Cash and cash equivalents at the end of the period	**56.3**	68.1	69.5

[1] Cash received on closing of the Edvard Grieg transaction with Statoil ASA.
[2] Cash received on the additional sale of newly issued and treasury shares to Statoil ASA.
[3] Cash of discontinued operations is included in the assets held for distribution as per 31 March 2017.

Consolidated Statement of Changes in Equity

Expressed in MUSD	Share capital	Additional paid-in-capital/Other reserves	Retained earnings	Dividends	Total	Non-controlling interest	Total equity
	Attributable to owners of the Parent Company						
At 1 January 2016	**0.5**	**-64.3**	**-434.4**	**–**	**-498.2**	**24.1**	**-474.1**
Comprehensive income							
Net result	–	–	115.4	–	115.4	-1.1	114.3
Other comprehensive income	–	59.3	–	–	59.3	2.3	61.6
Total comprehensive income	**–**	**59.3**	**115.4**	**–**	**174.7**	**1.2**	**175.9**
Transactions with owners							
Value of employee services	–	–	0.7	–	0.7	–	0.7
Total transactions with owners	**–**	**–**	**0.7**	**–**	**0.7**	**–**	**0.7**
At 31 March 2016	**0.5**	**-5.0**	**-318.3**	**–**	**-322.8**	**25.3**	**-297.5**
Comprehensive income							
Net result	–	–	-472.1	–	-472.1	-141.5	-613.6
Other comprehensive income	–	19.2	–	–	19.2	2.6	21.8
Total comprehensive income	**–**	**19.2**	**-472.1**	**–**	**-452.9**	**-138.9**	**-591.8**
Transactions with owners							
Issuance of shares/ Sale of treasury shares	0.0	534.1	–	–	534.1	–	534.1
Value of employee services	–	–	3.0	–	3.0	–	3.0
Total transaction with owners	**0.0**	**534.1**	**3.0**	**–**	**537.1**	**–**	**537.1**
At 31 December 2016	**0.5**	**548.3**	**-787.4**	**–**	**-238.6**	**-113.6**	**-352.2**
Comprehensive income							
Net result	–	–	64.5	–	64.5	-1.3	63.2
Other comprehensive income	–	19.7	–	–	19.7	0.1	19.8
Total comprehensive income	**–**	**19.7**	**64.5**	**–**	**84.2**	**-1.2**	**83.0**
Transactions with owners							
Proposed dividends	–	–	–	-410.0	-410.0	–	-410.0
Value of employee services	–	–	1.0	–	1.0	–	1.0
Total transaction with owners	**–**	**–**	**1.0**	**-410.0**	**-409.0**	**–**	**-409.0**
At 31 March 2017	**0.5**	**568.0**	**-721.9**	**-410.0**	**-563.4**	**-114.8**	**-678.2**

Notes to the Consolidated Financial Statements

Note 1 – Revenue MUSD	**1 Jan 2017– 31 Mar 2017 3 months**	1 Jan 2016 – 31 Mar 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Crude oil from own production	329.9	136.3	901.0
Crude oil from third party activities	19.1	0.3	2.1
Condensate	6.4	0.0	14.3
Gas	25.8	12.7	58.5
Net sales of oil and gas from continuing operations	**381.2**	149.3	975.9
Change in under/over lift position	35.6	-5.1	-29.1
Other revenue	4.7	0.9	3.2
Revenue from continuing operations	**421.5**	145.1	950.0

Note 2 – Production costs MUSD	**1 Jan 2017– 31 Mar 2017 3 months**	1 Jan 2016 – 31 Mar 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Cost of operations	26.4	27.1	113.1
Tariff and transportation expenses	7.7	8.6	33.9
Change in inventory position	-0.6	-0.3	-0.7
Other	2.6	6.2	22.1
Production costs from continuing operations	**36.1**	41.6	168.4

