Q4

YEAR END REPORT 2017

Lundin Petroleum AB (publ)

company registration number 556610-8055

Highlights

Lundin Petroleum reports excellent results for 2017. Full year production at record level and at low cash operating costs resulted in highest operating cash flow and EBITDA to date. Following these strong results, Lundin Petroleum's Board of Directors proposes an inaugural cash dividend to be paid after the 2018 AGM.

- Continued strong production from the Edvard Grieg field and the Alvheim area due to strong facilities and reservoir performance.
- Full year cash operating costs of USD 4.25 per barrel, including netting off tariff income.
- Johan Sverdrup project on schedule with over 65 percent of Phase 1 completed by end of 2017.
- Increase of proved plus possible reserves to 726.3 MMboe with a reserves replacement ratio of 144 percent.
- Record high award of 14 exploration licences in the 2017 Norwegian APA licensing round.
- The Board of Directors proposes to the 2018 AGM an inaugural cash dividend for 2017 of SEK 4.00 per share (approximately MUSD 175).

Financial summary

Continuing operations	**1 Jan 2017- 31 Dec 2017 12 months**	**1 Oct 2017- 31 Dec 2017 3 months**	1 Jan 2016- 31 Dec 2016 12 months	1 Oct 2016- 31 Dec 2016 3 months
Production in Mboepd	**86.1**	**83.1**	59.3	71.1
Revenue in MUSD	**1,997.0**	**593.7**	950.0	326.2
EBITDA in MUSD	**1,501.5**	**429.8**	752.5	276.7
Operating cash flow in MUSD	**1,530.0**	**434.5**	857.9	300.9
Net result in MUSD	**380.9**	**-50.9**	-399.3	-662.7
Earnings/share in USD[1]	**1.13**	**-0.15**	-0.79	-1.54
Earnings/share fully diluted in USD[1]	**1.13**	**-0.15**	-0.79	-1.53
Net debt	**3,883.6**	**3,883.6**	4,075.5	4,075.5

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.

Comment from Alex Schneiter, President and CEO of Lundin Petroleum:

"Looking back on the full year results for 2017 it is pleasing to report a record setting performance for Lundin Petroleum. With a continued strong performance in the fourth quarter, we delivered above expectations both in terms of record high production and record low cash operating costs for the year. These results are driven by continued strong performance from our core producing assets which have generated the highest operating cash flow for the Company to date, close to doubling operating cash flow and EBITDA compared to 2016.

I am very pleased to announce that the Board of Directors will propose to the 2018 AGM that an inaugural cash dividend of SEK 4.00 per share, totalling approximately MUSD 175, be paid out after the AGM. Based on current market conditions we anticipate an annual cash dividend of at least USD 350 million from next year.

We also announced good progress on the Johan Sverdrup project with more than 65 percent of Phase 1 completed at the end of the year with costs reduced by 25 percent compared to the PDO. 2018 will be a very busy offshore installation year with three additional jackets, two platform topsides and the export pipelines, progressing the field towards first oil in late 2019. We will also work with our partners to submit the PDO for Phase 2 of the project in the second half of 2018. Our recently announced increase in reserves is another positive update, led by particular success at our operated Edvard Grieg field where the best estimate ultimate gross recovery of 274 MMboe at year end represents a remarkable increase of 47 percent compared to the PDO.

While I would have liked to have seen more success with our exploration activities in 2017, this is a long-term game and I remain confident in our strategy to grow organically and expect our 2018 drilling programme to allow us to continue to find new resources and to create value within our core areas.

As we move forward, our strategy remains to focus on operational and execution excellence alongside safe and sustainable practices while continuing to pursue an active organic growth strategy. The future looks promising for Lundin Petroleum and we have some very exciting years ahead of us, increasing our production significantly by the time Johan Sverdrup comes onstream. By maintaining very low cash operating costs we will be able to deliver increased free cash flows, be very active on the organic growth front and deliver sustainable dividends, thereby continuing to create long-term value for our shareholders."

For definitions and abbreviations, see page 35.

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 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.

All the reported numbers and updates in the operational review relate to the financial year ended 31 December 2017 unless otherwise specified.

Continuing Operations
Norway

Reserves and Resources
Lundin Petroleum has 726.3 million barrels of oil equivalent (MMboe) of proved plus probable net reserves and 895.5 MMboe of proved plus probable plus possible net reserves as at 31 December 2017 as certified by an independent third party. Lundin Petroleum also has 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 203.4 MMboe as at 31 December 2017.

Production
Production for the year amounted to 86.1 thousand barrels of oil equivalent per day (Mboepd) (compared to 59.3 Mboepd for 2016), which was above the revised production guidance for the year of at or above 85 Mboepd and 15 percent above the mid-point of the original production guidance of 70 to 80 Mboepd. This performance is due to strong facilities and reservoir performance at both the Edvard Grieg field and the Alvheim area. The production guidance for 2018 is between 74 to 82 Mboepd.

Total cash operating cost for the year, including netting off tariff income, was USD 4.25 per barrel which was 8 percent below the revised guidance for the year of less than USD 4.60 per barrel and 20 percent below the original guidance of USD 5.30 per barrel. This performance is due to a combination of reduced costs and the increased production volumes.

The production was comprised as follows:

Production in Mboepd	**1 Jan 2017- 31 Dec 2017 12 months**	**1 Oct 2017- 31 Dec 2017 3 months**	1 Jan 2016- 31 Dec 2016 12 months	1 Oct 2016- 31 Dec 2016 3 months
Norway				
Crude oil	77.6	74.6	53.2	64.0
Gas	8.5	8.5	6.1	7.1
Total production	**86.1**	**83.1**	59.3	71.1
Quantity in Mboe	**31,427.7**	**7,647.0**	21,701.4	6,540.1

Production in Mboepd	WI [1]	**1 Jan 2017- 31 Dec 2017 12 months**	**1 Oct 2017- 31 Dec 2017 3 months**	1 Jan 2016- 31 Dec 2016 12 months	1 Oct 2016- 31 Dec 2016 3 months
Edvard Grieg	65%[2]	66.7	62.7	42.0	52.3
Ivar Aasen	1.385%	0.7	0.9	–	–
Alvheim	15%	12.4	9.8	10.0	12.5
Volund	35%	3.9	8.7	2.7	1.8
Bøyla	15%	1.1	0.9	1.7	1.6
Brynhild	51%[3]	1.2	–	2.6	2.6
Gaupe	40%	0.2	0.2	0.3	0.3
		86.1	**83.1**	59.3	71.1

[1] Lundin Petroleum's working interest (WI)
[2] WI 50% up to 30 June 2016.
[3] WI 90% up to 30 November 2017.

Net production from the Edvard Grieg field during the year was higher than forecast at 66.7 Mboepd due to increased facilities capacity, good production efficiency and strong reservoir performance. The Ivar Aasen field, which produces through the Edvard Grieg facilities, commenced production in December 2016 and the combined fields have been producing with a strong level of reliability, with Edvard Grieg production efficiency of 94 percent for the year. Capacity testing of the Edvard Grieg facilities confirmed that the facilities are able to produce at rates 15 percent above design levels at 145 thousand barrels of oil per day (Mbopd) combined from Edvard Grieg and Ivar Aasen. The current production fully utilises this higher facilities capacity whilst also honouring the contractual allocation of facilities capacity between the Edvard Grieg and Ivar Aasen fields. The contractual allocation changes through time, with the final contractual change occurring at the end of the third quarter 2018. The contractual capacity allocation is reflected in the 2018 production guidance.

The total operating cost for the Edvard Grieg field was USD 4.61 per barrel for the year and cash operating cost, including netting off tariff income, was USD 3.71 per barrel for the year.

In April 2017, Lundin Petroleum announced the successful Edvard Grieg Southwest appraisal well 16/1-27 which encountered a 15 metres gross oil column with significantly better sand quality and thickness compared to prognosis. The well results confirmed additional reserves in this area of the field, which combined with the results from the other wells drilled during the year and the strong reservoir performance, which has seen no water production to date, has resulted in the field's best estimate gross ultimate recovery increasing by 51 MMboe to 274 MMboe as at year end 2017, which is a 47 percent increase on the original estimate in the Plan for Development and Operation (PDO).

The Edvard Grieg development drilling plan within the PDO has been optimised within the same number of planned wells to access the southwest area of the field with one production well and one water injection well targeting this area of the field. During the year, three production wells and two water injection wells were successfully drilled on the Edvard Grieg field with results in line or better than expectations. One further production well has been successfully drilled in January 2018. To date, 12 out of a total of 14 development wells have been completed with drilling operations planned to continue into the second quarter of 2018. The production capacity from the eight production wells drilled so far exceeds expectations and significantly exceeds the available facilities capacity.

Net production from the Ivar Aasen field during the year was in line with forecast at 0.7 Mboepd. Water injection commenced during the second quarter of 2017 and the PDO drilling programme was completed during the third quarter of 2017.

