Lundin Petroleum

Q3

Report for the
NINE MONTHS
ended 30 September 2017

Lundin Petroleum AB (publ)

company registration number 556610-8055

Highlights

Lundin Petroleum delivers strong results for the first nine months 2017. High production levels at continuing low cash operating costs and a higher realised oil price resulted in a significant increase in revenue, EBITDA and operating cash flow compared to the same period in 2016.

Third quarter highlights

- Record quarter EBITDA and operating cash flow driven by high production, low costs and an increased oil price.
- Quarter production above guidance with full year production expected at or above the higher end of the 80–85 Mboepd guidance range.
- Continued low cash operating costs, forecast to be below the full year guidance of USD 4.60 per barrel.
- Positive update for the Johan Sverdrup project with 60 percent of Phase 1 complete and further cost reductions.
- 2017 full year development expenditure guidance reduced from MUSD 1,085 to MUSD 980.

Financial summary

Continuing operations	**1 Jan 2017– 30 Sep 2017 9 months**	**1 Jul 2017– 30 Sep 2017 3 months**	1 Jan 2016– 30 Sep 2016 9 months	1 Jul 2016– 30 Sep 2016 3 months	1 Jan 2016– 31 Dec 2016 12 months
Production in Mboepd	**87.1**	**89.2**	55.3	67.5	59.3
Revenue in MUSD	**1,403.3**	**517.2**	623.8	269.0	950.0
EBITDA in MUSD	**1,071.7**	**382.4**	475.8	215.3	752.5
Operating cash flow in MUSD	**1,095.5**	**389.6**	557.0	243.0	857.9
Net result in MUSD	**431.8**	**227.0**	263.4	169.8	-399.3
Earnings/share in USD[1]	**1.28**	**0.67**	0.83	0.52	-0.79
Earnings/share fully diluted in USD[1]	**1.28**	**0.67**	0.82	0.51	-0.79
Net debt	**4,024.0**	**4,024.0**	4,307.1	4,307.1	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:

"Lundin Petroleum has delivered another great quarter with record operating cash flow and EBITDA, driven by continued strong production performance from our core assets. With these excellent results we are firmly on track to meet or exceed the higher end of the full year production guidance and our total cash operating cost is forecast to be below the full year guidance of USD 4.60 per barrel.

The Johan Sverdrup development continues to improve both in terms of project completion and further cost reductions. Phase 1 is now 60 percent complete with over 40 million man-hours worked to date. Costs are about 25 percent lower for Phase 1 and 50 percent lower for Phase 2 compared to PDO submission and I believe we will see further savings as the project progresses.

We remain optimistic about the significant exploration potential in the southern Barents Sea, despite recent disappointing results. This is a new frontier area where more exploration is needed to understand and unlock its full potential. We are drilling two further exploration wells on the Filicudi trend before the end of this year (Hufsa and Hurri) and we will soon announce our 2018 drilling programme, targeting more prospects in the southern Barents Sea, the Utsira High and the Mandal High.

Oil prices strengthened in the third quarter on the back of healthy demand growth, decreasing oil inventories and the prospect of an extended OPEC quota. I believe we will see further upward pressure on the oil price as the supply market tightens following the significant under investments in our industry in the last few years. Lundin Petroleum has never been better positioned to benefit from the current oil market recovery with production due to double by late 2022 and with record low cash operating costs below USD 5 per barrel for the next decade. With a strong focus on cost discipline, operating efficiency and high HSE standards, Lundin Petroleum will continue to pursue an exciting organic growth strategy."

Lundin Petroleum is one of Europe's leading independent oil and gas exploration and production companies with operations focused on Norway and listed on NASDAQ Stockholm (ticker "LUPE"). Read more about Lundin Petroleum's business and operations at www.lundin-petroleum.com

For definitions and abbreviations, see page 35.

Financial Report for the Nine Months Ended 30 September 2017

OPERATIONAL REVIEW

Lundin Petroleum is an independent oil and gas exploration and production company with operations focused on Norway. The spin-off of Lundin Petroleum's non-Norwegian producing assets into 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 nine month period ending 30 September 2017 (reporting period) unless otherwise specified.

Continuing Operations
Norway

Reserves and Resources
Lundin Petroleum has 714.1 million barrels of oil equivalent (MMboe) of proved plus probable net reserves as at 31 December 2016 as certified by an independent third party. Lundin Petroleum also has discovered oil and gas resources which classify as contingent resources and are not yet classified as reserves. The best estimate contingent resources net to Lundin Petroleum amounted to 249 MMboe as at 31 December 2016.

Production
Production amounted to 87.1 thousand barrels of oil equivalent per day (Mboepd) (compared to 55.3 Mboepd for the same period in 2016), which was 2 percent above the mid-point of the production guidance for the reporting period and just below the top of the production guidance range for the reporting period. This performance is due to strong facilities and reservoir performance at both the Edvard Grieg field and the Alvheim area. Lundin Petroleum's latest production guidance for the full year 2017 of between 80 and 85 Mboepd assumes that the Ivar Aasen field will fully utilise the contractual allocation of the increased capacity on the Edvard Grieg facilities, including a contractual step-up in capacity allocation rights from the fourth quarter 2017. Based on the strong reservoir and operating performance, Lundin Petroleum's full year 2017 production is expected to be at or above the higher end of the guidance range.

Total cash operating cost, including netting off tariff income, was USD 4.15 per barrel and is forecast to be below the revised full year 2017 guidance of USD 4.60 per barrel that was updated with the second quarter results.

The full year 2017 development expenditure guidance is reduced from MUSD 1,085 to MUSD 980 mainly to reflect the cost reduction achieved on the Johan Sverdrup project during 2017.

The production was comprised as follows:

Production in Mboepd	**1 Jan 2017– 30 Sep 2017 9 months**	**1 Jul 2017– 30 Sep 2017 3 months**	1 Jan 2016 – 30 Sep 2016 9 months	1 Jul 2016 – 30 Sep 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Norway					
Crude oil	78.6	80.3	49.6	60.6	53.2
Gas	8.5	8.9	5.7	6.9	6.1
Total production	**87.1**	**89.2**	55.3	67.5	59.3
Quantity in Mboe	**23,780.7**	**8,205.7**	15,161.3	6,199.8	21,701.4

Production in Mboepd	WI [1]	**1 Jan 2017– 30 Sep 2017 9 months**	**1 Jul 2017– 30 Sep 2017 3 months**	1 Jan 2016 – 30 Sep 2016 9 months	1 Jul 2016 – 30 Sep 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Edvard Grieg	65%[2]	68.0	69.5	38.6	51.0	42.0
Ivar Aasen	1.385%	0.6	0.6	–	–	0.0
Alvheim	15%	13.3	10.9	9.1	9.4	10.0
Volund	35%	2.3	6.6	3.0	2.3	2.7
Bøyla	15%	1.1	1.0	1.8	1.5	1.7
Brynhild	90%[3]	1.6	0.4	2.6	3.0	2.6
Gaupe	40%	0.2	0.1	0.2	0.3	0.3
		87.1	**89.2**	55.3	67.5	59.3

[1] Lundin Petroleum's working interest (WI)
[2] WI 50% up to 30 June 2016
[3] WI will be reduced to 51%.

Net production from the Edvard Grieg field was higher than forecast at 68.0 Mboepd due to increased facilities capacity, good production efficiency and strong reservoir performance. Three Edvard Grieg production wells were successfully drilled and came on stream at planned production rates. In addition the third water injection well has been completed with results in line with expectations. The production capacity from the seven production wells drilled so far exceeds expectations and the reservoir depletion rate continues to be more favourable than anticipated.

