Lundin Petroleum

Q2

Report for the SIX MONTHS ended 30 June 2017

Lundin Petroleum AB (publ)

company registration number 556610-8055

Highlights

Record high production of 86.1 Mboepd for the six months ended 30 June 2017.

Phase 1 of the Johan Sverdrup project on schedule with over 50 percent completed.

Completion of the spin-off of the non-Norwegian producing assets into International Petroleum Corporation (IPC) on 24 April 2017 by distributing the IPC shares, on a pro-rata basis, to Lundin Petroleum shareholders.

Continuing operations: six months ended 30 June 2017 (30 June 2016)

- Production of 86.1 Mboepd (49.2 Mboepd)
- Revenue of MUSD 886.1 (MUSD 354.8)
- EBITDA of MUSD 689.3 (MUSD 260.5)
- Operating cash flow of MUSD 705.9 (MUSD 314.0)
- Net result of MUSD 204.8 (MUSD 93.6) including a net foreign exchange gain of MUSD 139.2 (MUSD 110.2)
- Net debt of MUSD 4,081 (31 December 2016: MUSD 4,075)

- Net result from discontinued operations of MUSD 47.9 (MUSD -27.6)

Continuing operations: second quarter ended 30 June 2017 (30 June 2016)

- Production of 89.5 Mboepd (50.6 Mboepd)
- Revenue of MUSD 464.6 (MUSD 209.7)
- EBITDA of MUSD 333.5 (MUSD 163.1)
- Operating cash flow of MUSD 340.0 (MUSD 180.6)
- Net result of MUSD 145.6 (MUSD -72.1) including a net foreign exchange gain of MUSD 118.8 (MUSD -78.1)

Continuing operations	1 Jan 2017– 30 Jun 2017 6 months	1 Apr 2017– 30 Jun 2017 3 months	1 Jan 2016 – 30 Jun 2016 6 months	1 Apr 2016 – 30 Jun 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Production in Mboepd	86.1	89.5	49.2	50.6	59.3
Revenue in MUSD	886.1	464.6	354.8	209.7	950.0
EBITDA in MUSD	689.3	333.5	260.5	163.1	752.5
Operating cash flow in MUSD	705.9	340.0	314.0	180.6	857.9
Net result in MUSD	204.8	145.6	93.6	-72.1	-399.3
Net result attributable to shareholders of the Parent Company in MUSD	207.3	146.8	95.9	-70.9	-256.7
Earnings/share in USD[1]	0.61	0.43	0.31	-0.23	-0.79
Earnings/share fully diluted in USD[1]	0.61	0.43	0.31	-0.23	-0.79

The numbers included in the table above are based on continuing operations (including 2016 comparatives)
[1] Based on net result attributable to shareholders of the Parent Company

Definitions

An extensive list of definitions can be found on www.lundin-petroleum.com under the heading “Definitions”.

Abbreviations

EBITDA	Earnings Before Interest, Tax, Depreciation and Amortisation
CAD	Canadian dollar
CHF	Swiss franc
EUR	Euro
NOK	Norwegian krona
RUR	Russian rouble
SEK	Swedish krona
USD	US dollar
TSEK	Thousand SEK
TUSD	Thousand USD
MSEK	Million SEK
MUSD	Million USD

Oil related terms and measurements

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

Letter to Shareholders

Dear fellow Shareholders,

I am pleased to report that Lundin Petroleum has delivered excellent results for the second quarter 2017 while maintaining a strong HSE performance. The quarter was characterised by strong production at low cash operating cost, solid operating cash flow generation, good progress on development projects and successful appraisal activity and organic growth in the southern Barents Sea. At the end of April, the spin-off of IPC was also successfully completed, resulting in a dividend distribution, through IPC shares, of USD 410 million to Lundin Petroleum's shareholders.

Production above guidance
Lundin Petroleum's production for the second quarter 2017 was above the upper end of the quarter production guidance with continued low cash operating costs, driven by strong performance from our operated Edvard Grieg field as well as from our non-operated Alvheim field. Edvard Grieg in particular continues to outperform at both the subsurface and facilities levels and I expect a reserves increase by year end. This performance has led us to revise, for the second time this year, Lundin Petroleum's full year guidance to a new increased production level of between 80 and 85 Mboepd and cash operating costs down to USD 4.60 per barrel from the previous guidance of USD 4.90 per barrel.

Johan Sverdrup development progressing
Our major world class development project Johan Sverdrup continues to progress according to plan and Phase 1 is now over 50 percent completed. First oil remains firmly on track for end of 2019. Both Phase 1 and Phase 2 costs have been reduced and are today between NOK 137 and 152 billion compared to the original estimate in the development plan of NOK 207 billion. This achievement of approximately 30 percent overall reduction in costs means that the full field break even oil price is now estimated at well below USD 25 per barrel. A significant milestone was also reached towards the end of July 2017, with the successful offshore installation of the first Johan Sverdrup riser platform steel jacket. The 26,000 tonnes jacket is one of the largest that has ever been built for the North Sea.

Outlook
We also continue to be active on the organic growth front. We completed the successful Alta-4 appraisal well which tested at over 6,000 bopd and are currently drilling a side-track well to assist with placement of a horizontal well for a possible extended well test that is planned for 2018. We are definitely moving in the right direction towards establishing commerciality of the Alta discovery.

In August, we begin a very active exploration drilling campaign in the southern Barents Sea, starting with the significant Korpfjell prospect and its multi-billion barrel resource potential, followed by the Børselv prospect, located on the Loppa High and on trend with the Alta discovery, and finally with the drilling of two large prospects on trend with our Filicudi discovery, the Hufsa and Hurri prospects. Our organic growth story is as exciting as ever with significant growth potential.

Lundin Petroleum is firmly on track to meet the production growth targets for 2017 and beyond, with a robust HSE culture in place and one of the lowest carbon intensity levels in the industry. We are well positioned to continue to deliver an exciting organic growth story for many years to come, creating long-term sustainable value for all our shareholders.

And even though the oil industry continues to face challenging times, marked by low oil prices and uncertainties, I am confident that we will continue to successfully steer the Company through these stormy seas and remain as one of the leading independent oil and gas companies in Europe, with significant future growth potential. This is only achievable with the passion, team spirit and entrepreneurship of my colleagues across the Company.

To you, fellow shareholders and the Board of Directors, thank you for your continued support.

Full steam ahead!

Yours Sincerely,

Alex Schneiter
President and CEO

Stockholm, 2 August 2017

OPERATIONAL REVIEW

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

Continuing Operations
Norway

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

Production
Production for the six month period ending 30 June 2017 (reporting period) amounted to 86.1 thousand barrels of oil equivalent per day (Mboepd) (compared to 49.2 Mboepd for the same period in 2016), which was 5 percent above the mid-point of the production guidance for the reporting period that was updated with the first quarter results released in May 2017 and just above the top of the updated production guidance range for the reporting period. This performance is due to strong facilities and reservoir performance at both the Edvard Grieg field and the Alvheim area during the reporting period. Based on this strong performance, Lundin Petroleum is further increasing its full year 2017 production guidance to between 80 to 85 Mboepd from the previous guidance of between 75 to 85 Mboepd. The revised guidance continues to assume that the Ivar Aasen field will fully utilise the contractual allocation of the increased capacity on the Edvard Grieg facilities from the fourth quarter 2017.

Total cash operating cost, including netting off tariff income, was USD 4.09 per barrel during the reporting period and is forecast to be USD 4.60 per barrel for the year from the previous guidance of 4.90 per barrel. The production during the reporting period was comprised as follows:

Production in Mboepd	**1 Jan 2017– 30 Jun 2017 6 months**	**1 Apr 2017– 30 Jun 2017 3 months**	1 Jan 2016 – 30 Jun 2016 6 months	1 Apr 2016 – 30 Jun 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Norway					
Crude oil	77.7	80.8	44.1	45.3	53.2
Gas	8.4	8.7	5.1	5.3	6.1
Total production	**86.1**	**89.5**	49.2	50.6	59.3
Quantity in Mboe	**15,575.0**	**8,144.6**	8,961.5	4,604.9	21,701.4

Production in Mboepd	WI [1]	**1 Jan 2017– 30 Jun 2017 6 months**	**1 Apr 2017– 30 Jun 2017 3 months**	1 Jan 2016 – 30 Jun 2016 6 months	1 Apr 2016 – 30 Jun 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Edvard Grieg	65%[2]	67.3	71.0	32.1	34.2	42.0
Ivar Aasen	1.385%	0.6	0.6	–	–	0.0
Alvheim	15%	14.5	14.3	9.0	9.1	10.0
Volund	35%	0.1	–	3.4	3.3	2.7
Bøyla	15%	1.2	1.2	2.0	1.9	1.7
Brynhild	90%[3]	2.2	2.2	2.5	1.9	2.6
Gaupe	40%	0.2	0.2	0.2	0.2	0.3
		86.1	**89.5**	49.2	50.6	59.3

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

Net production from the Edvard Grieg field during the reporting period was higher than forecast at 67.3 Mboepd due to increased facilities capacity, continued high production efficiency and strong reservoir performance. During the reporting period the fifth and sixth Edvard Grieg production wells were successfully drilled and came on stream at planned production rates. The production capacity from the first six production wells exceeds expectations and the reservoir depletion rate continues to be more favourable than anticipated.

The total operating cost for the Edvard Grieg field was USD 4.66 per barrel during the reporting period and is forecast to be USD 4.85 per barrel for the year. Cash operating cost, including netting off tariff income from the Ivar Aasen field, was USD 3.95 per barrel for the reporting period and is forecast to be USD 4.15 per barrel for the year.