Production during the year from the Alvheim area, consisting of the Alvheim, Volund and the Bøyla fields, was ahead of forecast due to reservoir performance continuing to be better than expected as well as higher than expected Alvheim FPSO production efficiency of 97 percent. The total operating cost for the Alvheim area was USD 3.70 per barrel for the year.

Net production from the Alvheim field during the year was better than forecast at 12.4 Mboepd. The reservoir continues to outperform with the most recent infill well A5 as well as the Viper and Kobra wells, which came on stream in 2016, all continuing to produce ahead of expectations. Drilling of two infill wells on the Boa area of the field were completed during the year with results in line with expectations and production start-up of both wells is planned in the first quarter of 2018.

Net production from the Volund field during the year was ahead of forecast at 3.9 Mboepd. Two new Volund infill wells were completed during the year and came on stream in the third quarter, with production from both wells exceeding expectations.

Net production from the Bøyla field during the year was in line with forecast at 1.1 Mboepd.

Net production from the Brynhild field during the year was lower than forecast at 1.2 Mboepd. The field has been shut-in since July 2017 due to a flow restriction that developed in the pipeline between the Brynhild subsea wells and the Haewene Brim FPSO. The restriction was due to an oil-water emulsion that developed in the pipeline due to a failure of the subsea emulsion inhibitor chemical injection system. Operations to clear the restriction are being progressed and the plan is to re-start production from the field during the first quarter 2018. The water injection system was re-instated in February 2017 and stable injection rates have been achieved since then. Terms for a revised processing and operations service agreement were agreed with Shell, which reduces future operating costs for the field.

In June 2017, Lundin Petroleum announced that it had entered into an agreement to divest a 39 percent working interest in the Brynhild field to CapeOmega. Lundin Norway has retained operatorship of the Brynhild field and following completion of the transaction at the end of November 2017 has a 51 percent working interest in the field. The effective date of the transaction is 1 January 2017.

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 year 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 Bn boe	Late 2019	660 Mbopd

Johan Sverdrup

Phase 1 of the Johan Sverdrup project is on schedule with over 65 percent completed at the end of 2017. Construction on all elements of Phase 1 of the project is underway with over 50 million direct man-hours having been worked to date. With the good progress on the project Phase 1 costs continue to be reduced.

Construction of the steel jacket for the riser platform was completed at the Kværner Verdal yard in Norway and was installed offshore at the end of July 2017. This is the first major offshore installation milestone and was achieved on schedule. The remaining three jackets and the four topsides are scheduled for installation in 2018 and 2019.

Construction of the remaining three steel jackets is underway at the Kværner Verdal yard in Norway and 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 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. The three large modules making up the drilling platform topsides were assembled on a barge on schedule in September 2017 and are currently located in Haugesund in Norway for hook-up and final completion. Installation of the four subsea water injection drilling templates and associated flowlines has been completed. In addition, civil engineering works are underway on the onshore power system at Haugsneset and for the oil export pipeline landfall at Mongstad.

The pre-drilling of development wells commenced in March 2016 with eight production wells completed in 2016 with results in line with expectations. Three pilot wells have been drilled to assist with the placement of the development wells with results in line with or better than prognosis. In addition, the pre-drilling of nine water injection wells was completed in 2017 with results in line with expectations. Pre-drilling activities were completed significantly ahead of schedule.

At the time of submitting the Phase 1 PDO in 2015, the capital expenditure for Phase 1 was estimated at gross NOK 123 billion (nominal). Due to improvements in project execution and delivery the latest cost estimate, as released by Statoil in September 2017, is NOK 92 billion (nominal). This represents a saving of 25 percent compared to the original estimate in the PDO, excluding additional foreign exchange rate savings in US dollar terms. The gross oil production capacity for Phase 1 of the project is estimated at 440 Mbopd and is scheduled to start production in late 2019.

The Johan Sverdrup partnership has decided on concept selection (DG2) for Phase 2 of the project, which will involve the installation of an additional processing platform bridge linked to the Phase 1 field centre and additional subsea 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 a 50 percent reduction compared to the estimate in the original PDO for Phase 1, which is due to a combination of 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. Additionally, procurement activities are being progressed for long-lead equipment items for Phase 2. The PDO submission for Phase 2 is scheduled for the second half of 2018 and Phase 2 is scheduled to come onstream in 2022.

During the year, 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 132 and 147 billion (nominal). Full field breakeven oil price is 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 Norway	65%	16/1-27 (Edvard Grieg Southwest)	March 2017	Completed April 2017
PL492	Lundin Norway	40%	7120/1-5 (Gohta-3)	March 2017	Completed May 2017
PL609	Lundin Norway	40%	7220/11-4 (Alta-4)	June 2017	Completed July 2017 sidetrack completed August 2017

In February 2017, the Tonjer well testing a possible northern extension of the Johan Sverdrup field was announced to have encountered an oil column of 16 metres in 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 with results as reported in the Production section above.

In May 2017, Lundin Petroleum announced that the Gohta-3 appraisal well located in PL492 some 4 km north of the original discovery well encountered a 300 metres gross sequence of Permian age carbonates with poor reservoir quality. The resource estimate for the discovery has been reduced as a consequence of this well. Gohta is considered a possible joint development opportunity together with the larger adjacent Alta discovery.

In July 2017, Lundin Petroleum announced that the Alta-4 appraisal well located approximately 2 km south of the original Alta discovery well had encountered a gross hydrocarbon column of 48 metres, comprising 4 metres of gas and 44 metres of oil in a sequence of Permian-Triassic carbonate sediments of varying reservoir characteristics. Pressure data show the same fluid contacts and gradients as observed in previous wells drilled on the Alta discovery, confirming good communication across the large Alta structure. A production test was performed in the oil zone, producing at a stabilised rate of 6,050 bopd with low pressure drawdown and constrained by rig testing facilities. The production test confirmed very good reservoir properties and good lateral continuity within the Permian-Triassic clastic reservoirs. In August 2017, a geological sidetrack was completed approximately 900 metres north of the Alta-4 well which confirmed the reservoir sequence and fluid contacts. An extended well test will be conducted at Alta in 2018 to reduce the uncertainty around the recovery mechanism in this complex reservoir and provide the basis for development studies.

Lundin Petroleum has a rig contract with Ocean Rig for the charter of the Leiv Eiriksson semi-submersible rig on a flexible basis which has drilled all of the operated wells in the southern Barents Sea in 2017 and will be used to conduct the Alta extended well test in 2018.

Lundin Petroleum has a rig contract with COSL Offshore Management for the charter of the COSL Innovator semi-submersible rig for a flexible term with multiple well option slots for a well programme in the Utsira High area in 2018. The rig will be utilised to drill appraisal wells at Luno II in PL359 and at Rolvsnes in PL338C. Both Luno II and Rolvsnes are possible subsea tie-back development opportunities to the Edvard Grieg facilities. Drilling operations at Luno II are scheduled to commence in February 2018.

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 Norway	Oil and gas discovery
PL859	7435/12-1	August 2017	Korpfjell	15%	Statoil	Small non-commercial gas discovery
PL609	7220/6-3	August 2017	Børselv	40%	Lundin Norway	Dry
PL533	7219/12-2	October 2017	Hufsa	35%	Lundin Norway	Non-commercial gas discovery
PL533	7219/12-3	December 2017	Hurri	35%	Lundin Norway	Dry
Alvheim Area						
PL150B	24/9-11S	June 2017	Volund West	35%	Aker BP	Dry
PL340	24/19-2S	January 2018	Frosk	15%	Aker BP	Ongoing

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 in PL532, encountered a 129 metres 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. After full review of the well data the discovery is estimated to contain gross contingent resources of 23 MMboe with additional upside potential in the eastern area of the discovery that would require further appraisal drilling.

In June 2017, the Volund West prospect in PL150B in the North Sea, to the west of the Volund field, was drilled and was dry. While the well encountered good reservoir sands there were poor hydrocarbon shows.

In August 2017, the Korpfjell prospect in PL859 in the southeastern Barents Sea was drilled and proved a small non-commercial gas discovery. The well encountered a gas column of 34 metres in sandstones with good reservoir quality in the shallow Jurassic age target with estimated gross resources of between 40 and 75 MMboe. Further drilling is planned in 2018 in PL859 to test the deeper prospectivity on the block.

In September 2017, the Børselv prospect in PL609 located on-trend north of the Alta and Neiden oil discoveries in the southern Barents Sea was drilled and was dry. The well encountered a 380 metres thick sequence of Permian-Carboniferous carbonates with medium to poor reservoir quality with oil shows, but the reservoir was water bearing.

In November 2017, the Hufsa prospect in PL533 in the southern Barents Sea on trend with the Filicudi oil discovery in the same block was drilled. The well encountered Jurassic and Triassic reservoir sands. A non-commercial gas discovery was made in the main well while the sidetrack was dry.

