Lundin
Petroleum

Q3

Report for the
NINE MONTHS
ended 30 September 2018

Lundin Petroleum AB (publ)
company registration number 556610-8055

Highlights

- Record high quarterly free cash flow generation of approximately MUSD 230
- Production for the nine month period in line with mid-point of revised full year guidance: 78 – 82 Mboepd
- Operating cost of USD 3.49 per barrel for the nine month period, full year guidance adjusted down to below USD 3.80 per barrel from below USD 4.00 per barrel
- Phase 1 of the Johan Sverdrup project over 80 percent completed, first oil expected in November 2019 and PDO for Phase 2 submitted
- Significantly de-risked the operated Rolvsnes and Alta discoveries through successful production testing
- Six potential new projects being progressed through appraisal phase with contingent resources anticipated to increase – Alta/Gohta, Rolvsnes, Luno II, Lille Prinsen, Frosk and Gekko

Financial summary

	1 Jan 2018-30 Sep 2018 9 months	**1 Jul 2018-30 Sep 2018 3 months**	1 Jan 2017-30 Sep 2017 9 months	1 Jul 2017-30 Sep 2017 3 months	1 Jan 2017-31 Dec 2017 12 months
Production in Mboepd	**80.8**	**78.2**	87.1	89.2	86.1
Revenue and other income in MUSD	**2,006.4**	**636.4**	1,403.3	517.2	1,997.0
Operating cash flow in MUSD	**1,428.7**	**461.1**	1,095.5	389.5	1,530.0
EBITDA in MUSD	**1,467.7**	**503.5**	1,071.7	382.4	1,501.5
Free cash flow in MUSD	**489.7**	**228.7**	43.1	67.6	203.7
Net result in MUSD	**327.4**	**62.6**	431.8	227.0	380.9
Earnings/share in USD[1]	**0.97**	**0.19**	1.28	0.67	1.13
Net debt	**3,569.9**	**3,569.9**	4,024.0	4,024.0	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:

"The third quarter has been another good period of operational and financial delivery, which has benefitted from continued high performance from our quality asset base and higher commodity prices. For the second quarter in a row, we have generated an EBITDA in excess of USD 500 million and also a record high quarterly free cash flow of approximately USD 230 million.

"Our key producing asset Edvard Grieg has continued to perform above expectations with capacity from the ten producing wells currently around double the facility's capacity contractually available. The reservoir performance continues to exceed expectations with no material water production to date, which will see plateau production extended further by around six months to mid-2020.

"The third quarter was also about success in moving our appraisal opportunities further towards development and we now have six 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 and resource increases. At Luno II we increased our working interest in PL359 to 65 percent to bring commercial and operational alignment with the Edvard Grieg partnership, where the discovery is planned to be tied back to.

"We have had another good period of project delivery at Johan Sverdrup Phase 1 development, which is now over 80 percent complete and on schedule. The offshore installation programme continues to progress well with all subsea infrastructure and jackets now in place, as well as two of the four topsides and all pre-drilled production wells completed. The oil export pipeline and power from shore cable have been installed and power supply to the facilities from shore commenced in October 2018, which was a milestone for the project and will make it one of the most carbon efficient fields in the world. We are also pleased to note that the key metrics for the project during the period were upgraded, lowering the total capex guidance, increasing reserves, confirming expected Phase 1 first oil to be in November 2019 and submitting the Phase 2 PDO.

"The fourth quarter will again be a busy period for us, as we progress our key projects towards commercialisation, including the Luno II field development where PDO will be submitted in early 2019 and the Rolvsnes extended well test. We will also be drilling three high impact exploration wells in the Froan Basin, Mandal High and southeastern Barents Sea core areas, as well as two important follow on exploration wells in the Alvheim area, significantly de-risked by the successful Frosk discovery earlier in the year. I am pleased with the continued delivery of our organic growth strategy and look forward to further successes as we move into the last quarter of 2018."

For definitions and abbreviations, see pages 30 and 31.

OPERATIONAL REVIEW

All the reported numbers and updates in the operational review relate to the nine month period ending 30 September 2018 (reporting period) unless otherwise specified.

Norway

Production

Production was 80.8 thousand barrels of oil equivalent per day (Mboepd) (compared to 87.1 Mboepd for the same period in 2017). This was in line with the updated production guidance for the full year of between 78 and 82 Mboepd. Lundin Petroleum's full year 2018 production forecast is expected to be in line with the mid-point of the updated guidance range.

Operating cost, including netting off tariff income, was USD 3.49 per barrel and based on performance the full year guidance is being adjusted down to below USD 3.80 per barrel from below USD 4.00 per barrel.

Production in Mboepd	**1 Jan 2018- 30 Sep 2018 9 months**	**1 Jul 2018- 30 Sep 2018 3 months**	1 Jan 2017- 30 Sep 2017 9 months	1 Jul 2017- 30 Sep 2017 3 months	1 Jan 2017- 31 Dec 2017 12 months
Norway					
Crude oil	71.4	68.9	78.6	80.3	77.6
Gas	9.4	9.3	8.5	8.9	8.5
Total production	**80.8**	**78.2**	87.1	89.2	86.1

Production in Mboepd	WI[1]	**1 Jan 2018- 30 Sep 2018 9 months**	**1 Jul 2018- 30 Sep 2018 3 months**	1 Jan 2017- 30 Sep 2017 9 months	1 Jul 2017- 30 Sep 2017 3 months	1 Jan 2017- 31 Dec 2017 12 months
Edvard Grieg	65%	63.0	61.6	68.0	69.5	66.7
Ivar Aasen	1.385%	0.9	0.9	0.6	0.6	0.7
Alvheim	15%	9.0	9.0	13.3	10.9	12.4
Volund	35%	7.0	5.9	2.3	6.6	3.9
Bøyla	15%	0.8	0.8	1.1	1.0	1.1
Brynhild	51%[2]	0.0	–	1.6	0.4	1.2
Gaupe	40%	0.1	0.0	0.2	0.1	0.2
		80.8	**78.2**	87.1	89.2	86.1

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

Production from the Edvard Grieg field was in line with forecast, supported by continued strong production efficiency at 97 percent. During the second quarter 2018, the PDO development drilling programme was completed with all development well results in line with or better than prognosis and the overall drilling programme was completed below budget. Reservoir performance continues to exceed expectations with no material water production to date, which will result in plateau production being extended further by around six months to mid 2020. The capacity from the ten production wells is currently around double the facility's capacity contractually available for Edvard Grieg production. A 4D seismic survey was acquired over the field during the third quarter 2018, in order to support an infill drilling programme that is being planned to commence in mid 2020. Operating cost for the Edvard Grieg field, including netting off tariff income, was USD 3.74 per barrel.

Production from the Ivar Aasen field was in line with forecast. 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 in line with forecast, supported by the strong reservoir performance and continued strong production efficiency for the Alvheim FPSO of 96 percent. An infill well targeting the Kameleon area of the Alvheim field was completed during the third quarter 2018, with results in line with expectations and the well is scheduled to commence production in early 2019, after completion of the subsea tie-ins, offsetting the natural area decline. Operating cost for the Alvheim area was USD 4.83 per barrel.

For the Brynhild field, the decision was taken in the second quarter 2018 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 over 80 percent completed. With the good project progress the operator has updated the expected schedule for Phase 1 first oil to November 2019.

2018 is a key installation year for Phase 1 of the project and the planned programme for this year is nearing completion. 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 export pipeline has been completed and the installation of the gas export pipeline is ongoing, with completion expected during the fourth quarter 2018. 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 ahead of schedule.

Construction of the topsides for the process platform is ongoing at Samsung Heavy Industries in Korea and for the living quarters platform at the Kvaerner Stord yard in Norway. Both these topsides are on schedule for installation in spring 2019.

