



Lundin
Petroleum



Report for the
SIX MONTHS
ended 30 June 2016

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

Highlights

Six months ended 30 June 2016 (30 June 2015)

- Production of 63.1 Mboepd (27.4 Mboepd)
- Revenue of MUSD 456.6 (MUSD 279.1)
- EBITDA of MUSD 330.9 (MUSD 192.4)
- Operating cash flow of MUSD 386.0 (MUSD 347.3)
- Net result of MUSD 66.0 (MUSD -171.0) including a net foreign exchange gain of MUSD 95.1 (loss of MUSD 176.7)
- Net debt of MUSD 4,224 (31 December 2015: MUSD 3,786)
- Record production level achieved following the Edvard Grieg field start-up in late 2015.
- Transaction to acquire 15 percent interest in the Edvard Grieg field and interests in associated pipeline assets from Statoil ASA completed on 30 June 2016. Lundin Petroleum AB issued 27.6 million new shares to Statoil ASA in consideration for the assets. In addition, the Company also issued 1.7 million new shares and transferred 2 million shares to Statoil ASA for a cash consideration of MUSD 64.1.
- New reserve-base lending facility of USD 5.0 billion entered into with an initial firm commitment of USD 4.3 billion subsequently increased by USD 0.7 billion to USD 5.0 billion.

Second quarter ended 30 June 2016 (30 June 2015)

- Production of 63.9 Mboepd (28.9 Mboepd)
- Revenue of MUSD 265.3 (MUSD 157.8)
- EBITDA of MUSD 206.1 (MUSD 106.5)
- Operating cash flow of MUSD 223.4 (MUSD 191.6)
- Net result of MUSD -48.3 (MUSD 59.9) including a net foreign exchange loss of MUSD 63.5 (gain of MUSD 27.3).

	1 Jan 2016– 30 Jun 2016 6 months	1 Apr 2016– 30 Jun 2016 3 months	1 Jan 2015– 30 Jun 2015 6 months	1 Apr 2015– 30 Jun 2015 3 months	1 Jan 2015– 31 Dec 2015 12 months
Production in Mboepd	63.1	63.9	27.4	28.9	32.3
Revenue in MUSD	456.6	265.3	279.1	157.8	569.3
Net result in MUSD	66.0	-48.3	-171.0	59.9	-866.3
Net result attributable to shareholders of the Parent Company in MUSD	68.3	-47.1	-168.8	61.1	-861.7
Earnings/share in USD ¹	0.22	-0.15	-0.55	0.20	-2.79
Earnings/share fully diluted in USD ¹	0.22	-0.15	-0.54	0.20	-2.79
EBITDA in MUSD	330.9	206.1	192.4	106.5	384.7
Operating cash flow in MUSD	386.0	223.4	347.3	191.6	699.6

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 very pleased with our second quarter operational performance with production about 15 percent ahead of mid-point guidance and corresponding cash operating costs at USD 8.85 per barrel. These strong results are led by the Edvard Grieg field which continues to perform ahead of expectations with high uptime and good reservoir performance. Our producing assets at the Alvheim hub as well as our other areas of operations have also contributed positively to our operational performance.

Whilst we continue to witness significant oil price volatility, we are beginning to see encouraging signs of a market rebalancing between supply and demand as a consequence of the significant scaling back of industry investments and project deferrals as well as oil demand continuing to grow at a healthy pace. This has led to a strengthening in oil prices from the lows in January of below USD 30 per barrel to current levels of close to USD 45 per barrel. Nevertheless, it is my view that we must be prepared to live with oil prices remaining lower for longer and retain our focus on optimising our costs and improving our operational efficiency to maintain a strong balance sheet and deliver significant sustainable value growth.

I am also excited to see the start of our exploration drilling activities in the southern Barents Sea, a core organic growth area for Lundin Petroleum.

Edvard Grieg transaction completed

Towards the end of the second quarter we successfully completed the acquisition of an additional 15 percent interest in the Edvard Grieg field from Statoil ASA, raising Lundin Petroleum's stake to 65 percent working interest in the field. I am very pleased to have completed this value driven transaction as it presented Lundin Petroleum the opportunity to increase our exposure to a world class field which we operate in one of our core areas. This transaction has further consolidated our balance sheet and will materially improve our operating cash flow during the years ahead of the Johan Sverdrup start-up. Following the completion of this transaction, Lundin Petroleum has issued 29.3 million new shares to Statoil which now owns approximately 68.4 million shares of Lundin Petroleum, representing 20.1 percent of the 340.4 million outstanding shares of Lundin Petroleum.

Production guidance exceeded

On the operational side we continue to deliver a strong performance with the second quarter average production for the Company of 63,900 boepd exceeding our mid-point guidance by about 15 percent. Performance on the Edvard Grieg field continues to exceed expectations and we are also very pleased to have successfully completed our first water injector well which is now fully operational. We experienced some delays in drilling the first water injection well and consequently the remaining drilling schedule has slipped somewhat which is likely to result in our production performance for the second half of 2016 being in the lower half of our production guidance. However, we firmly remain on track to achieve our full year production guidance of between 65,000 and 75,000 boepd. We also continue to achieve record low cash operating costs at USD 8.85 per barrel during the second quarter 2016.

Financial strength

On the financial side, another major milestone was achieved during the second quarter by bringing the total firm commitment from existing and new banks under the current reserve-based lending facility to USD 5.0 billion from the previously reported commitment of USD 4.5 billion. This puts Lundin Petroleum in an enviable position of strength for years to come.

Development progressing according to plan

Johan Sverdrup is progressing according to plan and I continue to firmly believe that we will see further costs savings as we progress with the project and as we finalise the definition of the Phase 2 concept selection.

In parallel, we continue to work on the feasibility studies of three existing discoveries: Alta and Gohta in the southern Barents Sea and the Luno II discovery in the Utsira high area.

Letter to Shareholders

Southern Barents Sea a key growth area

Our organic growth strategy continues and I was very pleased with the results of the 23rd licensing round which saw Lundin Norway as one of the leading companies in terms of licence awards received. Five new licences in the southern Barents Sea have been awarded to the Company in what is likely to become one of the most exciting growth areas in Norway in the years to come. In parallel, we have resumed our exploration and appraisal drilling activities on the Loppa High in the southern Barents Sea, with the drilling of three back to back wells. The southern Barents Sea is a key growth area for the Company and we have built over the years a very enviable strategic position in this exciting hydrocarbon province.

At this point, suffice to say, it is mission accomplished in terms of major Company developments during the first half of 2016. This is the result of a lot of enthusiasm, entrepreneurship and a hardworking culture within Lundin Petroleum. I am very grateful to the team for what they have achieved during these challenging yet rewarding times.

To you, fellow shareholders, the Board, I thank you for your continued support.

Full steam ahead!

Yours Sincerely,

Alex Schneider
President and CEO

Stockholm, 3 August 2016

Financial Report for the Six Months Ended 30 June 2016

OPERATIONAL REVIEW

Lundin Petroleum is an independent oil and gas exploration and production company with a principal focus on operations in Norway, with a portfolio of assets in Norway, Malaysia, France, the Netherlands and Russia. Norway represents the majority of Lundin Petroleum's operational activities with production for the six month period ending 30 June 2016 (reporting period) accounting for 78 percent of total production and with 96 percent of Lundin Petroleum's total reserves as at 1 January 2016.

Reserves and Resources

Lundin Petroleum has 716.2 million barrels of oil equivalent (MMboe) of proven plus probable reserves as at 1 January 2016 as certified by an independent third party. Lundin Petroleum also has a number of 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 amount to 386 MMboe as at 1 January 2016.

Production

Production for the reporting period amounted to 63.1 thousand barrels of oil equivalent per day (Mboepd) (compared to 27.4 Mboepd for the same period in 2015) and was comprised as follows:

Production in Mboepd	1 Jan 2016– 30 Jun 2016 6 months	1 Apr 2016– 30 Jun 2016 3 months	1 Jan 2015– 30 Jun 2015 6 months	1 Apr 2015– 30 Jun 2015 3 months	1 Jan 2015– 31 Dec 2015 12 months
Crude oil					
Norway	44.1	45.3	16.7	16.2	18.6
France	2.6	2.5	2.9	2.9	2.7
Malaysia	8.6	8.7	2.2	4.3	5.5
Total crude oil production	55.3	56.5	21.8	23.4	26.8
Gas					
Norway	5.1	5.3	2.2	2.2	2.1
Netherlands	1.6	1.6	1.7	1.6	1.8
Indonesia	1.1	0.5	1.7	1.7	1.6
Total gas production	7.8	7.4	5.6	5.5	5.5
Total production					
Quantity in Mboe	11,488.2	5,813.9	4,951.5	2,629.1	11,790.3
Quantity in Mboepd	63.1	63.9	27.4	28.9	32.3

Norway

Production

Production in Mboepd	WI ¹	1 Jan 2016– 30 Jun 2016 6 months	1 Apr 2016– 30 Jun 2016 3 months	1 Jan 2015– 30 Jun 2015 6 months	1 Apr 2015– 30 Jun 2015 3 months	1 Jan 2015– 31 Dec 2015 12 months
Edvard Grieg	50%	32.1	34.2	–	–	1.4
Alvheim	15%	9.0	9.1	8.1	7.6	7.8
Volund	35%	3.4	3.3	5.4	5.0	4.9
Bøyla	15%	2.0	1.9	1.9	1.9	2.1
Brynhild	90%	2.5	1.9	3.2	3.3	4.2
Gaupe	40%	0.2	0.2	0.3	0.6	0.3
		49.2	50.6	18.9	18.4	20.7

¹ Lundin Petroleum's working interest (WI)

Financial Report for the Six Months Ended 30 June 2016

Production from the Edvard Grieg field during the reporting period was higher than forecast at 32,100 boepd due to better reservoir performance and uptime than forecast. The Edvard Grieg field commenced production on 28 November 2015 with the initial production flowing from one well with the second and third production wells commencing production in December 2015 and January 2016 respectively. The first water injection well was successfully drilled during the reporting period, encountering better than expected reservoir sands that are in pressure communication with the production wells, and the well commenced water injection at planned rates in July 2016. The production capacity from the first three wells has exceeded expectations and the reservoir pressure depletion has been more favourable than anticipated, which is encouraging with respect to the field's future performance. In accordance with the reservoir management plan, the production levels have been held below the well potential whilst awaiting water injection wells to become available to balance production levels with available injection. The facilities uptime has also been exceptional with an average uptime of 96 percent for the reporting period. The facilities uptime in the second half of 2016 is expected to be lower than has been achieved to date due to potential disruptions in relation to a planned shutdown of the Sage gas terminal in the third quarter and the tie-in of the Ivar Aasen field during the fourth quarter of 2016.

