Lundin Petroleum

Q1

Report for the THREE MONTHS ended 31 March 2015

Lundin Petroleum AB (publ)

company registration number 556610-8055

Highlights

Three months ended 31 March 2015 (31 March 2014)

- Production of 25.8 Mboepd (26.6 Mboepd)[1]
- Revenue of MUSD 121.3 (MUSD 235.4)
- EBITDA of MUSD 86.0 (MUSD 177.8)
- Operating cash flow of MUSD 155.7 (MUSD 256.0)
- Net result of MUSD -230.9 (MUSD 3.2) including pre-tax exploration expenses of MUSD 45.4 and a net foreign exchange loss of MUSD 204.0
- Net debt of MUSD 3,063 (31 December 2014: MUSD 2,609)
- The Bøyla field, Norway and the Bertam field, Malaysia commenced production in January 2015 and April 2015 respectively
- The Plan for Development and Operations (PDO) for Johan Sverdrup Phase 1 was submitted to the Norwegian Ministry of Petroleum and Energy
- Eight exploration licences awarded in the Norwegian 2014 APA licensing round, six as operator

	1 Jan 2015– 31 Mar 2015 3 months	1 Jan 2014 – 31 Mar 2014 3 months	1 Jan 2014 – 31 Dec 2014 12 months
Production in Mboepd[1]	**25.8**	26.6	23.8
Revenue in MUSD	**121.3**	235.4	785.2
Net result in MUSD	**-230.9**	3.2	-431.9
Net result attributable to shareholders of the Parent Company in MUSD	**-229.9**	4.4	-427.2
Earnings/share in USD[2]	**-0.74**	0.01	-1.38
EBITDA in MUSD	**86.0**	177.8	671.3
Operating cash flow in MUSD	**155.7**	256.0	1,138.5

[1] Excluding production from Russian onshore assets following the sale of the assets in July 2014.
[2] Based on net result attributable to shareholders of the Parent Company.

Definitions

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

Abbreviations

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

Oil related terms and measurements

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

Letter to Shareholders

Dear fellow Shareholders,

I am very pleased to report that we are on track to deliver our 2015 objectives which I outlined in my year end 2014 Letter to Shareholders.

We brought onstream the Bertam field, offshore Malaysia, in early April 2015. This is the third new project which we have brought onstream in the last few months following the start-up of Brynhild and Bøyla, offshore Norway. Bertam is our first development project in South East Asia and we are very pleased that we have completed this fast-track project safely, on schedule and within budget. The cooperation between our team, partners, contractors and Petronas was excellent and I hope this will be a catalyst for further growth in this region. Edvard Grieg is our final project for delivery this year and it remains on schedule for first oil in the fourth quarter of 2015. The topsides are now completed and on barges awaiting offshore transportation. The flotel has arrived in Norway and the Thialf heavy lift crane is expected to arrive during the second quarter for a topside installation prior to offshore hook up and commissioning. As such we remain on track to achieve our forecast 2015 exit production rate of 75,000 boepd. We maintain our 2015 production guidance at 41,000 to 51,000 boepd.

The Johan Sverdrup Phase 1 plan of development was completed and submitted to the Norwegian Ministry of Petroleum and Energy for approval on schedule in February 2015. We expect to receive government approval in June 2015. This was a major milestone for Lundin Petroleum, our field partners and the Norwegian government. Johan Sverdrup is one of the five largest fields ever developed on the Norwegian Continental Shelf and is estimated to produce between 550,000 and 650,000 boepd and will ultimately recover reserves between 1.7 and 3.0 billion boe. At plateau, the field will contribute over 40 percent of total Norwegian oil production.

Four of the five partners of the Johan Sverdrup field have signed a Tract Participation Agreement which amongst other things allocated a working interest to Lundin Petroleum of 22.12 percent in the field. As a result of a lack of unanimous agreement of the Tract Participation Agreement, the Minister of Petroleum and Energy will set the final terms of the Field Tract Participation Agreement including working interests of the field partners. The unitisation issue has been the subject of a significant amount of press comment and public debate particularly in Norway. We have remained silent on the process and will continue to do so. However I think it is important that we make the following points. It is critical that the Tract Participation Agreement is structured to maximise the ultimate recoverable reserves of the Johan Sverdrup field and therefore the value of the whole field for the benefit of all stakeholders including the Norwegian State and the field partners. The Tract Participation Agreement which the four partners signed most certainly achieves these objectives even though we all had to make compromises to reach an agreement. Most importantly, we have together with the other partners who signed the Tract Participation Agreement ensured that the Johan Sverdrup development schedule proceeds as planned. We expect the Minister to opine on the final Tract Participation Agreement in June 2015 before the development plan approval.

We remain excited by the hydrocarbon potential of the southern Barents Sea. Our 2015 exploration and appraisal programme in the region is ongoing with the drilling of the first Alta appraisal well. This well will be followed by a further Alta appraisal well and two exploration wells. I hope that the programme will prove up additional resources and enable us to work with other operators in the area to find a commercially viable development solution to produce the discoveries in the southern Barents Sea.

Our access to liquidity remains very strong. Our existing production, low operating costs and minimal cash taxes ensure that we continue to generate positive operating cash flow even down to low oil prices. This coupled with the continued full availability of our USD 4 billion reserve based lending facility ensures that we have more than adequate liquidity to fulfill our ongoing development project costs as well as continuing to explore. Our liquidity position has been further enhanced recently with the finalisation of a NOK 4.5 billion Norwegian exploration facility from ten international banks.

Over recent weeks oil prices have recovered from the sub USD 50 per barrel prices which we saw earlier in the year. Lower oil prices have certainly had an impact on development drilling particularly in the North American shale oil business where operational rigs have reduced by over 50 percent from the height of activity last year. This has already started to have an impact upon oil supply growth with month to month US production growth having already turned negative. This will most certainly continue to reduce further over the forthcoming months. In addition, industry capital expenditures in the rest of the world have been significantly reduced. Very few developments are being sanctioned in this oil price environment and the result will be a reduction in oil supply levels going forward. At the same time oil demand has remained relatively robust despite the weak world economic growth. I remain confident that oil prices will increase further in the medium to long term.

As a result, the future looks bright for our Company. We will weather the industry storm created by lower oil prices. We will deliver significant production growth with Edvard Grieg coming onstream later this year. The Johan Sverdrup project is moving forward and will be approved this year and will deliver further production growth in years to come. I am confident that our exploration activities will yield further positive discoveries and I remain particularly excited about the southern Barents Sea prospectivity. We have the money, people and desire to achieve our objectives which will maximise shareholder value and at the same time we will continue to operate in a safe manner in line with our obligations of being a responsible Company.

Yours Sincerely,

C. Ashley Heppenstall
President and CEO

Stockholm, 6 May 2015

Financial Report for the Three Months Ended 31 March 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 70 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 1.7 and 3.0 billion boe and Lundin Petroleum will book its net working interest in Johan Sverdrup as reserves once the unitisation agreement has been finalised.

Production

Production for the three month period ending 31 March 2015 (reporting period) amounted to 25.8 thousand barrels of oil equivalent per day (Mboepd) (compared to 26.6 Mboepd over the same period in 2014) and was comprised as follows:

Production in Mboepd	**1 Jan 2015– 31 Mar 2015 3 months**	1 Jan 2014– 31 Mar 2014 3 months	1 Jan 2014– 31 Dec 2014 12 months
Crude oil			
Norway	17.3	17.0	15.0
France	2.9	3.0	2.9
Total crude oil production	**20.2**	20.0	17.9
Gas			
Norway	2.1	3.0	2.6
Netherlands	1.8	2.1	1.9
Indonesia	1.7	1.5	1.4
Total gas production	**5.6**	6.6	5.9
Total production			
Quantity in Mboe	**2,322.4**	2,390.3	8,688.8
Quantity in Mboepd	**25.8**	26.6	23.8

Note: The comparatives have been restated following the sale of the Russian onshore assets in 2014.

