Lundin Petroleum

YEAR END REPORT 2014

Q4

Lundin Petroleum AB (publ)

company registration number 556610-8055

Highlights

Twelve months ended 31 December 2014 (31 December 2013)

- Production of 24.9 Mboepd (32.7 Mboepd)[1]
- Revenue of MUSD 785.2 (MUSD 1,132.0)
- EBITDA of MUSD 671.3 (MUSD 955.7)
- Operating cash flow of MUSD 1,138.5 (MUSD 967.9)
- Net result of MUSD -431.9 (MUSD 72.9) including a pre-tax impairment of MUSD 400.7 and a net foreign exchange loss of MUSD 356.3
- Net debt of MUSD 2,609 (31 December 2013: MUSD 1,192)
- The Brynhild field, offshore Norway, commenced production in December 2014
- Alta oil discovery in the Barents Sea — gross recoverable resources estimated at between 125 and 400 MMboe
- Gohta appraisal well successfully completed in the Barents Sea
- 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

Fourth quarter ended 31 December 2014 (31 December 2013)

- Production of 22.0 Mboepd (31.1 Mboepd)[1]
- Revenue of MUSD 135.2 (MUSD 274.1)
- EBITDA of MUSD 164.4 (MUSD 218.0)
- Operating cash flow of MUSD 334.5 (MUSD 203.3)
- Net result of MUSD -437.0 (MUSD 23.0)

	1 Jan 2014- 31 Dec 2014 12 months	**1 Oct 2014- 31 Dec 2014 3 months**	1 Jan 2013- 31 Dec 2013 12 months	1 Oct 2013- 31 Dec 2013 3 months
Production in Mboepd[1]	**24.9**	**22.0**	32.7	31.1
Revenue in MUSD	**785.2**	**135.2**	1,132.0	274.1
Net result in MUSD	**-431.9**	**-437.0**	72.9	23.0
Net result attributable to shareholders of the Parent Company in MUSD	**-427.2**	**-436.0**	77.6	23.7
Earnings/share in USD[2]	**-1.36**	**-1.41**	0.25	0.08
EBITDA in MUSD	**671.3**	**164.4**	955.7	218.0
Operating cash flow in MUSD	**1,138.5**	**334.5**	967.9	203.3

[1] Including production from Russian onshore assets accounted for using the equity method under IFRS 11 Joint Arrangements up to completion of the sale of these assets in mid-July 2014.
[2] Based on net result attributable to shareholders of the Parent Company.

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

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,

We have seen oil prices fall further over the last three months to current levels where spot Brent is trading around USD 50 per barrel. It has become very clear that OPEC or more particularly Saudi Arabia is pursuing a policy to maintain market share. They are attempting, and I believe will be successful, in forcing high cost producers, particularly North American shale oil producers, to curtail production growth. There is currently a lot of uncertainty as to how long a period of low oil prices it will take to balance supply with demand and indeed where oil prices will trade during this period. I personally believe we are close to the bottom right now but there is certainly a possibility that we may see oil prices go even lower.

Our current producing and development assets as well as Johan Sverdrup will all generate value to shareholders at current oil prices but I believe strongly that the majority of our industry does not have a sustainable future if oil prices remain for the long term at these levels. I do believe that one of the positives that will come out of this down cycle will be an industry wide focus on cost levels and a serious attempt to introduce more standardisation and efficiency. However I think that will be insufficient to sustain a viable industry at today's prices. In terms of new greenfield oil development projects Johan Sverdrup is probably one of the few that will still go ahead based upon current prices. We should remember that this is one of the five largest discoveries ever made in Norway and it will be at the bottom of the cost curve because of its sheer size and favourable location.

Oil prices will recover as they have in previous cycles. Current oversupply which is estimated at up to 2 million barrels per day represents only about 2 percent of demand. This oversupply will be eroded and oil prices will recover in the medium to long term.

Lundin Petroleum is well prepared to weather the storm and will come out of this cycle as a stronger and much more valuable company. We are generating positive cash flow even at low oil prices due to our low cash operating costs and negligible cash taxes. Our production growth will ensure that our operating cash flow grows despite lower commodity prices. Our balance sheet is strong. We continue to have access to third party bank funding supported particularly by our long reserve life Norwegian asset base. We have approved a 2015 budget which predominantly focuses on the completion of our development projects in Norway and Malaysia as well as an appraisal and exploration drilling programme on our core Utsira High and Barents Sea south areas. However we are not complacent and will constantly review our expenditure plans in light of how markets develop.

Financial Results

Our objective is to deliver sustainable financial returns to our shareholders. It is obviously disappointing that the impact of unsuccessful exploration, asset impairment and non-cash foreign exchange losses resulted in a financial loss in 2014. But I am encouraged that our business continues to be cash generative with EBITDA and operating cash flow of USD 670 million and USD 1.14 billion respectively despite the reduction in oil prices.

Two of four development projects onstream - Production to exceed 75,000 boepd by year end 2015

Our production for 2014 was 24,900 boepd as compared to our guidance of 24,000 to 29,000 boepd. We were in the lower half of the range due to delays to production start-up at the Brynhild field.

I am pleased that the Brynhild and Bøyla fields, offshore Norway have now commenced production. And with the Bertam and Edvard Grieg development projects due to come onstream in the second and fourth quarter of this year we are forecasting 2015 production of between 41,000 and 51,000 boepd with a 2015 exit rate of over 75,000 boepd. It is very encouraging to see our production rates starting to increase again and I remain confident in our target to triple production over the course of 2015.

We are making good progress with the Bertam and Edvard Grieg development projects which both remain on schedule. I have just returned from South East Asia where Bertam is on track for first oil in the second quarter of 2015. The Bertam FPSO refurbishment is now complete and the vessel will sail from Singapore to the Bertam field later this month for final hook up and installation. The jacket and topsides have already been successfully installed and completed development wells are ready to commence production. Similarly we are on schedule to load out the completed Edvard Grieg topsides in the spring for offshore installation. Hook up and commissioning will be completed during the summer prior to first oil in the fourth quarter 2015. I believe both projects are today substantially de risked - procurement and construction are substantially complete, operations teams are ready and development drilling is ongoing.

The plan of development for Johan Sverdrup is scheduled to be delivered to the Norwegian Government later this month. The unitisation process will be completed prior to the submission of the plan of development. This will be a major milestone not only for Lundin Petroleum but for the Norwegian offshore industry. We have always believed since our initial discovery of Johan Sverdrup back in 2010 that we had something very special. The size, quality and location of this asset are unique and will be the cornerstone of our Company's growth for many years to come.

Letter to Shareholders

Exploration

In today's oil price environment there is little focus from the markets on exploration assets. Indeed many view them as a liability. We however continue to believe in higher medium term oil prices and as such the key to create long term value will remain access to resources. We do believe the best way to do this is through an organic growth model driven by exploration drilling.

We are very excited with the potential in the southern Barents Sea following our Gohta and Alta discoveries. We will appraise the Alta discovery in 2015 and drill exploration wells to test nearby prospectivity. I believe that as the major licence holder in this area we will find significant additional oil resources and ultimately this will act as a catalyst for the development of this region. We are taking a long term view which in the future will deliver value from this region for our shareholders. It is critical that exploration continues in the region despite current markets.

2015 Objectives

Our objectives for 2015 are very clear. We will deliver on our promise of project execution by bringing the Bertam and Edvard Grieg fields onstream to meet our year end production target. The Johan Sverdrup development project will be sanctioned and will secure a pipeline of further production growth for our Company of in excess of 150,000 boepd. The potential of the southern Barents Sea will be tested through our summer appraisal and exploration drilling programme. We will manage the liquidity constraints of whatever oil price the market throws at us to ensure the long term value of our business is preserved.

Finally we will continue to do this in a way which takes account of preserving our environment, the health and safety of all our stakeholders and which fulfils our stated goal of being a responsible corporate citizen.

Yours Sincerely,

C. Ashley Heppenstall
President and CEO

Stockholm, 4 February 2015

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 financial year of 2014 accounting for 71 percent of total production and with 79 percent of Lundin Petroleum's total reserves as at the end of 2014.

Reserves and Resources

Lundin Petroleum has 187.5 million barrels of oil equivalent (MMboe) of reserves as at 31 December 2014 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 located in Norway, the best estimate contingent resources net to Lundin Petroleum amount to 404 MMboe as at 31 December 2014. 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 year amounted to 24.9 thousand barrels of oil equivalent per day (Mboepd) (compared to 32.7 Mboepd in 2013) and was comprised as follows:

Production in Mboepd	**1 Jan 2014- 31 Dec 2014 12 months**	**1 Oct 2014- 31 Dec 2014 3 months**	1 Jan 2013- 31 Dec 2013 12 months	1 Oct 2013- 31 Dec 2013 3 months
Crude oil				
Norway	15.0	14.2	20.6	19.3
France	2.9	2.8	2.9	3.0
Russia[1]	1.1	–	2.3	2.1
Total crude oil production	**19.0**	**17.0**	25.8	24.4
Gas				
Norway	2.6	2.2	3.3	3.2
Netherlands	1.9	1.8	2.0	2.0
Indonesia	1.4	1.0	1.6	1.5
Total gas production	**5.9**	**5.0**	6.9	6.7
Total production				
Quantity in Mboe	**9,107.8**	**2,024.6**	11,939.6	2,859.9
Quantity in Mboepd	**24.9**	**22.0**	32.7	31.1

[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. In July 2014, Lundin Petroleum sold its entire interest in the Sotchemyu-Talyu and North Irael fields in the Komi Republic to Arawak Energy Russia BV.

