Lundin Petroleum

Report for the THREE MONTHS ended 31 March 2014

Q1

Lundin Petroleum AB (publ)

company registration number 556610-8055

Highlights

Three months ended 31 March 2014 (31 March 2013)

- Production of 28.8 Mboepd (35.6 Mboepd) [1]
- Revenue of MUSD 235.4 (MUSD 310.3)
- EBITDA of MUSD 177.8 (MUSD 274.5)
- Operating cash flow of MUSD 256.0 (MUSD 257.8)
- Net result of MUSD 3.2 (MUSD 47.0)
- Net debt of MUSD 1,475 (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

	1 Jan 2014– 31 Mar 2014 3 months	1 Jan 2013– 31 Mar 2013 3 months	1 Jan 2013– 31 Dec 2013 12 months
Production in Mboepd [1]	**28.8**	35.6	32.7
Revenue in MUSD	**235.4**	310.3	1,132.0
Net result in MUSD	**3.2**	47.0	72.9
Net result attributable to shareholders of the Parent Company in MUSD	**4.4**	48.2	77.6
Earnings/share in USD [2]	**0.01**	0.16	0.25
EBITDA in MUSD	**177.8**	274.5	955.7
Operating cash flow in MUSD	**256.0**	257.8	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.

Definitions

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

Abbreviations

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

Oil related terms and measurements

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

Letter to Shareholders

Dear fellow Shareholders,

I am pleased to announce that Lundin Petroleum continues to make excellent progress with our stated objectives of increasing our resources and production. If we are successful then the end result will be further increases to shareholder value which is the ultimate objective for all the management team of Lundin Petroleum.

I strongly believe that the foundations which we have built over recent years in our core areas of operation of Norway, South East Asia and Continental Europe will allow us to successfully build our business. These foundations are predominantly driven from a team of experienced and motivated people, excellent relationships with local governments and other stakeholders and a corporate philosophy to invest and take calculated risk.

It is very exciting to be at the centre of this Company and I am convinced that over the next few years we will deliver increased resources and production which will drive profitability and cash flow generation and ultimately increased shareholder value.

1. Production to more than double to 75,000 boepd excluding Johan Sverdrup

Our production for the first quarter of 2014 was 28,800 boepd which was within our previously guided range for the period. The existing production will naturally decline going forward but production will increase at the end of the second quarter of 2014 when we expect first oil from the Brynhild project, offshore Norway. As a result we maintain our 2014 production guidance of 30,000 to 35,000 boepd.

We forecast average production of approximately 50,000 boepd in 2015 with new production from our Bøyla, Bertam and Edvard Grieg developments during the year. Our production will exceed 75,000 boepd at the end of 2015 when all these projects are onstream.

2. Excellent progress with our ongoing development projects

Brynhild, offshore Norway is now close to first oil which is expected in June 2014. The new risers have been successfully installed and the upgrade and maintenance work on the Haewene Brim FPSO is substantially complete. The development drilling is ongoing with the first production well ready to be brought into production. Gross initial production rates are forecast at 12,000 boepd and I believe it will be achieved and potentially exceeded based upon the results of the well.

We are making good progress with our Bertam development, offshore Malaysia. The construction of the offshore platform contracted to TH Heavy Engineering is on schedule and I expect it will be completed before the end of the year. The Bertam project will use our 100 percent owned Ikdam FPSO which will be renamed the Bertam FPSO. The Bertam FPSO is currently undergoing modification and upgrade works at the Keppel shipyard in Singapore which will also be completed by the end of this year. Development drilling on Bertam will commence this summer and we still expect first oil from Bertam in the second quarter of 2015.

I was very pleased last month to visit the Kvaerner Verdal shipyard on the west coast of Norway to celebrate the completion of the Edvard Grieg jacket. Congratulations to the Kvaerner Verdal team on a job well done — safely, within budget and on schedule. The jacket has now been installed in the North Sea. Kvaerner are also making good progress with the Edvard Grieg topsides. The gas and oil pipelines will be installed in 2014 and 2015 respectively. The Rowan Viking jack up rig will commence the development drilling programme later this summer. It is very exciting for everyone at Lundin Petroleum to see this major project come together and we still forecast first oil in late 2015 with a gross plateau production rate of 100,000 boepd.

3. Appraisal of Johan Sverdrup complete

The appraisal drilling on the Johan Sverdrup field is now complete. Good progress is being made by Aker Solutions on the front end engineering contract for Phase 1 of the development with the plan of development submission still forecast for early 2015.

This field is the largest discovery made in the North Sea for many years and will have a transformational impact on Lundin Petroleum's reserves, production and valuation. Statoil the pre-development working operator for Johan Sverdrup announced in late 2013 recoverable resources for the field of between 1.8 billion and 2.9 billion barrels of oil equivalent. There is a unitisation processing ongoing as the field extends over various licences which will be resolved prior to submission of the development plan. Nevertheless the impact of Johan Sverdrup on our reserves and production will be huge with this field alone representing increases of over three to four times as compared to our current reserves and production.

4. Johan Sverdrup Phase 1 development concept agreed
A major milestone for Lundin Petroleum and the Johan Sverdrup partners was passed in February with the agreement on the development concept for Phase 1. The first phase will contain the field centre of four fixed platform installations as well as additional subsea installations. Phase 1 production will come onstream in late 2019 with a forecast production of between 315,000 and 380,000 boepd and after the full development of the field will increase to between 550,000 and 650,000 boepd.

In addition we have the financing capacity to fund the development costs of Johan Sverdrup without having to access any new debt facility or equity. The cash flow generation from our existing production, ongoing development projects and existing bank facilities will be sufficient to fund the development costs of Johan Sverdrup and maintain a healthy exploration budget.

5. Progressing project commercialisation
Our forward projections assume that we do not commercialise any of our existing discoveries or that we do not have any more exploration success. However the reality is somewhat different and I have high hopes that our appraisal drilling programme in 2014 including wells on the Tembakau discovery, offshore Malaysia and the Luno II and Gohta discoveries, offshore Norway will result in commercial development projects.

6. Exploration remains a key focus
Lundin Petroleum is today one of the most active explorers in our key growth markets of Norway and Malaysia. Our exploration teams have a proven track record of finding hydrocarbons and have built significant exploration licence positions in these areas. We will continue to allocate capital to fund aggressive exploration programmes and I am confident these will lead to new discoveries.

We continue to focus on our core areas of the Utsira High and Barents Sea in Norway, offshore peninsular Malaysia and offshore Sabah in Malaysia. We have high impact exploration wells in all of these areas before the end of 2014.

7. Oil demand will remain strong for the foreseeable future
Lundin Petroleum's business model is not dependent upon the strength of oil prices. Meeting our production and reserve growth forecasts will be the main driver of value creation. Nevertheless, as I have consistently stated I do believe oil prices will remain firm. Economic growth, particularly in the developing world, coupled with supply declines from old fields and continued geopolitical uncertainty will outweigh efficiency gains, unconventional production increases and fuel substitution. The result is that demand will continue to be strong particularly for good quality oil from low political risk countries.

I believe that Lundin Petroleum is today well positioned to embark on our next phase of growth. We have been very successful over the last decade in building our resource and people skill base. This will mean that going forward we will be able to increase our reserves and production for the benefit of all our stakeholders. Certainly from my viewpoint and despite all the difficulties the world faces today the future looks bright for Lundin Petroleum.

And it goes without saying that doing all this in a socially responsible, safe and environmentally friendly way is something that everyone at Lundin Petroleum expects and works towards.