In January 2018, the Hurri prospect in PL533 in the southern Barents Sea on trend with the Filicudi oil discovery in the same block was drilled. The well encountered good quality Jurassic reservoir sands but was dry.

In January 2018, drilling commenced on the Frosk prospect in PL340 in the North Sea, located northwest of the Bøyla field, targeting injectite sands similar of similar geology to the Volund field.

Additionally, acquisition of a large high-specification 3D seismic survey was completed in September 2017 over the Alta, Gohta and Filicudi discoveries and associated prospectivity. Processed seismic data from the survey will be available in 2018.

Licence awards, transactions and relinquishments

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%) and two non-operated in PL896 and PL869 (both with WI 20%).

In November 2017, Lundin Petroleum applied for licences in the 24th licensing round and awards are anticipated to be announced in mid-2018.

During the year, 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. The acquisitions of Shell's 20 percent working interest in PL715 and North E&P's 40 percent working interest in PL805 were completed. In addition, Lundin Petroleum completed a farm-in with Fortis Petroleum for a 10 percent working interest each in PL539 and PL860 on the Mandal High in the Norwegian North Sea. Subsequent to which Lundin Petroleum agreed the acquisition of a package of licences from Fortis Petroleum including a further 10 percent interest in each of PL539 and PL860 and 30 percent working interests in each of PL820S and PL825, subject to government and seller bank approvals. Lundin Petroleum has agreed a licence swap arrangement to acquire Statoil's 20 percent working interest in PL860 which is subject to government approval and upon completion will increase Lundin Petroleum's working interest in PL860 to 40 percent. Lundin Petroleum farmed out its 20 percent working interest in PL685 to Wellesley Petroleum and farmed out a 15 percent interest and transferred operatorship in each of PL758 and PL800 to Capricorn.

During the year, Lundin Petroleum relinquished PL410, PL579, PL625, PL653, PL674BS, PL678, PL694, PL734, PL736S, PL765, PL766, PL778 and PL789. Notices were also provided to relinquish PL700, PL700B, PL715 and PL805 which will become effective in 2018.

In January 2018, the Ministry of Petroleum and Energy announced the licence awards in the 2017 APA licensing round. Lundin Petroleum was awarded a total of 14 licences, of which six as operator in PL934 (WI 40%), PL886B (WI 40%), PL950 (WI 50%), PL952 (WI 60%), PL954 (WI 40%) and PL533B (WI 35%). Eight non-operated licences were awarded in PL904 (WI 20%), PL167C (20%), PL914S (WI 1.385%), PL916 (WI 20%), PL917 (WI 20%), PL919 (WI 15%), PL935 (WI 20%) and PL936 (WI 30%).

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. An appraisal plan has been agreed with the Russian licensing authority, Rosnedra, in order to maintain the licence in good standing while options for the asset are being reviewed. The appraisal plan requires no significant activities for several years.

Discontinued Operations
Non-Norwegian Producing Assets

The discontinued operations are reported on and accounted for until 24 April 2017 when the spin-off to IPC was completed.

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 spun-off to IPC amounted to 3.8 Mboepd and was comprised as follows:

Production in Mboepd	**1 Jan 2017- 31 Dec 2017 12 months**	**1 Oct 2017- 31 Dec 2017 3 months**	1 Jan 2016- 31 Dec 2016 12 months	1 Oct 2016- 31 Dec 2016 3 months
Crude oil				
France	0.8	–	2.6	2.6
Malaysia	2.5	–	8.6	8.3
Total crude oil production	**3.3**	**–**	11.2	10.9
Gas				
Netherlands	0.5	–	1.6	1.4
Indonesia	–	–	0.5	–
Total gas production	**0.5**	**–**	2.1	1.4
Total production	**3.8**	**–**	13.3	12.3
Quantity in Mboe	**1,370.4**	**–**	4,858.2	1,136.8

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

Health, Safety and Environment

For continuing operations, six low potential medical treatment incidents and one low level lost time incident were reported for the year in Norway, resulting in a Lost Time Incident Rate (LTIR) of 0.47 per million hours worked and a Total Recordable Incident Rate (TRIR) of 3.30 per million hours worked.

There were no material environmental incidents.

FINANCIAL REVIEW

Result

The operating profit from continuing operations for the financial year ended 31 December 2017 amounted to MUSD 812.4 (MUSD -244.7). The operating profit for the year was driven by the increased production and higher oil prices compared to last year. Last year was also negatively impacted by an impairment charge of MUSD 506.1 in respect of Russia.

The net result from continuing operations for the year amounted to MUSD 380.9 (MUSD -399.3). The net result from continuing operations in the year was mainly driven by the excellent production performance and a net foreign exchange gain as a result of the weakening US Dollar against the Norwegian Krone and the Euro, partly offset by expensed exploration costs and an impairment charge.

The net result from continuing operations attributable to shareholders of the Parent Company for the year amounted to MUSD 384.7 (MUSD -256.7) or MUSD 431.2 (MUSD -356.7) including discontinued operations representing earnings per share from continuing operations of USD 1.13 (USD -0.79) or USD 1.27 (USD -1.09) including discontinued operations.

Earnings before interest, tax, depletion and amortisation (EBITDA) from continuing operations for the year amounted to MUSD 1,501.5 (MUSD 752.5) representing EBITDA per share of USD 4.41 (USD 2.31). Operating cash flow from continuing operations for the year amounted to MUSD 1,530.0 (MUSD 857.9) representing operating cash flow per share of USD 4.50 (USD 2.63).

Changes in the Group

On 24 April 2017, Lundin Petroleum completed the spin-off of its assets in Malaysia, France and the Netherlands (the IPC assets) into International Petroleum Corporation (IPC) by distributing 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 until the completion of the spin-off and are shown as discontinued operations. For more information see Note 14.

Lundin Petroleum has updated the accounting judgement of the consolidation of the Russian operations and concluded that the investment in Mintley Caspian Ltd., which is the holding company of Lundin Petroleum´s investment in Russia, should be reclassified to a joint venture. The investment in Mintley Caspian Ltd. was therefore deconsolidated at the end of the third quarter. The deconsolidation has no significant impact to the income statement since the investment in Russia was fully impaired in prior years and the carrying value is considered to be close to zero. The deconsolidation has triggered a shift of MUSD 82.0 within total equity between equity attributable to the owners of the parent company and non-controlling interest. The shift within total equity had a negative impact on equity attributable to the owners of the parent company with this change being recorded at the end of the third quarter 2017.

Lundin Petroleum divested a 39 percent working interest in the Brynhild field to CapeOmega with an effective date of 1 January 2017 and a completion date of 30 November 2017. The transaction involved a consideration of MNOK 774, including historical tax and uplift balances. The transaction was accounted for at closing resulting in a net after tax accounting loss of MUSD 14.4 arising from the difference between the consideration received and the book value of the associated assets being divested. The accounting loss is reported as loss from sale of assets as detailed in the following table.

Expressed in MUSD	
Assets	
Oil and gas properties	–
Deferred tax	143.9
Total assets divested	**143.9**
Liabilities	
Site restoration provision	32.0
Working capital	3.8
Total liabilities divested	**35.8**
Net assets divested	**108.1**
Consideration received	93.7
Net after tax accounting loss	**14.4**

Revenue and other income

Revenue and other income for the year amounted to MUSD 1,997.0 (MUSD 950.0) 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 1,958.3 (MUSD 975.9). The average price achieved by Lundin Petroleum for a barrel of oil equivalent from own production amounted to USD 51.63 (USD 42.31) and is detailed in the following table. The average Dated Brent price for the year amounted to USD 54.25 (USD 43.73) per barrel.

Net sales of oil and gas from own production for the year 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 Dec 2017 12 months**	**1 Oct 2017- 31 Dec 2017 3 months**	1 Jan 2016- 31 Dec 2016 12 months	1 Oct 2016- 31 Dec 2016 3 months
Crude oil sales				
Norway				
– Quantity in Mboe	28,106.9	5,364.9	20,654.5	7,036.6
– *Average price per boe*	*53.37*	*62.41*	*43.60*	*49.63*
Gas and NGL sales				
Norway				
– Quantity in Mboe	3,943.1	1,325.0	2,352.1	658.5
– *Average price per boe*	*39.23*	*44.60*	*30.94*	*37.41*
Total sales from continuing operations				
– Quantity in Mboe	**32,050.0**	**6,689.9**	23,006.6	7,695.1
– Average price per boe	***51.63***	***58.87***	*42.31*	*48.58*

The table above excludes crude oil revenue from third party activities.

Net sales of crude oil from third party activities for the year amounted to MUSD 303.5 (MUSD 2.1) and consisted 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 13.8 (cost of MUSD 29.1) in the year due to the timing of the cargo liftings compared to production.

Other revenue amounted to MUSD 24.9 (MUSD 3.2) for the year and included a quality differential compensation on Alvheim blended crude and tariff income of MUSD 21.7 (MUSD 0.3) which is due to net income from Ivar Aasen tariffs paid to Edvard Grieg.