Norway

Production

Production in Mboepd	WI[1]	**1 Jan 2015– 31 Mar 2015 3 months**	1 Jan 2014– 31 Mar 2014 3 months	1 Jan 2014– 31 Dec 2014 12 months
Alvheim	15%	8.6	9.8	9.6
Volund	35%	5.8	9.5	7.4
Brynhild	90%	3.1	–	0.1
Bøyla	15%	1.9	–	–
Gaupe	40%	–	0.7	0.5
		19.4	20.0	17.6

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

Production from the Alvheim field during the reporting period has been slightly below forecast due predominantly to unscheduled facilities downtime. The reservoir on the Alvheim field continues to perform well and the Alvheim FPSO also continues to achieve excellent uptime. The drilling of a new infill well on Alvheim commenced during the fourth quarter of 2014 and the well commenced production in April 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. In addition to these infill wells, one well which is currently shut-in is planned to be worked-over during the second quarter of 2015. The development of the Viper/Kobra discoveries was sanctioned by the Alvheim partnership in December 2014 with two production wells planned to be drilled in 2016 with an expected production start-up in late 2016. The cost of operations for the Alvheim field, excluding well intervention work, was below USD 5 per barrel during the period.

The Volund field production during the reporting period has been better than forecast due to good reservoir performance and a stabilising water-cut rate. 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 cost of operations for the Volund field, during the reporting period was below USD 4 per barrel.

Production from the Brynhild field commenced on 25 December 2014. Two production wells have been completed and have been put into production with the initial production rates confirming the field's production plateau capacity of 12,000 boepd. Shortly after commencement of production certain issues caused the field to be shut-in for approximately seven weeks thus resulting in production for the reporting period being lower than forecast. The main issues leading to the shut-in related to a leak on the flexible gas injection line and a damaged connection point between one of the mooring lines and the riser buoy. The field re-commenced production in early March 2015 but has remained below well capacity due to facilities related issues. The third and fourth wells, one oil producer and one water injector, are in the process of being completed concurrently. Both of these wells are expected to come on-line mid-year 2015.

The Bøyla field commenced production on 19 January 2015 from one production well. The field has produced as expected during the reporting period with the water injection well coming on-line in March 2015. The third and final development well was drilled and completed during the reporting period and the well will be tied-in during the third quarter of 2015 when the field is expected to reach plateau production.

There was no production from the Gaupe field during the reporting period and no remaining reserves have been booked for this field. The field recommenced production in April 2015 and will be produced intermittently subject to economic conditions.

Development

Licence	Field	WI	PDO Approval	Estimated gross reserves	Production start expected	Gross plateau production rate expected
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	22.12%[1]	Expected mid-2015	1.7 – 3.0 billion boe[2]	Late 2019	550.0 – 650.0 Mboepd

[1] Subject to governmental approval, see Johan Sverdrup section below.
[2] Gross contingent resource range as disclosed by operator Statoil in February 2015.

Edvard Grieg

The Edvard Grieg field development is well advanced and is progressing as expected. In April 2015, Kværner completed the construction of the topsides on time and on budget. The onshore commissioning of the topsides is also complete and offshore installation of the topsides on the pre-installed jacket is scheduled during the second quarter of 2015. The newbuild flotel Safe Boreas which is to be used for the offshore commissioning has arrived in Norway and the Heerema heavy lift vessel Thialf is expected to arrive during the second quarter of 2015 for the offshore installation. The 94 km gas pipeline was installed in 2014 and the 43 km oil pipeline to the Grane oil export system was successfully installed during the reporting period. Development drilling commenced during the third quarter of 2014 with the Rowan Viking jack-up rig and drilling is progressing as per schedule. First oil from the pre-drilled wells is expected in the fourth quarter of 2015 following the completion of the offshore hook-up and commissioning. Plateau production from the Edvard Grieg field is expected during 2016 and development drilling will continue into 2017.

Following last year's successful appraisal well on the southeastern part of Edvard Grieg, which encountered moderate/good reservoir quality sandstone, a second 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 gross reserves by up to 50 MMboe.

Ivar Aasen

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. The construction of the steel jacket has been completed and installation is scheduled during the second quarter of 2015 and the pipeline installation is scheduled to commence during the third quarter of 2015. The topsides installation is scheduled during the summer of 2016. In April 2015, the operator Det norske oljeselskap announced that two geo-pilot wells on the central part of the field had been completed. One further appraisal well is planned to be drilled on the western part of the field during the second quarter of 2015. Ivar Aasen is forecast to come onstream during the fourth quarter of 2016.

Johan Sverdrup

In February 2015, the Johan Sverdrup partnership submitted a Plan for Development and Operations (PDO) for Phase 1 to the Ministry of Petroleum and Energy. The PDO for Phase 1 also outlines certain development concepts for the full field involving an expected full field gross plateau production level of between 550,000 boepd and 650,000 boepd and gross contingent resources of between 1.7 to 3.0 billion boe with approximately 95 percent of the resources being oil. In parallel with the PDO submission, the majority of the Johan Sverdrup partnership also submitted a Tract Participation agreement for the Johan Sverdrup field with a working interest of 22.12 percent to Lundin Petroleum. The Minister of Petroleum and Energy will now determine the final terms of the Tract Participation agreement.

The PDO for Phase 1 involves a field centre, consisting of one processing platform, one riser platform, one wellhead platform with drilling facilities and one living quarter platform. The platforms will be installed on steel jackets in 120 metres of water and will be bridge-linked. The partnership will be awarding most of the major contracts during 2015 with some major contracts already awarded including contracts for the steel jacket for the riser platform, an engineering and procurement contract for the riser and processing platform topsides, an EPC contract for the drilling platform topsides, an installation contract for three of the platforms and a contract for the power from shore project.

The Phase 1 development is scheduled to start production in late 2019 and is forecast to have a gross production capacity of between 315,000 and 380,000 bopd. 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 Phase 1 capital expenditure has been estimated at gross NOK 117 billion with the full field capital expenditure, including Phase 1, estimated at between NOK 170 to 220 billion.

Appraisal

2015 appraisal well programme

Licence	Operator	WI	Well	Spud Date	Status
PL609	Lundin Petroleum	40%	7220/11-2	March 2015	Ongoing
PL609	Lundin Petroleum	40%		May 2015	
PL338	Lundin Petroleum	50%		Second Quarter 2015	

Lundin Petroleum is currently drilling the first of two appraisal wells on its Alta discovery in the southern Barents Sea. The main objective of well 7220/11-2 is to confirm the reservoir model and prove the presence of hydrocarbon columns and fluid contacts similar to those established in the Alta discovery well which was drilled in 2014 approximately 6.5 km to the northeast. The second appraisal well which will be drilled immediately after the completion of the 7220/11-2 well will test the reservoir quality and extension on the eastern side of the Alta structure.

Exploration

2015 exploration well programme

Licence	Well	Spud Date	Target	WI	Operator	Result
Utsira High						
PL338C	16/1-24	February	Gemini	50%	Lundin Petroleum	Dry
PL674BS	26/10-1	January	Zulu	35%	Lundin Petroleum	Gas discovery — non-commercial
PL359		Second quarter	Luno II North	50%	Lundin Petroleum	
PL544		Fourth quarter	Fosen	40%	Lundin Petroleum	
Southern Barents Sea						
PL708		Fourth quarter	Ørnen	40%	Lundin Petroleum	
PL609		Third quarter	Neiden	40%	Lundin Petroleum	
Other Areas						
PL579	33/2-1	March	Morkel	50%	Lundin Petroleum	Ongoing
PL734		Third quarter	Zeppelin	30%	Wintershall	
PL700		Fourth quarter	Lorry	40%	Lundin Petroleum	

Lundin Petroleum has completed two exploration wells in Norway during the reporting period.

The drilling of the Zulu prospect in PL674BS encountered a 24 metres sand sequence containing gas. The Zulu gas discovery is viewed as being non-commercial.

The drilling of the Gemini prospect in PL338C located immediately to the west of the Edvard Grieg field failed to encounter any hydrocarbons and the well was plugged and abandoned as a dry.

In addition to the currently drilling Morkel well in PL579, Lundin Petroleum will drill another six wells offshore Norway during 2015 targeting net unrisked prospective resources of 515 MMboe.

Lundin Petroleum, together with 32 other companies signed a contract last 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. The Ministry of Petroleum and Energy has also announced the APA 2015 licensing round with an application deadline in September 2015 with possible awards expected during the first quarter of 2016.

Licence awards, transactions and relinquishments

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.