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

In April 2017, Lundin Petroleum announced the successful Edvard Grieg Southwest appraisal well 16/1-27 which encountered a 15 metres gross oil column with significantly better sand quality and thickness compared to prognosis. The well results confirm a preliminary gross resource upside for this part of the Edvard Grieg field in the range of 10 to 30 MMboe. In addition, these good results indicate potential resource upside in other areas of the field. The final implication for the total reserves for the Edvard Grieg field will be quantified in the 2017 year end reserves update. The development drilling plan within the Plan for Development and Operation (PDO) has been optimised within the same number of planned wells with one production well and one water injection well now being planned to access the southwest area of the field. The drilling of these wells is scheduled for the end of 2017 or early 2018.

The Ivar Aasen field, which produces through the Edvard Grieg facilities, commenced production in December 2016 and the combined fields have been producing with a high level of reliability. The Edvard Grieg production efficiency during the reporting period was 93 percent which is in line with expectations. Apart from a short period of instability with the Edvard Grieg power generation system due to remaining commissioning issues which have been resolved, production efficiency during the second quarter of 2017 has exceeded these levels and so there is a fair expectation of increased production efficiency going forward.

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

Net production from the Ivar Aasen field during the reporting period was in line with forecast at 0.6 Mboepd. Production ramp-up is in line with plan and water injection commenced during the second quarter of 2017. The PDO drilling programme will be completed during the third quarter of 2017.

Production from the Alvheim area during the reporting period was ahead of forecast due to reservoir performance continuing to be better than expected as well as higher than expected Alvheim FPSO production efficiency of 97 percent. Additionally, production has been optimised between the fields within the Alvheim area to maximise production through the Alvheim FPSO. The total operating cost for the Alvheim area was USD 3.41 per barrel during the reporting period and is forecast to be USD 4.08 per barrel for the year.

Net production from the Alvheim field during the reporting period was ahead of forecast at 14.5 Mboepd. The reservoir continues to outperform with the most recent infill well A5 as well as the Viper and Kobra wells, which came on stream in November 2016, all producing significantly ahead of expectation. Additionally, Alvheim field production has been prioritised over Volund production to maximise facilities throughput. The drilling of two infill wells on the Boa area of the field has commenced with production start-up of both wells expected in 2018.

Net production from the Volund field during the reporting period was slightly below forecast at 0.1 Mboepd. Cutback of Volund production was required during the first half of 2017 while two infill wells were being drilled on the field and additionally an arrangement was agreed to maximise total production through the Alvheim FPSO by further cutting back Volund field production and prioritising Alvheim field production until the new Volund infill wells start-up. The two new Volund infill wells have been completed with results in line with expectations. The first well came on stream in July 2017 at planned production rates and the second well is scheduled to start-up in mid-August 2017.

Net production from the Bøyla field during the reporting period was in line with forecast at 1.2 Mboepd.

Net production from the Brynhild field during the reporting period was slightly higher than forecast at 2.2 Mboepd. The water injection system was re-instated in February 2017 and stable injection rates have been achieved for the last few months. The Brynhild field achieved an uptime of 56 percent for the reporting period.

In June 2017, Lundin Petroleum announced that it had entered into an agreement to divest a 39 percent working interest in the Brynhild field to CapeOmega. Lundin Norway will retain operatorship and following the transaction will have a 51 percent working interest in the Brynhild field. The effective date of the transaction is 1 January 2017. Lundin Petroleum's lenders consented to the transaction in July 2017 whilst the transaction remains subject to customary government approval, with completion expected in the fourth quarter of 2017.

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

Development

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

Johan Sverdrup

Phase 1 of the Johan Sverdrup project is on schedule with over 50 percent completed at the end of the reporting period. Construction on all elements of Phase 1 of the project has commenced with work ongoing at 22 construction sites around the world and with project manning at peak levels of approximately 3 million man-hours per month. With all the major project contracts awarded and the good progress on the project, Phase 1 costs continue to be reduced.

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

Construction of the remaining three steel jackets is underway at the Kværner yard on the west coast of Norway and at the Dragados yard in Spain. Construction of the drilling platform and living quarters, through EPC contracts, is underway in Norway by Aibel an d Kværner/KBR respectively and construction of the riser platform and processing platform is ongoing at Samsung Heavy Industries in Korea with Aker Solutions being contracted for the procurement and engineering of the riser platform and processing platform. In addition, civil engineering works are underway on the onshore power system at Haugsneset and for the oil pipeline landfall at Mongstad.

The pre-drilling of development wells commenced in March 2016 with eight production wells completed in 2016 with results in line with expectations. Three pilot wells have been drilled to assist with the placement of the development wells with results in line or better than prognosis. In addition, the pre-drilling of ten water injection wells has commenced. Drilling progress continues to be significantly ahead of schedule.

At the time of submitting the Phase 1 PDO in February 2015, the capital expenditure for Phase 1 was estimated at gross NOK 123 billion (nominal). The latest cost estimate, as released by Statoil in early 2017, has been reduced to NOK 97 billion (nominal), a reduction of approximately 21 percent. This is based on a fixed project exchange rate of NOK 6 per USD and excludes additional foreign exchange rate savings in US dollar terms. The gross production capacity for Phase 1 of the project is estimated at 440 Mbopd and is scheduled to start production in late 2019.

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

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

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

Appraisal

2017 appraisal well programme

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

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

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

In May 2017, Lundin Petroleum announced that the Gohta-3 appraisal well located in PL492 some 4 km north of the original discovery well encountered a 300 metres gross sequence of Permian age carbonates with poor reservoir quality. The resource estimate for the discovery will be reduced as a consequence of this well with the resource estimate being updated at 2017 year end. Gohta is considered a satellite opportunity to the larger adjacent Alta discovery and this result has no impact on the appraisal and conceptual development plans for Alta.

In July 2017, Lundin Petroleum announced that the Alta-4 appraisal well located approximately 2 km south of the original Alta discovery well had encountered a gross hydrocarbon column of 48 metres, comprising 4 metres of gas and 44 metres of oil in a sequence of Permian-Triassic carbonate sediments of varying reservoir characteristics. Pressure data show the same fluid contacts and gradients as observed in previous wells drilled on the Alta discovery, confirming good communication across the large Alta structure. A production test was performed in the oil zone, producing at a stabilised rate of 6,050 bopd with low pressure drawdown and constrained by rig testing facilities. The production test confirmed very good reservoir properties and good lateral continuity within the Permian-Triassic clastic reservoirs. A geological sidetrack is currently being drilled approximately 900 metres north of the Alta-4 well to assist with placement of a horizontal well for a possible extended well test that is being planned for 2018.

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

Exploration

2017 exploration well programme

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

In February 2017, Lundin Petroleum announced a discovery on the Filicudi prospect in PL533 in the southern Barents Sea. The well, which was drilled approximately 40 km southwest of the Johan Castberg discovery in PL532, encountered a 129 metres hydrocarbon column, with 63 metres of oil and 66 metres of gas, in high quality Jurassic and Triassic sandstone reservoirs. A sidetrack well was drilled that also confirmed the reservoir and hydrocarbon column. The discovery is estimated to contain between 35 and 100 MMboe of gross resources.

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

In August 2017, exploration drilling will commence on the Korpfjell prospect in PL859 in the southeastern Barents Sea with results expected in the third quarter of 2017. The well is targeting one segment of the shallower horizons within the multi-billion barrel gross prospective resource potential of the Korpfjell prospect.

During 2017 Lundin Petroleum will also drill the Børselv prospect in PL609 located on-trend north of the Alta and Neiden discoveries in the southern Barents Sea.

Significant additional prospectivity is mapped along trend with the Filicudi discovery in PL533 in the southern Barents Sea and the follow-on Hufsa prospect will be drilled during the fourth quarter of 2017. Additionally, the partnership in PL533 is considering drilling the Hurri prospect which would spud towards the end of 2017, which is along trend from the Kayak oil discovery in PL532 that was recently announced by Statoil.

Additionally, acquisition of a large high-specification 3D seismic survey commenced in July 2017 over the Alta, Gohta and Filicudi discoveries and associated prospectivity.

The remaining exploration wells to be drilled in the southern Barents Sea in 2017 are targeting net unrisked prospective resources of over 500 MMboe.

Licence awards, transactions and relinquishments

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

During the reporting period, a licence exchange was completed with Engie to swap 10 percent of Lundin Petroleum's working interest in PL778 for Engie's 20 percent working interest in both PL715 and PL722. The acquisition of Shell's 20 percent working interest in PL715 was completed and the acquisition of North E&P's 40 percent working interest in PL805 was agreed but is still subject to government approval. In addition, Lundin Petroleum agreed a farm-in with Fortis Petroleum for a 10 percent working interest each in PL539 and PL860 on the Mandal High, which is subject to government approval, and farmed out its 20 percent working interest in PL685 to Wellesley Petroleum.

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

Russia

At year end 2016, Lundin Petroleum removed the contingent resources from its books associated with the Morskaya oil discovery and wrote down the entire book value of the asset. Management is reviewing options for the Morskaya asset. During the reporting period an appraisal plan was agreed with the Russian licensing authority, Rosnedra, in order to maintain the licence in good standing while options for the asset are being reviewed. The appraisal plan requires no significant activities for several years.

