Lundin Petroleum

Press Release

Stockholm 6 August 2014

REPORT FOR THE SIX MONTHS ENDED 30 JUNE 2014

HIGHLIGHTS

Six months ended 30 June 2014 (30 June 2013)

- Production of 28.1 Mboepd (35.2 Mboepd)[1]
- Revenue of MUSD 460.8 (MUSD 594.1)
- EBITDA of MUSD 349.3 (MUSD 517.6)
- Operating cash flow of MUSD 497.0 (MUSD 498.6)
- Net result of MUSD 0.8 (MUSD 48.2)
- Net debt of MUSD 1,777 (31 December 2013: MUSD 1,192)
- Increased credit facility from USD 2.5 billion to USD 4.0 billion
- Johan Sverdrup Phase 1 conceptual development plan was approved by the licence partners
- Nine exploration licences awarded in the Norwegian 2013 APA licensing round, four as operator

Second quarter ended 30 June 2014 (30 June 2013)

- Production of 27.5 Mboepd (34.8 Mboepd)[1]
- Revenue of MUSD 225.4 (MUSD 283.8)
- EBITDA of MUSD 171.5 (MUSD 243.1)
- Operating cash flow of MUSD 241.0 (MUSD 240.8)
- Net result of MUSD -2.4 (MUSD 1.2)

	1 Jan 2014- 30 Jun 2014 6 months	**1 Apr 2014- 30 Jun 2014 3 months**	1 Jan 2013- 30 Jun 2013 6 months	1 Apr 2013- 30 Jun 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Production in Mboepd[1]	28.1	27.5	35.2	34.8	32.7
Revenue in MUSD	460.8	225.4	594.1	283.8	1,132.0
Net result in MUSD	0.8	-2.4	48.2	1.2	72.9
Net result attributable to shareholders of the Parent Company in MUSD	3.2	-1.2	50.9	2.6	77.6
Earnings/share in USD[2]	0.01	0.00	0.16	0.01	0.25
EBITDA in MUSD	349.3	171.5	517.6	243.1	955.7
Operating cash flow in MUSD	497.0	241.0	498.6	240.8	967.9

[1] Including production from Russian onshore assets accounted for using the equity method under IFRS 11 Joint Arrangements.
[2] Based on net result attributable to shareholders of the Parent Company

Note: With effect from 1 January 2014, the Group has adopted IFRS 11 Joint Arrangements. As from the adoption date, the financial results attributable to the onshore Russian producing assets are accounted for using the equity method. Comparatives for the prior year have been restated.

Lundin Petroleum is a Swedish independent oil and gas exploration and production company with a well balanced portfolio of world-class assets primarily located in Europe and South East Asia. The Company is listed at the NASDAQ OMX, Stockholm (ticker "LUPE") and at the Toronto Stock Exchange (TSX) (Ticker "LUP"). Lundin Petroleum has proven and probable reserves of 194 million barrels of oil equivalent (MMboe).

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LETTER TO SHAREHOLDERS

Dear fellow Shareholders,

The world we live in today is one of increased geopolitical uncertainty. The recent sad events in Ukraine and the Middle East create an environment where the future is less clear and where the issue of energy security is much more in the public focus.

We strongly believe in a world where there will continue to be a strong demand for energy as the primary fuel to drive economic growth and that fossil fuels will remain the most important energy source for the foreseeable future.

Our business model is that if we are able to grow Lundin Petroleum’s oil and gas resources and production then this will result in the increase of value to our shareholders. We have been successful in recent years in increasing our resources particularly in Norway where we have arguably been the leading exploration company with a number of discoveries including Edvard Grieg and Johan Sverdrup. We are now very well advanced in bringing these discoveries to production and as a result you will see over the forthcoming months a significant growth in production, cash flow and profitability.

Production to close to triple by the end of 2015

Our production for the first half of 2014 was 28,100 boepd. The production from our core Norwegian Alvheim and Volund fields is still the major contributor representing over two thirds of production. Both fields have and continue to perform well but like most oil fields they have faced the onset of water breakthrough and increasing water cuts which will mean over time that oil production will continue to decline.

Our 2014 production forecast is retained at 24,000 to 29,000 boepd. The 2014 forecast has been impacted by the delays to the Brynhild field development first oil and the recent sale of our Russian onshore production.

Our forecast production will increase significantly in 2015 with production start-up from the Bøyla, Bertam and Edvard Grieg oil field developments. We retain our 2015 average production forecast of approximately 50,000 boepd and expect to exit 2015 in excess of 75,000 boepd when all these projects are onstream.

Development Projects

We have faced frustrating delays with the Brynhild development project, offshore Norway. The Brynhild field is a subsea development which is tied back to the Shell operated Pierce field facilities in the UK sector. The Pierce field production facility is the Bluewater operated Haewene Brim FPSO. The subsea element of the development is completed and development well capacity is ready to commence production. The delay to Brynhild first production has been a direct result of the inability of Shell and Bluewater to complete the FPSO related work scope on schedule to ensure the vessel is ready to recommence Pierce production and accept Brynhild oil. We are close to first oil which is now forecast in late September but based upon historically low levels of productivity and continued work scope changes I have low confidence in the Shell/Bluewater schedule and realistically expect Brynhild first oil to slip into the fourth quarter.

As I mentioned earlier we believe that based on the results of the completed wells there is potential that the gross initial Brynhild production rates of 12,000 boepd could be exceeded.

The news with regard to our other development projects, Bøyla, Bertam and Edvard Grieg is positive with all projects being on budget and schedule.

The progress on the Bertam development, offshore peninsular Malaysia is particularly encouraging with the successful installation of the Bertam wellhead platform jacket having being completed in May 2014. The completion of the offshore platform topsides and modification work on the 100 percent owned Bertam FPSO is still expected to be completed this year with first oil in the second quarter of 2015. The Seadrill owned West Prospero jack up rig has been contracted for the development drilling programme which will commence shortly.

I continue to be encouraged by the progress on the Edvard Grieg development following the successful installation of the jacket in the North Sea earlier this year. The topsides construction is progressing according to plan and we expect to achieve mechanical completion by the end of this year. The installation of the gas pipeline is ongoing at present and we expect to commence development drilling in the third quarter of 2014 with the Rowan Viking jack up rig. I remain confident that we will deliver first oil from Edvard Grieg in the fourth quarter of 2015 with a gross plateau production of 100,000 boepd.

I am pleased with progress on the preparation of the Johan Sverdrup plan of development which we still expect to be submitted to the Norwegian Government for approval in early 2015. The appraisal drilling programme is complete. Statoil, the working operator for the pre development phase, is finalising the subsurface modelling and is working closely with Aker Solutions who are completing the front end engineering contract. In tandem, the unitisation process is proceeding and will be resolved prior to the submission of the development plan.

The Johan Sverdrup project will be transformational for Lundin Petroleum and the first tangible evidence will be next year when we will be able to book the Johan Sverdrup resources as reserves, as a result of the development plan and unitisation. The impact from the Johan Sverdrup field on our reserves and production will be very significant with this field alone representing increases of over three to four times as compared to our current reserves and production.

Appraisal
We have been busy with appraisal drilling activity on three of our recent discoveries.

We recently completed the Gohta appraisal well in the Barents Sea with mixed results. We encountered a new conglomeratic reservoir which we successfully tested but the reservoir quality at this location of the karstified carbonate reservoir was below expectations. We are analysing the results of the well prior to agreeing a forward plan. The resource potential of Gohta, similar to other Barents Sea discoveries, is material but most likely below the economic threshold for a standalone development. I remain confident that oil export infrastructure will develop in this area of the Barents Sea to allow discoveries such as Gohta to be commercially developed.

In Malaysia, the results of the Tembakau appraisal well are positive and I am confident that this discovery can move forward to commerciality. The discovery is well located close to shore where there is a strong gas market. We will now be progressing with conceptual development studies and updating our resource estimates.

The Luno II appraisal well is ongoing in PL359 in the Utsira High area close to the Edvard Grieg and Johan Sverdrup fields. I am pleased that we were recently able to increase our ownership in PL359 to 50 percent and at the same time equalise the licence interests between the Edvard Grieg PL338 licence and PL359. This will facilitate the commercial arrangements for any potential tie back from Luno II to the Edvard Grieg facilities.

Exploration
We remain firmly committed to our organic growth model which is based upon our continued exploration drilling activity with a particular focus in Norway and Malaysia. Activity in the second half of 2014 will increase with 13 exploration wells forecast to be drilled before the end of the year. We will be drilling in our core Norwegian exploration areas of the Utsira High and Barents Sea where the Kopervik and Alta prospects are of particular interest whilst also seeking to open up new areas. In Malaysia we will be drilling exploration wells offshore peninsular Malaysia and offshore Sabah in proven petroleum basins close to infrastructure.

It is very clear from recent M&A activity in Norway and South East Asia that companies are paying premium values for good quality resources and with our historical track record of low finding costs we believe the best way to create this value is with the drill bit.

World Oil Markets
The world's leaders are facing major challenges associated with the increased geopolitical uncertainty around the world with consequent implications for energy security. World economic growth is slowly but surely returning to most areas and there is a growing acceptance that growth in China and the developing countries will continue. This is already leading to an increase in demand for commodities

including oil. I strongly believe that our industry will be challenged over the forthcoming years to continue to meet the world's increasing need for hydrocarbons.

In addition many oil companies are facing increasing pressure from shareholders to reduce costs, increase returns on capital and protect shareholder distributions. It is clearly a dilemma for industry executives to choose between short term returns and the need for long-term investment. However, a lack of investment today will clearly affect production in future years.

The management team and I are very focused on growing our resource and production base. I am extremely pleased that, with the support of our major shareholder, the Lundin family, we can continue to make long-term investments which will lead to the creation of value for our shareholders.

Yours Sincerely,

C. Ashley Heppenstall
President and CEO
Stockholm, 6 August 2014

OPERATIONAL REVIEW

Lundin Petroleum has exploration and production assets focused upon three core areas, Norway, South East Asia and Continental Europe. Norway continues to represent the majority of Lundin Petroleum's operational activities with production for the six month period ended 30 June 2014 (reporting period) accounting for 70 percent of total production and with 76 percent of Lundin Petroleum's total reserves as at the end of 2013.

RESERVES AND RESOURCES

Lundin Petroleum has 194.1 million barrels of oil equivalent (MMboe) of reserves at the end of 2013 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. Excluding the major Johan Sverdrup field in Norway, the best estimate contingent resources net to Lundin Petroleum amount to 342 MMboe as at the end of 2013. The Johan Sverdrup field contains gross contingent resources of between 1.8 and 2.9 billion boe as disclosed by pre-unit working operator Statoil. The Johan Sverdrup field is situated in licences PL501, PL502 and PL265 in Norway. Lundin Petroleum has a 40 percent interest in PL501 and a 10 percent interest in PL265.

PRODUCTION

Production for the reporting period amounted to 28.1 thousand barrels of oil equivalent per day (Mboepd) (compared to 35.2 Mboepd over the same period in 2013) and was comprised as follows:

Production in Mboepd	**1 Jan 2014- 30 Jun 2014 6 months**	**1 Apr 2014- 30 Jun 2014 3 months**	1 Jan 2013- 30 Jun 2013 6 months	1 Apr 2013- 30 Jun 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Crude oil					
Norway	16.6	16.2	22.5	22.4	20.6
France	2.9	2.9	2.8	2.8	2.9
Russia[1]	2.1	2.1	2.4	2.4	2.3
Total crude oil production	**21.6**	**21.2**	27.7	27.6	25.8
Gas					
Norway	3.0	2.9	3.8	3.6	3.3
Netherlands	2.0	1.9	2.1	2.0	2.0
Indonesia	1.5	1.5	1.6	1.6	1.6
Total gas production	**6.5**	**6.3**	7.5	7.2	6.9
Total production					
Quantity in Mboe	**5,090.8**	**2,502.5**	6,375.4	3,169.1	11,939.6
Quantity in Mboepd	**28.1**	**27.5**	35.2	34.8	32.7

[1] Following the adoption of IFRS 11 Joint Arrangements, the financial results attributable to the onshore Russian assets are accounted for using the equity method from 1 January 2014.