During the reporting period, Lundin Petroleum farmed out 30 percent in PL338C (WI 50% after farm-out) and 30 percent in PL544 (WI 50% after farm-out) to Lime Petroleum Norway. Lundin Petroleum's working interest in PL410 located on the Utsira High has increased to 82.352 percent following partner withdrawals. Lundin Petroleum has withdrawn from PL583. During the reporting period licences PL490, PL641, PL646 and PL639 have been relinquished. Certain of the above transactions and relinquishments remain subject to governmental approvals.

Continental Europe

Production

Production in Mboepd	WI	**1 Jan 2015– 31 Mar 2015 3 months**	1 Jan 2014 – 31 Mar 2014 3 months	1 Jan 2014 – 31 Dec 2014 12 months
France				
– Paris Basin	100%[1]	2.4	2.5	2.5
– Aquitaine	50%	0.5	0.5	0.4
Netherlands	Various	1.8	2.1	1.9
		4.7	5.1	4.8

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

France
Production levels during the reporting period from France are substantially in line with forecast with good production performance from Aquitaine following the completion of certain well work-over activity. The construction of onshore facilities and the drilling and completion of two development wells on the Vert la Gravelle re-development project in the Paris Basin has been finalised.

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

The K5-A5 (Licence Interest 2.03%) development well was successfully drilled in 2014 and is expected to be put on production by mid-2015. The K5-A6 (Licence Interest 2.03%) development well was drilled during the reporting period, however the reservoir was found to be depleted and the well has been plugged and abandoned. The E17-A5 (WI 1.20%) development well is currently drilling ahead. The Slootdorp-6 and 7 onshore development wells (WI 7.2325%) are also currently drilling.

The Langezwaag-2 exploration well on the Gorredijk licence (WI 7.75%) which was successfully drilled in 2014 was put on production in January 2015.

South East Asia

Malaysia
Offshore, Peninsular Malaysia
The Bertam field on PM307 (WI 75%) achieved first oil in April 2015 and has commenced production from four pre-drilled wells. The Bertam FPSO was successfully spread-moored and hooked-up to the wellhead platform during the reporting period and the drilling of the development wells is continuing until late 2015 when the Bertam field will achieve its plateau production rate of gross 15,000 boepd. The Bertam field is estimated to contain gross reserves of 18 MMboe and the total gross development costs are estimated at MUSD 400, excluding any FPSO related costs.

Two exploration wells are planned to be drilled on 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.

A 3D seismic survey is planned to be shot on PM328 (WI 50%) during 2015.

East Malaysia, offshore Sabah
Lundin Petroleum is currently high-grading its prospect inventory for SB307/SB308 (WI 42.5%) on existing 3D seismic, with a view to identify drilling targets for potential drilling in 2016.

Indonesia

Production

Production in Mboepd	WI	**1 Jan 2015– 31 Mar 2015 3 months**	1 Jan 2014– 31 Mar 2014 3 months	1 Jan 2014– 31 Dec 2014 12 months
Singa	25.9%	1.7	1.5	1.4

The production from the Singa field has been in line with the forecast during the reporting period. The field was shut-in during part of 2014 to allow for a re-routing of the gas pipeline and since the field re-commenced production in late 2014 the production performance has been good.

Exploration

South Sokang

Lundin Petroleum is continuing with its efforts to high-grade its prospect inventory on the South Sokang Block (WI 60%) from recently acquired 3D seismic data. Both oil and gas prospectivity has been 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 Cendrawasih VIII Block which is contiguous to Cendrawasih VII Block. The acquisition of 2D seismic has commenced.

Other Areas

Russia

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. Lundin Petroleum has submitted an application for a production licence for the Lagansky Block which will allow the field to be appraised.

Corporate Responsibility

During the reporting period, Lundin Petroleum had one low severity Lost Time Incident (LTI), which resulted in a LTI frequency rate of 0.18 per 200,000 hours. The total recordable incident rate (TRIR) was 0.54.

FINANCIAL REVIEW

Result

The net result for the three month period ended 31 March 2015 amounted to MUSD -230.9 (MUSD 3.2). The net result attributable to shareholders of the Parent Company for the reporting period amounted to MUSD -229.9 (MUSD 4.4) representing earnings per share of USD -0.74 (USD 0.01).

Earnings before interest, tax, depletion and amortisation (EBITDA) for the reporting period amounted to MUSD 86.0 (MUSD 177.8) representing EBITDA per share of USD 0.28 (USD 0.57). Operating cash flow for the reporting period amounted to MUSD 155.7 (MUSD 256.0) representing operating cash flow per share of USD 0.50 (USD 0.83).

Changes in the Group

There have been no significant changes in the Group during the reporting period.

Revenue

Revenue for the reporting period amounted to MUSD 121.3 (MUSD 235.4) and was comprised of net sales of oil and gas, change in under/over lift position and other revenue as detailed in Note 1.

Net sales of oil and gas for the reporting period amounted to MUSD 126.6 (MUSD 236.0). The average price achieved by Lundin Petroleum for a barrel of oil equivalent amounted to USD 52.71 (USD 97.63) and is detailed in the following table. The average Dated Brent price for the reporting period amounted to USD 53.94 (USD 108.21) per barrel.

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

Sales Average price per boe expressed in USD	**1 Jan 2015– 31 Mar 2015 3 months**	1 Jan 2014– 31 Mar 2014 3 months	1 Jan 2014– 31 Dec 2014 12 months
Crude oil sales			
Norway			
– Quantity in Mboe	1,704.8	1,575.9	5,183.3
– *Average price per boe*	*53.61*	*110.38*	*102.35*
France			
– Quantity in Mboe	203.3	232.6	1,028.7
– *Average price per boe*	*57.86*	*105.62*	*94.08*
Netherlands			
– Quantity in Mboe	0.5	0.6	1.1
– *Average price per boe*	*62.32*	*94.43*	*91.64*
Total crude oil sales			
– Quantity in Mboe	**1,908.6**	1,809.1	6,213.1
– Average price per boe	***54.07***	*109.77*	*100.98*
Gas and NGL sales			
Norway			
– Quantity in Mboe	195.8	299.7	1,080.8
– *Average price per boe*	*49.59*	*67.05*	*56.02*
Netherlands			
– Quantity in Mboe	160.9	188.1	687.9
– *Average price per boe*	*41.95*	*61.45*	*51.11*
Indonesia			
– Quantity in Mboe	136.8	120.9	457.2
– *Average price per boe*	*50.87*	*48.10*	*47.87*
Total gas and NGL sales			
– Quantity in Mboe	493.5	608.7	2,225.9
– *Average price per boe*	*47.46*	*61.55*	*52.83*
Total sales			
– Quantity in Mboe	**2,402.1**	2,417.8	8,439.0
– Average price per boe	***52.71***	*97.63*	*88.28*

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

The change in under/over lift position amounted to a net charge of MUSD 8.4 (MUSD 4.6) in the reporting period. There was an overlift of entitlement movement on the Brynhild field, partly offset by a net underlift on the Alvheim, Volund and Bøyla fields during the reporting period due to the timing of the cargo liftings compared to production.

Other revenue amounted to MUSD 3.1 (MUSD 4.0) for the reporting period and included a quality differential compensation on Alvheim blended crude, tariff income from France and the Netherlands and income for maintaining strategic inventory levels in France.

Production costs

Production costs including inventory movements for the reporting period amounted to MUSD 25.2 (MUSD 38.4) and are detailed in the table below.

Production costs	**1 Jan 2015– 31 Mar 2015 3 months**	1 Jan 2014 – 31 Mar 2014 3 months	1 Jan 2014 – 31 Dec 2014 12 months
Cost of operations			
– In MUSD	21.4	30.6	94.4
– In USD per boe	*9.20*	*12.80*	*10.86*
Tariff and transportation expenses			
– In MUSD	2.5	4.8	18.4
– In USD per boe	*1.10*	*2.02*	*2.12*
Royalty and direct production taxes			
– In MUSD	0.7	0.9	3.6
– In USD per boe	*0.31*	*0.39*	*0.41*
Change in inventory position			
– In MUSD	-2.4	-0.2	-0.8
– In USD per boe	*-1.04*	*-0.08*	*-0.09*
Other			
– In MUSD	3.0	2.3	-49.1
– In USD per boe	*1.30*	*0.92*	*-5.65*
Total production costs			
– In MUSD	**25.2**	38.4	66.5
– In USD per boe	***10.87***	*16.05*	*7.65*

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

The total cost of operations for the reporting period was MUSD 21.4 (MUSD 30.6). The comparative period 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. The total cost of operations excluding operational projects amounted to MUSD 20.3 (MUSD 18.1) with the increase versus the comparative period being attributable to operating costs of the Brynhild and Bøyla fields which came onstream in the fourth quarter of 2014 and the first quarter of 2015 respectively, partly offset by the impact of the stronger US Dollar on the funding of non-US Dollar denominated expenditures in the reporting period.