Discontinued Operations
Non-Norwegian Producing Assets

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

Reserves and Resources

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

Production

Production during the reporting period for the non-Norwegian producing assets spun-off to IPC amounted to 7.6 Mboepd and was comprised as follows:

Production in Mboepd	**1 Jan 2017– 30 Jun 2017 6 months**	**1 Apr 2017– 30 Jun 2017 3 months**	1 Jan 2016 – 30 Jun 2016 6 months	1 Apr 2016 – 30 Jun 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Crude oil					
France	1.6	0.8	2.6	2.5	2.6
Malaysia	5.0	2.4	8.6	8.7	8.6
Total crude oil production	**6.6**	**3.2**	11.2	11.2	11.2
Gas					
Netherlands	1.0	0.5	1.6	1.6	1.6
Indonesia	–	–	1.1	0.5	0.5
Total gas production	**1.0**	**0.5**	2.7	2.1	2.1
Total production	**7.6**	**3.7**	13.9	13.3	13.3
Quantity in Mboe	**1,370.4**	**334.4**	2,526.7	1,209.0	4,858.2

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

Health, Safety and Environment

For continuing operations, the Lost Time Incident Rate (LTIR) for the reporting period was 0.00 per million hours worked. Four medical treatment incidents were reported in Norway, resulting in a Total Recordable Incident Rate (TRIR) for the reporting period of 3.81 per million hours worked.

Two audits of the Edvard Grieg facilities were conducted by the Petroleum Safety Authorities and one by the Norwegian Petroleum Directorate in the second quarter 2017. The audit findings had a low level of severity and work is ongoing to address these.

There were no material environmental incidents during the reporting period.

FINANCIAL REVIEW

Result

The operating profit from continuing operations for the reporting period amounted to MUSD 373.8 (MUSD 46.0). The operating profit for the reporting period was driven by the increased production and higher oil prices compared to last year.

The net result from continuing operations for the reporting period amounted to MUSD 204.8 (MUSD 93.6). The net result from continuing operations in the reporting period was mainly driven by the excellent production performance and a net foreign exchange gain as a result of the weakening US Dollar against the Norwegian Krone and the Euro, partly offset by expensed exploration costs and an impairment charge.

The net result from continuing operations attributable to shareholders of the Parent Company for the reporting period amounted to MUSD 207.3 (MUSD 95.9) or MUSD 255.2 (MUSD 68.3) including discontinued operations representing earnings per share from continuing operations of USD 0.61 (USD 0.31) or USD 0.75 (USD 0.22) including discontinued operations.

Earnings before interest, tax, depletion and amortisation (EBITDA) from continuing operations for the reporting period amounted to MUSD 689.3 (MUSD 260.5) representing EBITDA per share of USD 2.03 (USD 0.84). Operating cash flow from continuing operations for the reporting period amounted to MUSD 705.9 (MUSD 314.0) representing operating cash flow per share of USD 2.07 (USD 1.01).

Changes in the Group

On 24 April 2017, Lundin Petroleum completed the spin-off of its assets in Malaysia, France and the Netherlands (the IPC assets) into International Petroleum Corporation (IPC) by distributing the IPC shares, on a pro-rata basis, to Lundin Petroleum shareholders. The results of the IPC business are included in the Lundin Petroleum financial statements until the completion of the spin-off and are shown as discontinued operations. For more information see Note 14.

Revenue

Revenue for the reporting period amounted to MUSD 886.1 (MUSD 354.8) and was comprised of net sales of oil and gas, change in under/over lift position and other revenue as detailed in Note 1.

Net sales of oil and gas for the reporting period amounted to MUSD 881.0 (MUSD 351.5). The average price achieved by Lundin Petroleum for a barrel of oil equivalent from own production amounted to USD 48.67 (USD 37.23) and is detailed in the following table. The average Dated Brent price for the reporting period amounted to USD 51.80 (USD 39.81) per barrel.

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

Sales from own production Average price per boe expressed in USD	**1 Jan 2017– 30 Jun 2017 6 months**	**1 Apr 2017– 30 Jun 2017 3 months**	1 Jan 2016 – 30 Jun 2016 6 months	1 Apr 2016 – 30 Jun 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Crude oil sales					
Norway					
– Quantity in Mboe	14,174.5	7,907.7	8,401.2	4,196.1	20,654.5
– Average price per boe	*50.29*	*48.43*	*38.09*	*43.78*	*43.60*
Gas and NGL sales					
Norway					
– Quantity in Mboe	1,808.3	994.7	1,040.6	635.2	2,352.1
– Average price per boe	*35.98*	*33.01*	*29.73*	*28.67*	*30.94*
Total sales from continuing operations					
– Quantity in Mboe	**15,982.8**	**8,902.4**	9,441.8	4,831.3	23,006.6
– Average price per boe	***48.67***	***46.70***	*37.23*	*41.84*	*42.31*

The table above excludes 2,133,019 barrels of crude oil purchased from outside the Group by Lundin Petroleum Marketing SA and sold to the market.

Sales of oil and gas are recognised when the risk of ownership is transferred to the purchaser. Sales quantities in a period can differ from production quantities as a result of permanent and timing differences. Timing differences can arise due to under/over lift of entitlement, inventory, storage and pipeline balances effects.

The change in under/over lift position amounted to a cost of MUSD 5.1 (income of MUSD 1.8) in the reporting period due to the timing of the cargo liftings compared to production.

Other revenue amounted to MUSD 10.2 (MUSD 1.5) for the reporting period and included a quality differential compensation on Alvheim blended crude and tariff income of MUSD 9.0 (MUSD –) which is due to net income from Ivar Aasen tariffs paid to Edvard Grieg.

Production costs

Production costs including inventory movements for the reporting period amounted to MUSD 78.0 (MUSD 82.3) and are detailed in Note 2. The total production cost per barrel of oil equivalent produced is detailed in the table below:

Production costs from continuing operations	**1 Jan 2017– 30 Jun 2017 6 months**	**1 Apr 2017– 30 Jun 2017 3 months**	1 Jan 2016 – 30 Jun 2016 6 months	1 Apr 2016 – 30 Jun 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Cost of operations					
– In MUSD	55.3	28.9	55.3	28.2	113.1
– In USD per boe	*3.55*	*3.54*	*6.17*	*6.13*	*5.21*
Tariff and transportation expenses					
– In MUSD	17.4	9.7	16.2	7.6	33.9
– In USD per boe	*1.12*	*1.19*	*1.81*	*1.65*	*1.56*
Cash operating costs					
– In MUSD	**72.7**	**38.6**	71.5	35.8	147.0
– In USD per boe [1]	***4.67***	***4.73***	*7.98*	*7.78*	*6.77*
Change in inventory position					
– In MUSD	-0.5	0.1	-0.4	-0.1	-0.7
– In USD per boe	*-0.03*	*0.01*	*-0.04*	*-0.01*	*-0.04*
Other					
– In MUSD	5.8	3.2	11.2	5.0	22.1
– In USD per boe	*0.37*	*0.40*	*1.24*	*1.06*	*1.02*
Production costs from continuing operations					
– In MUSD	**78.0**	**41.9**	82.3	40.7	168.4
– In USD per boe	***5.01***	***5.14***	*9.18*	*8.83*	*7.75*

Note: USD per boe is calculated by dividing the cost by total production volume for the period.
[1] The numbers in this table are excluding tariff income netting. Lundin Petroleum's cash operating cost for the reporting period of USD 4.67 is reduced to USD 4.09 when tariff income is netted off.

The total cost of operations for the reporting period amounted to MUSD 55.3 (MUSD 55.3). The total cost of operations excluding operational projects amounted to MUSD 51.2 (MUSD 49.8).

The cost of operations per barrel amounted to USD 3.55 (USD 6.17) including operational projects and USD 3.29 (USD 5.55) excluding operational projects. The cost of operations per barrel is lower than the updated guidance provided in May 2017.

Tariff and transportation expenses for the reporting period amounted to MUSD 17.4 (MUSD 16.2). The main reason for the reduction per barrel is due to the increased volumes in the Oseberg transportation system that the Edvard Grieg pipeline is part of.

Other costs amounted to MUSD 5.8 (MUSD 11.2) and mainly related to the operating cost share arrangement on the Brynhild field whereby the amount of operating cost varies with the oil price until the end of May-2017. This arrangement was being marked-to-market against the oil price curve.

Depletion and decommissioning costs

Depletion and decommissioning costs amounted to MUSD 275.3 (MUSD 157.0) at an average rate of USD 17.67 (USD 17.52) per barrel and are detailed in Note 3. The higher depletion costs for the reporting period compared to the same period last year is due to the depletion charge associated with the Edvard Grieg field as a result of the higher production levels achieved.

Exploration costs
Exploration costs expensed in the income statement for the reporting period amounted to MUSD 25.9 (MUSD 55.8) and are detailed in Note 3. Exploration and appraisal costs are capitalised as they are incurred. When exploration drilling is unsuccessful, the capitalised costs are expensed. All capitalised exploration costs are reviewed on a regular basis and are expensed where their recoverability is considered highly uncertain.

During the reporting period, exploration costs relating to Norway of MUSD 25.1 were expensed and mainly related to the unsuccessful Gohta appraisal well in PL492 and a dry well on the Volund West prospect as well as a number of Norwegian exploration licences in the process of relinquishment.

Impairment costs of oil and gas properties
Impairment costs in the income statement for the reporting period amounted to MUSD 13.2 (MUSD –) and are detailed in Note 3. The impairment costs related to the partial sale of the Brynhild field in PL148 where a 39 percent working interest will be divested subject to Norwegian government approval.

Other costs of sales
Other cost of sales for the reporting period amounted to MUSD 103.2 (MUSD –) and related to oil purchased from outside the Group by Lundin Petroleum Marketing SA.

General, administrative and depreciation expenses
The general administrative and depreciation expenses for the reporting period amounted to MUSD 16.7 (MUSD 13.7) which included a charge of MUSD 1.8 (MUSD 2.1) 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 1.3 (MUSD 1.7).

Finance income
Finance income for the reporting period amounted to MUSD 139.6 (MUSD 110.8) and is detailed in Note 4.