Two further pre-drilled water injection wells have been completed, taking the total number of pre-drilled wells to eight producers and twelve water injectors completing the pre-drilling operations significantly ahead of schedule. The drilling platform is scheduled to commence tie-back of the eight pre-drilled production wells, during the fourth quarter 2018.

At the time of submitting the Phase 1 PDO in 2015, the capital expenditure for Phase 1 was estimated at gross NOK 123 billion (nominal), due to further improvements in project execution and delivery, the latest cost estimate for Phase 1 has been further reduced by the operator to gross NOK 86 billion (nominal). This represents 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.

Phase 2 costs have been further reduced to gross NOK 41 billion (nominal), which represents over a 50 percent saving from the original estimate in the PDO for Phase 1, and is due to a combination of market conditions and optimisation of the Phase 2 facilities. The major topsides contracts 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	50%	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

Lundin Petroleum has completed its 2018 four well appraisal drilling and testing programme, with all wells being successful. These positive results will lead to potentially new development projects and will increase the Company's contingent resources when assessed with the year-end 2018 reserves process.

The Luno II appraisal well 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 and development studies are being progressed with the objective of submitting a PDO in early 2019. The development concept for Luno II is a subsea tie-back to the nearby Edvard Grieg platform. 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 Company's 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 was 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 (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, with the objective of sanctioning the extended test in early 2019. 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 tested through the Leiv Eiriksson rig and the produced volumes were flowed via a flexible flowline to the Teekay Scott Spirit tanker. 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. The results were better than expected, demonstrating excellent reservoir productivity and connectivity to a large volume, and are anticipated to increase the Alta resource estimate and reduce the uncertainty range. Once all new data gathered from the well, combined with the recently available latest generation 3D seismic survey (TopSeis) that covers the entire Alta and Gohta area, have been processed, the resource range for the Alta and Gohta discoveries will be updated in early 2019 with the Company's year-end 2018 reserves process. Studies for commercialising Alta are being progressed to determine additional appraisal drilling requirements and the optimal development concept.

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 colun. 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	Ongoing
PL860	MOL	40%	Driva/Oppdal	November 2018	
PL869	Aker BP	20%	Froskelår	November 2018	
PL869	Aker BP	20%	Rumpetroll	November 2018	
PL857	Equinor	20%	Gjøkåsen Shallow	December 2018	

The 2018 exploration drilling programme has been further updated to reflect changing rig schedules and priorities, with drilling of the Gjøkåsen Deep and JK prospects moved to 2019. The schedule is weighted towards the fourth quarter with five remaining wells to be drilled in 2018, targeting net unrisked resources of approximately 400 MMboe. The updated appraisal and exploration expenditure guidance for 2018 is being maintained at MUSD 300.

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 and Rumpetroll prospects in the adjacent PL869 are now planned in November 2018. Additionally, a production test well on the Frosk discovery, to be tied into the Bøyla subsea facilities, is being planned for 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 appraisal drilling is being planned for 2019.

In October 2018, drilling commenced on the Silfari prospect in PL830 located in the Froan Basin area of the Norwegian Sea. This is a play opening well on the undrilled Frøya High/Froan Basin area where the Company has secured a significant acreage position. The main objective of the well is to test the reservoir properties and hydrocarbon potential of the Permian and Jurassic formations and on success there are multiple follow-on drilling opportunities. The Silfari prospect is estimated to contain gross unrisked prospective resources of 193 MMboe. Drilling is being conducted by the Leiv Eiriksson rig, for which a flexible contract with multiple option slots is in place.

Licence awards and transactions

Lundin Petroleum continues to grow its exploration acreage position through licence rounds. In January 2018, Lundin Petroleum was awarded 14 licences in the 2017 APA licensing round, of which six are as operator, and in June 2018, the Company was awarded three licences in the 24th licensing round, of which one is as operator. In September 2018, Lundin Petroleum applied for licences in the 2018 APA licensing round where awards are anticipated to be announced in early 2019.

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.

Lundin Petroleum has 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 will receive 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.

Lundin Petroleum has concluded a licence swap with Edison in the southern Barents Sea where Lundin Petroleum will receive a 10 percent working interest in PL850 in exchange for Edison receiving a 10 percent working interest in PL952. Additionally, Lundin Petroleum has reached agreement to acquire a further 20 percent working interest in PL850 from Lime Petroleum, increasing the Company's working interest in PL850 to 30 percent.

Lundin Petroleum has concluded the acquisition of Equinor's 15 percent working interest in PL359 containing the Luno II oil discovery. The transaction involves a cash consideration payable to Equinor as well as Lundin Petroleum transferring its remaining 20 percent working interest in PL825 to Equinor. This transaction 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 and options for the asset are being reviewed.

Health, Safety and Environment

During the reporting period, one lost time incident and one medical treatment incident occurred, resulting in a Lost Time Incident Rate of 0.63 per million hours worked and a Total Recordable Incident Rate of 1.27 per million hours worked. There were no material safety or environmental incidents.

FINANCIAL REVIEW

Result

The operating profit from continuing operations for the reporting period amounted to MUSD 1,118.1 (MUSD 568.5). The increase compared to the comparative period was mainly driven by higher oil prices in combination with lower cost of sales and offset by lower production volumes.

The net result from continuing operations for the reporting period amounted to MUSD 327.4 (MUSD 431.8) and included a foreign currency exchange loss of MUSD 1.2 (gain of MUSD 324.9). The net result from continuing operations excluding foreign currency exchange results amounted to MUSD 328.6 (MUSD 106.9). The increase compared to the comparative period was mainly driven by higher oil prices in combination with lower cost of sales, somewhat offset by lower production volumes and a post-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 reporting period amounted to MUSD 327.4 (MUSD 435.6) representing earnings per share of USD 0.97 (USD 1.28).

Earnings before interest, tax, depletion and amortisation (EBITDA) from continuing operations for the reporting period amounted to MUSD 1,467.7 (MUSD 1,071.7) representing EBITDA per share of USD 4.33 (USD 3.15). Operating cash flow from continuing operations for the reporting period amounted to MUSD 1,428.7 (MUSD 1,095.5) representing operating cash flow per share of USD 4.22 (USD 3.22).

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 reporting period amounted to MUSD 2,006.4 (MUSD 1,403.3) and was comprised of net sales of oil and gas, change in under/over lift position and other revenue as detailed in Note 1.

Net sales of oil and gas for the reporting period amounted to MUSD 1,963.3 (MUSD 1,449.3). The average price achieved by Lundin Petroleum for a barrel of oil equivalent from own production amounted to USD 68.92 (USD 49.72) and is detailed in the following table. The average Dated Brent price for the reporting period amounted to USD 72.13 (USD 51.89) per barrel.

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

Sales from own production Average price per boe expressed in USD	**1 Jan 2018- 30 Sep 2018 9 months**	**1 Jul 2018- 30 Sep 2018 3 months**	1 Jan 2017- 30 Sep 2017 9 months	1 Jul 2017- 30 Sep 2017 3 months	1 Jan 2017- 31 Dec 2017 12 months
Crude oil sales					
– Quantity in Mboe	19,597.2	5,881.4	22,742.0	8,567.5	28,106.9
– *Average price per bbl*	*71.28*	*74.09*	*51.24*	*52.82*	*53.37*
Gas and NGL sales					
– Quantity in Mboe	2,805.6	1,233.9	2,618.1	809.8	3,943.1
– *Average price per boe*	*52.50*	*55.34*	*36.51*	*37.68*	*39.23*
Total sales					
– Quantity in Mboe	**22,402.8**	**7,115.3**	25,360.1	9,377.3	32,050.0
– Average price per boe	***68.92***	***70.84***	*49.72*	*51.57*	*51.63*

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

Net sales of crude oil from third party activities for the reporting period amounted to MUSD 419.1 (MUSD 188.4) and 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 income of MUSD 17.9 (cost of MUSD 62.8) in the reporting period due to the timing of the cargo liftings compared to production.