The first water injection well, which was drilled in the northwestern part of the field, encountered the top reservoir 23 metres shallow to prognosis with a 26 metres gross oil column. It is not yet known whether the shallower top reservoir in this location is a local high or whether the whole western area of the field has a shallower top reservoir than is currently mapped. The second water injection well which is currently being drilled in the western part of the field around 1.4 km southwest of the first water injection well, will provide further confirmation on the mapping of the top reservoir in the western area of the field and any associated reserves upside.

When the second water injection well has been completed, the drilling of the fourth production well will commence with expected start-up of production at the end of 2016 when the field is forecast to achieve its gross plateau production of 100,000 boepd. There were some operational delays to the drilling of the first water injection well, which has had an impact on the timing of the follow-on wells to be delivered in 2016. The current well is progressing to plan. Notwithstanding the delay in the drilling schedule and ramp-up to full plateau production, it is anticipated that the Company will achieve its production guidance for the full year following the strong performance seen in the first half of 2016. Second half production will likely be in the lower half of the production range guided.

A total of 14 development wells are scheduled to be drilled on Edvard Grieg with drilling operations expected to continue into 2018. The total operating cost for the Edvard Grieg field, including insurance costs, was USD 8.20 per barrel during the reporting period.

In May 2016, Lundin Petroleum announced that it had entered into an agreement to acquire an additional 15 percent working interest in the Edvard Grieg field from Statoil ASA. The effective date of the transaction is 1 January 2016 and the transaction completed on 30 June 2016. As a result of this transaction, Lundin Petroleum has increased its reserves by 31 MMboe (1 January 2016). The additional production from this transaction will be accounted for from 1 July 2016 and consequently the full year 2016 production guidance for Lundin Petroleum has been increased from between 60,000 and 70,000 boepd to between 65,000 and 75,000 boepd.

Production from the Greater Alvheim area during the reporting period was in line with forecast. Utilisation of the Alvheim FPSO processing capacity is optimised within the constraints of the commercial arrangements to maximise production across all the fields in the Greater Alvheim area resulting in some production changes at a field level. The Alvheim FPSO uptime at 98 percent during the reporting period was better than forecast. During August 2016, the Sage gas terminal in the UK will be shut-in for planned maintenance for 14 days and consequently the Alvheim FPSO will also be shut-in during this period. The total operating cost for the Greater Alvheim area was USD 5.30 per barrel during the reporting period and is forecast to be just over USD 6 per barrel for the year. The Greater Alvheim area partners signed a new contract for the Transocean Arctic rig to commence in December 2016 to drill three infill wells and a near-field exploration well.

Net production from the Alvheim field during the reporting period was in line with forecast at 9,000 boepd. The reservoir performance continues to be excellent with the most recent infill well, the A5 3-branched production well, commencing production in May 2016 at significantly higher rates than forecast. The outperformance from the A5 well has been offset by certain wells with a high gas-oil ratio having been production constrained due to the gas processing capacity on the Alvheim FPSO. The drilling of the Viper and Kobra development wells was completed in June 2016 with expected start-up of these two wells towards the end of 2016. Both wells drilled into excellent reservoir sands with the Kobra well being modified into a dual branch well with one branch completed in a shallower and previously unmapped reservoir section above the main reservoir. The Kobra well was also extended to test the Kobra east exploration prospect with the well successfully encountering an oil-filled reservoir. A further Alvheim infill well is planned to be drilled in 2017.

The Volund field net production during the reporting period was slightly below forecast at 3,400 boepd. Further infill opportunities have been identified on the Volund field and during the reporting period the top holes of two infill wells were successfully drilled by the Transocean Winner rig before it went off hire at the end of July. These two wells will be completed by the Transocean Arctic rig which is scheduled to commence drilling of the infill wells in December 2016 with an expected production start-up in the second half of 2017.

The Bøyla field net production during the reporting period was slightly ahead of forecast at 2,000 boepd due to good reservoir performance with lower water cut in the wells than expected.

Net production from the Brynhild field during the reporting period was lower than forecast at 2,500 boepd due to a temporary lower well capacity than forecast. The Brynhild field achieved an uptime of 76 percent for the reporting period. The Brynhild field had a planned shut-in for one month during the reporting period due to maintenance work on the FPSO and to convert one production well into a water injection well. The field re-commenced production in mid-April 2016. The field is now receiving water injection support from two wells and following various well-related production issues during June 2016, the field is now back on production.

Despite no remaining reserves being attributed to the Gaupe field, the field is producing intermittently subject to favourable economic conditions and achieved net production of 200 boepd during the reporting period.

Development

Licence	Field	WI	Operator	PDO Approval	Estimated gross reserves	Production start expected	Gross plateau production rate expected
Ivar Aasen Unit	Ivar Aasen	1.385%	Det norske	May 2013	183 MMboe	Q4 2016	65 Mboepd
Johan Sverdrup Unit	Johan Sverdrup	22.60%	Statoil	August 2015	1.65 – 3.0 Bn boe	Late 2019	550 – 650 Mboepd

Ivar Aasen

Ivar Aasen is being developed with a steel jacket platform with the topside facilities consisting of a living quarter and processing facilities with oil, gas and water separation and onward export to the Edvard Grieg platform for final processing and pipeline export. The steel jacket was successfully installed in June 2015 and the pipelines installation between Ivar Aasen and Edvard Grieg was completed during the third quarter of 2015. The topside construction was completed during the reporting period and successfully installed on the jacket in July 2016. Eight development wells have been drilled to date and the Ivar Aasen field is forecast to come onstream during the fourth quarter of 2016.

Johan Sverdrup

The Johan Sverdrup project is progressing on schedule with a majority of Phase 1 contracts now awarded, resulting in estimated total project costs being reduced compared to the original estimates. Phase 1 construction work commenced in 2015.

Construction of three steel jackets has commenced at the Kværner yard on the west coast of Norway and of one jacket at the Dragados yard in Spain. Construction of the drilling platform and living quarters is underway and construction of the riser platform and processing platform will commence at Samsung Heavy Industries in Korea in the third quarter. In addition civil engineering works are underway on the onshore power system at Haugneset in Norway. The pre-drilling of development wells commenced in March 2016 with four development wells being completed to date 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). With most of the major contracts now awarded, the latest cost estimate has been reduced to NOK 108.5 billion (nominal), a reduction of approximately 12 percent. The Phase 1 development is scheduled to start production in late 2019. The original gross production capacity for Phase 1 was estimated at 380,000 bopd. However, debottlenecking measures have concluded that the design processing capacity for Phase 1 will increase from the range of between 315,000 and 380,000 bopd to 440,000 bopd with gas processing capacity in addition. It is anticipated that 35 production and injection wells will be drilled to support Phase 1 production, of which 17 wells will be drilled prior to first oil with a semisubmersible rig to facilitate Phase 1 plateau production.

The PDO for Phase 1 involves a field centre, consisting of one processing platform, one riser platform, one wellhead platform with drilling facilities and one living quarters' platform. The platforms will be installed on steel jackets in 120 metres of water depth and will be bridge-linked. A majority of the contracts have already been awarded for the development of Phase 1. Notably, all four topside contracts have been awarded, with EPC type contracts being awarded to Aibel (drilling platform) and Kværner/KBR (living quarters and utilities) whilst a fabrication contract has been awarded to Samsung Heavy Industries (riser platform and processing platform) with Aker Solutions being contracted for the procurement and engineering of the riser and processing platforms. The contract for the heavy lift installations for three of the topsides has been awarded to Allseas and contracts for the construction of three of the steel jackets for the riser, drilling and processing platforms have been awarded to Kværner, whilst the contract for the jacket for the utility and living quarter platform has been awarded to Dragados Offshore. Odfjell Drilling has been awarded contracts for drilling of the wells. Rosenberg WorleyParsons has been awarded the contracts for the construction of the three bridges linking the platforms and for the construction of two flare booms.

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The PDO for Phase 1 also outlines certain concepts for the full field development involving an expected full field gross plateau production level of between 550,000 and 650,000 bopd and gross reserves of between 1.65 to 3.0 billion boe with 95 percent of the reserves being oil. Phase 1 is expected to start production in late 2019.

The full field development costs (Phase 1 and Phase 2) have also been revised down from between NOK 170 and 220 billion (real 2015) to between NOK 160 and 190 billion (real 2015), due to market savings relating to Phase 1 and optimisation of the Phase 2 facilities concept. Phase 2 is expected to start production in 2022.

Appraisal

2016 appraisal well programme

Licence	Operator	WI	Well	Spud Date	Status
PL609	Lundin Petroleum	40%	Re-enter 7220/11-3 (Alta-3)	July 2016	Ongoing

The 2016 exploration and appraisal drilling campaign consists of three wells commencing with the re-entry of the Alta-3 appraisal well 7220/11-3A in PL609 which was successfully drilled last year on the eastern flank of the Alta discovery. The objective of the Alta-3 re-entry is to deepen the well to further assess the quality of the Permian carbonate reservoirs as well as to conduct a production test. The original Alta-3 well encountered a gross hydrocarbon column of 120 metres and all three Alta wells drilled to date have proven pressure communication.

During the reporting period Lundin Petroleum entered into a rig contract with Ocean Rig for the charter of the Leiv Eiriksson semi-submersible rig for the upcoming appraisal and exploration campaign in the southern Barents Sea. The contract encompasses three firm wells and six further well-slot options which can be called at Lundin Petroleum's election.

Exploration

2016 exploration well programme

Licence	Well	Spud Date	Target	WI	Operator	Result
Utsira High						
PL544	16/4-10	January	Fosen	40%	Lundin Petroleum	Dry
Southern Barents Sea						
PL609	Re-enter 7220/6-2	Q3 2016	Neiden	40%	Lundin Petroleum	
PL533	n/a	Q4 2016	Filicudi	35%	Lundin Petroleum	

In January 2016, the Lorry well in PL700 in the Norwegian Sea which was spudded in November 2015 was announced as dry. The well failed to encounter the prognosed reservoir.

In March 2016, the Fosen well in PL544 in the North Sea was announced as dry. The well, which was drilled just south of Luno II, encountered a 160 metres reservoir section but was water-wet with oil shows.

Lundin Petroleum will drill a further two exploration wells offshore Norway during 2016 targeting net unrisked prospective resources of approximately 170 MMboe. The remaining 2016 exploration programme consists of the Neiden re-entry in PL609 (WI 40%) and the Filicudi prospect in PL533 (WI 35%) just south of the Johan Castberg discovery in the southern Barents Sea.