The net foreign currency exchange gain for the reporting period amounted to MUSD 139.2 (MUSD 110.2). Foreign exchange movements occur on the settlement of transactions denominated in foreign currencies and the revaluation of working capital and loan balances to the prevailing exchange rate at the balance sheet date where those monetary assets and liabilities are held in currencies other than the functional currencies of the Group's reporting entities. Lundin Petroleum has hedged certain foreign currency operational expenditure amounts against the US Dollar and for the period, the net realised exchange loss on settled foreign exchange hedges amounted to MUSD 6.2 (MUSD 33.9).

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

Finance costs
Finance costs for the reporting period amounted to MUSD 89.8 (MUSD 120.3) and are detailed in Note 5.

Interest expenses for the reporting period amounted to MUSD 58.1 (MUSD 73.6) and represented the portion of interest charged to the income statement. An additional amount of interest of MUSD 26.6 (MUSD 7.9) associated with the funding of the Norwegian development projects was capitalised in the reporting period. The total interest expense has increased compared to the same period last year due to slightly higher borrowings and higher interest rates. The result on interest rate hedge settlements amounted to a loss of MUSD 11.0 (MUSD 9.6) and increased compared to the comparative period due to the higher hedged amounts in 2017.

The amortisation of the deferred financing fees amounted to MUSD 8.5 (MUSD 28.7) for the reporting period and related to the expensing of the fees incurred in establishing the financing facilities over the period of usage of the facilities. The decrease compared to the same period last year is related to the fact that the current financing facilities were entered into during the second quarter of 2016 following which the unamortised portion of the capitalised financing fees incurred in establishing the previous financing facilities and the short term revolving credit facility were expensed amounting to MUSD 22.3.

Loan facility commitment fees for the reporting period amounted to MUSD 5.4 (MUSD 3.3) with the increase compared to the same period last year being due to the increased available borrowing amounts under the Group's reserve-based lending facility.

Tax
The overall tax charge for the reporting period amounted to MUSD 218.8 (credit of MUSD 57.1) and is detailed in Note 6.

The current tax charge for the reporting period amounted to a credit of MUSD 1.1 (credit MUSD 41.6) which included a tax credit of MUSD 1.4 (credit MUSD 41.9) relating to previous year for Norway.

The deferred tax charge for the reporting period amounted to MUSD 219.9 (credit of MUSD 15.5) which predominantly related to Norway. The deferred tax amount arises primarily where there is a difference in depletion for tax and accounting purposes.

The Group operates in various countries and fiscal regimes where corporate income tax rates are different from the regulations in Sweden. Corporate income tax rates for the Group vary between 12.5 and 78 percent. The effective tax rate for the reporting period is affected by items which do not receive a full tax credit such as the reported net foreign currency exchange gain, Norwegian financial items and by the uplift allowance applicable in Norway for development expenditures against the offshore tax regime.

Non-controlling interest

The net result attributable to non-controlling interest for the reporting period amounted to MUSD -2.5 (MUSD -2.3) and related mainly to the non-controlling interest's share in a Russian subsidiary which is fully consolidated.

Discontinued operations

The net result from discontinued operations amounted to MUSD 47.9 (MUSD -27.6) and is detailed in Note 14.

Balance Sheet

Non-current assets

Oil and gas properties amounted to MUSD 4,258.5 (MUSD 4,376.4) and are detailed in Note 7.

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

Development expenditure in MUSD	**1 Jan 2017– 30 Jun 2017 6 months**	**1 Apr 2017– 30 Jun 2017 3 months**	1 Jan 2016 – 30 Jun 2016 6 months	1 Apr 2016 – 30 Jun 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Norway	512.7	255.7	386.9	218.5	877.1
Development expenditures from continuing operations	**512.7**	**255.7**	386.9	218.5	877.1

An amount of MUSD 512.7 (MUSD 386.9) of development expenditure was incurred in Norway during the reporting period, primarily on the Johan Sverdrup, Edvard Grieg and Volund fields.

Exploration and appraisal expenditure in MUSD	**1 Jan 2017– 30 Jun 2017 6 months**	**1 Apr 2017– 30 Jun 2017 3 months**	1 Jan 2016 – 30 Jun 2016 6 months	1 Apr 2016 – 30 Jun 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Norway	103.0	48.9	58.5	17.6	142.1
Russia	0.8	0.4	0.6	0.3	1.4
Exploration and appraisal expenditure from continuing operations	**103.8**	**49.3**	59.1	17.9	143.5

Exploration and appraisal expenditure of MUSD 103.0 (MUSD 58.5) was incurred in Norway during the reporting period, primarily on the Filicudi exploration well in PL533 and the appraisal wells Edvard Grieg Southwest in PL338, Gotha-3 in PL492 and Alta-4 in PL609.

Other tangible fixed assets amounted to MUSD 13.5 (MUSD 166.1) and the decrease compared to the comparative period is related to the spin-off of the IPC business.

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

Financial assets amounted to MUSD 11.8 (MUSD 9.4) and are detailed in Note 8. Other shares and participations amounted to MUSD 11.3 (MUSD 8.9) and related to the shares held in ShaMaran Petroleum which are reported at market value with any change in value being recorded in other comprehensive income.

Derivative instruments amounted to MUSD 11.9 (MUSD 17.0) and related to the marked-to-market gain on the outstanding interest rate and currency hedge contracts due to be settled after twelve months.

Current assets

Inventories amounted to MUSD 32.2 (MUSD 54.9) and included both well supplies and hydrocarbon inventories. The decrease compared to the comparative period is related to the spin-off of the IPC business.

Trade and other receivables amounted to MUSD 222.7 (MUSD 288.9) and are detailed in Note 9. Trade receivables, which are all current, amounted to MUSD 135.6 (MUSD 193.4) and included invoiced cargoes. Underlift amounted to MUSD 12.0 (MUSD 28.9) and was attributable to a underlift position on the producing fields, mainly Brynhild. Joint operations debtors relating to various joint venture receivables amounted to MUSD 14.2 (MUSD 31.2). Prepaid expenses and accrued income amounted to MUSD 34.8 (MUSD 29.4) and represented mainly prepaid operational and insurance expenditure. Brynhild operating cost share amounted to MUSD — (MUSD 3.0) and related to the marked-to-market valuation of the arrangement where the share of the operating cost varies with the oil price. This arrangement ended during the reporting period. Other current assets amounted to MUSD 26.0 (MUSD 3.0) and included a short term receivable from IPC in relation to certain working capital balances following the IPC spin-off, VAT receivables and other miscellaneous receivable balances.

Derivative instruments amounted to MUSD 6.5 (MUSD 0.8) and related to the marked-to-market gain on the outstanding interest rate and currency hedge contracts due to be settled within twelve months.

Current tax assets amounted to MUSD 80.6 (MUSD 77.5) of which MUSD 80.5 related to the Norwegian corporate tax refund in respect of 2016 which will be received in the fourth quarter of 2017.

Cash and cash equivalents amounted to MUSD 74.2 (MUSD 69.5) of which MUSD 11.8 (MUSD —) is restricted. Cash balances are held to meet ongoing operational funding requirements.

Non-current liabilities

Financial liabilities amounted to MUSD 4,073.0 (MUSD 4,048.3) and are detailed in Note 10. Bank loans amounted to MUSD 4,155.0 (MUSD 4,145.0) and related to the outstanding loan under the Group's reserve-based lending facility. Capitalised financing fees relating to the establishment costs of the Group's financing facility amounted to MUSD 82.0 (MUSD 96.7) and are being amortised over the expected life of the facility.

Provisions amounted to MUSD 363.9 (MUSD 420.0) and are detailed in Note 11. The provision for site restoration amounted to MUSD 358.3 (MUSD 407.1) and related to future decommissioning obligations. The site restoration provision related to Norway amounted to MUSD 358.3 (MUSD 316.1). The increase in Norway mainly reflects the additional liability for Edvard Grieg and Volund production drilling and for the Johan Sverdrup development project.

Deferred tax liabilities amounted to MUSD 861.4 (MUSD 669.3). The provision mainly arises on the excess of book value over the tax value of oil and gas properties. Deferred tax assets are netted off against deferred tax liabilities where they relate to the same jurisdiction.

Derivative instruments amounted to MUSD 5.3 (MUSD 29.8) and related to the marked-to-market loss on outstanding interest rate and currency hedge contracts due to be settled after twelve months.

Other non-current liabilities amounted to MUSD 34.7 (MUSD 33.8) and mainly represent the full consolidation of a subsidiary in which the non-controlling interest entity has made funding advances in relation to LLC PetroResurs, Russia.

Current liabilities

Financial liabilities amounted to MUSD 12.4 (MUSD —) and are detailed in Note 10. Financial liabilities related to the obligation to settle the 2014 long-term performance based incentive plan in respect of Group management and a number of key employees, see also Remuneration section below.

Trade and other payables amounted to MUSD 267.9 (MUSD 308.4) and are detailed in Note 12. Overlift amounted to MUSD 19.7 (MUSD 29.9) and was attributable to an overlift position on the producing fields, mainly Edvard Grieg and Alvheim. Joint operations creditors and accrued expenses amounted to MUSD 193.1 (MUSD 238.8) and related to activity in Norway. Other accrued expenses amounted to MUSD 20.1 (MUSD 16.9) and other current liabilities amounted to MUSD 12.1 (MUSD 9.5).

Derivative instruments amounted to MUSD 23.9 (MUSD 37.6) and related to the marked-to-market loss on outstanding interest rate and currency hedge contracts due to be settled within twelve months.

Current provisions amounted to MUSD 4.8 (MUSD 6.9) and related to the current portion of the provision for Lundin Petroleum's Unit Bonus Plan.

Parent Company

The business of the Parent Company is investment in and management of oil and gas assets. The net result for the Parent Company amounted to MSEK 46,500.9 (MSEK -37.4) for the reporting period.
The result included MSEK 46,543.2 financial income as a result of an internal restructuring prior to the IPC spin-off. The result excluding this financial income amounts to MSEK -42.3 (MSEK -37.4).