Norway

Production

Production in Mboepd	WI[1]	**1 Jan 2014- 31 Dec 2014 12 months**	**1 Oct 2014- 31 Dec 2014 3 months**	1 Jan 2013- 31 Dec 2013 12 months	1 Oct 2013- 31 Dec 2013 3 months
Alvheim	15%	9.6	9.8	10.5	10.5
Volund	35%	7.4	6.1	12.2	11.1
Brynhild	90%	0.1	0.5	–	–
Gaupe	40%	0.5	–	1.2	0.9
		17.6	**16.4**	23.9	22.5

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

Production from the Alvheim field during the year has been better than forecast due to continued good reservoir performance, better FPSO uptime, and better than expected production from two wells which came back onstream during April 2014 following work-over activity. The production outperformance was partially offset by two short weather related shut-ins of the Alvheim FPSO during the first quarter of 2014. Production on the Alvheim FPSO was shut-in for approximately two weeks during September 2014 for planned maintenance work and completion of the Bøyla (WI 15%) tie-in scope. One producing well on Alvheim has been shut-in since November 2013 and a work-over of this well is scheduled during 2015. The drilling of a new infill well on Alvheim commenced during the fourth quarter of 2014 and the well is expected to commence production during the second quarter of 2015. Two further infill wells are planned to be drilled in 2015 with production from these two wells expected to commence in late 2015 or early 2016. The development of the Viper/Kobra accumulations within the Alvheim field was sanctioned by the Alvheim partnership in December 2014 with expected production start-up in late 2016. The Viper/Kobra resources have consequently been moved into reserves as at 31 December 2014. The cost of operations for the Alvheim field, excluding well intervention work, was approximately USD 5 per barrel during the year.

The Volund field production during the year 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 under performance has been partly offset by better than forecast FPSO uptime. Further infill opportunities have been identified on the Volund field and it is the intention to drill at least one infill well during 2016. The contingent resources associated with the infill target have consequently been moved into reserves as at 31 December 2014. The cost of operations for the Volund field, during the year was below USD 4 per barrel.

Production from the Brynhild field commenced on 25 December 2014. Two production wells have been completed and are available for production whilst the drilling and completion of the third well is ongoing. The production capacity from the first well was confirmed as production initially reached plateau. However during the first month of production the production rate has been below plateau due to an expected combination of facilities and well optimisation as well as weather related issues. The field is expected to ramp-up to a sustainable plateau of 12,000 boepd during the next few weeks. The fourth and final development well on Brynhild will be drilled immediately after the third well has been completed.

The Gaupe field produced as per forecast. The field is currently shut-in with the potential to recommence limited production in 2015 subject to economic conditions. However no reserves have been booked for the Gaupe field.

Development

Licence	Field	WI	PDO Approval	Estimated gross reserves	Production start expected	Gross plateau production rate expected
PL340	Bøyla	15%	October 2012	23 MMboe	Commenced January 2015	20.0 Mboepd
PL338	Edvard Grieg	50%	June 2012	187 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%	Expected mid-2015	1.8 — 2.9 billion boe[1]	Late 2019	550.0 — 650.0 Mboepd

[1] Gross contingent resource range as disclosed by pre-unit working operator Statoil.

Bøyla

The Bøyla field commenced production on 19 January 2015. The Bøyla field has been 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 two wells and the top hole section of the final production well. Subsea work to tie in the first two wells has been completed and production has commenced from one well. The second, and final, production well will be finalised and tied-in during the second quarter of 2015.

Edvard Grieg

The Edvard Grieg field development is well advanced and is progressing on schedule and on budget. The steel jacket was successfully installed offshore during the second quarter of 2014 and the installation of the 94 km gas pipeline to the Sage Beryl gas system was completed during the third quarter 2014. The construction work of the topsides by Kværner is substantially complete and onshore commissioning is ongoing. Installation of the oil export pipeline to the Grane field connection is ongoing. The installation of the topsides is planned during the second quarter of 2015. Development drilling commenced 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 following the completion of the offshore hook-up and commissioning.

The appraisal well 16/1-18 on the southeastern part of the Edvard Grieg field was successfully completed during the year. The well encountered 62 metres of moderate to good reservoir quality sandstone. A further appraisal well is planned in the southern part of Edvard Grieg during 2015 to better understand the distribution of this sandstone with the potential to increase reserves.

Ivar Aasen

During the year 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 the Ivar Aasen unit of 1.385 percent. The unitised interest is not subject to any re-determination. The operator of Ivar Aasen, Det norske oljeselskap (Det norske), 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 of 2016 and Lundin Petroleum has reported its 1.385 percent unitised interest as reserves as at 31 December 2014.

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 year, 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. The FEED work for Phase 1 was completed by Aker Solutions in late 2014 and the plan of development for Phase 1 is expected to be submitted in February 2015 as per schedule. In June 2014, the pre-unit working operator announced that a letter of intent had been signed with Kværner 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. A contract for the riser platform jacket was awarded to Kværner in January 2015 and a second contract was awarded to Aker Solution during January 2015 for the engineering and procurement management for the riser and processing platform topsides for phase one, in addition to hook-up work and gangways for the entire field.

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 35 production and injection wells will be drilled to support Phase 1 production, of which 14 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 and 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.

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

Two appraisal wells have been completed on the Johan Sverdrup field during the year. 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 sidetrack 16/3-8ST2 was also successfully completed. In April 2014, the appraisal well 16/2-19 and sidetrack 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	Completed August 2014

In addition to the Johan Sverdrup appraisal wells, a further two appraisal wells have been completed during the year.

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%) 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 was completed in August 2014 and encountered a 30 metres gross oil column underlying a thin gas cap. The well flow tested oil successfully however the reservoir quality failed to meet pre-drill expectations. The revised gross contingent resource range for Luno II is estimated at 27 to 71 MMboe.

Lundin Petroleum is planning to drill three to four appraisal wells offshore Norway during 2015. Two of these appraisal wells are planned on the Alta discovery in PL609 (WI 40%) in the Barents Sea. One appraisal well is planned to be drilled on the southeastern part of the Edvard Grieg field on PL338 (WI 50%). A further appraisal well may be drilled on the Gohta discovery on PL492 (WI 40%) in 2015.

Exploration

2014 exploration well programme

Licence	Well	Spud Date	Target	WI	Operator	Result
Utsira High						
PL501	16/2-20A	January 2014	Torvastad (sidetrack)	40%	Lundin Petroleum	Oil shows — non-commercial
PL625	25/10-12S	October 2014	Kopervik	40%	Lundin Petroleum	Dry hole
Barents Sea						
PL659	7222/11-2	January 2014	Langlitinden	20%	Det norske	Oil discovery — non-commercial
PL609	7220/11-1	August 2014	Alta	40%	Lundin Petroleum	Oil and Gas discovery — gross resources 125 — 400 MMboe
North Sea						
PL631	33/12-10S	September 2014	Vollgrav South	60%	Lundin Petroleum	Dry hole
PL584	6405/12-1	October 2014	Lindarormen	60%	Lundin Petroleum	Dry hole
PL555	33/2-1	October 2014	Storm	60%	Lundin Petroleum	Oil shows — non-commercial

Lundin Petroleum has completed seven exploration wells in Norway during the year. On the Utsira High the Torvastad sidetrack 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.

In October 2014, the Alta well 7220/11-1 in the Barents Sea was announced as an oil and gas discovery. The well was drilled on-trend with the Gohta discovery made in 2013 and encountered a 57 metre gross hydrocarbon column in carbonate rocks of good reservoir quality. The well flow tested approximately 3,300 barrels of oil per day and 1.7 million cubic feet of gas per day and the discovery is estimated to contain resources of between 125 to 400 MMboe.

The Vollgrav South prospect drilled close to the Statfjord field with well 33/12-10S failed to encounter any hydrocarbons and was announced as a dry hole in October 2014.

In December 2014, the Storm well 33/2-1 drilled 65 km northwest of the Snorre field was announced as having encountered hydrocarbons in Cretaceous and Jurassic reservoir sequences but in non-commercial quantities.

Also in December 2014, the Lindarormen well 6405/12-1 drilled 80 km northeast of the Ormen Lange field was announced as a dry hole with no hydrocarbons encountered.

In December 2014, the Kopervik well 25/10-12S was completed as a dry hole. The well was drilled 20 km northwest of the Johan Sverdrup field and encountered good quality Jurassic reservoir but failed to encounter any hydrocarbons.

During 2015, Lundin Petroleum is planning to drill seven operated exploration wells targeting net unrisked prospective resources of 475 MMboe.

Exploration wells 2015

Licence	WI	Targeting prospect
Barents Sea		
PL609	40%	Neiden
PL708	40%	Ørnen
Utsira High		
PL338	80%	Gemini
PL359	50%	Luno II North
PL674	35%	Zulu
PL544	40%	Fosen
Northern North Sea		
PL579	50%	Morkel

Lundin Petroleum, together with 32 other companies, has signed a contract during the year 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 was completed in the third quarter of 2014 and the processing is scheduled to be completed in the summer of 2015. In January 2015 the Norwegian Ministry of Petroleum and Energy announced that 57 blocks, or part blocks, will be offered for licensing in the 23rd Licensing round with the majority of blocks being located in the Barents Sea. The deadline for submitting licence applications is in December 2015 with awards expected to be announced during the first half of 2016.