Yours Sincerely,

C. Ashley Heppenstall
President and CEO

Stockholm, 7 May 2014

Financial Report for the Three Months Ended 31 March 2014

Operational Review

Lundin Petroleum has exploration and production assets focused upon two core areas, Norway and South East Asia. Lundin Petroleum also has assets in France, the Netherlands and Russia. Norway continues to represent the majority of Lundin Petroleum's operational activities with production for the three month period ended 31 March 2014 (reporting period) accounting for 69 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 1,800 and 2,900 MMboe 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 28.8 thousand barrels of oil equivalent per day (Mboepd) (compared to 35.6 Mboepd over the same period in 2013) and was comprised as follows:

Production in Mboepd	**1 Jan 2014– 31 Mar 2014 3 months**	1 Jan 2013– 31 Mar 2013 3 months	1 Jan 2013– 31 Dec 2013 12 months
Crude oil			
Norway	17.0	22.6	20.6
France	3.0	2.7	2.9
Russia [1]	2.2	2.5	2.3
Total crude oil production	**22.2**	27.8	25.8
Gas			
Norway	3.0	4.0	3.3
Netherlands	2.1	2.2	2.0
Indonesia	1.5	1.6	1.6
Total gas production	**6.6**	7.8	6.9
Total production			
Quantity in Mboe	**2,588.3**	3,206.3	11,939.6
Quantity in Mboepd	**28.8**	35.6	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	Working Interest (WI)	**1 Jan 2014– 31 Mar 2014 3 months**	1 Jan 2013– 31 Mar 2013 3 months	1 Jan 2013– 31 Dec 2013 12 months
Alvheim	15%	9.8	11.5	10.5
Volund	35%	9.5	13.1	12.2
Gaupe	40%	0.7	2.0	1.2
		20.0	26.6	23.9

Production from the Alvheim field during the reporting period has been better than forecast due to continued good reservoir performance which was partially offset by the two short weather related shut-ins of the Alvheim FPSO. Two production wells with well integrity issues were shut-in in January 2013.. The workover of both wells has now been successfully completed and the wells have recommenced production in April 2014. A third production well was shut-in in November 2013 and a workover of this well is scheduled for September 2014 with production recommencing in early 2015. The drilling of a new infill well on Alvheim will begin 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 5.50 per barrel during the reporting period.

The Volund field production during the reporting period has been slightly below forecast due to two short weather related shut-ins of the Alvheim FPSO during January 2014 and certain other facilities related issues. The cost of operations, excluding project specific costs, 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	June 2014	12.0 Mboepd
PL340	Bøyla	15%	October 2012	22 MMboe	First quarter 2015	20.0 Mboepd
PL338	Edvard Grieg	50%	June 2012	186 MMboe	Fourth quarter 2015	100.0 Mboepd

Brynhild
The Brynhild field is now approaching first oil. The subsea template and manifolds, as well as the production and injection flow lines have been successfully installed. The first of four development wells has been completed and is ready for production. The well found both the top of the reservoir and the quality of the reservoir as expected. The drilling of the second production well is ongoing. 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. The topside modification and life extension work is close to completion. First oil from the Brynhild field is forecast in June 2014.

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 reporting period and the Transocean Winner rig has commenced drilling the first production well. First oil is forecast to be produced in the first quarter of 2015 and the field is expected to have a gross plateau production of 20,000 boepd. The Bøyla field development costs remain on budget.

Edvard Grieg
The Edvard Grieg field development is well advanced and is progressing on schedule and on budget. Construction of the jacket at Kvaerner Verdal in Norway has been completed and the jacket has been installed offshore. The construction and engineering work on the topside and export pipelines is ongoing. First oil from the Edvard Grieg field is expected in the fourth quarter 2015.

The construction of the topsides by Kvaerner commenced in 2013 and is scheduled to be completed towards the end of 2014 with topside installation planned during the summer of 2015. The 43 km long oil pipeline to Grane will be installed in 2015 and the 94 km long gas pipeline to Sage Beryl gas system will be installed during the summer of 2014. The pipelines will be jointly owned by the licence partners in Edvard Grieg PL338 and Ivar Aasen PL001B/PL028B/PL242 with Lundin Petroleum having an ownership of 30 percent in the oil pipeline and 20 percent in the gas pipeline. Statoil will be the operator of the pipelines. Development drilling will commence in the second half of 2014 using the Rowan Viking jack-up-rig. 15 wells will be drilled for the Edvard Grieg development.

An appraisal well is ongoing in the southeastern part of the Edvard Grieg reservoir.

Appraisal
Johan Sverdrup
Lundin Petroleum discovered the Avaldsnes field in PL501 (WI 40%) in 2010. In 2011, Statoil made the Aldous Major South discovery on the neighbouring PL265 (WI 10%). Following appraisal drilling, it was determined that the discoveries were connected and in January 2012 the combined discovery was renamed Johan Sverdrup. During 2013, an appraisal well drilled in PL502 (WI 0%) confirmed that a small portion of the field also extends into PL502.

During the reporting period, one appraisal 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 of 4,900 bbl per day limited by facility constraints and measured exceptionally high permeabilities. A side-track 16/3-8ST2 was also successfully completed. In April 2014, appraisal well 16/2-19 and side-track well 16/2-19A on PL265 were completed.

A total of 22 wells and seven sidetracks have now been drilled on the Johan Sverdrup field and the appraisal campaign is now substantially 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.

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. Additional subsea installations will be installed to provide for water injection.

The first phase development is scheduled to start production in late 2019 and is forecast to have a gross production capacity of between 315,000 and 380,000 boepd. 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 analysed by all partners and will form the basis of later investment decisions.

The following table outlines the drilled wells on Johan Sverdrup in 2014.

2014 appraisal well programme on Johan Sverdrup

Licence	Operator	WI	Well	Spud Date	Status
PL501	Lundin Petroleum	40%	16/3-8 S & T2	January 2014	Completed March 2014
PL265	Statoil	10%	16/2-19	February 2014	Completed April 2014

Other appraisal

One appraisal well will be drilled in the Barents Sea during the second quarter of 2014 on the Gohta discovery on PL492 (WI 40%) which Lundin Petroleum made in 2013. In addition to the currently drilling Edvard Grieg appraisal well, one further appraisal well will be drilled in the Utsira High area during the second quarter of 2014 on the Luno II discovery in PL359 (WI 40%).

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. The Alta prospect will be drilled in the Barents Sea during the third quarter of2014, immediately following the appraisal of the Gohta discovery to the southwest of the Alta prospect. Further wells will be drilled on the Kopervik, Storm, Lindarormen and Vollgrav prospects. The Storm prospect on PL555 (WI 60%), located in the northern North Sea, will be drilled during the third quarter of 2014. In the fourth quarter of 2014, the Lindarormen well on PL584 (WI 60%) will be drilled in the Norwegian Sea to the south of the Asgard field and to the southwest of the Draugen field. 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. In the Utsira High the Kopervik prospect, located to the northwest of the Johan Sverdrup field, will be drilled during the fourth quarter of 2014.

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 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 January 2014, Lundin Petroleum farmed-out ten percent in PL546 (WI 50% after farm-out) to Petrolia Norway AS.

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 of 2015. Lundin Petroleum is planning to drill three exploration wells and one appraisal well in Malaysia in 2014.

Offshore, Peninsular Malaysia

Lundin Petroleum holds four licences offshore Peninsular Malaysia with a 75 percent operated working interest in PM307, a 35 percent operated working interest in PM308A, a 75 percent operated working interest in PM308B and a 85 percent operated working interest in PM319. Block PM307 contains the Bertam field and the Tembakau gas discovery.

