Lundin Petroleum

Q4

YEAR END REPORT 2018

Lundin Petroleum AB (publ)

company registration number 556610-8055

Highlights

- Strong financial performance with record free cash flow generation of MUSD 663
- Board of Directors propose a dividend for 2018 of USD 1.48 per share, corresponding to MUSD 500
- Production of 81.1 Mboepd at upper end of guidance for the year, supported by excellent performance from Edvard Grieg
- Operating cost of USD 3.66 per barrel, below the updated guidance for the year
- Johan Sverdrup project on schedule with approximately 85 percent of Phase 1 completed, start-up anticipated in November 2019
- Increase of proved plus probable reserves to 745 MMboe with a reserves replacement ratio of 163 percent

Financial summary

	1 Jan 2018- 31 Dec 2018 12 months	1 Oct 2018- 31 Dec 2018 3 months	1 Jan 2017- 31 Dec 2017 12 months	1 Oct 2017- 31 Dec 2017 3 months
Production in Mboepd	**81.1**	**82.1**	86.1	83.1
Revenue and other income in MUSD	**2,617.4**	**611.0**	1,997.0	593.7
Operating cash flow in MUSD	**1,847.8**	**419.1**	1,530.0	434.5
EBITDA in MUSD	**1,916.2**	**448.5**	1,501.5	429.8
Free cash flow in MUSD	**663.0**	**173.3**	203.7	160.6
Net result in MUSD	**222.1**	**-105.3**	380.9	-50.9
Earnings/share in USD[1]	**0.66**	**-0.31**	1.13	-0.15
Net debt	**3,398.2**	**3,398.2**	3,883.6	3,883.6

The numbers included in the table above for 2017 are based on continuing operations.
[1] Based on net result attributable to shareholders of the Parent Company.

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

"2018 proved to be a standout year across all areas of our business, with excellent performance from our producing assets, strong financial results and success with the drill bit. For the fifth consecutive year, we have ended the period having more than replaced our produced barrels with reserves.

"Buoyed by stronger commodity prices, operating cost below guidance and very strong production efficiency, we have delivered EBITDA in excess of USD 1.9 billion and also record high free cash flow of USD 663 million for the year. I am also very pleased to announce that in the light of this and our strong financial outlook over the next decade, the Board of Directors has adopted an updated dividend policy which will be sustainable and will deliver an annual cash dividend of USD 500 million, which we aim to grow further as the business continues to grow.

"The key producing assets Edvard Grieg and Alvheim have continued to perform above expectations. Production efficiency at Edvard Grieg was 98 percent for the year and reservoir performance continues to exceed expectations with a significantly slower build-up of water production than anticipated, leading to a six month extension of plateau production to mid-2020. This has been achieved while maintaining an industry leading, low carbon intensity per produced barrel, at about one quarter of the industry world average. Edvard Grieg really is a world-class asset, which epitomises what can be achieved when excellent reservoir management is coupled with new, modern facilities, which are able to utilise innovative, practical technologies and practices.

"The giant Johan Sverdrup field is now less than a year away from start-up and 2018 was a critical year of project delivery. Phase 1 is now approximately 85 percent complete and all four steel jackets have been successfully installed offshore, as well as the topsides for the drilling platform and the riser platform. I am also pleased that during the year the key metrics for the project were upgraded, lowering the total capital expenditure guidance, increasing reserves, confirming expected Phase 1 first oil to be in November 2019 and submitting the Phase 2 PDO.

"The 2018 exploration and appraisal campaign was one of our busiest and we enjoyed significant success with new discoveries made near our core areas on the Utsira High and the Alvheim area. We matured our appraisal opportunities further towards development and now have seven potential new projects in the pipeline. At Rolvsnes and Alta, we were able to de-risk the commercial potential of these unique discoveries through test production. Complementing our successful organic growth strategy, we were able to execute important additions to our Utsira High position. At Luno II we increased our working interest to 65 percent to bring commercial and operational alignment with the Edvard Grieg partnership and we recently announced the strategic acquisition of Lime Petroleum's interests in the licences containing the Rolvsnes oil discovery and Goddo prospect, increasing our working interest in this area that has potential of over 250 MMboe gross resources.

"Looking forward, 2019 will be one of the most significant years in Lundin Petroleum's history, which started with a record award in the 2018 APA licensing round, growing our acreage position by about 70 percent since year-end 2017. The giant Johan Sverdrup field is set to start production in November and we will deliver our busiest exploration and appraisal programme to date, targeting over 750 MMboe of additional net resources. I would like to thank all of our stakeholders for their support in 2018 and very much look forward to another period of continued delivery and growth."

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 pages 30 and 32.

OPERATIONAL REVIEW

All the reported numbers and updates in the operational review relate to the financial year ended 31 December 2018 unless otherwise specified.

Norway

Reserves and Resources
Lundin Petroleum has 745.4 million barrels of oil equivalent (MMboe) of proved plus probable net reserves and 900.9 MMboe of proved plus probable plus possible net reserves as at 31 December 2018 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 225 MMboe as at 31 December 2018. The proved plus probable reserves replacement ratio for 2018 was 163 percent.

Production
Production was 81.1 thousand barrels of oil equivalent per day (Mboepd) (compared to 86.1 Mboepd for 2017) which was at the upper end of the updated guidance for the year of between 78 and 82 Mboepd and 4 percent above the mid-point of the original production guidance of between 74 and 82 Mboepd. This performance is due to strong facilities and reservoir performance at both the Edvard Grieg field and the Alvheim area.

Operating cost, including netting off tariff income, was USD 3.66 per barrel which was below the revised full year guidance of less than USD 3.80 per barrel and 12 percent below the original guidance of USD 4.15 per barrel. This performance is due to a combination of reduced costs, increased production volumes and the termination of production from the Brynhild field during the year.

Production in Mboepd	**1 Jan 2018-31 Dec 2018 12 months**	**1 Oct 2018-31 Dec 2018 3 months**	1 Jan 2017-31 Dec 2017 12 months	1 Oct 2017-31 Dec 2017 3 months
Norway				
Crude oil	71.9	73.5	77.6	74.6
Gas	9.2	8.6	8.5	8.5
Total production	**81.1**	**82.1**	86.1	83.1

Production in Mboepd	WI[1]	**1 Jan 2018-31 Dec 2018 12 months**	**1 Oct 2018-31 Dec 2018 3 months**	1 Jan 2017-31 Dec 2017 12 months	1 Oct 2017-31 Dec 2017 3 months
Edvard Grieg	65%	63.6	65.6	66.7	62.7
Ivar Aasen	1.385%	0.9	0.8	0.7	0.9
Alvheim	15%	9.3	10.1	12.4	9.8
Volund	35%	6.5	5.2	3.9	8.7
Bøyla	15%	0.7	0.4	1.1	0.9
Brynhild	51%[2]	0.0	–	1.2	–
Gaupe	40%	0.1	–	0.2	0.2
		81.1	**82.1**	86.1	83.1

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

Production from the Edvard Grieg field was above forecast, supported by continued strong production efficiency at 98 percent. During the fourth quarter 2018, Edvard Grieg production benefitted from additional facility capacity due to a cut back of Ivar Aasen production during maintenance of one of the Edvard Grieg turbine generators. The PDO development drilling programme was completed in the middle of the year with all development well results in line with or better than prognosis and the overall drilling programme was completed below budget. Edvard Grieg reservoir performance continues to exceed expectations with significantly slower build-up of water production than anticipated, leading to around a six month extension of plateau production to mid-2020. The 4D seismic survey that has been acquired over the Edvard Grieg field as part of the reservoir monitoring programme, indicates that the water injection flood front is further away from the main production wells than predicted by the current reservoir models. This information is still under review and has not been incorporated into the reservoir models used to support the year end 2018 reserves estimate. An infill drilling programme is being planned at Edvard Grieg commencing in 2020 and sanction of this project is anticipated during 2019. Operating cost for the Edvard Grieg field, including netting off tariff income, was USD 3.95 per barrel.

Production from the Ivar Aasen field was slightly below forecast, impacted in the fourth quarter 2018 by the Edvard Grieg power system maintenance. During the second quarter 2018, two new water injection wells were successfully drilled to improve pressure support to the eastern area of the field.

Production from the Alvheim area, consisting of the Alvheim, Volund and the Bøyla fields, was slightly ahead of forecast, supported by the strong reservoir performance and continued strong production efficiency for the Alvheim FPSO of 97 percent. The results of the infill well in the Kameleon area of the Alvheim field were in line with expectations and the well was brought on line ahead of schedule during the fourth quarter 2018. Combined with the two infill wells in the Boa area of the field, brought on line at the beginning of the year, this largely offsets the natural production decline from the area. Operating cost for the Alvheim area was USD 4.96 per barrel.

For the Brynhild field, the decision has been taken to permanently shut-in production and work on a cessation plan is ongoing, which will be submitted in due course to the authorities for approval. The remaining book value for the field was written off at year end 2017.

Despite no remaining reserves being attributable to the Gaupe field, the field has produced intermittently subject to favourable economic conditions. As it is no longer economic to continue with Gaupe field production, the decision was taken in October 2018 to cease production from the field.

Development

Field	WI	Operator	PDO Approval	Estimated gross reserves	Production start expected	Expected gross plateau production
Johan Sverdrup	22.6%	Equinor	August 2015	2.2 – 3.2 Bn boe	November 2019	660 Mbopd

Johan Sverdrup

Phase 1 of the Johan Sverdrup project is on schedule with approximately 85 percent completed. With the good project progress the expected schedule for Phase 1 first oil is November 2019.

2018 was a key installation year for Phase 1 of the project and the programme for the year was completed as planned. All of the four steel jackets have now been successfully installed offshore, as well as the topsides for the drilling platform and the riser platform. The power from shore cable has been installed and power supply from shore to the offshore facilities commenced in October 2018. Installation of the oil and gas export pipelines have been completed. Two accommodation units are located offshore and at peak approximately 800 personnel have been working on the hook-up of the installed offshore facilities, which is progressing on schedule.