The cost of operations per barrel including operational projects amounted to USD 9.20 (USD 12.80) for the reporting period which is in line with guidance provided at the Capital Market Day in February 2015. Excluding operational projects, the cost of operations amounted to USD 8.75 (USD 7.56) per barrel which is also in line with the guidance provided in February.

Tariff and transportation expenses for the reporting period amounted to MUSD 2.6 (MUSD 4.8). The decrease in costs compared to the same period last year is mainly due to lower volumes from the Volund field and no production volumes from the Gaupe field in the reporting period.

Other costs amounted to MUSD 2.9 (MUSD 2.3) and related to the operating cost share arrangement on the Brynhild field whereby the amount of operating cost varies with the oil price until mid-2017. This arrangement is being marked-to-market against the oil price curve and due to the low oil price curve at the end of 2014, an asset was recognised as at 31 December 2014. This asset is being charged to the income statement over the remaining term of the arrangement.

Depletion and decommissioning costs

Depletion costs amounted to MUSD 43.1 (MUSD 35.1) at an average rate of USD 18.55 (USD 14.66) per barrel and are detailed in Note 3. Norway's contribution to the total depletion cost for the reporting period was 77 percent (68 percent) at an average rate of USD 18.91 (USD 13.14) per barrel. The higher depletion cost for the reporting period compared to the same period last year is due to the contributions of the Brynhild and Bøyla fields, partly offset by no production volumes from the Gaupe field and lower production volumes on the Alvheim and Volund fields in the reporting period.

Exploration costs

Exploration costs expensed in the income statement for the reporting period amounted to MUSD 45.4 (MUSD 126.9) and are detailed in Note 3. Exploration and appraisal costs are capitalised as they are incurred. When exploration drilling is unsuccessful, the capitalised costs are expensed. All capitalised exploration costs are reviewed on a regular basis and are expensed where their recoverability is considered highly uncertain.

During the reporting period, exploration costs relating to Norway of MUSD 44.9 were expensed and mainly related to two unsuccessful wells that were drilled in PL338C (Gemini) and PL674BS (Zulu).

General, administrative and depreciation expenses

The general, administrative and depreciation expenses for the reporting period amounted to MUSD 11.3 (MUSD 20.4) which included a charge of MUSD 0.6 (MUSD 5.4) in relation to the Group's long-term incentive plans (LTIP), see also Remuneration section below. Fixed asset depreciation charges for the reporting period amounted to MUSD 1.1 (MUSD 1.2).

Finance income

Finance income for the reporting period amounted to MUSD 0.9 (MUSD 27.4) and is detailed in Note 4. The comparative period includes a net foreign currency exchange gain of MUSD 26.9.

Finance costs

Finance costs for the reporting period amounted to MUSD 226.1 (MUSD 12.2) and are detailed in Note 5.

Interest expenses for the reporting period amounted to MUSD 11.8 (MUSD 1.9) and represented the portion of interest charged to the income statement. An additional amount of interest of MUSD 9.8 (MUSD 8.7) primarily associated with the funding of the Norwegian and Malaysian development projects was capitalised in the reporting period.

Net foreign exchange losses for the reporting period amounted to MUSD 204.0 (MUSD -26.9 gain). This foreign exchange loss mainly relates to the revaluation of loan balances at the prevailing exchange rates at the end of the reporting period. The US Dollar strengthened significantly against the Euro during the first quarter of 2015 resulting in a foreign exchange loss on the US Dollar denominated external loan which is borrowed by a subsidiary using Euro as functional currency. This foreign exchange loss was partly offset by a smaller foreign exchange gain relating to the strengthening of the Norwegian Krone against the Euro in the first quarter of 2015, generating a foreign exchange gain 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. For the reporting period, the net realised exchange loss on settled foreign exchange hedges amounted to MUSD 41.0 (MUSD 1.2 gain). In addition, there was a net foreign exchange loss recognised within other comprehensive income on foreign entities translated to the presentation currency of the Group of MUSD 18.4 (MUSD 8.6) and a further loss movement on the unsettled part of the cash flow hedges of MUSD 45.6 (MUSD -29.0 gain) which mainly related to the unsettled foreign currency hedges.

The amortisation of the deferred financing fees amounted to MUSD 2.9 (MUSD 2.8) for the reporting period and related to the expensing of the fees incurred in establishing the financing facility over the period of usage of the facility.

Loan facility commitment fees for the reporting period amounted to MUSD 3.0 (MUSD 4.9) with the decrease compared to the same period last year being due to the increased borrowings under the facility.

Tax

The tax charge for the reporting period amounted to MUSD 2.0 (MUSD 26.5).

The current tax credit for the reporting period amounted to MUSD 59.6 (MUSD 58.9) of which MUSD 61.1 (MUSD 64.5) related to the Norway exploration tax refund due to the significant level of development and exploration and appraisal expenditure in Norway in the reporting period and the tax depreciation on development expenditure incurred in prior years. The current tax credit in Norway for the reporting period is partly offset by the current tax charge relating to operations in France and the Netherlands.

The deferred tax charge for the reporting period amounted to MUSD 61.6 (MUSD 85.4) which predominantly related to Norway. The deferred tax charge arises primarily where there is a difference in depletion for tax and accounting purposes. There is a deferred tax credit of MUSD 35.0 relating to the Norwegian exploration costs expensed in the reporting period.

The Group operates in various countries and fiscal regimes where corporate income tax rates are different from the regulations in Sweden. Corporate income tax rates for the Group vary between 20 percent and 78 percent. The effective tax rate for the reporting period is affected by items which do not receive a full tax credit such as the net foreign exchange loss reported and by the uplift allowance applicable in Norway for development expenditures against the offshore 51 percent tax regime.

Non-controlling interest

The net result attributable to non-controlling interest for the reporting period amounted to MUSD -1.0 (MUSD -1.2) and related mainly to the non-controlling interest's share in a Russian subsidiary which is fully consolidated.

Balance Sheet

Non-current assets

Oil and gas properties amounted to MUSD 4,242.2 (MUSD 4,182.6) and are detailed in Note 7.

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

Development expenditure in MUSD	**1 Jan 2015– 31 Mar 2015 3 months**	1 Jan 2014– 31 Mar 2014 3 months	1 Jan 2014– 31 Dec 2014 12 months
Norway	240.1	286.1	1,068.2
France	9.4	2.3	29.3
Netherlands	1.0	0.7	3.9
Indonesia	–	–	-0.8
Malaysia	53.4	14.4	130.6
	303.9	303.5	1,231.2

An amount of MUSD 240.1 (MUSD 286.1) of development expenditure was incurred in Norway during the reporting period, of which MUSD 214.1 (MUSD 275.0) was invested in the Edvard Grieg, Brynhild and Johan Sverdrup field developments. In Malaysia, MUSD 53.4 (MUSD 14.4) was incurred during the reporting period on the Bertam field development.

An amount of MUSD 21.7 (MUSD 48.3) was incurred during the first quarter of 2015 on the continued upgrade of the Bertam FPSO in readiness for first production from 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 2015– 31 Mar 2015 3 months**	1 Jan 2014– 31 Mar 2014 3 months	1 Jan 2014– 31 Dec 2014 12 months
Norway	80.4	113.2	572.8
France	0.1	0.3	5.9
Indonesia	0.4	25.9	47.5
Malaysia	0.9	1.8	42.7
Russia	0.6	0.9	4.0
Other	0.1	0.5	1.6
	82.5	142.6	674.5

Exploration and appraisal expenditure of MUSD 80.4 (MUSD 113.2) was incurred in Norway during the reporting period, primarily on the appraisal drilling of the Alta discovery in the southern Barents Sea and the exploration wells on the Gemini, Zulu and Morkel prospects. Both the Alta and Morkel wells were drilling at 31 March 2015.

Other tangible fixed assets amounted to MUSD 218.2 (MUSD 200.3) and included amounts relating to the Bertam FPSO.