Licence awards, transactions and relinquishments

In January 2016, the Ministry of Petroleum and Energy announced the licence awards in the 2015 APA licensing round. Lundin Petroleum was awarded four licences of which two as operator in PL815 and PL830 (both with WI 40%) in addition to two non-operated working interests in PL678SB and PL831 (both with WI 20%). In May 2016 the licence awards in the 23rd licensing round in the southern Barents Sea were announced and Lundin Petroleum was awarded five licences of which three as operator. Lundin Petroleum was awarded two operated licences, PL851 and PL609C (both with WI 40%) in the Loppa High area, one operated licence, PL853 (WI 60%) in the Hoop area and two non-operated licences, PL857 and PL859 (WI 20% and 15% respectively) in the eastern Barents Sea.

During the reporting period, Lundin Petroleum relinquished PL438, PL519, PL555, PL631, PL673, PL674, PL741 and PL779.

South East Asia

Malaysia

Production

Production in Mboepd	WI	1 Jan 2016– 30 Jun 2016 6 months	1 Apr 2016– 30 Jun 2016 3 months	1 Jan 2015 – 30 Jun 2015 6 months	1 Apr 2015 – 30 Jun 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Bertam	75%	8.6	8.7	2.2	4.3	5.5

Peninsular Malaysia

Net production from the Bertam field on Block PM307 (WI 75%) during the reporting period was ahead of forecast at 8,600 boepd. The Bertam field has been producing from 11 wells as of mid-October 2015 with one additional well, the A15 well, commencing production in June 2016. The A15 well results were better than prognosed with production being constrained by facilities limitations. Overall field performance is better than prognosed due to better than expected reservoir performance and this outperformance has been partially offset by the shut-in of two production wells during the reporting period in relation to replacement of downhole electrical submersible pumps and for production shut-ins due to moving the drilling rig. The West Prospero drilling rig came off contract towards the end of May 2016. The Bertam FPSO continues to achieve an excellent uptime of 98 percent for the reporting period.

Lundin Petroleum has identified several infill drilling targets on the Bertam field.

During the reporting period, Lundin Petroleum relinquished PM308A and PM319.

Sabah, East Malaysia

Lundin Petroleum completed the drilling of the Imbok well on Block SB307/308 (WI 65%) in early January 2016. The well encountered only oil shows in Miocene sands and was plugged and abandoned as dry. Following the Imbok well, the rig was moved to drill the Bambazon prospect, also on Block SB307/308, which encountered 15 metres of net reservoir pay with oil shows. However, no moveable oil was recovered from sampling and the well was plugged and abandoned as dry. The West Prospero rig subsequently moved to the Maligan prospect on Block SB307/308 and whilst gas shows were encountered, the well was plugged and abandoned as dry.

Farm-out agreements

Lundin Petroleum signed a farm-out agreement with Dyas in December 2015 whereby Lundin Petroleum has transferred a 20 percent working interest in Block SB307/308 (WI 65% after farm-out) and a 20 percent working interest in Block SB303 (WI 55% after farm-out), located offshore Sabah, East Malaysia. A 15 percent working interest has been transferred in Block PM328 (WI 35% after farm-out), located offshore Peninsular Malaysia.

FPSO sale

Lundin Petroleum announced on 22 January that it had entered into an agreement to sell the FPSO Bertam to M3nergy Investment Ltd (M3nergy), a wholly owned subsidiary of M3nergy Berhad of Malaysia. The transaction was subject to M3nergy securing financing within a certain timeframe. Given M3nergy has been unable to secure the required financing the agreement to sell the FPSO has been terminated.

Indonesia

Production

Production in Mboepd	WI	1 Jan 2016– 30 Jun 2016 6 months	1 Apr 2016– 30 Jun 2016 3 months	1 Jan 2015 – 30 Jun 2015 6 months	1 Apr 2015 – 30 Jun 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Singa	25.9%	1.1	0.5	1.7	1.7	1.6

The production from the Singa field was substantially in line with forecast during the reporting period.

In October 2015, Lundin Petroleum announced the signing of a sale and purchase agreement to sell its business in Indonesia to PT Medco Energi Internasional TBK for a cash consideration of MUSD 22, with an effective date of 1 October 2015. The Indonesian assets include the non-operated interest in the producing Singa gas field and the operated interests in the South Sokang and Cendrawasih VII Blocks, as well as the joint study agreement in respect of the Cendrawasih VIII Block. Lundin Petroleum may also become entitled to certain contingent payments in respect of the Singa gas field and retains an option to receive a future interest in the Cendrawasih Blocks. Completion of the transaction occurred on 28 April 2016 and Lundin Petroleum ceased reporting the production contribution from Singa as of this date.

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Continental Europe

Production

Production in Mboepd	WI	1 Jan 2016– 30 Jun 2016 6 months	1 Apr 2016– 30 Jun 2016 3 months	1 Jan 2015 – 30 Jun 2015 6 months	1 Apr 2015 – 30 Jun 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
France						
– Paris Basin	100% ¹	2.2	2.1	2.3	2.3	2.3
– Aquitaine	50%	0.4	0.4	0.6	0.6	0.4
Netherlands	Various	1.6	1.6	1.7	1.6	1.8
		4.2	4.1	4.6	4.5	4.5

¹ Working interest in the Dommartin Lettree field 42.5 percent.

France

Net production during the reporting period from France was slightly above forecast at 2,600 boepd. Good production performance has been achieved from the Vert La Gravelle field (WI 100%) in the Paris Basin and the fields in the Aquitaine Basin have also performed well during the reporting period.

The Netherlands

Net production for the reporting period from the Netherlands was ahead of forecast at 1,600 boepd due to better than expected production and reduced shut-in time for the Slootdorp 6 and 7 wells (WI 7.2325%). The Slootdorp 6 and 7 wells are now producing through the recently installed permanent production facilities.

The drilling of the K5-F3 development well has been completed and the well is expected to be put on production early in the third quarter 2016. Lundin Petroleum is participating in one further development well and one onshore exploration well during the second half of 2016.

Russia

In 2008, a significant oil discovery called Morskaya was made in the northern Caspian and is estimated to contain gross contingent resources of 157 MMboe. In May 2015, Lundin Petroleum announced that Rosnedra, the Russian licensing authorities, had issued a production licence for the Morskaya field (WI 70%). During the reporting period the exploration area of the Lagansky block surrounding the Morskaya field was relinquished.

Corporate Responsibility

During the reporting period, Lundin Petroleum recorded three incidents among contractors, resulting in a year to date Lost Time Incident Rate of 1.29 per million hours worked and a Total Recordable Incident Rate of 3.23. In February 2016, a tragic fatal accident took place offshore Malaysia when a contractor undertook repair work on the FPSO export hose. A thorough investigation was undertaken and follow-up measures were implemented. Two Lost Time Incidents were recorded in France in February and April 2016.

In May 2016, Lundin Petroleum issued its first sustainability report based on the Global Reporting Initiative, GRI G4 guidance, providing more qualitative and quantitative sustainability data.

In June 2016, Lundin Petroleum reported to the Carbon Disclosure Project (CDP) on its climate change strategy and 2015 emissions performance.

FINANCIAL REVIEW

Result

The net result for the six month period ended 30 June 2016 amounted to MUSD 66.0 (MUSD -171.0). The profit for 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, partially offset by lower oil prices and expensed exploration costs. The net result attributable to shareholders of the Parent Company for the reporting period amounted to MUSD 68.3 (MUSD -168.8) representing earnings per share of USD 0.22 (USD -0.55).

Earnings before interest, tax, depletion and amortisation (EBITDA) for the reporting period amounted to MUSD 330.9 (MUSD 192.4) representing EBITDA per share of USD 1.06 (USD 0.62). Operating cash flow for the reporting period amounted to MUSD 386.0 (MUSD 347.3) representing operating cash flow per share of USD 1.24 (USD 1.12).

Changes in the Group

On 28 April 2016, Lundin Petroleum completed the sale of its Indonesia business, including the non-operated Singa gas field.

Edvard Grieg transaction

The transaction to acquire an additional 15 percent working interest in the Edvard Grieg field and interests in the associated pipeline assets from Statoil ASA with an effective date of 1 January 2016, completed on 30 June 2016. In consideration for the acquisition of the assets, Lundin Petroleum issued 27,580,806 new shares in Lundin Petroleum AB based upon an agreed share price of SEK 138 per share and a SEK/USD exchange rate of 8.098, which equates to a consideration of MUSD 470.0 as at 1 January 2016. The transaction was accounted for at closing in accordance with IFRS3 Business Combinations as required by the amended IFRS11 Joint Arrangements which provides guidance on the accounting for acquisitions of interests in joint operations in which the activity constitutes a business. The production and financial results from the additional working interest will be reflected from 1 July 2016.

A summary of the net assets acquired at closing is shown in the table below:

Expressed in MUSD	30 June 2016
Assets	
Oil and gas properties	454.9
Goodwill	127.1
Cash	31.0
Total Assets Acquired	613.0
Liabilities	
Deferred tax	114.0
Site restoration provision	24.2
Working capital	10.3
Total Liabilities Acquired	148.5
Net Assets Acquired	464.5

In accordance with the Norwegian Petroleum Tax Act, the consideration paid is on an after tax basis and the remaining tax balances were transferred from Statoil ASA to Lundin Petroleum. Lundin Petroleum is therefore not entitled to a tax deduction for the consideration paid over and above the tax values transferred. In accordance with IAS12 Income Taxes, a deferred tax liability for an amount of MUSD 127.1 was recognised on the difference between the assigned fair values and the related tax base as at 30 June 2016, and the offsetting accounting entry is to goodwill. The goodwill will form part of the impairment testing of the Edvard Grieg field going forward.

In addition, Lundin Petroleum transferred 2 million treasury shares and issued 1,735,309 new shares to Statoil ASA in exchange for a cash consideration of MSEK 544.1 (MUSD 64.1).

Financial Report for the Six Months Ended 30 June 2016

Revenue

Revenue for the reporting period amounted to MUSD 456.6 (MUSD 279.1) 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 443.7 (MUSD 260.6). The average price achieved by Lundin Petroleum for a barrel of oil equivalent amounted to USD 37.72 (USD 56.76) and is detailed in the following table. The average Dated Brent price for the reporting period amounted to USD 39.81 (USD 57.84) per barrel.