Licence awards, transactions and relinquishments

During the year, 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 and a 15 percent interest in PL359 was sold to Wintershall Norge. Following these transactions, Lundin Petroleum has a 50 percent interest in PL359 and these transactions have also ensured 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. In August 2014, Lundin Petroleum farmed-into PL674 acquiring a 35 percent working interest and into PL674BS acquiring a 15 percent working interest. During the year, PL409, PL570, PL495 and PL453S were relinquished. PL338 will be split into two licences where the original PL338 licence contains the Edvard Grieg field and the carved-out licence, PL338C contains the remaining exploration potential of the original licence including the Gemini and the Rolvsnes prospects. Lundin Petroleum will hold an 80 percent interest PL338C with OMV Norge holding the remaining 20 percent interest.

In January 2015, the Ministry of Petroleum and Energy announced the licence awards in the 2014 APA licensing round. Lundin Petroleum was awarded eight licences of which six were awarded to Lundin Petroleum as operator.

Continental Europe

Production

Production in Mboepd	WI	**1 Jan 2014-31 Dec 2014 12 months**	**1 Oct 2014-31 Dec 2014 3 months**	1 Jan 2013-31 Dec 2013 12 months	1 Oct 2013-31 Dec 2013 3 months
France					
– Paris Basin	100% [1]	2.5	2.4	2.5	2.5
– Aquitaine	50%	0.4	0.4	0.4	0.5
Netherlands	Various	1.9	1.8	2.0	2.0
		4.8	**4.6**	4.9	5.0

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

France

Production levels from France are substantially in line with forecast and incremental production from the Grandville redevelopment in the Paris Basin has been offsetting the natural decline from the other fields. Development drilling on the Vert la Gravelle re-development project commenced in the fourth quarter of 2014 but following the current weak oil price environment the drilling of the remaining five development wells will be deferred.

The Hoplites exploration well on the Est Champagne concession (WI 100%) was completed during the fourth quarter with no hydrocarbons encountered.

The Netherlands

Production from the Netherlands has been in line with the forecast during the year.

The K5-A5 (Licence Interest 2.03%) development well was successfully drilled during the year and is expected to be put on production by mid-2015. The drilling of the K5-A6 (Licence Interest 2.03%) development well completed in early January 2015. The encountered reservoir was pressure depleted and the well will be plugged and abandoned. The E17-A5 (WI 1.20%) development well is currently drilling ahead. Lundin Petroleum is expecting to participate in two further development wells and two exploration wells during 2015.

An exploration well on E17a/b (WI 1.20%) was drilled during the year and has encountered gas. Development options are currently being assessed.

The Hempens-1 exploration well on the Leeuwarden licence (WI 7.2325%) was completed during the year as a dry hole. The LW102ST development well also drilled on the Leeuwarden licence in the first quarter of 2014 was declared unsuccessful following testing.

The drilling of the Lambertschaag-2 exploration well on the Slootdorp licence (WI 7.2325%) was completed during the year and whilst gas was found in a shallower interval, the well is non-commercial.

The Langezwaag-2 exploration well on the Gorredijk licence (WI 7.75%) has been completed and gas was found in two intervals. The well is expected to commence production in the first quarter of 2015.

South East Asia

Malaysia

Offshore, Peninsular Malaysia

The Bertam field development on PM307 (WI 75%) is progressing according to schedule. The steel jacket was successfully completed and installed offshore Peninsular Malaysia during the year. The construction of the topside of the wellhead platform at the TH Heavy Engineering yard was successfully installed on the steel jacket during October 2014. The Bertam FPSO (formerly the Ikdam FPSO) upgrade and life extension work is now mechanically complete at the Keppel shipyard in Singapore and the Bertam FPSO is scheduled to be moored and hooked-up to the wellhead platform late in the first quarter 2015. During the third quarter of 2014, the jack-up drilling rig West Prospero commenced drilling the Bertam development wells and drilling is expected to continue until late 2015. The subsurface development concept consists of 13 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 on PM307 (WI 75%) has been successfully completed with production test results from the I10 and I20 sands yielding 15.9 and 15.8 MMscfd respectively. Conceptual development studies have been completed and any development decision will likely be dependent on achievable gas prices.

Two exploration wells are planned to be drilled within Block PM307 during the fourth quarter of 2015 following the completion of the Bertam development drilling campaign. The exploration wells are targeting the Mengkuang-1 oil prospect, estimated to contain gross unrisked prospective resources of 21 MMboe and the Rengas oil prospect which is targeting gross unrisked prospective resources 22 MMboe.

During the third quarter of 2014, Lundin Petroleum entered into a farm-in agreement with Petronas Carigali whereby Lundin Petroleum has acquired a 50 percent working interest and operatorship in PM328. The PM328 Block is located northeast of PM307 and spans 5,600 km^2. The initial PSC term covers three years with a work programme commitment of acquiring 600 km^2 of 3D seismic within the first 18 months.

The previously announced farm-out agreement with HiRex Petroleum in relation to PM308B will not complete and the agreement has been terminated.

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.

The Kitabu prospect, on SB307/SB308 (WI 42.5%), was drilled during the fourth quarter 2014 however the well failed to encounter any hydrocarbons.

Indonesia

Production

Production in Mboepd	WI	**1 Jan 2014- 31 Dec 2014 12 months**	**1 Oct 2014- 31 Dec 2014 3 months**	1 Jan 2013- 31 Dec 2013 12 months	1 Oct 2013- 31 Dec 2013 3 months
Singa	25.9%	**1.4**	**1.0**	1.6	1.5

The production from the Singa field was below forecast during the year, primarily due to certain facility issues and a shut-in to re-route the gas pipeline. In early 2014, a revised gas sales agreement, with an effective date of 2 January 2014, 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. The agreement provides for an annual price escalation.

Exploration

Baronang/Cakalang
Exploration drilling on the Balqis and Boni prospects in the Baronang Block (WI 85%) in the Natuna Sea, Indonesia, was completed during the year. Both wells encountered good quality reservoirs at the projected Oligocene level but neither well encountered any hydrocarbons and were declared as dry holes. Lundin Petroleum is in the process of relinquishing both the Baronang and the Cakalang Blocks.

Gurita
In October 2014, Lundin Petroleum announced that the exploration well on the Gobi prospect in the Gurita Block (WI 90%) was unsuccessful and has been plugged and abandoned as a dry hole.

South Sokang
A 3D seismic acquisition programme of 1,000 km² 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.

Cendrawasih VIII
In November 2014, Lundin Petroleum entered into a joint study agreement for 100 percent of the exploration Block Cendrawasih VIII which is contiguous to Cendrawasih VII Block.

Other Areas

Russia

Production

Production in Mboepd	WI	**1 Jan 2014- 31 Dec 2014 12 months**	**1 Oct 2014- 31 Dec 2014 3 months**	1 Jan 2013- 31 Dec 2013 12 months	1 Oct 2013- 31 Dec 2013 3 months
Komi Republic	50%	**1.1**	–	2.3	2.1

In July 2014, Lundin Petroleum sold its entire interest in the Sotchemyu-Talyu and North Irael fields in the Komi Republic to Arawak Energy Russia BV 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. The completion of the deal with Rosneft is uncertain due to a number of factors.

Corporate Responsibility

During the year, Lundin Petroleum had seven low severity Lost Time Incidents (LTI) among its contractors, which resulted in a LTI frequency rate of 0.25 per 200,000 hours. The LTI frequency rate in 2014 was the lowest rate recorded to date. The total recordable incident rate was 0.42. An oil spill occurred in France; removal of the polluted soil started immediately and the circumstances surrounding the spill are being investigated. There will be no lasting impact on the environment.

In September 2014, Lundin Petroleum signed the UN Global Compact's Call to Action, an appeal by companies to governments urging them to enhance measures to combat corruption. The Board of Directors approved of the decision to take this additional step in demonstrating Lundin Petroleum's commitment to anti-corruption.

In terms of disclosure regarding climate change, the Carbon Disclosure Project, CDP Nordic Report attributed a score of 90B to Lundin Petroleum. This is the highest score obtained among Nordic oil and gas companies. The highest score attributed to an energy company was 92A, while the average disclosure scores for the Nordic region is 80C and for Sweden 82B.

Financial Review

Result
The net result for the financial year 2014 amounted to MUSD -431.9 (MUSD 72.9). The net result attributable to shareholders of the Parent Company for the year amounted to MUSD -427.2 (MUSD 77.6) representing earnings per share of USD -1.36 (USD 0.25).

Earnings before interest, tax, depletion and amortisation (EBITDA) for the year amounted to MUSD 671.3 (MUSD 955.7) representing EBITDA per share of USD 2.14 (USD 3.08). Operating cash flow for the year amounted to MUSD 1,138.5 (MUSD 967.9) representing operating cash flow per share of USD 3.63 (USD 3.12).

Changes in the Group
In July 2014, Lundin Petroleum completed the sale of its interests in the Russian onshore producing assets in the Komi Region.

Revenue
Revenue for the year amounted to MUSD 785.2 (MUSD 1,132.0) 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 year amounted to MUSD 745.0 (MUSD 1,160.4). The average price achieved by Lundin Petroleum for a barrel of oil equivalent amounted to USD 88.28 (USD 100.19) and is detailed in the following table. The average Dated Brent price for the year amounted to USD 98.95 (USD 108.66) per barrel.