The Bertam field development commenced during the second half of 2013. The Bertam field will be developed using a 20 slot Wellhead Platform adjacent to the spread-moored Ikdam FPSO which is owned 100 percent by Lundin Petroleum. The subsurface development concept consists of 13 horizontal wells and one deviated well completed with electrical submersible pumps. The FPSO life extension work contract has been placed with Keppel Shipyard and work is ongoing in Singapore with anticipated completion in the fourth quarter of 2014. The wellhead platform contract has been awarded to TH Heavy Engineering (THHE) and work is well advanced at the yard located in Pulau Indah, close to Kuala Lumpur. The jacket is expected to be installed offshore during the summer 2014 and the topside is planned to be installed during the fourth quarter of 2014. Development drilling is planned to commence during the summer of 2014. The total gross capital investment associated with the Bertam field development, excluding any FPSO related costs, is estimated at approximately MUSD 400.

The Bertam field is estimated to contain gross reserves of 18.2 MMboe and is scheduled to commence first oil in the second quarter of 2015 with a gross plateau rate of 15,000 bopd.

The Tembakau gas discovery made in 2012, with gross contingent resources of 306 billion cubic feet (bcf), will be appraised as part of the Bertam development drilling campaign. The Tembakau appraisal well is expected to commence in the second quarter of 2014.

Two exploration wells are planned to be drilled within the PM307 Block during 2014. One well will be drilled on the Rengas oil prospect and one on the Mengkuang-1 oil prospect recently added to the 2014 exploration campaign. Both these exploration wells will be drilled by the jack-up rig used for the Bertam development drilling in the period when the Bertam topsides will be installed during the second half of 2014.

East Malaysia, offshore Sabah

Lundin Petroleum holds two licences offshore Sabah in east Malaysia with a 75 percent operated working interest in Block SB303 and a 42.5 percent operated working interest in Block SB307/308. Block SB303 contains four gas discoveries containing a gross best estimate contingent resource of 347 bcf.

Lundin Petroleum continues to evaluate the potential for commercialisation of the Berangan, Tarap, Cempulut and Titik Terang gas discoveries in Block SB303, most likely through a cluster development. Seismic processing of the 500 km^2 Emerald 3D survey on SB307 was completed in 2013 and two prospects, Maligan and Kitabu, within the Emerald 3D have been identified for drilling. The Kitabu prospect, located on trend with the currently producing Shell fields SF30 and South Furious, will be drilled during the third quarter of 2014 whilst the Maligan prospect will likely be drilled in 2015.

An additional 462 km^2 3D seismic acquisition referenced as the Francis 3D, on SB307/308 was completed at the end of July 2013 and processing of the seismic is scheduled to be completed in the first half of 2014.

Indonesia

Lundin Petroleum's assets in Indonesia are located in the Natuna Sea and offshore northeastern Indonesia and onshore south Sumatra. The Indonesian assets consist of approximately 24,750 km² of exploration acreage and one producing field onshore Sumatra.

Production

Production in Mboepd	WI	**1 Jan 2014– 31 Mar 2014 3 months**	1 Jan 2013– 31 Mar 2013 3 months	1 Jan 2013– 31 Dec 2013 12 months
Singa	25.9%	1.5	1.6	1.6

The production for the reporting period was slightly below forecast due to certain gas treatment issues during March 2014. 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 5.2 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. Nido Petroleum has exercised its option to increase its stake in the Baronang PSC from 10 percent to 15 percent awaiting SKKMigas approval.

Gurita

The Gobi prospect on the Gurita Block (WI 90%) was originally planned to be drilled immediately after the completion of the Balqis/Boni wells on the Baronang Block but due to late arrival of the Hakuryu 11 drilling rig, there was not sufficient time to complete three wells back-to-back and the drilling of the Gobi prospect has subsequently been moved to the fourth quarter of 2014.

South Sokang

A 3D seismic acquisition programme of 1,000 km² was completed on the South Sokang Block (WI 60%) in 2013. The seismic processing and interpretation is scheduled to be completed in the first half of 2014 and early results indicate potential for both oil and gas prospectivity at Miocene and Oligocene levels.

Cendrawasih VII

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

Continental Europe

Production

Production in Mboepd	WI	**1 Jan 2014– 31 Mar 2014 3 months**	1 Jan 2013– 31 Mar 2013 3 months	1 Jan 2013– 31 Dec 2013 12 months
France				
– Paris Basin	100% [1]	2.5	2.3	2.5
– Aquitaine	50%	0.5	0.4	0.4
Netherlands	Various	2.1	2.2	2.0
		5.1	4.9	4.9

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

France

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

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

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

Three further exploration wells are planned to be drilled by year end 2014; two onshore on the Gorredijk licence (WI 7.75%) and one offshore exploration well on licence E17a/b (WI 1.20%).

Russia

Production

Production in Mboepd	WI	**1 Jan 2014– 31 Mar 2014 3 months**	1 Jan 2013– 31 Mar 2013 3 months	1 Jan 2013– 31 Dec 2013 12 months
Komi Republic	50%	2.2	2.5	2.3

The production for the reporting period decreased compared to the prior reporting period as a result of the natural decline in the field.

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 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. It is expected that the Rosneft acquisition will be completed in the second quarter of 2014.

Corporate Responsibiltiy

During the reporting period, Lundin Petroleum had two Lost Time Incidents (LTI), which resulted in a LTI rate of 0.47 per 200,000 hours. Both incidents were of minor gravity. The total recordable incident rate was 0.7.

Lundin Malaysia, together with its contractors, reached the significant milestone of 2 million man-hours without a single recordable injury by the end of January 2014. This is an outstanding achievement in the oil and gas sector in Malaysia. Lundin Petroleum's senior management attended a ceremony in Malaysia to recognise this achievement and underline the importance of good HSE practice.

Lundin Petroleum made financial contributions during the reporting period to the Foundation for the Global Compact and the Carbon Disclosure Project and joined the Global Compact Nordic Network.

Financial Review

Result
The net result for the three month period ended 31 March 2014 amounted to MUSD 3.2 (MUSD 47.0). The net result attributable to shareholders of the Parent Company for the reporting period amounted to MUSD 4.4 (MUSD 48.2) 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 177.8 (MUSD 274.5) representing EBITDA per share of USD 0.57 (USD 0.88). Operating cash flow for the reporting period amounted to MUSD 256.0 (MUSD 257.8) representing operating cash flow per share of USD 0.83 (USD 0.83).

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, pages 79 and 91.