The total operating cost for the Edvard Grieg field was USD 4.68 per barrel and is forecast to be USD 4.85 per barrel for the year. Cash operating cost, including netting off tariff income, was USD 3.87 per barrel and is forecast to be USD 4.15 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 confirm a preliminary gross resource upside for this part of the Edvard Grieg field in the range of 10 to 30 MMboe. There is potential resource upside in other areas of the field and the final implication for the total reserves for the Edvard Grieg field will be quantified in the 2017 year end reserves update. The development drilling plan within the Plan for Development and Operation (PDO) has been optimised within the same number of planned wells with one production well and one water injection well now being planned to access the southwest area of the field.

The fourth Edvard Grieg water injection well which is targeting the southwest area of the field is currently drilling and will take until the end of 2017 to complete. To date, ten out of a total of 14 development wells have been completed with drilling operations planned to continue to mid-2018. Due to the strong reservoir performance infill drilling opportunities are being assessed with the potential to expand the 2018 drilling programme.

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. The Edvard Grieg production efficiency was 92 percent, which is slightly below expectations, impacted in the third quarter by short planned shutdowns of both the SAGE gas export system and the Sture oil terminal, as well as a number of unplanned power outages. Production efficiency has exceeded this level for periods and so there is a fair expectation of increased production efficiency going forward.

Capacity testing of the Edvard Grieg facilities has 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 of facilities capacity between the Edvard Grieg and Ivar Aasen fields changes through time, the details of which are reflected in Lundin Petroleum's quarterly production guidance for 2017.

Net production from the Ivar Aasen field was in line with forecast at 0.6 Mboepd. Water injection commenced during the second quarter and the PDO drilling programme was completed during the third quarter of 2017.

Production 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 3.45 per barrel and is forecast to be USD 4.08 per barrel for the year.

Net production from the Alvheim field was ahead of forecast at 13.3 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 significantly ahead of expectations. Drilling of two infill wells on the Boa area of the field is ongoing, with production start-up of both wells expected in 2018.

Net production from the Volund field was ahead of forecast at 2.3 Mboepd. Two new Volund infill wells have been completed with the wells coming on stream ahead of schedule, the first in July 2017 and the second in August 2017, with production from both wells exceeding expectations.

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

Net production from the Brynhild field was lower than forecast at 1.6 Mboepd. The field has been shut-in for the last three months due to a flow restriction that has developed in the pipeline between the Brynhild subsea wells and the Haewene Brim FPSO. Brynhild production cannot resume until the pipeline restriction has been cleared and specialist equipment has been secured to conduct this operation in November 2017. During the reporting period the Brynhild field achieved an uptime of 42 percent, significantly impacted by the pipeline shut-in. 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 have been agreed with Shell, which will reduce 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 will retain operatorship and following the transaction will have a 51 percent working interest in the Brynhild field. The effective date of the transaction is 1 January 2017. Lundin Petroleum's lenders have consented to the transaction and government approval has been received, with completion now expected at the end of November 2017.

Despite no remaining reserves being attributed to the Gaupe field, the field is producing intermittently subject to favourable economic conditions and net production 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 60 percent completed at the end of the reporting period. Construction on all elements of Phase 1 of the project are underway with project manning at peak levels with over 40 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 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 yard on the west coast of 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 ten water injection wells is well advanced with nine wells completed with results in line with expectations. Drilling progress continues to be significantly ahead of schedule.

At the time of submitting the Phase 1 PDO in February 2015, the capital expenditure for Phase 1 was estimated at gross NOK 123 billion (nominal). Due to improvements in project execution and delivery the latest cost estimate, as released by Statoil in September 2017, has been further reduced by NOK 5 billion to 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 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 to proceed with concept selection (DG2) for Phase 2 of the project. This will involve the installation of an additional processing platform bridge linked to the Phase 1 field centre and additional facilities to allow the tie-in of 28 additional wells to access the Avaldsnes, Kvitsøy and Geitungen satellite areas of the field. These additional facilities will take the full field gross plateau level to 660 Mbopd. Phase 2 costs are estimated at NOK 40 to 55 billion (nominal) and represent approximately 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. The PDO for Phase 2 is scheduled for the second half of 2018 and Phase 2 is scheduled to come on-stream in 2022.

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

The full field development costs (Phase 1 and Phase 2) are revised down from the original PDO total of NOK 207 billion to between NOK 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 will be reduced as a consequence of this well with the resource estimate being updated at 2017 year end. Gohta is considered a satellite opportunity to the larger adjacent Alta discovery and this result has no impact on the appraisal and conceptual development plans for Alta.

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. A possible extended well test at Alta is being planned for 2018.

Lundin Petroleum has a rig contract with Ocean Rig for the charter of the Leiv Eiriksson semi-submersible rig for a flexible term with multiple well option slots that can be called at Lundin Petroleum's election. This rig is currently planned to carry out all of Lundin Petroleum's operated wells in the southern Barents Sea for the 2017/2018 drilling campaign.

Lundin Petroleum has secured 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, and with further opportunities being considered as part of the 2018 budget process. Both Luno II and Rolvsnes are possible subsea tie-back development opportunities to the Edvard Grieg facilities. Drilling operations are scheduled to commence in the first quarter of 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	
PL533	7219/12-3	End of 2017	Hurri	35%	Lundin Norway	
Alvheim Area						
PL150B	24/9-11S	June 2017	Volund West	35%	Aker BP	Dry

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. The discovery is estimated to contain between 35 and 100 MMboe of gross resources.

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 expected to take place 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.

Significant additional prospectivity is mapped along trend with the Filicudi discovery in PL533 in the southern Barents Sea. The follow-on Hufsa prospect commenced drilling in October 2017 with results anticipated before the end of 2017. Following completion of drilling the Hufsa prospect, the Hurri prospect will be drilled with results expected during the first quarter of 2018. These two wells are targeting net unrisked prospective resources of 175 MMboe.

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 the first half of 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 in Norway. Lundin Petroleum was awarded four licences, of which two as operator in PL902 (WI 50%) and PL886 (WI 40%) and two non-operated in PL896 and PL869 (both with WI 20%).

In September 2017, Lundin Petroleum applied for licences in the 2017 APA licensing round and awards are anticipated to be announced in early 2018.

During the reporting period, a licence exchange was completed with Engie to swap 10 percent of Lundin Petroleum's working interest in PL778 for Engie's 20 percent working interest in both PL715 and PL722. 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. 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. The transaction to Capricorn is subject to government approval.

During the reporting period, Lundin Petroleum relinquished PL410, PL579, PL625, PL653, PL674BS, PL678, PL694, PL734, PL736S, PL765, PL766 and PL789.

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 5.0 Mboepd and was comprised as follows:

Production in Mboepd	**1 Jan 2017– 30 Sep 2017 9 months**	**1 Jul 2017– 30 Sep 2017 3 months**	1 Jan 2016 – 30 Sep 2016 9 months	1 Jul 2016 – 30 Sep 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Crude oil					
France	1.1	–	2.6	2.5	2.6
Malaysia	3.3	–	8.7	8.9	8.6
Total crude oil production	**4.4**	**–**	11.3	11.4	11.2
Gas					
Netherlands	0.6	–	1.6	1.5	1.6
Indonesia	–	–	0.7	–	0.5
Total gas production	**0.6**	**–**	2.3	1.5	2.1
Total production	**5.0**	**–**	13.6	12.9	13.3
Quantity in Mboe	**1,370.4**	**–**	3,721.4	1,194.7	4,858.2

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, the Lost Time Incident Rate (LTIR) was 0.00 per million hours worked. Five low potential medical treatment incidents were reported in Norway, resulting in a Total Recordable Incident Rate (TRIR) of 3.13 per million hours worked.