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

Sales Average price per boe expressed in USD	**1 Jan 2014- 31 Dec 2014 12 months**	**1 Oct 2014- 31 Dec 2014 3 months**	1 Jan 2013- 31 Dec 2013 12 months	1 Oct 2013- 31 Dec 2013 3 months
Crude oil sales				
Norway				
– Quantity in Mboe	5,183.3	1,181.5	7,925.4	1,845.7
– Average price per boe	*102.35*	*71.08*	*111.87*	*113.65*
France				
– Quantity in Mboe	1,028.7	223.8	1,030.4	233.0
– Average price per boe	*94.08*	*57.63*	*106.93*	*108.02*
Netherlands				
– Quantity in Mboe	1.1	–	1.8	0.6
– Average price per boe	*91.64*	–	*96.24*	*94.06*
Total crude oil sales				
– Quantity in Mboe	**6,213.1**	**1,405.3**	8,957.6	2,079.3
– Average price per boe	***100.98***	***68.94***	*111.30*	*113.02*

Sales continued Average price per boe expressed in USD	**1 Jan 2014- 31 Dec 2014 12 months**	**1 Oct 2014- 31 Dec 2014 3 months**	1 Jan 2013- 31 Dec 2013 12 months	1 Oct 2013- 31 Dec 2013 3 months
Gas and NGL sales				
Norway				
– Quantity in Mboe	1,080.8	215.8	1,389.4	341.9
– *Average price per boe*	*56.02*	*56.65*	*72.33*	*75.46*
Netherlands				
– Quantity in Mboe	687.9	161.4	715.7	184.5
– *Average price per boe*	*51.11*	*49.93*	*64.34*	*67.24*
Indonesia				
– Quantity in Mboe	457.2	83.4	520.1	124.0
– *Average price per boe*	*47.87*	*46.95*	*32.54*	*32.79*
Total gas and NGL sales				
– Quantity in Mboe	2,225.9	460.6	2,625.2	650.4
– *Average price per boe*	*52.83*	*52.55*	*62.27*	*64.98*
Total sales				
– Quantity in Mboe	**8,439.0**	**1,865.9**	11,582.8	2,729.7
– Average price per boe	***88.28***	***64.89***	*100.19*	*101.57*

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

The change in under/over lift position amounted to a net credit of MUSD 23.4 (charge of MUSD 45.2) in the year. There was an underlift of entitlement movement on the Alvheim and Volund fields during the year due to the timing of the cargo liftings compared to production.

Other revenue amounted to MUSD 16.8 (MUSD 16.8) for the year 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 year amounted to MUSD 66.5 (MUSD 139.6) and are detailed in the table below.

Production costs	**1 Jan 2014- 31 Dec 2014 12 months**	**1 Oct 2014- 31 Dec 2014 3 months**	1 Jan 2013- 31 Dec 2013 12 months	1 Oct 2013- 31 Dec 2013 3 months
Cost of operations				
– In MUSD	94.4	22.2	103.0	29.8
– In USD per boe	*10.86*	*10.95*	*9.28*	*11.18*
Tariff and transportation expenses				
– In MUSD	18.4	3.4	21.6	5.0
– In USD per boe	*2.12*	*1.68*	*1.95*	*1.86*
Royalty and direct production taxes				
– In MUSD	3.6	0.8	3.4	0.8
– In USD per boe	*0.41*	*0.39*	*0.31*	*0.35*
Change in inventory position				
– In MUSD	-0.8	-1.3	-2.0	-1.9
– In USD per boe	*-0.09*	*-0.66*	*-0.18*	*-0.71*
Other				
– In MUSD	-49.1	-63.3	13.6	12.2
– In USD per boe	*-5.65*	*-31.26*	*1.21*	*4.48*
Total production costs				
– In MUSD	**66.5**	**-38.2**	139.6	45.9
– In USD per boe	**7.65**	**-18.90**	*12.57*	*17.16*

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

The total cost of operations for the year was MUSD 94.4 (MUSD 103.0) 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 total cost of operations excluding operational projects amounted to MUSD 72.3 (MUSD 77.3) with most of the decrease versus the comparative period being attributable to the Gaupe field in Norway which was shut-in for most of the second half of 2014.

The cost of operations per barrel amounted to USD 10.86 (USD 9.28) for the year 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 primarily due to the lower production volumes in the year. Excluding operational projects, the cost of operations amounted to USD 8.32 (USD 6.96) per barrel. The cost of operations per barrel is in line with the guidance provided at the end of the third quarter of 2014.

Other costs amounted to a credit of MUSD 49.1 (charge of MUSD 13.6) and substantially related to an operating cost share arrangement on the Brynhild field whereby the amount of operating cost varies with the oil price until mid-2017. This arrangement is being marked-to-market against the oil price curve and due to the low oil price at the end of 2014, it resulted in the provision booked at the end of the third quarter being reversed and an asset being recognised. The asset will be charged to the income statement over the term of the arrangement.

Depletion and decommissioning costs

Depletion costs amounted to MUSD 131.6 (MUSD 156.0) and are detailed in Note 3. Norway's contribution to the total depletion cost for the year was 67 percent (75 percent) at an average rate of USD 13.75 (USD 13.40) per barrel. The lower depletion cost for the year compared to the same period last year is in line with the lower production volumes.

Decommissioning costs amounted to MUSD — (MUSD 13.3). The non-cash decommissioning costs charged to the income statement in the comparative period related to an increase in the site restoration estimate of the Gaupe field in Norway.

Exploration costs

Exploration costs expensed in the income statement for the year amounted to MUSD 386.4 (MUSD 287.8) and are detailed in Note 3. Exploration and appraisal costs are capitalised as they are incurred. When exploration drilling is unsuccessful, the capitalised costs are expensed. All capitalised exploration costs are reviewed on a regular basis and are expensed where their recoverability is considered highly uncertain.

During the fourth quarter of 2014, exploration costs relating to Norway of MUSD 198.0 were expensed and mainly related to four unsuccessful wells that were drilled on PL631 (Vollgrav), PL555 (Storm), PL584 (Lindarormen) and PL625 (Kopervik). In addition, costs associated with the unsuccessful Kitabu-1 well on SB307/SB308, offshore Malaysia and the Gobi-1 well on the Gurita Block, offshore Indonesia, were expensed for an amount of MUSD 54.0.

In addition, exploration costs relating to the drilling of the wells on PL501 (Torvastad) and PL659 (Langlitinden) in Norway and the Balqis and Boni wells in Indonesia were expensed in the first quarter of 2014.

Impairment costs

Impairment costs expensed in the income statement for the year amounted to MUSD 400.7 (MUSD 123.4). The carrying value of oil and gas properties are continually assessed to ensure recoverability and due to the significantly lower oil price at the end of 2014, a non-cash pre-tax MUSD 400.7 impairment cost against the Brynhild field, Norway, was recognised. A deferred tax credit on the impairment of MUSD 309.7 was recognised in the deferred tax line of the income statement. The amount in the comparative period related to discoveries in Malaysia and Norway which were deemed uncommercial.

General, administrative and depreciation expenses

The general, administrative and depreciation expenses for the year amounted to MUSD 52.2 (MUSD 41.2) which included a charge of MUSD 8.9 (MUSD 4.7) in relation to the Group's long-term incentive plans (LTIP), see also Remuneration section below. Fixed asset depreciation charges for the year amounted to MUSD 4.8 (MUSD 4.4).

Finance income

Finance income for the year amounted to MUSD 1.8 (MUSD 3.4) and is detailed in Note 4.

Finance costs

Finance costs for the year amounted to MUSD 421.8 (MUSD 85.9) and are detailed in Note 5.

Interest expenses for the year amounted to MUSD 21.1 (MUSD 5.1) and represented the proportion of interest charged to the income statement. An additional amount of interest of MUSD 36.6 (MUSD 18.2) primarily associated with the funding of the Norwegian development projects was capitalised in the year.

Net foreign exchange losses for the year amounted to MUSD 356.3 (MUSD 46.5) and MUSD 289.5 (MUSD13.3) for the fourth quarter of 2014. Foreign exchange movements occur on the settlement of transactions denominated in foreign currencies and the revaluation of working capital and loan balances to the prevailing exchange rate at the balance sheet date where those monetary assets and liabilities are held in currencies other than the functional currencies of the Group's reporting entities. The US Dollar strengthened against the Euro during the fourth quarter of 2014 resulting in a foreign currency exchange loss on the US Dollar denominated external loan which is borrowed by a subsidiary using a functional currency of the Euro. In addition, the Norwegian Krone significantly weakened in the fourth quarter of 2014, generating a foreign currency exchange loss on an intercompany loan balance denominated in Norwegian Krone. 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 year, the net realised exchange loss on settled foreign exchange hedges amounted to MUSD 22.8 (MUSD 5.5 gain). In addition, there were net foreign exchange losses recognised within other comprehensive income on foreign entities translated to the presentation currency of the Group of MUSD 196.3 (MUSD 31.7). In other comprehensive income there were also losses on the unsettled part of the cash flow hedges of MUSD 148.7 (MUSD 8.1) which mainly related to the unsettled foreign currency hedges.

The amortisation of the deferred financing fees amounted to MUSD 12.6 (MUSD 8.7) for the year 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.

Loan facility commitment fees for the year amounted to MUSD 21.4 (MUSD 17.1) with the increase over the comparative period being attributable to the increased facility size.

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 year 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. The onshore Russian assets were sold in July 2014.