Revenue

Revenue for the reporting period amounted to MUSD 235.4 (MUSD 310.3) and 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 236.0 (MUSD 314.2). The average price achieved by Lundin Petroleum for a barrel of oil equivalent amounted to USD 97.63 (USD 103.11) and is detailed in the following table. The average Dated Brent price for the reporting period amounted to USD 108.21 (USD 112.57) 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– 31 Mar 2014 3 months**	1 Jan 2013– 31 Mar 2013 3 months	1 Jan 2013– 31 Dec 2013 12 months
Crude oil sales			
Norway			
– Quantity in Mboe	1,575.9	2,114.8	7,925.4
– *Average price per boe*	*110.38*	*115.33*	*111.87*
France			
– Quantity in Mboe	232.6	213.1	1,030.4
– *Average price per boe*	*105.62*	*108.52*	*106.93*
Netherlands			
– Quantity in Mboe	0.6	0.6	1.8
– *Average price per boe*	*94.43*	*104.80*	*96.24*
Total crude oil sales			
– Quantity in Mboe	**1,809.1**	2,328.5	8,957.6
– Average price per boe	***109.77***	*114.71*	*111.30*
Gas and NGL sales			
Norway			
– Quantity in Mboe	299.7	390.6	1,389.4
– *Average price per boe*	*67.05*	*77.06*	*72.33*
Netherlands			
– Quantity in Mboe	188.1	195.9	715.7
– *Average price per boe*	*61.45*	*65.22*	*64.34*
Indonesia			
– Quantity in Mboe	120.9	131.8	520.1
– *Average price per boe*	*48.10*	*31.87*	*32.54*
Total gas and NGL sales			
– Quantity in Mboe	608.7	718.3	2,625.2
– *Average price per boe*	*61.55*	*65.55*	*62.27*
Total sales			
– Quantity in Mboe	**2,417.8**	3,046.8	11,582.8
– Average price per boe	***97.63***	*103.11*	*100.19*

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 4.6 (MUSD 8.6) in the reporting period. There was a small overlift of entitlement on Alvheim and Volund fields due to the timing of the cargo liftings.

Other revenue amounted to MUSD 4.0 (MUSD 4.7) 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 38.4 (MUSD 29.0) and are detailed in the table below.

Production costs	**1 Jan 2014– 31 Mar 2014 3 months**	1 Jan 2013– 31 Mar 2013 3 months	1 Jan 2013– 31 Dec 2013 12 months
Cost of operations			
– In MUSD	30.6	23.7	103.0
– In USD per boe	*12.80*	*7.94*	*9.28*
Tariff and transportation expenses			
– In MUSD	4.8	5.4	21.6
– In USD per boe	*2.02*	*1.80*	*1.95*
Royalty and direct production taxes			
– In MUSD	0.9	0.9	3.4
– In USD per boe	*0.39*	*0.28*	*0.31*
Change in inventory position			
– In MUSD	-0.2	-1.0	-2.0
– In USD per boe	*-0.08*	*-0.30*	*-0.18*
Other			
– In MUSD	2.3	–	13.6
– In USD per boe	*0.92*	–	*1.21*
Total production costs			
– In MUSD	**38.4**	29.0	139.6
– In USD per boe	***16.05***	*9.72*	*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 30.6 (MUSD 23.7) and included costs of MUSD 10.9 associated with well intervention work on two wells on the Alvheim field which commenced in the fourth quarter of 2013.

The cost of operations per barrel amounted to USD 12.80 (USD 7.94) per barrel for the reporting period including the Alvheim well intervention work and other operational projects. January 2014 guidance for average 2014 cost of operations per barrel, including operational projects, was USD 11.35 per barrel, however increased costs on the Alvheim intervention work plus the addition of a further Alvheim well workover scheduled for the third quarter of 2014 results in a latest forecast of approximately USD 13.00 per barrel. Excluding operational projects, the cost of operations was MUSD 18.1 (MUSD 20.6) for the reporting period equating to USD 7.56 (USD 6.91) per barrel.

Other costs amounted to MUSD 2.3 (MUSD –) and related to an increase in the mark-to-market valuation of an operating cost share arrangement on the Brynhild field whereby the amount of operating cost share for the first three years of production varies with the oil price. This charge is a non-cash item and will unwind against actual expenses in the future.

Depletion and decommissioning costs

Depletion charges amounted to MUSD 35.1 (MUSD 41.6) and are detailed in Note 3. Norway's contribution to the total depletion charge for the reporting period was 68 percent (76 percent) at an average rate of USD 13.14 (USD 13.20) per barrel. The lower depletion charge 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 126.9 (MUSD 72.0) 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 72.8 were expensed and mainly related to the costs of drilling the wells and associated costs on the Torvastad and Langlitinden prospects, on PL501 and PL659 respectively. A further MUSD 53.6 of exploration costs were expensed relating to Indonesia, being mainly costs associated with the Baronang and Cakalang Blocks following the results of the Balqis and Boni wells drilled during the quarter.

General, administrative and depreciation expenses

The general, administrative and depreciation expenses for the reporting period amounted to MUSD 20.4 (MUSD 7.8) which included a charge of MUSD 5.4 (credit of MUSD 1.4) in relation to the Group's long-term incentive plans (LTIP), see Remuneration section below. Excluding the cost relating to the LTIP, the general, administrative and depreciation expenses for the reporting period amounted to MUSD 15.0 (MUSD 9.2) and include advisory fees. Fixed asset depreciation charges for the reporting period included in the total amounted to MUSD 1.2 (MUSD 0.9).

Finance income

Finance income for the reporting period amounted to MUSD 27.4 (MUSD 0.9) and is detailed in Note 4. Included in the amount is a net foreign exchange gain of MUSD 26.9 (MUSD 0.3 loss). 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 US Dollar weakened against the Norwegian Krona and this has resulted in reported foreign exchange gains. Lundin Petroleum's underlying value is US Dollar based as this is the currency in which the majority of revenues are derived. A weakening US Dollar currency has a negative overall value effect on the business as it decreases the purchasing power of the US Dollar to purchase the currencies in which the Group incurs operational expenditure. However, 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 1.2 (MUSD 3.0).

Finance costs

Finance costs for the reporting period amounted to MUSD 12.2 (MUSD 10.2) and are detailed in Note 5. Interest expenses for the reporting period amounted to MUSD 1.9 (MUSD 1.2) and represented the proportion of interest charged to the income statement. An additional amount of interest of MUSD 8.7 (MUSD 2.6) associated with the funding of the Norwegian development projects was capitalised in the reporting period. The amortisation of the deferred financing fees amounted to MUSD 2.8 (MUSD 2.2) for the reporting period and related to the expensing of the fees incurred in establishing the original USD 2.5 billion financing facility and subsequent increase to USD 4.0 billion over the period of usage of the facility.

Tax

The overall tax charge for the reporting period amounted to MUSD 26.5 (MUSD 103.7).

The current tax credit for the reporting period amounted to MUSD 58.9 (MUSD 23.5 charge) of which MUSD 64.5 credit (MUSD 17.0 charge) related to Norway due to the level of development and exploration expenditure in Norway in the first quarter 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 85.4 (MUSD 80.2) which predominantly related to Norway. The deferred tax charge arises primarily where there is a difference in depletion for tax and accounting purposes. There were also deferred tax credits which totalled MUSD 61.3 in the reporting period on the exploration costs expensed in the first quarter.

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 89 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.

Non-controlling interest

The net result attributable to non-controlling interest for the reporting period amounted to MUSD -1.2 (MUSD -1.2) and related mainly to the non-controlling interest's share in a Russian subsidiary which is fully consolidated.

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Balance Sheet

Non-current assets

Oil and gas properties amounted to MUSD 4,155.7 (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– 31 Mar 2014 3 months**	1 Jan 2013– 31 Mar 2013 3 months	1 Jan 2013– 31 Dec 2013 12 months
Norway	286.1	178.7	1,105.9
France	2.3	2.0	7.0
Netherlands	0.7	0.9	4.8
Indonesia	–	–	-1.9
Malaysia	14.4	–	12.7
	303.5	181.6	1,128.5

An amount of MUSD 286.1 (MUSD 178.7) of development expenditure was incurred in Norway during the reporting period, of which MUSD 275.0 (MUSD 158.0) was invested in the Brynhild and Edvard Grieg field developments. In Malaysia, MUSD 14.4 (MUSD –) was incurred during the reporting period on the Bertam field development.