Of the last two remaining topsides, the process platform topside sailed away from the Samsung Heavy Industries yard in South Korea in December 2018 and is expected to arrive at the Kværner Stord yard in Norway in February 2019. Construction of the living quarters topside at the Kværner yard has been completed and both these topsides are on schedule for installation in spring 2019.

Pre-drilling operations were completed significantly ahead of schedule with a total of eight pre-drilled producers and twelve water injectors completed. In December 2018, the drilling platform commenced tie-back operations on the eight pre-drilled production wells.

The latest capital expenditure estimate for Phase 1 is gross NOK 86 billion (nominal) compared to the Phase 1 PDO estimate in 2015 of gross NOK 123 billion (nominal), representing a saving of over 30 percent, excluding additional foreign exchange rate savings in US dollar terms. The gross production capacity of Phase 1 is estimated at 440 Mbopd.

The Phase 2 PDO was submitted to the Norwegian Ministry of Petroleum and Energy in August 2018, with Phase 2 first oil scheduled in the fourth quarter 2022. Phase 2 involves an additional processing platform bridge linked to the Phase 1 field centre, additional subsea facilities to allow the tie-in of additional wells to access the Avaldsnes, Kvitsøy and Geitungen satellite areas of the field and implementation of full field water alternating gas injection (WAG) for enhanced recovery. 28 new wells are planned to be drilled in connection with the Phase 2 development. These additional facilities will take the gross plateau production capacity to 660 Mbopd. With the inclusion of WAG, the gross resource range has been further increased to between 2.2 and 3.2 billion boe.

The Phase 2 capital expenditure is estimated at gross NOK 41 billion (nominal), which represents over a 50 percent saving from the original estimate in the phase 1 PDO, and is due to a combination of market conditions and optimisation of the Phase 2 facilities. The major topsides contracts and the jacket contract for the Phase 2 facilities have been awarded and detailed engineering is progressing to plan. Full field breakeven oil price is estimated at below 20 USD per barrel.

Appraisal

2018 appraisal well programme

Licence	Operator	WI	Well	Spud Date	Status
PL359	Lundin Norway	65%	Luno II	February 2018	Completed March 2018
PL338C	Lundin Norway	50%	Rolvsnes	April 2018	Completed August 2018
PL609	Lundin Norway	40%	Alta	April 2018	Completed September 2018
PL203	Aker BP	15%	Gekko	September 2018	Completed October 2018

All four wells in the 2018 appraisal drilling and testing programme were successful. Combined with two new exploration discoveries that were made during 2018, means that Lundin Petroleum has six potential projects being moved through the appraisal phase. These positive results contributed to increasing the booked contingent resources at year end 2018.

The Luno II appraisal well in PL359 on the Utsira High was successfully completed in March 2018 and encountered a gross oil column of 22 metres in Triassic sandstones with very good reservoir quality, which was significantly better than expected. Following the positive well results, the gross resource range for the Luno II discovery has been increased to between 40 and 100 MMboe. The development concept for Luno II is a subsea tie-back to the nearby Edvard Grieg platform. Phase 1 of the Luno II development project is expected to be sanctioned and the PDO submitted in the first quarter of 2019. To create commercial and operational alignment between the Edvard Grieg and Luno II partnerships, Lundin Petroleum has acquired Equinor's 15 percent interest in Luno II, increasing the working interest to 65 percent.

Appraisal drilling and production testing operations on the Rolvsnes basement oil discovery in PL338C in the Utsira High area of the North Sea were completed in August 2018. The horizontal well confirmed good productivity from fractured and weathered basement reservoirs and achieved a constrained production rate of 7,000 bopd. The successful well and testing operations have led to a substantial increase in gross resources for Rolvsnes to between 14 and 78 MMboe from previously 3 to 16 MMboe. The long-term production behavior from this reservoir needs to be understood better and the next step is to conduct an extended well test via a subsea tie-back of the suspended appraisal well to the Edvard Grieg platform. It is expected that the extended well test will be sanctioned in the first quarter of 2019 and implementation will be in parallel with the Luno II development project. The positive well result at Rolvsnes de-risks the similar on-trend prospectivity on the adjacent PL815 licence where an exploration well will be drilled on the Goddo prospect in 2019. The combined Rolvsnes and Goddo prospective area is estimated to contain gross potential resources of more than 250 MMboe.

The extended production testing on the Alta discovery in the southern Barents Sea was successfully completed in September 2018. The well was produced over a period of about two months with a maximum production rate of 18,000 bopd constrained by the surface facilities and with a total of approximately 660,000 barrels of oil produced to a tanker. The results were better than expected, demonstrating excellent reservoir productivity and connectivity to a large volume of oil. The large amount of new information from the positive results from the Alta extended production test and latest generation 3D seismic survey (Topseis) over the entire Alta and Gohta area is still being evaluated. The contingent resources for the Alta and Gohta discoveries are therefore unchanged from year end 2017 and will be updated during 2019 when the future appraisal plans for the area is defined and all the additional data has been processed.

The Gekko appraisal well located to the southeast of the Alvheim field was successfully completed in October 2018. The objective of the two branch well was to test the potential for improved reservoir quality away from the Gekko discovery well and determine the thickness of the oil column. Both well branches encountered good quality Heimdal sands with an approximately 6 metre oil rim below gas. Following the positive well results, the gross resource range for the Gekko discovery is between 28 and 52 MMboe. Options for the economic development of Gekko are being assessed.

Exploration

2018 exploration well programme

Licence	Operator	WI	Well	Spud Date	Result
PL340	Aker BP	15%	Frosk	January 2018	Oil discovery
PL167	Equinor	20%	Lille Prinsen	April 2018	Oil discovery
PL659	Aker BP	20%	Svanefjell	May 2018	Minor gas discovery
PL830	Lundin Norway	40%	Silfari	October 2018	Dry
PL860	MOL	40%	Driva/Oppdal	November 2018	Dry
PL857	Equinor	20%	Gjøkåsen Shallow	December 2018	Ongoing
PL857	Equinor	20%	Gjøkåsen Deep	January 2019	Ongoing
PL767	Lundin Norway	50%	Pointer/Setter	January 2019	Ongoing
PL869	AkerBP	20%	Froskelår Main	January 2019	Ongoing

The 2018 exploration drilling programme was impacted by changing rig schedules and priorities, which resulted in a number of wells moving into 2019. Five exploration wells were completed in 2018 resulting in two potential commercial discoveries, Frosk and Lille Prinsen. Exploration and appraisal expenditure in 2018 was MUSD 311.

In February 2018, the Frosk prospect in the North Sea, located northwest of the Bøyla field, proved an oil discovery. The discovery is estimated to contain gross resources of between 30 and 60 MMboe, which is significantly more than the pre-drill estimates and has a positive impact on the assessment of further exploration potential in the area. Two follow-up wells on the Froskelår Main and Rumpetroll prospects in the adjacent PL869 will be drilled in the first half of 2019, with the first of these wells currently ongoing. Additionally, a production test well on the Frosk discovery, to be tied into the Bøyla subsea facilities, will be drilled in the first half of 2019.

In May 2018, the Svanefjell prospect in PL659 in the southern Barents Sea proved a minor, non-commercial gas discovery.

In June 2018, the Lille Prinsen prospect in the North Sea, located northeast of the Ivar Aasen field, proved an oil discovery. The discovery is estimated to contain gross resources of between 15 and 35 MMboe and with significant appraisal upside potential of over 100 MMboe. It is expected that Lille Prinsen will be economic to develop and an appraisal well is planned for 2019.

In December 2018, the Silfari prospect in PL830 located in the Froan Basin area of the Norwegian Sea encountered good quality Jurassic reservoir sands but with no hydrocarbon indications and the second Permian carbonate target encountered no reservoir intervals or hydrocarbons. The potential of the undrilled, adjacent Frøya High area is unaffected by the Silfari result.

In December 2018, drilling commenced on the Gjøkåsen Shallow prospect in PL857 located in the southeastern Barents Sea. Gjøkåsen is a large, multi-horizon structure, remote from well control and as the deeper reservoir targets offset the shallow targets, it requires two wells to fully test the prospect. Gjøkåsen Shallow has estimated total gross unrisked prospective resources of 768 MMboe. Gjøkåsen Deep well will be drilled back-to-back with the Gjøkåsen Shallow well.

In January 2019, the Driva/Oppdal dual target prospect in PL860 located in the Mandal High area of the North Sea was drilled and was dry. While the well encountered Paleocene and Rotliegendes reservoirs there were no hydrocarbons present. The second Mandal High area dual target well, Vinstra/Otta on the adjacent PL539 licence, will be drilled in 2019.

In January 2019, drilling commenced on the Pointer/Setter prospect in PL767 located southeast of the Alta and Gohta discoveries in the southern Barents Sea. Pointer/Setter is a prospect with two distinct lower Cretaceous sandstone targets, with estimated total gross unrisked prospective resources of 312 MMboe. Drilling is being conducted by the Leiv Eiriksson rig which is under a flexible contract with sufficient option slots to meet the Company's operated 2019 drilling programme.

Licence awards and transactions

Lundin Petroleum continues to grow its exploration acreage position through licence rounds. In January 2018, the Company was awarded 14 licences in the 2017 APA licensing round, of which six as operator. In June 2018, the Company was awarded three licences in the 24th licensing round, of which one as operator. In January 2019, the Company was awarded 15 licences in the 2018 APA licensing round, of which 9 as operator. Currently, the Company holds 82 exploration licences in Norway, compared to 49 licences at the beginning of January 2018, which is an increase of approximately 70 percent.