Tax

The overall tax credit for the year amounted to MUSD 253.2 (charge of MUSD 215.1).

The current tax credit for the year amounted to MUSD 419.7 (charge of MUSD 24.7) of which MUSD 431.7 (MUSD 2.9) related to Norway due to the significant level of development and exploration and appraisal expenditure in Norway in the year and the tax depreciation on development expenditure incurred in prior years. The current tax credit in Norway for the year is partly offset by the current tax charge relating to operations in France and the Netherlands.

The deferred tax charge for the year amounted to MUSD 166.5 (MUSD 190.4) which predominantly related to Norway. The deferred tax charge arises primarily where there is a difference in depletion for tax and accounting purposes. During the fourth quarter of 2014, a deferred tax credit was recognised in the income statement on the impairment of Brynhild and on the Norwegian expensed exploration costs which amounted to MUSD 309.7 and MUSD 154.4 respectively.

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 calculated from the face of the income statement is 37 percent and does not reflect the effective rate of tax paid within each country of operation. The effective tax rate is also affected by items which do not receive a full tax credit such as the expensed exploration costs in Indonesia, net foreign exchange losses and the expense relating to the sale of the onshore Russian assets.

Non-controlling interest

The net result attributable to non-controlling interest for the year amounted to MUSD -4.7 (MUSD -4.7) 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 4,182.6 (MUSD 3,820.8) and are detailed in Note 7.

Development and exploration and appraisal expenditure incurred in the financial year 2014 was as follows:

Development expenditure in MUSD	**1 Jan 2014-31 Dec 2014 12 months**	**1 Oct 2014-31 Dec 2014 3 months**	1 Jan 2013-31 Dec 2013 12 months	1 Oct 2013-31 Dec 2013 3 months
Norway	1,068.2	249.5	1,105.9	347.9
France	29.3	14.7	7.0	1.5
Netherlands	3.9	1.1	4.8	1.3
Indonesia	-0.8	-0.2	-1.9	-0.9
Malaysia	130.6	32.8	12.7	7.9
	1,231.2	**297.9**	1,128.5	357.7

An amount of MUSD 1,068.2 (MUSD 1,105.9) of development expenditure was incurred in Norway during the year, of which MUSD 1,035.3 (MUSD 1,091.7) was invested in the Edvard Grieg, Brynhild and Bøyla field developments. In Malaysia, MUSD 130.6 (MUSD 12.7) was incurred during the year on the Bertam field development.

An amount of MUSD 118.8 (MUSD 29.8) was incurred during the year 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- 31 Dec 2014 12 months**	**1 Oct 2014- 31 Dec 2014 3 months**	1 Jan 2013- 31 Dec 2013 12 months	1 Oct 2013- 31 Dec 2013 3 months
Norway	572.8	221.3	506.4	116.9
France	5.9	3.7	2.4	0.3
Indonesia	47.5	17.5	18.5	10.7
Malaysia	42.7	12.7	36.1	2.9
Russia	4.0	1.4	6.0	2.3
Other	1.6	0.2	0.5	0.2
	674.5	**256.8**	569.9	133.3

Exploration and appraisal expenditure of MUSD 572.8 (MUSD 506.4) was incurred in Norway during the year, primarily on the appraisal drilling of the Johan Sverdrup field and the Edvard Grieg southeastern extension, Gohta, and Luno II appraisal wells, as well as seven exploration wells. During the year MUSD 47.5 (MUSD 18.5) was spent in Indonesia mainly on drilling of the Balqis and Boni wells on the Baronang Block and the Gobi-1 well on the Gurita Block. In Malaysia, MUSD 42.7 (MUSD 36.1) was incurred in the year mainly on the appraisal drilling of Tembakau (PM307) and the Kitabu-1 well (SB307/SB308).

Other tangible fixed assets amounted to MUSD 200.3 (MUSD 85.0) and included amounts relating to the Bertam FPSO.

Investments accounted for using the equity method amounted to MUSD — (MUSD 24.6) following the sale of the onshore Russian assets in July 2014.

Financial assets amounted to MUSD 49.9 (MUSD 69.0) and are detailed in Note 8. Other shares and participations amounted to MUSD 4.7 (MUSD 22.0) and related to the shares held in ShaMaran Petroleum which are reported at market value with any change in value being recorded in other comprehensive income. Long-term receivables amounted to MUSD — (MUSD 9.7) and the comparative amount related to the loan due from the sub-group which contained the onshore Russian assets that was accounted for using the equity method until the sale of the assets in July 2014. Deferred tax assets amounted to MUSD 12.9 (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. The reduction in the deferred tax asset balance compared to the previous year was primarily due to a reclassification of a deferred tax liability. 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 — (MUSD 3.0) and related to the mark-to-market gain on outstanding hedges due to be settled after twelve months, see also Derivative financial instruments section below. Brynhild operating cost share amounted to MUSD 31.0 (MUSD —) and related to the long-term portion of the mark-to-market valuation of the arrangement where the share of the operating cost varies with the oil price.

Current assets

Receivables and inventories amounted to MUSD 578.7 (MUSD 279.6) and are detailed in Note 9.

Inventories amounted to MUSD 41.6 (MUSD 21.2) and included both well supplies and hydrocarbon inventories. The increase compared to the previous year is mainly due to drilling and other inventory bought for the Bertam project in Malaysia. Trade receivables, which are all current, amounted to MUSD 40.3 (MUSD 125.8). Underlift amounted to MUSD 3.6 (MUSD 9.4) and represented small underlift positions in Norway, France and the Netherlands. Joint venture debtors amounted to MUSD 49.1 (MUSD 25.2) and included a significant amount that was settled in January 2015. Corporate tax amounted to MUSD 373.6 (MUSD 6.5) and mainly related to the Norwegian corporate tax refund in respect of 2014 which is due to be received in December 2015. Prepaid expenses and accrued income amounted to MUSD 41.5 (MUSD 61.7) and represented prepaid operational and insurance expenditure. Brynhild operating cost share amounted to MUSD 21.6 (MUSD —) and related to the short-term portion of the mark-to-market valuation of the arrangement where the share of the operating cost varies with the oil price. Other current assets amounted to MUSD 7.6 (MUSD 26.6) and included VAT and other miscellaneous balances. The comparative amount included amounts receivable on farm-out deals in Norway and Indonesia.

Cash and cash equivalents amounted to MUSD 80.5 (MUSD 82.4). Cash balances are held to meet ongoing operational funding requirements.

Non-current liabilities

Provisions amounted to MUSD 1,295.2 (MUSD 1,345.1) and are detailed in Note 10.

The provision for site restoration amounted to MUSD 274.1 (MUSD 241.6) and related to future decommissioning obligations. The provision has increased during the year due to the additions of infrastructure that has been put in place on the

Norwegian and Malaysian development projects. The provision for deferred taxes amounted to MUSD 973.3 (MUSD 1,066.0) of which MUSD 844.8 (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 1.8 (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 was reclassified to current liabilities in the second quarter of 2014. The remaining entitlement under the phantom option plan for the former VP Finance and CFO was settled during the third quarter of 2014 in accordance with the rules of the plan. Derivative instruments amounted to MUSD 33.9 (MUSD 1.6) and related to the mark-to-market loss on outstanding foreign currency and interest rate hedges due to be settled after twelve months. Farm-in payment amounted to MUSD 7.5 (MUSD –) and related to a provision for payments towards historic costs on Block PM307, Malaysia, see also Current Liabilities section.

Financial liabilities amounted to MUSD 2,654.0 (MUSD 1,239.1). Bank loans amounted to MUSD 2,690.0 (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 36.0 (MUSD 35.9) and are being amortised over the expected life of the financing facility. The increase in capitalised financing fees in the year was attributable to the costs associated with the increasing of the financing facility to USD 4.0 billion.

Other non-current liabilities amounted to MUSD 29.1 (MUSD 25.0) and mainly arised 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 594.6 (MUSD 439.2) and are detailed in Note 12.

Overlift amounted to MUSD – (MUSD 29.2) with the overlift position at the start of the year being reversed into a small underlift position at the end of 2014. Joint venture creditors and accrued expenses amounted to MUSD 383.5 (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 46.1 (MUSD 39.4) and included an amount of MUSD 19.4 (MUSD 4.8) relating to the work done on the Bertam FPSO. The liability for the long-term incentive plan amounted to MUSD 28.2 (MUSD –) and represented the second tranche of the phantom option plan including social costs due within twelve months. The phantom option plan is now fully vested and the liability has been reclassified from provisions to current liabilities. Derivative instruments amounted to MUSD 101.4 (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 53.4 (MUSD 46.2) and included 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. Also included in short term provisions is an amount of MUSD 4.9 (MUSD 46.2) relating to the current portion of the provision for Lundin Petroleum's Unit Bonus Plan.

Parent Company
The business of the Parent Company is investment in and management of oil and gas assets. The net result for the Parent Company amounted to MSEK 108.7 (MSEK 76.1) for the year.

The result included general and administrative expenses of MSEK 144.9 (MSEK 105.7) and finance income of MSEK 209.9 (MSEK 181.4), including a dividend of MSEK 205.7 (MSEK 178.2) and guarantee fees of MSEK 3.5 (MSEK 3.1).

The tax credit amounting to MSEK 36.4 reported as income tax expense represents the reversal of a historic tax provision.

Pledged assets of MSEK 8,717.8 (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 year, the Group has entered into transactions with related parties on a commercial basis as described below.