There were no material environmental incidents.

FINANCIAL REVIEW

Result

The operating profit from continuing operations for the reporting period amounted to MUSD 568.5 (MUSD 145.6). The operating profit for the reporting period was driven by the increased production and higher oil prices compared to last year.

The net result from continuing operations for the reporting period amounted to MUSD 431.8 (MUSD 263.4). The net result from continuing operations in the reporting period 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 reporting period amounted to MUSD 435.6 (MUSD 266.8) or MUSD 483.2 (MUSD 243.2) including discontinued operations representing earnings per share from continuing operations of USD 1.28 (USD 0.83) or USD 1.42 (USD 0.76) including discontinued operations.

Earnings before interest, tax, depletion and amortisation (EBITDA) from continuing operations for the reporting period amounted to MUSD 1,071.7 (MUSD 475.8) representing EBITDA per share of USD 3.15 (USD 1.48). Operating cash flow from continuing operations for the reporting period amounted to MUSD 1,095.5 (MUSD 557.0) representing operating cash flow per share of USD 3.22 (USD 1.74).

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 reporting period.

Revenue

Revenue for the reporting period amounted to MUSD 1,403.3 (MUSD 623.8) and was comprised of net sales of oil and gas, change in under/over lift position and other revenue as detailed in Note 1.

Net sales of oil and gas for the reporting period amounted to MUSD 1,449.3 (MUSD 602.0). The average price achieved by Lundin Petroleum for a barrel of oil equivalent from own production amounted to USD 49.72 (USD 39.17) and is detailed in the following table. The average Dated Brent price for the reporting period amounted to USD 51.89 (USD 41.88) per barrel.

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

Sales from own production Average price per boe expressed in USD	**1 Jan 2017– 30 Sep 2017 9 months**	**1 Jul 2017– 30 Sep 2017 3 months**	1 Jan 2016 – 30 Sep 2016 9 months	1 Jul 2016 – 30 Sep 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Crude oil sales					
Norway					
– Quantity in Mboe	22,742.0	8,567.5	13,617.9	5,216.7	20,654.5
– *Average price per boe*	*51.24*	*52.82*	*40.51*	*44.29*	*43.60*
Gas and NGL sales					
Norway					
– Quantity in Mboe	2,618.1	809.8	1,693.6	653.0	2,352.1
– *Average price per boe*	*36.51*	*37.68*	*28.43*	*26.36*	*30.94*
Total sales from continuing operations					
– Quantity in Mboe	**25,360.1**	**9,377.3**	15,311.5	5,869.7	23,006.6
– Average price per boe	***49.72***	***51.57***	*39.17*	*42.30*	*42.31*

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

Net sales of crude oil from third party activities for the reporting period amounted to MUSD 188.4 (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 a cost of MUSD 62.8 (income of MUSD 19.5) in the reporting period due to the timing of the cargo liftings compared to production.

Other revenue amounted to MUSD 16.8 (MUSD 2.3) for the reporting period and included a quality differential compensation on Alvheim blended crude and tariff income of MUSD 14.5 (MUSD —) which is due to net income from Ivar Aasen tariffs paid to Edvard Grieg.

Production costs

Production costs including inventory movements for the reporting period amounted to MUSD 120.6 (MUSD 128.6) and are detailed in Note 2. The total production cost per barrel of oil equivalent produced is detailed in the table below:

Production costs from continuing operations	**1 Jan 2017– 30 Sep 2017 9 months**	**1 Jul 2017– 30 Sep 2017 3 months**	1 Jan 2016— 30 Sep 2016 9 months	1 Jul 2016— 30 Sep 2016 3 months	1 Jan 2016— 31 Dec 2016 12 months
Cost of operations					
— In MUSD	84.4	29.1	85.8	30.5	113.1
– In USD per boe	*3.55*	*3.54*	*5.66*	*4.93*	*5.21*
Tariff and transportation expenses					
— In MUSD	28.9	11.5	26.9	10.7	33.9
– In USD per boe	*1.22*	*1.40*	*1.77*	*1.72*	*1.56*
Cash operating costs					
– In MUSD	**113.3**	**40.6**	112.7	41.2	147.0
***– In USD per boe* [1]**	***4.77***	***4.94***	*7.43*	*6.65*	*6.77*
Change in inventory position					
— In MUSD	-0.3	0.2	-0.2	0.2	-0.7
– In USD per boe	*-0.01*	*0.02*	*-0.02*	*0.02*	*-0.04*
Other					
— In MUSD	7.6	1.8	16.1	4.9	22.1
– In USD per boe	*0.32*	*0.22*	*1.06*	*0.78*	*1.02*
Production costs from continuing operations					
– In MUSD	**120.6**	**42.6**	128.6	46.3	168.4
– In USD per boe	***5.08***	***5.18***	*8.47*	*7.45*	*7.75*

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

[1] The numbers in this table are excluding tariff income netting. Lundin Petroleum's cash operating cost for the reporting period of USD 4.77 is reduced to USD 4.15 when tariff income is netted off.

The total cost of operations for the reporting period amounted to MUSD 84.4 (MUSD 85.8). The total cost of operations excluding operational projects amounted to MUSD 77.5 (MUSD 77.1).

The cost of operations per barrel amounted to USD 3.55 (USD 5.66) including operational projects and USD 3.26 (USD 5.09) excluding operational projects.

Tariff and transportation expenses for the reporting period amounted to MUSD 28.9 (MUSD 26.9). 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 7.6 (MUSD 16.1) 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 428.5 (MUSD 270.1) at an average rate of USD 18.02 (USD 17.82) per barrel and are detailed in Note 3. The higher depletion costs for the reporting period compared to the same period last year is due to the depletion charge associated with the Edvard Grieg field as a result of the higher production levels achieved.

Exploration costs
Exploration costs expensed in the income statement for the reporting period amounted to MUSD 42.2 (MUSD 57.8) and are detailed in Note 3. Exploration and appraisal costs are capitalised as they are incurred. When exploration drilling is unsuccessful, the capitalised costs are expensed. All capitalised exploration costs are reviewed on a regular basis and are expensed where their recoverability is considered highly uncertain.

During the reporting period, exploration costs relating to Norway of MUSD 41.1 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 dry wells on the Volund West prospect in PL150B and the Børselv prospect in PL609 as well as a number of Norwegian exploration licences in the process of relinquishment.

Impairment costs of oil and gas properties
Impairment costs in the income statement for the reporting period amounted to MUSD 30.6 (MUSD –) and are detailed in Note 3. The impairment costs related to the Brynhild field in PL148.

Other costs of sales
Other cost of sales for the reporting period amounted to MUSD 188.0 (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 reporting period amounted to MUSD 24.9 (MUSD 19.6) which included a charge of MUSD 3.1 (MUSD 3.4) in relation to the Group's long-term incentive plans (LTIP), see also Remuneration section below. Fixed asset depreciation expenses for the reporting period amounted to MUSD 1.9 (MUSD 2.4).

Finance income
Finance income for the reporting period amounted to MUSD 325.6 (MUSD 250.0) and is detailed in Note 4.

The net foreign currency exchange gain for the reporting period amounted to MUSD 324.9 (MUSD 249.3). Foreign exchange movements occur on the settlement of transactions denominated in foreign currencies and the revaluation of working capital and loan balances to the prevailing exchange rate at the balance sheet date where those monetary assets and liabilities are held in currencies other than the functional currencies of the Group's reporting entities. Lundin Petroleum has hedged certain foreign currency operational expenditure amounts against the US Dollar and for the reporting period, the net realised exchange loss on settled foreign exchange hedges amounted to MUSD 2.9 (MUSD 31.3).