In January 2018, Lundin Petroleum acquired a 10 percent working interest in each of PL539 and PL860 and a 30 percent working interest in each of PL820S and PL825 from Fortis Petroleum and also acquired a 20 percent working interest in PL860 from Equinor, increasing Lundin Petroleum's working interest in PL860 to 40 percent and in PL539 to 20 percent.

In May 2018, Lundin Petroleum concluded a licence swap with DNO to create an initial entry position in the Tampen/Horda Platform area of the Norwegian North Sea. Lundin Petroleum received a 10 percent working interest in each of PL926 and PL929 and 15 percent in each of PL921 and PL924 in exchange for DNO receiving 10 percent working interests in each of PL825, PL767, PL902 and PL950.

In June 2018, Lundin Petroleum concluded a licence swap with Edison in the southern Barents Sea where Lundin Petroleum received a 10 percent working interest in PL850, in exchange for Edison receiving a 10 percent working interest in PL952. In October 2018, Lundin Petroleum acquired a further 20 percent working interest in PL850 from Lime Petroleum, increasing the Company's working interest in PL850 to 30 percent.

In October 2018, Lundin Petroleum acquired Equinor's 15 percent working interest in PL359 containing the Luno II oil discovery. The transaction involved a cash consideration payable to Equinor as well as Lundin Petroleum transferring its remaining interest in PL825 to Equinor.

In January 2019, Lundin Petroleum entered into a sales and purchase agreement involving the acquisition of Lime Petroleum's 30 percent working interest in each of PL338C and PL338E and 20 percent working interest in PL815, which contain the Rolvsnes oil discovery and Goddo prospect. The transaction will increase the Company's working interest in each of PL338C and PL338E to 80 percent and in PL815 to 60 percent. The transaction involves a cash consideration payable to Lime Petroleum and is subject to customary government approvals.

Russia

Lundin Petroleum has previously written down the entire contingent resources and book value for the Morskaya oil discovery as it was deemed unlikely that the discovery could commercially be developed in the foreseeable future. Having reviewed potential options, the partnership concluded that it is not possible for the partnership to create value from the asset and consequently the Morskaya licence has been relinquished.

Health, Safety and Environment

During the year, one lost time incident and one medical treatment incident occurred, resulting in a Lost Time Incident Rate of 0.5 per million hours worked and a Total Recordable Incident Rate of 1.0 per million hours worked. There were no material safety or environmental incidents.

FINANCIAL REVIEW

Result

The operating profit from continuing operations for the financial year amounted to MUSD 1,402.4 (MUSD 812.4). The increase compared to the comparative period was mainly driven by higher oil prices in combination with lower production costs and depletion costs, somewhat offset by lower production volumes.

The net result from continuing operations for the year amounted to MUSD 222.1 (MUSD 380.9) and included a foreign currency exchange loss of MUSD 164.9 (gain of MUSD 255.3). The net result from continuing operations excluding foreign currency exchange results amounted to MUSD 387.0 (MUSD 125.6). The increase compared to the comparative period was mainly driven by higher oil prices in combination with lower production costs and depletion costs, somewhat offset by lower production volumes and an after tax accounting gain of MUSD 98.1 as a result of the re-negotiated improved borrowing terms for the reserve-based lending facility that unwinds to the income statement over the remaining period of the facility.

The net result from continuing operations attributable to shareholders of the Parent Company for the year amounted to MUSD 222.1 (MUSD 384.7) representing earnings per share of USD 0.66 (USD 1.13).

Earnings before interest, tax, depletion and amortisation (EBITDA) from continuing operations for the year amounted to MUSD 1,916.2 (MUSD 1,501.5) representing EBITDA per share of USD 5.65 (USD 4.41). Operating cash flow from continuing operations for the year amounted to MUSD 1,847.8 (MUSD 1,530.0) representing operating cash flow per share of USD 5.46 (USD 4.50).

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 in the comparative periods.

Revenue and other income

Revenue and other income for the year amounted to MUSD 2,617.4 (MUSD 1,997.0) 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 2,607.9 (MUSD 1,958.3). The average price achieved by Lundin Petroleum for a barrel of oil equivalent from own production amounted to USD 67.89 (USD 51.63) and is detailed in the following table. The average Dated Brent price for the year amounted to USD 71.31 (USD 54.25) 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 2018- 31 Dec 2018 12 months**	**1 Oct 2018- 31 Dec 2018 3 months**	1 Jan 2017- 31 Dec 2017 12 months	1 Oct 2017- 31 Dec 2017 3 months
Crude oil sales				
– Quantity in Mboe	26,834.7	7,237.5	28,106.9	5,364.9
– *Average price per bbl*	*69.97*	*66.42*	*53.37*	*62.41*
Gas and NGL sales				
– Quantity in Mboe	3,682.0	876.4	3,943.1	1,325.0
– *Average price per boe*	*52.74*	*53.50*	*39.23*	*44.60*
Total sales				
– Quantity in Mboe	**30,516.7**	**8,113.9**	32,050.0	6,689.9
– Average price per boe	***67.89***	***65.03***	*51.63*	*58.87*

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 536.1 (MUSD 303.5) and mainly consisted of Grane Blend 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 expense of MUSD 23.3 (income of MUSD 13.8) in the year due to the timing of the cargo liftings compared to production.

Other income for the year amounted to MUSD 32.8 (MUSD 24.9) and included a quality differential compensation on Alvheim blended crude and tariff income of MUSD 29.4 (MUSD 21.7) 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 145.4 (MUSD 164.2) and are detailed in Note 2. The total production cost per barrel of oil equivalent produced is detailed in the table below:

Production costs	1 Jan 2018-31 Dec 2018 12 months	1 Oct 2018-31 Dec 2018 3 months	1 Jan 2017-31 Dec 2017 12 months	1 Oct 2017-31 Dec 2017 3 months
Cost of operations				
– In MUSD	102.5	28.5	117.3	32.9
– In USD per boe	*3.46*	*3.78*	*3.73*	*4.31*
Tariff and transportation expenses				
– In MUSD	35.2	9.4	37.9	9.0
– In USD per boe	*1.19*	*1.24*	*1.21*	*1.17*
Operating costs				
– In MUSD	**137.7**	**37.9**	155.2	41.9
– In USD per boe[1]	***4.65***	***5.02***	*4.94*	*5.48*
Change in inventory position				
– In MUSD	0.6	0.0	-0.4	-0.1
– In USD per boe	*0.02*	*0.00*	*-0.02*	*-0.02*
Other				
– In MUSD	7.1	1.7	9.4	1.8
– In USD per boe	*0.24*	*0.23*	*0.30*	*0.23*
Production costs				
– In MUSD	**145.4**	**39.6**	164.2	43.6
– In USD per boe	***4.91***	***5.25***	*5.22*	*5.69*

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 operating cost for the year of USD 4.65 (USD 4.94) per barrel is reduced to USD 3.66 (USD 4.25) when tariff income is netted off. The operating cost for the fourth quarter 2018 of USD 5.02 (USD 5.48) per barrel is reduced to USD 4.14 (USD 4.54) when tariff income is netted off.

The total cost of operations for the year amounted to MUSD 102.5 (MUSD 117.3). The total cost of operations excluding operational projects amounted to MUSD 93.0 (MUSD 105.9). The reduction compared to the comparative period is the result of the termination of production from the Brynhild field during the year.

The cost of operations per barrel for the year amounted to USD 3.46 (USD 3.73) including operational projects and USD 3.14 (USD 3.37) excluding operational projects.

Tariff and transportation expenses for the year amounted to MUSD 35.2 (MUSD 37.9) or USD 1.19 (USD 1.21) per barrel.

Other costs for the year amounted to MUSD 7.1 (MUSD 9.4) and related to the business interruption insurance. The comparative period also included the operating cost share arrangement on the Brynhild field whereby the amount of operating cost varied 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 for the year amounted to MUSD 458.0 (MUSD 567.3) at an average rate of USD 15.46 (USD 18.05) per barrel and are detailed in Note 3. The lower depletion costs for the year compared to the comparative period is due to the lower depletion rate per barrel for the Edvard Grieg field as a result of the increased reserves per end 2017 and lower production volumes.

Exploration costs

Exploration costs expensed in the income statement for the year amounted to MUSD 53.2 (MUSD 73.1) and are detailed in Note 3. Exploration and appraisal costs are capitalised as they are incurred. When exploration drilling is unsuccessful, the capitalised costs are expensed. All capitalised exploration costs are reviewed on a regular basis and are expensed where their recoverability is considered highly uncertain.

Impairment costs of oil and gas properties

Impairment costs in the income statement for the year amounted to MUSD — (MUSD 30.6) and are detailed in note 3. The impairment costs in the comparative period were triggered by the partial sale of the Brynhild field in PL148 where a 39 percent working interest was divested.

Loss from sale of assets

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

Purchase of crude oil from third parties

Purchase of crude oil from third parties for the year amounted to MUSD 533.8 (MUSD 303.3) and related mainly to Grane Blend crude 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 24.6 (MUSD 31.7) which included a charge of MUSD 3.9 (MUSD 4.3) 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 2.6 (MUSD 2.5).

Finance income

Finance income for the year amounted to MUSD 192.2 (MUSD 256.7) and is detailed in Note 4.

During the year the reserve-based lending facility was successfully re-negotiated resulting in the interest rate margin over LIBOR being reduced from 3.15 percent to a current rate of 2.25 percent effective as of 1 June 2018. The amendment of the interest rate margin has resulted in an accounting gain of MUSD 183.7 (MUSD —) in accordance with IFRS 9. When a financial liability, measured at amortised cost, is modified without this resulting in derecognition, a gain or loss should be recognised in the income statement based on IFRS 9. The gain or loss is calculated as the difference between the original contractual cash flows and the modified cash flows discounted at the original effective interest rate.

Other financial income amounted to MUSD 3.3 (MUSD 0.4) and included the change in fair value under IFRS 9 of the shares held in ShaMaran as described on page 11. The shares held in ShaMaran were sold during the year at the prevailing market price.