Financial assets amounted to MUSD 33.7 (MUSD 37.0) and are detailed in Note 8. Other shares and participations amounted to MUSD 7.3 (MUSD 4.7) 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. The main change in the value since the year end relates to the additional shares acquired from the ShaMaran rights issue completed during the first quarter of 2015, see also Related Party Transactions section below. Brynhild operating cost share amounted to MUSD 25.1 (MUSD 31.0) 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.

Deferred tax assets amounted to MUSD 10.4 (MUSD 12.9) 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.

Other non-current assets amounted to MUSD 58.6 (MUSD –) and related to the Norwegian corporate tax refund in respect of the current year which will be received in December 2016.

Current assets

Inventories amounted to MUSD 34.7 (MUSD 41.6) and included both well supplies mainly held in Norway and Malaysia and hydrocarbon inventories.

Trade and other receivables amounted to MUSD 146.6 (MUSD 163.5) and are detailed in Note 10. Trade receivables, which are all current, amounted to MUSD 52.8 (MUSD 40.3). Underlift amounted to MUSD 5.4 (MUSD 3.6) and was mainly attributable to a net underlift position in Norway on the Alvheim, Volund and Bøyla fields. Joint operations debtors amounted to MUSD 29.0 (MUSD 49.1) and the comparative amount included a significant amount that was settled in January 2015. Prepaid expenses and accrued income amounted to MUSD 32.1 (MUSD 41.5) and represented prepaid operational and insurance expenditure. Brynhild operating cost share amounted to MUSD 20.4 (MUSD 21.6) 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 6.9 (MUSD 7.4) and included VAT and other miscellaneous balances.

Current tax assets amounted to MUSD 346.2 (MUSD 373.6) and mainly related to the Norwegian corporate tax refund in respect of 2014 which is due to be received in December 2015. The amount is denominated in Norwegian Kroner and the movement in US Dollar terms since year end results from the strengthening of the US Dollar against the Norwegian Krone.

Cash and cash equivalents amounted to MUSD 51.9 (MUSD 80.5). Cash balances are held to meet ongoing operational funding requirements.

Non-current liabilities

Financial liabilities amounted to MUSD 3,084.4 (MUSD 2,654.0) and are detailed in Note 11. Bank loans amounted to MUSD 3,115.0 (MUSD 2,690.0) and related to the outstanding loan under the Group's USD 4.0 billion revolving borrowing base facility. Capitalised financing fees relating to the establishment costs of the financing facility amounted to MUSD 30.6 (MUSD 36.0) and are being amortised over the expected life of the financing facility.

Provisions amounted to MUSD 292.6 (MUSD 288.0) and are detailed in Note 12. The provision for site restoration amounted to MUSD 278.5 (MUSD 274.1) and related to future decommissioning obligations. The provision has increased during the reporting period due to additions relating to the Norwegian and Malaysian development projects. The non-current portion of the provision for Lundin Petroleum's LTIP scheme amounted to MUSD 2.5 (MUSD 1.8). Lundin Petroleum's LTIP scheme is outlined in this report under the Remuneration section. Farm-in payment amounted to MUSD 6.5 (MUSD 7.5) and related to a provision for payments towards historic costs based on production milestones on Block PM307, Malaysia, see also Current Liabilities section.

Deferred tax liabilities amounted to MUSD 958.5 (MUSD 973.3) of which MUSD 833.3 (MUSD 844.8) 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.

Derivative instruments amounted to MUSD 48.6 (MUSD 33.9) and related to the mark-to-market loss on outstanding foreign currency and interest rate hedges due to be settled after twelve months.

Other non-current liabilities amounted to MUSD 29.5 (MUSD 29.1) and mainly represent the full consolidation of a subsidiary in which the non-controlling interest entity has made funding advances in relation to LLC PetroResurs, Russia.

Current liabilities

Trade and other payables amounted to MUSD 394.2 (MUSD 491.4) and are detailed in Note 13. Overlift amounted to MUSD 10.1 (MUSD –) and related to the Brynhild field where the first cargo was lifted in March 2015. Joint operations creditors and accrued expenses amounted to MUSD 309.6 (MUSD 383.5) and related mainly to the development and drilling activity in Norway and on the Bertam field, Malaysia. Other accrued expenses amounted to MUSD 42.0 (MUSD 46.1) and included an amount of MUSD 21.5 (MUSD 19.4) relating to the work done on the Bertam FPSO. The liability for the long-term incentive plans amounted to MUSD 22.6 (MUSD 28.2) and largely represents the second tranche of the 2009 phantom option plan due within twelve months.

Derivative instruments amounted to MUSD 114.8 (MUSD 101.4) and related to the mark-to-market loss on outstanding foreign currency and interest rate hedge contracts due to be settled within twelve months.

Current provisions amounted to MUSD 47.1 (MUSD 53.4) and included an amount of MUSD 42.0 (MUSD 48.5) relating to a payment for historic costs on Block PM307, Malaysia, which is payable on first oil from the Bertam project. The amount is payable in Malaysian Ringgit and the strengthening of the US Dollar against the Malaysian Ringgit has resulted in a reduction of the liability in US Dollar terms since the year end. An amount of MUSD 5.1 (MUSD 4.9) relating to the current portion of the provision for Lundin Petroleum's Unit Bonus Plan is included in current provisions.

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 -17.2 (MSEK -40.3) for the reporting period.

The result included general and administrative expenses of MSEK 25.7 (MSEK 41.7) and finance income of MSEK 1.8 (MSEK 0.8).

Pledged assets of MSEK 7,157.3 (MSEK 8,717.8) 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 0.1 (MUSD 0.1) from related parties for the provision of office and other services. The Group paid MUSD – (MUSD 0.1) to related parties in respect of services received.

Following a rights issue by ShaMaran Petroleum that was completed in February 2015, Lundin Petroleum acquired 46.5 million ShaMaran shares for a total consideration of CAD 4.65 million and received a further 7.3 million ShaMaran shares as a fee for guaranteeing the offering along with other major shareholders. As at 31 March 2015, Lundin Petroleum holds a total of 103.8 million ShaMaran shares, representing approximately 6.6 percent of the total outstanding ShaMaran shares at that date.

Liquidity

In 2014, Lundin Petroleum increased its financing facility to USD 4.0 billion. The financing facility is a revolving borrowing base facility secured against certain cash flows generated by the Group. The amount available under the facility is recalculated every six months based upon the calculated cash flow generated by certain producing fields and fields under development at an oil price and economic assumptions agreed with the banking syndicate providing the facility. The facility is secured by a pledge over the shares of certain Group companies and a charge over some of the bank accounts of the pledged companies. The pledged amount at 31 March 2015 is MUSD 828.9 (MUSD 1,126.8) 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 March 2015 was MUSD 40.3. An additional bank guarantee in support of work commitments in Indonesia was also in place at 31 March 2015 for an amount of MUSD 1.0.

Subsequent Events

The Bertam field, offshore Malaysia, commenced production in April 2015.

In April 2015, Lundin Petroleum has entered into a NOK 4.5 billion Norwegian exploration facility with ten international banks. The facility is secured against the tax refunds generated from Lundin Norway's exploration and appraisal activities on the Norwegian Continental Shelf and extends for a period of two years.

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. At 31 March 2015 the Company holds 2,000,000 of its own shares.

Remuneration

Lundin Petroleum's principles for remuneration and details of the long-term incentive plans are provided in the Company's 2014 Annual Report and in the materials provided to shareholders in respect of the 2015 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 March 205 were 114,100, 270,316 and 375,024 respectively.

Performance Based Incentive Plan

The AGM 2014 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 1 July 2014 and 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. Each award was fair valued at the date of grant at SEK 81.40 using an option pricing model.

Accounting Policies

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

The accounting policies adopted are in all other aspects consistent with those followed in the preparation of the Group's annual financial statements for the year ended 31 December 2014.

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

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

Risks and Risk Management

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

A detailed analysis of Lundin Petroleum's strategic, operational, financial and external risks and mitigation of those risks through risk management is described in Lundin Petroleum's 2014 Annual Report.