Other income for the reporting period amounted to MUSD 25.2 (MUSD 16.8) and included a quality differential compensation on Alvheim blended crude and tariff income of MUSD 22.7 (MUSD 14.5) which is due to net income from Ivar Aasen tariffs paid to Edvard Grieg.

Production costs
Production costs including inventory movements for the reporting period amounted to MUSD 105.8 (MUSD 120.6) and are detailed in Note 2. The total production cost per barrel of oil equivalent produced is detailed in the table below:

Production costs	**1 Jan 2018- 30 Sep 2018 9 months**	**1 Jul 2018- 30 Sep 2018 3 months**	1 Jan 2017- 30 Sep 2017 9 months	1 Jul 2017- 30 Sep 2017 3 months	1 Jan 2017- 31 Dec 2017 12 months
Cost of operations					
– In MUSD	74.0	26.6	84.4	29.1	117.3
– In USD per boe	*3.35*	*3.70*	*3.55*	*3.54*	*3.73*
Tariff and transportation expenses					
– In MUSD	25.8	8.6	28.9	11.5	37.9
– In USD per boe	*1.17*	*1.19*	*1.22*	*1.40*	*1.21*
Operating costs					
– In MUSD	**99.8**	**35.2**	113.3	40.6	155.2
– In USD per boe[1]	***4.52***	***4.89***	*4.77*	*4.94*	*4.94*
Change in inventory position					
– In MUSD	0.6	0.0	-0.3	0.2	-0.4
– In USD per boe	*0.03*	*0.00*	*-0.01*	*0.02*	*-0.02*
Other					
– In MUSD	5.4	1.7	7.6	1.8	9.4
– In USD per boe	*0.24*	*0.24*	*0.32*	*0.22*	*0.30*
Production costs					
– In MUSD	**105.8**	**36.9**	120.6	42.6	164.2
– In USD per boe	***4.79***	***5.13***	*5.08*	*5.18*	*5.22*

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 reporting period of USD 4.52 (USD 4.77) per barrel is reduced to USD 3.49 (USD 4.15) when tariff income is netted off. The operating cost for the third quarter 2018 of USD 4.89 (USD 4.94) per barrel is reduced to USD 3.88 (USD 4.27) when tariff income is netted off.

The total cost of operations for the reporting period amounted to MUSD 74.0 (MUSD 84.4). The total cost of operations excluding operational projects amounted to MUSD 67.5 (MUSD 77.5). The reduction compared to the comparative period included the reversal of an accrual as a result of the termination of production from the Brynhild field of MUSD 5.5.

The cost of operations per barrel for the reporting period amounted to USD 3.35 (USD 3.55) including operational projects and USD 3.06 (USD 3.26) excluding operational projects.

Tariff and transportation expenses for the reporting period amounted to MUSD 25.8 (MUSD 28.9) or USD 1.17 (USD 1.22) per barrel.

Other costs for the reporting period amounted to MUSD 5.4 (MUSD 7.6) 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 reporting period amounted to MUSD 341.5 (MUSD 428.5) at an average rate of USD 15.48 (USD 18.02) per barrel and are detailed in Note 3. The lower depletion costs for the reporting period 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 reporting period amounted to MUSD 6.1 (MUSD 42.2) 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 reporting period 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.

Purchase of crude oil from third parties
Purchase of crude oil from third parties for the reporting period amounted to MUSD 417.2 (MUSD 188.0) and related 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 reporting period amounted to MUSD 17.7 (MUSD 24.9) which included a charge of MUSD 3.4 (MUSD 3.1) in relation to the Group's long-term incentive plans (LTIP), see also Remuneration section below. Fixed asset depreciation expenses for the reporting period amounted to MUSD 2.0 (MUSD 1.9).

Finance income

Finance income for the reporting period amounted to MUSD 188.2 (MUSD 325.6) and is detailed in Note 4.

During the reporting period 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 0.3) 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 reporting period at the prevailing market price.

Finance costs

Finance costs for the reporting period amounted to MUSD 138.3 (MUSD 133.9) and are detailed in Note 5.

The net foreign currency exchange loss for the reporting period amounted to MUSD 1.2 (gain of MUSD 324.9). 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 reporting period, the net realised exchange gain on these settled foreign exchange hedges amounted to MUSD 7.4 (loss of MUSD 2.9).

The US Dollar strengthened against the Euro during the reporting period 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 strengthened against the Euro in the reporting period, generating a net foreign currency exchange gain on an intercompany loan balance denominated in Norwegian Krone.

Interest expenses for the reporting period amounted to MUSD 68.7 (MUSD 88.2) and represented the portion of interest charged to the income statement. An additional amount of interest of MUSD 64.9 (MUSD 44.1) associated with the funding of the Norwegian development projects was capitalised in the reporting period. The total interest expense is in line compared to the comparative period mainly due to higher interest rates offset by lower drawn debt under the reserve-based lending facility. The result on interest rate hedge settlements amounted to a gain of MUSD 0.1 (loss of MUSD 14.4).

The amortisation of the deferred financing fees for the reporting period amounted to MUSD 13.5 (MUSD 13.1) 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 reporting period amounted to MUSD 9.7 (MUSD 8.1) 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 percentage for commitment fees as agreed through the recent amendment of the facility effective as of 1 June 2018.

The loan modification fees 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 a post-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 amounted to MUSD 15.1 (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 reporting period amounted to MUSD -0.6 (MUSD —) and related to the share in the result of the investment in Mintley Caspian Ltd.

Tax

The overall tax charge for the reporting period amounted to MUSD 840.0 (MUSD 328.4) and is detailed in Note 6.

The current tax charge for the reporting period amounted to MUSD 54.7 (MUSD -0.8) of which MUSD 53.7 (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 reporting period amounted to MUSD 5.0 which has resulted in an increase in current tax liabilities compared to the comparative period.

The deferred tax charge for the reporting period amounted to MUSD 785.3 (MUSD 329.2) 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 reporting period is affected by items which do not receive a full tax credit such as the reported net foreign currency exchange gain, Norwegian financial items and by the uplift allowance applicable in Norway for development expenditures against the offshore tax regime.

Non-controlling interest

The net result attributable to non-controlling interest for the reporting period amounted to MUSD — (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 5,542.0 (MUSD 4,937.1) and are detailed in Note 7.

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

Development expenditure in MUSD	**1 Jan 2018- 30 Sep 2018 9 months**	**1 Jul 2018- 30 Sep 2018 3 months**	1 Jan 2017- 30 Sep 2017 9 months	1 Jul 2017- 30 Sep 2017 3 months	1 Jan 2017- 31 Dec 2017 12 months
Norway	550.9	174.6	734.0	221.3	950.0
Development expenditures	**550.9**	**174.6**	734.0	221.3	950.0

Development expenditure of MUSD 550.9 (MUSD 734.0) was incurred in Norway during the reporting period, primarily on the Johan Sverdrup and Edvard Grieg fields. In addition an amount of MUSD 64.9 (MUSD 44.1) of interest was capitalised.