Finance costs

Finance costs for the year amounted to MUSD 345.4 (MUSD 186.6) and are detailed in Note 5.

The net foreign currency exchange loss for the year amounted to MUSD 164.9 (gain of MUSD 255.3). 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 capital expenditure amounts against the US Dollar and for the year, the net realised exchange gain on these settled foreign exchange hedges amounted to MUSD 5.2 (loss of MUSD 1.8).

The US Dollar strengthened against the Euro during the year resulting in a net foreign currency exchange loss 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.

Interest expenses for the year amounted to MUSD 88.7 (MUSD 115.0) and represented the portion of interest charged to the income statement. An additional amount of interest of MUSD 87.6 (MUSD 63.5) associated with the funding of the Norwegian development projects was capitalised in the year. The total interest expense is slightly lower compared to the comparative period mainly due to lower drawn debt under the reserve-based lending facility offset by higher interest rates. The result on interest rate hedge settlements amounted to a gain of MUSD 3.5 (loss of MUSD 17.4) and is reported as financial income.

The amortisation of the deferred financing fees for the year amounted to MUSD 17.8 (MUSD 17.5) and related to the fees incurred in establishing the reserve-based lending facility. The fees are being expensed over the expected life of the facility.

Loan facility commitment fees for the year amounted to MUSD 13.0 (MUSD 11.1) with the increase compared to the comparative period being the result of the lower drawn debt under the reserve-based lending facility somewhat offset by a lower margin for commitment fees as agreed through the amendment of the facility effective as of 1 June 2018.

The loan modification fees for the year amounted to MUSD 17.3 (MUSD —) and related to the fees incurred for the re-negotiated reserve-based lending facility resulting in the interest rate margin over LIBOR being reduced from 3.15 percent to a current rate of 2.25 percent effective as of 1 June 2018. The net accounting gain when offsetting these loan modification fees against the reported loan modification gain amounted to MUSD 166.4. The associated deferred taxes amounted to MUSD 68.3 resulting in an after tax accounting gain of MUSD 98.1 that unwinds to the income statement over the remaining period of the facility.

The unwinding of the loan modification gain for the year amounted to MUSD 26.1 (MUSD —) and related to the expensing of the accounting gain from the re-negotiated improved borrowing terms for the reserve-based lending facility over the period of usage of the facility.

Share in result of associate company

Share in result of associated company for the year amounted to MUSD -1.3 (MUSD -0.4) and related to the share in the result of the investment in Mintley Caspian Ltd.

Tax

The overall tax charge for the year amounted to MUSD 1,025.8 (MUSD 501.2) and is detailed in Note 6.

The current tax charge for the year amounted to MUSD 90.4 (MUSD -0.5) of which MUSD 89.0 (MUSD -1.5) related to Norway. The current tax charge for Norway related to Corporate Tax only with no current tax charge to the income statement in relation to the Special Petroleum Tax (SPT) as the Company continues to be sheltered from SPT tax losses. The paid tax installments in Norway during the year amounted to MUSD 14.8 which has resulted in an increase in current tax liabilities compared to the comparative period.

The deferred tax charge for the year amounted to MUSD 935.4 (MUSD 501.7) and 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 results, 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 — (MUSD -3.8) and related in the comparative period 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. The investment in Mintley Caspian Ltd. was deconsolidated at the end of the third quarter 2017 and the results are now reported as share in result of associated company.

Balance Sheet

Non-current assets

Oil and gas properties amounted to MUSD 5,341.1 (MUSD 4,937.1) and are detailed in Note 7.

Development, exploration and appraisal expenditure incurred for the year was as follows:

Development expenditure in MUSD	**1 Jan 2018- 31 Dec 2018 12 months**	**1 Oct 2018- 31 Dec 2018 3 months**	1 Jan 2017- 31 Dec 2017 12 months	1 Oct 2017- 31 Dec 2017 3 months
Norway	701.9	151.0	950.0	216.0
Development expenditures	**701.9**	**151.0**	950.0	216.0

Development expenditure of MUSD 701.9 (MUSD 950.00) was incurred in Norway during the year, primarily on the Johan Sverdrup and Edvard Grieg fields. In addition an amount of MUSD 87.6 (MUSD 63.5) of interest was capitalised.

Exploration and appraisal expenditure in MUSD	**1 Jan 2018- 31 Dec 2018 12 months**	**1 Oct 2018- 31 Dec 2018 3 months**	1 Jan 2017- 31 Dec 2017 12 months	1 Oct 2017- 31 Dec 2017 3 months
Norway	310.6	85.4	227.1	54.6
Russia	—	—	1.1	—
Exploration and appraisal expenditure	**310.6**	**85.4**	228.2	54.6

Exploration and appraisal expenditure of MUSD 310.6 (MUSD 227.1) was incurred in Norway during the year, primarily for the appraisal wells Luno II in PL359, Rolvsnes in PL338C and Alta in PL609, the exploration wells Frosk in PL340, Svanefjell in PL659, Lille Prinsen in PL167, Silfari in PL830 and Driva/Oppdal in PL860 as well as for Phase 2 of the Johan Sverdrup project. The income associated with the oil produced during the extended production test of the Alta appraisal well in PL609 during the third quarter was offset against the capitalised appraisal expenditure in the year.

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 0.4 (MUSD 6.7). The comparative period included the shares held in ShaMaran which were sold during the year to a related party, see also the Related Party Transactions section below.

Derivative instruments amounted to MUSD 2.7 (MUSD 26.5) 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 36.5 (MUSD 33.7) and included both well supplies and hydrocarbon inventories.

Trade and other receivables amounted to MUSD 219.3 (MUSD 304.4) and are detailed in Note 8. Trade receivables, which are all current, amounted to MUSD 153.7 (MUSD 202.7) and included invoiced cargoes. Underlift amounted to MUSD 4.6 (MUSD 29.4) and was attributable to an underlift position on the producing fields. Joint operations debtors relating to various joint venture receivables amounted to MUSD 17.0 (MUSD 15.6). Prepaid expenses and accrued income amounted to MUSD 26.9 (MUSD 29.3) and represented mainly prepaid operational and insurance expenditure. Other current assets amounted to MUSD 17.1 (MUSD 27.4) and included a short term receivable from IPC in relation to certain working capital balances following the IPC spin-off amounting to MUSD 14.0 and other miscellaneous receivable balances.

Derivative instruments amounted to MUSD 34.0 (MUSD 7.7) and related to the marked-to-market gain on the outstanding interest rate and currency hedge contracts due to be settled within twelve months.

Cash and cash equivalents amounted to MUSD 66.8 (MUSD 71.4). Cash balances are held to meet ongoing operational funding requirements.

Non-current liabilities
Financial liabilities amounted to MUSD 3,262.0 (MUSD 3,880.0) and are detailed in Note 9. Bank loans amounted to MUSD 3,465.0 (MUSD 3,955.0) and related to the outstanding loan under the reserve-based lending facility. Capitalised financing fees relating to the establishment of the facility amounted to MUSD 54.1 (MUSD 75.0) and are being amortised over the expected life of the facility. The capitalised loan modification gain relating to the re-negotiated improved borrowing terms for the lending facility amounted to MUSD 148.9 (MUSD —) and are being amortised over the expected life of the facility.

Provisions amounted to MUSD 489.1 (MUSD 420.6) and are detailed in Note 10. The provision for site restoration amounted to MUSD 483.9 (MUSD 414.6) and related to the long-term portion of the future decommissioning obligations. The increase mainly reflects the additional liability for Edvard Grieg and for the Johan Sverdrup development project. The short-term portion of the future decommissioning obligations was classified as current liabilities.

Deferred tax liabilities amounted to MUSD 2,103.0 (MUSD 1,302.2). 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 64.9 (MUSD 3.1) and related to the marked-to-market loss on outstanding interest rate and currency hedge contracts due to be settled after twelve months.

Current liabilities
Trade and other payables amounted to MUSD 204.6 (MUSD 259.0) and are detailed in Note 11. Overlift amounted to MUSD 5.4 (MUSD 12.8) and was attributable to an overlift position in relation to the Edvard Grieg field. Joint operations creditors and accrued expenses amounted to MUSD 147.4 (MUSD 188.9) and related to activity in Norway. Other accrued expenses amounted to MUSD 17.6 (MUSD 19.5) and other current liabilities amounted to MUSD 7.6 (MUSD 7.7).

Derivative instruments amounted to MUSD 20.0 (MUSD 6.4) and related to the marked-to-market loss on outstanding interest rate and currency hedge contracts due to be settled within twelve months.

Current tax liabilities amounted to MUSD 70.4 (MUSD 0.6) and related mainly to Corporate Tax due in Norway.

Current provisions amounted to MUSD 12.5 (MUSD 7.7) and are detailed in Note 10. The short-term portion of the future decommissioning obligations amounted to MUSD 6.6 (MUSD —) and the current portion of the provision for Lundin Petroleum's Unit Bonus Plan amounted to MUSD 5.9 (MUSD 7.7).

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 for the year amounted to MSEK 1,657.8 (MSEK 46,648.6). The net result for the year included MSEK 1,812.4 financial income as a result of received dividends from a subsidiary. The net result for the comparative period included MSEK 46,543.2 financial income as a result of an internal restructuring prior to the IPC spin-off in 2017. The net result excluding these financial income items amounted to MSEK -154.6 (MSEK 105.4).

The net result included general and administrative expenses of MSEK 180.9 (MSEK 146.7) and net finance income of MSEK 5.3 (MSEK 243.2) when excluding the finance income items as mentioned above.

Pledged assets of MSEK 55,118.9 (MSEK 55,118.9) relate to the carrying value of the pledge of the shares in respect of the reserve-based lending 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 various transactions with related parties on a commercial basis including the transactions described below.