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

Finance costs
Finance costs for the reporting period amounted to MUSD 133.9 (MUSD 170.7) and are detailed in Note 5.

Interest expenses for the reporting period amounted to MUSD 88.2 (MUSD 106.8) and represented the portion of interest charged to the income statement. An additional amount of interest of MUSD 44.1 (MUSD 14.4) associated with the funding of the Norwegian development projects was capitalised in the reporting period. The total interest expense has increased compared to the same period last year due to slightly higher borrowings and higher interest rates. The result on interest rate hedge settlements amounted to a loss of MUSD 14.4 (MUSD 14.8).

The amortisation of the deferred financing fees amounted to MUSD 13.1 (MUSD 34.1) for the reporting period 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 the same period 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 reporting period amounted to MUSD 8.1 (MUSD 6.4) with the increase compared to the same period last year being due to the increased available borrowing amounts under the Group's reserve-based lending facility.

Tax
The overall tax charge for the reporting period amounted to MUSD 328.4 (credit of MUSD 38.5) and is detailed in Note 6.

The current tax charge for the reporting period amounted to a credit of MUSD 0.8 (credit MUSD 64.0) which included a tax credit of MUSD 1.5 (credit MUSD 64.3) relating to previous year for Norway.

The deferred tax charge for the reporting period amounted to MUSD 329.2 (MUSD 25.5) 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 reporting period is affected by items which do not receive a full tax credit such as the reported net foreign currency exchange gain, Norwegian financial items and by the uplift allowance applicable in Norway for development expenditures against the offshore tax regime.

Non-controlling interest

The net result attributable to non-controlling interest for the reporting period amounted to MUSD -3.8 (MUSD -3.4) 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. 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.

Discontinued operations

The net result from discontinued operations amounted to MUSD 47.6 (MUSD -23.6) and is detailed in Note 14.

Balance Sheet

Non-current assets

Oil and gas properties amounted to MUSD 4,919.4 (MUSD 4,376.4) and are detailed in Note 7.

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

Development expenditure in MUSD	**1 Jan 2017– 30 Sep 2017 9 months**	**1 Jul 2017– 30 Sep 2017 3 months**	1 Jan 2016– 30 Sep 2016 9 months	1 Jul 2016– 30 Sep 2016 3 months	1 Jan 2016– 31 Dec 2016 12 months
Norway	734.0	221.3	619.1	232.2	877.1
Development expenditures from continuing operations	**734.0**	**221.3**	619.1	232.2	877.1

An amount of MUSD 734.0 (MUSD 619.1) of development expenditure was incurred in Norway during the reporting period, primarily on the Johan Sverdrup, Edvard Grieg and Volund fields.

Exploration and appraisal expenditure in MUSD	**1 Jan 2017– 30 Sep 2017 9 months**	**1 Jul 2017– 30 Sep 2017 3 months**	1 Jan 2016– 30 Sep 2016 9 months	1 Jul 2016– 30 Sep 2016 3 months	1 Jan 2016– 31 Dec 2016 12 months
Norway	172.5	69.5	90.3	31.8	142.1
Russia	1.1	0.3	0.9	0.3	1.4
Exploration and appraisal expenditure from continuing operations	**173.6**	**69.8**	91.2	32.1	143.5

Exploration and appraisal expenditure of MUSD 172.5 (MUSD 90.3) was incurred in Norway during the reporting period, primarily on the Filicudi exploration well 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 comparative period 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 10.8 (MUSD 9.4) and are detailed in Note 8. Other shares and participations amounted to MUSD 10.3 (MUSD 8.9) and related to the shares held in ShaMaran Petroleum which are reported at market value with any change in value being recorded in other comprehensive income.

Derivative instruments amounted to MUSD 26.6 (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 33.8 (MUSD 54.9) and included both well supplies and hydrocarbon inventories. The decrease compared to the same period last year is related to the spin-off of the IPC business.

Trade and other receivables amounted to MUSD 252.8 (MUSD 288.9) and are detailed in Note 9. Trade receivables, which are all current, amounted to MUSD 168.7 (MUSD 193.4) and included invoiced cargoes. Underlift amounted to MUSD 7.1 (MUSD 28.9) and was attributable to an underlift position on the producing fields, mainly NGL from Edvard Grieg. Joint operations debtors relating to various joint venture receivables amounted to MUSD 19.0 (MUSD 31.2). Prepaid expenses and accrued income amounted to MUSD 31.5 (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 reporting period. Other current assets amounted to MUSD 26.5 (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 21.6 (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 84.7 (MUSD 77.5) relating to the Norwegian corporate tax refund in respect of 2016 which will be received in the fourth quarter of 2017.

Cash and cash equivalents amounted to MUSD 91.0 (MUSD 69.5). Cash balances are held to meet ongoing operational funding requirements.

Non-current liabilities

Financial liabilities amounted to MUSD 4,033.3 (MUSD 4,048.3) and are detailed in Note 10. Bank loans amounted to MUSD 4,115.0 (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 81.7 (MUSD 96.7) and are being amortised over the expected life of the facility.

Provisions amounted to MUSD 421.0 (MUSD 420.0) and are detailed in Note 11. The provision for site restoration amounted to MUSD 416.1 (MUSD 407.1) and related to future decommissioning obligations. The site restoration provision related to Norway amounted to MUSD 416.1 (MUSD 316.1). The increase in Norway mainly reflects the additional liability for Edvard Grieg and Volund production drilling and for the Johan Sverdrup development project.

Deferred tax liabilities amounted to MUSD 1,013.7 (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 0.8 (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 above.

Current liabilities

Trade and other payables amounted to MUSD 340.2 (MUSD 308.4) and are detailed in Note 12. Overlift amounted to MUSD 75.1 (MUSD 29.9) and was attributable to an overlift position on the producing fields, mainly crude oil from Edvard Grieg. Joint operations creditors and accrued expenses amounted to MUSD 207.4 (MUSD 238.8) and related to activity in Norway. Other accrued expenses amounted to MUSD 21.6 (MUSD 16.9) and other current liabilities amounted to MUSD 7.1 (MUSD 9.5).

Derivative instruments amounted to MUSD 15.1 (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 6.7 (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 46,453.9 (MSEK -55.8) for the reporting period.

The result included MSEK 46,543.2 financial income as a result of an internal restructuring prior to the IPC spin-off. The result excluding this financial income amounts to MSEK -89.3 (MSEK -55.8).

The result included general and administrative expenses of MSEK 96.5 (MSEK 57.2) and net finance income of MSEK 0.2 (MSEK -1.5) when excluding the finance income as a result of the internal restructuring.

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 reporting period, 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 177.6.

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

Lundin Petroleum entered into additional forward currency hedges for the years 2020 to 2022 to meet part of its future NOK capital requirements relating to the Johan Sverdrup field development to buy MNOK 2,250.0 and sell MUSD 293.9 at an average contractual exchange rate of NOK 7.65:USD 1. The company also entered into additional interest rate hedge contracts for the years 2020 to 2022 comprising of MUSD 1,750 for 2020; MUSD 1,000 for 2021 and MUSD 1,000 for 2022 fixing the floating LIBOR rate at an average weighted rate of 2.15 percent.

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 reporting period Lundin Petroleum purchased 373,234 of its own shares at an average price of SEK 170.45 based on the approval granted at the AGM 2017.

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 30 September 2017 were 136,083, 224,992 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 30 September 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 30 September 2017 is 426,436 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 30 September 2017 is 672,224 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.