Exploration and appraisal expenditure in MUSD	**1 Jan 2018- 30 Sep 2018 9 months**	**1 Jul 2018- 30 Sep 2018 3 months**	1 Jan 2017- 30 Sep 2017 9 months	1 Jul 2017- 30 Sep 2017 3 months	1 Jan 2017- 31 Dec 2017 12 months
Norway	225.2	52.5	172.5	69.5	227.1
Russia	—	—	1.1	0.3	1.1
Exploration and appraisal expenditure	**225.2**	**52.5**	173.6	69.8	228.2

Exploration and appraisal expenditure of MUSD 225.2 (MUSD 172.5) was incurred in Norway during the reporting period, 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 and Lille Prinsen in PL167 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 reporting period.

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 reporting period to a related party, see also the Related Party Transactions section below.

Derivative instruments amounted to MUSD 40.1 (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 58.8 (MUSD 33.7) and included both well supplies and hydrocarbon inventories including the oil produced during the Alta extended production test.

Trade and other receivables amounted to MUSD 277.1 (MUSD 304.4) and are detailed in Note 8. Trade receivables, which are all current, amounted to MUSD 172.4 (MUSD 202.7) and included invoiced cargoes. Underlift amounted to MUSD 40.8 (MUSD 29.4) and was attributable to an underlift position on the producing fields, mainly from the Alvheim area and Edvard Grieg. Joint operations debtors relating to various joint venture receivables amounted to MUSD 16.8 (MUSD 15.6). Prepaid expenses and accrued income amounted to MUSD 22.0 (MUSD 29.3) and represented mainly prepaid operational and insurance expenditure. Other current assets amounted to MUSD 25.1 (MUSD 27.4) and included a short term receivable from IPC in relation to certain working capital balances following the IPC spin-off and other miscellaneous receivable balances.

Derivative instruments amounted to MUSD 40.6 (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 75.1 (MUSD 71.4). Cash balances are held to meet ongoing operational funding requirements.

Non-current liabilities

Financial liabilities amounted to MUSD 3,414.8 (MUSD 3,880.0) and are detailed in Note 9. Bank loans amounted to MUSD 3,645.0 (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 62.0 (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 168.2 (MUSD —) and are being amortised over the expected life of the facility.

Provisions amounted to MUSD 531.3 (MUSD 420.6) and are detailed in Note 10. The provision for site restoration amounted to MUSD 526.4 (MUSD 414.6) and related to future decommissioning obligations. The increase mainly reflects the additional liability for Edvard Grieg and for the Johan Sverdrup development project.

Deferred tax liabilities amounted to MUSD 2,075.7 (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 11.5 (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 230.9 (MUSD 259.0) and are detailed in Note 11. Overlift amounted to MUSD 6.6 (MUSD 12.8) and was attributable to an overlift position on the producing fields, mainly from Brynhild. Joint operations creditors and accrued expenses amounted to MUSD 168.2 (MUSD 188.9) and related to activity in Norway. Other accrued expenses amounted to MUSD 23.2 (MUSD 19.5) and other current liabilities amounted to MUSD 8.5 (MUSD 7.7).

Derivative instruments amounted to MUSD 2.3 (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 provisions amounted to MUSD 7.8 (MUSD 7.7) and related to the current portion of the provision for Lundin Petroleum's Unit Bonus Plan.

Parent Company

The business of the Parent Company is investment in and management of oil and gas assets. The net result for the Parent Company for the reporting period amounted to MSEK 1,605.0 (MSEK 46,453.9). The net result for the reporting period included MSEK 1,714.6 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 -109.6 (MSEK -89.3).

The net result included general and administrative expenses of MSEK 124.4 (MSEK 96.5) and net finance income of MSEK 5.6 (MSEK 0.2) 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 reporting period, 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 247.5 (MUSD —).

The Group has sold oil and related products to the Equinor group on an arm's-length basis amounting to MUSD 760.7 (MUSD 177.6).

As at the date of the IPC spin-off, the Group had a residual receivable for working capital from IPC of MUSD 27.4, which has been reduced to MUSD 23.8. 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.

Subsequent Events

Subsequent to the reporting period, Lundin Petroleum has announced an agreement with Equinor whereby Lundin Petroleum will acquire a 15 percent working interest in PL359 containing the Luno II oil discovery. The transaction involves a cash consideration payable to Equinor as well as Lundin Petroleum transferring its remaining 20 percent working interest in PL825 to Equinor. This transaction is subject to customary government approvals.

Subsequent to the reporting period, Lundin Petroleum entered into additional interest rate hedge contracts for the years 2020-2022 comprising of MUSD 250 for 2020; MUSD 1,000 for 2021 and MUSD 1,000 for 2022 fixing the floating LIBOR rate at an average weighted rate of 3.14 percent.

Subsequent to the reporting period, 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 729 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.

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 reporting period 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 reporting period.

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. An annual cash dividend of at least MUSD 350.0 is anticipated from next year.

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 30 September 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 30 September 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 30 September 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 30 September 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 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 reporting period 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 revenue 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 assets and liabilities arising from all leases, with some exceptions, to be recognised in the balance sheet. The Group is currently assessing the full impact of this standard.

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. At 30 September 2018, Lundin Petroleum had outstanding currency hedges as summarised below:

Buy	Sell	Average contractual Exchange rate	Settlement period
MNOK 871.9	MUSD 105.6	NOK 8.26:USD 1	Oct 2018 – Dec 2018
MNOK 2,722.4	MUSD 332.6	NOK 8.19:USD 1	Jan 2019 – Dec 2019
MNOK 1,835.0	MUSD 237.0	NOK 7.74:USD 1	Jan 2020 – Dec 2020
MNOK 1,450.0	MUSD 189.4	NOK 7.66:USD 1	Jan 2021 – Dec 2021
MNOK 1,200.0	MUSD 158.2	NOK 7.59:USD 1	Jan 2022 – Dec 2022

Lundin Petroleum entered into interest rate hedge contracts and at 30 September 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	1.87%	Oct 2018 – Dec 2018
3,000	1.42%	Jan 2019 – Dec 2019
1,750	2.01%	Jan 2020 – Dec 2020
1,000	2.17%	Jan 2021 – Dec 2021
1,000	2.37%	Jan 2022 – Dec 2022

Under 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 reporting period, the following currency exchange rates have been used.

	30 Sep 2018		30 Sep 2017		31 Dec 2017	
	Average	Period end	Average	Period end	Average	Period end
1 USD equals NOK	8.0295	8.1777	8.3067	7.9726	8.2712	8.2050
1 USD equals Euro	0.8369	0.8639	0.8983	0.8470	0.8855	0.8338
1 USD equals SEK	8.5757	8.9055	8.6238	8.1730	8.5481	8.2080