Note 3 – Segment information MUSD	**1 Jan 2017– 31 Mar 2017 3 months**	1 Jan 2016 – 31 Mar 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Norway			
Crude oil from own production	329.9	136.3	901.0
Condensate	6.4	0.0	14.3
Gas	25.8	12.7	58.5
Net sales of oil and gas	**362.1**	149.0	973.8
Change in under/over lift position	35.6	-5.1	-29.1
Other revenue	4.3	0.4	1.5
Revenue	**402.0**	144.3	946.2
Production costs	-36.1	-41.6	-168.4
Depletion and decommissioning costs	-131.1	-75.9	-386.2
Exploration costs	-3.8	-54.5	-101.9
Gross profit/loss	**231.0**	-27.7	289.7

Note 3 – Segment information cont. MUSD	**1 Jan 2017– 31 Mar 2017 3 months**	1 Jan 2016 – 31 Mar 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Other			
Crude oil from third party activities	19.1	0.3	2.1
Net sales of oil and gas	**19.1**	0.3	2.1
Other revenue	0.4	0.5	1.7
Revenue	**19.5**	0.8	3.8
Exploration costs	-0.4	–	–
Impairment costs of oil and gas properties	–	–	-506.1
Other cost of sales	-19.3	–	-2.1
Gross profit/loss	**-0.2**	0.8	-504.4
Total from continuing operations			
Crude oil from own production	329.9	136.3	901.0
Crude oil from third party activities	19.1	0.3	2.1
Condensate	6.4	0.0	14.3
Gas	25.8	12.7	58.5
Net sales of oil and gas	**381.2**	149.3	975.9
Change in under/over lift position	35.6	-5.1	-29.1
Other revenue	4.7	0.9	3.2
Revenue	**421.5**	145.1	950.0
Production costs	-36.1	-41.6	-168.4
Depletion and decommissioning costs	-131.1	-75.9	-386.2
Exploration costs	-4.2	-54.5	-101.9
Impairment costs of oil and gas properties	–	–	-506.1
Other cost of sales	-19.3	–	-2.1
Gross profit/loss from continuing operations	**230.8**	-26.9	-214.7

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 2017– 31 Mar 2017 3 months**	1 Jan 2016 – 31 Mar 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Foreign currency exchange gain, net	20.4	188.3	–
Interest income	0.1	0.3	2.3
Guarantee fees	0.1	0.1	0.4
Total finance income from continuing operations	**20.6**	188.7	2.7

Note 5 – Finance costs MUSD	**1 Jan 2017– 31 Mar 2017 3 months**	1 Jan 2016 – 31 Mar 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Interest expense	28.6	34.2	137.3
Foreign currency exchange loss, net	–	–	4.2
Result on interest rate hedge settlement	6.0	4.3	19.5
Unwinding of site restoration discount	2.8	2.4	11.6
Amortisation of deferred financing fees	4.3	5.4	38.9
Loan facility commitment fees	2.8	1.2	9.3
Other	0.8	0.2	0.7
Finance costs from continuing operations	**45.3**	47.7	221.5

Note 6 – Income tax MUSD	**1 Jan 2017– 31 Mar 2017 3 months**	1 Jan 2016 – 31 Mar 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Current tax	0.3	-30.0	-78.4
Deferred tax	135.6	-28.6	14.2
Total income tax from continuing operations	**135.9**	-58.6	-64.2

Note 7 – Oil and gas properties MUSD	**31 Mar 2017**	31 Dec 2016
Norway	4,277.6	4,055.7
Malaysia	–	130.6
France	–	171.0
Netherlands	–	19.1
	4,277.6	4,376.4

Note 8 – Financial assets MUSD	**31 Mar 2017**	31 Dec 2016
Other shares and participations	9.6	8.9
Other	0.5	0.5
	10.1	9.4

Note 9 – Trade and other receivables MUSD	**31 Mar 2017**	31 Dec 2016
Trade receivables	84.1	193.4
Underlift	33.1	28.9
Joint operations debtors	10.3	31.2
Prepaid expenses and accrued income	33.1	29.4
Brynhild operating cost share	1.6	3.0
Other	3.2	3.0
	165.4	288.9

Note 10 – Financial liabilities

MUSD	31 Mar 2017	31 Dec 2016
Non-current:		
Bank loans	4,085.0	4,145.0
Capitalised financing fees	-84.4	-96.7
	4,000.6	4,048.3