The Group received MUSD 0.7 (MUSD 0.4) from related parties for the provision of office and other services. The Group paid MUSD 0.6 (MUSD 0.4) to related parties in respect of services received.

In 2013, the Group entered into a loan agreement with the former VP Finance and CFO for a maximum amount of MUSD 3.0. All amounts plus interest have been repaid during the financial year of 2014.

In October 2014, Lundin Petroleum signed a rights offering standby purchase agreement in relation to a rights offering of CAD 75 million proposed to be made by ShaMaran Petroleum. If such offering concludes, Lundin Petroleum, together with the major shareholders of ShaMaran Petroleum, has agreed to purchase all shares not otherwise subscribed for by rights holders other than the major shareholders. Lundin Petroleum holds 6.2 percent of the total shares of ShaMaran Petroleum as at 31 December 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 December 2014 is MUSD 1,126.8 (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 its financing facility agreement.

Lundin Petroleum has, through its subsidiary Lundin Malaysia BV, entered into Production Sharing Contracts (PSC) with Petroliam Nasional Berhad, the oil and gas company of the Government of Malaysia (Petronas). Bank guarantees have been issued in support of the work commitments and other related costs in relation to certain of these PSCs and the outstanding amount of the bank guarantees at 31 December 2014 was MUSD 40.4. An additional bank guarantee in support of work commitments in Indonesia was put in place in December 2014 for an amount of MUSD 1.0.

Subsequent Events

In January 2015, Lundin Petroleum announced that it had been awarded eight licences in the Norwegian 2014 APA licensing round, six as operator.

The Bøyla field, Norway, commenced production on 19 January 2015.

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 year 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 31 December 2014 the Company holds 2,000,000 of its own shares.

The Board of directors will propose to the AGM that no dividend will be paid to the shareholders for the financial year 2014.

Remuneration

Lundin Petroleum's principles for remuneration and details of the long-term incentive plans are provided in the Company's 2013 Annual Report and in the materials provided to shareholders in respect of the 2014 AGM, available on www.lundin-petroleum.com.

Unit Bonus Plan

The number of units relating to the awards made in 2012, 2013 and 2014 under the Unit Bonus Plan outstanding as at 31 December 2014 were 114,100, 270,316 and 371,514 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 awards under the plan have been accounted for in the year. The total number of awards made in respect of 2014 was 608,103 and the related cost is recognised on a straight line basis over the three year performance period subject to certain performance conditions being met by Lundin Petroleum. Each award was fair valued at the date of grant at SEK 81.40 using an option pricing model and as at 31 December 2014 an amount of MUSD 1.0 was accounted for.

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 31 December 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 5,547.1	MUSD 897.4	NOK 6.18: USD 1	Jan 2014 – Dec 2014
MNOK 4,424.5	MUSD 690.8	NOK 6.40: USD 1	Jan 2015 – Dec 2015
MNOK 1,251.8	MUSD 182.5	NOK 6.86: USD 1	Jan 2016 – Jun 2016

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 year 2014, the following currency exchange rates have been used.

	31 Dec 2014		31 Dec 2013	
	Average	Period end	Average	Period end
1 USD equals NOK	6.3011	7.4332	5.8753	6.0837
1 USD equals Euro	0.7526	0.8236	0.7529	0.7251
1 USD equals Rouble	38.3878	59.5808	31.8675	32.8653
1 USD equals SEK	6.8457	7.7366	6.5132	6.4238

Consolidated Income Statement in Summary

Expressed in MUSD	Note	**1 Jan 2014-31 Dec 2014 12 months**	**1 Oct 2014-31 Dec 2014 3 months**	1 Jan 2013-31 Dec 2013 12 months	1 Oct 2013-31 Dec 2013 3 months
Revenue	1	**785.2**	**135.2**	1,132.0	274.1
Cost of sales					
Production costs	2	-66.5	38.2	-139.6	-45.9
Depletion and decommissioning costs		-131.6	-33.2	-169.3	-51.0
Exploration costs		-386.4	-256.9	-287.8	-135.0
Impairment costs of oil and gas properties		**-400.7**	**-400.7**	-123.4	–
Gross profit/loss	3	**-200.0**	**-517.4**	411.9	42.2
General, administration and depreciation expenses		-52.2	-10.2	-41.2	-11.4
Operating profit/loss		**-252.2**	**-527.6**	370.7	30.8
Result from financial investments					
Finance income	4	1.8	0.5	3.4	0.8
Finance costs	5	-421.8	-308.8	-85.9	-22.6
		-420.0	**-308.3**	-82.5	-21.8
Share of the result of joint ventures accounted for using the equity method		-12.9	–	-0.2	-0.3
Profit/loss before tax		**-685.1**	**-835.9**	288.0	8.7
Income tax expense	6	253.2	398.9	-215.1	14.3
Net result		**-431.9**	**-437.0**	72.9	23.0
Attributable to:					
Owners of the Parent Company		-427.2	-436.0	77.6	23.7
Non-controlling interest		-4.7	-1.0	-4.7	-0.7
		-431.9	**-437.0**	72.9	23.0
Earnings per share – USD[1]		-1.36	-1.41	0.25	0.08

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 Dec 2014 12 months**	**1 Oct 2014-31 Dec 2014 3 months**	1 Jan 2013-31 Dec 2013 12 months	1 Oct 2013-31 Dec 2013 3 months
Net result	**-431.9**	**-437.0**	72.9	23.0
Other comprehensive income				
Items that may be subsequently reclassified to profit or loss:				
Exchange differences foreign operations	-196.3	-95.2	-31.7	2.6
Cash flow hedges	-148.7	-111.6	-8.1	5.2
Available-for-sale financial assets	-15.3	-9.0	1.9	2.8
Income tax relating to other comprehensive income	–	–	1.9	-1.4
Other comprehensive income, net of tax	-360.3	-215.8	-36.0	9.2
Total comprehensive income	**-792.2**	**-652.8**	36.9	32.2
Attributable to:				
Owners of the Parent Company	-766.7	-638.8	44.7	33.4
Non-controlling interest	-25.5	-14.0	-7.8	-1.2
	-792.2	**-652.8**	36.9	32.2

Consolidated Balance Sheet in Summary

Expressed in MUSD	Note	**31 December 2014**	31 December 2013
ASSETS			
Non-current assets			
Oil and gas properties	7	4,182.6	3,820.8
Other tangible fixed assets		200.3	85.0
Investments accounted for using the equity method		–	24.6
Financial assets	8	49.9	69.0
Total non-current assets		**4,432.8**	3,999.4
Current assets			
Receivables and inventories	9	578.7	279.6
Cash and cash equivalents		80.5	82.4
Total current assets		**659.2**	362.0
TOTAL ASSETS		**5,092.0**	4,361.4
EQUITY AND LIABILITIES			
Equity			
Shareholders' equity		431.5	1,207.0
Non-controlling interest		34.2	59.8
Total equity		**465.7**	1,266.8
Liabilities			
Non-current liabilities			
Provisions	10	1,295.2	1,345.1
Financial liabilities	11	2,654.0	1,239.1
Other non-current liabilities		29.1	25.0
Total non-current liabilities		**3,978.3**	2,609.2
Current liabilities			
Current liabilities	12	594.6	439.2
Provisions	13	53.4	46.2
Total current liabilities		**648.0**	485.4
Total liabilities		**4,626.3**	3,094.6
TOTAL EQUITY AND LIABILITIES		**5,092.0**	4,361.4

Consolidated Statement of Cash Flows in Summary

Expressed in MUSD	Note	**1 Jan 2014-31 Dec 2014 12 months**	**1 Oct 2014-31 Dec 2014 3 months**	1 Jan 2013-31 Dec 2013 12 months	1 Oct 2013-31 Dec 2013 3 months
Cash flows from operating activities					
Net result		-431.9	-437.0	72.9	23.0
Adjustments for non-cash related items	14	1,033.7	533.3	880.1	192.2
Interest received		0.9	0.4	0.9	0.1
Interest paid		-56.5	-18.8	-21.8	-8.0
Income taxes paid		-13.8	-1.5	-188.2	-13.5
Changes in working capital		109.0	-50.4	162.7	-62.5
Total cash flows from operating activities		**641.4**	**26.0**	906.6	131.3
Cash flows from investing activities					
Investment in oil and gas properties		-1,957.8	-579.9	-1,698.4	-491.1
Investment in other fixed assets		-124.9	-19.0	-36.2	-16.4
Disposal of bonds		10.5	–	–	–
Investment in subsidiaries		–	–	-3.5	–
Share in result in associated company		11.7	–	–	–
Decommissioning costs paid		-1.2	-0.3	-1.5	-0.8
Other payments		-0.1	–	-0.4	–
Total cash flows from investing activities		**-2,061.8**	**-599.2**	-1,740.0	-508.3
Cash flows from financing activities					
Changes in long-term receivables		9.8	–	3.5	-0.2
Changes in long-term liabilities		1,419.2	526.3	845.1	370.4
Financing fees paid		-20.7	–	–	–
Purchase of own shares		-9.8	–	-20.1	–
Distributions		-0.1	–	-0.1	–
Total cash flows from financing activities		**1,398.4**	**526.3**	828.4	370.2
Change in cash and cash equivalents		-22.0	-46.9	-5.0	-6.8
Cash and cash equivalents at the beginning of the period		82.4	111.9	87.6	90.0
Currency exchange difference in cash and cash equivalents		20.1	15.5	-0.2	-0.8
Cash and cash equivalents at the end of the period		**80.5**	**80.5**	82.4	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	–	–	77.6	77.6	-4.7	72.9
Other comprehensive income	–	-32.9	–	-32.9	-3.1	-36.0
Total comprehensive income	**–**	**-32.9**	**77.6**	**44.7**	**-7.8**	**36.9**
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	–	–	-427.2	-427.2	-4.7	-431.9
Other comprehensive income	–	-339.5		-339.5	-20.8	-360.3
Total comprehensive income	**–**	**-339.5**	**-427.2**	**-766.7**	**-25.5**	**-792.2**
Transactions with owners[1]						
Distributions	–	–	–	–	-0.1	-0.1
Purchase of own shares	–	-9.8	–	-9.8	–	-9.8
Value of employee services	–	–	1.0	1.0	–	1.0
Total transaction with owners	**–**	**-9.8**	**1.0**	**-8.8**	**-0.1**	**-8.9**
At 31 December 2014	**0.5**	**8.8**	**422.2**	**431.5**	**34.2**	**465.7**