Consolidated Income Statement

Expressed in MUSD	Note	1 Jan 2018-30 Sep 2018 9 months	1 Jul 2018-30 Sep 2018 3 months	1 Jan 2017-30 Sep 2017 9 months	1 Jul 2017-30 Sep 2017 3 months	1 Jan 2017-31 Dec 2017 12 months
Revenue and other income	1					
Revenue		1,963.3	596.6	1,449.3	568.3	1,958.3
Other income		43.1	39.8	-46.0	-51.1	38.7
		2,006.4	**636.4**	1,403.3	517.2	1,997.0
Cost of sales						
Production costs	2	-105.8	-36.9	-120.6	-42.6	-164.2
Depletion and decommissioning costs		-341.5	-108.8	-428.5	-153.2	-567.3
Exploration costs		-6.1	-0.2	-42.2	-16.3	-73.1
Impairment costs of oil and gas properties		–	–	-30.6	-17.4	-30.6
Loss from sale of assets		–	–	–	–	-14.4
Purchase of crude oil from third parties		-417.2	-92.4	-188.0	-84.8	-303.3
Gross profit/loss	3	**1,135.8**	**398.1**	593.4	202.9	844.1
General, administration and depreciation expenses		-17.7	-4.2	-24.9	-8.2	-31.7
Operating profit/loss		**1,118.1**	**393.9**	568.5	194.7	812.4
Net financial items						
Finance income	4	188.2	-9.2	325.6	186.0	256.7
Finance costs	5	-138.3	-42.2	-133.9	-44.1	-186.6
		49.9	**-51.4**	191.7	141.9	70.1
Share in result of associated company		-0.6	-0.6	–	–	-0.4
Profit/loss before tax		**1,167.4**	**341.9**	760.2	336.6	882.1
Income tax	6	-840.0	-279.3	-328.4	-109.6	-501.2
Net result from continuing operations		**327.4**	**62.6**	431.8	227.0	380.9
Discontinued operations						
Net result - IPC		–	–	47.6	-0.3	46.5
Net result		**327.4**	**62.6**	479.4	226.7	427.4
Attributable to:						
Shareholders of the Parent Company		327.4	62.6	483.2	228.0	431.2
Non-controlling interest		–	–	-3.8	-1.3	-3.8
		327.4	**62.6**	479.4	226.7	427.4
Earnings per share – USD[1]						
From continuing operations		0.97	0.19	1.28	0.67	1.13
From discontinued operations		–	–	0.14	0.00	0.14
Earnings per share fully diluted – USD[1]						
From continuing operations		0.96	0.18	1.28	0.67	1.13
From discontinued operations		–	–	0.14	0.00	0.14

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

Consolidated Statement of Comprehensive Income

Expressed in MUSD	**1 Jan 2018- 30 Sep 2018 9 months**	**1 Jul 2018- 30 Sep 2018 3 months**	1 Jan 2017- 30 Sep 2017 9 months	1 Jul 2017- 30 Sep 2017 3 months	1 Jan 2017- 31 Dec 2017 12 months
Net result	**327.4**	**62.6**	479.4	226.7	427.4
Items that may be subsequently reclassified to profit or loss:					
Exchange differences foreign operations	15.9	3.6	-66.1	-7.6	-96.2
Cash flow hedges	44.5	5.3	82.8	42.1	76.4
Available-for-sale financial assets	—	—	-1.2	-1.4	4.9
Other comprehensive income, net of tax	**60.4**	**8.9**	15.5	33.1	-14.9
Total comprehensive income	**387.8**	**71.5**	494.9	259.8	412.5
Attributable to:					
Shareholders of the Parent Company	387.8	71.5	498.7	261.1	416.3
Non-controlling interest	—	—	-3.8	-1.3	-3.8
	387.8	**71.5**	494.9	259.8	412.5

Consolidated Balance Sheet

Expressed in MUSD	Note	30 September 2018	31 December 2017
ASSETS			
Non-current assets			
Oil and gas properties	7	5,542.0	4,937.1
Other tangible fixed assets		13.8	13.2
Goodwill		128.1	128.1
Financial assets		0.4	6.7
Derivative instruments	12	40.1	26.5
Total non-current assets		**5,724.4**	5,111.6
Current assets			
Inventories		58.8	33.7
Trade and other receivables	8	277.1	304.4
Derivative instruments	12	40.6	7.7
Cash and cash equivalents		75.1	71.4
Total current assets		**451.6**	417.2
TOTAL ASSETS		**6,176.0**	5,528.8
EQUITY AND LIABILITIES			
Equity			
Shareholders´ equity		**-146.8**	-350.8
Liabilities			
Non-current liabilities			
Financial liabilities	9	3,414.8	3,880.0
Provisions	10	531.3	420.6
Deferred tax liabilities		2,075.7	1,302.2
Derivative instruments	12	11.5	3.1
Total non-current liabilities		**6,033.3**	5,605.9
Current liabilities			
Trade and other payables	11	230.9	259.0
Derivative instruments	12	2.3	6.4
Current tax liabilities		48.5	0.6
Provisions	10	7.8	7.7
Total current liabilities		**289.5**	273.7
Total liabilities		**6,322.8**	5,879.6
TOTAL EQUITY AND LIABILITIES		**6,176.0**	5,528.8

Consolidated Statement of Cash Flows

Expressed in MUSD	1 Jan 2018- 30 Sep 2018 9 months	1 Jul 2018- 30 Sep 2018 3 months	1 Jan 2017- 30 Sep 2017 9 months	1 Jul 2017- 30 Sep 2017 3 months	1 Jan 2017- 31 Dec 2017 12 months
Cash flows from operating activities					
Net result	327.4	62.6	431.8	227.0	380.9
Adjustments for:					
Exploration costs	6.1	0.2	42.2	16.3	73.1
Depletion, depreciation and amortisation	343.5	109.4	430.4	153.9	570.9
Impairment of oil and gas properties	–	–	30.6	17.4	30.6
Current tax	54.7	46.0	-0.8	0.3	-0.5
Deferred tax	785.3	233.3	329.2	109.3	501.7
Impairment of other shares	–	–	–	–	11.2
Long-term incentive plans	14.1	4.2	9.5	3.4	12.7
Foreign currency exchange gain/ loss	1.0	10.7	-327.9	-181.5	-258.0
Interest expense	68.7	19.6	88.2	30.1	115.0
Loan modification gain	-183.7	–	–	–	–
Loan modification fees	17.3	–	–	–	–
Unwinding of loan modification gain	15.1	11.4	–	–	–
Capitalised financing fees	13.5	4.3	13.1	4.6	17.5
Other	8.4	4.8	8.8	3.2	26.4
Interest received	0.8	0.2	0.5	0.3	1.0
Interest paid	-133.1	-41.2	-131.2	-47.2	-177.3
Income taxes paid / received	-5.8	-5.1	-0.4	-0.2	82.2
Changes in working capital	-47.7	17.8	36.6	22.3	-88.1
Total cash flows from operating activities	**1,285.6**	**478.2**	960.6	359.2	1,299.3
Cash flows from investing activities					
Investment in oil and gas properties	-801.7	-248.0	-907.7	-291.2	-1,178.2
Investment in other fixed assets	-2.7	-0.7	-0.9	-0.1	-1.6
Investment in other shares and participations[1]	9.3	–	-1.3	–	-1.3
Decommissioning costs paid	-0.8	-0.8	-0.1	–	-0.4
Disposal of fixed assets [2]	–	–	–	–	93.7
Other payments	–	–	-7.5	-0.3	-7.8
Total cash flows from investing activities	**-795.9**	**-249.5**	-917.5	-291.6	-1,095.6
Cash flows from financing activities					
Changes in long-term liabilities	-310.0	-250.0	-28.7	-39.6	-188.7
Financing fees paid	-17.3	-0.4	–	–	–
Cash funded from / to discontinued operations	–	–	31.7	–	31.7
Dividends paid	-153.1	–	-7.8	-7.8	–
Purchase of own shares	-14.3	–	–	–	-28.0
Total cash flows from financing activities	**-494.7**	**-250.4**	-4.8	-47.4	-185.0
Change in cash and cash equivalents	-5.0	-21.7	38.3	20.2	18.7
Cash and cash equivalents at the beginning of the period	71.4	96.5	56.1	74.2	56.1
Currency exchange difference in cash and cash equivalents	8.7	0.3	-3.2	-3.2	-3.2
Cash and cash equivalent of deconsolidated operations	–	–	-0.2	-0.2	-0.2
Cash and cash equivalents at the end of the period	**75.1**	**75.1**	91.0	91.0	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	–	–	483.2	–	483.2	-3.8	479.4
Other comprehensive income	–	15.5	–	–	15.5	–	15.5
Total comprehensive income	**–**	**15.5**	**483.2**	**–**	**498.7**	**-3.8**	**494.9**
Transactions with owners							
Change in consolidation	–	–	-82.0	–	-82.0	117.1	35.1
Distributions	–	–	–	-410.0	-410.0	–	-410.0
Purchase of own shares	–	-7.8	–	–	-7.8	–	-7.8
Spin off IPC	–	–	–	–	–	0.3	0.3
Share based payments	–	-13.2	–	–	-13.2	–	-13.2
Value of employee services	–	–	3.7	–	3.7	–	3.7
Total transactions with owners	**–**	**-21.0**	**-78.3**	**-410.0**	**-509.3**	**117.4**	**-391.9**
At 30 September 2017	**0.5**	**542.8**	**-382.5**	**-410.0**	**-249.2**	**–**	**-249.2**
Comprehensive income							
Net result	–	–	-52.0	–	-52.0	–	-52.0
Other comprehensive income	–	-30.4	–	–	-30.4	–	-30.4
Total comprehensive income	**–**	**-30.4**	**-52.0**	**–**	**-82.4**	**–**	**-82.4**
Transactions with owners							
Purchase of own shares	–	-20.2	–	–	-20.2	–	-20.2
Value of employee services	–	–	1.0	–	1.0	–	1.0
Total transaction with owners	**–**	**-20.2**	**1.0**	**–**	**-19.2**	**–**	**-19.2**
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	–	–	327.4	–	327.4	–	327.4
Other comprehensive income	–	60.4	–	–	60.4	–	60.4
Total comprehensive income	**–**	**60.4**	**327.4**	**–**	**387.8**	**–**	**387.8**
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	–	–	4.4	–	4.4	–	4.4
Total transaction with owners	**–**	**-35.1**	**4.4**	**-153.1**	**-183.8**	**–**	**-183.8**
At 30 September 2018	**0.5**	**107.5**	**-101.7**	**-153.1**	**-146.8**	**–**	**-146.8**

