Lundin Petroleum AB (publ)

company registration number 556610-8055

Report for the

SIX MONTHS

ended 30 June 2013

Q2

Six months ended 30 June 2013 (30 June 2012)

- Production of 35.2 Mboepd (35.1 Mboepd)
- Revenue of MUSD 627.8 (MUSD 685.6)
- EBITDA of MUSD 520.2 (MUSD 580.6)
- Operating cash flow of MUSD 502.9 (MUSD 375.6)
- Net result of MUSD 48.2 (MUSD 111.7)
- Net debt of MUSD 599 (31 Dec 2012 MUSD 335)
- Oil discovery in Luno II, offshore Norway
- Extensive appraisal drilling on the Johan Sverdrup field
- Seven licences awarded in the Norwegian 2012 APA licensing round and a further exploration licence located in the Barents Sea awarded in the 22nd Norwegian licensing round

Second quarter ended 30 June 2013 (30 June 2012)

- Production of 34.8 Mboepd (35.5 Mboepd)
- Revenue of MUSD 300.2 (MUSD 321.0)
- EBITDA of MUSD 244.0 (MUSD 271.4)
- Operating cash flow of MUSD 242.9 (MUSD 209.0)
- Net result of MUSD 1.2 (MUSD 64.5)
- Non-cash Norwegian impairment and expensed exploration costs amounted to MUSD 44.3 after tax
- New Production Sharing Contract awarded offshore eastern Indonesia – Cendrawasih VII Block

	1 Jan 2013- 30 Jun 2013 6 months	**1 Apr 2013- 30 Jun 2013 3 months**	1 Jan 2012- 30 Jun 2012 6 months	1 Apr 2012- 30 Jun 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Production in Mboepd	**35.2**	**34.8**	35.1	35.5	35.7
Revenue in MUSD	**627.8**	**300.2**	685.6	321.0	1,375.8
Net result in MUSD	**48.2**	**1.2**	111.7	64.5	103.9
Net result attributable to shareholders of the Parent Company in MUSD	**50.9**	**2.7**	113.8	65.0	108.2
Earnings/share in USD[1]	**0.16**	**–**	0.37	0.21	0.35
EBITDA in MUSD	**520.2**	**244.0**	580.6	271.4	1,144.1
Operating cash flow in MUSD	**502.9**	**242.9**	375.6	209.0	831.4

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

Definitions

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

Abbreviations

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

Oil related terms and measurements

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

Dear fellow Shareholders,
I am very pleased to report that Lundin Petroleum continues to deliver on the key themes of our strategy which will ultimately result in achieving our objective of increasing shareholder value.

Strong operating cash flow
The cash flow generation from our business remains strong. During the first six months of this year we achieved operating cash flow of USD 502.9 million primarily as a result of the continued excellent production performance from our offshore Norwegian assets Alvheim and Volund. We still remain firmly on target to generate over USD 1 billion in operating cash flow this year.

We retain our production guidance of 33,000 to 38,000 boepd for 2013 with the main variables being the start-up date of the Brynhild field and uptime levels on the Alvheim FPSO. We expect 2013 exit production to be in excess of 40,000 boepd as the Brynhild field ramps up to plateau production of over 10,000 boepd net to Lundin Petroleum.

Production to double from existing development projects
Our development projects on the Brynhild, Bøyla and Edvard Grieg fields are all progressing satisfactorily in respect of budget and schedule. Collectively these three projects, where first oil is expected in late 2013, 2014 and 2015, will double our production by the end 2015 to over 70,000 boepd.

The Brynhild project is expected to start production in the fourth quarter of this year. Everything is going well with the subsea installation work having been substantially completed, development drilling ongoing and the Haewene Brim FPSO in dry dock in Scotland having modification works completed to accept Brynhild oil.

The Edvard Grieg jacket and topside construction is well underway and a large element of the procurement process is behind us. We remain within budget and on schedule. The oil and gas export pipelines will be operated by Statoil who will install them in the summer of 2014 well in advance of first oil date of late 2015. The development drilling programme will also commence in the summer of 2014.

Johan Sverdrup conceptual development plan is on schedule for late 2013
The Johan Sverdrup discovery made by Lundin Petroleum in 2010 is one of the largest ever discoveries made in the North Sea and certainly the largest made in the last 25 years. The discovery is world class and represents a major percentage of Lundin Petroleum's net asset value. It is my view that the size and quality of this asset will result in its value continuing to increase over time.

Lundin Petroleum as operator of PL501 and Statoil as operator of PL265 have substantially completed the appraisal programme with close to 20 wells already drilled on the structure. We have been working closely with Statoil as working operator for the development. A huge amount of data has been reviewed and I am very pleased that Statoil remain firmly on schedule to announce a conceptual development decision in conjunction with an updated resource estimate by the end of the year.