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

Sales	1 Jan 2016– 30 Jun 2016 6 months	1 Apr 2016– 30 Jun 2016 3 months	1 Jan 2015 – 30 Jun 2015 6 months	1 Apr 2015 – 30 Jun 2015 3 months	1 Jan 2015 – 31 Dec 2015 12 months
Average price per boe expressed in USD					
Crude oil sales					
Norway					
– Quantity in Mboe	8,401.2	4,196.1	2,838.2	1,133.4	5,939.4
– Average price per boe	38.09	43.78	58.82	66.64	52.97
France					
– Quantity in Mboe	522.8	326.4	551.2	347.9	971.4
– Average price per boe	40.68	44.77	60.33	61.77	52.07
Netherlands					
– Quantity in Mboe	0.6	–	0.6	0.1	1.2
– Average price per boe	30.86	–	50.95	–	50.20
Malaysia					
– Quantity in Mboe	1,324.3	648.7	222.7	222.7	1,455.6
– Average price per boe	40.85	46.71	64.86	64.86	48.92
Total crude oil sales					
– Quantity in Mboe	10,248.9	5,171.2	3,612.7	1,704.1	8,367.6
– Average price per boe	38.63 ¹	44.26 ¹	59.42	65.41	52.16
Gas and NGL sales					
Norway					
– Quantity in Mboe	1,040.6	635.2	391.8	196.0	745.7
– Average price per boe	29.73	28.67	48.16	46.73	44.21
Netherlands					
– Quantity in Mboe	297.0	142.0	303.8	142.9	633.3
– Average price per boe	25.70	25.36	41.70	41.42	38.88
Indonesia					
– Quantity in Mboe	178.2	39.5	282.6	145.8	527.7
– Average price per boe	52.02	52.54	50.90	50.93	50.99
Total gas and NGL sales					
– Quantity in Mboe	1,515.8	816.7	978.2	484.7	1,906.7
– Average price per boe	31.56	29.25	46.94	46.43	44.31
Total sales					
– Quantity in Mboe	11,764.7	5,987.9	4,590.9	2,188.8	10,274.3
– Average price per boe	37.72 ¹	42.21 ¹	56.76	61.21	50.71

¹ Includes MUSD 0.5 additional sales revenue achieved by Lundin Petroleum Marketing SA.

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. Permanent differences arise as a result of paying royalties in kind as well as the effects from production sharing agreements. 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 net credit of MUSD 1.8 (credit of MUSD 9.7) in the reporting period due to the timing of the cargo liftings compared to production.

Other revenue amounted to MUSD 11.1 (MUSD 8.8) for the reporting period and included Bertam FPSO lease income, a quality differential compensation on Alveheim blended crude, tariff income from France and the Netherlands and income for maintaining strategic inventory levels in France.

Production costs

Production costs including inventory movements for the reporting period amounted to MUSD 113.3 (MUSD 64.5) and are detailed in the table below.

Production costs	1 Jan 2016– 30 Jun 2016 6 months	1 Apr 2016– 30 Jun 2016 3 months	1 Jan 2015– 30 Jun 2015 6 months	1 Apr 2015– 30 Jun 2015 3 months	1 Jan 2015– 31 Dec 2015 12 months
Cost of operations					
– In MUSD	83.7	41.5	55.8	34.4	121.1
– In USD per boe	7.28	7.12	11.27	13.10	10.27
Tariff and transportation expenses					
– In MUSD	18.5	9.2	5.8	3.3	11.8
– In USD per boe	1.61	1.58	1.18	1.25	1.00
Royalty and direct production taxes					
– In MUSD	1.6	0.8	1.5	0.8	3.5
– In USD per boe	0.14	0.15	0.31	0.31	0.29
Cash operating costs					
– In MUSD	103.8	51.5	63.1	38.5	136.4
– In USD per boe	9.03	8.85	12.76	14.66	11.56
Change in inventory position					
– In MUSD	-1.6	-1.8	-5.5	-3.1	-12.6
– In USD per boe	-0.14	-0.30	-1.11	-1.17	-1.07
Other					
– In MUSD	11.1	4.9	6.9	3.9	26.5
– In USD per boe	0.97	0.84	1.39	1.47	2.25
Total production costs					
– In MUSD	113.3	54.6	64.5	39.3	150.3
– In USD per boe	9.86	9.39	13.04	14.96	12.74

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

The total cost of operations for the reporting period was MUSD 83.7 (MUSD 55.8). The increase compared to the same period last year is due to the contribution of the Edvard Grieg and Bertam fields which commenced production in November 2015 and April 2015 respectively. The total cost of operations excluding operational projects amounted to MUSD 74.6 (MUSD 46.8).

The cost of operations per barrel for the reporting period amounted to USD 7.28 (USD 11.27) including operational projects and USD 6.49 (USD 9.45) per barrel excluding operational projects.

Tariff and transportation expenses for the reporting period amounted to MUSD 18.5 (MUSD 5.8). The increase compared to comparative period is mainly due the impact of the Edvard Grieg field.

Other costs amounted to MUSD 11.1 (MUSD 6.9) 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 mid-2017. This arrangement is being marked-to-market against the oil price curve and due to the low oil price curve at the end of 2015, an asset was recognised as at 31 December 2015. This asset is being charged to the income statement over the remaining term of the arrangement.

Depletion and decommissioning costs

Depletion and decommissioning costs amounted to MUSD 199.9 (MUSD 98.5) and are detailed in Note 3. The depletion costs associated with oil and gas properties amounted to MUSD 199.9 (MUSD 98.5) at an average rate of USD 17.40 (USD 21.54) per barrel. 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 and Bertam fields, partly offset by a lower Brynhild field depletion rate following the impairment of the carrying value at the end of 2015.

Depletion of other assets amounted to MUSD 15.6 (MUSD 8.2) for the reporting period and related to the Bertam FPSO which was depreciated from April 2015.

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Exploration costs

Exploration costs expensed in the income statement for the reporting period amounted to MUSD 68.9 (MUSD 106.9) and are detailed in Note 3. Exploration and appraisal costs are capitalised as they are incurred. When exploration drilling is unsuccessful, the capitalised costs are expensed. All capitalised exploration costs are reviewed on a regular basis and are expensed where their recoverability is considered highly uncertain.

During the reporting period, exploration costs relating to Norway of MUSD 55.8 were expensed and mainly related to the unsuccessful exploration wells that were drilled in PL700 (Lorry) and PL544 (Fosen). In addition, exploration costs were expensed relating to Malaysia of MUSD 13.1 following the drilling of the unsuccessful Bambazon and Maligan wells in SB307/308.

Sale of assets

Sale of assets amounted to a charge of MUSD 3.5 (MUSD –) for the reporting period. The reported charge related to the disposal of the Indonesian business which completed on 28 April 2016. The effective date of the deal was 1 October 2015 for a cash consideration of MUSD 22.

General, administrative and depreciation expenses

The general administrative and depreciation expenses for the reporting period amounted to MUSD 14.6 (MUSD 24.4) which included a charge of MUSD 2.1 (MUSD 5.0) in relation to the Group's long-term incentive plans (LTIP), see also Remuneration section below. Fixed asset depreciation expenses for the reporting period amounted to MUSD 2.3 (MUSD 2.3).

Finance income

Finance income for the reporting period amounted to MUSD 95.7 (MUSD 1.3) and is detailed in Note 4.

The net foreign currency exchange gain for the reporting period amounted to MUSD 95.1 (loss of MUSD 176.7). 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. 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 strengthened against the Euro during the reporting period, generating a net foreign currency exchange gain on an intercompany loan balance denominated in Norwegian Krone. The Norwegian Krone weakened against both currencies during the second quarter of 2016 resulting in a partial reversal of the net foreign currency exchange gain reported in the first quarter. Lundin Petroleum has hedged certain foreign currency operational expenditure amounts against the US Dollar and for the reporting period, the net realised exchange loss on settled foreign exchange hedges amounted to MUSD 33.9 (MUSD 79.8).

Finance costs

Finance costs for the reporting period amounted to MUSD 125.6 (MUSD 225.0) and are detailed in Note 5.

Interest expenses for the reporting period amounted to MUSD 73.6 (MUSD 27.8) and represented the portion of interest charged to the income statement. An additional amount of interest of MUSD 7.9 (MUSD 19.7) 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 the higher borrowings. The result on interest rate hedge settlements amounted to a loss of MUSD 9.6 (MUSD 3.5) and increased compared to the same period last year due to the higher fixed interest rate that was hedged in 2016.

The amortisation of the deferred financing fees amounted to MUSD 32.1 (MUSD 6.1) for the reporting period and related to the expensing of the fees incurred in establishing the new Group financing facility and the Norwegian exploration refund facility over the period of usage of the facilities. In addition, the unamortised portion of the capitalised financing fees incurred in establishing the previous financing facilities and the short term revolving credit facility were expensed in the reporting period and amounted to MUSD 22.3.

Loan facility commitment fees for the reporting period amounted to MUSD 3.3 (MUSD 5.2) with the decrease compared to the comparative period being due to the increased borrowings under the financing arrangements.

Tax

The overall tax credit for the reporting period amounted to MUSD 55.1 (MUSD 76.1).

The current tax credit for the reporting period amounted to MUSD 42.7 (MUSD 132.8) which included MUSD 41.9 (MUSD 136.1) relating to the Norway exploration tax refund due to the development and exploration and appraisal expenditure in Norway in the reporting period and the tax depreciation on development expenditure incurred in prior years.

The deferred tax credit for the reporting period amounted to MUSD 12.4 (charge of MUSD 56.7) and included a deferred tax credit of MUSD 10.5 related to the expensing of the capitalised financing fees.

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 20 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 and Malaysian exploration costs, 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 -2.3 (MUSD -2.2) and related mainly to the non-controlling interest's share in a Russian subsidiary which is fully consolidated.

Balance Sheet

Non-current assets

Oil and gas properties amounted to MUSD 4,871.4 (MUSD 4,015.4) 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 2016– 30 Jun 2016 6 months	1 Apr 2016– 30 Jun 2016 3 months	1 Jan 2015– 30 Jun 2015 6 months	1 Apr 2015– 30 Jun 2015 3 months	1 Jan 2015– 31 Dec 2015 12 months
Norway	386.9	218.5	481.6	241.5	880.7
Malaysia	16.2	9.4	104.5	51.1	130.1
France	1.5	0.6	14.4	5.0	16.9
Netherlands	1.5	0.8	1.7	0.7	2.7
Indonesia	0.1	–	-0.7	-0.7	-1.1
	406.2	229.3	601.5	297.6	1,029.3

An amount of MUSD 386.9 (MUSD 481.6) of development expenditure was incurred in Norway during the reporting period, primarily on the Johan Sverdrup and Edvard Grieg field developments. In Malaysia, MUSD 16.2 (MUSD 104.5) was incurred during the reporting period primarily on the Bertam field A15 development well.