NORWAY

Production

Production in Mboepd	WI[1]	**1 Jan 2014- 30 Jun 2014 6 months**	**1 Apr 2014- 30 Jun 2014 3 months**	1 Jan 2013- 30 Jun 2013 6 months	1 Apr 2013- 30 Jun 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Alvheim	15%	10.0	10.3	11.3	11.1	10.5
Volund	35%	8.9	8.1	13.3	13.4	12.2
Gaupe	40%	0.7	0.7	1.7	1.5	1.2
		19.6	**19.1**	26.3	26.0	23.9

[1] Lundin Petroleum's working interest (WI)

Production from the Alvheim field during the reporting period has been better than forecast due to continued good reservoir performance and better than expected production from two wells, following workover activity, which came back onstream during April 2014. The production outperformance was partially offset by two short weather related shut-ins of the Alvheim FPSO during the reporting period. A third production well was shut-in in November 2013 and a workover of this well is scheduled during 2015. The drilling of a new infill well on Alvheim will be drilled in the fourth quarter of 2014 and the well is expected to commence production in early 2015. Two further infill wells are planned to be drilled in 2015. The cost of operations for the Alvheim field, excluding well intervention work, was below USD 5.0 per barrel during the reporting period.

The Volund field production during the reporting period has been below forecast due to a combination of two short weather related shut-ins of the Alvheim FPSO, lower liquid throughput compared to the forecast and a higher water-cut than forecast. The cost of operations for the Volund field during the reporting period was below USD 3.50 per barrel.

The Gaupe field produced as per forecast and is expected to cease production in 2014.

Development

Licence	Field	WI	PDO Approval	Estimated gross reserves	Production start expected	Gross plateau production rate expected
PL148	Brynhild	90%	November 2011	23 MMboe	September 2014	12.0 Mboepd
PL340	Bøyla	15%	October 2012	22 MMboe	Q1 2015	20.0 Mboepd
PL338	Edvard Grieg	50%	June 2012	186 MMboe	Q4 2015	100.0 Mboepd
Various	Ivar Aasen	1.385%	May 2013	192 MMboe	Q4 2016	65.0 Mboepd
Various	Johan Sverdrup	10%-40%	N/A	1.8 – 2.9 billion boe[1]	Late 2019	550.0 – 650.0 Mboepd

Brynhild

First oil from the Brynhild field is expected in September 2014. The subsea template and manifolds, as well as the production and injection flow lines have been successfully installed. The first two of four development wells are expected to be completed and ready for production from first oil. The two completed wells have found both the reservoir thickness and the quality of the reservoir as expected. The Haewene Brim FPSO has been successfully re-moored at the Pierce field offshore United Kingdom and the new production risers have been hooked-up to the FPSO. Commissioning work is ongoing prior to first oil.

Bøyla

The Bøyla field is being developed as a 28 km subsea tie-back to the Alvheim FPSO with two production wells and one water injection well. The production manifold was successfully installed during the first quarter of 2014 and the Transocean Winner rig has completed the drilling of the first production well and is currently drilling the second production well. First oil is forecast in the first quarter of 2015 and the field is expected to have a gross plateau production of 20.0 Mboepd. The Bøyla field development costs remain on budget.

Edvard Grieg

The steel jacket was successfully installed offshore during the second quarter of 2014. The installation of the 94 km gas pipeline to the Sage Beryl gas system is ongoing. The construction and engineering work on the topside and export oil pipeline is ongoing with the Y-connection into the Grane oil pipeline successfully installed. The installation of the 43 km long oil pipeline to the Grane Y-connection is planned during the spring of 2015. Development drilling is expected to commence during the third quarter of 2014 with the Rowan Viking jack-up rig. First oil from the Edvard Grieg field is expected in the fourth quarter of 2015. The Edvard Grieg field development is well advanced and is progressing on schedule and on budget.

The construction of the topsides by Kvaerner commenced in 2013 and is scheduled to be mechanically completed towards the end of 2014 with commissioning starting thereafter. Topside installation offshore is planned during the spring of 2015. The living quarters module has been successfully delivered by Apply Leirvik to the Kvaerner yard in Stord for integration with the other topside equipment.

The appraisal well 16/1-18 on the southeastern part of the Edvard Grieg field was successfully completed during the reporting period. The well encountered 62 metres of conglomeratic sandstone

[1] Gross contingent resource range as disclosed by working operator Statoil

of which the majority contained good reservoir quality. A further well is planned in the southern part of Edvard Grieg to better understand the distribution of this conglomeratic sandstone.

Ivar Aasen

During the reporting period the Ivar Aasen field, which is located immediately to the north of the Edvard Grieg field, has been unitised across three licences PL001b/PL242, PL338BS (WI 50%) and PL457. The PL338BS is a stratigraphic carve-out of PL338 with the same ownership as in PL338 (WI 50%). PL338BS has been assigned a 2.77 percent unitised interest in the Ivar Aasen development which therefore gives Lundin Petroleum a net ownership in Ivar Aasen of 1.385 percent. The unitised interest is not subject to any re-determination. The operator of Ivar Aasen, Det norske oljeselskap, estimates the field to contain gross reserves of 192 MMboe excluding the Hanz discovery which is not a part of the Ivar Aasen unit. Ivar Aasen is being developed with a steel jacket platform with the topside facilities consisting of a living quarter and drilling facilities with oil, gas and water separation and onward export to the Edvard Grieg platform for final processing and pipeline export. Ivar Aasen is forecast to come onstream during the fourth quarter 2016.

Johan Sverdrup

Lundin Petroleum discovered the Johan Sverdrup field in 2010 with the well 16/2-6 drilled on PL501 (WI 40%). A total of 22 wells and seven sidetracks have been drilled on the Johan Sverdrup field and the appraisal campaign is complete. In December 2013 Statoil, the pre-unit working operator of the field released an updated gross contingent resource estimate for the Johan Sverdrup field of 1.8 to 2.9 billion boe and a first oil date of late 2019. The field spans over three licences PL501 (WI 40%), PL265 (WI 10%) and a small portion of the field extends into PL502.

During the reporting period, the Phase 1 conceptual development plan was announced. The Phase 1 development will contain a field centre, consisting of one processing platform, one riser platform, one wellhead platform with drilling facilities and one living quarter platform. The platforms will be installed on steel jackets in 120 metres of water and will be bridge-linked. A FEED contract for Phase 1 was awarded to Aker Solutions in late 2013. In June 2014 the pre-unit working operator announced that a letter of intent had been signed with Kvaerner in Norway for delivery of two of the steel jackets for the phase 1 development. The steel jacket for the riser platform is scheduled for delivery in 2017 and the steel jacket for the drilling platform is scheduled for delivery in 2018.

The first phase development is scheduled to start production in late 2019 and is forecast to have a gross production capacity of between 315 and 380 Mboepd. It is anticipated that between 40 and 50 production and injection wells will be drilled to support Phase 1 production, of which 11 to 17 wells will be drilled prior to first oil with a semi-submersible rig to facilitate Phase 1 plateau production.

The gross capital investment for Phase 1, which includes oil and gas export pipelines as well as a power supply from shore, is estimated to between NOK 100 to 120 billion, including contingencies and certain market allowances for potential future increases in market rates. The Phase 1 field centre will also have spare capacity to facilitate future phases of development and potential enhanced recovery.

The Johan Sverdrup oil and gas production will be transported to shore via dedicated oil and gas pipelines. A 274 km 36” oil pipeline will be installed and connected to the Mongstad oil terminal on the west coast of Norway. A 165 km 18” gas pipeline will be installed and connected to the Kårstø gas terminal for processing and onward transportation. A plan of development for Johan Sverdrup phase 1 is planned to be submitted for approval to the Norwegian Government in early 2015.

The Johan Sverdrup resources not developed as part of Phase 1 will be developed through subsequent development phases. The scope and costs of further development phases are currently being matured by all partners and will form the basis of later investment decisions.

During the reporting period, two appraisal wells have been completed on the Johan Sverdrup field. Well 16/3-8S was successfully completed on PL501 on the Avaldsnes High between wells 16/2-6, 16/2-7 and 16/3-4 encountering 13 metres of oil filled reservoir of late Jurassic Draupne sandstones. The well achieved an excellent test flow rate and measured exceptionally high permeabilities. A side-track 16/3-8ST2 was also successfully completed. In April 2014 the appraisal well 16/2-19 and side-track well 16/2-19A on PL265 were completed. The results from the wells were below expectations with thinner than expected reservoir towards the basement high.

Appraisal

2014 appraisal well programme

Licence	Operator	WI	Well	Spud Date	Status
PL501	Lundin Petroleum	40%	16/3-8S & T2	January 2014	Completed March 2014
PL265	Statoil	10%	16/2-19	February 2014	Completed April 2014
PL492	Lundin Petroleum	40%	7120/1-4S	May 2014	Completed July 2014
PL359	Lundin Petroleum	50%	16/4-8S	June 2014	Ongoing

In addition to the Johan Sverdrup appraisal wells, a further two appraisal wells have been completed during the reporting period. In July 2014 the appraisal well on the Gohta discovery in the Barents Sea was completed. The Gohta appraisal well 7120/1-4S on PL492 (WI 40%) in the Barents Sea encountered 10 metres of gas and condensate in Upper Permian limestone conglomerate with good reservoir properties overlying fractured limestone of limited reservoir quality. A test produced over 26 million standard cubic feet of gas per day (MMscfd) and 880 barrels of condensate per day. The 16/4-8S appraisal well on PL359 (WI 50%) on the Luno II discovery on the Utsira High spudded in June 2014 and is aiming to test the quality and extent of the Jurassic/Triassic reservoir.

Exploration

2014 exploration well programme

Licence	Well	Spud Date	Target	WI	Operator	Result
Utsira High						
PL501	16/2-20A	January 2014	Torvastad (side-track)	40%	Lundin Petroleum	Oil shows – non-commercial
Barents Sea						
PL659	7222/11-2	January 2014	Langlitinden	20%	Det norske	Oil discovery – non-commercial

On the Utsira High the Torvastad side-track well 16/2-20A, targeting an Upper Jurassic reservoir sequence 770 metres west of the Torvastad exploration well 16/2-20, was completed in February 2014. The sidetrack encountered oil but found poorer than expected reservoir quality and was declared non-commercial.

In the Barents Sea, the Langlitinden well 7222/11-2 drilled on the southeast of the Loppa High was completed in February 2014. The well encountered oil in middle Triassic sandstone reservoir but the reservoir quality was poorer than expected and the well was consequently announced as non-commercial.