[1] During the year 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- 31 Dec 2014 12 months**	**1 Oct 2014- 31 Dec 2014 3 months**	1 Jan 2013- 31 Dec 2013 12 months	1 Oct 2013- 31 Dec 2013 3 months
Crude oil	627.4	96.9	997.0	235.0
Condensate	3.0	0.2	3.4	1.1
Gas	114.6	24.0	160.0	41.1
Net sales of oil and gas	**745.0**	**121.1**	1,160.4	277.2
Change in under/over lift position	23.4	9.6	-45.2	-7.2
Other revenue	16.8	4.5	16.8	4.1
Revenue	**785.2**	**135.2**	1,132.0	274.1

Note 2. Production costs MUSD	**1 Jan 2014- 31 Dec 2014 12 months**	**1 Oct 2014- 31 Dec 2014 3 months**	1 Jan 2013- 31 Dec 2013 12 months	1 Oct 2013- 31 Dec 2013 3 months
Cost of operations	94.4	22.2	103.0	29.8
Tariff and transportation expenses	18.4	3.4	21.6	5.0
Direct production taxes	3.6	0.8	3.4	0.8
Change in inventory position	-0.8	-1.3	-2.0	-1.9
Other	-49.1	-63.3	13.6	12.2
	66.5	**-38.2**	139.6	45.9

Note 3. Segment information MUSD	**1 Jan 2014- 31 Dec 2014 12 months**	**1 Oct 2014- 31 Dec 2014 3 months**	1 Jan 2013- 31 Dec 2013 12 months	1 Oct 2013- 31 Dec 2013 3 months
Norway				
Crude oil	530.5	84.0	886.6	209.7
Condensate	1.7	–	2.0	0.5
Gas	58.8	12.2	98.5	25.3
Net sales of oil and gas	**591.0**	**96.2**	987.1	235.5
Change in under/over lift position	24.4	10.0	-47.0	-9.1
Other revenue	3.8	0.7	5.6	1.5
Revenue	**619.2**	**106.9**	945.7	227.9
Production costs	-11.3	52.6	-85.1	-32.7
Depletion and decommissioning costs	-88.5	-23.6	-130.2	-41.0
Exploration costs	-272.1	-197.9	-285.4	-134.8
Impairment costs of oil and gas properties	-400.7	-400.7	-81.7	–
Gross profit/loss	**-153.4**	**-462.7**	363.3	19.4
France				
Crude oil	96.8	12.9	110.2	25.2
Net sales of oil and gas	**96.8**	**12.9**	110.2	25.2
Change in under/over lift position	-0.5	-0.6	-0.4	1.6
Other revenue	1.7	0.4	2.2	0.4
Revenue	**98.0**	**12.7**	112.0	27.2
Production costs	-33.1	-7.9	-34.3	-6.6
Depletion and decommissioning costs	-16.9	-4.1	-12.5	-3.4
Exploration costs	-4.6	-4.6	-0.2	-0.1
Gross profit/loss	**43.4**	**-3.9**	65.0	17.1

Note 3. Segment information cont. MUSD	1 Jan 2014- 31 Dec 2014 12 months	1 Oct 2014- 31 Dec 2014 3 months	1 Jan 2013- 31 Dec 2013 12 months	1 Oct 2013- 31 Dec 2013 3 months
Netherlands				
Crude oil	0.1	–	0.2	0.1
Condensate	1.3	0.2	1.4	0.6
Gas	33.8	7.8	44.6	11.8
Net sales of oil and gas	**35.2**	**8.0**	46.2	12.5
Change in under/over lift position	-0.5	0.2	2.2	0.3
Other revenue	2.2	0.5	1.7	0.4
Revenue	**36.9**	**8.7**	50.1	13.2
Production costs	-16.8	-4.7	-14.7	-4.9
Depletion and decommissioning costs	-15.9	-3.7	-15.0	-3.7
Exploration costs	-1.4	-0.4	-1.3	–
Gross profit/loss	**2.8**	**-0.1**	19.1	4.6
Malaysia				
Exploration costs	-14.4	-14.3	-0.5	–
Impairment costs of oil and gas properties	–	–	-41.7	–
Gross profit/loss	**-14.4**	**-14.3**	-42.2	–
Indonesia				
Gas	22.0	4.0	16.9	4.0
Net sales of oil and gas	**22.0**	**4.0**	16.9	4.0
Other revenue	–	–	–	–
Revenue	**22.0**	**4.0**	16.9	4.0
Production costs	-5.4	-1.9	-5.0	-1.2
Depletion and decommissioning costs	-10.3	-1.8	-11.4	-2.7
Exploration costs	-94.2	-40.0	-0.4	-0.1
Gross profit/loss	**-87.9**	**-39.7**	0.1	–
Other				
Other revenue	9.1	2.9	7.3	1.8
Revenue	**9.1**	**2.9**	7.3	1.8
Production costs	0.1	0.1	-0.5	-0.5
Depletion and decommissioning costs	–	–	-0.2	-0.2
Exploration costs	0.3	0.3	–	–
Gross profit/loss	**9.5**	**3.3**	6.6	1.1

Note 3. Segment information cont. MUSD	**1 Jan 2014- 31 Dec 2014 12 months**	**1 Oct 2014- 31 Dec 2014 3 months**	1 Jan 2013- 31 Dec 2013 12 months	1 Oct 2013- 31 Dec 2013 3 months
Total				
Crude oil	627.4	96.9	997.0	235.0
Condensate	3.0	0.2	3.4	1.1
Gas	114.6	24.0	160.0	41.1
Net sales of oil and gas	**745.0**	**121.1**	1,160.4	277.2
Change in under/over lift position	23.4	9.6	-45.2	-7.2
Other revenue	16.8	4.5	16.8	4.1
Revenue	**785.2**	**135.2**	1,132.0	274.1
Production costs	-66.5	38.2	-139.6	-45.9
Depletion and decommissioning costs	-131.6	-33.2	-169.3	-51.0
Exploration costs	-386.4	-256.9	-287.8	-135.0
Impairment costs of oil and gas properties	-400.7	-400.7	-123.4	–
Gross profit /loss	**-200.0**	**-517.4**	411.9	42.2

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

Note 4. Finance income MUSD	**1 Jan 2014- 31 Dec 2014 12 months**	**1 Oct 2014- 31 Dec 2014 3 months**	1 Jan 2013- 31 Dec 2013 12 months	1 Oct 2013- 31 Dec 2013 3 months
Interest income	1.2	0.4	2.4	0.5
Foreign currency exchange gain, net	–	–	–	–
Guarantee fees	0.5	0.1	0.5	0.2
Other	0.1	–	0.5	0.1
	1.8	**0.5**	3.4	0.8

Note 5. Finance costs MUSD	**1 Jan 2014- 31 Dec 2014 12 months**	**1 Oct 2014- 31 Dec 2014 3 months**	1 Jan 2013- 31 Dec 2013 12 months	1 Oct 2013- 31 Dec 2013 3 months
Interest expense	21.1	9.4	5.1	1.5
Foreign currency exchange loss, net	356.3	289.5	46.5	13.3
Result on interest rate hedge settlement	2.4	0.7	1.5	0.5
Unwinding of site restoration discount	7.0	1.7	5.9	1.4
Amortisation of deferred financing fees	12.6	2.8	8.7	2.2
Loan facility commitment fees	21.4	4.5	17.1	3.3
Other	1.0	0.2	1.1	0.4
	421.8	**308.8**	85.9	22.6

Note 6. Income tax expense MUSD	**1 Jan 2014- 31 Dec 2014 12 months**	**1 Oct 2014- 31 Dec 2014 3 months**	1 Jan 2013- 31 Dec 2013 12 months	1 Oct 2013- 31 Dec 2013 3 months
Current tax	-419.7	-161.0	24.7	25.0
Deferred tax	166.5	-237.9	190.4	-39.3
	-253.2	**-398.9**	215.1	-14.3

Notes to the Consolidated Financial Statements

Note 7. Oil and gas properties

MUSD	**31 Dec 2014**	31 Dec 2013
Norway	2,960.7	2,685.6
France	210.1	224.4
Netherlands	38.6	60.1
Indonesia	43.9	101.7
Russia	501.0	559.1
Malaysia	428.3	189.9
	4,182.6	3,820.8