Exploration and appraisal expenditure in MUSD	1 Jan 2016– 30 Jun 2016 6 months	1 Apr 2016– 30 Jun 2016 3 months	1 Jan 2015– 30 Jun 2015 6 months	1 Apr 2015– 30 Jun 2015 3 months	1 Jan 2015– 31 Dec 2015 12 months
Norway	58.5	17.6	169.0	88.6	370.2
Malaysia	17.4	-3.9	4.6	3.7	33.3
France	0.2	0.1	0.4	0.3	0.4
Russia	0.6	0.3	3.6	3.0	5.3
Indonesia	–	–	2.7	2.3	3.1
Netherlands	0.3	0.2	1.2	1.1	1.5
	77.0	14.3	181.5	99.0	413.8

Exploration and appraisal expenditure of MUSD 58.5 (MUSD 169.0) was incurred in Norway during the reporting period, primarily on the Fosen well in PL544 and the Lorry well in PL700. In Malaysia, MUSD 17.4 (MUSD 4.6) was incurred during the reporting period mainly on the Bambazon and Maligan wells in SB307/308.

In addition, MUSD 454.9 was added to the oil and gas properties at 30 June 2016 related to the additional 15 percent of the Edvard Grieg field acquired from Statoil.

Other tangible fixed assets amounted to MUSD 184.6 (MUSD 204.3) and included the accounting book value of the Bertam FPSO.

Goodwill amounted to MUSD 127.1 (MUSD –) and is described in the section Edvard Grieg transaction above.

Financial assets amounted to MUSD 6.1 (MUSD 10.7) and are detailed in Note 8. Other shares and participations amounted to MUSD 5.6 (MUSD 4.1) 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.

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Deferred tax assets amounted to MUSD 15.8 (MUSD 13.4) and are mainly related to Malaysia following the impairment of the Bertam field at year end 2015 resulting in the depreciable tax pool value being higher than the accounting book value.

Derivative instruments amounted to MUSD 5.4 (MUSD –) and related to the marked-to-market valuation of the long term portion of the outstanding currency hedges.

Other non-current assets amounted to MUSD 42.2 (MUSD –) and related to the Norwegian corporate tax refund in respect of the current year which will be received in December 2017.

Current assets

Inventories amounted to MUSD 57.6 (MUSD 45.6) and included both hydrocarbon inventories and well and operational supplies mainly held in Norway and Malaysia.

Trade and other receivables amounted to MUSD 199.7 (MUSD 159.3) and are detailed in Note 10. Trade receivables, which are all current, amounted to MUSD 94.2 (MUSD 35.2) and included two Edvard Grieg cargoes that were invoiced at 30 June 2016. Underlift amounted to MUSD 30.2 (MUSD 26.5) and was mainly attributable to a net underlift position on the Norwegian producing fields. Joint operations debtors relating to various joint venture receivables amounted to MUSD 28.0 (MUSD 48.4). Prepaid expenses and accrued income amounted to MUSD 32.3 (MUSD 29.5) and represented prepaid operational and insurance expenditure. Brynhild operating cost share amounted to MUSD 11.9 (MUSD 14.7) and related to marked-to-market valuation of the arrangement where the share of the Brynhild field operating cost varies with the oil price. Other current assets amounted to MUSD 3.1 (MUSD 5.0) and included VAT and other miscellaneous receivable balances.

Derivative instruments amounted to MUSD 2.5 (MUSD –) and related to the marked-to-market valuation of the short term portion of the outstanding currency hedges.

Current tax assets amounted to MUSD 275.8 (MUSD 264.7) of which MUSD 275.0 related to the Norwegian corporate tax refund in respect of 2015 which will be received in December 2016.

Cash and cash equivalents amounted to MUSD 34.4 (MUSD 71.9). Cash balances are held to meet ongoing operational funding requirements.

Non-current liabilities

Financial liabilities amounted to MUSD 3,961.8 (MUSD 3,834.8) and are detailed in Note 11. Bank loans amounted to MUSD 4,065.0 (MUSD 3,858.0) and related to the outstanding loan under the Group's reserve-based lending facility. Capitalised financing fees relating to the establishment costs of the financing facilities, including the Norwegian exploration refund facility, amounted to MUSD 103.2 (MUSD 23.2) and are being amortised over the period of usage of the financing facilities.

Provisions amounted to MUSD 436.9 (MUSD 379.9) and are detailed in Note 12. The provision for site restoration amounted to MUSD 425.7 (MUSD 368.2) and related to future decommissioning obligations. The provision has increased during the reporting period due to additions relating to the Norwegian development projects and by MUSD 24.2 related to the additional 15 percent of the Edvard Grieg field acquired at 30 June 2016. Farm-in payment amounted to MUSD 5.0 (MUSD 4.6) and related to a provision for payments towards historic costs based on production milestones on Block PM307, Malaysia.

Deferred tax liabilities amounted to MUSD 661.0 (MUSD 542.6) of which MUSD 538.8 (MUSD 407.9) related to Norway and included a net deferred tax liability of MUSD 114.0 related to the additional 15 percent of Edvard Grieg. 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 36.1 (MUSD 48.4) and related to the marked-to-market loss on the outstanding interest rate hedges due to be settled after twelve months.

Other non-current liabilities amounted to MUSD 32.8 (MUSD 32.2) 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 193.4 (MUSD –) and represent the amount drawn under the Norwegian exploration financing facility against the Norwegian exploration tax refund in respect of 2015. The short loan will be repaid in December 2016 when the tax refund is received.

Trade and other payables amounted to MUSD 263.2 (MUSD 349.9) and are detailed in Note 13. Deferred revenue amounted to MUSD 13.6 (MUSD 20.2) and represented a payment advanced by the buyer under the Alvheim Blend oil sales contract. Once the buyer lifts the oil, the liability will be reversed and the revenue will be recognised in the income statement. Joint operations creditors and accrued expenses amounted to MUSD 205.9 (MUSD 271.5) and related mainly to the development and drilling activity in Norway and Malaysia. Other accrued expenses amounted to MUSD 20.0 (MUSD 23.7) and other current liabilities amounted to MUSD 9.6 (MUSD 11.4).

Derivative instruments amounted to MUSD 23.6 (MUSD 66.1) and related to the marked-to-market loss on the outstanding interest rate hedge contracts due to be settled within twelve months.

Current provisions amounted to MUSD 3.5 (MUSD 4.8) 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 -37.4 (MSEK -40.6) for the reporting period.

The result included general and administrative expenses of MSEK 36.9 (MSEK 50.6) and net finance costs of MSEK 2.4 (net finance income of MSEK 2.5).

On 30 June 2016, following 2016 EGM resolutions, Lundin Petroleum AB issued 27,580,806 new shares to Statoil ASA as part of the Edvard Grieg transaction. In addition, the Company also issued 1,735,309 new shares and transferred 2 million treasury shares held to Statoil ASA in exchange for a cash consideration of MSEK 544.1 based upon a share price of SEK 145.66 per share. These three share transactions increased the share capital/premium of the Company by an amount of MSEK 4,533.8.

Following the sale of the 2 million treasury shares to Statoil ASA, the Company did not hold any own shares at 30 June 2016.

Pledged assets of MSEK 7,409.2 (MSEK 3,569.7) relate to the accounting value of the pledge of the shares in respect of the financing facility entered into by its fully-owned subsidiary Lundin Petroleum 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 as described below.

The Group received MUSD 0.2 (MUSD 0.1) from related parties for the provision of office and other services.

Liquidity

In February 2016, Lundin Petroleum replaced its existing USD 4.0 billion lending facility, which was due to reduce in availability from June 2016 and mature in 2019, with a committed seven year senior secured reserve-based lending facility of up to USD 5.0 billion, with an initial committed amount of USD 4.3 billion. The committed amount has subsequently been increased to 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. The pledged amount at 30 June 2016 is MUSD 872.8 (MUSD 422.9) equivalent and represents the accounting value of net assets of the Group companies whose shares are pledged as described in the Parent Company section above.

In April 2015, Lundin Petroleum entered into a NOK 4.5 billion Norwegian exploration refund facility with ten international banks. The facility is secured against the tax refunds generated from Lundin Norway's exploration and appraisal activities on the Norwegian Continental Shelf and extends until the end of 2016. Following the receipt of the 2014 Norwegian exploration tax refund in December 2015, the facility size was reduced to NOK 2.15 billion. As at 30 June 2016, the amount outstanding under the exploration refund facility was NOK 1.62 billion.

In March 2016, Lundin Petroleum entered into a six month revolving credit facility (RCF) of MUSD 300 with the option to extend by a further three months. Following the increased commitments under the Group's USD 5.0 billion reserve-based lending facility and the completion of the Edvard Grieg transaction, the RCF was cancelled effective 30 June 2016.

Lundin Petroleum has, through its subsidiary Lundin Malaysia BV, entered into Production Sharing Contracts (PSC) with Petroliam Nasional Berhad, the oil and gas company of the Government of Malaysia (Petronas). Bank guarantees have been issued in support of the work commitments and other related costs in relation to certain of these PSCs and the outstanding amount of the bank guarantees at 30 June 2016 was MUSD 10.6.

Subsequent Events

No events have occurred after the end of the reporting period that are expected to have a substantial effect on this financial report.

Share Data

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

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Remuneration

Lundin Petroleum's principles for remuneration and details of the long-term incentive plans are provided in the Company's 2015 Annual Report and in the materials provided to shareholders in respect of the 2016 AGM, available on www.lundin-petroleum.com.

Unit Bonus Plan

The number of units relating to the awards made in 2014, 2015 and 2016 under the Unit Bonus Plan outstanding as at 30 June 2016 were 122,745, 291,752 and 360,099 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 will be accounted for from the second half of 2016. The total number of awards made in respect of 2016 was 530,503 and the awards vest over three years from 1 July 2016 subject to certain performance conditions being met.

The 2015 plan is effective from 1 July 2015 and the total outstanding number of awards made in respect of 2015 was 694,011 which vest over three years from 1 July 2015 subject to certain performance conditions being met. Each award was fair valued at the date of grant at SEK 91.40 using an option pricing model.

The 2014 plan is effective from 1 July 2014 and the total outstanding number of awards made in respect of 2014 was 602,554 which vest over three years from 1 July 2014 subject to certain performance conditions being met. Each award was fair valued at the date of grant at SEK 81.40 using an option pricing model.

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 2015.

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 2015 Annual Report.