An amount of MUSD 48.3 (MUSD 2.2) was incurred in the reporting period on upgrading the Ikdam 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– 31 Mar 2014 3 months**	1 Jan 2013– 31 Mar 2013 3 months	1 Jan 2013– 31 Dec 2013 12 months
Norway	113.2	124.8	506.4
France	0.3	0.6	2.4
Indonesia	25.9	1.8	18.5
Malaysia	1.8	17.5	36.1
Russia	0.9	1.1	6.0
Other	0.5	0.1	0.5
	142.6	145.9	569.9

Exploration and appraisal expenditure of MUSD 113.2 (MUSD 124.8) was incurred in Norway during the reporting period, primarily on the Torvastad well (PL501), the Langlitinden well (PL659) and on the Edvard Grieg southeastern extension appraisal well (PL338) which was drilling at the quarter end. During the reporting period MUSD 25.9 (MUSD 1.8) was spent in Indonesia on drilling of the Balqis and Boni wells on the Baronang Block.

Other tangible fixed assets amounted to MUSD 132.9 (MUSD 85.0) and included amounts relating to the Ikdam FPSO and to other fixed assets.

Financial assets amounted to MUSD 130.0 (MUSD 69.0) and are detailed in Note 8. Other shares and participations amounted to MUSD 20.8 (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 receivable amounted to MUSD 9.7 (MUSD 9.7) and represents the loan due from the sub-group, which contains the onshore Russian assets, and is being accounted for using the equity method. Deferred tax assets amounted to MUSD 22.4 (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 65.6 (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 reporting period. Derivative instruments amounted to MUSD 10.0 (MUSD 3.0) and relates to the mark-to-market on the outstanding foreign currency and interest rate hedges due to be settled after twelve months, see Derivative financial instruments section below.

Current assets

Receivables and inventories amounted to MUSD 268.9 (MUSD 279.6) and are detailed in Note 9.

Inventories amounted to MUSD 21.2 (MUSD 21.2) and included both hydrocarbon inventories and well supplies. Trade receivables amounted to MUSD 110.5 (MUSD 125.8) and included MUSD 87.7 (MUSD 102.5) relating to Norway. All trade receivables are current. Corporate tax amounted to MUSD 8.2 (MUSD 6.5) and included a tax refund due in France of MUSD 7.9 (MUSD 5.8). Derivative instruments amounted to MUSD 20.6 (MUSD 3.2) and related to the mark-to-market on part of the outstanding foreign currency and interest hedge contracts due to be settled within twelve months, see Derivative financial instruments section below. Prepaid expenses and accrued income amounted to MUSD 65.5 (MUSD 61.7) and represented prepaid operational and insurance expenditure including mobilisation costs of a Norwegian rig to be charged out to future wells. Other current assets amounted to MUSD 15.7 (MUSD 26.6) and included amounts receivable on farm-outs in Indonesia, VAT and other miscellaneous receivables.

Cash and cash equivalents amounted to MUSD 94.9 (MUSD 82.4). Cash balances are held to meet ongoing operational funding requirements.

Non-current liabilities
Provisions amounted to MUSD 1,458.1 (MUSD 1,345.1) and are detailed in Note 10.

The provision for site restoration amounted to MUSD 250.6 (MUSD 241.6) and related to future decommissioning obligations. The provision for deferred taxes amounted to MUSD 1,168.1 (MUSD 1,066.0) of which MUSD 1,026.9 (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 34.0 (MUSD 30.8). Lundin Petroleum's LTIP scheme is outlined in this report under the Remuneration section. The phantom option plan vests in May 2014 at which time 50 percent of the vested amount will become payable and this amount due is included in provisions in current liabilities, see also the Related party transactions section below. The non-current portion of the provision includes the vested amount of the phantom option plan which is payable in May 2015.

Financial liabilities amounted to MUSD 1,515.7 (MUSD 1,239.1). Bank loans amounted to MUSD 1,570.0 (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 amounted to MUSD 54.3 (MUSD 35.9) relating to the establishment costs of the financing facility 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 by USD 1.5 billion.

Other non-current liabilities amounted to MUSD 25.7 (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 476.8 (MUSD 439.2) and are detailed in Note 12.

The overlift position amounted to MUSD 33.1 (MUSD 29.2) and related to the overlift of the Alvheim and Volund fields production entitlement at 31 March 2014. Joint venture creditors and accrued expenses amounted to MUSD 344.9 (MUSD 334.5) and related mainly to the increased development and drilling activity in Norway, the Bertam project, Malaysia and drilling activity in Indonesia. Other accrued expenses amounted to MUSD 74.5 (MUSD 39.4) and included an amount of MUSD 35.1 (MUSD 4.8) relating to the work done on the Ikdam FPSO.

Short term provisions amounted to MUSD 50.2 (MUSD 46.2) and related to the current portion of the provision for Lundin Petroleum's LTIP scheme. The current portion of the provision includes the vested amount of the phantom option plan payable in May 2014, see also the Related party transactions section below.

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 -40.3 (MSEK -11.5) for the reporting period.

The result included general and administrative expenses of MSEK 41.7 (MSEK 12.2) and financial income relating to guarantee fees of MSEK 0.8 (MSEK 0.7).

Pledged assets of MSEK 12,439.7 (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 0.1 (MUSD 0.2) from ShaMaran Petroleum for the provision of office and other services. The Group paid MUSD – (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 who will leave the Company in mid-2014 for a maximum amount of MUSD 3.0. All amounts plus interest are repayable on or before 30 June 2014.

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 31 March 2014 is MUSD 1,916.8 (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 covenance.

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 31 March 2014 was MUSD 11.8.

Subsequent Events

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

Share Data

Lundin Petroleum AB's issued share capital amounted to SEK 3,179,106 represented by 317,910,580 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 and holds 8,840,250 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 2011, 2012 and 2013 Unit Bonus Plans outstanding as at 31 March 2014 were 120,992, 238,203 and 415,821 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 will vest in May 2014 being the fifth anniversary of the date of grant.

Lundin Petroleum purchased 6,882,638 of its own shares up to 31 December 2010 at an average cost of SEK 46.51 per share to mitigate against the exposure of the LTIP. The Lundin Petroleum share price at 31 March 2014 was SEK 133.10. The provision for the Phantom Option Plan amounted to MUSD 72.7 including social charges at 31 March 2014 and the market value of these shares held was MUSD 141.2. The gain in the value of the own shares held cannot be offset against the cost for the LTIP in the financial statements in accordance with accounting rules. For more detail on the accounting treatment refer to the section on non-current liabilities above.

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, pages 79 and 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 31 March 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 4,397.5	MUSD 710.8	NOK 6.19: 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, staring 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.