Notes to the Consolidated Financial Statements

Note 1 – Revenue and other income MUSD	**1 Jan 2018- 30 Sep 2018 9 months**	**1 Jul 2018- 30 Sep 2018 3 months**	1 Jan 2017- 30 Sep 2017 9 months	1 Jul 2017- 30 Sep 2017 3 months	1 Jan 2017- 31 Dec 2017 12 months
Revenue					
Crude oil from own production	1,396.9	435.7	1,165.3	452.5	1,500.2
Crude oil from third party activities	419.1	92.6	188.4	85.3	303.5
Condensate	34.5	25.5	21.2	5.1	43.0
Gas	112.8	42.8	74.4	25.4	111.6
Net sales of oil and gas	**1,963.3**	**596.6**	1,449.3	568.3	1,958.3
Other income					
Change in under/over lift position	17.9	31.8	-62.8	-57.7	13.8
Other	25.2	8.0	16.8	6.6	24.9
Other income	**43.1**	**39.8**	-46.0	-51.1	38.7
Revenue and other income	**2,006.4**	**636.4**	1,403.3	517.2	1,997.0

Note 2 – Production costs MUSD	**1 Jan 2018- 30 Sep 2018 9 months**	**1 Jul 2018- 30 Sep 2018 3 months**	1 Jan 2017- 30 Sep 2017 9 months	1 Jul 2017- 30 Sep 2017 3 months	1 Jan 2017- 31 Dec 2017 12 months
Cost of operations	74.0	26.6	84.4	29.1	117.3
Tariff and transportation expenses	25.8	8.6	28.9	11.5	37.9
Change in inventory position	0.6	–	-0.3	0.2	-0.4
Other	5.4	1.7	7.6	1.8	9.4
Production costs	**105.8**	**36.9**	120.6	42.6	164.2

Note 3 – Segment information MUSD	**1 Jan 2018- 30 Sep 2018 9 months**	**1 Jul 2018- 30 Sep 2018 3 months**	1 Jan 2017- 30 Sep 2017 9 months	1 Jul 2017- 30 Sep 2017 3 months	1 Jan 2017- 31 Dec 2017 12 months
Norway					
Crude oil from own production	1,396.9	435.7	1,165.3	452,5	1,500.2
Condensate	34.5	25.5	21.2	5.1	43.0
Gas	112.8	42.8	74.4	25.4	111.6
Revenue	**1,544.2**	**504.0**	1,260.9	483.0	1,654.8
Change in under/over lift position	17.9	31.8	-62.8	-57.7	13.8
Other	25.2	8.0	15.2	5.9	24.4
Revenue and other income	**1,587.3**	**543.8**	1,213.3	431.2	1,693.0
Production costs	-105.8	-36.9	-120.6	-42.6	-164.2
Depletion and decommissioning costs	-341.5	-108.8	-428.5	-153.2	-567.3
Exploration costs	-6.1	-0.2	-41.1	-16.0	-72.0
Impairment costs of oil and gas properties	–	–	-30.6	-17.4	-30.6
Loss from sale of assets	–	–	–	–	-14.4
Gross profit/loss	**1,133.9**	**397.9**	592.5	202.0	844.5

Note 3 – Segment information cont. MUSD	**1 Jan 2018- 30 Sep 2018 9 months**	**1 Jul 2018- 30 Sep 2018 3 months**	1 Jan 2017- 30 Sep 2017 9 months	1 Jul 2017- 30 Sep 2017 3 months	1 Jan 2017- 31 Dec 2017 12 months
Other					
Crude oil from third party activities	419.1	92.6	188.4	85.3	303.5
Revenue	**419.1**	**92.6**	188.4	85.3	303.5
Other income	–	–	1.6	0.7	0.5
Revenue and other income	**419.1**	**92.6**	190.0	86.0	304.0
Exploration costs	–	–	-1.1	-0.3	-1.1
Purchase of crude oil from third parties	-417.2	-92.4	-188.0	-84.8	-303.3
Gross profit/loss	**1.9**	**0.2**	0.9	0.9	-0.4
Total					
Crude oil from own production	1,396.9	435.7	1,165.3	452.5	1,500.2
Crude oil from third party activities	419.1	92.6	188.4	85.3	303.5
Condensate	34.5	25.5	21.2	5.1	43.0
Gas	112.8	42.8	74.4	25.4	111.6
Revenue	**1,963.3**	**596.6**	1,449.3	568.3	1,958.3
Change in under/over lift position	17.9	31.8	-62.8	-57.7	13.8
Other income	25.2	8.0	16.8	6.6	24.9
Revenue and other income	**2,006.4**	**636.4**	1,403.3	517.2	1,997.0
Production costs	-105.8	-36.9	-120.6	-42.6	-164.2
Depletion and decommissioning costs	-341.5	-108.8	-428.5	-153.2	-567.3
Exploration costs	-6.1	-0.2	-42.2	-16.3	-73.1
Impairment costs of oil and gas properties	–	–	-30.6	-17.4	-30.6
Loss from sale of assets	–	–	–	–	-14.4
Purchase of crude oil from third parties	-417.2	-92.4	-188.0	-84.8	-303.3
Gross profit/loss	**1,135.8**	**398.1**	593.4	202.9	844.1

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- 30 Sep 2018 9 months**	**1 Jul 2018- 30 Sep 2018 3 months**	1 Jan 2017- 30 Sep 2017 9 months	1 Jul 2017- 30 Sep 2017 3 months	1 Jan 2017- 31 Dec 2017 12 months
Foreign currency exchange gain, net	–	-9.6	324.9	185.7	255.3
Loan modification gain	183.7	–	–	–	–
Interest income	1.1	0.3	0.4	0.2	1.0
Result on interest rate hedge settlement	0.1	0.1	–	–	–
Other	3.3	–	0.3	0.1	0.4
Total finance income	**188.2**	**-9.2**	325.6	186.0	256.7