Production costs

Production costs including inventory movements for the year amounted to MUSD 164.2 (MUSD 168.4) 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 Dec 2017 12 months**	**1 Oct 2017- 31 Dec 2017 3 months**	1 Jan 2016- 31 Dec 2016 12 months	1 Oct 2016- 31 Dec 2016 3 months
Cost of operations				
– In MUSD	117.3	32.9	113.1	27.3
– In USD per boe	*3.73*	*4.31*	*5.21*	*4.17*
Tariff and transportation expenses				
– In MUSD	37.9	9.0	33.9	7.0
– In USD per boe	*1.21*	*1.17*	*1.56*	*1.08*
Cash operating costs				
– In MUSD	**155.2**	**41.9**	147.0	34.3
– In USD per boe [1]	***4.94***	***5.48***	*6.77*	*5.25*
Change in inventory position				
– In MUSD	-0.4	-0.1	-0.7	-0.5
– In USD per boe	*-0.02*	*-0.02*	*-0.04*	*-0.08*
Other				
– In MUSD	9.4	1.8	22.1	6.0
– In USD per boe	*0.30*	*0.23*	*1.02*	*0.93*
Production costs from continuing operations				
– In MUSD	**164.2**	**43.6**	168.4	39.8
– In USD per boe	***5.22***	***5.69***	*7.75*	*6.10*

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 cost for the reporting period of USD 4.94 is reduced to USD 4.25 when tariff income is netted off.

The total cost of operations for the year amounted to MUSD 117.3 (MUSD 113.1). The total cost of operations excluding operational projects amounted to MUSD 105.9 (MUSD 103.8).

The cost of operations per barrel amounted to USD 3.73 (USD 5.21) including operational projects and USD 3.37 (USD 4.78) excluding operational projects.

Tariff and transportation expenses for the year amounted to MUSD 37.9 (MUSD 33.9) or USD 1.21 (1.56) per barrel. 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 9.4 (MUSD 22.1) and related to the business interruption insurance and the operating cost share arrangement on the Brynhild field whereby the amount of operating cost varies with the oil price until the end of May 2017. This arrangement was being marked-to-market against the oil price curve.

Depletion and decommissioning costs

Depletion and decommissioning costs amounted to MUSD 567.3 (MUSD 386.2) at an average rate of USD 18.05 (USD 17.80) per barrel and are detailed in Note 3. The higher depletion costs for the year compared to 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 year amounted to MUSD 73.1 (MUSD 101.9) 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 72.0 were expensed and mainly related to the unsuccessful Gohta appraisal well in PL492, the non-commercial gas discovery on the Korpfjell prospect in PL859, and the dry well on the Hufsa prospect in PL533, the dry well on the Volund West prospect in PL150B, the dry well on the Børselv prospect in PL609 and the dry well on the Hurri prospect in PL533 as well as a number of Norwegian exploration licences in the process of relinquishment.

Impairment costs of oil and gas properties

Impairment costs amounted to MUSD 30.6 (MUSD 506.1) and are detailed in Note 3. The impairment costs related to the Brynhild field in PL148. The impairment costs in the comparative period related to Russia.

Loss from sale of assets

Loss from sale of assets for the year amounted to MUSD 14.4 (MUSD —) and related to the after tax result on the divestment of a 39 percent working interest in the Brynhild field.

Other costs of sales

Other costs of sales for the year amounted to MUSD 303.3 (MUSD 2.1) 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 year amounted to MUSD 31.7 (MUSD 30.0) which included a charge of MUSD 4.3 (MUSD 4.6) 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 2.5 (MUSD 3.1).

Finance income

Finance income for the year amounted to MUSD 256.7 (MUSD 2.7) and is detailed in Note 4.

The net foreign currency exchange gain for the year amounted to MUSD 255.3 (MUSD —). 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 1.8 (MUSD 29.1).

The US Dollar weakened against the Euro during the year 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 year, generating a net foreign currency exchange loss on an intercompany loan balance denominated in Norwegian Krone.

Finance costs

Finance costs for the year amounted to MUSD 186.6 (MUSD 221.5) and are detailed in Note 5.

Interest expenses for the year amounted to MUSD 115.0 (MUSD 137.3) and represented the portion of interest charged to the income statement. An additional amount of interest of MUSD 63.5 (MUSD 23.4) 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 higher interest rates. The result on interest rate hedge settlements amounted to a loss of MUSD 17.4 (MUSD 19.5).

The amortisation of the deferred financing fees amounted to MUSD 17.5 (MUSD 38.9) for the year and related to the expensing of the fees incurred in establishing the financing facilities over the period of usage of the facilities. The decrease compared to last year is related to the fact that the current financing facilities were entered into during the second quarter of 2016 following which the unamortised portion of the capitalised financing fees incurred in establishing the previous financing facilities and the short term revolving credit facility were expensed amounting to MUSD 22.3.

Loan facility commitment fees for the year amounted to MUSD 11.1 (MUSD 9.3) 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.

Lundin Petroleum owns 121.5 million shares in ShaMaran Petroleum Corp. (ShaMaran) and this investment was booked at the fair value of the shares at the date of acquisition and under accounting rules, subsequent movements in the fair value of the shares were being recognised in the consolidated statement of comprehensive income. During the year, ShaMaran announced that it had achieved first oil from the Atrush field. As the share price of ShaMaran did not recover in the period since first oil, an impairment charge was recorded representing the cumulative loss recorded in other comprehensive income equal to MUSD 11.2 that was recycled to the income statement.

Share in result of associate company

Share in result of associated company amounted to MUSD 0.4 (MUSD —) and related to the share in the result of the investment in Mintley Caspian Ltd. following the deconsolidation of this investment at the end of the third quarter 2017.

Tax

The overall tax charge for the year amounted to MUSD 501.2 (credit of MUSD 64.2) and is detailed in Note 6.

The current tax charge for the year amounted to a credit of MUSD 0.5 (credit MUSD 78.4) which included a tax credit of MUSD 1.5 (credit MUSD 78.9) relating to the tax refund on Norwegian exploration and appraisal expenditure.

The deferred tax charge for the year amounted to MUSD 501.7 (MUSD 14.2) 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 12.5 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 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 year amounted to MUSD -3.8 (MUSD -142.6) and related to the non-controlling interest's share in Mintley Caspian Ltd., which is the holding company of Lundin Petroleum´s investment in Russia, which was fully consolidated up to the end of the third quarter 2017. Lundin Petroleum has updated the accounting judgement of the consolidation of this investment and concluded that this investment should be reclassified to a joint venture. The investment was therefore deconsolidated at the end of the third quarter 2017.

Discontinued operations

The net result from discontinued operations amounted to MUSD 46.5 (MUSD -100.0) and is detailed in Note 14.

Balance Sheet

Non-current assets

Oil and gas properties amounted to MUSD 4,937.1 (MUSD 4,376.4) 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 2017- 31 Dec 2017 12 months**	**1 Oct 2017- 31 Dec 2017 3 months**	1 Jan 2016- 31 Dec 2016 12 months	1 Oct 2016- 31 Dec 2016 3 months
Norway	950.0	216.0	877.1	257.9
Development expenditures from continuing operations	**950.0**	**216.0**	877.1	257.9

An amount of MUSD 950.0 (MUSD 877.1) of development expenditure was incurred in Norway during the year, primarily on the Johan Sverdrup, Edvard Grieg and Alvheim area. In addition an amount of MUSD 63.5 of interest was capitalised.

Exploration and appraisal expenditure in MUSD	**1 Jan 2017- 31 Dec 2017 12 months**	**1 Oct 2017- 31 Dec 2017 3 months**	1 Jan 2016- 31 Dec 2016 12 months	1 Oct 2016- 31 Dec 2016 3 months
Norway	227.1	54.6	142.1	51.8
Russia	1.1	—	1.4	0.5
Exploration and appraisal expenditure from continuing operations	**228.2**	**54.6**	143.5	52.3

Exploration and appraisal expenditure of MUSD 227.1 (MUSD 142.1) was incurred in Norway during the year, primarily on the Filicudi, Hufsa and Hurri exploration wells in PL533, the Korpfjell exploration well in PL859, the Børselv exploration well in PL609 and the appraisal wells Edvard Grieg Southwest in PL338, Gotha-3 in PL492 and Alta-4 in PL609.

Other tangible fixed assets amounted to MUSD 13.2 (MUSD 166.1) and the decrease compared to the last year is related to the spin-off of the IPC business.

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 6.7 (MUSD 9.4) and are detailed in Note 8. Other shares and participations amounted to MUSD 6.3 (MUSD 8.9) and related to the shares held in ShaMaran which are reported at market value.

Derivative instruments amounted to MUSD 26.5 (MUSD 17.0) and related to the marked-to-market gain on the outstanding interest rate and currency hedge contracts due to be settled after twelve months.