Lundin Petroleum plans to drill another five exploration wells in Norway during 2014. Drilling on the Alta prospect in PL609 (WI 40%) has commenced. The Alta prospect is situated immediately to the northeast of the Gohta discovery in PL492 and is estimated to contain gross unrisked prospective resources of 261 MMboe. Further wells will be drilled on Kopervik, Storm, Lindarormen and Vollgrav. The Storm prospect on PL555 (WI 60%), located in the northern North Sea, is scheduled to be drilled during the fourth quarter 2014 and is targeting 89 MMboe. In the fourth quarter 2014, the Lindarormen well on PL584 (WI 60%) is scheduled to be drilled in the Norwegian Sea to the south of the Asgard field and to the southwest of the Draugen field and is targeting 194 MMboe. In the third quarter of 2014, the Vollgrav well on PL631 (WI 60%) is also planned to be drilled in the northern North Sea between the Statfjord and Gullfaks fields and is targeting 57 MMboe. In the Utsira High the Kopervik prospect in PL625 (WI 40%), located to the northwest of the Johan Sverdrup field, is scheduled to be drilled during the fourth quarter of 2014 and is targeting 163 MMboe.

Lundin Petroleum, together with 32 other companies, has during the reporting period signed a contract with Western Geco and PGS for an extended 3D seismic acquisition in the Norwegian east Barents Sea ahead of the 23rd licensing round. The 3D acquisition is scheduled to be completed in the third quarter of 2014 and the processing is scheduled to be completed in the summer of 2015.

Licence awards, transactions and relinquishments
During the reporting period Lundin Petroleum was awarded nine licences through the APA 2013 licensing round, including four new licences in the Barents Sea. In addition Lundin Petroleum acquired from Premier Oil a 30 percent interest in PL359 where Lundin Petroleum already held a 40 percent interest and is operator. Lundin Petroleum subsequently entered into two separate transactions whereby a five percent interest in PL359 was sold to OMV Norge AS and a 15 percent interest in PL359 was sold to Wintershall Norge AS. Following these transactions, both of which remain subject to government approval, Lundin Petroleum will have a 50 percent interest in PL359 and these transactions will also ensure full partner alignment between PL359 and PL338 where the Edvard Grieg field is located. In January 2014, Lundin Petroleum farmed out ten percent in PL546 (WI 50% after farm-out) to Petrolia Norway AS. During the reporting period PL409 and PL570 were relinquished.

CONTINENTAL EUROPE

Production

Production in Mboepd	WI	**1 Jan 2014- 30 Jun 2014 6 months**	**1 Apr 2014- 30 Jun 2014 3 months**	1 Jan 2013- 30 Jun 2013 6 months	1 Apr 2013- 30 Jun 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
France						
- Paris Basin	100%[1]	2.4	2.4	2.4	2.4	2.5
- Aquitaine	50%	0.5	0.5	0.4	0.4	0.4
Netherlands	Various	2.0	1.9	2.1	2.0	2.0
		4.9	**4.8**	4.9	4.8	4.9

[1] Working interest in the Dommartin Lettree field 42.5 percent

France
Production levels from France are in line with forecast and have increased compared to the same period last year due to the incremental production from the Grandville redevelopment in the Paris Basin which has more than offset the natural decline from the other fields. A rig contract has been signed in relation to the Vert la Gravelle development with drilling activity expected to commence during the fourth quarter 2014.

The Hoplites exploration well on the Est Champagne concession (WI 100%) is planned to be drilled in the third quarter 2014.

The Netherlands
Production from the Netherlands has been in line with the forecast during the reporting period.

Two offshore development wells on E17a/b (WI 1.20%) and on K4b/K5a (WI 2.03%) are expected to spud during the third quarter of 2014.

One exploration well on E17a/b (WI 1.20%) has been drilled during the reporting period and has encountered gas. Well testing is currently ongoing.

The Hempens-1 exploration well on the Leeuwarden licence (WI 7.2325%) was completed during the reporting period as a dry hole. The drilling of the Lambertschaag-2 exploration well on the Slootdorp licence (WI 7.2325%) was completed during the reporting period. Although the primary target was dry, gas was found in a shallower section and is currently being evaluated.

Two further exploration wells are planned to be drilled by year end 2014 on the onshore Gorredijk licence (WI 7.75%).

SOUTH EAST ASIA

Malaysia
The Bertam oil field, offshore Peninsular Malaysia, received development approval from Petronas in October 2013 with first oil expected in the second quarter 2015. During the second half of 2014 Lundin Petroleum is planning to drill three exploration wells offshore Malaysia and one appraisal well is currently drilling.

Offshore, Peninsular Malaysia
The Bertam field development on PM307 (WI 75%) is progressing according to schedule. During the reporting period the steel jacket was successfully completed and installed offshore Peninsular Malaysia. The construction of the topside of the wellhead platform at the TH Heavy Engineering yard located in Pulau Indah, close to Kuala Lumpur, is well advanced and remains on schedule for installation during the fourth quarter of 2014. The Bertam FPSO (formerly the Ikdam FPSO) upgrade and life extension work is ongoing at the Keppel shipyard in Singapore and the completion of this work remains on schedule with expected completion during the fourth quarter 2014. During the reporting period Lundin Petroleum entered into a rig contract with Seadrill for the leasing of the jack-up rig West Prospero to drill the Bertam development wells. The subsurface development concept consists of 14 horizontal wells completed with electrical submersible pumps.

The Bertam field is estimated to contain gross reserves of 18 MMboe and is being developed through an un-manned wellhead platform adjacent to the spread-moored Bertam FPSO with a total estimated development cost of MUSD 400, excluding any FPSO related costs. The Bertam field is expected to commence first oil in the second quarter of 2015 with a gross plateau rate of 15.0 Mbopd.

The Tembakau-2 appraisal well has been successfully completed with production test results from the I10 and I20 sands yielding 15.9 and 15.8 MMscfd respectively. The results of the well will now be incorporated into an updated resource estimate and conceptual development options will be reviewed. Pre drill gross contingent resources were 306 billion cubic feet (bcf).

Two exploration wells are planned to be drilled within Block PM307 during the second half of 2014. One well will be drilled on the Rengas oil prospect, estimated to contain gross unrisked prospective resources of 22 MMboe, and one on the Mengkuang-1 oil prospect which is targeting 21 MMboe. Both of these exploration wells will be drilled by the jack-up rig West Prospero during the period when the Bertam topsides will be installed during the fourth quarter of 2014.

East Malaysia, offshore Sabah
Lundin Petroleum continues to evaluate the potential for commercialisation of the Berangan, Tarap, Cempulut and Titik Terang gas discoveries in Block SB303 (WI 75%), most likely through a cluster development. These four discoveries are estimated to contain gross best estimate contingent resources of 347 bcf. Seismic processing of the 500 km^2 Emerald 3D survey on SB307/308 (WI 42.5%) was completed in 2013 and two prospects, Maligan and Kitabu, within the Emerald 3D have been identified for drilling. The Kitabu prospect, which is estimated to contain gross unrisked prospective resources of 71 MMboe, is located on trend with the currently producing Shell fields SF30 and South Furious and is planned to be drilled during the fourth quarter of 2014.

Indonesia

Production

Production in Mboepd	WI	**1 Jan 2014- 30 Jun 2014 6 months**	**1 Apr 2014- 30 Jun 2014 3 months**	1 Jan 2013- 30 Jun 2013 6 months	1 Apr 2013- 30 Jun 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Singa	25.9%	**1.5**	**1.5**	1.6	1.6	1.6

The production was slightly below forecast due to certain facility issues during the reporting period. In early 2014 a revised gas sales agreement was put in place for the Singa field resulting in an increased gas sales price of USD 7.97 per million British Thermal Units (MMbtu) compared to the previous price of USD 5.20 per MMbtu with an effective date of 2 January 2014.

Exploration
Baronang/Cakalang
Exploration drilling on the Balqis and Boni prospect in the Baronang Block (WI 85%) in the Natuna Sea, Indonesia, was completed during the reporting period. Both wells encountered good quality reservoirs at the projected Oligocene level but neither well encountered any hydrocarbons and have

been declared as dry holes. Lundin Petroleum is planning to relinquish both the Baronang and the Cakalang Blocks.

Gurita
The drilling of the Gobi prospect on the Gurita Block (WI 90%) is expected to commence late in the third quarter of 2014 with the Hakuryu 11 drilling rig. The Gobi prospect is estimated to contain gross unrisked prospective resources of 25 MMboe.

South Sokang
A 3D seismic acquisition programme of 1,000 km^2 has been completed on the South Sokang Block (WI 60%) in 2013. The seismic processing and interpretation is substantially complete with both oil and gas prospectivity identified at Miocene and Oligocene levels.

Cendrawasih VII
Lundin Petroleum is undertaking geological and technical studies on the Cendrawasih VII Block (WI 100%), offshore eastern Indonesia.

OTHER AREAS

Russia

Production

Production in Mboepd	WI	**1 Jan 2014- 30 Jun 2014 6 months**	**1 Apr 2014- 30 Jun 2014 3 months**	1 Jan 2013- 30 Jun 2013 6 months	1 Apr 2013- 30 Jun 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Komi Republic	50%	**2.1**	**2.1**	2.4	2.4	2.3

In July 2014 Lundin Petroleum completed an agreement with Arawak Energy Russia BV whereby Lundin Petroleum sold its entire interest in the Sotchemyu-Talyu and North Irael fields in the Komi Republic for a cash consideration.

Lagansky Block
In the Lagansky Block (WI 70%) in the northern Caspian a major oil discovery, Morskaya, was made in 2008 and is estimated to contain gross best estimate contingent resources of 157 MMboe. In October 2013, Lundin Petroleum announced a Heads of Agreement with Rosneft whereby Rosneft will acquire a 51 percent shareholding in LLC PetroResurs which owns a 100 percent interest in the Lagansky Block. Rosneft's consideration in return for the 51 percent equity stake relates to historical spending on the Block and will be paid to Lundin Petroleum and Lundin Petroleum's partner, Gunvor, through a deferred payment mechanism. Following the completion of this transaction, Lundin Petroleum will have a 34.3 percent effective interest in the Lagansky Block.

CORPORATE RESPONSIBILTIY

During the reporting period, Lundin Petroleum had two Lost Time Incidents (LTI), which resulted in a LTI rate of 0.32 per 200,000 hours. Both incidents were of minor gravity. The total recordable incident rate was 0.56.

In May 2014, Lundin Petroleum submitted its UN Global Compact Communication on Progress and its Carbon Disclosure Project report. During the reporting period Lundin Petroleum also met with the Secretariat of the Extractive Industries Transparency Initiative (EITI) in Indonesia to further demonstrate its commitment to anti-corruption.

FINANCIAL REVIEW

Result

The net result for the six month period ended 30 June 2014 (reporting period) amounted to MUSD 0.8 (MUSD 48.2). The net result attributable to shareholders of the Parent Company for the reporting period amounted to MUSD 3.2 (MUSD 50.9) representing earnings per share of USD 0.01 (USD 0.16).

Earnings before interest, tax, depletion and amortisation (EBITDA) for the reporting period amounted to MUSD 349.3 (MUSD 517.6) representing EBITDA per share of USD 1.13 (USD 1.67). Operating cash flow for the reporting period amounted to MUSD 497.0 (MUSD 498.6) representing operating cash flow per share of USD 1.60 (USD 1.61).

Changes in the Group

There are no significant changes to the Group for the reporting period.

Adoption of IFRS 11 Joint Arrangements

With effect from 1 January 2014, the Group has adopted IFRS 11 Joint Arrangements. As from the adoption date, the financial results attributable to the onshore Russian producing assets are accounted for using the equity method. Comparatives for the prior year have been restated. For further information, please refer to the 2013 Annual Report, page 91.

Revenue

Revenue for the reporting period amounted to MUSD 460.8 (MUSD 594.1) 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 483.3 (MUSD 569.5). The average price achieved by Lundin Petroleum for a barrel of oil equivalent amounted to USD 98.45 (USD 98.77) and is detailed in the following table. The average Dated Brent price for the reporting period amounted to USD 108.93 (USD 107.50) per barrel.