Note 11 – Provisions

MUSD	31 Mar 2017	31 Dec 2016
Non-current:		
Site restoration	336.4	407.1
Long-term incentive plans	3.8	3.2
Farm-in payment	–	5.5
Other	4.1	4.2
	344.3	420.0
Current:		
Long-term incentive plans	7.7	6.9
	7.7	6.9
	352.0	426.9

Note 12 – Trade and other payables

MUSD	31 Mar 2017	31 Dec 2016
Trade payables	21.2	13.3
Overlift	0.5	29.9
Joint operations creditors and accrued expenses	216.4	238.8
Proposed dividends	410.0	–
Other accrued expenses	7.9	16.9
Other	2.6	9.5
	658.6	308.4

Note 13 – Financial instruments

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 March 2017 MUSD	Level 1	Level 2	Level 3
Assets			
Other shares and participations	9.6	–	–
Derivative instruments – non-current	–	16.6	–
Derivative instruments – current	–	3.4	–
	9.6	**20.0**	**–**
Liabilities			
Derivative instruments – non-current	–	19.4	–
Derivative instruments – current	–	32.0	–
	–	**51.4**	**–**

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	**–**

There were no transfers between the levels during the reporting period.

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.

Note 14 – Discontinued operations - IPC

On 13 February 2017, Lundin Petroleum announced its intention to spin-off its assets in Malaysia, France and the Netherlands (the IPC assets) into a newly formed company called International Petroleum Corporation (IPC) and to distribute the IPC shares, on a pro-rata basis, to Lundin Petroleum shareholders. The results of the IPC business are included in the Lundin Petroleum financial statements in the reporting period and are shown as discontinued operations. The spin-off occurred on 24 April 2017.

The financial performance, net assets held for distribution and cash flow information for the discontinued operations is as follows:

Expressed in MUSD	**1 Jan 2017– 31 Mar 2017 3 months**	1 Jan 2016 – 31 Mar 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Revenue	**51.9**	46.2	209.9
Cost of sales			
Production costs	-11.9	-17.1	-59.1
Depletion and decommissioning costs	-14.5	-21.4	-85.2
Depletion of other assets	-7.8	-7.8	-31.1
Exploration costs	-0.1	-16.6	-14.2
Impairment costs of oil and gas properties	–	–	-126.0
Gross profit/loss	**17.6**	-16.7	-105.7
Sale of assets	–	–	-3.5
General, administration and depreciation expenses	-0.9	-2.0	-1.9
Operating profit/loss	**16.7**	-18.7	-111.1
Net financial items			
Finance income	–	–	23.9
Finance costs	-11.4	-31.0	-7.9
	-11.4	-31.0	16.0
Profit/loss before tax	**5.3**	-49.7	-95.1
Income tax	-1.3	-1.7	-4.9
Net result from discontinued operations	**4.0**	-51.4	-100.0

Expressed in MUSD	**31 Mar 2017**	31 Dec 2016
Assets held for distribution		
Oil and gas properties	310.8	–
Other tangible fixed assets	144.5	–
Financial asset	8.1	–
Deferred tax assets	13.3	–
Inventories	26.3	–
Trade and other receivables	43.4	–
Cash and cash equivalents	20.1	–
Total assets held for distribution	**566.5**	–
Liabilities held for distribution		
Provisions	99.0	–
Deferred tax liabilities	49.5	–
Trade and other payables	19.9	–
Total liabilities held for distribution	**168.4**	–
Net assets held for distribution	**398.1**	–