Current assets

Inventories amounted to MUSD 33.7 (MUSD 54.9) and included both well supplies and hydrocarbon inventories. The decrease compared to last year is related to the spin-off of the IPC business.

Trade and other receivables amounted to MUSD 304.4 (MUSD 288.9) and are detailed in Note 9. Trade receivables, which are all current, amounted to MUSD 202.7 (MUSD 193.4) and included invoiced cargoes. Underlift amounted to MUSD 29.4 (MUSD 28.9) and was attributable to an underlift position on the producing fields, mainly from the Alvheim area. Joint operations debtors relating to various joint venture receivables amounted to MUSD 15.6 (MUSD 31.2). Prepaid expenses and accrued income amounted to MUSD 29.3 (MUSD 29.4) and represented mainly prepaid operational and insurance expenditure. Brynhild operating cost share amounted to MUSD — (MUSD 3.0) and related to the marked-to-market valuation of the arrangement where the share of the operating cost varies with the oil price. This arrangement ended during the year. Other current assets amounted to MUSD 27.4 (MUSD 3.0) and included a short term receivable from IPC in relation to certain working capital balances following the IPC spin-off, VAT receivables and other miscellaneous receivable balances.

Derivative instruments amounted to MUSD 7.7 (MUSD 0.8) and related to the marked-to-market gain on the outstanding interest rate and currency hedge contracts due to be settled within twelve months.

Current tax assets amounted to MUSD — (MUSD 77.5) and related to the Norwegian corporate tax refund in respect of 2016 which was received in the fourth quarter of 2017.

Cash and cash equivalents amounted to MUSD 71.4 (MUSD 69.5). Cash balances are held to meet ongoing operational funding requirements.

Non-current liabilities

Financial liabilities amounted to MUSD 3,880.0 (MUSD 4,048.3) and are detailed in Note 10. Bank loans amounted to MUSD 3,955.0 (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 75.0 (MUSD 96.7) and are being amortised over the expected life of the facility.

Provisions amounted to MUSD 420.6 (MUSD 420.0) and are detailed in Note 11. The provision for site restoration amounted to MUSD 414.6 (MUSD 407.1) and related to future decommissioning obligations. The site restoration provision related to Norway amounted to MUSD 414.6 (MUSD 316.1). The increase in Norway mainly reflects the additional liability for Edvard Grieg, the Alvheim area and for the Johan Sverdrup development project partly offset by the 39 percent divestment in Brynhild.

Deferred tax liabilities amounted to MUSD 1,302.2 (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 3.1 (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 — (MUSD 33.8) and related to the full consolidation of Mintley Caspian Ltd. in which the non-controlling interest entity has made funding advances. The subsidiary was deconsolidated at the end of the third quarter, see section Changes in the Group.

Current liabilities

Trade and other payables amounted to MUSD 259.0 (MUSD 308.4) and are detailed in Note 12. Overlift amounted to MUSD 12.8 (MUSD 29.9) and was attributable to an overlift position on the producing fields, mainly from Brynhild and NGL from Edvard Grieg. Joint operations creditors and accrued expenses amounted to MUSD 188.9 (MUSD 238.8) and related to activity in Norway. Other accrued expenses amounted to MUSD 19.5 (MUSD 16.9) and other current liabilities amounted to MUSD 7.7 (MUSD 9.5).

Derivative instruments amounted to MUSD 6.4 (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.

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 46,648.6 (MSEK -103.3) for the year.

The result included MSEK 46,542.9 financial income as a result of an internal restructuring prior to the IPC spin-off. The result excluding this financial income amounts to MSEK 105.7 (MSEK -103.3).

The result included general and administrative expenses of MSEK 146.7 (MSEK 106.6) and net finance income of MSEK 243.1 (MSEK -0.5) when excluding the finance income as a result of the internal restructuring. Net financial income includes MSEK 238.6 (MSEK —) dividend received from a subsidiary.

The financial income as a result of the internal restructuring consists of received dividends from a subsidiary and results on the sale of subsidiary companies offset by the charges in relation to the IPC spin-off. As part of the internal restructuring that was completed on 7 April 2017, Lundin Petroleum AB sold all the shares held in two subsidiary companies and acquired all the shares of a newly incorporated company that holds all the shares in Lundin Norway AS. These transactions increased the shares in subsidiaries of the Company to MSEK 55,118.9.

Pledged assets of MSEK 55,118.9 (MSEK 6,740.3) relate to the carrying value of the pledge of the shares in respect of the financing facility entered into by its wholly-owned subsidiary Lundin Petroleum Holding 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 and the material transactions are described below.

The Group has sold oil and related products to the Statoil group on an arm's-length basis amounting to MUSD 273.1.

As at the date of the IPC spin-off, the Group had a residual receivable for working capital from IPC of MUSD 27.4 which has been reduced to MUSD 23.5. This receivable is reported as current asset as it is due during 2018.

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.

Subsequent Events

There are no subsequent events to report.

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).

During the year Lundin Petroleum purchased 1,233,310 of its own shares at an average price of SEK 186.14 based on the approval granted at the AGM 2017.

The Board of Directors has decided to recommend to the AGM of Lundin Petroleum to be held on 3 May 2018 in Stockholm that an inaugural cash dividend distribution for the year 2017 of SEK 4.00 per share be made, based on the current number of shares, excluding own shares held by the Company. This represents an amount equal to SEK 1,357 million, or approximately USD 175 million, to be paid after the 2018 AGM.

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 2015, 2016 and 2017 under the Unit Bonus Plan outstanding as at 31 December 2017 were 135,902, 224,043 and 288,216 respectively.

Performance Based Incentive Plan

The AGM 2017 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 2017 and the 2017 award is accounted for from the second half of 2017. The total outstanding number of awards at 31 December 2017 was 355,954 and the awards vest over three years from 1 July 2017 subject to certain performance conditions being met. Each original award was fair valued at the date of grant at SEK 100.10 using an option pricing model.

The 2016 plan is effective from 1 July 2016 and the total outstanding number of awards at 31 December 2017 is 406,902 and the awards vest over three years from 1 July 2016 subject to certain performance conditions being met. The outstanding number of awards increased compared to the original number of awards as a result of the dividend distribution of the IPC business as per the plan rules. Each original award was fair valued at the date of grant at SEK 89.30 using an option pricing model. Awards given to employees now employed by IPC following the IPC spin-off have been pro-rated until the spin-off date 24 April 2017.

The 2015 plan is effective from 1 July 2015 and the total outstanding number of awards at 31 December 2017 is 646,503 and the awards vest over three years from 1 July 2015 subject to certain performance conditions being met. The outstanding number of awards increased compared to the original number of awards as a result of the dividend distribution of the IPC business as per the plan rules. Each original award was fair valued at the date of grant at SEK 91.40 using an option pricing model. Awards given to employees now employed by IPC following the IPC spin-off have been pro-rated until the spin-off date 24 April 2017.

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.

Lundin Petroleum has assessed the impact of IFRS9 (with effective date 1 January 2018) on the financial statements of the Group and concluded that this standard has no significant impact on the financial statements.

Lundin Petroleum has assessed the impact of IFRS 15 (with effective date 1 January 2018) on the financial statements of the Group and concluded that this standard will have no impact on the timing when revenue is recognised in the Group, but will have an impact on the consolidated income statement as certain transactions will no longer be reported as revenue but as other revenue instead. This change primarily relates to reporting of change in under- and overlift which is detailed in Note 1.

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

Buy	Sell	Average contractual Exchange rate	Settlement period
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
MNOK 1,000.0	MUSD 130.0	NOK 7.69:USD 1	Jan 2020 – Dec 2020
MNOK 750.0	MUSD 98.3	NOK 7.63:USD 1	Jan 2021 – Dec 2021
MNOK 500.0	MUSD 65.6	NOK 7.62:USD 1	Jan 2022 – Dec 2022

Lundin Petroleum entered into interest rate hedge contracts and at 31 December 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	1.87%	Jan 2018 – Dec 2018
3,000	1.42%	Jan 2019 – Dec 2019
1,750	2.01%	Jan 2020 – Dec 2020
1,000	2.17%	Jan 2021 – Dec 2021
1,000	2.37%	Jan 2022 – Dec 2022

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 Dec 2017		31 Dec 2016	
	Average	Period end	Average	Period end
1 USD equals NOK	8.2712	8.2050	8.4014	8.6200
1 USD equals Euro	0.8855	0.8338	0.9037	0.9487
1 USD equals Rouble	58.3353	57.8604	67.0692	60.9999
1 USD equals SEK	8.5481	8.2080	8.5610	9.0622