Derivative financial instruments

At 30 June 2016, Lundin Petroleum had outstanding currency hedges as summarised below:

Buy	Sell	Average contractual exchange rate	Settlement period
MNOK 2,058.4	MUSD 243.9	NOK 8.44:USD 1	Jul 2016 – Dec 2016
MNOK 1,839.2	MUSD 217.3	NOK 8.46:USD 1	Jan 2017 – Dec 2017
MNOK 1,926.3	MUSD 228.0	NOK 8.45:USD 1	Jan 2018 – Dec 2018
MNOK 1,672.4	MUSD 200.4	NOK 8.35:USD 1	Jan 2019 – Dec 2019

At 30 June 2016, Lundin Petroleum had also entered into the following interest rate hedge contracts as follows:

Borrowings expressed in MUSD	Fixing of floating LIBOR Rate per annum	Settlement period
2,000	1.50%	Jul 2016 – Dec 2016
1,500	2.32%	Jan 2017 – Dec 2017
1,000	3.06%	Jan 2018 – Dec 2018

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 2016		30 Jun 2015		31 Dec 2015	
	Average	Period end	Average	Period end	Average	Period end
1 USD equals NOK	8.4521	8.3776	7.7508	7.8568	8.0637	8.8090
1 USD equals Euro	0.8964	0.9007	0.8961	0.8937	0.9012	0.9185
1 USD equals Rouble	70.2913	64.4208	57.8952	55.7288	61.2881	74.1009
1 USD equals SEK	8.3382	8.4887	8.3722	8.2358	8.4303	8.4408

Consolidated Income Statement

Expressed in MUSD	Note	1 Jan 2016– 30 Jun 2016 6 months	1 Apr 2016– 30 Jun 2016 3 months	1 Jan 2015– 30 Jun 2015 6 months	1 Apr 2015– 30 Jun 2015 3 months	1 Jan 2015– 31 Dec 2015 12 months
Revenue	1	456.6	265.3	279.1	157.8	569.3
Cost of sales						
Production costs	2	-113.3	-54.6	-64.5	-39.3	-150.3
Depletion and decommissioning costs		-199.9	-102.6	-98.5	-55.4	-260.6
Depletion of other assets		-15.6	-7.8	-8.2	-8.2	-23.7
Exploration costs		-68.9	2.2	-106.9	-61.5	-184.1
Impairment costs of oil and gas properties		–	–	–	–	-737.0
Gross profit/loss	3	58.9	102.5	1.0	-6.6	-786.4
Sale of assets		-3.5	-3.5	–	–	–
General, administration and depreciation expenses		-14.6	-5.6	-24.4	-13.1	-39.5
Operating profit/loss		40.8	93.4	-23.4	-19.7	-825.9
Net financial items						
Finance income	4	95.7	-63.3	1.3	0.4	7.4
Finance costs	5	-125.6	-76.6	-225.0	1.1	-617.9
		-29.9	-139.9	-223.7	1.5	-610.5
Profit/loss before tax		10.9	-46.5	-247.1	-18.2	-1,436.4
Income tax	6	55.1	-1.8	76.1	78.1	570.1
Net result		66.0	-48.3	-171.0	59.9	-866.3
Attributable to:						
Shareholders of the Parent Company		68.3	-47.1	-168.8	61.1	-861.7
Non-controlling interest		-2.3	-1.2	-2.2	-1.2	-4.6
		66.0	-48.3	-171.0	59.9	-866.3
Earnings per share – USD ¹		0.22	-0.15	-0.55	0.20	-2.79
Earnings per share fully diluted – USD ¹		0.22	-0.15	-0.54	0.20	-2.79

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

Consolidated Statement of Comprehensive Income

Expressed in MUSD	1 Jan 2016– 30 Jun 2016 6 months	1 Apr 2016– 30 Jun 2016 3 months	1 Jan 2015– 30 Jun 2015 6 months	1 Apr 2015– 30 Jun 2015 3 months	1 Jan 2015– 31 Dec 2015 12 months
Net result	66.0	-48.3	-171.0	59.9	-866.3
Items that may be subsequently reclassified to profit or loss:					
Exchange differences foreign operations	16.4	8.7	-17.6	0.8	-81.7
Cash flow hedges	65.3	16.2	18.5	64.1	6.9
Available-for-sale financial assets	1.2	-3.6	-0.6	-0.3	-3.7
Other comprehensive income, net of tax	82.9	21.3	0.3	64.6	-78.5
Total comprehensive income	148.9	-27.0	-170.7	124.5	-944.8
Attributable to:					
Shareholders of the Parent Company	147.8	-26.9	-170.2	124.8	-934.8
Non-controlling interest	1.1	-0.1	-0.5	-0.3	-10.0
	148.9	-27.0	-170.7	124.5	-944.8

Consolidated Balance Sheet

Expressed in MUSD	Note	30 June 2016	31 December 2015
ASSETS			
Non-current assets			
Oil and gas properties	7	4,871.4	4,015.4
Other tangible fixed assets		184.6	204.3
Goodwill		127.1	—
Financial assets	8	6.1	10.7
Deferred tax assets		15.8	13.4
Derivative instruments	14	5.4	—
Other non-current assets	9	42.2	—
Total non-current assets		5,252.6	4,243.8
Current assets			
Inventories		57.6	45.6
Trade and other receivables	10	199.7	159.3
Derivative instruments	14	2.5	—
Current tax assets		275.8	264.7
Cash and cash equivalents		34.4	71.9
Total current assets		570.0	541.5
TOTAL ASSETS		5,822.6	4,785.3
EQUITY AND LIABILITIES			
Equity			
Shareholders' equity		184.9	-498.2
Non-controlling interest		25.2	24.1
Total equity		210.1	-474.1
Liabilities			
Non-current liabilities			
Financial liabilities	11	3,961.8	3,834.8
Provisions	12	436.9	379.9
Deferred tax liabilities		661.0	542.6
Derivative instruments	14	36.1	48.4
Other non-current liabilities		32.8	32.2
Total non-current liabilities		5,128.6	4,837.9
Current liabilities			
Financial liabilities	11	193.4	—
Trade and other payables	13	263.2	349.9
Derivative instruments	14	23.6	66.1
Current tax liabilities		0.2	0.7
Provisions	12	3.5	4.8
Total current liabilities		483.9	421.5
Total liabilities		5,612.5	5,259.4
TOTAL EQUITY AND LIABILITIES		5,822.6	4,785.3

Consolidated Statement of Cash Flows

Expressed in MUSD	1 Jan 2016– 30 Jun 2016 6 months	1 Apr 2016– 30 Jun 2016 3 months	1 Jan 2015– 30 Jun 2015 6 months	1 Apr 2015– 30 Jun 2015 3 months	1 Jan 2015– 31 Dec 2015 12 months
Cash flows from operating activities					
Net result	66.0	-48.3	-171.0	59.9	-866.3
Adjustments for:					
Exploration costs	68.9	-2.2	106.9	61.5	184.1
Depletion, depreciation and amortisation	217.8	111.4	108.9	64.7	286.9
Impairment of oil and gas properties	—	—	—	—	737.0
Current tax	-42.7	-12.7	-132.8	-73.2	-280.6
Deferred tax	-12.4	14.5	56.7	-4.9	-289.5
Long-term incentive plans	6.8	3.0	9.8	7.6	15.2
Foreign currency exchange loss	-129.0	47.5	97.0	-65.9	374.6
Interest expense	73.6	39.4	27.7	15.9	71.3
Capitalised financing fees	32.1	26.4	6.1	3.2	12.4
Other	16.5	9.0	13.2	8.4	28.5
Interest received	0.4	0.1	0.3	0.2	6.1
Interest paid	-75.1	-38.1	-46.8	-25.5	-110.1
Income taxes paid / received	3.1	3.3	0.1	4.0	335.6
Changes in working capital	10.0	-19.6	-105.1	-38.0	-193.7
Total cash flows from operating activities	236.0	133.7	-29.0	17.9	311.5
Cash flows from investing activities					
Investment in oil and gas properties	-483.0	-243.4	-783.0	-396.6	-1,443.3
Investment in other fixed assets	1.5	—	-32.4	-10.5	-36.0
Investment in subsidiaries	—	—	—	—	-0.1
Investment in other shares and participations	—	—	-3.7	—	-3.7
Decommissioning costs paid	-9.7	-8.9	-4.1	-3.9	-10.6
Disposal of fixed assets ¹	23.7	23.7	—	—	—
Other ²	31.0	31.0	-0.5	-0.4	-0.5
Total cash flows from investing activities	-436.5	-197.6	-823.7	-411.4	-1,494.2
Cash flows from financing activities					
Changes in long-term liabilities	207.7	-24.9	864.8	439.3	1,171.0
Financing fees paid	-107.0	-9.4	-3.1	-3.1	-3.3
Issuance of shares/Sale of treasury shares ³	64.1	64.1	—	—	—
Total cash flows from financing activities	164.8	29.8	861.7	436.2	1,167.7
Change in cash and cash equivalents	-35.4	-34.1	9.0	42.7	-15.0
Cash and cash equivalents at the beginning of the period	71.9	68.1	80.5	51.9	80.5
Currency exchange difference in cash and cash equivalents	-1.8	0.4	3.5	-1.6	6.4
Cash and cash equivalents at the end of the period	34.4	34.4	93.0	93.0	71.9

1 Cash received on the sale of the Indonesian business on closing including settlement of net working capital

2 Cash received on closing of the Edvard Grieg transaction with Statoil ASA

3 Cash received on the additional sale of newly issued and treasury shares to Statoil ASA

Consolidated Statement of Changes in Equity

Expressed in MUSD	Attributable to owners of the Parent Company				Non-controlling interest	Total equity
	Share capital	Additional paid-in-capital/Other reserves	Retained earnings	Total		
At 1 January 2015	0.5	8.8	422.2	431.5	34.2	465.7
Comprehensive income						
Net result	—	—	-168.8	-168.8	-2.2	-171.0
Other comprehensive income	—	-1.4	—	-1.4	1.7	0.3
Total comprehensive income	—	-1.4	-168.8	-170.2	-0.5	-170.7
Transactions with owners						
Value of employee services	—	—	3.6	3.6	—	3.6
Total transaction with owners	—	—	3.6	3.6	—	3.6
At 30 June 2015	0.5	7.4	257.0	264.9	33.7	298.6
Comprehensive income						
Net result	—	—	-692.9	-692.9	-2.4	-695.3
Other comprehensive income	—	-71.7	—	-71.7	-7.1	-78.8
Total comprehensive income	—	-71.7	-692.9	-764.6	-9.5	-774.1
Transactions with owners						
Investment in subsidiaries	—	—	—	—	-0.1	-0.1
Value of employee services	—	—	1.5	1.5	—	1.5
Total transaction with owners	—	—	1.5	1.5	-0.1	1.4
At 31 December 2015	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 transaction 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