	31 Mar 2014		31 Mar 2013		31 Dec 2013	
	Average	Period end	Average	Period end	Average	Period end
1 USD equals NOK	6.0944	5.9871	5.6276	5.8665	5.8753	6.0837
1 USD equals Euro	0.7301	0.7253	0.7573	0.7809	0.7529	0.7251
1 USD equals Rouble	35.1001	35.3786	30.4088	31.0517	31.8675	32.8653
1 USD equals SEK	6.4666	6.4899	6.4318	6.5250	6.5132	6.4238

Consolidated Income Statement in Summary

Expressed in MUSD	Note	**1 Jan 2014– 31 Mar 2014 3 months**	1 Jan 2013– 31 Mar 2013 3 months	1 Jan 2013– 31 Dec 2013 12 months
Revenue [1]	1	**235.4**	310.3	1,132.0
Cost of sales				
Production costs	2	-38.4	-29.0	-139.6
Depletion and decommissioning costs		-35.1	-41.6	-169.3
Exploration costs		-126.9	-72.0	-287.8
Impairment costs of oil and gas properties		–	–	-123.4
Gross profit	3	**35.0**	167.7	411.9
General, administration and depreciation expenses		-20.4	-7.8	-41.2
Operating profit		**14.6**	159.9	370.7
Result from financial investments				
Finance income	4	27.4	0.9	3.4
Finance costs	5	-12.2	-10.2	-85.9
		15.2	-9.3	-82.5
Share of the result of joint ventures accounted for using the equity method		-0.1	0.1	-0.2
Profit before tax		**29.7**	150.7	288.0
Income tax expense	6	-26.5	-103.7	-215.1
Net result		**3.2**	47.0	72.9
Attributable to:				
Owners of the Parent Company		4.4	48.2	77.6
Non-controlling interest		-1.2	-1.2	-4.7
		3.2	47.0	72.9
Earnings per share – USD [1]		0.01	0.16	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– 31 Mar 2014 3 months**	1 Jan 2013– 31 Mar 2013 3 months	1 Jan 2013– 31 Dec 2013 12 months
Net result	**3.2**	47.0	72.9
Other comprehensive income			
Items that may be subsequently reclassified to profit or loss:			
Exchange differences foreign operations	-8.6	-44.3	-31.7
Cash flow hedges	29.0	-8.8	-8.1
Available-for-sale financial assets	-1.1	-3.0	1.9
Income tax relating to other comprehensive income	–	2.3	1.9
Other comprehensive income, net of tax	19.3	-53.8	-36.0
Total comprehensive income	**22.5**	-6.8	36.9
Attributable to:			
Owners of the Parent Company	27.1	-4.5	44.7
Non-controlling interest	-4.6	-2.3	-7.8
	22.5	-6.8	36.9

Consolidated Balance Sheet in Summary

Expressed in MUSD	Note	**31 March 2014**	31 December 2013
ASSETS			
Non-current assets			
Oil and gas properties	7	4,155.7	3,820.8
Other tangible fixed assets		132.9	85.0
Investments accounted for using the equity method		23.6	24.6
Financial assets	8	130.0	69.0
Total non-current assets		**4,442.2**	3,999.4
Current assets			
Receivables and inventories	9	268.9	279.6
Cash and cash equivalents		94.9	82.4
Total current assets		**363.8**	362.0
TOTAL ASSETS		**4,806.0**	4,361.4
EQUITY AND LIABILITIES			
Equity			
Shareholders´ equity		1,224.3	1,207.0
Non-controlling interest		55.2	59.8
Total equity		**1,279.5**	1,266.8
Liabilities			
Non-current liabilities			
Provisions	10	1,458.1	1,345.1
Financial liabilities	11	1,515.7	1,239.1
Other non-current liabilities		25.7	25.0
Total non-current liabilities		**2,999.5**	2,609.2
Current liabilities			
Current liabilities	12	476.8	439.2
Provisions	10	50.2	46.2
Total current liabilities		**527.0**	485.4
Total liabilities		**3,526.5**	3,094.6
TOTAL EQUITY AND LIABILITIES		**4,806.0**	4,361.4

Consolidated Statement of Cash Flows in Summary

Expressed in MUSD	Note	**1 Jan 2014– 31 Mar 2014 3 months**	1 Jan 2013– 31 Mar 2013 3 months	1 Jan 2013– 31 Dec 2013 12 months
Cash flows from operating activities				
Net result		3.2	47.0	72.9
Adjustments for non-cash related items	14	178.2	227.7	880.1
Interest received		0.2	0.2	0.9
Interest paid		-10.2	-3.6	-21.8
Income taxes paid		-7.0	-60.0	-188.2
Changes in working capital		75.7	42.9	162.7
Total cash flows from operating activities		**240.1**	254.2	906.6
Cash flows from investing activities				
Investment in oil and gas properties		-454.3	-327.5	-1,698.4
Investment in office equipment and other assets		-49.1	-2.8	-36.2
Disposal of bonds		10.5	–	–
Investment in subsidiaries		–	–	-3.5
Decommissioning costs paid		-0.1	-0.1	-1.5
Other payments		–	-0.2	-0.4
Total cash flows from investing activities		**-493.0**	-330.6	-1,740.0
Cash flows from financing activities				
Changes in long-term receivables		–	3.9	3.5
Changes in long-term liabilities		295.8	103.7	845.1
Financing fees paid		-20.6	–	–
Purchase of own shares		-9.8	–	-20.1
Distributions		–	–	-0.1
Total cash flows from financing activities		**265.4**	107.6	828.4
Change in cash and cash equivalents		12.5	31.2	-5.0
Cash and cash equivalents at the beginning of the period		82.4	87.6	87.6
Currency exchange difference in cash and cash equivalents		–	0.8	-0.2
Cash and cash equivalents at the end of the period		**94.9**	119.6	82.4

Consolidated Statement of Changes in Equity in Summary

Expressed in MUSD	Share capital	Additional paid-in-capital/Other reserves	Retained earnings	Total	Non-controlling interest	Total equity
	Attributable to owners of the Parent company					
At 1 January 2013	**0.5**	**411.1**	**770.8**	**1,182.4**	**67.7**	**1,250.1**
Comprehensive income						
Net result	–	–	48.2	48.2	-1.2	47.0
Other comprehensive income	–	-52.7	–	-52.7	-1.1	-53.8
Total comprehensive income	**–**	**-52.7**	**48.2**	**-4.5**	**-2.3**	**-6.8**
At 31 March 2013	**0.5**	**358.4**	**819.0**	**1,177.9**	**65.4**	**1,243.3**
Comprehensive income						
Net result	–	–	29.4	29.4	-3,5	25.9
Other comprehensive income	–	19.8	–	19.8	-2.0	17.8
Total comprehensive income	**–**	**19.8**	**29.4**	**49.2**	**-5.5**	**43.7**
Transactions with owners						
Distributions	–	–	–	–	-0.1	-0.1
Purchase of own shares	–	-20.1	–	-20.1	–	-20.1
Total transactions with owners	**–**	**-20.1**	**–**	**-20.1**	**-0.1**	**-20.2**
At 31 December 2013	**0.5**	**358.1**	**848.4**	**1,207.0**	**59.8**	**1,266.8**
Comprehensive income						
Net result	–	–	4.4	4.4	-1.2	3.2
Other comprehensive income	–	22.7	–	22.7	-3.4	19.3
Total comprehensive income	**–**	**22.7**	**4.4**	**27.1**	**-4.6**	**22.5**
Transactions with owners						
Purchase of own shares	–	-9.8	–	-9.8	–	-9.8
Total transaction with owners	**–**	**-9.8**	**–**	**-9.8**	**–**	**-9.8**
At 31 March 2014	**0.5**	**371.0**	**852.8**	**1,224.3**	**55.2**	**1,279.5**

Notes to the Consolidated Financial Statements

Note 1. Revenue MUSD	**1 Jan 2014– 31 Mar 2014 3 months**	1 Jan 2013– 31 Mar 2013 3 months	1 Jan 2013– 31 Dec 2013 12 months
Crude oil	198.6	267.1	997.0
Condensate	1.1	1.1	3.4
Gas	36.3	46.0	160.0
Net sales of oil and gas	**236.0**	314.2	1,160.4
Change in under/over lift position	-4.6	-8.6	-45.2
Other revenue	4.0	4.7	16.8
Revenue	**235.4**	310.3	1,132.0