The result included general and administrative expenses of MSEK 47.6 (MSEK 36.9) and net finance income of MSEK 0.8 (MSEK -2.4) when excluding the finance income as a result of the internal restructuring.

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

Pledged assets of MSEK 55,118.9 (MSEK 6,740.3) relate to the carrying value of the pledge of the shares in respect of the financing facility entered into by its wholly-owned subsidiary Lundin Petroleum Holding BV, see also the Liquidity section below.

Related Party Transactions

During the reporting period, the Group has entered into transactions with related parties on a commercial basis and the material transactions are described below.

The Group has sold oil and related products to the Statoil group on an arm's-length basis amounting to MUSD 174.3.

Liquidity

In February 2016, Lundin Petroleum entered into a committed seven year senior secured reserve-based lending facility of USD 5.0 billion. The financing facility is a reserve-based lending facility secured against certain cash flows generated by the Group. The amount available under the facility is recalculated every six months based upon the calculated cash flow generated by certain producing fields and fields under development at an oil price and economic assumptions agreed with the banking syndicate providing the facility. The facility is secured by a pledge over the shares of certain Group companies and a charge over some of the bank accounts of the pledged companies.

Lundin Petroleum has outstanding bank guarantees in support of the work commitments and other related costs in relation to Production Sharing Contracts in Malaysia and the outstanding amount of the bank guarantees at 30 June 2017 was MUSD 10.1. IPC has indemnified the Company for this amount.

Subsequent Events

There are no subsequent events to be reported.

Share Data

Lundin Petroleum AB's issued share capital amounted to SEK 3,478,713 represented by 340,386,445 shares with a quota value of SEK 0.01 each (rounded off).

Remuneration

Lundin Petroleum's principles for remuneration and details of the long-term incentive plans are provided in the Company's 2016 Annual Report and in the materials provided to shareholders in respect of the 2017 AGM, available on www.lundin-petroleum.com.

Unit Bonus Plan

The number of units relating to the awards made in 2015, 2016 and 2017 under the Unit Bonus Plan outstanding as at 30 June 2017 were 139,546, 225,626 and 288,216 respectively.

Performance Based Incentive Plan

The AGM 2016 resolved a long-term performance based incentive plan in respect of Group management and a number of key employees. The plan is effective from 1 July 2016 and the 2016 award is accounted for from the second half of 2016. The total outstanding number of awards at 30 June 2017 is 426,436 and the awards vest over three years from 1 July 2016 subject to certain performance conditions being met. The outstanding number of awards increased compared to the original number of awards as a result of the dividend distribution of the IPC business as per the plan rules. Each original award was fair valued at the date of grant at SEK 89.30 using an option pricing model. Awards given to employees now employed by IPC following the IPC spin-off have been pro-rated until the spin-off date 24 April 2017.

The 2015 plan is effective from 1 July 2015 and the total outstanding number of awards at 30 June 2017 is 672,224 and the awards vest over three years from 1 July 2015 subject to certain performance conditions being met. The outstanding number of awards increased compared to the original number of awards as a result of the dividend distribution of the IPC business as per the plan rules. Each original award was fair valued at the date of grant at SEK 91.40. Awards given to employees now employed by IPC following the IPC spin-off have been pro-rated until the spin-off date 24 April 2017.

The 2014 plan is effective from 1 July 2014 and the total outstanding number of awards at 30 June 2017 is 652,142 and the awards vest over three years from 1 July 2014 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 81.40.

Accounting Policies

This interim report has been prepared in accordance with International Accounting Standard (IAS) 34, Interim Financial Reporting, and the Swedish Annual Accounts Act (SFS 1995:1554).

The accounting policies adopted are in all other aspects consistent with those followed in the preparation of the Group's annual financial statements for the year ended 31 December 2016.

The financial reporting of the Parent Company has been prepared in accordance with accounting principles generally accepted in Sweden, applying RFR 2 Reporting for legal entities, issued by the Swedish Financial Reporting Board and the Annual Accounts Act (SFS 1995:1554).

Under Swedish company regulations it is not allowed to report the Parent Company results in any other currency than Swedish Krona or Euro and consequently the Parent Company's financial information is reported in Swedish Krona and not the Group's reporting currency of US Dollar.

Risks and Risk Management

The objective of Business Risk Management is to identify, understand and manage threats and opportunities within the business on a continual basis. This objective is achieved by creating a mandate and commitment to risk management at all levels of the business. This approach actively addresses risk as an integral and continual part of decision making within the Group and is designed to ensure that all risks are identified, fully acknowledged, understood and communicated well in advance. The ability to manage and or mitigate these risks represents a key component in ensuring that the business aim of the Company is achieved. Nevertheless, oil and gas exploration, development and production involve high operational and financial risks, which even a combination of experience, knowledge and careful evaluation may not be able to fully eliminate or which are beyond the Company's control.

A detailed analysis of Lundin Petroleum's strategic, operational, financial and external risks and mitigation of those risks through risk management is described in Lundin Petroleum's 2016 Annual Report.

Derivative financial instruments

Lundin Petroleum has entered into forward currency hedges to meet part of its future NOK capital requirements relating to the Johan Sverdrup field development. At 30 June 2017, Lundin Petroleum had outstanding currency hedges as summarised below:

Buy	Sell	Average contractual exchange rate	Settlement period
MNOK 1,744.6	MUSD 211.2	NOK 8.26:USD 1	Jul 2017 – Dec 2017
MNOK 3,493.0	MUSD 424.2	NOK 8.23:USD 1	Jan 2018 – Dec 2018
MNOK 1,672.4	MUSD 200.4	NOK 8.35:USD 1	Jan 2019 – Dec 2019

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

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

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

Exchange Rates

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

	30 Jun 2017		30 Jun 2016		31 Dec 2016	
	Average	Period end	Average	Period end	Average	Period end
1 USD equals NOK	8.4784	8.3870	8.4521	8.3776	8.4014	8.6200
1 USD equals Euro	0.9238	0.8763	0.8964	0.9007	0.9037	0.9487
1 USD equals Rouble	57.9597	59.1876	70.2913	64.4208	67.0692	60.9999
1 USD equals SEK	8.8660	8.4471	8.3382	8.4887	8.5610	9.0622

Consolidated Income Statement

Expressed in MUSD	Note	1 Jan 2017– 30 Jun 2017 6 months	1 Apr 2017– 30 Jun 2017 3 months	1 Jan 2016 – 30 Jun 2016 6 months	1 Apr 2016 – 30 Jun 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
		Continuing operations	Continuing operations	Continuing operations	Continuing operations	Continuing operations
Revenue	1	**886.1**	**464.6**	354.8	209.7	950.0
Cost of sales						
Production costs	2	-78.0	-41.9	-82.3	-40.7	-168.4
Depletion and decommissioning costs		-275.3	-144.2	-157.0	-81.1	-386.2
Exploration costs		-25.9	-21.7	-55.8	-1.3	-101.9
Impairment costs of oil and gas properties		-13.2	-13.2	–	–	-506.1
Other cost of sales		-103.2	-83.9	–	–	-2.1
Gross profit/loss	3	**390.5**	**159.7**	59.7	86.6	-214.7
General, administration and depreciation expenses		-16.7	-5.7	-13.7	-6.7	-30.0
Operating profit/loss		**373.8**	**154.0**	46.0	79.9	-244.7
Net financial items						
Finance income	4	139.6	119.0	110.8	-77.9	2.7
Finance costs	5	-89.8	-44.5	-120.3	-72.6	-221.5
		49.8	**74.5**	-9.5	-150.5	-218.8
Profit/loss before tax		**423.6**	**228.5**	36.5	-70.6	-463.5
Income tax	6	-218.8	-82.9	57.1	-1.5	64.2
Net result from continuing operations		**204.8**	**145.6**	93.6	-72.1	-399.3
Discontinued operations						
Net result - IPC	14	47.9	43.9	-27.6	23.8	-100.0
Net result		**252.7**	**189.5**	66.0	-48.3	-499.3
Attributable to:						
Shareholders of the Parent Company		255.2	190.7	68.3	-47.1	-356.7
Non-controlling interest		-2.5	-1.2	-2.3	-1.2	-142.6
		252.7	**189.5**	66.0	-48.3	-499.3
Earnings per share – USD[1]						
From continuing operations		0.61	0.43	0.31	-0.23	-0.79
From discontinued operations		0.14	0.13	-0.09	0.08	-0.30
Earnings per share fully diluted – USD[1]						
From continuing operations		0.61	0.43	0.31	-0.23	-0.79
From discontinued operations		0.14	0.13	-0.09	0.08	-0.30

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

Consolidated Statement of Comprehensive Income

Expressed in MUSD	**1 Jan 2017– 30 Jun 2017 6 months**	**1 Apr 2017– 30 Jun 2017 3 months**	1 Jan 2016 – 30 Jun 2016 6 months	1 Apr 2016 – 30 Jun 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Net result	**252.7**	**189.5**	66.0	-48.3	-499.3
Items that may be subsequently reclassified to profit or loss:					
Exchange differences foreign operations	-58.5	-60.4	16.4	8.7	13.8
Cash flow hedges	40.7	22.0	65.3	16.2	64.3
Available-for-sale financial assets	0.2	1.0	1.2	-3.6	5.3
Other comprehensive income, net of tax	**-17.6**	**-37.4**	82.9	21.3	83.4
Total comprehensive income	**235.1**	**152.1**	148.9	-27.0	-415.9
Attributable to:					
Shareholders of the Parent Company	237.6	153.4	147.8	-26.9	-278.2
Non-controlling interest	-2.5	-1.3	1.1	-0.1	-137.7
	235.1	**152.1**	148.9	-27.0	-415.9