Notes to the Consolidated Financial Statements

Note 1 – Revenue MUSD	1 Jan 2016– 30 Jun 2016 6 months	1 Apr 2016– 30 Jun 2016 3 months	1 Jan 2015– 30 Jun 2015 6 months	1 Apr 2015– 30 Jun 2015 3 months	1 Jan 2015– 31 Dec 2015 12 months
Crude oil	395.9	228.8	214.7	111.5	436.5
Condensate	5.7	5.6	0.3	0.2	0.6
Gas	42.1	18.3	45.6	22.3	83.9
Net sales of oil and gas	443.7	252.7	260.6	134.0	521.0
Change in under/over lift position	1.8	7.1	9.7	18.1	25.6
Other revenue	11.1	5.5	8.8	5.7	22.7
Revenue	456.6	265.3	279.1	157.8	569.3

Note 2 – Production costs MUSD	1 Jan 2016– 30 Jun 2016 6 months	1 Apr 2016– 30 Jun 2016 3 months	1 Jan 2015– 30 Jun 2015 6 months	1 Apr 2015– 30 Jun 2015 3 months	1 Jan 2015– 31 Dec 2015 12 months
Cost of operations	83.7	41.5	55.8	34.4	121.1
Tariff and transportation expenses	18.5	9.2	5.8	3.3	11.8
Direct production taxes	1.6	0.8	1.5	0.8	3.5
Change in inventory position	-1.6	-1.8	-5.5	-3.1	-12.6
Other	11.1	4.9	6.9	3.9	26.5
	113.3	54.6	64.5	39.3	150.3

Note 3 – Segment information MUSD	1 Jan 2016– 30 Jun 2016 6 months	1 Apr 2016– 30 Jun 2016 3 months	1 Jan 2015– 30 Jun 2015 6 months	1 Apr 2015– 30 Jun 2015 3 months	1 Jan 2015– 31 Dec 2015 12 months
Norway					
Crude oil	320.0	183.7	166.9	75.5	314.6
Condensate	5.5	5.5	–	–	–
Gas	25.4	12.7	18.9	9.2	33.0
Net sales of oil and gas	350.9	201.9	185.8	84.7	347.6
Change in under/over lift position	1.8	6.9	9.5	18.0	25.9
Other revenue	0.6	0.2	1.1	0.6	2.0
Revenue	353.3	209.0	196.4	103.3	375.5
Production costs	-82.3	-40.7	-44.7	-27.0	-104.5
Depletion and decommissioning costs	-157.0	-81.1	-65.3	-32.1	-158.9
Exploration costs	-55.8	-1.3	-105.9	-61.0	-146.5
Impairment costs of oil and gas properties	–	–	–	–	-526.0
Gross profit/loss	58.2	85.9	-19.5	-16.8	-560.4

Notes to the Consolidated Financial Statements

Note 3 – Segment information cont. MUSD	1 Jan 2016– 30 Jun 2016 6 months	1 Apr 2016– 30 Jun 2016 3 months	1 Jan 2015– 30 Jun 2015 6 months	1 Apr 2015– 30 Jun 2015 3 months	1 Jan 2015– 31 Dec 2015 12 months
France					
Crude oil	21.3	14.6	33.3	21.5	50.6
Net sales of oil and gas	21.3	14.6	33.3	21.5	50.6
Change in under/over lift position	0.2	0.2	0.2	0.1	-0.2
Other revenue	0.6	0.3	0.7	0.3	1.5
Revenue	22.1	15.1	34.2	21.9	51.9
Production costs	-12.3	-7.9	-13.6	-9.9	-25.1
Depletion and decommissioning costs	-7.2	-3.6	-8.3	-4.2	-15.5
Exploration costs	–	–	-0.6	-0.6	-0.6
Gross profit/loss	2.6	3.6	11.7	7.2	10.7
Netherlands					
Crude oil	–	–	–	–	0.1
Condensate	0.2	0.1	0.3	0.2	0.6
Gas	7.4	3.5	12.3	5.7	24.0
Net sales of oil and gas	7.6	3.6	12.6	5.9	24.7
Change in under/over lift position	-0.2	–	–	–	-0.1
Other revenue	1.0	0.5	0.9	0.5	1.8
Revenue	8.4	4.1	13.5	6.4	26.4
Production costs	-5.4	-2.8	-5.8	-3.0	-12.0
Depletion and decommissioning costs	-5.3	-2.5	-5.5	-2.7	-10.7
Exploration costs	–	–	-0.4	–	-0.7
Gross profit/loss	-2.3	-1.2	1.8	0.7	3.0
Malaysia					
Crude oil	54.1	30.3	14.5	14.5	71.2
Net sales of oil and gas	54.1	30.3	14.5	14.5	71.2
Other revenue	7.5	3.8	3.5	3.5	10.8
Revenue	61.6	34.1	18.0	18.0	82.0
Production costs	-11.9	-2.9	1.6	1.6	-4.4
Depletion and decommissioning costs	-30.4	-15.4	-13.2	-13.2	-66.4
Depletion of other assets	-15.6	-7.8	-8.2	-8.2	-23.7
Exploration costs	-13.1	3.5	–	–	-36.3
Impairment costs of oil and gas properties	–	–	–	–	-191.8
Gross profit/loss	-9.4	11.5	-1.8	-1.8	-240.6
Indonesia					
Gas	9.3	2.1	14.4	7.4	26.9
Net sales of oil and gas	9.3	2.1	14.4	7.4	26.9
Other revenue	–	–	–	–	–
Revenue	9.3	2.1	14.4	7.4	26.9
Production costs	-1.4	-0.3	-2.0	-1.0	-4.3
Depletion and decommissioning costs	–	–	-6.2	-3.2	-9.1
Exploration costs	–	–	–	0.1	–
Impairment costs of oil and gas properties	–	–	–	–	-19.2
Gross profit/loss	7.9	1.8	6.2	3.3	-5.7

Note 3 – Segment information cont. MUSD	1 Jan 2016– 30 Jun 2016 6 months	1 Apr 2016– 30 Jun 2016 3 months	1 Jan 2015– 30 Jun 2015 6 months	1 Apr 2015– 30 Jun 2015 3 months	1 Jan 2015– 31 Dec 2015 12 months
Other					
Crude oil	0.5	0.2	–	–	–
Net sales of oil and gas	0.5	0.2	–	–	–
Other revenue	1.4	0.7	2.6	0.8	6.6
Revenue	1.9	0.9	2.6	0.8	6.6
Gross profit/loss	1.9	0.9	2.6	0.8	6.6

Total					
Crude oil	395.9	228.8	214.7	111.5	436.5
Condensate	5.7	5.6	0.3	0.2	0.6
Gas	42.1	18.3	45.6	22.3	83.9
Net sales of oil and gas	443.7	252.7	260.6	134.0	521.0
Change in under/over lift position	1.8	7.1	9.7	18.1	25.6
Other revenue	11.1	5.5	8.8	5.7	22.7
Revenue	456.6	265.3	279.1	157.8	569.3
Production costs	-113.3	-54.6	-64.5	-39.3	-150.3
Depletion and decommissioning costs	-199.9	-102.6	-98.5	-55.4	-260.6
Depletion of other assets	-15.6	-7.8	-8.2	-8.2	-23.7
Exploration costs	-68.9	2.2	-106.9	-61.5	-184.1
Impairment costs of oil and gas properties	–	–	–	–	-737.0
Gross profit/loss	58.9	102.5	1.0	-6.6	-786.4

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 2016– 30 Jun 2016 6 months	1 Apr 2016– 30 Jun 2016 3 months	1 Jan 2015– 30 Jun 2015 6 months	1 Apr 2015– 30 Jun 2015 3 months	1 Jan 2015– 31 Dec 2015 12 months
Foreign currency exchange gain, net	95.1	-63.5	–	–	–
Interest income	0.4	0.1	0.3	0.2	6.1
Guarantee fees	0.1	–	1.0	0.2	0.7
Other	0.1	0.1	–	–	0.6
	95.7	-63.3	1.3	0.4	7.4

Note 5 – Finance costs MUSD	1 Jan 2016– 30 Jun 2016 6 months	1 Apr 2016– 30 Jun 2016 3 months	1 Jan 2015– 30 Jun 2015 6 months	1 Apr 2015– 30 Jun 2015 3 months	1 Jan 2015– 31 Dec 2015 12 months
Interest expense	73.6	39.4	27.8	16.0	71.4
Foreign currency exchange loss, net	–	–	176.7	-27.3	507.3
Result on interest rate hedge settlement	9.6	5.3	3.5	1.7	6.9
Unwinding of site restoration discount	6.7	3.4	4.8	2.5	10.0
Amortisation of deferred financing fees	32.1	26.4	6.1	3.2	12.4
Loan facility commitment fees	3.3	2.1	5.2	2.2	7.7
Other	0.3	–	0.9	0.6	2.2
	125.6	76.6	225.0	-1.1	617.9

Notes to the Consolidated Financial Statements

Note 6 – Income tax MUSD	1 Jan 2016– 30 Jun 2016 6 months	1 Apr 2016– 30 Jun 2016 3 months	1 Jan 2015– 30 Jun 2015 6 months	1 Apr 2015– 30 Jun 2015 3 months	1 Jan 2015– 31 Dec 2015 12 months
Current tax	-42.7	-12.7	-132.8	-73.2	-280.6
Deferred tax	-12.4	14.5	56.7	-4.9	-289.5
	-55.1	1.8	-76.1	-78.1	-570.1

Note 7 – Oil and gas properties MUSD	30 Jun 2016	31 Dec 2015
Norway	3,864.9	2,987.5
Malaysia	291.8	301.6
France	185.1	187.0
Netherlands	28.7	31.5
Russia	500.9	490.2
Indonesia	–	17.6
	4,871.4	4,015.4

Note 8 – Financial assets MUSD	30 Jun 2016	31 Dec 2015
Other shares and participations	5.6	4.1
Brynhild operating cost share	–	5.5
Other	0.5	1.1
	6.1	10.7

Note 9 – Other non-current assets MUSD	30 Jun 2016	31 Dec 2015
Corporate tax	42.2	–
	42.2	–