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

Buy	Sell	Average contractual Exchange rate	Settlement period
MNOK 872.1	MUSD 105.6	NOK 8.26:USD 1	Oct 2017 – Dec 2017
MNOK 3,493.0	MUSD 424.2	NOK 8.23:USD 1	Jan 2018 – Dec 2018
MNOK 1,672.4	MUSD 200.4	NOK 8.35:USD 1	Jan 2019 – Dec 2019

During the reporting period, Lundin Petroleum entered into additional interest rate hedge contracts and at 30 September 2017 had outstanding interest rate hedge contracts as follows:

Borrowings expressed in MUSD	Fixing of floating LIBOR average rate per annum	Settlement period
3,000	1.66%	Oct 2017 – Dec 2017
3,000	1.87%	Jan 2018 – Dec 2018
3,000	1.42%	Jan 2019 – Dec 2019

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

Exchange Rates
For the preparation of the financial statements for the reporting period, the following currency exchange rates have been used.

	30 Sep 2017		30 Sep 2016		30 Dec 2016	
	Average	Period end	Average	Period end	Average	Period end
1 USD equals NOK	8.3067	7.9726	8.4087	8.0517	8.4014	8.6200
1 USD equals Euro	0.8983	0.8470	0.8962	0.8959	0.9037	0.9487
1 USD equals Rouble	58.2991	57.8112	68.4272	63.1789	67.0692	60.9999
1 USD equals SEK	8.6238	8.1730	8.3997	8.6202	8.5610	9.0622

Consolidated Income Statement

Expressed in MUSD	Note	1 Jan 2017–30 Sep 2017 9 months	1 Jul 2017–30 Sep 2017 3 months	1 Jan 2016–30 Sep 2016 9 months	1 Jul 2016–30 Sep 2016 3 months	1 Jan 2016–31 Dec 2016 12 months
		Continuing operations	Continuing operations	Continuing operations	Continuing operations	Continuing operations
Revenue	1	**1,403.3**	**517.2**	623.8	269.0	950.0
Cost of sales						
Production costs	2	-120.6	-42.6	-128.6	-46.3	-168.4
Depletion and decommissioning costs		-428.5	-153.2	-270.1	-113.1	-386.2
Exploration costs		-42.2	-16.3	-57.8	-2.0	-101.9
Impairment costs of oil and gas properties		-30.6	-17.4	–	–	-506.1
Other cost of sales		-188.0	-84.8	-2.1	-2.1	-2.1
Gross profit/loss	3	**593.4**	**202.9**	165.2	105.5	-214.7
General, administration and depreciation expenses		-24.9	-8.2	-19.6	-5.9	-30.0
Operating profit/loss		**568.5**	**194.7**	145.6	99.6	-244.7
Net financial items						
Finance income	4	325.6	186.0	250.0	139.2	2.7
Finance costs	5	-133.9	-44.1	-170.7	-50.4	-221.5
		191.7	**141.9**	79.3	88.8	-218.8
Profit/loss before tax		**760.2**	**336.6**	224.9	188.4	-463.5
Income tax	6	-328.4	-109.6	38.5	-18.6	64.2
Net result from continuing operations		**431.8**	**227.0**	263.4	169.8	-399.3
Discontinued operations						
Net result - IPC	14	47.6	-0.3	-23.6	4.0	-100.0
Net result		**479.4**	**226.7**	239.8	173.8	-499.3
Attributable to:						
Shareholders of the Parent Company		483.2	228.0	243.2	174.9	-356.7
Non-controlling interest		-3.8	-1.3	-3.4	-1.1	-142.6
		479.4	**226.7**	239.8	173.8	-499.3
Earnings per share – USD[1]						
From continuing operations		1.28	0.67	0.83	0.52	-0.79
From discontinued operations		0.14	0.00	-0.07	0.02	-0.30
Earnings per share fully diluted – USD[1]						
From continuing operations		1.28	0.67	0.82	0.51	-0.79
From discontinued operations		0.14	0.00	-0.07	0.02	-0.30

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

Consolidated Statement of Comprehensive Income

Expressed in MUSD	**1 Jan 2017– 30 Sep 2017 9 months**	**1 Jul 2017– 30 Sep 2017 3 months**	1 Jan 2016 – 30 Sep 2016 9 months	1 Jul 2016 – 30 Sep 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Net result	**479.4**	**226.7**	239.8	173.8	-499.3
Items that may be subsequently reclassified to profit or loss:					
Exchange differences foreign operations	-66.1	-7.6	22.0	5.6	13.8
Cash flow hedges	82.8	42.1	109.5	44.2	64.3
Available-for-sale financial assets	-1.2	-1.4	1.8	0.6	5.3
Other comprehensive income, net of tax	**15.5**	**33.1**	133.3	50.4	83.4
Total comprehensive income	**494.9**	**259.8**	373.1	224.2	-415.9
Attributable to:					
Shareholders of the Parent Company	498.7	261.1	372.6	224.8	-278.2
Non-controlling interest	-3.8	-1.3	0.5	-0.6	-137.7
	494.9	**259.8**	373.1	224.2	-415.9

Consolidated Balance Sheet

Expressed in MUSD	Note	30 September 2017	31 December 2016
ASSETS			
Non-current assets			
Oil and gas properties	7	4,919.4	4,376.4
Other tangible fixed assets		13.2	166.1
Goodwill		128.1	128.1
Financial assets	8	10.8	9.4
Deferred tax assets		–	13.5
Derivative instruments	13	26.6	17.0
Total non-current assets		**5,098.1**	4,710.5
Current assets			
Inventories		33.8	54.9
Trade and other receivables	9	252.8	288.9
Derivative instruments	13	21.6	0.8
Current tax assets		84.7	77.5
Cash and cash equivalents		91.0	69.5
Total current assets		**483.9**	491.6
TOTAL ASSETS		**5,582.0**	5,202.1
EQUITY AND LIABILITIES			
Equity			
Shareholders´ equity		-249.2	-238.6
Non-controlling interest		–	-113.6
Total equity		**-249.2**	-352.2
Liabilities			
Non-current liabilities			
Financial liabilities	10	4,033.3	4,048.3
Provisions	11	421.0	420.0
Deferred tax liabilities		1,013.7	669.3
Derivative instruments	13	0.8	29.8
Other non-current liabilities		–	33.8
Total non-current liabilities		**5,468.8**	5,201.2
Current liabilities			
Trade and other payables	12	340.2	308.4
Derivative instruments	13	15.1	37.6
Current tax liabilities		0.4	0.2
Provisions	11	6.7	6.9
Total current liabilities		**362.4**	353.1
Total liabilities		**5.831.2**	5,554.3
TOTAL EQUITY AND LIABILITIES		**5,582.0**	5,202.1