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

Sales Average price per boe expressed in USD	**1 Jan 2014- 30 Jun 2014 6 months**	**1 Apr 2014- 30 Jun 2014 3 months**	1 Jan 2013- 30 Jun 2013 6 months	1 Apr 2013- 30 Jun 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Crude oil sales					
Norway					
– Quantity in Mboe	3,210.9	1,635.0	3,941.5	1,826.7	7,925.4
– *Average price per boe*	*113.50*	*116.51*[1]	*110.81*	*105.56*	*111.87*
France					
– Quantity in Mboe	453.0	220.4	433.5	220.4	1,030.4
– *Average price per boe*	*107.79*	*110.08*	*104.87*	*101.34*	*106.93*
Netherlands					
– Quantity in Mboe	0.6	–	1.2	0.6	1.8
– *Average price per boe*	*93.90*	–	*97.07*	*89.54*	*96.24*
Total crude oil sales					
– Quantity in Mboe	**3,664.5**	**1,855.4**	4,376.2	2,047.7	8,957.6
– Average price per boe	***112.79***	***115.75***	*110.22*	*105.11*	*111.30*
Gas and NGL sales					
Norway					
– Quantity in Mboe	638.3	338.6	761.8	371.2	1,389.4
– *Average price per boe*	*59.49*	*52.80*	*72.55*	*67.79*	*72.33*
Netherlands					
– Quantity in Mboe	362.6	174.5	363.9	168.0	715.7
– *Average price per boe*	*55.67*	*49.44*	*64.25*	*63.13*	*64.34*

Indonesia					
– Quantity in Mboe	243.6	122.7	263.9	132.1	520.1
– Average price per boe	*48.33*	*48.56*	*32.32*	*32.74*	*32.54*
Total gas and NGL sales					
– Quantity in Mboe	**1,244.5**	**635.8**	1,389.6	671.3	2,625.2
– Average price per boe	***56.19***	***51.06***	*62.74*	*59.73*	*62.27*
Total sales					
– Quantity in Mboe	**4,909.0**	**2,491.2**	5,765.8	2,719.0	11,582.8
– Average price per boe	***98.45***	***99.23***	*98.77*	*93.91*	*100.19*

[1] Includes pricing adjustments relating to prior periods of MUSD 2.0.

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 charge of MUSD 30.5 (credit of MUSD 16.0) in the reporting period. There was an overlift of entitlement on Alvheim and Volund fields during the reporting period due to the timing of the cargo liftings compared to production.

Other revenue amounted to MUSD 8.0 (MUSD 8.6) for the reporting period and included the quality differential compensation received from the Vilje field owners to the Alvheim and Volund field owners, 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 80.3 (MUSD 64.3) and are detailed in the table below.

Production costs	**1 Jan 2014- 30 Jun 2014 6 months**	**1 Apr 2014- 30 Jun 2014 3 months**	1 Jan 2013- 30 Jun 2013 6 months	1 Apr 2013- 30 Jun 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Cost of operations					
– In MUSD	52.5	21.9	52.4	28.7	103.0
– In USD per boe	*11.16*	*9.46*	*8.84*	*9.75*	*9.28*
Tariff and transportation expenses					
– In MUSD	9.8	5.0	11.1	5.7	21.6
– In USD per boe	*2.08*	*2.14*	*1.88*	*1.96*	*1.95*
Royalty and direct production taxes					
– In MUSD	1.9	1.0	1.7	0.8	3.4
– In USD per boe	*0.40*	*0.40*	*0.29*	*0.30*	*0.31*
Change in inventory position					
– In MUSD	-1.6	-1.4	-2.3	-1.3	-2.0
– In USD per boe	*-0.35*	*-0.62*	*-0.40*	*-0.49*	*-0.18*
Other					
– In MUSD	17.7	15.4	1.4	1.4	13.6
– In USD per boe	*3.78*	*6.74*	*0.24*	*0.48*	*1.21*
Total production costs					
– In MUSD	**80.3**	**41.9**	64.3	35.3	139.6
– In USD per boe	***17.07***	***18.12***	*10.85*	*12.00*	*12.57*

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 52.5 (MUSD 52.4) and included costs of MUSD 10.9 associated with well intervention work on two wells on the Alvheim field which was completed in the first quarter of 2014. There was well intervention work on the Alvheim and Volund fields, as well as radial drilling in the Paris Basin in the comparative period.

The cost of operations per barrel amounted to USD 11.16 (USD 8.84) for the reporting period including the Alvheim well intervention work and other operational projects. The increase in the cost of operations per barrel compared to the same period last year is due to the lower production volumes in the reporting period. The full year forecast for the cost of operations per barrel including operational projects is approximately USD 12.20 compared to the guidance of USD 13.00 given at the end of the first quarter. The decrease is mainly attributable to the rescheduling of an Alvheim field well workover from the third quarter of 2014 to 2015. Excluding operational projects, the cost of operations was MUSD 36.2 (MUSD 39.6) for the reporting period equating to USD 7.70 (USD 6.67) per barrel.

Other costs amounted to MUSD 17.7 (MUSD 1.4) and substantially relate to the cost share of the FPSO facilities to be used by the Brynhild field based on booked capacity. The FPSO cost share has been provided for the period from 1 June 2014 to an estimated September 2014 first oil date. The FPSO cost share thereafter will be reported as cost of operations.

Depletion and decommissioning costs
Depletion costs amounted to MUSD 68.8 (MUSD 83.0) and are detailed in Note 3. Norway's contribution to the total depletion charge for the reporting period was 67 percent (76 percent) at an average rate of USD 13.08 (USD 13.27) per barrel. The lower depletion cost for the reporting period compared to the same period last year is in line with the lower production volumes.

Exploration costs
Exploration costs expensed in the income statement for the reporting period amounted to MUSD 129.2 (MUSD 134.3) 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 74.6 were expensed and mainly related to the cost of drilling the wells on the Torvastad (PL501) and Langlitinden (PL659) prospects during the first quarter of 2014. A further MUSD 54.0 of exploration costs were expensed relating to Indonesia, being mainly costs expensed in the first quarter of 2014 associated with the Baronang and Cakalang Blocks following the results of the Balqis and Boni wells.

General, administrative and depreciation expenses
The general, administrative and depreciation expenses for the reporting period amounted to MUSD 33.7 (MUSD 14.3) which included a charge of MUSD 7.8 (credit of MUSD 2.5) in relation to the Group's long-term incentive plans (LTIP), see also Remuneration section below. Excluding the cost relating to the LTIP, the general, administrative and depreciation expenses for the reporting period amounted to MUSD 25.9 (MUSD 16.7). Fixed asset depreciation charges for the reporting period included in the total amounted to MUSD 2.5 (MUSD 2.1).

Finance income
Finance income for the reporting period amounted to MUSD 1.0 (MUSD 1.8) and is detailed in Note 4. During the second quarter of 2014, net foreign exchange losses amounted to MUSD 35.7 which reversed the foreign exchange gain reported for the first quarter of 2014, see also Finance costs section below.

Finance costs
Finance costs for the reporting period amounted to MUSD 38.5 (MUSD 36.3) and are detailed in Note 5. Interest expenses for the reporting period amounted to MUSD 6.8 (MUSD 2.6) and represented the proportion of interest charged to the income statement. An additional amount of interest of MUSD 16.7 (MUSD 6.0) associated with the funding of the Norwegian development projects was capitalised in the reporting period. Net foreign exchange losses for the reporting period amounted to MUSD 8.8 (MUSD 15.8). 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 reporting entities. During the reporting period the Norwegian Krone weakened and this has resulted in the reported foreign exchange losses. Lundin Petroleum's underlying value is US Dollar based as this is the currency in which the majority of revenues are derived. A strengthening US Dollar currency has a positive overall value effect on the

business as it increases the purchasing power of the US Dollar to purchase the currencies in which the Group incurs operational expenditure. Lundin Petroleum has hedged certain foreign currency operational expenditure amounts against the US Dollar as detailed in the Derivative financial instruments section below. During the reporting period, the realised exchange gain on settled foreign exchange hedges amounted to MUSD 8.0 (MUSD 4.7). The amortisation of the deferred financing fees amounted to MUSD 6.1 (MUSD 4.4) for the reporting period and related to the expensing of the fees incurred in establishing the original USD 2.5 billion financing facility, and the subsequent increase to USD 4.0 billion in February 2014, over the period of usage of the facility.

Share of result of joint ventures accounted for using the equity method

Share of result of joint ventures accounted for using the equity method for the reporting period amounted to a loss of MUSD 12.9 (MUSD 0.2) and included a MUSD 12.6 (MUSD –) non-cash expense relating to the carrying value of the onshore Russian assets following the agreement to sell the assets.

Tax

The overall tax charge for the reporting period amounted to MUSD 97.6 (MUSD 133.6).

The current tax credit for the reporting period amounted to MUSD 116.5 (MUSD 31.2 charge) of which MUSD 127.4 credit (MUSD 22.6 charge) related to Norway due to the significant level of development and exploration and appraisal expenditure in Norway in the reporting period and the tax depreciation on development expenditure incurred in prior years. The current tax credit in Norway for the reporting period is partly offset by the current tax charge relating to operations in France and the Netherlands.

The deferred tax charge for the reporting period amounted to MUSD 214.1 (MUSD 102.4) which predominantly related to Norway. The deferred tax charge arises primarily where there is a difference in depletion for tax and accounting purposes.

The Group operates in various countries and fiscal regimes where corporate income tax rates are different from the regulations in Sweden. Corporate income tax rates for the Group vary between 20 percent and 78 percent. The effective tax rate for the Group for the reporting period amounted to 99 percent. This effective rate is calculated from the face of the income statement and does not reflect the effective rate of tax paid within each country of operation. The high overall effective rate of tax for the reporting period is largely driven by Norway where the tax rate is 78 percent and that there was not a full tax credit on the expensed exploration costs in Indonesia, net foreign exchange losses or the expense relating to the agreement to sell the onshore Russian assets.

Non-controlling interest

The net result attributable to non-controlling interest for the reporting period amounted to MUSD -2.4 (MUSD -2.7) 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 4,552.0 (MUSD 3,820.8) 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 2014- 30 Jun 2014 6 months**	**1 Apr 2014- 30 Jun 2014 3 months**	1 Jan 2013- 30 Jun 2013 6 months	1 Apr 2013- 30 Jun 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Norway	575.2	289.1	378.2	199.5	1,105.9
France	6.2	3.9	3.3	1.3	7.0
Netherlands	2.0	1.3	1.9	1.0	4.8
Indonesia	–	–	-1.0	-1.0	-1.9
Malaysia	48.9	34.5	–	–	12.7
	632.3	**328.8**	382.4	200.8	1,128.5

An amount of MUSD 575.2 (MUSD 378.2) of development expenditure was incurred in Norway during the reporting period, of which MUSD 495.7 (MUSD 350.1) was invested in the Brynhild and Edvard Grieg field developments. In Malaysia, MUSD 48.9 (MUSD –) was incurred during the reporting period on the Bertam field development.

An amount of MUSD 78.7 (MUSD 5.0) was incurred in the reporting period on upgrading the Bertam FPSO for use on the Bertam field, Malaysia. This amount is not shown in the table above and has been capitalised as part of other tangible fixed assets.