Consolidated Income Statement

Expressed in MUSD	Note	1 Jan 2017-31 Dec 2017 12 months	1 Oct 2017-31 Dec 2017 3 months	1 Jan 2016-31 Dec 2016 12 months	1 Oct 2016-31 Dec 2016 3 months
		Continuing operations	Continuing operations	Continuing operations	Continuing operations
Revenue and other income	1	**1,997.0**	**593.7**	950.0	326.2
Cost of sales					
Production costs	2	-164.2	-43.6	-168.4	-39.8
Depletion and decommissioning costs		-567.3	-138.8	-386.2	-116.1
Exploration costs		-73.1	-30.9	-101.9	-44.1
Impairment costs of oil and gas properties		-30.6	–	-506.1	-506.1
Loss from sale of assets[1]		-14.4	-14.4	–	–
Other cost of sales		-303.3	-115.3	-2.1	–
Gross profit/loss	3	**844.1**	**250.7**	-214.7	-379.9
General, administration and depreciation expenses		-31.7	-6.8	-30.0	-10.4
Operating profit/loss		**812.4**	**243.9**	-244.7	-390.3
Net financial items					
Finance income	4	256.7	-68.9	2.7	-247.3
Finance costs	5	-186.6	-52.7	-221.5	-50.8
		70.1	**-121.6**	-218.8	-298.1
Share in result of associated company		-0.4	-0.4	–	–
Profit/loss before tax		**882.1**	**121.9**	-463.5	-688.4
Income tax	6	-501.2	-172.8	64.2	25.7
Net result from continuing operations		**380.9**	**-50.9**	-399.3	-662.7
Discontinued operations					
Net result – IPC	14	46.5	-1.1	-100.0	-76.4
Net result		**427.4**	**-52.0**	-499.3	-739.1
Attributable to:					
Shareholders of the Parent Company		431.2	-52.0	-356.7	-599.9
Non-controlling interest		-3.8	–	-142.6	-139.2
		427.4	**-52.0**	-499.3	-739.1
Earnings per share – USD[2]					
From continuing operations		1.13	-0.15	-0.79	-1.54
From discontinued operations		0.14	0.00	-0.30	-0.22
Earnings per share fully diluted – USD[2]					
From continuing operations		1.13	-0.15	-0.79	-1.53
From discontinued operations		0.14	0.00	-0.30	-0.23

[1]Relates to the after tax result on the divestment of a 39 percent working interest in the Brynhild field.

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

Consolidated Statement of Comprehensive Income

Expressed in MUSD	1 Jan 2017- 31 Dec 2017 12 months	1 Oct 2017- 31 Dec 2017 3 months	1 Jan 2016- 31 Dec 2016 12 months	1 Oct 2016- 31 Dec 2016 3 months
Net result	**427.4**	**-52.0**	-499.3	-739.1
Items that may be subsequently reclassified to profit or loss:				
Exchange differences foreign operations	-96.3	-30.2	13.8	-8.2
Cash flow hedges	76.4	-6.4	64.3	45.2
Available-for-sale financial assets	5.0	6.2	5.3	3.5
Other comprehensive income, net of tax	**-14.9**	**-30.4**	83.4	-49.9
Total comprehensive income	**412.5**	**-82.4**	-415.9	-789.0
Attributable to:				
Shareholders of the Parent Company	416.3	-82.4	-278.2	-650.8
Non-controlling interest	-3.8	–	-137.7	-138.2
	412.5	**-82.4**	-415.9	-789.0

Consolidated Balance Sheet

Expressed in MUSD	Note	31 December 2017	31 December 2016
ASSETS			
Non-current assets			
Oil and gas properties	7	4,937.1	4,376.4
Other tangible fixed assets		13.2	166.1
Goodwill		128.1	128.1
Financial assets	8	6.7	9.4
Deferred tax assets		–	13.5
Derivative instruments	13	26.5	17.0
Total non-current assets		**5,111.6**	4,710.5
Current assets			
Inventories		33.7	54.9
Trade and other receivables	9	304.4	288.9
Derivative instruments	13	7.7	0.8
Current tax assets		–	77.5
Cash and cash equivalents		71.4	69.5
Total current assets		**417.2**	491.6
TOTAL ASSETS		**5,528.8**	5,202.1
EQUITY AND LIABILITIES			
Equity			
Shareholders´ equity		-350.8	-238.6
Non-controlling interest		–	-113.6
Total equity		**-350.8**	-352.2
Liabilities			
Non-current liabilities			
Financial liabilities	10	3,880,0	4,048.3
Provisions	11	420.6	420.0
Deferred tax liabilities		1,302.2	669.3
Derivative instruments	13	3.1	29.8
Other non-current liabilities		–	33.8
Total non-current liabilities		**5,605.9**	5,201.2
Current liabilities			
Trade and other payables	12	259.0	308.4
Derivative instruments	13	6.4	37.6
Current tax liabilities		0.6	0.2
Provisions	11	7.7	6.9
Total current liabilities		**273.7**	353.1
Total liabilities		**5.879.6**	5,554.3
TOTAL EQUITY AND LIABILITIES		**5,528.8**	5,202.1

Consolidated Balance of Cash Flows

Expressed in MUSD	**1 Jan 2017- 31 Dec 2017 12 months**	**1 Oct 2017- 31 Dec 2017 3 months**	1 Jan 2016- 31 Dec 2016 12 months	1 Oct 2016- 31 Dec 2016 3 months
	Continuing operations	Continuing operations	Continuing operations	Continuing operations
Cash flows from operating activities				
Net result	380.9	-50.9	-399.3	-662.7
Adjustments for:				
Exploration costs	73.1	30.9	101.9	44.1
Depletion, depreciation and amortisation	570.9	140.5	391.7	119.2
Impairment of oil and gas properties	30.6	–	506.1	506.1
Current tax	-0.5	0.3	-78.4	-14.4
Deferred tax	501.7	172.5	14.2	-11.3
Impairment of other shares	11.2	11.2	–	–
Long-term incentive plans	12.7	3.2	15.6	6.3
Foreign currency exchange gain	-258.0	69.9	-24.9	255.4
Interest expense	115.0	26.8	137.3	30.5
Capitalised financing fees	17.5	4.4	38.9	4.8
Other	26.4	17.6	12.6	-0.6
Interest received	1.0	0.5	2.3	1.8
Interest paid	-177.3	-46.1	-153.7	-39.2
Income taxes paid / received	82.2	82.6	273.5	274.2
Changes in working capital	-88.1	-124.7	-169.1	-250.7
Total cash flows from operating activities	**1,299.3**	**338.7**	668.7	263.5
Cash flows from investing activities				
Investment in oil and gas properties	-1,178.2	-270.5	-1,020.6	-310.2
Investment in other fixed assets	-1.6	-0.7	-1.1	-0.5
Investment in other shares and participations	-1.3	–	–	–
Decommissioning costs paid	-0.4	-0.3	-1.0	-0.4
Disposal of fixed assets [1]	93.7	93.7	–	–
Other payments	-7.8	-0.3	25.8	-5.2
Total cash flows from investing activities	**-1,095.6**	**-178.1**	-996.9	-316.3
Cash flows from financing activities				
Changes in long-term liabilities	-188.7	-160.0	288.7	40.6
Financing fees paid	–	–	-104.0	-0.1
Cash funded from / to discontinued operations	31.7	–	92.5	28.0
Purchase of own shares	-28.0	-20.2	–	–
Issuance of shares/Sale of treasury shares[2]	–	–	64.1	–
Total cash flows from financing activities	**-185.0**	**-180.2**	341.3	68.5
Change in cash and cash equivalents	18.7	-19.6	13.1	15.7
Cash and cash equivalents at the beginning of the period	56.1	91.0	42.4	48.8
Currency exchange difference in cash and cash equivalents	-3.2	–	0.6	–
Cash and cash equivalent of deconsolidated operations	-0.2	–	–	–
Cash and cash equivalent of discontinued operations	–	–	13.4	5.0
Cash and cash equivalents at the end of the period	**71.4**	**71.4**	69.5	69.5

[1] Cash received on the divestment of a 39 percent working interest in the Brynhild field on closing including settlement of net working capital.
[2] Cash received on the additional sale of newly issued and treasury shares to Statoil ASA.