Note 5 – Finance costs MUSD	**1 Jan 2018- 30 Sep 2018 9 months**	**1 Jul 2018- 30 Sep 2018 3 months**	1 Jan 2017- 30 Sep 2017 9 months	1 Jul 2017- 30 Sep 2017 3 months	1 Jan 2017- 31 Dec 2017 12 months
Foreign currency exchange loss, net	1.2	1.2	–	–	–
Interest expense	68.7	19.6	88.2	30.1	115.0
Result on interest rate hedge settlement	–	-1.7	14.4	3.4	17.4
Unwinding of site restoration discount	12.0	4.3	9.2	3.4	13.7
Amortisation of deferred financing fees	13.5	4.3	13.1	4.6	17.5
Loan facility commitment fees	9.7	2.9	8.1	2.7	11.1
Loan modification fees	17.3	–	–	–	–
Unwinding of loan modification gain	15.1	11.4	–	–	–
Impairment of other shares	–	–	–	–	11.2
Other	0.8	0.2	0.9	-0.1	0.7
Finance costs	**138.3**	**42.2**	133.9	44.1	186.6

Note 6 – Income tax MUSD	**1 Jan 2018- 30 Sep 2018 9 months**	**1 Jul 2018- 30 Sep 2018 3 months**	1 Jan 2017- 30 Sep 2017 9 months	1 Jul 2017- 30 Sep 2017 3 months	1 Jan 2017- 31 Dec 2017 12 months
Current tax	54.7	46.0	-0.8	0.3	-0.5
Deferred tax	785.3	233.3	329.2	109.3	501.7
Total income tax	**840.0**	**279.3**	328.4	109.6	501.2

Note 7 – Oil and gas properties MUSD	**30 Sep 2018**	31 Dec 2017
Norway		
Producing assets	2,023.4	2,169.7
Assets under development	2,764.7	2,162.4
Capitalised exploration and appraisal expenditure	753.9	605.0
	5,542.0	4,937.1

Note 8 – Trade and other receivables MUSD	**30 Sep 2018**	31 Dec 2017
Trade receivables	172.4	202.7
Underlift	40.8	29.4
Joint operations debtors	16.8	15.6
Prepaid expenses and accrued income	22.0	29.3
Other	25.1	27.4
	277.1	304.4

Note 9 – Financial liabilities MUSD	**30 Sep 2018**	31 Dec 2017
Non-current:		
Bank loans	3,645.0	3,955.0
Capitalised financing fees	-62.0	-75.0
Capitalised loan modification gain	-168.2	–
	3,414.8	3,880.0

Note 10 – Provisions MUSD	**30 Sep 2018**	31 Dec 2017
Non-current:		
Site restoration	526.4	414.6
Long-term incentive plans	2.6	2.8
Other	2.3	3.2
	531.3	420.6
Current:		
Long-term incentive plans	7.8	7.7
	7.8	7.7
	539.1	428.3

Note 11 – Trade and other payables

MUSD	30 Sep 2018	31 Dec 2017
Trade payables	24.4	30.1
Overlift	6.6	12.8
Joint operations creditors and accrued expenses	168.2	188.9
Other accrued expenses	23.2	19.5
Other	8.5	7.7
	230.9	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:

30 September 2018 MUSD	Level 1	Level 2	Level 3
Assets			
Other shares and participations	–	–	–
Derivative instruments – non-current	–	40.1	–
Derivative instruments – current	–	40.6	–
	–	**80.7**	**–**
Liabilities			
Derivative instruments – non-current	–	11.5	–
Derivative instruments – current	–	2.3	–
	–	**13.8**	**–**

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 reporting period.

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

Parent Company Income Statement

Expressed in MSEK	**1 Jan 2018- 30 Sep 2018 9 months**	**1 Jul 2018- 30 Sep 2018 3 months**	1 Jan 2017- 30 Sep 2017 9 months	1 Jul 2017- 30 Sep 2017 3 months	1 Jan 2017- 31 Dec 2017 12 months
Revenue	9.2	0.9	7.0	2.5	9.4
General and administration expenses	-124.4	-57.6	-96.5	-48.9	-146.7
Operating profit/loss	**-115.2**	**-56.7**	-89.5	-46.4	-137.3
Net financial items					
Finance income	1,720.6	-0.3	46,543.9	-0.6	46,786.4
Finance costs	-0.4	-0.2	-0.5	–	-0.5
	1,720.2	**-0.5**	46,543.4	-0.6	46,785.9
Profit/loss before tax	**1,605.0**	**-57.2**	46,453.9	-47.0	46,648.6
Income tax	–	–	–	–	–
Net result	**1,605.0**	**-57.2**	46,453.9	-47.0	46,648.6

Parent Company Comprehensive Income Statement

Expressed in MSEK	**1 Jan 2018- 30 Sep 2018 9 months**	**1 Jul 2018- 30 Sep 2018 3 months**	1 Jan 2017- 30 Sep 2017 9 months	1 Jul 2017- 30 Sep 2017 3 months	1 Jan 2017- 31 Dec 2017 12 months
Net result	**1,605.0**	**-57.2**	46,453.9	-47.0	46,648.6
Other comprehensive income	–	–	–	–	–
Total comprehensive income	**1,605.0**	**-57.2**	46,453.9	-47.0	46,648.6
Attributable to:					
Shareholders of the Parent Company	1,605.0	-57.2	46,453.9	-47.0	46,648.6
	1,605.0	**-57.2**	46,453.9	-47.0	46,648.6

Parent Company Balance Sheet

Expressed in MSEK	**30 September 2018**	31 December 2017
ASSETS		
Non-current assets		
Shares in subsidiaries	55,118.9	55,118.9
Other tangible fixed assets	0.1	–
Total non-current assets	**55,119.0**	55,118.9
Current assets		
Receivables	5.1	7.5
Cash and cash equivalents	31.6	4.8
Total current assets	**36.7**	12.3
TOTAL ASSETS	**55,155.7**	55,131.2
SHAREHOLDERS´EQUITY AND LIABILITIES		
Shareholders´ equity including net result for the period	55,068.0	54,936.6
Non-current liabilities		
Provisions	0.8	0.6
Total non-current liabilities	**0.8**	0.6
Current liabilities		
Current liabilities	86.9	194.0
Total current liabilities	**86.9**	194.0
Total liabilities	**87.7**	194.6
TOTAL EQUITY AND LIABILITIES	**55,155.7**	55,131.2

Parent Company Cash Flow Statement

Expressed in MSEK	**1 Jan 2018- 30 Sep 2018 9 months**	**1 Jul 2018- 30 Sep 2018 3 months**	1 Jan 2017- 30 Sep 2017 9 months	1 Jul 2017- 30 Sep 2017 3 months	1 Jan 2017- 31 Dec 2017 12 months
Cash flow from operations					
Net result	1,605.0	-57.2	46,453.9	-47.0	46,648.6
Adjustment for non-cash related items	-5.0	0.6	-46,607.6	-1.8	-46,608.2
Changes in working capital	-105.5	55.1	267.4	158.8	189.2
Total cash flow from operations	**1,494.5**	**-1.5**	113.7	110.0	229.6
Cash flow from investing					
Investments in other fixed assets	-0.1	—	—	—	—
Total cash flow from investing	-0.1	—	—	—	—
Cash flow from financing					
Dividends paid	-1,354.1	—	—	—	—
Purchase of own shares	-119.5	—	-63.6	-63.6	-229.6
Total cash flow from financing	-1,473.6	—	-63.6	-63.6	-229.6
Change in cash and cash equivalents	20.8	-1.5	50.1	46.4	—
Cash and cash equivalents at the beginning of the period	4.8	33.4	3.2	6.2	3.2
Currency exchange difference in cash and cash equivalents	6.0	-0.3	0.9	1.6	1.6
Cash and cash equivalents at the end of the period	**31.6**	**31.6**	54.2	54.2	4.8