The front end engineering will then be completed prior to the submission of a final development plan by the end of 2014. A unitisation agreement will have been completed by this time between all parties with working interests in the field. The unitisation process has been completed many times before on other field developments and I do not believe will have an impact on the project schedule.

Whilst work is still ongoing regarding the concept selection, I expect the gross plateau production from Johan Sverdrup to be in excess of 500,000 bopd. Putting this in context this represents over 25 percent of current Norwegian oil production. The net impact on Lundin Petroleum's production will be to take our net production levels to about 150,000 boepd or four times our current production. As I will explain later when I discuss financing, we will be able to fund the capital associated with this fourfold increase in production from internally generated cash flow coupled with a conservative level of third party borrowings.

South East Asia business to deliver tangible growth
I am very pleased that we recently completed a plan of development for the Bertam field, offshore Malaysia. I expect the plan of development to be approved by Petronas in the next few months. The Bertam field is expected to produce first oil in early 2015 at a net plateau production rate to Lundin Petroleum of over 10,000 boepd. As we have done in Norway over recent years we have grown our organisation in South East Asia to be able to operate exploration and development project activities. I believe that the Bertam field will be the first of numerous projects which we develop in South East Asia.

We will be appraising early next year the Tembakau gas discovery which we believe contains about 300 bcf of recoverable gas resources. It is located only about 100 km offshore Peninsular Malaysia from the Kerteh gas plant and as such I expect this discovery to move forward as a commercial project.

Exploration activity remains high with Luno II another likely commercial discovery
Lundin Petroleum's philosophy is that it is the discovery of new hydrocarbon resources through exploration which creates maximum value to our shareholders in the upstream oil and gas business. As such we continue to invest heavily in our exploration activities with an annual budget of about USD 500 million focused primarily in Norway and South East Asia.

We have unquestionably been the most successful exploration company in Norway over recent years with numerous discoveries including Edvard Grieg and Johan Sverdrup. Earlier this year the Luno II prospect was confirmed as a further discovery in the Utsira High area and we will be appraising the discovery with a multi well appraisal programme commencing either later this year or earlier next year. Exploration activity levels are currently at an all-time high with three ongoing wells in the Utsira High, Barents Sea and Utgard High regions. This will continue when we receive in the third quarter the newly built Island Innovator semisubmersible rig which we have contracted for at least two years solely for our use to drill exploration and appraisal wells in Norway. We are firmly committed for the foreseeable future to continue to explore in Norway and I believe this will lead to further exploration success for our Company. Norway is still relatively under explored and we have one of the best exploration teams in Norway, access to the latest technology and a corporate philosophy committed to explore aggressively.

In South East Asia, I am pleased to announce that our exploration investments are starting to deliver positive results with the Bertam and Tembakau discoveries likely now to move forward to commercial development. We have invested heavily in 3D seismic acquisition which we believe is the key tool for exploration success in what are relatively mature exploration areas. We are drilling two exploration wells and a sidetrack offshore Indonesia this year which will be followed by at least four exploration and appraisal wells offshore Malaysia next year. In addition, our licence portfolio continues to expand with a very large and prospective new exploration block in east Indonesia called Cendrawasih VII which was signed recently.

Strong liquidity will fund forward development and exploration expenditures

We are generating strong operating cash flow which will increase in the next few years as our Norwegian and Malaysian development projects are completed. Last year we signed a new USD 2.5 billion reserve based lending facility with 25 international banks. The facility does not attribute any borrowing value to our Johan Sverdrup asset. This facility coupled with our internally generated cash flow is sufficient to fund the costs of our Norwegian and Malaysian development projects as well as our ongoing exploration expenditure. In addition, once the Edvard Grieg project is on stream we believe that the development costs associated with the Johan Sverdrup development will be self funding. We have therefore significant flexibility with regard to our financing requirements going forward and do not expect to need to raise further equity capital.

Despite the continued uncertainty with regard to world economic growth, Brent oil prices have remained firmly above USD 100 per barrel. We see some early encouraging signs of economic growth in the developed world particularly the United States. However the uncertainty of the impact of the removal of central bank accommodative financial policy coupled with the growth rates in the developing world particularly China will probably result in oil prices trading around current levels in the short term. Unlike certain commentators, I do not believe oil prices will fall further as this would negatively impact many unconventional projects as well as put pressure on the finances of many OPEC countries. I remain confident that oil prices will increase in the medium to long term as growth returns driven by the emerging economies. Whilst Lundin Petroleum would benefit from higher oil prices, our business model remains very robust at and below today’s current oil price.

Our Company remains in strong health and I am very confident that our exploration and development project pipeline will continue the increase to shareholder value that we strive to achieve.