The Group has purchased oil from the Equinor group (previously Statoil) on an arm's-length basis amounting to MUSD 296.2 (MUSD —).

The Group has sold oil and related products to the Equinor group on an arm's-length basis amounting to MUSD 879.5 (MUSD 176.2).

The Group has acquired from the Equinor group a 15 percent working interest in PL359 containing the Luno II oil discovery. The transaction involved a cash consideration payable to Equinor as well as Lundin Petroleum transferring its 20 percent working interest in PL825 to Equinor. The transaction completed in December 2018.

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 14.0. This receivable is due by mid-2019.

The Group has sold the shares held in ShaMaran to Zebra Holdings and Investment (Guernsey) Ltd. based on the quoted market share price of ShaMaran amounting to MUSD 9.3.

Liquidity

In February 2016, Lundin Petroleum entered into a committed seven year senior secured reserve-based lending facility of USD 5.0 billion. The facility was amended during the second quarter of 2018 resulting in the interest rate margin over LIBOR being reduced from 3.15 percent to a current rate of 2.25 percent. The facility is secured against certain cash flows generated by the Group. The amount available under the facility is recalculated every twelve 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, a pledge over the Company's working interest in some production licenses and a charge over some of the bank accounts of the pledged companies.

Contingent liabilities

The Swedish Prosecution Authority issued a notification of a corporate fine and forfeiture of economic benefits against Lundin Petroleum in relation to past operations in Sudan from 1997 to 2003. The notification indicated that the Prosecutor might seek a corporate fine of SEK 3 million and forfeiture of economic benefits from the alleged offense in the amount of SEK 3,282 million, based on the profit of the sale of the Block 5A asset in 2003 of SEK 720 million. Any potential corporate fine or forfeiture would only be imposed after the conclusion of a trial, should one occur. The investigation is in its ninth year and Lundin Petroleum remains convinced that there are absolutely no grounds for any allegations of wrongdoing by any Company representative and the Company will firmly contest any corporate fine or forfeiture of economic benefits. The Company considers this to be a contingent liability and therefore no provision has been recognised.

Subsequent Events

In January 2019, Lundin Petroleum entered into a sales and purchase agreement involving the acquisition of Lime Petroleum's 30 percent working interest in each of PL338C and PL338E and 20 percent working interest in PL815, which contain the Rolvsnes oil discovery and Goddo prospect. The transaction will increase the Company's working interest in each of PL338C and PL338E to 80 percent and in PL815 to 60 percent. The transaction involves a cash consideration payable to Lime Petroleum of MUSD 43 and a contingent payment of an additional MUSD 2 which potentially becomes payable 12 months after the completion date of the transaction. The transaction is subject to customary government approvals.

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 2017, 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. During the year, Lundin Petroleum purchased an additional 640,000 of its own shares at an average price of SEK 186.77 based on the approval granted at the AGM 2017 resulting in 1,873,310 of its own shares held at the end of the year.

The AGM of Lundin Petroleum held on 3 May 2018 in Stockholm approved an inaugural cash dividend distribution for the year 2017 of SEK 4.00 per share and the dividend was distributed on 11 May 2018. Based on the number of shares outstanding, excluding own shares held by the Company, the dividend distribution amounted to MSEK 1,354.1, equaling MUSD 153.1 based on the exchange rate on the date of AGM approval.

Updated dividend policy and 2018 dividend proposal

Lundin Petroleum's objective is to create attractive shareholder returns by investing through the business cycle with capital investments allocated to exploration, development and production assets. The Company's expectation is to create shareholder returns both through share price appreciation and by distributing a sustainable yearly dividend - paid in quarterly instalments and denominated in USD - with the plan of maintaining or increasing the dividend over time in line with the Company's financial performance and being sustainable below an oil price of USD 50 per barrel. The dividend shall be sustainable in the context of allowing the Company to continue to pursue its organic growth strategy and to develop its contingent resources whilst maintaining a conservative gearing ratio and retaining an appropriate liquidity position within its available credit lines.

In accordance with the updated dividend policy, the Board of Directors will propose to the 2019 Annual General Meeting a dividend for 2018 of USD 1.48 per share, corresponding to USD 500 million (rounded off), to be paid in quarterly instalments of USD 0.37 per share, corresponding to USD 125 million (rounded off). Before payment, each quarterly dividend of USD 0.37 per share shall be converted into a SEK amount, and paid out in SEK, based on the USD to SEK exchange rate published by Sweden's central bank (Riksbanken) four business days prior to each record date (rounded off to the nearest whole SEK 0.01 per share). The final USD equivalent amount received by the shareholders may therefore slightly differ depending on what the USD to SEK exchange rate is on the date of the dividend payment. The SEK amount per share to be distributed each quarter will be announced in a press release four business days prior to each record date.

The first dividend payment is expected to be paid around 5 April 2019, with an expected record date of 2 April 2019 and expected ex-dividend date of 1 April 2019. The second dividend payment is expected to be paid around 8 July 2019, with an expected record date of 3 July 2019 and expected ex-dividend date of 2 July 2019. The third dividend payment is expected to be paid around 7 October 2019, with an expected record date of 2 October 2019 and an expected ex-dividend date of 1 October 2019.

The fourth dividend payment is expected to be paid around 9 January 2020, with an expected record date of 3 January 2020 and an expected ex-dividend date of 2 January 2020.

In order to comply with Swedish company law, a maximum total SEK amount shall be pre-determined to ensure that the dividend distributed does not exceed the available distributable reserves of the Company and such maximum amount for the 2018 dividend has been set to a cap of SEK 7.665 billion (i.e., SEK 1.916 billion per quarter). If the total dividend would exceed the cap of SEK 7.665 billion, the dividend will be automatically adjusted downwards so that the total dividend corresponds to the cap of SEK 7.665 billion.

Remuneration

Lundin Petroleum's principles for remuneration and details of the long-term incentive plans are provided in the Company's 2017 Annual Report and in the materials provided to shareholders in respect of the 2018 AGM, available on www.lundin-petroleum.com

Unit Bonus Plan

The number of units relating to the awards made in 2016, 2017 and 2018 under the Unit Bonus Plan outstanding as at 31 December 2018 were 107,794, 188,064 and 226,389 respectively.

Performance Based Incentive Plan

The AGM 2018 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 2018 and the 2018 award is accounted for from the second half of 2018. The total outstanding number of awards at 31 December 2018 was 278,917 and the awards vest over three years from 1 July 2018 subject to certain performance conditions being met. Each original award was fair valued at the date of grant at SEK 167.10 using an option pricing model.

The 2017 plan is effective from 1 July 2017 and the total outstanding number of awards at 31 December 2018 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 2018 was 409,343 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.

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).

IFRS 9 has come into effect with effective date 1 January 2018. IFRS 9 Financial instruments, addresses the classification, measurement and recognition of financial assets and financial liabilities, introduced new rules for hedge accounting and a new impairment model for financial assets. Based on this standard, the investment in ShaMaran Petroleum Corp. (ShaMaran) was booked at fair value of the shares with movements in the fair value of the shares being directly recognised in the consolidated income statement. The ShaMaran shares were sold during the year. The Group applies the new rules retrospectively from 1 January 2018 and the comparatives are not restated.

Based on IFRS 9, a net accounting gain of MUSD 166.4 was recognised during the year as a result of the re-negotiated improved borrowing terms for the reserve-based lending facility taking effect as of 1 June 2018. See also Financial Income section on page 8.

IFRS 15 has come into effect with effective date 1 January 2018. IFRS 15 Revenue from contract with customers, addresses revenue recognition and established principles for reporting useful information to users of financial statements. Based on this standard, certain transactions are no longer reported as revenue but as other income instead. The Group applies the new rules using the full retrospective approach and the comparatives have been restated.

IFRS 16 Leases is effective from 1 January 2019 and will replace IAS 17. The new standard requires recognition in the balance sheet for each contract, with some exceptions, that meets the definition of a lease as a right of use asset and lease liability, while lease payments are to be reflected as interest expense and a reduction of lease liability. The Group has made the following transition choices in relation to IFRS 16: (a) application of the modified retrospective method, (b) right of use assets will be measured at an amount equal to the lease liability and (c) leases with a less than 12 months remaining lease term at year end 2018 will not be reflected as leases. The Group has made the following application policy choice: short term leases (less than 12 months) and leases of low value assets will not be reflected in the balance sheet, but will be expensed as incurred.

Lundin Petroleum has assessed the impact of IFRS 16 on the financial statements of the Group and only identified one relevant contract containing a lease with no material impact on the financial statements of the Group.

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 2017.

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 2017 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 and to meet part of its future NOK Corporate Tax requirements. At 31 December 2018, Lundin Petroleum had outstanding currency hedges as summarised below:

Buy	Sell	Average contractual Exchange rate	Settlement period
MNOK 3,822.4	MUSD 464.0	NOK 8.24:USD 1	Jan 2019 – Dec 2019
MNOK 2,405.0	MUSD 306.0	NOK 7.86:USD 1	Jan 2020 – Dec 2020
MNOK 2,130.0	MUSD 272.7	NOK 7.81:USD 1	Jan 2021 – Dec 2021
MNOK 1,200.0	MUSD 158.2	NOK 7.59:USD 1	Jan 2022 – Dec 2022
MNOK 410.0	MUSD 51.0	NOK 8.04:USD 1	Jan 2023 – Dec 2023

Lundin Petroleum entered into interest rate hedge contracts and at 31 December 2018 had outstanding interest rate hedge contracts as follows:

Borrowings expressed in MUSD	Fixing of floating LIBOR average rate per annum	Settlement period
3,000	1.42%	Jan 2019 – Dec 2019
2,000	2.15%	Jan 2020 – Dec 2020
2,000	2.67%	Jan 2021 – Dec 2021
2,000	2.74%	Jan 2022 – Dec 2022

Under IFRS 9, subject to hedge effectiveness testing, all of the hedges are treated as effective and changes to the fair value are reflected in other comprehensive income.