Derivative financial instruments

At 31 March 2015, Lundin Petroleum had outstanding currency swap hedges to meet a part of the future NOK operational requirements as summarised below:

Buy	Sell	Average contractual exchange rate	Settlement period
MNOK 2,938.4	MUSD 458.2	NOK 6.41:USD 1	Apr 2015 – Dec 2015
MNOK 1,251.8	MUSD 182.5	NOK 6.86:USD 1	Jan 2016 – Jun 2016

At 31 March 2015, Lundin Petroleum had also entered into the following interest rate hedge contracts as follows:

Borrowings expressed in MUSD	Fixing of floating LIBOR Rate per annum	Settlement period
500	0.57%	1 Apr 2013 – 31 Mar 2016
1,500	0.52%	1 Jan 2015 – 31 Dec 2015
1,500	1.50%	1 Jan 2016 – 31 Mar 2016
2,000	1.50%	1 Apr 2016 – 31 Dec 2016
1,500	2.32%	1 Jan 2017 – 31 Dec 2017
1,000	3.06%	1 Jan 2018 – 31 Dec 2018

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

Exchange Rates

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

	31 Mar 2015		31 Mar 2014		31 Dec 2014	
	Average	Period end	Average	Period end	Average	Period end
1 USD equals NOK	7.7533	8.0895	6.0944	5.9871	6.3011	7.4332
1 USD equals Euro	0.8873	0.9295	0.7301	0.7253	0.7526	0.8236
1 USD equals Rouble	63.0779	58.0351	35.1001	35.3786	38.3878	59.5808
1 USD equals SEK	8.3267	8.6347	6.4666	6.4899	6.8457	7.7366

Consolidated Income Statement

Expressed in MUSD	Note	**1 Jan 2015– 31 Mar 2015 3 months**	1 Jan 2014 – 31 Mar 2014 3 months	1 Jan 2014 – 31 Dec 2014 12 months
Revenue	1	**121.3**	235.4	785.2
Cost of sales				
Production costs	2	-25.2	-38.4	-66.5
Depletion and decommissioning costs		-43.1	-35.1	-131.6
Exploration costs		-45.4	-126.9	-386.4
Impairment costs of oil and gas properties		–	–	-400.7
Gross profit/loss	3	**7.6**	35.0	-200.0
General, administration and depreciation expenses		-11.3	-20.4	-52.2
Operating profit/loss		**-3.7**	14.6	-252.2
Result from financial investments				
Finance income	4	0.9	27.4	1.8
Finance costs	5	-226.1	-12.2	-421.8
		-225.2	15.2	-420.0
Share of the result of joint ventures accounted for using the equity method		–	-0.1	-12.9
Profit/loss before tax		**-228.9**	29.7	-685.1
Income tax expense	6	-2.0	-26.5	253.2
Net result		**-230.9**	3.2	-431.9
Attributable to:				
Owners of the Parent Company		-229.9	4.4	-427.2
Non-controlling interest		-1.0	-1.2	-4.7
		-230.9	3.2	-431.9
Earnings per share – USD[1]		-0.74	0.01	-1.38
Earnings per share fully diluted – USD[1]		-0.74	0.01	-1.38

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

Consolidated Statement of Comprehensive Income

Expressed in MUSD	**1 Jan 2015– 31 Mar 2015 3 months**	1 Jan 2014– 31 Mar 2014 3 months	1 Jan 2014– 31 Dec 2014 12 months
Net result	**-230.9**	3.2	-431.9
Other comprehensive income			
Items that may be subsequently reclassified to profit or loss:			
Exchange differences foreign operations	-18.4	-8.6	-196.3
Cash flow hedges	-45.6	29.0	-148.7
Available-for-sale financial assets	-0.3	-1.1	-15.3
Other comprehensive income, net of tax	-64.3	19.3	-360.3
Total comprehensive income	**-295.2**	22.5	-792.2
Attributable to:			
Owners of the Parent Company	-295.0	27.1	-766.7
Non-controlling interest	-0.2	-4.6	-25.5
	-295.2	22.5	-792.2

Consolidated Balance Sheet

Expressed in MUSD	Note	31 March 2015	31 December 2014
ASSETS			
Non-current assets			
Oil and gas properties	7	4,242.2	4,182.6
Other tangible fixed assets		218.2	200.3
Financial assets	8	33.7	37.0
Deferred tax assets		10.4	12.9
Other non-current assets	9	58.6	–
Total non-current assets		**4,563.1**	4,432.8
Current assets			
Inventories		34.7	41.6
Trade and other receivables	10	146.6	163.5
Current tax assets		346.2	373.6
Cash and cash equivalents		51.9	80.5
Total current assets		**579.4**	659.2
TOTAL ASSETS		**5,142.5**	5,092.0
EQUITY AND LIABILITIES			
Equity			
Shareholders´ equity		136.9	431.5
Non-controlling interest		34.0	34.2
Total equity		**170.9**	465.7
Liabilities			
Non-current liabilities			
Financial liabilities	11	3,084.4	2,654.0
Provisions	12	292.6	288.0
Deferred tax liabilities		958.5	973.3
Derivative instruments	14	48.6	33.9
Other non-current liabilities		29.5	29.1
Total non-current liabilities		**4,413.6**	3,978.3
Current liabilities			
Trade and other payables	13	394.2	491.4
Derivative instruments	14	114.8	101.4
Current tax liabilities		1.9	1.8
Provisions	12	47.1	53.4
Total current liabilities		**558.0**	648.0
Total liabilities		**4,971.6**	4,626.3
TOTAL EQUITY AND LIABILITIES		**5,142.5**	5,092.0

Consolidated Statement of Cash Flows

Expressed in MUSD	**1 Jan 2015– 31 Mar 2015 3 months**	1 Jan 2014 – 31 Mar 2014 3 months	1 Jan 2014 – 31 Dec 2014 12 months
Cash flows from operating activities			
Net result	-230.9	3.2	-431.9
Adjustments for:			
Exploration costs	45.4	126.9	386.4
Depletion, depreciation and amortisation	44.2	36.3	136.2
Current tax	-59.6	-58.9	-419.7
Deferred tax	61.6	85.4	166.5
Impairment of oil and gas properties	–	–	400.7
Long-term incentive plans	2.2	8.0	14.5
Foreign currency exchange loss	162.9	-25.7	333.1
Other	19.5	6.3	16.0
Interest received	0.1	0.2	0.9
Interest paid	-21.3	-10.2	-56.5
Income taxes paid	-3.9	-7.0	-13.8
Changes in working capital	-57.3	75.6	109.0
Total cash flows from operating activities	**-37.1**	240.1	641.4
Cash flows from investing activities			
Investment in oil and gas properties	-396.2	-454.3	-1,957.8
Investment in other fixed assets	-21.9	-49.1	-124.9
Disposal of bonds	–	10.5	10.5
Investment in other shares and participations	-3.7	–	–
Share in result in associated company	–	–	11.7
Decommissioning costs paid	-0.2	-0.1	-1.2
Other payments	-0.1	–	-0.1
Total cash flows from investing activities	**-422.1**	-493.0	-2,061.8
Cash flows from financing activities			
Changes in long-term receivables	–	–	9.8
Changes in long-term liabilities	425.5	295.8	1,419.2
Financing fees paid	–	-20.6	-20.7
Purchase of own shares	–	-9.8	-9.8
Distributions	–	–	-0.1
Total cash flows from financing activities	**425.5**	265.4	1,398.4
Change in cash and cash equivalents	-33.7	12.5	-22.0
Cash and cash equivalents at the beginning of the period	80.5	82.4	82.4
Currency exchange difference in cash and cash equivalents	5.1	–	20.1
Cash and cash equivalents at the end of the period	**51.9**	94.9	80.5