Consolidated Balance Sheet

Expressed in MUSD	Note	**30 June 2017**	31 December 2016
ASSETS			
Non-current assets			
Oil and gas properties	7	4,528.5	4,376.4
Other tangible fixed assets		13.5	166.1
Goodwill		128.1	128.1
Financial assets	8	11.8	9.4
Deferred tax assets		–	13.5
Derivative instruments	13	11.9	17.0
Total non-current assets		**4,693.8**	4,710.5
Current assets			
Inventories		32.2	54.9
Trade and other receivables	9	222.7	288.9
Derivative instruments	13	6.5	0.8
Current tax assets		80.6	77.5
Cash and cash equivalents		74.2	69.5
Total current assets		**416.2**	491.6
TOTAL ASSETS		**5,110.0**	5,202.1
EQUITY AND LIABILITIES			
Equity			
Shareholders´ equity		-421.8	-238.6
Non-controlling interest		-115.8	-113.6
Total equity		**-537.6**	-352.2
Liabilities			
Non-current liabilities			
Financial liabilities	10	4,073.0	4,048.3
Provisions	11	363.9	420.0
Deferred tax liabilities		861.4	669.3
Derivative instruments	13	5.3	29.8
Other non-current liabilities		34.7	33.8
Total non-current liabilities		**5,338.3**	5,201.2
Current liabilities			
Financial liabilities	10	12.4	–
Trade and other payables	12	267.9	308.4
Derivative instruments	13	23.9	37.6
Current tax liabilities		0.3	0.2
Provisions	11	4.8	6.9
Total current liabilities		**309.3**	353.1
Total liabilities		**5.647.6**	5,554.3
TOTAL EQUITY AND LIABILITIES		**5,110.0**	5,202.1

Consolidated Statement of Cash Flows

Expressed in MUSD	1 Jan 2017– 30 Jun 2017 6 months	1 Apr 2017– 30 Jun 2017 3 months	1 Jan 2016 – 30 Jun 2016 6 months	1 Apr 2016 – 30 Jun 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
	Continuing operations	Continuing operations	Continuing operations	Continuing operations	Continuing operations
Cash flows from operating activities					
Net result	204.8	145.6	93.6	-72.1	-399.3
Adjustments for:					
Exploration costs	25.9	21.7	55.8	1.3	101.9
Depletion, depreciation and amortisation	276.5	144.8	158.7	81.9	391.7
Impairment of oil and gas properties	13.2	13.2	–	–	506.1
Current tax	-1.1	-1.4	-41.6	-11.6	-78.4
Deferred tax	219.9	84.3	-15.5	13.1	14.2
Long-term incentive plans	6.1	2.8	6.8	3.0	15.6
Foreign currency exchange loss	-146.4	-123.6	-143.8	62.0	-24.9
Interest expense	58.1	29.5	73.6	39.4	137.3
Capitalised financing fees	8.5	4.2	28.7	23.3	38.9
Other	5.6	2.9	10.1	4.7	12.6
Interest received	0.2	0.1	0.4	0.1	2.3
Interest paid	-84.0	-43.4	-75.1	-38.1	-153.7
Income taxes paid / received	-0.2	-0.2	-0.5	-0.3	273.5
Changes in working capital	14.3	-19.8	25.9	-5.3	-169.1
Total cash flows from operating activities	**601.4**	**260.7**	177.1	101.4	668.7
Cash flows from investing activities					
Investment in oil and gas properties	-616.5	-305.0	-446.0	-236.4	-1,020.6
Investment in other fixed assets	-0.8	-0.2	-0.4	–	-1.1
Investment in other shares and participations	-1.3	–	–	–	–
Decommissioning costs paid	-0.1	-0.3	-0.5	–	-1.0
Other payments	-7.2	-7.2	31.0	31.0	25.8
Total cash flows from investing activities	**-625.9**	**-312.7**	-415.9	-205.4	-996.9
Cash flows from financing activities					
Changes in long-term liabilities	10.9	70.4	207.7	-24.9	288.7
Financing fees paid	–	–	-96.6	-9.4	-104.0
Cash funded from / to discontinued operations	31.7	–	36.1	42.9	92.5
Issuance of shares/Sale of treasury shares[1]	–	–	64.1	64.1	64.1
Total cash flows from financing activities	**42.6**	**70.4**	211.3	72.7	341.3
Change in cash and cash equivalents	18.1	18.4	-27.5	-31.3	13.1
Cash and cash equivalents at the beginning of the period	56.1	56.3	42.4	68.1	42.4
Currency exchange difference in cash and cash equivalents	0.0	-0.5	0.3	0.7	0.6
Cash and cash equivalent of discontinued operations	–	–	19.2	-3.1	13.4
Cash and cash equivalents at the end of the period	**74.2**	**74.2**	34.4	34.4	69.5

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

Consolidated Statement of Changes in Equity

Expressed in MUSD	Share capital	Additional paid-in-capital/Other reserves	Retained earnings	Dividends	Total	Non-controlling interest	Total equity
	Attributable to owners of the Parent Company						
At 1 January 2016	**0.5**	**-64.3**	**-434.4**	**–**	**-498.2**	**24.1**	**-474.1**
Comprehensive income							
Net result	–	–	68.3	–	68.3	-2.3	66.0
Other comprehensive income	–	79.5	–	–	79.5	3.4	82.9
Total comprehensive income	**–**	**79.5**	**68.3**	**–**	**147.8**	**1.1**	**148.9**
Transactions with owners							
Issuance of shares/Sale of treasury shares	–	534.1	–	–	534.1	–	534.1
Value of employee services	–	–	1.2	–	1.2	–	1.2
Total transactions with owners	**–**	**534.1**	**1.2**	**–**	**535.3**	**–**	**535.3**
At 30 June 2016	**0.5**	**549.3**	**-364.9**	**–**	**184.9**	**25.2**	**210.1**
Comprehensive income							
Net result	–	–	-425.0	–	-425.0	-140.3	-565.3
Other comprehensive income	–	-1.0	–	–	-1.0	1.5	0.5
Total comprehensive income	**–**	**-1.0**	**-425.0**	**–**	**-426.0**	**-138.8**	**-564.8**
Transactions with owners							
Value of employee services	–	–	2.5	–	2.5	–	2.5
Total transaction with owners	**–**	**–**	**2.5**	**–**	**2.5**	**–**	**2.5**
At 31 December 2016	**0.5**	**548.3**	**-787.4**	**–**	**-238.6**	**-113.6**	**-352.2**
Comprehensive income							
Net result	–	–	255.2	–	255.2	-2.5	252.7
Other comprehensive income	–	-17.6	–	–	-17.6	–	-17.6
Total comprehensive income	**–**	**-17.6**	**255.2**	**–**	**237.6**	**-2.5**	**235.1**
Transactions with owners							
Distributions	–	–	–	-410.0	-410.0	–	-410.0
Spin off IPC	–	–	–	–	–	0.3	0.3
Share based payments	–	-12.4	–	–	-12.4	–	-12.4
Value of employee services	–	–	1.6	–	1.6	–	1.6
Total transaction with owners	**–**	**-12.4**	**1.6**	**-410.0**	**-420.8**	**0.3**	**-420.5**
At 30 June 2017	**0.5**	**518.3**	**-530.6**	**-410.0**	**-421.8**	**-115.8**	**-537.6**

Notes to the Consolidated Financial Statements

Note 1 – Revenue MUSD	**1 Jan 2017– 30 Jun 2017 6 months**	**1 Apr 2017– 30 Jun 2017 3 months**	1 Jan 2016 – 30 Jun 2016 6 months	1 Apr 2016 – 30 Jun 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Crude oil from own production	712.8	382.9	320.0	183.7	901.0
Crude oil from third party activities	103.1	84.0	0.5	0.2	2.1
Condensate	16.1	9.7	5.5	5.5	14.3
Gas	49.0	23.2	25.5	12.8	58.5
Net sales of oil and gas from continuing operations	**881.0**	**499.8**	351.5	202.2	975.9
Change in under/over lift position	-5.1	-40.7	1.8	6.9	-29.1
Other revenue	10.2	5.5	1.5	0.6	3.2
Revenue from continuing operations	**886.1**	**464.6**	354.8	209.7	950.0

Note 2 – Production costs MUSD	**1 Jan 2017– 30 Jun 2017 6 months**	**1 Apr 2017– 30 Jun 2017 3 months**	1 Jan 2016 – 30 Jun 2016 6 months	1 Apr 2016 – 30 Jun 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Cost of operations	55.3	28.9	55.3	28.2	113.1
Tariff and transportation expenses	17.4	9.7	16.2	7.6	33.9
Change in inventory position	-0.5	0.1	-0.4	-0.1	-0.7
Other	5.8	3.2	11.2	5.0	22.1
Production costs from continuing operations	**78.0**	**41.9**	82.3	40.7	168.4

Note 3 – Segment information MUSD	**1 Jan 2017– 30 Jun 2017 6 months**	**1 Apr 2017– 30 Jun 2017 3 months**	1 Jan 2016 – 30 Jun 2016 6 months	1 Apr 2016 – 30 Jun 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Norway					
Crude oil from own production	712.8	382.9	320.0	183.7	901.0
Condensate	16.1	9.7	5.5	5.5	14.3
Gas	49.0	23.2	25.5	12.8	58.5
Net sales of oil and gas	**777.9**	**415.8**	351.0	202.0	973.8
Change in under/over lift position	-5.1	-40.7	1.8	6.9	-29.1
Other revenue	9.3	5.0	0.6	0.2	1.5
Revenue	**782.1**	**380.1**	353.4	209.1	946.2
Production costs	-78.0	-41.9	-82.3	-40.7	-168.4
Depletion and decommissioning costs	-275.3	-144.2	-157.0	-81.1	-386.2
Exploration costs	-25.1	-21.3	-55.8	-1.3	-101.9
Impairment costs of oil and gas properties	-13.2	-13.2	–	–	–
Gross profit/loss	**390.5**	**159.5**	58.3	86.0	289.7