Consolidated Statement of Cash Flows

Expressed in MUSD	1 Jan 2017– 30 Sep 2017 9 months	1 Jul 2017– 30 Sep 2017 3 months	1 Jan 2016 – 30 Sep 2016 9 months	1 Jul 2016 – 30 Sep 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
	Continuing operations	Continuing operations	Continuing operations	Continuing operations	Continuing operations
Cash flows from operating activities					
Net result	431.8	227.0	263.4	169.8	-399.3
Adjustments for:					
Exploration costs	42.2	16.3	57.8	2.0	101.9
Depletion, depreciation and amortisation	430.4	153.9	272.5	113.8	391.7
Impairment of oil and gas properties	30.6	17.4	–	–	506.1
Current tax	-0.8	0.3	-64.0	-22.4	-78.4
Deferred tax	329.2	109.3	25.5	41.0	14.2
Long-term incentive plans	9.5	3.4	9.3	2.5	15.6
Foreign currency exchange gain	-327.9	-181.5	-280.3	-136.5	-24.9
Interest expense	88.2	30.1	106.8	33.2	137.3
Capitalised financing fees	13.1	4.6	34.1	5.4	38.9
Other	8.8	3.2	13.2	3.1	12.6
Interest received	0.5	0.3	0.5	0.1	2.3
Interest paid	-131.2	-47.2	-114.5	-39.4	-153.7
Income taxes paid / received	-0.4	-0.2	-0.7	-0.2	273.5
Changes in working capital	36.6	22.3	81.6	55.7	-169.1
Total cash flows from operating activities	**960.6**	**359.2**	405.2	228.1	668.7
Cash flows from investing activities					
Investment in oil and gas properties	-907.7	-291.2	-710.4	-264.4	-1,020.6
Investment in other fixed assets	-0.9	-0.1	-0.6	-0.2	-1.1
Investment in other shares and participations	-1.3	–	–	–	–
Decommissioning costs paid	-0.1	–	-0.6	-0.1	-1.0
Other payments	-7.5	-0.3	31.0	–	25.8
Total cash flows from investing activities	**-917.5**	**-291.6**	-680.6	-264.7	-996.9
Cash flows from financing activities					
Changes in long-term liabilities	-28.7	-39.6	248.1	40.4	288.7
Financing fees paid	–	–	-103.9	-7.3	-104.0
Cash funded from / to discontinued operations	31.7	–	64.5	28.4	92.5
Purchase of own shares	-7.8	-7.8	–	–	–
Issuance of shares/Sale of treasury shares[1]	–	–	64.1	–	64.1
Total cash flows from financing activities	**-4.8**	**-47.4**	272.8	61.5	341.3
Change in cash and cash equivalents	38.3	20.2	-2.6	24.9	13.1
Cash and cash equivalents at the beginning of the period	56.1	74.2	42.4	34.4	42.4
Currency exchange difference in cash and cash equivalents	-3.2	-3.2	0.6	0.3	0.6
Cash and cash equivalent of deconsolidated operations	-0.2	-0.2	–	–	–
Cash and cash equivalent of discontinued operations	–	–	8.4	-10.8	13.4
Cash and cash equivalents at the end of the period	**91.0**	**91.0**	48.8	48.8	69.5

[1] Cash received on the additional sale of newly issued and treasury shares to Statoil ASA.

Consolidated Statement of Changes in Equity

Expressed in MUSD	Share capital	Additional paid-in-capital/Other reserves	Retained earnings	Dividends	Total	Non-controlling interest	Total equity
	Attributable to owners of the Parent Company						
At 1 January 2016	**0.5**	**-64.3**	**-434.4**	**–**	**-498.2**	**24.1**	**-474.1**
Comprehensive income							
Net result	–	–	243.2	–	243.2	-3.4	239.8
Other comprehensive income	–	129.4	–	–	129.4	3.9	133.3
Total comprehensive income	**–**	**129.4**	**243.2**	**–**	**372.6**	**0.5**	**373.1**
Transactions with owners							
Issuance of shares/Sale of treasury shares	–	534.1	–	–	534.1	–	534.1
Value of employee services	–	–	2.4	–	2.4	–	2.4
Total transactions with owners	**–**	**534.1**	**2.4**	**–**	**536.5**	**–**	**536.5**
At 30 September 2016	**0.5**	**599.2**	**-188.8**	**–**	**410.9**	**24.6**	**435.5**
Comprehensive income							
Net result	–	–	-599.9	–	-599.9	-139.2	-739.1
Other comprehensive income	–	-50.9	–	–	-50.9	1.0	-49.9
Total comprehensive income	**–**	**-50.9**	**-599.9**	**–**	**-650.8**	**-138.2**	**-789.0**
Transactions with owners							
Value of employee services	–	–	1.3	–	1.3	–	1.3
Total transaction with owners	**–**	**–**	**1.3**	**–**	**1.3**	**–**	**1.3**
At 31 December 2016	**0.5**	**548.3**	**-787.4**	**–**	**-238.6**	**-113.6**	**-352.2**
Comprehensive income							
Net result	–	–	483.2	–	483.2	-3.8	479.4
Other comprehensive income	–	15.5	–	–	15.5	–	15.5
Total comprehensive income	**–**	**15.5**	**483.2**	**–**	**498.7**	**-3.8**	**494.9**
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	–	-7.8	–	–	-7.8	–	-7.8
Spin off IPC	–	–	–	–	–	0.3	0.3
Share based payments	–	-13.2	–	–	-13.2	–	-13.2
Value of employee services	–	–	3.7	–	3.7	–	3.7
Total transaction with owners	**–**	**-21.0**	**-78.3**	**-410.0**	**-509.3**	**117.4**	**-391.9**
At 30 September 2017	**0.5**	**542.8**	**-382.5**	**-410.0**	**-249.2**	**–**	**-249.2**

Notes to the Consolidated Financial Statements

Note 1 – Revenue MUSD	**1 Jan 2017– 30 Sep 2017 9 months**	**1 Jul 2017– 30 Sep 2017 3 months**	1 Jan 2016 – 30 Sep 2016 9 months	1 Jul 2016 – 30 Sep 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Crude oil from own production	1,165.3	452.5	551.8	231.8	901.0
Crude oil from third party activities	188.4	85.3	2.1	1.6	2.1
Condensate	21.2	5.1	9.4	3.9	14.3
Gas	74.4	25.4	38.7	13.2	58.5
Net sales of oil and gas from continuing operations	**1,449.3**	**568.3**	602.0	250.5	975.9
Change in under/over lift position	-62.8	-57.7	19.5	17.7	-29.1
Other revenue	16.8	6.6	2.3	0.8	3.2
Revenue from continuing operations	**1,403.3**	**517.2**	623.8	269.0	950.0

Note 2 – Production costs MUSD	**1 Jan 2017– 30 Sep 2017 9 months**	**1 Jul 2017– 30 Sep 2017 3 months**	1 Jan 2016 – 30 Sep 2016 9 months	1 Jul 2016 – 30 Sep 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Cost of operations	84.4	29.1	85.8	30.5	113.1
Tariff and transportation expenses	28.9	11.5	26.9	10.7	33.9
Change in inventory position	-0.3	0.2	-0.2	0.2	-0.7
Other	7.6	1.8	16.1	4.9	22.1
Production costs from continuing operations	**120.6**	**42.6**	128.6	46.3	168.4

Note 3 – Segment information MUSD	**1 Jan 2017– 30 Sep 2017 9 months**	**1 Jul 2017– 30 Sep 2017 3 months**	1 Jan 2016 – 30 Sep 2016 9 months	1 Jul 2016 – 30 Sep 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Norway					
Crude oil from own production	1,165.3	452,5	551.8	231.8	901.0
Condensate	21.2	5.1	9.4	3.9	14.3
Gas	74.4	25.4	38.7	13.2	58.5
Net sales of oil and gas	**1,260.9**	**483.0**	599.9	248.9	973.8
Change in under/over lift position	-62.8	-57.7	19.5	17.7	-29.1
Other revenue	15.2	5.9	0.9	0.3	1.5
Revenue	**1,213.3**	**431.2**	620.3	266.9	946.2
Production costs	-120.6	-42.6	-128.6	-46.3	-168.4
Depletion and decommissioning costs	-428.5	-153.2	-270.1	-113.1	-386.2
Exploration costs	-41.1	-16.0	-57.8	-2.0	-101.9
Impairment costs of oil and gas properties	-30.6	-17.4	–	–	–
Gross profit/loss	**592.5**	**202.0**	163.8	105.6	289.7