Consolidated Statement of Changes in Equity

	Attributable to owners of the Parent Company					
Expressed in MUSD	Share capital	Additional paid-in-capital/Other reserves	Retained earnings	Total	Non-controlling interest	Total equity
At 1 January 2014	**0.5**	**358.1**	**848.4**	**1,207.0**	**59.8**	**1,266.8**
Comprehensive income						
Net result	–	–	4.4	4.4	-1.2	3.2
Other comprehensive income	–	22.7	–	22.7	-3.4	19.3
Total comprehensive income	**–**	**22.7**	**4.4**	**27.1**	**-4.6**	**22.5**
Transactions with owners						
Purchase of own shares	–	-9.8	–	-9.8	–	-9.8
Total transactions with owners	**–**	**-9.8**	**–**	**-9.8**	**–**	**-9.8**
At 31 March 2014	**0.5**	**371.0**	**852.8**	**1,224.3**	**55.2**	**1,279.5**
Comprehensive income						
Net result	–	–	-431.6	-431.6	-3.5	-435.1
Other comprehensive income	–	-362.2	–	-362.2	-17.4	-379.6
Total comprehensive income	**–**	**-362.2**	**-431.6**	**-793.8**	**-20.9**	**-814.7**
Transactions with owners						
Distributions	–	–	–	–	-0.1	-0.1
Value of employee services	–	–	1.0	1.0	–	1.0
Total transaction with owners	**–**	**–**	**1.0**	**1.0**	**-0.1**	**0.9**
At 31 December 2014	**0.5**	**8.8**	**422.2**	**431.5**	**34.2**	**465.7**
Comprehensive income						
Net result	–	–	-229.9	-229.9	-1.0	-230.9
Other comprehensive income	–	-65.1	–	-65.1	0.8	-64.3
Total comprehensive income	**–**	**-65.1**	**-229.9**	**-295.0**	**-0.2**	**-295.2**
Transactions with owners						
Value of employee services	–	–	0.4	0.4	–	0.4
Total transaction with owners	**–**	**–**	**0.4**	**0.4**	**–**	**0.4**
At 31 March 2015	**0.5**	**-56.3**	**192.7**	**136.9**	**34.0**	**170.9**

In 2014 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 2015– 31 Mar 2015 3 months**	1 Jan 2014– 31 Mar 2014 3 months	1 Jan 2014– 31 Dec 2014 12 months
Crude oil	103.2	198.6	627.4
Condensate	0.1	1.1	3.0
Gas	23.3	36.3	114.6
Net sales of oil and gas	**126.6**	236.0	745.0
Change in under/over lift position	-8.4	-4.6	23.4
Other revenue	3.1	4.0	16.8
Revenue	**121.3**	235.4	785.2

Note 2. Production costs MUSD	**1 Jan 2015– 31 Mar 2015 3 months**	1 Jan 2014– 31 Mar 2014 3 months	1 Jan 2014– 31 Dec 2014 12 months
Cost of operations	21.4	30.6	94.4
Tariff and transportation expenses	2.6	4.8	18.4
Direct production taxes	0.7	0.9	3.6
Change in inventory position	-2.4	-0.2	-0.8
Other	2.9	2.3	-49.1
	25.2	38.4	66.5

Note 3. Segment information MUSD	**1 Jan 2015– 31 Mar 2015 3 months**	1 Jan 2014– 31 Mar 2014 3 months	1 Jan 2014– 31 Dec 2014 12 months
Norway			
Crude oil	91.4	174.0	530.5
Condensate	–	0.8	1.7
Gas	9.7	19.3	58.8
Net sales of oil and gas	**101.1**	194.1	591.0
Change in under/over lift position	-8.5	-4.6	24.4
Other revenue	0.5	1.2	3.8
Revenue	**93.1**	190.7	619.2
Production costs	-17.7	-25.8	-11.3
Depletion and decommissioning costs	-33.2	-23.8	-88.5
Exploration costs	-44.9	-72.8	-272.1
Impairment costs of oil and gas properties	–	–	-400.7
Gross profit/loss	**-2.7**	68.3	-153.4

Note 3. Segment information cont. MUSD	**1 Jan 2015– 31 Mar 2015 3 months**	1 Jan 2014 – 31 Mar 2014 3 months	1 Jan 2014 – 31 Dec 2014 12 months
France			
Crude oil	11.8	24.5	96.8
Net sales of oil and gas	**11.8**	24.5	96.8
Change in under/over lift position	0.1	–	-0.5
Other revenue	0.4	0.4	1.7
Revenue	**12.3**	24.9	98.0
Production costs	-3.7	-8.0	-33.1
Depletion and decommissioning costs	-4.1	-4.3	-16.9
Exploration costs	–	–	-4.6
Gross profit/loss	**4.5**	12.6	43.4
Netherlands			
Crude oil	–	0.1	0.1
Condensate	0.1	0.3	1.3
Gas	6.6	11.2	33.8
Net sales of oil and gas	**6.7**	11.6	35.2
Change in under/over lift position	–	–	-0.5
Other revenue	0.4	0.5	2.2
Revenue	**7.1**	12.1	36.9
Production costs	-2.8	-3.6	-16.8
Depletion and decommissioning costs	-2.8	-4.3	-15.9
Exploration costs	-0.4	-0.5	-1.4
Gross profit/loss	**1.1**	3.7	2.8
Malaysia			
Exploration costs	–	–	-14.4
Gross profit	**–**	–	-14.4
Indonesia			
Gas	7.0	5.8	22.0
Net sales of oil and gas	**7.0**	5.8	22.0
Other revenue	–	–	–
Revenue	**7.0**	5.8	22.0
Production costs	-1.0	-1.0	-5.4
Depletion and decommissioning costs	-3.0	-2.7	-10.3
Exploration costs	-0.1	-53.6	-94.2
Gross profit/loss	**2.9**	-51.5	-87.9
Other			
Other revenue	1.8	1.9	9.1
Revenue	**1.8**	1.9	9.1
Production costs	–	–	0.1
Exploration costs	–	–	0.3
Gross profit/loss	**1.8**	1.9	9.5

Note 3. Segment information cont. MUSD	**1 Jan 2015– 31 Mar 2015 3 months**	1 Jan 2014– 31 Mar 2014 3 months	1 Jan 2014– 31 Dec 2014 12 months
Total			
Crude oil	103.2	198.6	627.4
Condensate	0.1	1.1	3.0
Gas	23.3	36.3	114.6
Net sales of oil and gas	**126.6**	236.0	745.0
Change in under/over lift position	-8.4	-4.6	23.4
Other revenue	3.1	4.0	16.8
Revenue	**121.3**	235.4	785.2
Production costs	-25.2	-38.4	-66.5
Depletion and decommissioning costs	-43.1	-35.1	-131.6
Exploration costs	-45.4	-126.9	-386.4
Impairment costs of oil and gas properties	–	–	-400.7
Gross profit/loss	**7.6**	35.0	-200.0

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 2015– 31 Mar 2015 3 months**	1 Jan 2014– 31 Mar 2014 3 months	1 Jan 2014– 31 Dec 2014 12 months
Interest income	0.1	0.4	1.2
Foreign currency exchange gain, net	–	26.9	–
Guarantee fees	0.8	0.1	0.5
Other	–	–	0.1
	0.9	27.4	1.8

Note 5. Finance costs MUSD	**1 Jan 2015– 31 Mar 2015 3 months**	1 Jan 2014– 31 Mar 2014 3 months	1 Jan 2014– 31 Dec 2014 12 months
Interest expense	11.8	1.9	21.1
Foreign currency exchange loss, net	204.0	–	356.3
Result on interest rate hedge settlement	1.8	0.5	2.4
Unwinding of site restoration discount	2.3	1.8	7.0
Amortisation of deferred financing fees	2.9	2.8	12.6
Loan facility commitment fees	3.0	4.9	21.4
Other	0.3	0.3	1.0
	226.1	12.2	421.8

Note 6. Income tax expense MUSD	**1 Jan 2015– 31 Mar 2015 3 months**	1 Jan 2014– 31 Mar 2014 3 months	1 Jan 2014– 31 Dec 2014 12 months
Current tax	-59.6	-58.9	-419.7
Deferred tax	61.6	85.4	166.5
	2.0	26.5	-253.2

Note 7. Oil and gas properties

MUSD	**31 Mar 2015**	31 Dec 2014
Norway	2,976.6	2,960.7
France	191.4	210.1
Netherlands	32.2	38.6
Malaysia	497.2	428.3
Indonesia	41.1	43.9
Russia	503.7	501.0
	4,242.2	4,182.6

Note 8. Financial assets

MUSD	**31 Mar 2015**	31 Dec 2014
Other shares and participations	7.3	4.7
Brynhild operating cost share	25.1	31.0
Other	1.3	1.3
	33.7	37.0

Note 9. Other non-current assets

MUSD	**31 Mar 2015**	31 Dec 2014
Corporate tax	58.6	–
	58.6	–

Note 10. Trade and other receivables

MUSD	**31 Mar 2015**	31 Dec 2014
Trade receivables	52.8	40.3
Underlift	5.4	3.6
Joint operations debtors	29.0	49.1
Prepaid expenses and accrued income	32.1	41.5
Brynhild operating cost share	20.4	21.6
Other	6.9	7.4
	146.6	163.5