Exploration and appraisal expenditure in MUSD	**1 Jan 2014- 30 Jun 2014 6 months**	**1 Apr 2014- 30 Jun 2014 3 months**	1 Jan 2013- 30 Jun 2013 6 months	1 Apr 2013- 30 Jun 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Norway	211.0	97.8	238.8	114.0	506.4
France	1.7	1.4	1.1	0.5	2.4
Indonesia	27.6	1.7	8.5	6.7	18.5
Malaysia	11.4	9.6	25.9	8.4	36.1
Russia	1.9	1.0	2.1	1.0	6.0
Other	0.9	0.4	0.2	0.1	0.5
	254.5	**111.9**	276.6	130.7	569.9

Exploration and appraisal expenditure of MUSD 211.0 (MUSD 238.8) was incurred in Norway during the reporting period, primarily on the appraisal drilling of the Johan Sverdrup field, the Gohta appraisal well and the Edvard Grieg southeastern extension appraisal well, as well as the Torvastad well (PL501) and the Langlitinden (PL659) exploration wells. During the reporting period MUSD 27.6 (MUSD 8.5) was spent in Indonesia mainly on drilling of the Balqis and Boni wells on the Baronang Block and MUSD 11.4 (MUSD 25.9) in Malaysia on the appraisal drilling of Tembakau (PM307).

Other tangible fixed assets amounted to MUSD 162.5 (MUSD 85.0) and included amounts relating to the Bertam FPSO and to other fixed assets.

Investments accounted for using the equity method amounted to MUSD 11.7 (MUSD 24.6) and relates to the investment in the onshore Russian assets which was written down as at 30 June 2014, following an agreement to sell the assets.

Financial assets amounted to MUSD 179.6 (MUSD 69.0) and are detailed in Note 8. Other shares and participations amounted to MUSD 19.8 (MUSD 22.0) and mainly 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. Long-term receivables amounted to MUSD 9.8 (MUSD 9.7) and represent the loan due from the sub-group which contains the onshore Russian assets being accounted for using the equity method. Deferred tax assets amounted to MUSD 22.2 (MUSD 22.4) and are mainly related to the part of the tax loss carry forwards in the Netherlands that are expected to be utilised against future tax liabilities. Corporate tax amounted to MUSD 125.2 (MUSD –) and is the Norwegian corporate tax refund in respect of the current year which will be received in December 2015. This is shown as part of financial assets and will be reclassified to current assets at the end of 2014. Bonds amounted to MUSD – (MUSD 10.4) following the sale of the Etrion Corporation bonds during the first quarter of 2014. Derivative instruments amounted to MUSD 1.1 (MUSD 3.0) and related to the mark-to-market gain on outstanding foreign currency hedges due to be settled after twelve months, see also Derivative financial instruments section below.

Current assets
Receivables and inventories amounted to MUSD 259.8 (MUSD 279.6) and are detailed in Note 9.

Inventories amounted to MUSD 24.1 (MUSD 21.2) and included both hydrocarbon inventories and well supplies. Trade receivables amounted to MUSD 127.9 (MUSD 125.8) and included MUSD 105.5 (MUSD 102.5) relating to Norway. All trade receivables are current. Corporate tax amounted to MUSD 1.8 (MUSD 6.5) and the comparative as at 31 December 2013 included a tax refund due in France of MUSD 5.8 which was settled during the second quarter of 2014. Derivative instruments amounted to MUSD 5.4 (MUSD 3.2) and related to the mark-to-market gain on outstanding foreign currency contracts due to be settled within twelve months. Prepaid expenses and accrued income amounted to MUSD 59.5 (MUSD 61.7) and represented prepaid operational and insurance expenditure. Other current assets amounted to MUSD 11.5 (MUSD 26.6) and included VAT and other miscellaneous balances.

Cash and cash equivalents amounted to MUSD 73.1 (MUSD 82.4). Cash balances are held to meet ongoing operational funding requirements.

Non-current liabilities
Provisions amounted to MUSD 1,562.3 (MUSD 1,345.1) and are detailed in Note 10.

The provision for site restoration amounted to MUSD 263.9 (MUSD 241.6) and relates to future decommissioning obligations. The provision for deferred taxes amounted to MUSD 1,264.9 (MUSD 1,066.0) of which MUSD 1,126.3 (MUSD 924.6) related to Norway. 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. The non-current portion of the provision for Lundin Petroleum's LTIP scheme amounted to MUSD 1.3 (MUSD 30.8). Lundin Petroleum's LTIP scheme is outlined in this report under the Remuneration section. The phantom option plan vested in May 2014 and 50 percent of the vested amount was paid during the second quarter of 2014. The second tranche of the phantom scheme payable within twelve months has been reclassified to current liabilities as at 30 June 2014. Derivative instruments amounted to MUSD 12.6 (MUSD 1.6) and related mainly to the mark-to-market loss on outstanding interest rate hedges due to be settled after twelve months. Farm-in payment amounted to MUSD 7.5 (MUSD –) and relates to a provision for payments towards historic costs on Block PM307, Malaysia, see also Current liabilities section below. Other non-current provisions amounted to MUSD 10.6 (MUSD 3.6) and include the long term portion of the mark-to-market valuation of the Brynhild field operating cost share agreement.

Financial liabilities amounted to MUSD 1,800.1 (MUSD 1,239.1). Bank loans amounted to MUSD 1,850.0 (MUSD 1,275.0) and related to the outstanding loan under the Group's increased USD 4.0 billion revolving borrowing base facility. Capitalised financing fees relating to the establishment costs of the financing facility amounted to MUSD 49.9 (MUSD 35.9) and are being amortised over the expected life of the financing facility. The increase in capitalised financing fees in the reporting period is attributable to the costs associated with increasing the financing facility to USD 4.0 billion.

Other non-current liabilities amounted to MUSD 26.2 (MUSD 25.0) and mainly arise from 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
Current liabilities amounted to MUSD 551.5 (MUSD 439.2) and are detailed in Note 12.

The overlift position amounted to MUSD 53.8 (MUSD 29.2) and related to the overlift of the Alvheim and Volund fields production entitlement at 30 June 2014. Joint venture creditors and accrued expenses amounted to MUSD 358.8 (MUSD 334.5) and related mainly to the increased development and drilling activity in Norway and the Bertam project, Malaysia. Other accrued expenses amounted to MUSD 77.5 (MUSD 39.4) and included an amount of MUSD 41.2 (MUSD 4.8) relating to the work done on the Bertam FPSO. Long-term incentive plan amounted to MUSD 38.1 (MUSD –) and represents the second tranche of the phantom option plan including social costs due within twelve months. The plan is now fully vested and the liability has been reclassified from provisions to current liabilities. Derivative instruments amounted to MUSD 3.3 (MUSD 4.0) and related to the mark-to-market loss on outstanding foreign currency and interest rate hedge contracts due to be settled within twelve months.

Short term provisions amounted to MUSD 69.2 (MUSD 46.2) and includes an amount of MUSD 48.5 (MUSD –) relating to a payment for historic costs on Block PM307, Malaysia, which is payable on first oil from the Bertam project. This provision has been recognised in the reporting period now that there is more certainty over the amount and timing of the payment. An amount of MUSD 17.0 (MUSD –) is included relating to the Brynhild field cost share provided for the period to the first oil date, the short term mark-to-market valuation of the Brynhild operating cost share agreement and a provision for contractual obligations post the expected cessation of production date on the Gaupe field. Also included in short term provisions is an amount of MUSD 3.7 (MUSD 46.2) relating to the current portion of the provision for Lundin Petroleum's LTIP scheme.

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 -77.9 (MSEK -29.4) for the reporting period.

The result included general and administrative expenses of MSEK 84.5 (MSEK 30.9) and finance income of MSEK 1.8 (MSEK 1.7), mainly relating to guarantee fees.

Pledged assets of MSEK 12,618.9 (MSEK 12,014.5) 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 0.2) from ShaMaran Petroleum for the provision of office and other services. The Group paid MUSD 0.1 (MUSD 0.1) to other related parties in respect of aviation services received.

In 2013, the Group entered into a loan agreement with Geoff Turbott, former VP Finance and CFO for a maximum amount of MUSD 3.0. All amounts plus interest have been repaid during the reporting period.

LIQUIDITY

On 25 June 2012, Lundin Petroleum entered into a seven year senior secured revolving borrowing base facility of USD 2.5 billion with a group of 25 banks to provide funding for Lundin Petroleum's ongoing exploration expenditure and development costs. On 6 February 2014, Lundin Petroleum increased the facility to USD 4.0 billion on similar terms. The financing facility is a revolving borrowing base 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 2014 is MUSD 1,878.2 (MUSD 1,870.3) 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. The Group is not in breach of the debt covenants.

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 in relation to certain of these PSCs and the outstanding amount of the bank guarantees at 30 June 2014 was MUSD 8.5.

SUBSEQUENT EVENTS

In July 2014, Lundin Petroleum announced that it had sold its interests in the Russian onshore producing assets in the Komi Region. The deal completed in mid-July. As a result of the transaction, a non-cash expense of MUSD 12.6 was recognised in the reporting period ended 30 June 2014 related to the carrying value of the participation interest and the related funding loans.

As mentioned in the operations report, Lundin Petroleum entered into agreements to increase its interest by a net 10 percent in PL359, Norway and to obtain through a unitisation process 1.385 percent of the Ivar Aasen field, Norway. The agreements are subject to government approval which is expected in the second half of 2014.

SHARE DATA

Lundin Petroleum AB's issued share capital amounted to SEK 3,179,106 represented by 311,070,330 shares with a quota value of SEK 0.01 each.

During the reporting period Lundin Petroleum purchased a further 500,000 of its own shares at an average price of SEK 124.07. Following a 2014 AGM resolution, the Company reduced its share capital with an amount of SEK 68,402.50 through the cancellation of 6,840,250 shares held in treasury. The reduction of the share capital was followed by a bonus issue of the same amount and in consequence the cancellation of shares did not impact the Company's share capital. This resulted in a minor change in the quota value 0f each share as no new shares were issued. At 30 June 2014 the Company holds 2,000,000 of its own shares.

REMUNERATION

Lundin Petroleum's principles for remuneration and details of the long-term incentive plans are provided in the Company's 2013 Annual Report.

Unit Bonus Plan

The number of units relating to the 2012, 2013 and 2014 Unit Bonus Plans outstanding as at 30 June 2014 were 116,392, 276,110 and 374,277 respectively.

Phantom Option Plan

The plan for Executive Management includes 5,500,928 phantom options with an exercise price of SEK 52.91. The phantom options vested in May 2014 being the fifth anniversary of the date of grant. Each option was valued at SEK 81.45 based on the average share price for the fifth year of the plan amounting to SEK 134.36.

Performance Based Incentive Plan

The AGM 2014 has resolved a new long-term performance based incentive plan in respect of Group Management and a number of key employees. The plan is effective from 1st of July 2014 and the 2014 award under the plan will be accounted for in the second half of the year. The total awards made in respect of 2014 was 608,103 and vest over three years subject to the certain performance conditions being met by Lundin Petroleum.

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. As from 1 January 2014, Lundin Petroleum has adopted IFRS 11 Joint Arrangements and the comparatives for the prior year have been restated. For further information, please refer to the 2013 Annual Report, page 91. 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 2013.

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 SEK or Euro and consequently the Parent Company's financial information is reported in SEK and not the Group's reporting currency of USD.

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 2013 Annual Report.

Derivative financial instruments

At 30 June 2014, Lundin Petroleum had entered into the following currency hedging contracts to meet part of the 2014 and future NOK operational requirements as summarised in the table below.