Note 2. Production costs, MUSD	**1 Jan 2014– 31 Mar 2014 3 months**	1 Jan 2013– 31 Mar 2013 3 months	1 Jan 2013– 31 Dec 2013 12 months
Cost of operations	30.6	23.7	103.0
Tariff and transportation expenses	4.8	5.4	21.6
Direct production taxes	0.9	0.9	3.4
Change in inventory position	-0.2	-1.0	-2.0
Other	2.3	–	13.6
	38.4	29.0	139.6

Note 3. Segment information, MUSD	**1 Jan 2014– 31 Mar 2014 3 months**	1 Jan 2013– 31 Mar 2013 3 months	1 Jan 2013– 31 Dec 2013 12 months
Norway			
Crude oil	174.0	243.9	886.6
Condensate	0.8	0.8	2.0
Gas	19.3	29.3	98.5
Net sales of oil and gas	**194.1**	274.0	987.1
Change in under/over lift position	-4.6	-9.3	-47.0
Other revenue	1.2	1.6	5.6
Revenue	**190.7**	266.3	945.7
Production costs	-25.8	-17.3	-85.1
Depletion and decommissioning costs	-23.8	-31.6	-130.2
Exploration costs	-72.8	-71.4	-285.4
Impairment costs of oil and gas properties	–	–	-81.7
Gross profit	**68.3**	146.0	363.3

Note 3. Segment information cont., MUSD	**1 Jan 2014– 31 Mar 2014 3 months**	1 Jan 2013– 31 Mar 2013 3 months	1 Jan 2013– 31 Dec 2013 12 months
France			
Crude oil	24.5	23.1	110.2
Net sales of oil and gas	**24.5**	23.1	110.2
Change in under/over lift position	–	-0.3	-0.4
Other revenue	0.4	0.5	2.2
Revenue	**24.9**	23.3	112.0
Production costs	-8.0	-7.6	-34.3
Depletion and decommissioning costs	-4.3	-2.9	-12.5
Exploration costs	–	–	-0.2
Gross profit	**12.6**	12.8	65.0
Netherlands			
Crude oil	0.1	0.1	0.2
Condensate	0.3	0.3	1.4
Gas	11.2	12.5	44.6
Net sales of oil and gas	**11.6**	12.9	46.2
Change in under/over lift position	–	1.0	2.2
Other revenue	0.5	0.5	1.7
Revenue	**12.1**	14.4	50.1
Production costs	-3.6	-3.0	-14.7
Depletion and decommissioning costs	-4.3	-4.2	-15.0
Exploration costs	-0.5	–	-1.3
Gross profit	**3.7**	7.2	19.1
Indonesia			
Gas	5.8	4.2	16.9
Net sales of oil and gas	**5.8**	4.2	16.9
Other revenue	–	–	–
Revenue	**5.8**	4.2	16.9
Production costs	-1.0	-1.1	-5.0
Depletion and decommissioning costs	-2.7	-2.9	-11.4
Exploration costs	-53.6	-0.1	-0.4
Gross profit	**-51.5**	0.1	0.1
Other			
Crude oil	–	–	–
Net sales of oil and gas	–	–	–
Other revenue	1.9	2.1	7.3
Revenue	**1.9**	2.1	7.3
Production costs	–	–	-0.5
Depletion and decommissioning costs	–	–	-0.2
Exploration costs	–	-0.5	-0.5
Impairment costs of oil and gas properties [1]	–	–	-41.7
Gross profit	**1.9**	1.6	-35.6

Note 3. Segment information cont., MUSD	**1 Jan 2014– 31 Mar 2014 3 months**	1 Jan 2013– 31 Mar 2013 3 months	1 Jan 2013– 31 Dec 2013 12 months
Total			
Crude oil	198.6	267.1	997.0
Condensate	1.1	1.1	3.4
Gas	36.3	46.0	160.0
Net sales of oil and gas	**236.0**	314.2	1,160.4
Change in under/over lift position	-4.6	-8.6	-45.2
Other revenue	4.0	4.7	16.8
Revenue	**235.4**	310.3	1,132.0
Production costs	-38.4	-29.0	-139.6
Depletion and decommissioning costs	-35.1	-41.6	-169.3
Exploration costs	-126.9	-72.0	-287.8
Impairment costs of oil and gas properties	–	–	-123.4
Gross profit	**35.0**	167.7	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– 31 Mar 2014 3 months**	1 Jan 2013– 31 Mar 2013 3 months	1 Jan 2013– 31 Dec 2013 12 months
Interest income	0.4	0.5	2.4
Foreign currency exchange gain, net	26.9	–	–
Guarantee fees	0.1	0.1	0.5
Other	–	0.3	0.5
	27.4	0.9	3.4

Note 5. Finance costs, MUSD	**1 Jan 2014– 31 Mar 2014 3 months**	1 Jan 2013– 31 Mar 2013 3 months	1 Jan 2013– 31 Dec 2013 12 months
Interest expense	1.9	1.2	5.1
Foreign currency exchange loss, net	–	0.3	46.5
Result on interest rate hedge settlement	0.5	–	1.5
Unwinding of site restoration discount	1.8	1.5	5.9
Amortisation of deferred financing fees	2.8	2.2	8.7
Loan facility commitment fees	4.9	4.9	17.1
Other	0.3	0.1	1.1
	12.2	10.2	85.9

Note 6. Income tax expense, MUSD	**1 Jan 2014– 31 Mar 2014 3 months**	1 Jan 2013– 31 Mar 2013 3 months	1 Jan 2013– 31 Dec 2013 12 months
Current tax	-58.9	23.5	24.7
Deferred tax	85.4	80.2	190.4
	26.5	103.7	215.1

Notes to the Consolidated Financial Statements

Note 7. Oil and gas properties, MUSD	31 Mar 2014	31 Dec 2013
Norway	3,049.0	2,685.6
France	222.6	224.4
Netherlands	56.4	60.1
Indonesia	71.2	101.7
Russia	550.4	559.1
Malaysia	206.1	189.9
	4,155.7	3,820.8

Note 8. Financial assets, MUSD	31 Mar 2014	31 Dec 2013
Other shares and participations	20.8	22.0
Long-term receivable	9.7	9.7
Deferred tax	22.4	22.4
Corporate tax	65.6	–
Bonds	–	10.4
Derivative instruments	10.0	3.0
Other	1.5	1.5
	130.0	69.0

Note 9. Receivables and inventories, MUSD	31 Mar 2014	31 Dec 2013
Inventories	21.2	21.2
Trade receivables	110.5	125.8
Underlift	8.2	9.4
Corporate tax	8.2	6.5
Joint venture debtors	19.0	25.2
Derivative instruments	20.6	3.2
Prepaid expenses and accrued income	65.5	61.7
Other	15.7	26.6
	268.9	279.6

Note 10. Provisions, MUSD	31 Mar 2014	31 Dec 2013
Non-current:		
Site restoration	250.6	241.6
Deferred tax	1,168.1	1,066.0
Long-term incentive plan	34.0	30.8
Derivative instruments	0.2	1.6
Pension	1.5	1.5
Other	3.7	3.6
	1,458.1	1,345.1
Current:		
Long-term incentive plan	50.2	46.2
	50.2	46.2
	1,508.3	1,391.3