Note 11. Financial liabilities

MUSD	**31 Mar 2015**	31 Dec 2014
Bank loans	3,115.0	2,690.0
Capitalised financing fees	-30.6	-36.0
	3,084.4	2,654.0

Note 12. Provisions

MUSD	**31 Mar 2015**	31 Dec 2014
Non-current:		
Site restoration	278.5	274.1
Long-term incentive plans	2.5	1.8
Farm-in payment	6.5	7.5
Other	5.1	4.6
	292.6	288.0
Current:		
Farm-in payment	42.0	48.5
Long-term incentive plans	5.1	4.9
	47.1	53.4
	339.7	341.4

Note 13. Trade and other payables

MUSD	**31 Mar 2015**	31 Dec 2014
Trade payables	7.1	23.9
Overlift	10.1	–
Joint operations creditors and accrued expenses	309.6	383.5
Other accrued expenses	42.0	46.1
Long-term incentive plans	22.6	28.2
Other	2.8	9.7
	394.2	491.4

Note 14. Financial instruments
MUSD

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

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

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

31 March 2015 MUSD	Level 1	Level 2	Level 3
Assets			
Cash and cash equivalents	51.9	–	–
Financial assets	33.7	–	–
	85.6	**–**	**–**
Liabilities			
Derivative instruments – non-current	–	48.6	–
Derivative instruments – current	–	114.8	–
	–	**163.4**	**–**

31 December 2014 MUSD	Level 1	Level 2	Level 3
Assets			
Cash and cash equivalents	80.5	–	–
Financial assets	37.0	–	–
	117.5	**–**	**–**
Liabilities			
Derivative instruments – non-current	–	33.9	–
Derivative instruments – current	–	101.4	–
	–	**135.3**	**–**

There were no transfers between the levels during the year.

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

The Group's USD 4.0 billion 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 maturity date of the 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.

Parent Company Income Statement

Expressed in MSEK	**1 Jan 2015– 31 Mar 2015 3 months**	1 Jan 2014– 31 Mar 2014 3 months	1 Jan 2014– 31 Dec 2014 12 months
Revenue	**6.7**	1.1	9.2
General and administration expenses	-25.7	-41.7	-144.9
Operating loss	**-19.0**	-40.6	-135.7
Result from financial investments			
Finance income	1.8	0.8	209.9
Finance costs	–	-0.5	-1.9
	1.8	0.3	208.0
Profit/loss before tax	**-17.2**	-40.3	72.3
Income tax	–	–	36.4
Net result	**-17.2**	-40.3	108.7

Parent Company Comprehensive Income Statement

Expressed in MSEK	**1 Jan 2015– 31 Mar 2015 3 months**	1 Jan 2014– 31 Mar 2014 3 months	1 Jan 2014– 31 Dec 2014 12 months
Net result	**-17.2**	-40.3	108.7
Other comprehensive income	–	–	–
Total comprehensive income	**-17.2**	-40.3	108.7
Attributable to:			
Owners of the Parent Company	-17.2	-40.3	108.7
	-17.2	-40.3	108.7

Parent Company Balance Sheet

Expressed in MSEK	**31 Mar 2015**	31 Dec 2014
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	23.4	16.7
Cash and cash equivalents	7.1	1.8
Total current assets	**30.5**	18.5
TOTAL ASSETS	**7,902.5**	7,890.5
SHAREHOLDERS´EQUITY AND LIABILITIES		
Shareholders´ equity including net result for the period	7,843.3	7,860.5
Non-current liabilities		
Provisions	0.4	0.3
Total non-current liabilities	**0.4**	0.3
Current liabilities		
Current liabilities	14.2	16.2
Payables to group companies	44.6	13.5
Total current liabilities	**58.8**	29.7
Total liabilities	**59.2**	30.0
TOTAL EQUITY AND LIABILITIES	**7,902.5**	7,890.5
Pledged assets	7,157.3	8,717.8

Parent Company Cash Flow Statement

Expressed in MSEK	**1 Jan 2015–31 Mar 2015 3 months**	1 Jan 2014–31 Mar 2014 3 months	1 Jan 2014–31 Dec 2014 12 months
Cash flow from operations			
Net result	-17.2	-40.3	108.7
Adjustment for non-cash related items	-0.7	63.8	-36.7
Changes in working capital	23.4	-6.2	11.0
Total cash flow from operations	**5.5**	17.3	83.0
Cash flow from investments			
Change in other fixed assets	–	–	-0.1
Total Cash flow from investments	**–**	–	-0.1
Cash flow from financing			
Change in long-term liabilities	–	44.2	-21.7
Purchase of own shares	–	-62.2	-62.2
Total cash flow from financing	**–**	-18.0	-83.9
Change in cash and cash equivalents	5.5	-0.7	-1.0
Cash and cash equivalents at the beginning of the period	1.8	2.6	2.6
Currency exchange difference in cash and cash equivalents	-0.2	–	0.2
Cash and cash equivalents at the end of the period	**7.1**	1.9	1.8

Parent Company Statement of Changes in Equity

	Restricted equity		Unrestricted equity			
Expressed in MSEK	Share capital	Statutory reserve	Other reserves	Retained earnings	Total	Total equity
Balance at 1 January 2014	**3.2**	**861.3**	**2,357.5**	**4,592.0**	**6,949.5**	**7,814.0**
Total comprehensive income	**–**	**–**	**–**	**-40.3**	**-40.3**	**-40.3**
Transactions with owners						
Purchase of own shares	–	–	-62.2	–	-62.2	-62.2
Total transactions with owners	**–**	**–**	**-62.2**	**–**	**-62.2**	**-62.2**
Balance at 31 March 2014	**3.2**	**861.3**	**2,295.3**	**4,551.7**	**6,847.0**	**7,711.5**
Total comprehensive income	**–**	**–**	**–**	**149.0**	**149.0**	**149.0**
Balance at 31 December 2014	**3.2**	**861.3**	**2,295.3**	**4,700.7**	**6,996.0**	**7,860.5**
Total comprehensive income	**–**	**–**	**–**	**-17.2**	**-17.2**	**-17.2**
Balance at 31 March 2015	**3.2**	**861.3**	**2,295.3**	**4,683.5**	**6,978.8**	**7,843.3**

In 2014 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 2015–31 Mar 2015 3 months**	1 Jan 2014–31 Mar 2014 3 months	1 Jan 2014–31 Dec 2014 12 months
Revenue	121.3	235.4	785.2
EBITDA	86.0	177.8	671.3
Net result	-230.9	3.2	-431.9
Operating cash flow	155.7	256.0	1,138.5
Data per share (USD)			
Shareholders' equity per share	0.44	3.96	1.40
Operating cash flow per share	0.50	0.83	3.68
Cash flow from operations per share	-0.12	0.78	2.07
Earnings per share	-0.74	0.01	-1.38
Earnings per share fully diluted	-0.74	0.01	-1.38
EBITDA per share	0.28	0.57	2.17
Dividend per share	–	–	–
Number of shares issued at period end	311,070,330	317,910,580	311,070,330
Number of shares in circulation at period end	309,070,330	309,070,330	309,070,330
Weighted average number of shares for the period	309,070,330	309,478,548	309,170,986
Weighted average number of shares for the period fully diluted	309,678,433	309,478,548	309,475,038
Share price			
Quoted price at period end (SEK)	118.10	113.10	112.40
Key ratios			
Return on equity (%)	-72	–	-50
Return on capital employed (%)	–	–	-11
Net debt/equity ratio (%)	2,238	120	605
Equity ratio (%)	3	27	9
Share of risk capital (%)	22	50	28
Interest coverage ratio	-1	2	-13
Operating cash flow/interest ratio	12	104	49
Yield	–	–	–

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 of the awards outstanding under the Group's performance based incentive plan.

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

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

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

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

Return on capital employed: Income before tax plus interest expenses plus/less 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.

The financial information relating to the three month period ended 31 March 2015 has not been subject to review by the auditors of the Company.

Stockholm, 6 May 2015

C. Ashley Heppenstall
President & CEO

The Company will publish the following reports:

- 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 year end report (January—December 2015) will be published on 3 February 2016.

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.

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