Exchange Rates

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

	31 Dec 2018		31 Dec 2017	
	Average	Period end	Average	Period end
1 USD equals NOK	8.1329	8.6885	8.2712	8.2050
1 USD equals Euro	0.8464	0.8734	0.8855	0.8338
1 USD equals SEK	8.6921	8.9562	8.5481	8.2080

Consolidated Income Statement

Expressed in MUSD	Note	**1 Jan 2018- 31 Dec 2018 12 months**	**1 Oct 2018- 31 Dec 2018 3 months**	1 Jan 2017- 31 Dec 2017 12 months	1 Oct 2017- 31 Dec 2017 3 months
Revenue and other income	1				
Revenue		2,607.9	644.6	1,958.3	509.0
Other income		9.5	-33.6	38.7	84.7
		2,617.4	**611.0**	1,997.0	593.7
Cost of sales					
Production costs	2	-145.4	-39.6	-164.2	-43.6
Depletion and decommissioning costs		-458.0	-116.5	-567.3	-138.8
Exploration costs		-53.2	-47.1	-73.1	-30.9
Impairment costs of oil and gas properties		—	—	-30.6	—
Loss from sale of assets		—	—	-14.4	-14.4
Purchase of crude oil from third parties		-533.8	-116.6	-303.3	-115.3
Gross profit	3	**1,427.0**	**291.2**	844.1	250.7
General, administration and depreciation expenses		-24.6	-6.9	-31.7	-6.8
Operating profit		**1,402.4**	**284.3**	812.4	243.9
Net financial items					
Finance income	4	192.2	4.0	256.7	-68.9
Finance costs	5	-345.4	-207.1	-186.6	-52.7
		-153.2	**-203.1**	70.1	-121.6
Share in result of associated company		-1.3	-0.7	-0.4	-0.4
Profit before tax		**1,247.9**	**80.5**	882.1	121.9
Income tax	6	-1,025.8	-185.8	-501.2	-172.8
Net result from continuing operations		**222.1**	**-105.3**	380.9	-50.9
Discontinued operations					
Net result - IPC		—	—	46.5	-1.1
Net result		**222.1**	**-105.3**	427.4	-52.0
Attributable to:					
Shareholders of the Parent Company		222.1	-105.3	431.2	-52.0
Non-controlling interest		—	—	-3.8	—
		222.1	**-105.3**	427.4	-52.0
Earnings per share – USD[1]					
From continuing operations		0.66	-0.31	1.13	-0.15
From discontinued operations		—	—	0.14	0.00
Earnings per share fully diluted – USD[1]					
From continuing operations		0.65	-0.31	1.13	-0.15
From discontinued operations		—	—	0.14	0.00

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

Consolidated Statement of Comprehensive Income

Expressed in MUSD	**1 Jan 2018- 31 Dec 2018 12 months**	**1 Oct 2018- 31 Dec 2018 3 months**	1 Jan 2017- 31 Dec 2017 12 months	1 Oct 2017- 31 Dec 2017 3 months
Net result	**222.1**	**-105.3**	427.4	-52.0
Items that may be subsequently reclassified to profit or loss:				
Exchange differences foreign operations	1.5	-14.4	-96.3	-30.2
Cash flow hedges	-74.1	-118.6	76.4	-6.4
Available-for-sale financial assets	–	–	5.0	6.2
Other comprehensive income, net of tax	**-72.6**	**-133.0**	-14.9	-30.4
Total comprehensive income	**149.5**	**-238.3**	412.5	-82.4
Attributable to:				
Shareholders of the Parent Company	149.5	-238.3	416.3	-82.4
Non-controlling interest	–	–	-3.8	–
	149.5	**-238.3**	412.5	-82.4

Consolidated Balance Sheet

Expressed in MUSD	Note	31 December 2018	31 December 2017
ASSETS			
Non-current assets			
Oil and gas properties	7	5,341.1	4,937.1
Other tangible fixed assets		13.6	13.2
Goodwill		128.1	128.1
Financial assets		0.4	6.7
Derivative instruments	12	2.7	26.5
Total non-current assets		**5,485.9**	5,111.6
Current assets			
Inventories		36.5	33.7
Trade and other receivables	8	219.3	304.4
Derivative instruments	12	34.0	7.7
Cash and cash equivalents		66.8	71.4
Total current assets		**356.6**	417.2
TOTAL ASSETS		**5,842.5**	5,528.8
EQUITY AND LIABILITIES			
Equity			
Shareholders´ equity		**-384.0**	-350.8
Liabilities			
Non-current liabilities			
Financial liabilities	9	3,262.0	3,880.0
Provisions	10	489.1	420.6
Deferred tax liabilities		2,103.0	1,302.2
Derivative instruments	12	64.9	3.1
Total non-current liabilities		**5,919.0**	5,605.9
Current liabilities			
Trade and other payables	11	204.6	259.0
Derivative instruments	12	20.0	6.4
Current tax liabilities		70.4	0.6
Provisions	10	12.5	7.7
Total current liabilities		**307.5**	273.7
Total liabilities		**6,226.5**	5,879.6
TOTAL EQUITY AND LIABILITIES		**5,842.5**	5,528.8

Consolidated Statement of Cash Flows

Expressed in MUSD	1 Jan 2018- 31 Dec 2018 12 months	1 Oct 2018- 31 Dec 2018 3 months	1 Jan 2017- 31 Dec 2017 12 months	1 Oct 2017- 31 Dec 2017 3 months
Cash flows from operating activities				
Net result	222.1	-105.3	380.9	-50.9
Adjustments for:				
Exploration costs	53.2	47.1	73.1	30.9
Depletion, depreciation and amortisation	460.6	117.1	570.9	140.5
Impairment of oil and gas properties	–	–	30.6	–
Current tax	90.4	35.7	-0.5	0.3
Deferred tax	935.4	150.1	501.7	172.5
Impairment of other shares	–	–	11.2	11.2
Long-term incentive plans	14.6	0.5	12.7	3.2
Foreign currency exchange gain/ loss	162.5	161.5	-258.0	69.9
Interest expense	88.7	20.0	115.0	26.8
Loan modification gain	-183.7	–	–	–
Loan modification fees	17.3	–	–	–
Unwinding of loan modification gain	26.1	11.0	–	–
Capitalised financing fees	17.8	4.3	17.5	4.4
Other	12.8	4.4	26.4	17.6
Interest received	1.1	0.3	1.0	0.5
Interest paid	-176.0	-42.9	-177.3	-46.1
Income taxes paid / received	-15.8	-10.0	82.2	82.6
Changes in working capital	-8.8	38.9	-88.1	-124.7
Total cash flows from operating activities	**1,718.3**	**432.7**	1,299.3	338.7
Cash flows from investing activities				
Investment in oil and gas properties	-1,060.1	-258.4	-1,178.2	-270.5
Investment in other fixed assets	-3.2	-0.5	-1.6	-0.7
Investment in other shares and participations[1]	9.3	–	-1.3	–
Decommissioning costs paid	-1.3	-0.5	-0.4	-0.3
Disposal of fixed assets [2]	–	–	93.7	93.7
Other payments	–	–	-7.8	-0.3
Total cash flows from investing activities	**-1,055.3**	**-259.4**	-1,095.6	-178.1
Cash flows from financing activities				
Changes in long-term liabilities	-490.0	-180.0	-188.7	-160.0
Financing fees paid	-17.3	–	–	–
Cash funded from / to discontinued operations	–	–	31.7	–
Dividends paid	-153.1	–	–	–
Purchase of own shares	-14.3	–	-28.0	-20.2
Total cash flows from financing activities	**-674.7**	**-180.0**	-185.0	-180.2
Change in cash and cash equivalents	-11.7	-6.7	18.7	-19.6
Cash and cash equivalents at the beginning of the period	71.4	75.1	56.1	91.0
Currency exchange difference in cash and cash equivalents	7.1	-1.6	-3.2	–
Cash and cash equivalent of deconsolidated operations	–	–	-0.2	–
Cash and cash equivalents at the end of the period	**66.8**	**66.8**	71.4	71.4

[1] Cash received on the sale of the shares held in ShaMaran.
[2] Cash received on the divestment of a 39 percent working interest in the Brynhild field on closing including settlement of net working capital.

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 2017	**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 transactions 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**
Transfer of prior year dividends	–	-410.0	–	410.0	–	–	–
Comprehensive income							
Net result	–	–	222.1	–	222.1	–	222.1
Other comprehensive income	–	-72.6	–	–	-72.6	–	-72.6
Total comprehensive income	**–**	**-72.6**	**222.1**	**–**	**149.5**	–	**149.5**
Transactions with owners							
Distributions	–	–	–	-153.1	-153.1	–	-153.1
Purchase of own shares	–	-14.3	–	–	-14.3	–	-14.3
Share based payments	–	-20.8	–	–	-20.8	–	-20.8
Value of employee services	–	–	5.5	–	5.5	–	5.5
Total transaction with owners	**–**	**-35.1**	**5.5**	**-153.1**	**-182.7**	–	**-182.7**
At 31 December 2018	**0.5**	**-25.5**	**-205.9**	**-153.1**	**-384.0**	–	**-384.0**

Notes to the Consolidated Financial Statements

Note 1 – Revenue and other income MUSD	**1 Jan 2018- 31 Dec 2018 12 months**	**1 Oct 2018- 31 Dec 2018 3 months**	1 Jan 2017- 31 Dec 2017 12 months	1 Oct 2017- 31 Dec 2017 3 months
Revenue				
Crude oil from own production	1,877.6	480.7	1,500.2	334.9
Crude oil from third party activities	536.1	117.0	303.5	115.1
Condensate	41.8	7.3	43.0	21.8
Gas	152.4	39.6	111.6	37.2
Sales of oil and gas	**2,607.9**	**644.6**	1,958.3	509.0
Other income				
Change in under/over lift position	-23.3	-41.2	13.8	76.6
Other	32.8	7.6	24.9	8.1
Other income	**9.5**	**-33.6**	38.7	84.7
Revenue and other income	**2,617.4**	**611.0**	1,997.0	593.7