Note 11. Financial liabilities,
MUSD

	31 Mar 2014	31 Dec 2013
Bank loans	1,570.0	1,275.0
Capitalised financing fees	-54.3	-35.9
	1,515.7	1,239.1

Note 12. Current liabilities,
MUSD

	31 Mar 2014	31 Dec 2013
Trade payables	13.1	16.3
Overlift	33.1	29.2
Tax liabilities	4.5	4.3
Joint venture creditors and accrued expenses	344.9	334.5
Other accrued expenses	74.5	39.4
Derivative instruments	0.8	4.0
Other	5.9	11.5
	476.8	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:

31 March 2014 MUSD	Level 1	Level 2	Level 3
Assets			
Available for sale financial assets			
– Other shares and participations	20.4	–	0.4
– Bonds	–	–	–
– Derivative instruments – non-current	–	10.0	–
– Derivative instruments – current	–	20.6	–
	20.4	**30.6**	**0.4**
Liabilities			
– Derivative instruments – non-current	–	0.2	–
– Derivative instruments – current	–	0.8	–
	–	**1.0**	**–**

Note 13. Financial instruments, cont.,
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– 31 Mar 2014 3 months**	1 Jan 2013– 31 Mar 2013 3 months	1 Jan 2013– 31 Dec 2013 12 months
Exploration costs	126.9	72.0	287.9
Depletion, depreciation and amortisation	36.3	42.6	160.4
Current tax	-58.9	23.5	24.7
Deferred tax	85.4	80.2	190.4
Impairment of oil and gas properties	–	–	123.4
Long-term incentive plan	8.0	1.9	9.9
Other [1]	-19.5	7.5	83.4
	178.2	227.7	880.1

[1] Other adjustments include foreign exchange gains of MUSD 25.7 (MUSD -3.3 exchange loss) for the reporting period.

Parent Company Income Statement in Summary

Expressed in MSEK	**1 Jan 2014– 31 Mar 2014 3 months**	1 Jan 2013– 31 Mar 2013 3 months	1 Jan 2013– 31 Dec 2013 12 months
Revenue	**1.1**	-0.1	3.1
General and administration expenses	-41.7	-12.2	-105.7
Operating profit	**-40.6**	-12.3	-102.6
Result from financial investments			
Financial income	0.8	0.9	181.4
Financial expenses	-0.5	-0.1	-2.7
	0.3	0.8	178.7
Profit before tax	**-40.3**	-11.5	76.1
Income tax expense	–	–	–
Net result	**-40.3**	-11.5	76.1

Parent Company Comprehensive Income Statement in Summary

Expressed in MSEK	**1 Jan 2014– 31 Mar 2014 3 months**	1 Jan 2013– 31 Mar 2013 3 months	1 Jan 2013– 31 Dec 2013 12 months
Net result	**-40.3**	-11.5	76.1
Other comprehensive income	–	–	–
Total comprehensive income	**-40.3**	-11.5	76.1
Attributable to:			
Owners of the Parent Company	-40.3	-11.5	76.1
	-40.3	-11.5	76.1

Parent Company Balance Sheet in Summary

Expressed in MSEK	**31 March 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	19.7	17.3
Cash and cash equivalents	1.9	2.6
Total current assets	**21.6**	19.9
TOTAL ASSETS	**7,893.6**	7,891.9
SHAREHOLDERS´EQUITY AND LIABILITIES		
Shareholders´ equity including net result for the period	7,711.5	7,814.0
Non-current liabilities		
Provisions	36.6	36.6
Payables to group companies	129.4	21.6
Total non-current liabilities	**166.0**	58.2
Current liabilities		
Current liabilities	16.1	19.7
Total current liabilities	**16.1**	19.7
Total liabilities	**182,1**	77,9
TOTAL EQUITY AND LIABILITIES	**7,893.6**	7,891.9
Pledged assets	12,439.7	12,014.5

Parent Company Cash Flow Statement in Summary

Expressed in MSEK	**1 Jan 2014– 31 Mar 2014 3 months**	1 Jan 2013– 31 Mar 2013 3 months	1 Jan 2013– 31 Dec 2013 12 months
Cash flow from operations			
Net result	-40.3	-11.5	76.1
Adjustment for non-cash related items	63.8	-0.3	-18.9
Changes in working capital	-6.2	5.7	14.2
Total cash flow from operations	**17.3**	-6.1	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	44.2	–	62.2
Purchase of own shares	-62.2	–	-131.9
Total cash flow from financing	**-18.0**	–	-69.7
Change in cash and cash equivalents	-0.7	-0.4	1.5
Cash and cash equivalents at the beginning of the period	2.6	1.1	1.1
Cash and cash equivalents at the end of the period	**1.9**	0.7	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	**–**	**–**	**–**	**-11.5**	**-11.5**	**-11.5**
Balance at 31 March 2013	**3.2**	**861.3**	**2,489.4**	**4,504.4**	**6,993.8**	**7,858.3**
Total comprehensive income	**–**	**–**	**–**	**87.6**	**87.6**	**87.6**
Transactions with owners						
Purchase of own shares	–	–	-131.9	–	-131.9	-131.9
Total transactions with owners	**–**	**–**	**-131.9**	**–**	**-131.9**	**-131.9**
Balance at 31 December 2013	**3.2**	**861.3**	**2,357.5**	**4,592.0**	**6,949.5**	**7,814.0**
Total comprehensive income	**–**	**–**	**–**	**-40.3**	**-40.3**	**-40.3**
Transactions with owners						
Purchase of own shares	–	–	-62.2	–	-62.2	-62.2
Total transactions with owners	**–**	**–**	**-62.2**	**–**	**-62.2**	**-62.2**
Balance at 31 March 2014	**3.2**	**861.3**	**2,295.3**	**4,551.7**	**6,847.0**	**7,711.5**

Key Financial Data

Financial data (MUSD)	**1 Jan 2014–31 Mar 2014 3 months**	1 Jan 2013–31 Mar 2013 3 months	1 Jan 2013–31 Dec 2013 12 months
Revenue [1]	235.4	310.3	1,132.0
EBITDA	177.8	274.5	955.7
Net result	3.2	47.0	72.9
Operating cash flow	256.0	257.8	967.9

Data per share (USD)			
Shareholders' equity per share	3.96	3.79	3.90
Operating cash flow per share	0.83	0.83	3.12
Cash flow from operations per share	0.78	0.82	2.92
Earnings per share	0.01	0.16	0.25
Earnings per share fully diluted	0.01	0.16	0.25
EBITDA per share	0.57	0.88	3.08
Dividend per share	–	–	–
Number of shares issued at period end	317,910,580	317,910,580	317,910,580
Number of shares in circulation at period end	309,070,330	310,542,295	309,570,330
Weighted average number of shares for the period	309,478,548	310,542,295	310,017,074

Share price			
Quoted price at period end (SEK)	133.10	141.00	125.40
Quoted price at period end (CAD)	22.70	21.87	19.73

Key ratios			
Return on equity (%)	–	4	6
Return on capital employed (%)	–	9	16
Net debt/equity ratio (%)	120	35	99
Equity ratio (%)	27	37	29
Share of risk capital (%)	50	65	53
Interest coverage ratio	2	126	52
Operating cash flow/interest ratio	104	214	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.

Financial Information

Stockholm, 7 May 2014

C. Ashley Heppenstall
President & CEO

The financial information relating to the three month period ended 31 March 2014 has not been subject to review by the auditors of the Company.

The Company will publish the following reports:

- The six month report (January — June 2014) will be published on 6 August 2014
- 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 AGM will be held on 15 May 2014 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.

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