Buy	Sell	Average contractual exchange rate	Settlement period
MNOK 5,323.3	MUSD 861.4	NOK 6.18: USD 1	Jan 2014 –Dec 2014
MNOK 1,861.3	MUSD 297.1	NOK 6.26: USD 1	Jan 2015 –Dec 2015

During March 2013, Lundin Petroleum entered into a three year fixed interest rate swap, starting 1 April 2013 in respect of MUSD 500 of borrowings, fixing the floating LIBOR rate at approximately 0.57 percent per annum for the duration of the hedge. In March 2014, Lundin Petroleum entered into further interest rate hedge swaps starting 1 July 2014 and ending in December 2018 as follows:

Borrowings expressed in MUSD	Fixing of floating LIBOR Rate per annum	Settlement period
1,000	0.21%	1 Jul 2014 – 31 Dec 2014
1,500	0.52%	1 Jan 2015 – 31 Dec 2015
1,500	1.50%	1 Jan 2016 – 31 Mar 2016
2,000	1.50%	1 Apr 2016 – 31 Dec 2016
1,500	2.32%	1 Jan 2017 – 31 Dec 2017
1,000	3.06%	1 Jan 2018 – 31 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 2014		30 Jun 2013		31 Dec 2013	
	Average	Period end	Average	Period end	Average	Period end
1 USD equals NOK	6.0399	6.1528	5.7271	6.0279	5.8753	6.0837
1 USD equals Euro	0.7297	0.7322	0.7613	0.7645	0.7529	0.7251
1 USD equals Rouble	35.0390	33.9566	31.0355	32.7561	31.8675	32.8653
1 USD equals SEK	6.5338	6.7186	6.4940	6.7105	6.5132	6.4238

CONSOLIDATED INCOME STATEMENT IN SUMMARY

Expressed in MUSD	Note	**1 Jan 2014- 30 Jun 2014 6 months**	**1 Apr 2014- 30 Jun 2014 3 months**	1 Jan 2013- 30 Jun 2013 6 months	1 Apr 2013- 30 Jun 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Revenue	1	**460.8**	**225.4**	594.1	283.8	1,132.0
Cost of sales						
Production costs	2	-80.3	-41.9	-64.3	-35.3	-139.6
Depletion and decommissioning costs		-68.8	-33.7	-83.0	-41.4	-169.3
Exploration costs		-129.2	-2.3	-134.3	-62.3	-287.8
Impairment costs of oil and gas properties		–	–	-81.7	-81.7	-123.4
Gross profit	3	**182.5**	**147.5**	230.8	63.1	411.9
General, administration and depreciation expenses		-33.7	-13.3	-14.3	-6.5	-41.2
Operating profit		**148.8**	**134.2**	216.5	56.6	370.7
Result from financial investments						
Finance income	4	1.0	-26.4	1.8	0.9	3.4
Finance costs	5	-38.5	-26.3	-36.3	-26.1	-85.9
		-37.5	**-52.7**	-34.5	-25.2	-82.5
Share of the result of joint ventures accounted for using the equity method		-12.9	-12.8	-0.2	-0.3	-0.2
Profit before tax		**98.4**	**68.7**	181.8	31.1	288.0
Income tax expense	6	-97.6	-71.1	-133.6	-29.9	-215.1
Net result		**0.8**	**-2.4**	48.2	1.2	72.9
Attributable to:						
Owners of the Parent Company		3.2	-1.2	50.9	2.7	77.6
Non-controlling interest		-2.4	-1.2	-2.7	-1.5	-4.7
		0.8	**-2.4**	48.2	1.2	72.9
Earnings per share – USD[1]		0.01	0.00	0.16	0.01	0.25

The comparatives in the financial statements have been restated following the adoption of IFRS 11 Joint Arrangements, effective 1 January 2014.

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

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME IN SUMMARY

Expressed in MUSD	**1 Jan 2014- 30 Jun 2014 6 months**	**1 Apr 2014- 30 Jun 2014 3 months**	1 Jan 2013- 30 Jun 2013 6 months	1 Apr 2013- 30 Jun 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Net result	0.8	-2.4	48.2	1.2	72.9
Other comprehensive income					
Items that may be subsequently reclassified to profit or loss:					
Exchange differences foreign operations	-16.3	-7.7	-57.4	-13.1	-31.7
Cash flow hedges	-10.1	-39.1	-17.0	-8.2	-8.1
Available-for-sale financial assets	-2.0	-0.9	-2.3	0.7	1.9
Income tax relating to other comprehensive income	–	–	4.3	2.0	1.9
Other comprehensive income, net of tax	-28.4	-47.7	-72.4	-18.6	-36.0
Total comprehensive income	**-27.6**	**-50.1**	-24.2	-17.4	36.9
Attributable to:					
Owners of the Parent Company	-23.5	-50.6	-18.2	-13.7	44.7
Non-controlling interest	-4.1	0.5	-6.0	-3.7	-7.8
	-27.6	-50.1	-24.2	-17.4	36.9

CONSOLIDATED BALANCE SHEET IN SUMMARY

Expressed in MUSD	Note	**30 June 2014**	31 December 2013
ASSETS			
Non-current assets			
Oil and gas properties	7	4,552.0	3,820.8
Other tangible fixed assets		162.5	85.0
Investments accounted for using the equity method		11.7	24.6
Financial assets	8	179.6	69.0
Total non-current assets		**4,905.8**	3,999.4
Current assets			
Receivables and inventories	9	259.8	279.6
Cash and cash equivalents		73.1	82.4
Total current assets		**332.9**	362.0
TOTAL ASSETS		**5,238.7**	4,361.4
EQUITY AND LIABILITIES			
Equity			
Shareholders´ equity		1,173.7	1,207.0
Non-controlling interest		55.7	59.8
Total equity		**1,229.4**	1,266.8
Liabilities			
Non-current liabilities			
Provisions	10	1,562.3	1,345.1
Financial liabilities	11	1,800.1	1,239.1
Other non-current liabilities		26.2	25.0
Total non-current liabilities		**3,388.6**	2,609.2
Current liabilities			
Current liabilities	12	551.5	439.2
Provisions	10	69.2	46.2
Total current liabilities		**620.7**	485.4
Total liabilities		**4,009.3**	3,094.6
TOTAL EQUITY AND LIABILITIES		**5,238.7**	4,361.4

CONSOLIDATED STATEMENT OF CASH FLOWS IN SUMMARY

Expressed in MUSD	Note	**1 Jan 2014- 30 Jun 2014 6 months**	**1 Apr 2014- 30 Jun 2014 3 months**	1 Jan 2013- 30 Jun 2013 6 months	1 Apr 2013- 30 Jun 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Cash flows from operating activities						
Net result		0.8	-2.4	48.2	1.2	72.9
Adjustments for non-cash related items	14	354.3	176.1	464.7	237.0	880.1
Interest received		0.3	0.1	0.6	0.4	0.9
Interest paid		-22.8	-12.6	-8.0	-4.4	-21.8
Income taxes paid		-8.6	-1.6	-165.6	-105.6	-188.2
Changes in working capital		92.3	16.6	78.3	35.4	162.7
Total cash flows from operating activities		**416.3**	**176.2**	418.2	164.0	906.6
Cash flows from investing activities						
Investment in oil and gas properties		-903.5	-449.2	-658.7	-331.2	-1,698.4
Investment in other fixed assets		-80.4	-31.3	-9.2	-6.4	-36.2
Disposal of bonds		10.5	–	–	–	–
Investment in subsidiaries		–	–	–	–	-3.5
Decommissioning costs paid		-0.4	-0.3	-0.9	-0.8	-1.5
Other payments		-0.1	-0.1	-0.2	–	-0.4
Total cash flows from investing activities		**-973.9**	**-480.9**	-669.0	-338.4	-1,740.0
Cash flows from financing activities						
Changes in long-term receivables		-0.1	-0.1	3.7	-0.2	3.5
Changes in long-term liabilities		576.2	280.4	254.1	150.4	845.1
Financing fees paid		-20.7	-0.1	–	–	–
Purchase of own shares		-9.8	–	-18.4	-18.4	-20.1
Distributions		-0.1	-0.1	-0.1	-0.1	-0.1
Total cash flows from financing activities		**545.5**	**280.1**	239.3	131.7	828.4
Change in cash and cash equivalents		-12.1	-24.6	-11.5	-42.7	-5.0
Cash and cash equivalents at the beginning of the period		82.4	94.9	87.6	119.6	87.6
Currency exchange difference in cash and cash equivalents		2.8	2.8	4.5	3.7	-0.2
Cash and cash equivalents at the end of the period		**73.1**	**73.1**	80.6	80.6	82.4

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY IN SUMMARY

Expressed in MUSD	Attributable to owners of the Parent company Share capital	Additional paid-in-capital/Other reserves	Retained earnings	Total	Non-controlling interest	Total equity
At 1 January 2013	**0.5**	**411.1**	**770.8**	**1,182.4**	**67.7**	**1,250.1**
Comprehensive income						
Net result	–	–	50.9	50.9	-2.7	48.2
Other comprehensive income	–	-69.1	–	-69.1	-3.3	-72.4
Total comprehensive income	**–**	**-69.1**	**50.9**	**-18.2**	**-6.0**	**-24.2**
Transactions with owners						
Distributions	–	–	–	–	-0.1	-0.1
Purchase of own shares	–	-18.4	–	-18.4	–	-18.4
Total transactions with owners	**–**	**-18.4**	**–**	**-18.4**	**-0.1**	**-18.5**
At 30 June 2013	**0.5**	**323.6**	**821.7**	**1,145.8**	**61.6**	**1,207.4**
Comprehensive income						
Net result	–	–	26.7	26.7	-5.1	21.6
Other comprehensive income	–	36.2	–	36.2	3.3	39.5
Total comprehensive income	**–**	**36.2**	**26.7**	**62.9**	**-1.8**	**61.1**
Transactions with owners						
Distributions	–	–	–	–	–	–
Purchase of own shares	–	-1.7	–	-1.7	–	-1.7
Total transactions with owners	**–**	**-1.7**	**–**	**-1.7**	–	**-1.7**
At 31 December 2013	**0.5**	**358.1**	**848.4**	**1,207.0**	**59.8**	**1,266.8**
Comprehensive income						
Net result	–	–	3.2	3.2	-2.4	0.8
Other comprehensive income	–	-26.7	–	-26.7	-1.7	-28.4
Total comprehensive income	**–**	**-26.7**	**3.2**	**-23.5**	**-4.1**	**-27.6**
Transactions with owners[1]						
Distributions	–	–	–	–	0.0	0.0
Purchase of own shares	–	-9.8	–	-9.8	–	-9.8
Total transaction with owners	**–**	**-9.8**	**–**	**-9.8**	0.0	**-9.8**
At 30 June 2014	**0.5**	**321.6**	**851.6**	**1,173.7**	**55.7**	**1,229.4**

[1] During the reporting period the Parent Company reduced its share capital with an amount of SEK 68,402.50 through the cancellation of 6,840,250 shares held in treasury. The reduction of the share capital was followed by a bonus issue of the same amount. The amounts were recognised against other reserves. In consequence the cancellation of shares did not impact the Company's share capital.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Revenue, MUSD	**1 Jan 2014- 30 Jun 2014 6 months**	**1 Apr 2014- 30 Jun 2014 3 months**	1 Jan 2013- 30 Jun 2013 6 months	1 Apr 2013- 30 Jun 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Crude oil	413.3	214.7	482.3	215.2	997.0
Condensate	1.8	0.7	1.4	0.3	3.4
Gas	68.2	31.9	85.8	39.8	160.0
Net sales of oil and gas	**483.3**	**247.3**	569.5	255.3	1,160.4
Change in under/over lift position	-30.5	-25.9	16.0	24.6	-45.2
Other revenue	8.0	4.0	8.6	3.9	16.8
Revenue	**460.8**	**225.4**	594.1	283.8	1,132.0