Note 2 – Production costs MUSD	**1 Jan 2018- 31 Dec 2018 12 months**	**1 Oct 2018- 31 Dec 2018 3 months**	1 Jan 2017- 31 Dec 2017 12 months	1 Oct 2017- 31 Dec 2017 3 months
Cost of operations	102.5	28.5	117.3	32.9
Tariff and transportation expenses	35.2	9.4	37.9	9.0
Change in inventory position	0.6	–	-0.4	-0.1
Other	7.1	1.7	9.4	1.8
Production costs	**145.4**	**39.6**	164.2	43.6

Note 3 – Segment information MUSD	**1 Jan 2018- 31 Dec 2018 12 months**	**1 Oct 2018- 31 Dec 2018 3 months**	1 Jan 2017- 31 Dec 2017 12 months	1 Oct 2017- 31 Dec 2017 3 months
Norway				
Crude oil from own production	1,877.6	480.7	1,500.2	334.9
Condensate	41.8	7.3	43.0	21.8
Gas	152.4	39.6	111.6	37.2
Revenue	**2,071.8**	**527.6**	1,654.8	393.9
Change in under/over lift position	-23.3	-41.2	13.8	76.6
Other	32.8	7.6	24.4	9.2
Revenue and other income	**2,081.3**	**494.0**	1,693.0	479.7
Production costs	-145.4	-39.6	-164.2	-43.6
Depletion and decommissioning costs	-458.0	-116.5	-567.3	-138.8
Exploration costs	-53.2	-47.1	-72.0	-30.9
Impairment costs of oil and gas properties	–	–	-30.6	–
Loss from sale of assets	–	–	-14.4	-14.4
Gross profit	**1,424.7**	**290.8**	844.5	252.0

Note 3 – Segment information cont. MUSD	**1 Jan 2018- 31 Dec 2018 12 months**	**1 Oct 2018- 31 Dec 2018 3 months**	1 Jan 2017- 31 Dec 2017 12 months	1 Oct 2017- 31 Dec 2017 3 months
Other				
Crude oil from third party activities	536.1	117.0	303.5	115.1
Revenue	**536.1**	**117.0**	303.5	115.1
Other income	–	–	0.5	-1.1
Revenue and other income	**536.1**	**117.0**	304.0	114.0
Exploration costs	–	–	-1.1	–
Purchase of crude oil from third parties	-533.8	-116.6	-303.3	-115.3
Gross profit/loss	**2.3**	**0.4**	-0.4	-1.3
Total				
Crude oil from own production	1,877.6	480.7	1,500.2	334.9
Crude oil from third party activities	536.1	117.0	303.5	115.1
Condensate	41.8	7.3	43.0	21.8
Gas	152.4	39.6	111.6	37.2
Revenue	**2,607.9**	**644.6**	1,958.3	509.0
Change in under/over lift position	-23.3	-41.2	13.8	76.6
Other	32.8	7.6	24.9	8.1
Revenue and other income	**2,617.4**	**611.0**	1,997.0	593.7
Production costs	-145.4	-39.6	-164.2	-43.6
Depletion and decommissioning costs	-458.0	-116.5	-567.3	-138.8
Exploration costs	-53.2	-47.1	-73.1	-30.9
Impairment costs of oil and gas properties	–	–	-30.6	–
Loss from sale of assets	–	–	-14.4	-14.4
Purchase of crude oil from third parties	-533.8	-116.6	-303.3	-115.3
Gross profit	**1,427.0**	**291.2**	844.1	250.7

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 2018- 31 Dec 2018 12 months**	**1 Oct 2018- 31 Dec 2018 3 months**	1 Jan 2017- 31 Dec 2017 12 months	1 Oct 2017- 31 Dec 2017 3 months
Foreign currency exchange gain, net	–	–	255.3	-69.6
Loan modification gain	183.7	–	–	–
Interest income	1.7	0.6	1.0	0.6
Gain on interest rate hedge settlement	3.5	3.4	–	–
Other	3.3	–	0.4	0.1
Finance income	**192.2**	**4.0**	256.7	-68.9

Note 5 – Finance costs MUSD	**1 Jan 2018- 31 Dec 2018 12 months**	**1 Oct 2018- 31 Dec 2018 3 months**	1 Jan 2017- 31 Dec 2017 12 months	1 Oct 2017- 31 Dec 2017 3 months
Foreign currency exchange loss, net	164.9	163.7	–	–
Interest expense	88.7	20.0	115.0	26.8
Loss on interest rate hedge settlement	–	–	17.4	3.0
Unwinding of site restoration discount	16.4	4.4	13.7	4.5
Amortisation of deferred financing fees	17.8	4.3	17.5	4.4
Loan facility commitment fees	13.0	3.3	11.1	3.0
Loan modification fees	17.3	–	–	–
Unwinding of loan modification gain	26.1	11.0	–	–
Impairment of other shares	–	–	11.2	11.2
Other	1.2	0.4	0.7	-0.2
Finance costs	**345.4**	**207.1**	186.6	52.7

Note 6 – Income tax MUSD	**1 Jan 2018- 31 Dec 2018 12 months**	**1 Oct 2018- 31 Dec 2018 3 months**	1 Jan 2017- 31 Dec 2017 12 months	1 Oct 2017- 31 Dec 2017 3 months
Current tax	90.4	35.7	-0.5	0.3
Deferred tax	935.4	150.1	501.7	172.5
Income tax	**1,025.8**	**185.8**	501.2	172.8

Note 7 – Oil and gas properties MUSD	**31 Dec 2018**	31 Dec 2017
Norway		
Producing assets	1,808.1	2,169.7
Assets under development	2,740.5	2,162.4
Capitalised exploration and appraisal expenditure	792.5	605.0
	5,341.1	4,937.1

Note 8 – Trade and other receivables MUSD	**31 Dec 2018**	31 Dec 2017
Trade receivables	153.7	202.7
Underlift	4.6	29.4
Joint operations debtors	17.0	15.6
Prepaid expenses and accrued income	26.9	29.3
Other	17.1	27.4
	219.3	304.4

Note 9 – Financial liabilities MUSD	**31 Dec 2018**	31 Dec 2017
Non-current:		
Bank loans	3,465.0	3,955.0
Capitalised financing fees	-54.1	-75.0
Capitalised loan modification gain	-148.9	–
	3,262.0	3,880.0

Note 10 – Provisions MUSD	**31 Dec 2018**	31 Dec 2017
Non-current:		
Site restoration	483.9	414.6
Long-term incentive plans	2.4	2.8
Other	2.8	3.2
	489.1	420.6
Current:		
Site restoration	6.6	–
Long-term incentive plans	5.9	7.7
	12.5	7.7
	501.6	428.3

Note 11 – Trade and other payables

MUSD	**31 Dec 2018**	31 Dec 2017
Trade payables	26.6	30.1
Overlift	5.4	12.8
Joint operations creditors and accrued expenses	147.4	188.9
Other accrued expenses	17.6	19.5
Other	7.6	7.7
	204.6	259.0

Note 12 – 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 2018

MUSD	Level 1	Level 2	Level 3
Assets			
Other shares and participations	–	–	–
Derivative instruments – non-current	–	2.7	–
Derivative instruments – current	–	34.0	–
	–	**36.7**	**–**
Liabilities			
Derivative instruments – non-current	–	64.9	–
Derivative instruments – current	–	20.0	–
	–	**84.9**	**–**

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	–

There were no transfers between the levels during the year.

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

Parent Company Income Statement

Expressed in MSEK	1 Jan 2018- 31 Dec 2018 12 months	1 Oct 2018- 31 Dec 2018 3 months	1 Jan 2017- 31 Dec 2017 12 months	1 Oct 2017- 31 Dec 2017 3 months
Revenue	21.0	11.8	9.4	2.4
General and administration expenses	-180.9	-56.5	-146.7	-50.2
Operating loss	**-159.9**	**-44.7**	-137.3	-47.8
Net financial items				
Finance income	1,818.1	97.5	46,786.4	242.5
Finance costs	-0.4	—	-0.5	—
	1,817.7	**97.5**	46,785.9	242.5
Profit before tax	**1,657.8**	**52.8**	46,648.6	194.7
Income tax	—	—	—	—
Net result	**1,657.8**	**52.8**	46,648.6	194.7

Parent Company Comprehensive Income Statement

Expressed in MSEK	1 Jan 2018- 31 Dec 2018 12 months	1 Oct 2018- 31 Dec 2018 3 months	1 Jan 2017- 31 Dec 2017 12 months	1 Oct 2017- 31 Dec 2017 3 months
Net result	**1,657.8**	**52.8**	46,648.6	194.7
Other comprehensive income	—	—	—	—
Total comprehensive income	**1,657.8**	**52.8**	46,648.6	194.7
Attributable to:				
Shareholders of the Parent Company	1,657.8	52.8	46,648.6	194.7
	1,657.8	**52.8**	46,648.6	194.7

Parent Company Balance Sheet

Expressed in MSEK	**31 December 2018**	31 December 2017
ASSETS		
Non-current assets		
Shares in subsidiaries	55,118.9	55,118.9
Other tangible fixed assets	0.4	–
Total non-current assets	**55,119.3**	55,118.9
Current assets		
Receivables	5.4	7.5
Cash and cash equivalents	29.5	4.8
Total current assets	**34.9**	12.3
TOTAL ASSETS	**55,154.2**	55,131.2
SHAREHOLDERS´EQUITY AND LIABILITIES		
Shareholders´ equity including net result for the period	55,120.8	54,936.6
Non-current liabilities		
Provisions	0.7	0.6
Total non-current liabilities	**0.7**	0.6
Current liabilities		
Current liabilities	32.7	194.0
Total current liabilities	**32.7**	194.0
Total liabilities	**33.4**	194.6
TOTAL EQUITY AND LIABILITIES	**55,154.2**	55,131.2