Consolidated Statement of Changes in Equity

	Attributable to owners of the Parent Company						
Expressed in MUSD	Share capital	Additional paid-in-capital/Other reserves	Retained earnings	Dividends	Total	Non-controlling interest	Total equity
At 1 January 2016	**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 transactions 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**
Comprehensive income							
Net result	–	–	431.2	–	431.2	-3.8	427.4
Other comprehensive income	–	-14.9	–	–	-14.9	–	-14.9
Total comprehensive income	**–**	**-14.9**	**431.2**	**–**	**416.3**	**-3.8**	**412.5**
Transactions with owners							
Change in consolidation	–	–	-82.0	–	-82.0	117.1	35.1
Distributions	–	–	–	-410.0	-410.0	–	-410.0
Purchase of own shares	–	-28.0	–	–	-28.0	–	-28.0
Spin off IPC	–	–	–	–	–	0.3	0.3
Share based payments	–	-13.2	–	–	-13.2	–	-13.2
Value of employee services	–	–	4.7	–	4.7	–	4.7
Total transaction with owners	**–**	**-41.2**	**-77.3**	**-410.0**	**-528.5**	**117.4**	**-411.1**
At 31 December 2017	**0.5**	**492.2**	**-433.5**	**-410.0**	**-350.8**	–	**-350.8**

Note 1 – Revenue and other income MUSD	**1 Jan 2017- 31 Dec 2017 12 months**	**1 Oct 2017- 31 Dec 2017 3 months**	1 Jan 2016- 31 Dec 2016 12 months	1 Oct 2016- 31 Dec 2016 3 months
Crude oil from own production	1,500.2	334.9	901.0	349.2
Crude oil from third party activities	303.5	115.1	2.1	–
Condensate	43.0	21.8	14.3	4.9
Gas	111.6	37.2	58.5	19.8
Net sales of oil and gas from continuing operations	**1,958.3**	**509.0**	975.9	373.9
Change in under/over lift position	13.8	76.6	-29.1	-48.6
Other revenue	24.9	8.1	3.2	0.9
Revenue from continuing operations	**1,997.0**	**593.7**	950.0	326.2

Note 2 – Production costs MUSD	**1 Jan 2017- 31 Dec 2017 12 months**	**1 Oct 2017- 31 Dec 2017 3 months**	1 Jan 2016- 31 Dec 2016 12 months	1 Oct 2016- 31 Dec 2016 3 months
Cost of operations	117.3	32.9	113.1	27.3
Tariff and transportation expenses	37.9	9.0	33.9	7.0
Change in inventory position	-0.4	-0.1	-0.7	-0.5
Other	9.4	1.8	22.1	6.0
Production costs from continuing operations	**164.2**	**43.6**	168.4	39.8

Note 3 – Segment information MUSD	**1 Jan 2017- 31 Dec 2017 12 months**	**1 Oct 2017- 31 Dec 2017 3 months**	1 Jan 2016- 31 Dec 2016 12 months	1 Oct 2016- 31 Dec 2016 3 months
Norway				
Crude oil from own production	1,500.2	334.9	901.0	349.2
Condensate	43.0	21.8	14.3	4.9
Gas	111.6	37.2	58.5	19.8
Net sales of oil and gas	**1,654.8**	**393.9**	973.8	373.9
Change in under/over lift position	13.8	76.6	-29.1	-48.6
Other revenue	24.4	9.2	1.5	0.6
Revenue	**1,693.0**	**479.7**	946.2	325.9
Production costs	-164.2	-43.6	-168.4	-39.8
Depletion and decommissioning costs	-567.3	-138.8	-386.2	-116.1
Exploration costs	-72.0	-30.9	-101.9	-44.1
Impairment costs of oil and gas properties	-30.6	–	–	–
Loss from sale of assets	-14.4	-14.4	–	–
Gross profit/loss	**844.5**	**252.0**	289.7	125.9

Note 3 – Segment information cont. MUSD	**1 Jan 2017- 31 Dec 2017 12 months**	**1 Oct 2017- 31 Dec 2017 3 months**	1 Jan 2016- 31 Dec 2016 12 months	1 Oct 2016- 31 Dec 2016 3 months
Other				
Crude oil from third party activities	303.5	115.1	2.1	–
Net sales of oil and gas	**303.5**	**115.1**	2.1	–
Other revenue	0.5	-1.1	1.7	0.3
Revenue	**304.0**	**114.0**	3.8	0.3
Exploration costs	-1.1	–	–	–
Impairment costs of oil and gas properties	–	–	-506.1	-506.1
Other cost of sales	-303.3	-115.3	-2.1	–
Gross profit/loss	**-0.4**	**-1.3**	-504.4	-505.8
Total from continuing operations				
Crude oil from own production	1,500.2	334.9	901.0	349.2
Crude oil from third party activities	303.5	115.1	2.1	–
Condensate	43.0	21.8	14.3	4.9
Gas	111.6	37.2	58.5	19.8
Net sales of oil and gas	**1,958.3**	**509.0**	975.9	373.9
Change in under/over lift position	13.8	76.6	-29.1	-48.6
Other revenue	24.9	8.1	3.2	0.9
Revenue	**1,997.0**	**593.7**	950.0	326.2
Production costs	-164.2	-43.6	-168.4	-39.8
Depletion and decommissioning costs	-567.3	-138.8	-386.2	-116.1
Exploration costs	-73.1	-30.9	-101.9	-44.1
Impairment costs of oil and gas properties	-30.6	–	-506.1	-506.1
Loss from sale of assets	-14.4	-14.4	–	–
Other cost of sales	-303.3	-115.3	-2.1	–
Gross profit/loss from continuing operations	**844.1**	**250.7**	-214.7	-379.9

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 Dec 2017 12 months**	**1 Oct 2017- 31 Dec 2017 3 months**	1 Jan 2016- 31 Dec 2016 12 months	1 Oct 2016- 31 Dec 2016 3 months
Foreign currency exchange gain, net	255.3	-69.6	–	-249.3
Interest income	1.0	0.6	2.3	1.8
Guarantee fees	0.4	0.1	0.4	0.2
Total finance income from continuing operations	**256.7**	**-68.9**	2.7	-247.3

Note 5 – Finance costs MUSD	**1 Jan 2017- 31 Dec 2017 12 months**	**1 Oct 2017- 31 Dec 2017 3 months**	1 Jan 2016- 31 Dec 2016 12 months	1 Oct 2016- 31 Dec 2016 3 months
Interest expense	115.0	26.8	137.3	30.5
Foreign currency exchange loss, net	–	–	4.2	4.2
Result on interest rate hedge settlement	17.4	3.0	19.5	4.7
Unwinding of site restoration discount	13.7	4.5	11.6	3.7
Amortisation of deferred financing fees	17.5	4.4	38.9	4.8
Loan facility commitment fees	11.1	3.0	9.3	2.9
Impairment of other shares	11.2	11.2	–	–
Other	0.7	-0.2	0.7	–
Finance costs from continuing operations	**186.6**	**52.7**	221.5	50.8

Note 6 – Income tax MUSD	**1 Jan 2017- 31 Dec 2017 12 months**	**1 Oct 2017- 31 Dec 2017 3 months**	1 Jan 2016- 31 Dec 2016 12 months	1 Oct 2016- 31 Dec 2016 3 months
Current tax	-0.5	0.3	-78.4	-14.4
Deferred tax	501.7	172.5	14.2	-11.3
Total income tax from continuing operations	**501.2**	**172.8**	-64.2	-25.7

Note 7 – Oil and gas properties MUSD	**31 Dec 2017**	31 Dec 2016
Norway	4,937.1	4,055.7
Malaysia	–	130.6
France	–	171.0
Netherlands	–	19.1
	4,937.1	4,376.4

Note 8 – Financial assets MUSD	**31 Dec 2017**	31 Dec 2016
Other shares and participations	6.3	8.9
Other	0.4	0.5
	6.7	9.4

Note 9 – Trade and other receivables MUSD	**31 Dec 2017**	31 Dec 2016
Trade receivables	202.7	193.4
Underlift	29.4	28.9
Joint operations debtors	15.6	31.2
Prepaid expenses and accrued income	29.3	29.4
Brynhild operating cost share	–	3.0
Other	27.4	3.0
	304.4	288.9

Note 10 – Financial liabilities

MUSD	**31 Dec 2017**	31 Dec 2016
Non-current:		
Bank loans	3,955.0	4,145.0
Capitalised financing fees	-75.0	-96.7
	3,880.0	4,048.3

Note 11 – Provisions

MUSD	**31 Dec 2017**	31 Dec 2016
Non-current:		
Site restoration	414.6	407.1
Long-term incentive plans	2.8	3.2
Farm-in payment	–	5.5
Other	3.2	4.2
	420.6	420.0
Current:		
Long-term incentive plans	7.7	6.9
	7.7	6.9
	428.3	426.9

Note 12 – Trade and other payables

MUSD	**31 Dec 2017**	31 Dec 2016
Trade payables	30.1	13.3
Overlift	12.8	29.9
Joint operations creditors and accrued expenses	188.9	238.8
Other accrued expenses	19.5	16.9
Other	7.7	9.5
	259.0	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 December 2017 MUSD	Level 1	Level 2	Level 3
Assets			
Other shares and participations	6.3	–	–
Derivative instruments – non-current	–	26.5	–
Derivative instruments – current	–	7.7	–
	6.3	**34.2**	**–**
Liabilities			
Derivative instruments – non-current	–	3.1	–
Derivative instruments – current	–	6.4	–
	–	**9.5**	**–**

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 24 April 2017, Lundin Petroleum completed the spin-off of its assets in Malaysia, France and the Netherlands (the IPC assets) into a newly formed company called International Petroleum Corporation (IPC) by distributing 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 until spin-off date and are shown as discontinued operations.