Notes to the Consolidated Financial Statements

Note 3 – Segment information cont. MUSD	**1 Jan 2017– 30 Jun 2017 6 months**	**1 Apr 2017– 30 Jun 2017 3 months**	1 Jan 2016 – 30 Jun 2016 6 months	1 Apr 2016 – 30 Jun 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Other					
Crude oil from third party activities	103.1	84.0	0.5	0.2	2.1
Net sales of oil and gas	**103.1**	**84.0**	0.5	0.2	2.1
Other revenue	0.9	0.5	0.9	0.4	1.7
Revenue	**104.0**	**84.5**	1.4	0.6	3.8
Exploration costs	-0.8	-0.4	–	–	–
Impairment costs of oil and gas properties	–	–	–	–	-506.1
Other cost of sales	-103.2	-83.9	–	–	-2.1
Gross profit/loss	**0.0**	**0.2**	1.4	0.6	-504.4
Total from continuing operations					
Crude oil from own production	712.8	382.9	320.0	183.7	901.0
Crude oil from third party activities	103.1	84.0	0.5	0.2	2.1
Condensate	16.1	9.7	5.5	5.5	14.3
Gas	49.0	23.2	25.5	12.8	58.5
Net sales of oil and gas	**881.0**	**499.8**	351.5	202.2	975.9
Change in under/over lift position	-5.1	-40.7	1.8	6.9	-29.1
Other revenue	10.2	5.5	1.5	0.6	3.2
Revenue	**886.1**	**464.6**	354.8	209.7	950.0
Production costs	-78.0	-41.9	-82.3	-40.7	-168.4
Depletion and decommissioning costs	-275.3	-144.2	-157.0	-81.1	-386.2
Exploration costs	-25.9	-21.7	-55.8	-1.3	-101.9
Impairment costs of oil and gas properties	-13.2	-13.2	–	–	-506.1
Other cost of sales	-103.2	-83.9	–	–	-2.1
Gross profit/loss from continuing operations	**390.5**	**159.7**	59.7	86.6	-214.7

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

Note 4 – Finance income MUSD	**1 Jan 2017– 30 Jun 2017 6 months**	**1 Apr 2017– 30 Jun 2017 3 months**	1 Jan 2016 – 30 Jun 2016 6 months	1 Apr 2016 – 30 Jun 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Foreign currency exchange gain, net	139.2	118.8	110.2	-78.1	–
Interest income	0.2	0.1	0.4	0.1	2.3
Guarantee fees	0.2	0.1	0.2	0.1	0.4
Total finance income from continuing operations	**139.6**	**119.0**	110.8	-77.9	2.7

Note 5 – Finance costs MUSD	**1 Jan 2017– 30 Jun 2017 6 months**	**1 Apr 2017– 30 Jun 2017 3 months**	1 Jan 2016 – 30 Jun 2016 6 months	1 Apr 2016 – 30 Jun 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Interest expense	58.1	29.5	73.6	39.4	137.3
Foreign currency exchange loss, net	–	–	–	–	4.2
Result on interest rate hedge settlement	11.0	5.0	9.6	5.3	19.5
Unwinding of site restoration discount	5.8	3.0	4.9	2.5	11.6
Amortisation of deferred financing fees	8.5	4.2	28.7	23.3	38.9
Loan facility commitment fees	5.4	2.6	3.3	2.1	9.3
Other	1.0	0.2	0.2	–	0.7
Finance costs from continuing operations	**89.8**	**44.5**	120.3	72.6	221.5

Note 6 – Income tax MUSD	**1 Jan 2017– 30 Jun 2017 6 months**	**1 Apr 2017– 30 Jun 2017 3 months**	1 Jan 2016 – 30 Jun 2016 6 months	1 Apr 2016 – 30 Jun 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Current tax	-1.1	-1.4	-41.6	-11.6	-78.4
Deferred tax	219.9	84.3	-15.5	13.1	14.2
Total income tax from continuing operations	**218.8**	**82.9**	-57.1	1.5	-64.2

Note 7 – Oil and gas properties MUSD	**30 Jun 2017**	31 Dec 2016
Norway	4,528.5	4,055.7
Malaysia	–	130.6
France	–	171.0
Netherlands	–	19.1
	4,528.5	4,376.4

Note 8 – Financial assets MUSD	**30 Jun 2017**	31 Dec 2016
Other shares and participations	11.3	8.9
Other	0.5	0.5
	11.8	9.4

Note 9 – Trade and other receivables MUSD	**30 Jun 2017**	31 Dec 2016
Trade receivables	135.6	193.4
Underlift	12.0	28.9
Joint operations debtors	14.2	31.2
Prepaid expenses and accrued income	34.8	29.4
Brynhild operating cost share	–	3.0
Other	26.0	3.0
	222.7	288.9

Notes to the Consolidated Financial Statements

Note 10 – Financial liabilities

MUSD	**30 Jun 2017**	31 Dec 2016
Non-current:		
Bank loans	4,155.0	4,145.0
Capitalised financing fees	-82.0	-96.7
	4,073.0	4,048.3
Current:		
Other	12.4	–
	12.4	–
	4,085.4	4,048.3

Note 11 – Provisions

MUSD	**30 Jun 2017**	31 Dec 2016
Non-current:		
Site restoration	358.3	407.1
Long-term incentive plans	1.2	3.2
Farm-in payment	–	5.5
Other	4.4	4.2
	363.9	420.0
Current:		
Long-term incentive plans	4.8	6.9
	4.8	6.9
	368.7	426.9

Note 12 – Trade and other payables

MUSD	**30 Jun 2017**	31 Dec 2016
Trade payables	22.9	13.3
Overlift	19.7	29.9
Joint operations creditors and accrued expenses	193.1	238.8
Other accrued expenses	20.1	16.9
Other	12.1	9.5
	267.9	308.4

Note 13 – Financial instruments

For financial instruments measured at fair value in the balance sheet, the following fair value measurement hierarchy is used:

— Level 1: based on quoted prices in active markets;
— Level 2: based on inputs other than quoted prices as within level 1, that are either directly or indirectly observable;
— Level 3: based on inputs which are not based on observable market data.

Based on this hierarchy, financial instruments measured at fair value can be detailed as follows:

30 June 2017

MUSD	Level 1	Level 2	Level 3
Assets			
Other shares and participations	11.3	–	–
Derivative instruments – non-current	–	11.9	–
Derivative instruments – current	–	6.5	–
	11.3	**18.4**	**–**
Liabilities			
Derivative instruments – non-current	–	5.3	–
Derivative instruments – current	–	23.9	–
	–	**29.2**	**–**

31 December 2016

MUSD	Level 1	Level 2	Level 3
Assets			
Other shares and participations	8.9	–	–
Derivative instruments – non-current	–	17.0	–
Derivative instruments – current	–	0.8	–
	8.9	17.8	–
Liabilities			
Derivative instruments – non-current	–	29.8	–
Derivative instruments – current	–	37.6	–
	–	67.4	–

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

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

Note 14 – Discontinued operations - IPC

On 24 April 2017, Lundin Petroleum completed the spin-off of its assets in Malaysia, France and the Netherlands (the IPC assets) into a newly formed company called International Petroleum Corporation (IPC) by distributing the IPC shares, on a pro-rata basis, to Lundin Petroleum shareholders. The results of the IPC business are included in the Lundin Petroleum financial statements until spin-off date and are shown as discontinued operations.

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

Expressed in MUSD	**1 Jan 2017– 30 Jun 2017 6 months**	**1 Apr 2017– 30 Jun 2017 3 months**	1 Jan 2016 – 30 Jun 2016 6 months	1 Apr 2016 – 30 Jun 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Revenue	**69.1**	**17.2**	101.8	55.6	209.9
Cost of sales					
Production costs	-17.4	-5.5	-31.0	-13.9	-59.1
Depletion and decommissioning costs	-19.1	-4.6	-42.9	-21.5	-85.2
Depletion of other assets	-10.4	-2.6	-15.6	-7.8	-31.1
Exploration costs	0.1	0.2	-13.1	3.5	-14.2
Impairment costs of oil and gas properties	–	–	–	–	-126.0
Gross profit/loss	**22.3**	**4.7**	-0.8	15.9	-105.7
Sale of assets	–	–	-3.5	-3.5	-3.5
General, administration and depreciation expenses	-1.0	-0.1	-0.9	1.1	-1.9
Operating profit/loss	**21.3**	**4.6**	-5.2	13.5	-111.1
Net financial items					
Finance income	–	–	–	–	23.9
Finance costs	-24.1	-12.7	-20.4	10.6	-7.9
	-24.1	**-12.7**	-20.4	10.6	16.0
Profit/loss before tax	**-2.8**	**-8.1**	-25.6	24.1	-95.1
Income tax	-1.2	0.1	-2.0	-0.3	-4.9
	-4.0	**-8.0**	-27.6	23.8	-100.0
Gain on distribution of assets	51.9	51.9	–	–	–
Net result from discontinued operations	**47.9**	**43.9**	-27.6	23.8	-100.0

Parent Company Income Statement

Expressed in MSEK	1 Jan 2017– 30 Jun 2017 6 months	1 Apr 2017– 30 Jun 2017 3 months	1 Jan 2016 – 30 Jun 2016 6 months	1 Apr 2016 – 30 Jun 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Revenue	4.5	3.5	1.9	0.9	3.8
General and administration expenses	-47.6	-17.0	-36.9	-23.8	-106.6
Operating profit/loss	**-43.1**	**-13.5**	-35.0	-22.9	-102.8
Net financial items					
Finance income	46,544.5	46,544.2	1.8	1.3	3.5
Finance costs	-0.5	—	-4.2	-3.4	-4.0
	46,544.0	**46,544.2**	-2.4	-2.1	-0.5
Profit/loss before tax	**46,500.9**	**46,530.7**	-37.4	-25.0	-103.3
Income tax	—	—	—	—	—
Net result	**46,500.9**	**46,530.7**	-37.4	-25.0	-103.3