Note 2. Production costs, MUSD	**1 Jan 2014- 30 Jun 2014 6 months**	**1 Apr 2014- 30 Jun 2014 3 months**	1 Jan 2013- 30 Jun 2013 6 months	1 Apr 2013- 30 Jun 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Cost of operations	52.5	21.9	52.4	28.7	103.0
Tariff and transportation expenses	9.8	5.0	11.1	5.7	21.6
Direct production taxes	1.9	1.0	1.7	0.8	3.4
Change in inventory position	-1.6	-1.4	-2.3	-1.3	-2.0
Other	17.7	15.4	1.4	1.4	13.6
	80.3	**41.9**	64.3	35.3	139.6

Note 3. Segment information, MUSD	**1 Jan 2014- 30 Jun 2014 6 months**	**1 Apr 2014- 30 Jun 2014 3 months**	1 Jan 2013- 30 Jun 2013 6 months	1 Apr 2013- 30 Jun 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Norway					
Crude oil	364.4	190.4	436.7	192.8	886.6
Condensate	1.1	0.3	0.8	–	2.0
Gas	36.9	17.6	54.5	25.2	98.5
Net sales of oil and gas	**402.4**	**208.3**	492.0	218.0	987.1
Change in under/over lift position	-30.4	-25.8	14.2	23.5	-47.0
Other revenue	2.3	1.1	2.9	1.3	5.6
Revenue	**374.3**	**183.6**	509.1	242.8	945.7
Production costs	-55.8	-30.0	-38.4	-21.1	-85.1
Depletion and decommissioning costs	-46.4	-22.6	-63.2	-31.6	-130.2
Exploration costs	-74.6	-1.8	-133.4	-62.0	-285.4
Impairment costs of oil and gas properties	–	–	-81.7	-81.7	-81.7
Gross profit	**197.5**	**129.2**	192.4	46.4	363.3
France					
Crude oil	48.8	24.3	45.5	22.4	110.2
Net sales of oil and gas	**48.8**	**24.3**	45.5	22.4	110.2
Change in under/over lift position	0.3	0.3	-0.2	0.1	-0.4
Other revenue	0.9	0.5	1.1	0.6	2.2
Revenue	**50.0**	**25.1**	46.4	23.1	112.0
Production costs	-14.8	-6.8	-17.2	-9.6	-34.3
Depletion and decommissioning costs	-8.6	-4.3	-6.0	-3.0	-12.5
Exploration costs	–	–	-0.1	-0.1	-0.2
Gross profit	**26.6**	**14.0**	23.1	10.4	65.0

Note 3. Segment information cont., MUSD	**1 Jan 2014- 30 Jun 2014 6 months**	**1 Apr 2014- 30 Jun 2014 3 months**	1 Jan 2013- 30 Jun 2013 6 months	1 Apr 2013- 30 Jun 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Netherlands					
Crude oil	0.1	–	0.1	–	0.2
Condensate	0.7	0.4	0.6	0.3	1.4
Gas	19.5	8.3	22.8	10.3	44.6
Net sales of oil and gas	**20.3**	**8.7**	23.5	10.6	46.2
Change in under/over lift position	-0.4	-0.4	2.0	1.0	2.2
Other revenue	1.0	0.5	0.9	0.4	1.7
Revenue	**20.9**	**8.8**	26.4	12.0	50.1
Production costs	-7.6	-4.0	-6.4	-3.4	-14.7
Depletion and decommissioning costs	-8.3	-4.0	-8.0	-3.8	-15.0
Exploration costs	-0.5	–	–	–	-1.3
Gross profit	**4.5**	**0.8**	12.0	4.8	19.1
Indonesia					
Gas	11.8	6.0	8.5	4.3	16.9
Net sales of oil and gas	**11.8**	**6.0**	8.5	4.3	16.9
Other revenue	–	–	–	–	–
Revenue	**11.8**	**6.0**	8.5	4.3	16.9
Production costs	-2.1	-1.1	-2.3	-1.2	-5.0
Depletion and decommissioning costs	-5.5	-2.8	-5.8	-2.9	-11.4
Exploration costs	-54.0	-0.4	-0.2	-0.1	-0.4
Gross profit	**-49.8**	**1.7**	0.2	0.1	0.1
Other					
Crude oil	–	–	–	–	–
Net sales of oil and gas	–	–	–	–	–
Other revenue	3.8	1.9	3.7	1.5	7.3
Revenue	**3.8**	**1.9**	3.7	1.5	7.3
Production costs	–	–	–	–	-0.5
Depletion and decommissioning costs	–	–	–	–	-0.2
Exploration costs	-0.1	-0.1	-0.6	-0.1	-0.5
Impairment costs of oil and gas properties[1]	–	–	–	–	-41.7
Gross profit	**3.7**	**1.8**	3.1	1.4	-35.6
Total					
Crude oil	413.3	214.7	482.3	215.2	997.0
Condensate	1.8	0.7	1.4	0.3	3.4
Gas	68.2	31.9	85.8	39.8	160.0
Net sales of oil and gas	**483.3**	**247.3**	569.5	255.3	1,160.4
Change in under/over lift position	-30.5	-25.9	16.0	24.6	-45.2
Other revenue	8.0	4.0	8.6	3.9	16.8
Revenue	**460.8**	**225.4**	594.1	283.8	1,132.0
Production costs	-80.3	-41.9	-64.3	-35.3	-139.6
Depletion and decommissioning costs	-68.8	-33.7	-83.0	-41.4	-169.3
Exploration costs	-129.2	-2.3	-134.3	-62.3	-287.8
Impairment costs of oil and gas properties	–	–	-81.7	-81.7	-123.4
Gross profit	**182.5**	**147.5**	230.8	63.1	411.9

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

[1] Impairment costs of oil and gas properties in 2013 related to Malaysia.

Note 4. Finance income, MUSD	**1 Jan 2014- 30 Jun 2014 6 months**	**1 Apr 2014- 30 Jun 2014 3 months**	1 Jan 2013- 30 Jun 2013 6 months	1 Apr 2013- 30 Jun 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Interest income	0.6	0.2	1.2	0.7	2.4
Foreign currency exchange gain, net	–	-26.9	–	–	–
Guarantee fees	0.3	0.2	0.2	0.1	0.5
Other	0.1	0.1	0.4	0.1	0.5
	1.0	**-26.4**	1.8	0.9	3.4

Note 5. Finance costs, MUSD	**1 Jan 2014- 30 Jun 2014 6 months**	**1 Apr 2014- 30 Jun 2014 3 months**	1 Jan 2013- 30 Jun 2013 6 months	1 Apr 2013- 30 Jun 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Interest expense	6.8	4.9	2.6	1.4	5.1
Foreign currency exchange loss, net	8.8	8.8	15.8	15.5	46.5
Result on interest rate hedge settlement	1.0	0.5	0.5	0.5	1.5
Unwinding of site restoration discount	3.6	1.8	3.0	1.5	5.9
Amortisation of deferred financing fees	6.1	3.3	4.4	2.2	8.7
Loan facility commitment fees	11.4	6.5	9.6	4.7	17.1
Other	0.8	0.5	0.4	0.3	1.1
	38.5	**26.3**	36.3	26.1	85.9

Note 6. Income tax expense, MUSD	**1 Jan 2014- 30 Jun 2014 6 months**	**1 Apr 2014- 30 Jun 2014 3 months**	1 Jan 2013- 30 Jun 2013 6 months	1 Apr 2013- 30 Jun 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Current tax	-116.5	-57.6	31.2	7.7	24.7
Deferred tax	214.1	128.7	102.4	22.2	190.4
	97.6	**71.1**	133.6	29.9	215.1

Note 7. Oil and gas properties, MUSD	**30 Jun 2014**	31 Dec 2013
Norway	3,336.6	2,685.6
France	221.7	224.4
Netherlands	53.7	60.1
Indonesia	69.7	101.7
Russia	556.7	559.1
Malaysia	313.6	189.9
	4,552.0	3,820.8

Note 8. Financial assets, MUSD	**30 Jun 2014**	31 Dec 2013
Other shares and participations	19.8	22.0
Long-term receivable	9.8	9.7
Deferred tax	22.2	22.4
Corporate tax	125.2	–
Bonds	–	10.4
Derivative instruments	1.1	3.0
Other	1.5	1.5
	179.6	69.0

Note 9. Receivables and inventories, MUSD	**30 Jun 2014**	31 Dec 2013
Inventories	24.1	21.2
Trade receivables	127.9	125.8
Underlift	4.3	9.4
Corporate tax	1.8	6.5
Joint venture debtors	25.3	25.2
Derivative instruments	5.4	3.2
Prepaid expenses and accrued income	59.5	61.7
Other	11.5	26.6
	259.8	279.6

Note 10. Provisions, MUSD	**30 Jun 2014**	31 Dec 2013
Non-current:		
Site restoration	263.9	241.6
Deferred tax	1,264.9	1,066.0
Long-term incentive plan	1.3	30.8
Derivative instruments	12.6	1.6
Pension	1.5	1.5
Farm-in payment	7.5	–
Other	10.6	3.6
	1,562.3	1,345.1
Current:		
Farm-in payment	48.5	–
Long-term incentive plan	3.7	46.2
Other	17.0	–
	69.2	46.2
	1,631.5	1,391.3

Note 11. Financial liabilities, MUSD	**30 Jun 2014**	31 Dec 2013
Bank loans	1,850.0	1,275.0
Capitalised financing fees	-49.9	-35.9
	1,800.1	1,239.1

Note 12. Current liabilities, MUSD	**30 Jun 2014**	31 Dec 2013
Trade payables	10.4	16.3
Overlift	53.8	29.2
Tax liabilities	2.1	4.3
Joint venture creditors and accrued expenses	358.8	334.5
Other accrued expenses	77.5	39.4
Long-term incentive plan	38.1	-
Derivative instruments	3.3	4.0
Other	7.5	11.5
	551.5	439.2

Note 13. 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 2014 MUSD	Level 1	Level 2	Level 3
Assets			
Available for sale financial assets			
- Other shares and participations	19.4	–	0.4
- Derivative instruments – non-current	–	1.1	–
- Derivative instruments - current	–	5.4	–
	19.4	6.5	0.4
Liabilities			
- Derivative instruments – non-current	–	12.6	–
- Derivative instruments – current	–	3.3	–
	–	15.9	–

31 December 2013 MUSD	Level 1	Level 2	Level 3
Assets			
Available for sale financial assets			
- Other shares and participations	21.6	–	0.4
- Bonds	10.4	–	–
- Derivative instruments – non-current	–	3.0	–
- Derivative instruments - current	–	3.2	–
	32.0	6.2	0.4
Liabilities			
- Derivative instruments – non-current	–	1.6	–
- Derivative instruments – current	–	4.0	–
	–	5.6	–

There were no transfers between the levels during the reporting period. Other shares and participations and bonds are specified in Note 8 Financial assets.

Derivative instruments are valued using marked-to-market valuations provided by the counterparties to the hedge at the balance sheet date. The hedge counterparties are all banks which are party to the loan facility agreement.

Fair value of the following financial assets and liabilities is estimated to equal the carrying value.

- Trade receivables
- Joint venture debtors
- Cash and cash equivalents
- Trade payables
- Joint venture creditors
- Bank loans
- Other non-current liabilities

The USD 2.5 billion financing facility, entered into on 25 June 2012 is a revolving borrowing base facility secured against certain cash flows generated by the Group. On 6 February 2014, Lundin Petroleum increased the facility to USD 4.0 billion on similar terms. 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 maturity date of the new bank facility is June 2019 and there is a loan reduction schedule which commences in 2016 and reduces to zero by the final maturity date. In addition, the amount available to borrow under the facility is based upon a net present value calculation of the assets' future cash flows. Based on the reduction schedule and the current availability calculation, part of the current outstanding bank loan balance falls due within five years, at the end of 2017.