Note 14 – Discontinued operations - IPC cont. Expressed in MUSD	1 Jan 2017– 31 Mar 2017 3 months	1 Jan 2016 – 31 Mar 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
	Discontinued operations	Discontinued operations	Discontinued operations
Cash flows from operating activities			
Net result	4.0	-51.4	-100.0
Adjustments for:			
Exploration costs	0.1	16.6	14.2
Depletion, depreciation and amortisation	22.5	29.6	117.5
Impairment of oil and gas properties	–	–	126.0
Current tax	0.4	–	-2.2
Deferred tax	0.9	1.7	7.1
Foreign currency exchange loss	10.0	29.3	-19.2
Capitalised financing fees	0.4	0.3	4.3
Other	0.9	2.1	8.7
Income taxes paid / received	–	–	4.9
Changes in working capital	3.5	-1.6	-51.9
Total cash flows from operating activities	**42.7**	26.6	109.4
Cash flows from investing activities			
Investment in oil and gas properties	-2.1	-30.0	-35.0
Investment in other fixed assets	0.1	1.9	1.7
Decommissioning costs paid	-0.3	-0.3	-9.7
Disposal of fixed assets[1]	–	–	23.7
Other payments	–	–	-0.1
Total cash flows from investing activities	**-2.3**	-28.4	-19.4
Cash flows from financing activities			
Financing fees paid	–	-10.4	-10.3
Cash funded from / to continuing operations	-31.7	6.8	-92.5
Total cash flows from financing activities	**-31.7**	-3.6	-102.8
Change in cash and cash equivalents	**8.7**	-5.4	-12.8
Cash and cash equivalents at the beginning of the period	13.4	29.5	29.5
Currency exchange difference in cash and cash equivalents	-2.0	-1.8	-3.3
Cash and cash equivalents at the end of the period	**20.1**	22.3	13.4

[1] Cash received on the sale of the Indonesian business on closing including settlement of net working capital.

Parent Company Income Statement

Expressed in MSEK	1 Jan 2017– 31 Mar 2017 3 months	1 Jan 2016 – 31 Mar 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Revenue	**1.0**	1.0	3.8
General and administration expenses	-30.6	-13.1	-106.6
Operating profit/loss	**-29.6**	-12.1	-102.8
Net financial items			
Finance income	0.3	0.5	3.5
Finance costs	-0.5	-0.8	-4.0
	-0.2	-0.3	-0.5
Profit/loss before tax	**-29.8**	-12.4	-103.3
Income tax	–	–	–
Net result	**-29.8**	-12.4	-103.3

Parent Company Comprehensive Income Statement

Expressed in MSEK	1 Jan 2017– 31 Mar 2017 3 months	1 Jan 2016 – 31 Mar 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Net result	**-29.8**	-12.4	-103.3
Other comprehensive income	–	–	–
Total comprehensive income	**-29.8**	-12.4	-103.3
Attributable to:			
Shareholders of the Parent Company	-29.8	-12.4	-103.3
	-29.8	-12.4	-103.3

Parent Company Balance Sheet

Expressed in MSEK	**31 March 2017**	31 December 2016
ASSETS		
Non-current assets		
Shares in subsidiaries	12,256.6	12,256.6
Total non-current assets	**12,256.6**	12,256.6
Current assets		
Receivables	16.0	20.7
Cash and cash equivalents	16.6	3.2
Total current assets	**32.6**	23.9
TOTAL ASSETS	**12,289.2**	12,280.5
SHAREHOLDERS´EQUITY AND LIABILITIES		
Shareholders´ equity including net result for the period	8,527.5	12,212.9
Non-current liabilities		
Provisions	0.7	0.6
Payables to group companies	93.5	49.4
Total non-current liabilities	**94.2**	50.0
Current liabilities		
Current liabilities	3,667.5	17.6
Total current liabilities	**3,667.5**	17.6
Total liabilities	**3,761.7**	67.6
TOTAL EQUITY AND LIABILITIES	**12,289.2**	12,280.5
Pledged assets	**7,457.3**	6,740.3

Parent Company Cash Flow Statement

Expressed in MSEK	**1 Jan 2017– 31 Mar 2017 3 months**	1 Jan 2016 – 31 Mar 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Cash flow from operations			
Net result	-29.8	-12.4	-103.3
Adjustment for non-cash related items	2.9	4.6	24.6
Changes in working capital	-1.4	-5.3	7.4
Total cash flow from operations	**-28.3**	-13.1	-71.3
Cash flow from financing			
Change in long-term liabilities	41.9	20.5	-467.5
Proceeds from share issues /treasury shares	–	–	544.1
Total cash flow from financing	**41.9**	20.5	76.6
Change in cash and cash equivalents	13.6	7.4	5.3
Cash and cash equivalents at the beginning of the period	**3.2**	0.4	0.4
Currency exchange difference in cash and cash equivalents	-0.2	-0.2	-2.5
Cash and cash equivalents at the end of the period	**16.6**	7.6	3.2