Parent Company Comprehensive Income Statement

Expressed in MSEK	1 Jan 2017– 30 Jun 2017 6 months	1 Apr 2017– 30 Jun 2017 3 months	1 Jan 2016 – 30 Jun 2016 6 months	1 Apr 2016 – 30 Jun 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Net result	**46,500.9**	**46,530.7**	-37.4	-25.0	-103.3
Other comprehensive income	—	—	—	—	—
Total comprehensive income	**46,500.9**	**46,530.7**	-37.4	-25.0	-103.3
Attributable to:					
Shareholders of the Parent Company	46,500.9	46,530.7	-37.4	-25.0	-103.3
	46,500.9	**46,530.7**	-37.4	-25.0	-103.3

Parent Company Balance Sheet

Expressed in MSEK	30 June 2017	31 December 2016
ASSETS		
Non-current assets		
Shares in subsidiaries	55,118.9	12,256.6
Total non-current assets	**55,118.9**	12,256.6
Current assets		
Receivables	9.7	20.7
Cash and cash equivalents	6.2	3.2
Total current assets	**15.9**	23.9
TOTAL ASSETS	**55,134.8**	12,280.5
SHAREHOLDERS´EQUITY AND LIABILITIES		
Shareholders´ equity including net result for the period	55,018.5	12,212.9
Non-current liabilities		
Provisions	1.0	0.6
Payables to group companies	–	49.4
Total non-current liabilities	**1.0**	50.0
Current liabilities		
Current liabilities	115.3	17.6
Total current liabilities	**115.3**	17.6
Total liabilities	**116.3**	67.6
TOTAL EQUITY AND LIABILITIES	**55,134.8**	12,280.5

Parent Company Cash Flow Statement

Expressed in MSEK	1 Jan 2017– 30 Jun 2017 6 months	1 Apr 2017– 30 Jun 2017 3 months	1 Jan 2016 – 30 Jun 2016 6 months	1 Apr 2016 – 30 Jun 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Cash flow from operations					
Net result	46,500.9	46,530.7	-37.4	-25.0	-103.3
Adjustment for non-cash related items	-46,605.8	-46,608.7	13.1	8.5	24.6
Changes in working capital	108.6	110.0	-4.3	1.0	7.4
Total cash flow from operations	**3.7**	**32.0**	-28.6	-15.5	-71.3
Cash flow from financing					
Change in long-term liabilities	–	-41.9	-507.9	-528.4	-467.5
Proceeds from share issues /treasury shares	–	–	544.1	544.1	544.1
Total cash flow from financing	–	**-41.9**	36.2	15.7	76.6
Change in cash and cash equivalents	3,7	-9.9	7.6	0.2	5.3
Cash and cash equivalents at the beginning of the period	**3.2**	**16.6**	0.4	7.6	0.4
Currency exchange difference in cash and cash equivalents	-0.7	-0.5	-2.5	-2.3	-2.5
Cash and cash equivalents at the end of the period	**6.2**	**6.2**	5.5	5.5	3.2

Parent Company Statement of Changes in Equity

Expressed in MSEK	Restricted equity: Share capital	Restricted equity: Statutory reserve	Unrestricted equity: Other reserves	Unrestricted equity: Retained earnings	Unrestricted equity: Dividends	Unrestricted equity: Total	Total equity
Balance at 1 January 2016	**3.2**	**861.3**	**2,295.3**	**4,622.6**	**–**	**6,917.9**	**7,782.4**
Total comprehensive income	**–**	**–**	**–**	**-37.4**	**–**	**-37.4**	**-37.4**
Transactions with owners							
Issuance of shares / Sale of treasury shares	0.3	–	4,533.5	–	–	4,533.5	4,533.8
Total transactions with owners	**0.3**	**–**	**4,533.5**	**–**	**–**	**4,533.5**	**4,533.8**
Balance at 30 June 2016	**3.5**	**861.3**	**6,828.8**	**4,585.2**	**–**	**11,414.0**	**12,278.8**
Total comprehensive income	**–**	**–**	**–**	**-65.9**	**–**	**-65.9**	**-65.9**
Balance at 31 December 2016	**3.5**	**861.3**	**6,828.8**	**4,519.3**	**–**	**11,348.1**	**12,212.9**
Total comprehensive income	**–**	**–**	**–**	**46,500.9**	**–**	**46,500.9**	**46,500.9**
Transactions with owners							
Distributions	–	–	–	–	-3,695.3	-3,695.3	-3,695.3
Total transactions with owners	**–**	**–**	**–**	**–**	**-3,695.3**	**-3,695.3**	**-3,695.3**
Balance at 30 June 2017	**3.5**	**861.3**	**6,828.8**	**51,020.2**	**-3,695.3**	**54,153.7**	**55,018.5**

Key Financial Data

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

Financial data from continuing operations MUSD	**1 Jan 2017– 30 Jun 2017 6 months**	**1 Apr 2017– 30 Jun 2017 3 months**	1 Jan 2016 – 30 Jun 2016 6 months	1 Apr 2016 – 30 Jun 2016 3 months	1 Jan 2016 – 31 Dec 2016 12 months
Revenue	886.1	464.6	354.8	209.7	950.0
EBITDA	689.3	333.5	260.5	163.1	752.5
Net result	204.8	145.6	93.6	-72.1	-399.3
Operating cash flow	705.9	340.0	314.0	180.6	857.9
Data per share from continuing operations USD					
Shareholders' equity per share	-1.24	-1.24	0.54	0.54	-0.70
Operating cash flow per share	2.07	1.00	1.01	0.58	2.63
Cash flow from operations per share	1.77	0.77	0.57	0.33	2.05
Earnings per share	0.61	0.43	0.31	-0.23	-0.79
Earnings per share fully diluted	0.61	0.43	0.31	-0.23	-0.79
EBITDA per share	2.03	0.98	0.84	0.52	2.31
EBITDA per share – fully diluted	2.02	0.98	0.83	0.52	2.30
Number of shares issued at period end	340,386,445	340,386,445	340,386,445	340,386,445	340,386,445
Number of shares in circulation at period end	340,386,445	340,386,445	340,386,445	340,386,445	340,386,445
Weighted average number of shares for the period	340,386,445	340,386,445	311,233,197	311,396,065	325,808,486
Weighted average number of shares for the period fully diluted	341,628,882	341,628,882	312,529,762	312,692,630	326,738,233
Share price SEK					
Share price at period end	162.10	162.10	152.70	152.70	198.10
Key ratios from continuing operations					
Return on equity (%) [1]	–	–	–	–	–
Return on capital employed (%)	10	4	0	1	-9
Net debt/equity ratio (%) [1]	–	–	–	–	–
Equity ratio (%)	-11	-11	-7	-7	-17
Share of risk capital (%)	6	6	5	5	-3
Interest coverage ratio	5	4	0	1	-2
Operating cash flow/interest ratio	10	10	4	4	5
Yield	6	6	n/a	n/a	n/a

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

Key Ratio Definitions

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Board Assurance

The Board of Directors and the President and CEO certify that the financial report for the six months ended 30 June 2017 gives a fair view of the performance of the business, position and profit or loss of the Company and the Group, and describes the principal risks and uncertainties that the Company and the companies in the Group face.

Stockholm, 2 August 2017

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

Review Report

We have reviewed this report for the period 1 January 2017 to 30 June 2017 for Lundin Petroleum AB (publ). The board of directors and the President and CEO are responsible for the preparation and presentation of this interim report in accordance with IAS 34 and the Swedish Annual Accounts Act. Our responsibility is to express a conclusion on this interim report based on our review.

We conducted our review in accordance with the Swedish Standard on Review Engagements ISRE 2410, Review of Interim Report Performed by the Independent Auditor of the Entity. A review consists of making inquiries, primarily of persons responsible for financial and accounting matters, and applying analytical and other review procedures. A review is substantially less in scope than an audit conducted in accordance with International Standards on Auditing, ISA, and other generally accepted auditing standards in Sweden. The procedures performed in a review do not enable us to obtain assurance that we would become aware of all significant matters that might be identified in an audit. Accordingly, we do not express an audit opinion.

Based on our review, nothing has come to our attention that causes us to believe that the interim report is not prepared, in all material respects, in accordance with IAS 34 and the Swedish Annual Accounts Act, regarding the Group, and with the Swedish Annual Accounts Act, regarding the Parent Company.

Stockholm, 2 August 2017

PricewaterhouseCoopers AB

Johan Rippe
Authorised Public Accountant
Lead Partner

Johan Malmqvist
Authorised Public Accountant

Financial Information

The Company will publish the following reports:

- The nine month report (January — September 2017) will be published on 1 November 2017.
- The year end report (January — December 2017) will be published on 1 February 2018.
- The three month report (January — March 2018) will be published on 2 May 2018.

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

For further information, please contact:

Alex Budden
VP Communications &
Investor Relations
Tel: +41 22 595 10 19
alex.budden@lundin.ch

Sofia Antunes
Investor Relations Officer
Tel: +41 22 595 10 00
sofia.antunes@lundin.ch

Robert Eriksson
Manager, Media Communications
Tel: +46 701 11 26 15
robert.eriksson@lundin-petroleum.se

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 CEST on 2 August 2017.

Forward-Looking Statements

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

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

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
E info@lundin.ch
W lundin-petroleum.com