Parent Company Cash Flow Statement

Expressed in MSEK	**1 Jan 2018-31 Dec 2018 12 months**	**1 Oct 2018-31 Dec 2018 3 months**	1 Jan 2017-31 Dec 2017 12 months	1 Oct 2017-31 Dec 2017 3 months
Cash flow from operations				
Net result	1,657.8	52.8	46,648.6	194.7
Adjustment for non-cash related items	-4.8	0.2	-46,608.2	-0.6
Changes in working capital	-159.9	-54.4	189.2	-78.2
Total cash flow from operations	**1,493.1**	**-1.4**	229.6	115.9
Cash flow from investing				
Investments in other fixed assets	-0.4	-0.3	–	–
Total cash flow from investing	-0.4	-0.3	–	–
Cash flow from financing				
Dividends paid	-1,354.1	–	–	–
Purchase of own shares	-119.5	–	-229.6	-166.0
Total cash flow from financing	-1,473.6	–	-229.6	-166.0
Change in cash and cash equivalents	19.1	-1.7	–	-50.1
Cash and cash equivalents at the beginning of the period	4.8	31.6	3.2	54.2
Currency exchange difference in cash and cash equivalents	5.6	-0.4	1.6	0.7
Cash and cash equivalents at the end of the period	**29.5**	**29.5**	4.8	4.8

Parent Company Statement of Changes in Equity

Expressed in MSEK	Restricted equity		Unrestricted equity				
	Share capital	Statutory reserve	Other reserves	Retained earnings	Dividends	Total	Total equity
Balance at 1 January 2017	**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							
Distributions	–	–	–	–	-3,695.3	-3,695.3	-3,695.3
Purchase of own shares	–	–	-229.6	–	–	-229.6	-229.6
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**
Transfer of prior year dividends	–	–	–	-3,695.3	3,695.3	–	–
Total comprehensive income	**–**	**–**	**–**	**1,657.8**	**–**	**1,657.8**	**1,657.8**
Transactions with owners							
Distributions	–	–	–	–	-1,354.1	-1,354.1	-1,354.1
Purchase of own shares	–	–	-119.5	–	–	-119.5	-119.5
Total transactions with owners	**–**	**–**	**-119.5**	**–**	**-1,354.1**	**-1,473.6**	**-1,473.6**
Balance at 31 December 2018	**3.5**	**861.3**	**6,479.7**	**49,130.4**	**-1,354.1**	**54,256.0**	**55,120.8**

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. Lundin Petroleum believes that the alternative performance measures provide useful supplement information to management, investors, security analysts and other stakeholders and are meant to provide an enhanced insight into the financial development of Lundin Petroleum's business operations and to improve comparability between periods. Reconciliations of relevant alternative performance measures are provided on the following page. Definitions of the performance measures are provided under the key ratio definitions below:

Financial data from continuing operations MUSD	**1 Jan 2018- 31 Dec 2018 12 months**	**1 Oct 2018- 31 Dec 2018 3 months**	1 Jan 2017- 31 Dec 2017 12 months	1 Oct 2017- 31 Dec 2017 3 months
Revenue and other income	2,617.4	611.0	1,997.0	593.7
EBITDA[1]	1,916.2	448.5	1,501.5	429.8
Net result	222.1	-105.3	380.9	-50.9
Operating cash flow[1]	1,847.8	419.1	1,530.0	434.5
Free cash flow	663.0	173.3	203.7	160.6
Data per share from continuing operations USD				
Shareholders' equity per share	-1.13	-1.13	-1.03	-1.03
Operating cash flow per share	5.46	1.24	4.50	1.28
Cash flow from operations per share	5.07	1.28	3.82	0.99
Earnings per share	0.66	-0.31	1.13	-0.15
Earnings per share fully diluted	0.65	-0.31	1.13	-0.15
EBITDA per share	5.65	1.32	4.41	1.26
EBITDA per share — fully diluted	5.64	1.32	4.40	1.26
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	338,513,135	338,513,135	339,153,135	339,153,135
Weighted average number of shares for the period	338,592,250	338,513,135	340,237,772	339,815,228
Weighted average number of shares for the period fully diluted	339,513,634	339,078,717	341,380,316	340,616,757
Share price				
Share price at period end in SEK	221.40	221.40	187.80	187.80
Share price at period end in USD[2]	24.72	24.72	22.88	22.88
Key ratios from continuing operations				
Return on equity (%)[3]	—	—	—	—
Return on capital employed (%)	47	8	22	6
Net debt/equity ratio (%)[3]	—	—	—	—
Net debt/EBITDA ratio[4]	1.8	1.8	2.6	2.6
Equity ratio (%)	-7	-7	-6	-6
Share of risk capital (%)	29	29	17	17
Interest coverage ratio	17	13	6	7
Operating cash flow/interest ratio	21	21	12	15
Yield	2	—	5	—

[1] Excludes the reported after tax accounting loss in 2017 of MUSD 14.4 on the divestment of a 39 percent working interest in the Brynhild field.

[2] Share price at period end in USD is calculated based on quoted share price in SEK and applicable SEK/USD exchange rate as per period end.

[3] As the equity at 31 December 2018 and 31 December 2017 is negative, these ratios have not been calculated.

[4] Net debt/EBITDA ratio is calculated using the EBITDA of the last four quarters.

Relevant Reconciliations of Alternative Performance Measures

EBITDA MUSD	**1 Jan 2018- 31 Dec 2018 12 months**	**1 Oct 2018- 31 Dec 2018 3 months**	1 Jan 2017- 31 Dec 2017 12 months	1 Oct 2017- 31 Dec 2017 3 months
Operating profit	1,402.4	284.3	812.4	243.9
Add: depletion of oil and gas properties	458.0	116.5	568.4	139.9
Add: exploration costs	53.2	47.1	73.1	30.9
Add: impairment costs of oil and gas properties	–	–	30.6	–
Add: loss from sale of assets	–	–	14.4	14.4
Add: depreciation of other tangible assets	2.6	0.6	2.6	0.7
EBITDA	**1,916.2**	**448.5**	1,501.5	429.8

Operating cash flow MUSD	**1 Jan 2018- 31 Dec 2018 12 months**	**1 Oct 2018- 31 Dec 2018 3 months**	1 Jan 2017- 31 Dec 2017 12 months	1 Oct 2017- 31 Dec 2017 3 months
Revenue and other income	2,617.4	611.0	1,997.0	593.7
Minus: production costs	-145.4	-39.6	-164.2	-43.6
Minus: purchase of crude oil from third parties	-533.8	-116.6	-303.3	-115.3
Minus: current taxes	-90.4	-35.7	0.5	-0.3
Operating cash flow	**1,847.8**	**419.1**	1,530.0	434.5

Free cash flow MUSD	**1 Jan 2018- 31 Dec 2018 12 months**	**1 Oct 2018- 31 Dec 2018 3 months**	1 Jan 2017- 31 Dec 2017 12 months	1 Oct 2017- 31 Dec 2017 3 months
Cash flows from operating activities	1,718.3	432.7	1,299.3	338.7
Minus: cash flows from investing activities	-1,055.3	-259.4	-1,095.6	-178.1
Free cash flow	**663.0**	**173.3**	203.7	160.6

Net debt MUSD	**1 Jan 2018- 31 Dec 2018 12 months**	**1 Oct 2018- 31 Dec 2018 3 months**	1 Jan 2017- 31 Dec 2017 12 months	1 Oct 2017- 31 Dec 2017 3 months
Bank loans	3,465.0	3,465.0	3,955.0	3,955.0
Minus: cash and cash equivalents	-66.8	-66.8	-71.4	-71.4
Net debt	**3,398.2**	**3,398.2**	3,883.6	3,883.6

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 and other income less production costs less purchase of crude oil from third parties and less current taxes.

Free cash flow: Cash flow from operating activities less cash flow from investing activities in accordance with the consolidated statement of cash flow.

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

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

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

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

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

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

EBITDA per share fully diluted: EBITDA divided by the weighted average number of shares for the period after considering any dilution effect.

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

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

Net debt/EBITDA ratio: Bank loan less cash and cash equivalents divided by EBITDA.

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

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

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

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

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

Board Assurance

The Board of Directors and the President and CEO certify that the financial report for the twelve months ended 31 December 2018 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, 30 January 2019

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

Financial Information

The Company will publish the following reports:

- The three month report (January – March 2019) will be published on 2 May 2019.
- The six month report (January – June 2019) will be published on 31 July 2019.
- The nine month report (January – September 2019) will be published on 31 October 2019.

The AGM will be held on 29 March 2019 in Stockholm, Sweden.

For further information, please contact:

Edward Westropp	Sofia Antunes	Robert Eriksson
VP Investor Relations	Investor Relations Officer	Manager Media Communications
Tel: +41 22 595 10 14	Tel: +41 795 23 60 75	Tel: +46 701 11 26 15
edward.westropp@lundin.ch	sofia.antunes@lundin.ch	robert.eriksson@lundin-petroleum.se

Definitions and abbreviations
An extensive list of definitions can be found on www.lundin-petroleum.com under the heading "Definitions".

EBITDA	Earnings Before Interest, Tax, Depreciation and Amortisation
CHF	Swiss franc
EUR	Euro
NOK	Norwegian krona
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 30 January 2019.

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.

Corporate Head Office
Lundin Petroleum AB (publ)
Hovslagargatan 5
SE-111 48 Stockholm, Sweden
T   +46-8-440 54 50
F   +46-8-440 54 59
W lundin-petroleum.com