Note 3 – Segment information cont. MUSD	**1 Jan 2017–** **30 Sep 2017** **9 months**	**1 Jul 2017–** **30 Sep 2017** **3 months**	1 Jan 2016 – 30 Sep 2016 9 months	1 Jul 2016 – 30 Sep 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Other					
Crude oil from third party activities	188.4	85.3	2.1	1.6	2.1
Net sales of oil and gas	**188.4**	**85.3**	2.1	1.6	2.1
Other revenue	1.6	0.7	1.4	0.5	1.7
Revenue	**190.0**	**86.0**	3.5	2.1	3.8
Exploration costs	-1.1	-0.3	–	–	–
Impairment costs of oil and gas properties	–	–	–	–	-506.1
Other cost of sales	-188.0	-84.8	-2.1	-2.1	-2.1
Gross profit/loss	**0.9**	**0.9**	1.4	0.0	-504.4
Total from continuing operations					
Crude oil from own production	1,165.3	452.5	551.8	231.8	901.0
Crude oil from third party activities	188.4	85.3	2.1	1.6	2.1
Condensate	21.2	5.1	9.4	3.9	14.3
Gas	74.4	25.4	38.7	13.2	58.5
Net sales of oil and gas	**1,449.3**	**568.3**	602.0	250.5	975.9
Change in under/over lift position	-62.8	-57.7	19.5	17.7	-29.1
Other revenue	16.8	6.6	2.3	0.8	3.2
Revenue	**1,403.3**	**517.2**	623.8	269.0	950.0
Production costs	-120.6	-42.6	-128.6	-46.3	-168.4
Depletion and decommissioning costs	-428.5	-153.2	-270.1	-113.1	-386.2
Exploration costs	-42.2	-16.3	-57.8	-2.0	-101.9
Impairment costs of oil and gas properties	-30.6	-17.4	–	–	-506.1
Other cost of sales	-188.0	-84.8	-2.1	-2.1	-2.1
Gross profit/loss from continuing operations	**593.4**	**202.9**	165.2	105.5	-214.7

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

Note 4 – Finance income MUSD	**1 Jan 2017–** **30 Sep 2017** **9 months**	**1 Jul 2017–** **30 Sep 2017** **3 months**	1 Jan 2016 – 30 Sep 2016 9 months	1 Jul 2016 – 30 Sep 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Foreign currency exchange gain, net	324.9	185.7	249.3	139.1	–
Interest income	0.4	0.2	0.5	0.1	2.3
Guarantee fees	0.3	0.1	0.2	0.0	0.4
Total finance income from continuing operations	**325.6**	**186.0**	250.0	139.2	2.7

Note 5 – Finance costs MUSD	**1 Jan 2017– 30 Sep 2017 9 months**	**1 Jul 2017– 30 Sep 2017 3 months**	1 Jan 2016 – 30 Sep 2016 9 months	1 Jul 2016 – 30 Sep 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Interest expense	88.2	30.1	106.8	33.2	137.3
Foreign currency exchange loss, net	–	–	–	–	4.2
Result on interest rate hedge settlement	14.4	3.4	14.8	5.2	19.5
Unwinding of site restoration discount	9.2	3.4	7.9	3.0	11.6
Amortisation of deferred financing fees	13.1	4.6	34.1	5.4	38.9
Loan facility commitment fees	8.1	2.7	6.4	3.1	9.3
Other	0.9	-0.1	0.7	0.5	0.7
Finance costs from continuing operations	**133.9**	**44.1**	170.7	50.4	221.5

Note 6 – Income tax MUSD	**1 Jan 2017– 30 Sep 2017 9 months**	**1 Jul 2017– 30 Sep 2017 3 months**	1 Jan 2016 – 30 Sep 2016 9 months	1 Jul 2016 – 30 Sep 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Current tax	-0.8	0.3	-64.0	-22.4	-78.4
Deferred tax	329.2	109.3	25.5	41.0	14.2
Total income tax from continuing operations	**328.4**	**109.6**	-38.5	18.6	-64.2

Note 7 – Oil and gas properties MUSD	**30 Sep 2017**	31 Dec 2016
Norway	4,919.4	4,055.7
Malaysia	–	130.6
France	–	171.0
Netherlands	–	19.1
	4,919.4	4,376.4

Note 8 – Financial assets MUSD	**30 Sep 2017**	31 Dec 2016
Other shares and participations	10.3	8.9
Other	0.5	0.5
	10.8	9.4

Note 9 – Trade and other receivables MUSD	**30 Sep 2017**	31 Dec 2016
Trade receivables	168.7	193.4
Underlift	7.1	28.9
Joint operations debtors	19.0	31.2
Prepaid expenses and accrued income	31.5	29.4
Brynhild operating cost share	–	3.0
Other	26.5	3.0
	252.8	288.9

Note 10 – Financial liabilities

MUSD	**30 Sep 2017**	31 Dec 2016
Non-current:		
Bank loans	4,115.0	4,145.0
Capitalised financing fees	-81.7	-96.7
	4,033.3	4,048.3

Note 11 – Provisions

MUSD	**30 Sep 2017**	31 Dec 2016
Non-current:		
Site restoration	416.1	407.1
Long-term incentive plans	2.0	3.2
Farm-in payment	–	5.5
Other	2.9	4.2
	421.0	420.0
Current:		
Long-term incentive plans	6.7	6.9
	6.7	6.9
	427.7	426.9

Note 12 – Trade and other payables

MUSD	**30 Sep 2017**	31 Dec 2016
Trade payables	29.0	13.3
Overlift	75.1	29.9
Joint operations creditors and accrued expenses	207.4	238.8
Other accrued expenses	21.6	16.9
Other	7.1	9.5
	340.2	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:

30 September 2017 MUSD	Level 1	Level 2	Level 3
Assets			
Other shares and participations	10.3	–	–
Derivative instruments – non-current	–	26.6	–
Derivative instruments – current	–	21.6	–
	10.3	**48.2**	**–**
Liabilities			
Derivative instruments – non-current	–	0.8	–
Derivative instruments – current	–	15.1	–
	–	**15.9**	**–**

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– 30 Sep 2017 9 months**	**1 Jul 2017– 30 Sep 2017 3 months**	1 Jan 2016 – 30 Sep 2016 9 months	1 Jul 2016 – 30 Sep 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Revenue	**69.1**	**–**	150.2	48.4	209.9
Cost of sales					
Production costs	-17.4	–	-40.6	-9.6	-59.1
Depletion and decommissioning costs	-19.1	–	-64.8	-21.9	-85.2
Depletion of other assets	-10.4	–	-23.4	-7.8	-31.1
Exploration costs	0.1	–	-12.5	0.6	-14.2
Impairment costs of oil and gas properties	–	–	–	–	-126.0
Gross profit/loss	**22.3**	**–**	8.9	9.7	-105.7
Sale of assets	–	–	-3.5	–	-3.5
General, administration and depreciation expenses	-1.0	–	-1.7	-0.8	-1.9
Operating profit/loss	**21.3**	**–**	3.7	8.9	-111.1
Net financial items					
Finance income	–	–	–	–	23.9
Finance costs	-24.1	–	-25.0	-4.6	-7.9
	-24.1	**–**	-25.0	-4.6	16.0
Profit/loss before tax	**-2.8**	**–**	-21.3	4.3	-95.1
Income tax	-1.2	–	-2.3	-0.3	-4.9
	-4.0	**–**	-23.6	4.0	-100.0
Gain on distribution of assets	51.6	-0.3	–	–	–
Net result from discontinued operations	**47.6**	**-0.3**	-23.6	4.0	-100.0