The financial performance for the discontinued operations until spin-off date is as follows:

Expressed in MUSD	**1 Jan 2017- 31 Dec 2017 12 months**	**1 Oct 2017- 31 Dec 2017 3 months**	1 Jan 2016- 31 Dec 2016 12 months	1 Oct 2016- 31 Dec 2016 3 months
Revenue	**69.1**	**–**	209.9	59.7
Cost of sales				
Production costs	-17.4	–	-59.1	-18.5
Depletion and decommissioning costs	-19.1	–	-85.2	-20.4
Depletion of other assets	-10.4	–	-31.1	-7.7
Exploration costs	0.1	–	-14.2	-1.7
Impairment costs of oil and gas properties	–	–	-126.0	-126.0
Gross profit/loss	**22.3**	**–**	-105.7	-114.6
Sale of assets	–	–	-3.5	–
General, administration and depreciation expenses	-2.3	-1.3	-1.9	-0.2
Operating profit/loss	**20.0**	**-1.3**	-111.1	-114.8
Net financial items				
Finance income	–	–	23.9	23.9
Finance costs	-24.1	–	-7.9	17.1
	-24.1	**–**	16.0	41.0
Profit/loss before tax	**-4.1**	**-1.3**	-95.1	-73.8
Income tax	-1.2	–	-4.9	-2.6
	-5.3	**-1.3**	-100.0	-76.4
Gain on distribution of assets	51.8	0.2	–	–
Net result from discontinued operations	**46.5**	**-1.1**	-100.0	-76.4

Parent Company Income Statement

Expressed in MSEK	**1 Jan 2017-31 Dec 2017 12 months**	**1 Oct 2017-31 Dec 2017 3 months**	1 Jan 2016-31 Dec 2016 12 months	1 Oct 2016-31 Dec 2016 3 months
Revenue	9.4	2.4	3.8	0.9
General and administration expenses	-146.7	-50.2	-106.6	-49.4
Operating profit/loss	**-137.3**	-47.8	-102.8	-48.5
Net financial items				
Finance income	46,786.4	242.5	3.5	0.8
Finance costs	-0.5	–	-4.0	0.2
	46,785.9	242.5	-0.5	1.0
Profit/loss before tax	**46,648.6**	194.7	-103.3	-47.5
Income tax	–	–	–	–
Net result	**46,648.6**	194.7	-103.3	-47.5

Parent Company Comprehensive Income Statement

Expressed in MSEK	**1 Jan 2017-31 Dec 2017 12 months**	**1 Oct 2017-31 Dec 2017 3 months**	1 Jan 2016-31 Dec 2016 12 months	1 Oct 2016-31 Dec 2016 3 months
Net result	**46,648.6**	**194.7**	-103.3	-47.5
Other comprehensive income	–	–	–	–
Total comprehensive income	**46,648.6**	**194.7**	-103.3	-47.5
Attributable to:				
Shareholders of the Parent Company	46,648.6	194.7	-103.3	-47.5
	46,648.6	**194.7**	-103.3	-47.5

Parent Company Balance Sheet

Expressed in MSEK	**31 December 2017**	31 December 2016
ASSETS		
Non-current assets		
Shares in subsidiaries	55,118.9	12,256.6
Total non-current assets	**55,118.9**	12,256.6
Current assets		
Receivables	7.5	20.7
Cash and cash equivalents	4.8	3.2
Total current assets	**12.3**	23.9
TOTAL ASSETS	**55,131.2**	12,280.5
SHAREHOLDERS´EQUITY AND LIABILITIES		
Shareholders´ equity including net result for the period	54,936.6	12,212.9
Non-current liabilities		
Provisions	0.6	0.6
Payables to group companies	–	49.4
Total non-current liabilities	**0.6**	50.0
Current liabilities		
Current liabilities	194.0	17.6
Total current liabilities	**194.0**	17.6
Total liabilities	**194.6**	67.6
TOTAL EQUITY AND LIABILITIES	**55,131.2**	12,280.5

Parent Company Cash Flow Statement

Expressed in MSEK	**1 Jan 2017- 31 Dec 2017 12 months**	**1 Oct 2017- 31 Dec 2017 3 months**	1 Jan 2016- 31 Dec 2016 12 months	1 Oct 2016- 31 Dec 2016 3 months
Cash flow from operations				
Net result	46,648.6	194.7	-103.3	-47.5
Adjustment for non-cash related items	-46,608.2	-0.6	24.6	9.1
Changes in working capital	189.2	-78.2	7.4	6.5
Total cash flow from operations	**229.6**	**115.9**	-71.3	-31.9
Cash flow from financing				
Change in long-term receivables	—	—	—	-10.6
Change in long-term liabilities	—	—	-467.5	41.2
Purchase of own shares	-229.6	-166.0	—	—
Proceeds from share issues /treasury shares	—	—	544.1	—
Total cash flow from financing	-229.6	-166.0	76.6	30.6
Change in cash and cash equivalents	—	-50.1	5.3	-1.3
Cash and cash equivalents at the beginning of the period	3.2	54.2	0.4	4.5
Currency exchange difference in cash and cash equivalents	1.6	0.7	-2.5	—
Cash and cash equivalents at the end of the period	**4.8**	**4.8**	3.2	3.2

Parent Company Statement of Changes in Equity

Expressed in MSEK	Restricted equity: Share capital	Restricted equity: Statutory reserve	Unrestricted equity: Other reserves	Unrestricted equity: Retained earnings	Unrestricted equity: Dividends	Unrestricted equity: 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	**–**	**–**	**–**	**-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**
Total comprehensive income	**–**	**–**	**–**	**46,648.6**	**–**	**46,648.6**	**46,648.6**
Transactions with owners							
Purchase of own shares	–	–	-229.6	–	–	-229.6	-229.6
Distributions	–	–	–	–	-3,695.3	-3,695.3	-3,695.3
Total transactions with owners	**–**	**–**	**-229.6**	**–**	**-3,695.3**	**-3,924.9**	**-3,924.9**
Balance at 31 December 2017	**3.5**	**861.3**	**6,599.2**	**51,167.9**	**-3,695.3**	**54,071.8**	**54,936.6**

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 Dec 2017 12 months**	**1 Oct 2017- 31 Dec 2017 3 months**	1 Jan 2016- 31 Dec 2016 12 months	1 Oct 2016- 31 Dec 2016 3 months
Revenue	1,997.0	593.7	950.0	326.2
EBITDA[1]	1,501.5	429.8	752.5	276.7
Net result	380.9	-50.9	-399.3	-662.7
Operating cash flow [1]	1,530.0	434.5	857.9	300.9
Data per share from continuing operations USD				
Shareholders' equity per share	-1.03	-1.03	-0.70	-0.70
Operating cash flow per share	4.50	1.28	2.63	0.88
Cash flow from operations per share	3.82	0.99	2.05	0.77
Earnings per share	1.13	-0.15	-0.79	-1.54
Earnings per share fully diluted	1.13	-0.15	-0.79	-1.53
EBITDA per share	4.41	1.26	2.31	0.81
EBITDA per share — fully diluted	4.40	1.26	2.30	0.81
Number of shares issued at period end	340,386,445	340,386,445	340,386,445	340,386,445
Number of shares in circulation at period end	339,153,135	339,153,135	340,386,445	340,386,445
Weighted average number of shares for the period	340,237,772	339,815,228	325,808,486	340,386,445
Weighted average number of shares for the period fully diluted	341,380,316	340,616,757	326,738,233	341,316,192
Share price SEK				
Share price at period end	187.80	187.80	198.10	198.10
Key ratios from continuing operations				
Return on equity (%) [2]	–	–	–	–
Return on capital employed (%)	22	6	-9	-11
Net debt/equity ratio (%) [2]	–	–	–	–
Equity ratio (%)	-6	-6	-17	-17
Share of risk capital (%)	17	17	-3	-3
Interest coverage ratio	6	7	-2	-2
Operating cash flow/interest ratio	12	15	5	9
Yield	5	n/a	n/a	n/a

[1] Excludes the reported after tax accounting loss of MUSD 14.4 on the divestment of a 39 percent working interest in the Brynhild field.

[2] As the equity at 31 December 2017 and 31 December 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.

Board Assurance

The Board of Directors and the President and CEO certify that the financial report for the twelve months ended 31 December 2017 gives a fair view of the performance of the business, position and profit or loss of the Company and the Group, and describes the principal risks and uncertainties that the Company and the companies in the Group face.

Stockholm, 1 February 2018

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

Financial Information

The Company will publish the following reports:

- The three month report (January — March 2018) will be published on 2 May 2018.
- The six month report (January — June 2018) will be published on 31 July 2018.
- The nine month report (January — September 2018) will be published on 7 November 2018.

The AGM will be held on 3 May 2018 in Stockholm, Sweden.

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Definitions and Abbreviations

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

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 07.30 CET on 1 February 2018.

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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