Parent Company Statement of Changes in Equity

	Restricted equity		Unrestricted equity				
Expressed in MSEK	Share capital	Statutory reserve	Other reserves	Retained earnings	Dividends	Total	Total equity
Balance at 1 January 2016	**3.2**	**861.3**	**2,295.3**	**4,622.6**	**–**	**6,917.9**	**7,782.4**
Total comprehensive income	**–**	**–**	**–**	**-12.4**	**–**	**-12.4**	**-12.4**
Balance at 31 March 2016	**3.2**	**861.3**	**2,295.3**	**4,610.2**	**–**	**6,905.5**	**7,770.0**
Total comprehensive income	**–**	**–**	**–**	**-90.9**	**–**	**-90.9**	**-90.9**
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**
Total comprehensive income	**–**	**–**	**–**	**-29.8**	**–**	**-29.8**	**-29.8**
Transactions with owners							
Proposed dividends	–	–	–	–	-3,655.6	-3,655.6	-3,655.6
Total transactions with owners	**–**	**–**	**–**	**–**	**-3,655.6**	**-3,655.6**	**-3,655.6**
Balance at 31 March 2017	**3.5**	**861.3**	**6,828.8**	**4,489.5**	**-3,655.6**	**7,662.7**	**8,527.5**

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 from continuing operations MUSD	**1 Jan 2017– 31 Mar 2017 3 months**	1 Jan 2016 – 31 Mar 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Revenue	421.5	145.1	950.0
EBITDA	355.8	97.4	752.5
Net result	59.2	165.7	-399.3
Operating cash flow	365.9	133.4	857.9
Data per share from continuing operations USD			
Shareholders' equity per share	-1.66	-1.04	-0.70
Operating cash flow per share	1.07	0.43	2.63
Cash flow from operations per share	1.00	0.24	2.05
Earnings per share	0.18	0.54	-0.79
Earnings per share fully diluted	0.18	0.54	-0.79
EBITDA per share	1.05	0.32	2.31
EBITDA per share – fully diluted	1.04	0.31	2.30
Number of shares issued at period end	340,386,445	311,070,330	340,386,445
Number of shares in circulation at period end	340,386,445	309,070,330	340,386,445
Weighted average number of shares for the period	340,386,445	309,070,330	325,808,486
Weighted average number of shares for the period fully diluted	341,466,152	310,193,392	326,738,233
Share price SEK			
Share price at period end	181.80	137.50	198.10
Key ratios from continuing operations			
Return on equity (%) [1]	–	–	–
Return on capital employed (%)	7	-1	-9
Net debt/equity ratio (%) [1]	–	–	–
Equity ratio (%)	-14	-21	-17
Share of risk capital (%)	2	-10	-3
Interest coverage ratio	6	-1	-2
Operating cash flow/interest ratio	11	3	5
Yield	n/a	n/a	n/a

[1] As the equity at 31 March 2017, 31 December 2016 and 31 March 2016 is negative, these ratios have not been calculated.

Key Ratio Definitions

EBITDA (Earnings Before Interest, Taxes, Depreciation and Amortisation): Operating 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.

Cash operating costs: Cost of operations, tariff and transportation expenses and royalty and direct production taxes.

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

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

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 year.

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

Earnings per share fully diluted: Net result attributable to shareholders of the Parent Company divided by the weighted average number of shares for the year after considering any dilution effect.

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

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

Weighted average number of shares for the year fully diluted: The number of shares at the beginning of the year with changes in the number of shares weighted for the proportion of the year they are in issue after considering any dilution effect.

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 year.

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

Financial Information

The financial information relating to the three month period ended 31 March 2017 has not been subject to review by the auditors of the Company.

Stockholm, 3 May 2017

Alex Schneiter
President and CEO

The Company will publish the following reports:

- 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 year end report (January—December 2017) will be published on 7 February 2018.

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 CEST on 3 May 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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