Parent Company Income Statement

Expressed in MSEK	1 Jan 2017– 30 Sep 2017 9 months	1 Jul 2017– 30 Sep 2017 3 months	1 Jan 2016 – 30 Sep 2016 9 months	1 Jul 2016 – 30 Sep 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Revenue	7.0	2.5	2.9	1.0	3.8
General and administration expenses	-96.5	-48.9	-57.2	-20.3	-106.6
Operating profit/loss	**-89.5**	**-46.4**	-54.3	-19.3	-102.8
Net financial items					
Finance income	46,543.9	-0.6	2.7	0.9	3.5
Finance costs	-0.5	–	-4.2	–	-4.0
	46,543.4	**-0.6**	-1.5	0.9	-0.5
Profit/loss before tax	**46,453.9**	**-47.0**	-55.8	-18.4	-103.3
Income tax	–	–	–	–	–
Net result	**46,453.9**	**-47.0**	-55.8	-18.4	-103.3

Parent Company Comprehensive Income Statement

Expressed in MSEK	1 Jan 2017– 30 Sep 2017 9 months	1 Jul 2017– 30 Sep 2017 3 months	1 Jan 2016 – 30 Sep 2016 9 months	1 Jul 2016 – 30 Sep 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Net result	**46,453.9**	**-47.0**	-55.8	-18.4	-103.3
Other comprehensive income	–	–	–	–	–
Total comprehensive income	**46,453.9**	**-47.0**	-55.8	-18.4	-103.3
Attributable to:					
Shareholders of the Parent Company	46,453.9	-47.0	-55.8	-18.4	-103.3
	46,453.9	**-47.0**	-55.8	-18.4	-103.3

Parent Company Balance Sheet

Expressed in MSEK	30 September 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	5.2	20.7
Cash and cash equivalents	54.2	3.2
Total current assets	**59.4**	23.9
TOTAL ASSETS	**55,178.3**	12,280.5
SHAREHOLDERS´EQUITY AND LIABILITIES		
Shareholders´ equity including net result for the period	54,907.9	12,212.9
Non-current liabilities		
Provisions	0.4	0.6
Payables to group companies	–	49.4
Total non-current liabilities	**0.4**	50.0
Current liabilities		
Current liabilities	270.0	17.6
Total current liabilities	**270.0**	17.6
Total liabilities	**270.4**	67.6
TOTAL EQUITY AND LIABILITIES	**55,178.3**	12,280.5

Parent Company Cash Flow Statement

Expressed in MSEK	**1 Jan 2017– 30 Sep 2017 9 months**	**1 Jul 2017– 30 Sep 2017 3 months**	1 Jan 2016 – 30 Sep 2016 9 months	1 Jul 2016 – 30 Sep 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Cash flow from operations					
Net result	46,453.9	-47.0	-55.8	-18.4	-103.3
Adjustment for non-cash related items	-46,607.6	-1.8	15.5	2.4	24.6
Changes in working capital	267.4	158.8	0.9	5.2	7.4
Total cash flow from operations	**113.7**	**110.0**	-39.4	-10.8	-71.3
Cash flow from financing					
Change in long-term receivables	–	–	10.6	10.6	–
Change in long-term liabilities	–	–	-508.7	-0.8	-467.5
Purchase of own shares	-63.6	-63.6	–	–	–
Proceeds from share issues /treasury shares	–	–	544.1	–	544.1
Total cash flow from financing	-63.6	-63.6	46.0	9.8	76.6
Change in cash and cash equivalents	50.1	46.4	6.6	-1.0	5.3
Cash and cash equivalents at the beginning of the period	**3.2**	**6.2**	0.4	5.5	0.4
Currency exchange difference in cash and cash equivalents	0.9	1.6	-2.5	–	-2.5
Cash and cash equivalents at the end of the period	**54.2**	**54.2**	4.5	4.5	3.2

Parent Company Statement of Changes in Equity

	Restricted equity		Unrestricted equity				
Expressed in MSEK	Share capital	Statutory reserve	Other reserves	Retained earnings	Dividends	Total	Total equity
Balance at 1 January 2016	**3.2**	**861.3**	**2,295.3**	**4,622.6**	**–**	**6,917.9**	**7,782.4**
Total comprehensive income	**–**	**–**	**–**	**-55.8**	**–**	**-55.8**	**-55.8**
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 30 September 2016	**3.5**	**861.3**	**6,828.8**	**4,566.8**	**–**	**11,395.6**	**12,260.4**
Total comprehensive income	**–**	**–**	**–**	**-47.5**	**–**	**-65.9**	**-65.9**
Balance at 31 December 2016	**3.5**	**861.3**	**6,828.8**	**4,519.3**	**–**	**11,348.1**	**12,212.9**
Total comprehensive income	**–**	**–**	**–**	**46,453.9**	**–**	**46,453.9**	**46,453.9**
Transactions with owners							
Purchase of own shares	–	–	-63.6	–	–	-63.6	-63.6
Distributions	–	–	–	–	-3,695.3	-3,695.3	-3,695.3
Total transactions with owners	**–**	**–**	**-63.6**	**–**	**-3,695.3**	**-3,758.9**	**-3,758.9**
Balance at 30 June 2017	**3.5**	**861.3**	**6,765.2**	**50,973.2**	**-3,695.3**	**54,043.1**	**54,907.9**

Key Financial Data

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

Financial data from continuing operations MUSD	**1 Jan 2017– 30 Sep 2017 9 months**	**1 Jul 2017– 30 Sep 2017 3 months**	1 Jan 2016 – 30 Sep 2016 9 months	1 Jul 2016 – 30 Sep 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Revenue	1,403.3	517.2	623.8	269.0	950.0
EBITDA	1,071.7	382.4	475.8	215.3	752.5
Net result	431.8	227.0	263.4	169.8	-399.3
Operating cash flow	1,095.5	389.6	557.0	243.0	857.9
Data per share from continuing operations USD					
Shareholders' equity per share	-0.73	-0.73	1.21	1.21	-0.70
Operating cash flow per share	3.22	1.15	1.74	0.71	2.63
Cash flow from operations per share	2.82	1.05	1.26	0.69	2.05
Earnings per share	1.28	0.67	0.83	0.52	-0.79
Earnings per share fully diluted	1.28	0.67	0.82	0.51	-0.79
EBITDA per share	3.15	1.12	1.48	0.64	2.31
EBITDA per share – fully diluted	3.14	1.12	1.48	0.65	2.30
Number of shares issued at period end	340,386,445	340,386,445	340,386,445	340,386,445	340,386,445
Number of shares in circulation at period end	340,013,211	340,013,211	340,386,445	340,386,445	340,386,445
Weighted average number of shares for the period	340,351,886	340,282,769	320,482,368	340,386,445	325,808,486
Weighted average number of shares for the period fully diluted	341,558,091	341,233,400	322,271,559	341,815,636	326,738,233
Share price SEK					
Share price at period end	178.20	178.20	146.20	146.20	198.10
Key ratios from continuing operations					
Return on equity (%) [1]	–	–	–	–	–
Return on capital employed (%)	15	5	2	2	-9
Net debt/equity ratio (%) [1]	–	–	–	–	–
Equity ratio (%)	-4	-4	-2	-2	-17
Share of risk capital (%)	14	14	10	10	-3
Interest coverage ratio	5	6	1	2	-2
Operating cash flow/interest ratio	11	12	5	6	5
Yield	6	6	n/a	n/a	n/a

[1] As the equity at 30 September 2017, 31 December 2016 and 30 September 2016 is negative, these ratios have not been calculated.

Key Ratio Definitions

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Financial Information

The Company will publish the following reports:

- The year end report (January — December 2017) will be published on 1 February 2018.
- The three month report (January — March 2018) will be published on 2 May 2018.
- The six month report (April — June 2018) will be published on 31 July 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 November 2017.

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

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

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