Note 14. Adjustment for non-cash related items, MUSD	**1 Jan 2014-30 Jun 2014 6 months**	**1 Apr 2014-30 Jun 2014 3 months**	1 Jan 2013-30 Jun 2013 6 months	1 Apr 2013-30 Jun 2013 3 months	1 Jan 2013-31 Dec 2013 12 months
Exploration costs	129.2	2.3	134.3	62.3	287.8
Depletion, depreciation and amortisation	71.3	35.0	85.0	42.4	160.4
Current tax	-116.5	-57.6	31.2	7.7	24.7
Deferred tax	214.1	128.7	102.4	22.2	190.4
Impairment of oil and gas properties	–	–	81.7	81.7	123.4
Long-term incentive plan	10.9	2.9	0.4	-1.5	9.9
Other[1]	45.3	64.8	29.7	22.2	83.5
	354.3	**176.1**	464.7	237.0	880.1

[1] Other adjustments include foreign exchange losses of MUSD 16.4 (MUSD 20.9) for the reporting period.

PARENT COMPANY INCOME STATEMENT IN SUMMARY

Expressed in MSEK	**1 Jan 2014- 30 Jun 2014 6 months**	**1 Apr 2014- 30 Jun 2014 3 months**	1 Jan 2013- 30 Jun 2013 6 months	1 Apr 2013- 30 Jun 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Revenue	6.6	5.5	-0.1	–	3.1
General and administration expenses	-84.5	-42.8	-30.9	-18.7	-105.7
Operating profit	**-77.9**	**-37.3**	-31.0	-18.7	-102.6
Result from financial investments					
Finance income	1.8	1.0	1.7	0.8	181.4
Finance costs	-1.8	-1.3	-0.1	–	-2.7
	0.0	**-0.3**	1.6	0.8	178.7
Profit before tax	**-77.9**	**-37.6**	-29.4	-17.9	76.1
Income tax expense	–	–	–	–	–
Net result	**-77.9**	**-37.6**	-29.4	-17.9	76.1

PARENT COMPANY COMPREHENSIVE INCOME STATEMENT IN SUMMARY

Expressed in MSEK	**1 Jan 2014- 30 Jun 2014 6 months**	**1 Apr 2014- 30 Jun 2014 3 months**	1 Jan 2013- 30 Jun 2013 6 months	1 Apr 2013- 30 Jun 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Net result	**-77.9**	**-37.6**	-29.4	-17.9	76.1
Other comprehensive income	–	–	–	–	–
Total comprehensive income	**-77.9**	**-37.6**	-29.4	-17.9	76.1
Total comprehensive income attributable to:					
Shareholders of the Parent Company	-77.9	-37.6	-29.4	-17.9	76.1
	-77.9	**-37.6**	-29.4	-17.9	76.1

PARENT COMPANY BALANCE SHEET IN SUMMARY

Expressed in MSEK	**30 Jun 2014**	31 December 2013
ASSETS		
Non-current assets		
Shares in subsidiaries	7,871.8	7,871.8
Other tangible fixed assets	0.2	0.2
Total non-current assets	**7,872.0**	7,872.0
Current assets		
Receivables	24.4	17.3
Cash and cash equivalents	4.6	2.6
Total current assets	**29.0**	19.9
TOTAL ASSETS	**7,901.0**	7,891.9
SHAREHOLDERS´EQUITY AND LIABILITIES		
Shareholders´ equity including net result for the period	7,673.9	7,814.0
Non-current liabilities		
Provisions	36.6	36.6
Payables to group companies	175.6	21.6
Total non-current liabilities	**212.2**	58.2
Current liabilities		
Current liabilities	14.9	19.7
Total current liabilities	**14.9**	19.7
Total liabilities	**227.1**	77,9
TOTAL EQUITY AND LIABILITIES	**7,901.0**	7,891.9
Pledged assets	12,618.9	12,014.5

PARENT COMPANY CASH FLOW STATEMENT IN SUMMARY

Expressed in MSEK	**1 Jan 2014-30 Jun 2014 6 months**	**1 Apr 2014-30 Jun 2014 3 months**	1 Jan 2013-30 Jun 2013 6 months	1 Apr 2013-30 Jun 2013 3 months	1 Jan 2013-31 Dec 2013 12 months
Cash flow from operations					
Net result	-77.9	-37.6	-29.4	-17.9	76.1
Adjustment for non-cash related items	0.1	0.1	–	0.3	-18.9
Changes in working capital	-12.0	-5.8	10.2	4.5	14.2
Total cash flow from operations	**-89.8**	**-43.3**	-19.2	-13.1	71.4
Cash flow from investments					
Change in other fixed assets	–	–	–	-5.7	-0.2
Total Cash flow from investments	–	–	–	-5.7	-0.2
Cash flow from financing					
Change in long-term liabilities	153.9	45.9	143.1	143.1	62.2
Purchase of own shares	-62.2	–	-120.5	-120.5	-131.9
Total cash flow from financing	**91.7**	**45.9**	22.6	22.6	-69.7
Change in cash and cash equivalents	1.9	2.6	3.4	3.8	1.5
Cash and cash equivalents at the beginning of the period	**2.6**	**1.9**	1.1	0.7	1.1
Currency exchange difference in cash and cash equivalents	0.1	0.1	-0.1	-0.1	–
Cash and cash equivalents at the end of the period	**4.6**	**4.6**	4.4	4.4	2.6

PARENT COMPANY STATEMENT OF CHANGES IN EQUITY IN SUMMARY

	Restricted equity		Unrestricted equity			
Expressed in MSEK	Share capital	Statutory reserve	Other reserves	Retained earnings	Total	Total equity
Balance at 1 January 2013	**3.2**	**861.3**	**2,489.4**	**4,515.9**	**7,005.3**	**7,869.8**
Total comprehensive income	**–**	**–**	**–**	**-29.4**	**-29.4**	**-29.4**
Transactions with owners						
Purchase of own shares	–	–	-120.5	–	-120.5	-120.5
Total transactions with owners	**–**	**–**	**-120.5**	**–**	**-120.5**	**-120.5**
Balance at 30 June 2013	**3.2**	**861.3**	**2,368.9**	**4,486.5**	**6,855.4**	**7,719.9**
Total comprehensive income	**–**	**–**	**–**	**105.5**	**105.5**	**105.5**
Transactions with owners						
Purchase of own shares	–	–	-11.4	–	-11.4	-11.4
Total transactions with owners	**–**	**–**	**-11.4**	**–**	**-11.4**	**-11.4**
Balance at 31 December 2013	**3.2**	**861.3**	**2,357.5**	**4,592.0**	**6,949.5**	**7,814.0**
Total comprehensive income	**–**	**–**	**–**	**-77.9**	**-77.9**	**-77.9**
Transactions with owners[1]						
Purchase of own shares	–	–	-62.2	–	-62.2	-62.2
Total transactions with owners	**–**	**–**	**-62.2**	**–**	**-62.2**	**-62.2**
Balance at 30 June 2014	**3.2**	**861.3**	**2,295.3**	**4,514.1**	**6,809.4**	**7,673.9**

[1] During the reporting period the Company reduced its share capital with an amount of SEK 68,402.50 through the cancellation of 6,840,250 shares held in treasury. The reduction of the share capital was followed by a bonus issue of the same amount. The amounts were recognised against other reserves. In consequence the cancellation of shares did not impact the Company's share capital.

KEY FINANCIAL DATA

Financial data (MUSD)	**1 Jan 2014- 30 Jun 2014 6 months**	**1 Apr 2014- 30 Jun 2014 3 months**	1 Jan 2013- 30 Jun 2013 6 months	1 Apr 2013- 30 Jun 2013 3 months	1 Jan 2013- 31 Dec 2013 12 months
Revenue[1]	460.8	225.4	594.1	283.8	1,132.0
EBITDA	349.3	171.5	517.6	243.1	955.7
Net result	0.8	-2.4	48.2	1.2	72.9
Operating cash flow	497.0	241.0	498.6	240.8	967.9
Data per share (USD)					
Shareholders' equity per share	3.80	3.80	3.70	3.70	3.90
Operating cash flow per share	1.60	0.78	1.61	0.78	3.12
Cash flow from operations per share	1.34	0.57	1.35	0.53	2.92
Earnings per share	0.01	-0.00	0.16	0.01	0.25
Earnings per share fully diluted	0.01	-0.00	0.16	0.01	0.25
EBITDA per share	1.13	0.55	1.67	0.78	3.08
Dividend per share	–	–	–	–	–
Number of shares issued at period end	311,070,330	311,070,330	317,910,580	317,910,580	317,910,580
Number of shares in circulation at period end	309,070,330	309,070,330	309,655,610	309,655,610	309,570,330
Weighted average number of shares for the period	310,045,004	310,682,627	310,059,705	309,901,766	310,017,074
Share price					
Quoted price at period end (SEK)	135.20	135.20	133.00	133.00	125.40
Quoted price at period end (CAD)	21.32	21.32	20.54	20.54	19.73
Key ratios					
Return on equity (%)	0	0	4	0	6
Return on capital employed (%)	4	4	11	3	16
Net debt/equity ratio (%)	151	151	53	52	99
Equity ratio (%)	23	23	35	35	29
Share of risk capital (%)	47	47	63	63	53
Interest coverage ratio	15	20	66	26	52
Operating cash flow/interest ratio	63	45	164	135	149
Yield	–	–	–	–	–

[1] The comparatives have been restated for the effect of the adoption of IFRS 11 Joint Arrangements.

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: Revenue less production costs and less current taxes 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.

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.

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

Return on capital employed: Income before tax plus interest expenses plus/less 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 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 charge 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 2014 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, 6 August 2014

Ian H. Lundin Chairman	C. Ashley Heppenstall President and CEO	Peggy Bruzelius
Asbjørn Larsen	Lukas H. Lundin	William A. Rand
Magnus Unger	Cecilia Vieweg	

Review report

We have reviewed this report for the period 1 January 2014 to 30 June 2014 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, 6 August 2014

PricewaterhouseCoopers AB

Klas Brand Authorised Public Accountant Lead Auditor	Johan Malmqvist Authorised Public Accountant

Financial information

The Company will publish the following reports:

- The nine month report (January – September 2014) will be published on 5 November 2014.
- The year end report (January – December 2014) will be published on 4 February 2015.
- The three month report (January – March 2015) will be published on 6 May 2015.

The AGM will be held on 7 May 2015 in Stockholm, Sweden.

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This information has been made public in accordance with the Securities Market Act (SFS 2007:528) and/or the Financial Instruments Trading Act (SFS 1991:980).

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

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

Reserves and Resources
Unless otherwise stated, Lundin Petroleum’s reserve and resource estimates are as at 31 December 2013, and have been prepared and audited in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook"). Unless otherwise stated, all reserves estimates contained herein are the aggregate of “Proved Reserves” and “Probable Reserves”, together also known as “2P Reserves”. For further information on reserve and resource classifications, see “Reserves, Resources and Production” in the Company’s annual report.

Contingent Resources
Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. There is no certainty that it will be commercially viable for

the Company to produce any portion of the Contingent Resources. Unless otherwise stated, all contingent resource estimates contained herein are the best estimate ("2C") contingent resources.

Prospective Resources

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both a chance of discovery and a chance of development. There is no certainty that any portion of the Prospective Resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the Prospective Resources. Unless otherwise stated, all Prospective Resource estimates contained herein are reflecting a P50 Prospective Resource estimate. Risked Prospective Resources reported herein are partially risked. They have been risked for chance of discovery, but have not been risked for chance of development.

BOEs

BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.