Note 8. Financial assets

MUSD	**31 Dec 2014**	31 Dec 2013
Other shares and participations	4.7	22.0
Long-term receivables	–	9.7
Deferred tax	12.9	22.4
Bonds	–	10.4
Derivative instruments	–	3.0
Brynhild operating cost share	31.0	–
Other	1.3	1.5
	49.9	69.0

Note 9. Receivables and inventories

MUSD	**31 Dec 2014**	31 Dec 2013
Inventories	41.6	21.2
Trade receivables	40.3	125.8
Underlift	3.6	9.4
Corporate tax	373.6	6.5
Joint venture debtors	49.1	25.2
Derivative instruments	–	3.2
Prepaid expenses and accrued income	41.5	61.7
Brynhild operating cost share	21.6	–
Other	7.4	26.6
	578.7	279.6

Note 10. Provisions

MUSD	**31 Dec 2014**	31 Dec 2013
Non-current:		
Site restoration	274.1	241.6
Deferred tax	973.3	1,066.0
Long-term incentive plan	1.8	30.8
Derivative instruments	33.9	1.6
Pension	1.2	1.5
Farm-in payment	7.5	–
Other	3.4	3.6
	1,295.2	1,345.1
Current:		
Farm-in payment	48.5	–
Long-term incentive plan	4.9	46.2
Other	–	–
	53.4	46.2
	1,348.6	1,391.3

Note 11. Financial liabilities

MUSD	31 Dec 2014	31 Dec 2013
Bank loans	2,690.0	1,275.0
Capitalised financing fees	-36.0	-35.9
	2,654.0	1,239.1

Note 12. Current liabilities

MUSD	31 Dec 2014	31 Dec 2013
Trade payables	23.9	16.3
Overlift	–	29.2
Tax liabilities	1.8	4.3
Joint venture creditors and accrued expenses	383.5	334.5
Other accrued expenses	46.1	39.4
Long-term incentive plan	28.2	–
Derivative instruments	101.4	4.0
Other	9.7	11.5
	594.6	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 December 2014 MUSD	Level 1	Level 2	Level 3
Assets			
Available for sale financial assets			
– Other shares and participations	4.7	–	–
	4.7	**–**	**–**
Liabilities			
– Derivative instruments – non-current	–	33.9	–
– Derivative instruments – current	–	101.4	–
	–	**135.3**	**–**

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 year. 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, during 2017.

Note 14. Adjustment for non-cash related items MUSD	**1 Jan 2014- 31 Dec 2014 12 months**	**1 Oct 2014- 31 Dec 2014 3 months**	1 Jan 2013- 31 Dec 2013 12 months	1 Oct 2013- 31 Dec 2013 3 months
Exploration costs	386.4	256.9	287.8	135.0
Depletion, depreciation and amortisation	136.3	34.2	160.4	38.9
Current tax	-419.7	-161.0	24.7	25.0
Deferred tax	166.5	-237.9	190.4	-39.4
Impairment of oil and gas properties	400.7	400.7	123.4	–
Long-term incentive plan	14.5	2.0	9.9	0.6
Foreign currency exchange loss	333.1	261.3	52.1	13.4
Other	15.9	-22.9	31.4	18.7
	1,033.7	**533.3**	880.1	192.2

Parent Company Income Statement in Summary

Expressed in MSEK	**1 Jan 2014- 31 Dec 2014 12 months**	**1 Oct 2014- 31 Dec 2014 3 months**	1 Jan 2013- 31 Dec 2013 12 months	1 Oct 2013- 31 Dec 2013 3 months
Revenue	**9.2**	**1.6**	3.1	2.2
General and administration expenses	-144.9	-35.1	-105.7	-47.6
Operating profit/loss	**-135.7**	**-33.5**	-102.6	-45.4
Result from financial investments				
Finance income	209.9	206.9	181.4	179.0
Finance costs	-1.9	–	-2.7	-1.1
	208.0	**206.9**	178.7	177.9
Profit before tax	**72.3**	**173.4**	76.1	132.5
Income tax	36.4	36.4	–	–
Net result	**108.7**	**209.8**	76.1	132.5

Parent Company Comprehensive Income Statement in Summary

Expressed in MSEK	**1 Jan 2014- 31 Dec 2014 12 months**	**1 Oct 2014- 31 Dec 2014 3 months**	1 Jan 2013- 31 Dec 2013 12 months	1 Oct 2013- 31 Dec 2013 3 months
Net result	**108.7**	**209.8**	76.1	132.5
Other comprehensive income	–	–	–	–
Total comprehensive income	**108.7**	**209.8**	76.1	132.5
Attributable to:				
Shareholders of the Parent Company	108.7	209.8	76.1	132.5
	108.7	**209.8**	76.1	132.5

Parent Company Balance Sheet in Summary

Expressed in MSEK	**31 December 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	16.7	17.3
Cash and cash equivalents	1.8	2.6
Total current assets	**18.5**	19.9
TOTAL ASSETS	**7,890.5**	7,891.9
SHAREHOLDERS' EQUITY AND LIABILITIES		
Shareholders' equity including net result for the period	7,860.5	7,814.0
Non-current liabilities		
Provisions	0.3	36.6
Payables to group companies	–	21.6
Total non-current liabilities	**0.3**	58.2
Current liabilities		
Current liabilities	16.2	19.7
Payables to group companies	13.5	–
Total current liabilities	**29.7**	19.7
Total liabilities	**30.0**	77.9
TOTAL EQUITY AND LIABILITIES	**7,890.5**	7,891.9
Pledged assets	8,717.8	12,014.5

Parent Company Cash Flow Statement in Summary

Expressed in MSEK	**1 Jan 2014-31 Dec 2014 12 months**	**1 Oct 2014-31 Dec 2014 3 months**	1 Jan 2013-31 Dec 2013 12 months	1 Oct 2013-31 Dec 2013 3 months
Cash flow from operations				
Net result	108.7	209.8	76.1	132.5
Adjustment for non-cash related items	-36.7	-36.5	-18.9	-19.2
Changes in working capital	11.0	-173.8	14.2	4.3
Total cash flow from operations	**83.0**	**-0.5**	71.4	117.6
Cash flow from investments				
Change in other fixed assets	-0.1	–	-0.2	-0.2
Total Cash flow from investments	**-0.1**	**–**	-0.2	-0.2
Cash flow from financing				
Change in long-term liabilities	-21.7	–	62.2	-116.3
Purchase of own shares	-62.2	–	-131.9	–
Total cash flow from financing	**-83.9**	**–**	-69.7	-116.3
Change in cash and cash equivalents	-1.0	-0.5	1.5	1.1
Cash and cash equivalents at the beginning of the period	**2.6**	**2.3**	1.1	1.5
Currency exchange difference in cash and cash equivalents	0.2	–	–	–
Cash and cash equivalents at the end of the period	**1.8**	**1.8**	2.6	2.6

Parent Company Statement of Changes in Equity in Summary

Expressed in MSEK	Restricted equity: Share capital	Restricted equity: Statutory reserve	Unrestricted equity: Other reserves	Unrestricted equity: Retained earnings	Unrestricted equity: 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	**–**	**–**	**–**	**76.1**	**76.1**	**76.1**
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	**–**	**–**	**–**	**108.7**	**108.7**	**108.7**
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 31 December 2014	**3.2**	**861.3**	**2,295.3**	**4,700.7**	**6,996.0**	**7,860.5**

[1] During the year 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- 31 Dec 2014 12 months**	**1 Oct 2014- 31 Dec 2014 3 months**	1 Jan 2013- 31 Dec 2013 12 months	1 Oct 2013- 31 Dec 2013 3 months
Revenue[1]	785.2	135.2	1,132.0	274.1
EBITDA	671.3	164.4	955.7	218.0
Net result	-431.9	-437.0	72.9	23.1
Operating cash flow	1,138.5	334.5	967.9	203.3

Data per share (USD)				
Shareholders' equity per share	1.40	1.40	3.90	3.90
Operating cash flow per share	3.63	1.08	3.12	0.66
Cash flow from operations per share	2.05	0.08	2.92	0.42
Earnings per share	-1.36	-1.41	0.25	0.08
Earnings per share fully diluted	-1.36	-1.41	0.25	0.08
EBITDA per share	2.14	0.53	3.08	0.70
Dividend per share	–	–	–	–
Number of shares issued at period end	311,070,330	311,070,330	317,910,580	317,910,580
Number of shares in circulation at period end	309,070,330	309,070,330	309,570,330	309,570,330
Weighted average number of shares for the period	313,387,579	309,070,330	310,017,074	309,570,330

Share price				
Quoted price at period end (SEK)	112.40	112.40	125.40	125.40
Quoted price at period end (CAD)[2]	–	–	19.73	19.73

Key ratios				
Return on equity (%)	-50	-50	6	2
Return on capital employed (%)	-11	-19	16	1
Net debt/equity ratio (%)	605	605	99	99
Equity ratio (%)	9	9	29	29
Share of risk capital (%)	28	28	53	53
Interest coverage ratio	-13	-54	52	13
Operating cash flow/interest ratio	49	33	149	108
Yield	–	–	–	–

[1] The comparatives have been restated for the effect of the adoption of IFRS 11 Joint Arrangements.
[2] The Lundin Petroleum share was delisted by management decision from the Toronto Stock exchange in November 2014.

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.

Stockholm, 4 February 2015

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

The Company will publish the following reports:

- The three month report (January — March 2015) will be published on 6 May 2015.
- The six month report (January — June 2015) will be published on 5 August 2015.
- The nine month report (January — September 2015) will be published on 4 November 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 2014, 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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