Note 10 – Trade and other receivables MUSD	30 Jun 2016	31 Dec 2015
Trade receivables	94.2	35.2
Underlift	30.2	26.5
Joint operations debtors	28.0	48.4
Prepaid expenses and accrued income	32.3	29.5
Brynhild operating cost share	11.9	14.7
Other	3.1	5.0
	199.7	159.3

Note 11 – Financial liabilities		
MUSD	30 Jun 2016	31 Dec 2015
Non-current:		
Bank loans	4,065.0	3,858.0
Capitalised financing fees	-103.2	-23.2
	3,961.8	3,834.8
Current:		
Short-term bank loans	193.4	–
	193.4	–
	4,155.2	3,834.8

Note 12 – Provisions		
MUSD	30 Jun 2016	31 Dec 2015
Non-current:		
Site restoration	425.7	368.2
Long-term incentive plans	1.2	2.2
Farm-in payment	5.0	4.6
Other	5.0	4.9
	436.9	379.9
Current:		
Long-term incentive plans	3.5	4.8
	3.5	4.8
	440.4	384.7

Note 13 – Trade and other payables		
MUSD	30 Jun 2016	31 Dec 2015
Trade payables	14.1	23.1
Deferred revenue	13.6	20.2
Joint operations creditors and accrued expenses	205.9	271.5
Other accrued expenses	20.0	23.7
Other	9.6	11.4
	263.2	349.9

Notes to the Consolidated Financial Statements

Note 14 – Financial instruments

MUSD

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 2016

MUSD	Level 1	Level 2	Level 3
Assets			
Other shares and participations	5.6	–	–
Derivative instruments – non-current	–	5.4	–
Derivative instruments – current	–	2.5	–
	5.6	7.9	–
Liabilities			
Derivative instruments – non-current	–	36.1	–
Derivative instruments – current	–	23.6	–
	–	59.7	–

31 December 2015

MUSD	Level 1	Level 2	Level 3
Assets			
Other shares and participations	4.1	–	–
	4.1	–	–
Liabilities			
Derivative instruments – non-current	–	48.4	–
Derivative instruments – current	–	66.1	–
	–	114.5	–

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

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

Parent Company Income Statement

Expressed in MSEK	1 Jan 2016– 30 Jun 2016 6 months	1 Apr 2016– 30 Jun 2016 3 months	1 Jan 2015– 30 Jun 2015 6 months	1 Apr 2015– 30 Jun 2015 3 months	1 Jan 2015– 31 Dec 2015 12 months
Revenue	1.9	0.9	7.5	0.8	8.7
General and administration expenses	-36.9	-23.8	-50.6	-24.9	-89.6
Operating profit/loss	-35.0	-22.9	-43.1	-24.1	-80.9
Net financial items					
Finance income	1.8	1.3	2.5	0.7	4.6
Finance costs	-4.2	-3.4	–	–	-1.8
	-2.4	-2.1	2.5	0.7	2.8
Profit/loss before tax	-37.4	-25.0	-40.6	-23.4	-78.1
Income tax	–	–	–	–	–
Net result	-37.4	-25.0	-40.6	-23.4	-78.1

Parent Company Comprehensive Income Statement

Expressed in MSEK	1 Jan 2016– 30 Jun 2016 6 months	1 Apr 2016– 30 Jun 2016 3 months	1 Jan 2015– 30 Jun 2015 6 months	1 Apr 2015– 30 Jun 2015 3 months	1 Jan 2015– 31 Dec 2015 12 months
Net result	-37.4	-25.0	-40.6	-23.4	-78.1
Other comprehensive income	–	–	–	–	–
Total comprehensive income	-37.4	-25.0	-40.6	-23.4	-78.1
Attributable to:					
Shareholders of the Parent Company	-37.4	-25.0	-40.6	-23.4	-78.1
	-37.4	-25.0	-40.6	-23.4	-78.1

Parent Company Balance Sheet

Expressed in MSEK	30 June 2016	31 December 2015
ASSETS		
Non-current assets		
Shares in subsidiaries	12,256.6	7,871.8
Other tangible fixed assets	1.9	0.2
Receivables to group companies	0.1	–
Total non-current assets	12,258.6	7,872.0
Current assets		
Receivables	22.8	17.5
Cash and cash equivalents	5.5	0.4
Total current assets	28.3	17.9
TOTAL ASSETS	12,286.9	7,889.9
SHAREHOLDERS' EQUITY AND LIABILITIES		
Shareholders' equity including net result for the period	12,278.8	7,782.4
Non-current liabilities		
Provisions	0.3	0.4
Payables to group companies	–	100.7
Total non-current liabilities	0.3	101.1
Current liabilities		
Current liabilities	7.8	6.4
Total current liabilities	7.8	6.4
Total liabilities	8.1	107.5
TOTAL EQUITY AND LIABILITIES	12,286.9	7,889.9
Pledged assets	7,409.2	3,569.7

Parent Company Cash Flow Statement

Expressed in MSEK	1 Jan 2016– 30 Jun 2016 6 months	1 Apr 2016– 30 Jun 2016 3 months	1 Jan 2015– 30 Jun 2015 6 months	1 Apr 2015– 30 Jun 2015 3 months	1 Jan 2015– 31 Dec 2015 12 months
Cash flow from operations					
Net result	-37.4	-25.0	-40.6	-23.4	-78.1
Adjustment for non-cash related items	13.1	8.5	0.1	0.8	0.3
Changes in working capital	-4.3	1.0	41.9	18.5	-23.8
Total cash flow from operations	-28.6	-15.5	1.4	-4.1	-101.6
Cash flow from financing					
Change in long-term liabilities	-507.9	-528.4	–	–	100.4
Proceeds from share issues /treasury shares	544.1	544.1	–	–	–
Total cash flow from financing	36.2	15.7	–	–	100.4
Change in cash and cash equivalents	7.6	0.2	1.4	-4.1	-1.2
Cash and cash equivalents at the beginning of the period	0.4	7.6	1.8	7.1	1.8
Currency exchange difference in cash and cash equivalents	-2.5	-2.3	-0.3	-0.1	-0.2
Cash and cash equivalents at the end of the period	5.5	5.5	2.9	2.9	0.4

Parent Company Statement of Changes in Equity

Expressed in MSEK	Restricted equity		Unrestricted equity			Total equity
	Share capital	Statutory reserve	Other reserves	Retained earnings	Total	
Balance at 1 January 2015	3.2	861.3	2,295.3	4,700.7	6,996.0	7,860.5
Total comprehensive income	–	–	–	-40.6	-40.6	-40.6
Balance at 30 June 2015	3.2	861.3	2,295.3	4,660.1	6,955.4	7,819.9
Total comprehensive income	–	–	–	-37.5	-37.5	-37.5
Balance at 31 December 2015	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
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

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 (MUSD)	1 Jan 2016– 30 Jun 2016 6 months	1 Apr 2016– 30 Jun 2016 3 months	1 Jan 2015– 30 Jun 2015 6 months	1 Apr 2015– 30 Jun 2015 3 months	1 Jan 2015– 31 Dec 2015 12 months
Revenue	456.6	265.3	279.1	157.8	569.3
EBITDA	330.9	206.1	192.4	106.5	384.7
Net result	66.0	-48.3	-171.0	59.9	-866.3
Operating cash flow	386.0	223.4	347.3	191.6	699.6
Data per share (USD)					
Shareholders' equity per share	0.54	0.54	0.86	0.86	-1.61
Operating cash flow per share	1.24	0.72	1.12	0.62	2.26
Cash flow from operations per share	0.76	0.43	-0.03	0.09	1.01
Earnings per share	0.22	-0.15	-0.55	0.20	-2.79
Earnings per share fully diluted	0.22	-0.15	-0.54	0.20	-2.79
EBITDA per share	1.06	0.66	0.62	0.34	1.24
Dividend per share	–	–	–	–	–
Number of shares issued at period end	340,386,445	340,386,445	311,070,330	311,070,330	311,070,330
Number of shares in circulation at period end	340,386,445	340,386,445	309,070,330	309,070,330	309,070,330
Weighted average number of shares for the period	311,233,197	311,396,065	309,070,330	309,070,330	309,070,330
Weighted average number of shares for the period fully diluted	312,529,762	312,692,630	309,678,433	309,678,433	310,019,890
Share price					
Share price at period end (SEK)	152.70	152.70	142.00	142.00	122.60
Key ratios					
Return on equity (%) ¹	-50	-37	-45	16	–
Return on capital employed (%)	0	2	-1	-1	-26
Net debt/equity ratio (%) ¹	2,285	2,285	1,320	1,320	–
Equity ratio (%)	4	4	5	5	-10
Share of risk capital (%)	15	15	22	22	1
Interest coverage ratio	0	1	-1	-2	-11
Operating cash flow/interest ratio	5	5	11	11	9
Yield	n/a	n/a	n/a	n/a	n/a

¹ As the equity at 31 December 2015 was negative, these ratios have not been calculated.

Key Ratio Definitions

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.

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

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

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

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

Earnings per share fully diluted: Net result attributable to shareholders of the Parent Company divided by the weighted average number of shares for the period after considering the dilution effect of the awards outstanding under the Group's performance based incentive plan.

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

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

Weighted average number of shares for the period fully diluted: The number of shares at the beginning of the period with changes in the number of shares weighted for the proportion of the period they are in issue after considering the dilution effect of the awards outstanding under the Group's performance based incentive plan.

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

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

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

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

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

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

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

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

Board Assurance

The Board of Directors and the President and CEO certify that the financial report for the six months ended 30 June 2016 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, 3 August 2016

Ian H. Lundin
Chairman

Alex Schneiter
President and CEO

Peggy Bruzelius

C. Ashley Heppenstall

Lukas H. Lundin

Grace Reksten Skaugen

Magnus Unger

Cecilia Vieweg

Review Report

We have reviewed this report for the period 1 January 2016 to 30 June 2016 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, 3 August 2016

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 2016) will be published on 2 November 2016.
- The year end report (January – December 2016) will be published on 1 February 2017.
- The three month report (January – March 2017) will be published on 3 May 2017.

The AGM will be held on 4 May 2017 in Stockholm, Sweden.

For further information, please contact:

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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 07.00 CEST on 3 August 2016.

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), production costs, availability of drilling equipment, reliance on key personnel, reserve estimates, health, safety and environmental issues, legal risks and regulatory changes, competition, geopolitical risk, and financial risks. These risks and uncertainties are described in more detail under the heading “Risks and Risk Management” and elsewhere in the Company’s annual report. Readers are cautioned that the foregoing list of risk factors should not be construed as exhaustive. Actual results may differ materially from those expressed or implied by such forward-looking statements. Forward-looking statements are expressly qualified by this cautionary statement.

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