Parent Company Statement of Changes in Equity

	Restricted equity		Unrestricted equity				
Expressed in MSEK	Share capital	Statutory reserve	Other reserves	Retained earnings	Dividends	Total	Total equity
Balance at 1 January 2017	**3.5**	**861.3**	**6,828.8**	**4,519.3**	**–**	**11,348.1**	**12,212.9**
Total comprehensive income	**–**	**–**	**–**	**46,453.9**	**–**	**46,453.9**	**46,453.9**
Transactions with owners							
Distributions	–	–	–	–	-3,695.3	-3,695.3	-3,695.3
Purchase of own shares	–	–	-63.6	–	–	-63.6	-63.6
Total transactions with owners	**–**	**–**	-63.6	**–**	**-3,695.3**	**-3,758.9**	**-3,758.9**
Balance at 30 September 2017	**3.5**	**861.3**	**6,765.2**	**50,973.2**	**-3,695.3**	**54,043.1**	**54,907.9**
Total comprehensive income	**–**	**–**	**–**	**194.7**	**–**	**194.7**	**194.7**
Transactions with owners							
Purchase of own shares	–	–	-166.0	–	–	-166.0	-166.0
Total transactions with owners	**–**	**–**	**-166.0**	**–**	**–**	**-166.0**	**-166.0**
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	**–**	**–**	**–**	**1,605.0**	**–**	**1,605.0**	**1,605.0**
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 30 September 2018	**3.5**	**861.3**	**6,479.7**	**49,077.6**	**-1,354.1**	**54,203.2**	**55,068.0**

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- 30 Sep 2018 9 months**	**1 Jul 2018- 30 Sep 2018 3 months**	1 Jan 2017- 30 Sep 2017 9 months	1 Jul 2017- 30 Sep 2017 3 months	1 Jan 2017- 31 Dec 2017 12 months
Revenue and other income	2,006.4	636.4	1,403.3	517.2	1,997.0
EBITDA[1]	1,467.7	503.5	1,071.7	382.4	1,501.5
Net result	327.4	62.6	431.8	227.0	380.9
Operating cash flow[1]	1,428.7	461.1	1,095.5	389.5	1,530.0
Free cash flow	489.7	228.7	43.1	67.6	203.7
Data per share from continuing operations USD					
Shareholders' equity per share	-0.43	-0.43	-0.73	-0.73	-1.03
Operating cash flow per share	4.22	1.36	3.22	1.15	4.50
Cash flow from operations per share	3.79	1.41	2.82	1.05	3.82
Earnings per share	0.97	0.19	1.28	0.67	1.13
Earnings per share fully diluted	0.96	0.18	1.28	0.67	1.13
EBITDA per share	4.33	1.48	3.15	1.12	4.41
EBITDA per share — fully diluted	4.32	1.48	3.14	1.12	4.40
Number of shares issued at period end	340,386,445	340,386,445	340,386,445	340,386,445	340,386,445
Number of shares in circulation at period end	338,513,135	338,513,135	340,013,211	340,013,211	339,153,135
Weighted average number of shares for the period	338,618,911	338,513,135	340,351,886	340,282,769	340,237,772
Weighted average number of shares for the period fully diluted	339,588,763	339,223,597	341,558,091	341,233,400	341,380,316
Share price					
Share price at period end in SEK	340.20	340.20	178.20	178.20	187.80
Share price at period end in USD[2]	38.20	38.20	21.80	21.80	22.88
Key ratios from continuing operations					
Return on equity (%)[3]	—	—	—	—	—
Return on capital employed (%)	36	11	15	5	22
Net debt/equity ratio (%)[3]	—	—	—	—	—
Equity ratio (%)	-2	-2	-4	-4	-6
Share of risk capital (%)	31	31	14	14	17
Interest coverage ratio	18	21	5	6	6
Operating cash flow/interest ratio	21	26	11	12	12
Yield	1	1	6	6	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 30 September 2018, 31 December 2017 and 30 September 2017 is negative, these ratios have not been calculated.

Relevant Reconciliations of Alternative Performance Measures

EBITDA MUSD	**1 Jan 2018- 30 Sep 2018 9 months**	**1 Jul 2018- 30 Sep 2018 3 months**	1 Jan 2017- 30 Sep 2017 9 months	1 Jul 2017- 30 Sep 2017 3 months	1 Jan 2017- 31 Dec 2017 12 months
Operating profit	1,118.1	393.9	568.5	194.7	812.4
Add: depletion of oil and gas properties	341.5	108.8	428.5	153.2	568.4
Add: exploration costs	6.1	0.2	42.2	16.3	73.1
Add: impairment costs of oil and gas properties	–	–	30.6	17.4	30.6
Add: loss from sale of assets	–	–	–	–	14.4
Add: depreciation of other tangible assets	2.0	0.6	1.9	0.8	2.6
EBITDA	**1,467.7**	**503.5**	1,071.7	382.4	1,501.5

Operating cash flow MUSD	**1 Jan 2018- 30 Sep 2018 9 months**	**1 Jul 2018- 30 Sep 2018 3 months**	1 Jan 2017- 30 Sep 2017 9 months	1 Jul 2017- 30 Sep 2017 3 months	1 Jan 2017- 31 Dec 2017 12 months
Revenue and other income	2,006.4	636.4	1,403.3	517.2	1,997.0
Minus: production costs	-105.8	-36.9	-120.6	-42.6	-164.2
Minus: purchase of crude oil from third parties	-417.2	-92.4	-188.0	-84.8	-303.3
Minus: current taxes	-54.7	-46.0	0.8	-0.3	0.5
Operating cash flow	**1,428.7**	**461.1**	1,095.5	389.5	1,530.0

Free cash flow MUSD	**1 Jan 2018- 30 Sep 2018 9 months**	**1 Jul 2018- 30 Sep 2018 3 months**	1 Jan 2017- 30 Sep 2017 9 months	1 Jul 2017- 30 Sep 2017 3 months	1 Jan 2017- 31 Dec 2017 12 months
Cash flows from operating activities	1,285.6	478.2	960.6	359.2	1,299.3
Minus: cash flows from investing activities	-795.9	-249.5	-917.5	-291.6	-1,095.6
Free cash flow	**489.7**	**228.7**	43.1	67.6	203.7

Net debt MUSD	**1 Jan 2018- 30 Sep 2018 9 months**	**1 Jul 2018- 30 Sep 2018 3 months**	1 Jan 2017- 30 Sep 2017 9 months	1 Jul 2017- 30 Sep 2017 3 months	1 Jan 2017- 31 Dec 2017 12 months
Bank loans	3,645.0	3,645.0	4,115.0	4,115.0	3,955.0
Minus: cash and cash equivalents	-75.1	-75.1	-91.0	-91.0	-71.4
Net debt	**3,569.9**	**3,569.9**	4,024.0	4,024.0	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.

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.

Financial Information

The Company will publish the following reports:

- The year end report (January – December 2018) will be published on 30 January 2019.
- 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 AGM will be held on 29 March 2019 in Stockholm, Sweden.

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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
CAD	Canadian dollar
CHF	Swiss franc
EUR	Euro
NOK	Norwegian krona
RUR	Russian rouble
SEK	Swedish krona
USD	US dollar
TSEK	Thousand SEK
TUSD	Thousand USD
MSEK	Million SEK
MUSD	Million USD

Oil related terms and measurements

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

This information is information that Lundin Petroleum AB is required to make public pursuant to the EU Market Abuse Regulation and the Securities Markets Act. The information was submitted for publication, through the contact persons set out above, at 07.30 CET on 7 November 2018.

Forward-Looking Statements

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

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

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