Yours sincerely,

C. Ashley Heppenstall
President and CEO

Stockholm, 7 August 2013

OPERATIONAL REVIEW

Lundin Petroleum has exploration and production assets focused upon two core areas, Norway and South East Asia, as well as assets in France, The Netherlands and Russia. Norway continues to represent the majority of Lundin Petroleum's operational activities with production during 2012 accounting for 76 percent of total 2012 production and with 75 percent of Lundin Petroleum's total reserves as at the end of 2012.

Reserves and Resources

Lundin Petroleum has 201.5 million barrels of oil equivalent (MMboe) of reserves as certified at the end of 2012. Lundin Petroleum also has a number of discovered oil and gas resources which classify as contingent resources and are not yet classified as reserves. The Johan Sverdrup field in Norway constitutes more than two thirds of the 923 MMboe[1] of Lundin Petroleum's best estimate contingent resources and will be moved to reserves following the finalisation of a unitisation agreement and the submission of a development plan.

Production

Production for the six month period ended 30 June 2013 (reporting period) amounted to 35.2 thousand barrels of oil equivalent per day (Mboepd) (compared to 35.1 Mboepd over the same period in 2012) and was comprised as follows:

Production in Mboepd	**1 Jan 2013- 30 Jun 2013 6 months**	**1 Apr 2013- 30 Jun 2013 3 months**	1 Jan 2012- 30 Jun 2012 6 months	1 Apr 2012- 30 Jun 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Crude oil					
Norway	22.5	22.4	23.3	23.7	23.3
France	2.8	2.8	2.9	2.9	2.8
Russia	2.4	2.4	2.8	2.8	2.7
Tunisia	–	–	0.2	–	0.1
Total crude oil production	**27.7**	**27.6**	**29.2**	29.4	28.9
Gas					
Norway	3.8	3.6	3.1	3.6	3.9
Netherlands	2.1	2.0	1.9	1.9	1.9
Indonesia	1.6	1.6	0.9	0.6	1.0
Total gas production	**7.5**	**7.2**	**5.9**	6.1	6.8
Total production					
Quantity in Mboe	**6,375.4**	**3,169.1**	**6,385.1**	3,231.0	13,050.4
Quantity in Mboepd	**35.2**	**34.8**	**35.1**	35.5	35.7

NORWAY

Production

Production in Mboepd	Lundin Petroleum Working Interest (WI)	**1 Jan 2013- 30 Jun 2013 6 months**	**1 Apr 2013- 30 Jun 2013 3 months**	1 Jan 2012- 30 Jun 2012 6 months	1 Apr 2012- 30 Jun 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Alvheim	15%	11.3	11.1	12.0	11.8	11.8
Volund	35%	13.3	13.4	13.2	13.2	13.1
Gaupe	40%	1.7	1.5	1.2	2.3	2.3
		26.3	**26.0**	**26.4**	27.3	27.2

The Alvheim field continues to sustain a high production level following two new infill wells being put on production during 2012. The net production from the Alvheim field during the reporting period was below expectations because of the shut-in of three production wells due to well integrity issues in two of the wells, both of which were shut-in in January 2013, and a flowline integrity issue in one of the wells which was shut-in in June 2013. The flowline integrity issue is anticipated to be resolved in the third quarter 2013 whilst the remaining two shut-in wells are scheduled to be worked over in the second half of 2013 and brought back onstream in early 2014. The loss of production from these three wells has been partially offset by production optimisation from the remaining wells and excellent uptime performance on the Alvheim FPSO.

[1] Includes mid point of the guided range for the PL501 part of Johan Sverdrup (range 800 – 1,800 MMboe, gross) and mid point of Statoil's guided range for the PL265 part of Johan Sverdrup (range 900 – 1,500 MMboe, gross) plus Geitungen (range 140 – 270 MMboe, gross).

The one-off well intervention work during 2013 will be recorded as cost of operations and is forecast to increase Lundin Petroleum's total cost of operations by USD 1.50 per barrel for the full year. The cost of operations for the Alvheim field, excluding well intervention and other one-off related project work, was below USD 5 per barrel during the reporting period. The Alvheim FPSO will have certain planned maintenance work carried out during the third quarter of 2013 and consequently both the Alvheim and Volund fields will be shut-in for approximately two weeks during this period. At least a further four infill wells are scheduled to be drilled on Alvheim in 2014 and 2015.

The Volund field production during the reporting period has exceeded forecast due to better than expected reservoir performance and the Alvheim FPSO uptime performance also being ahead of forecast. During 2012 an additional Volund development well was drilled and put onstream early in 2013 resulting in Volund continuing to produce at close to full flowline capacity. The cost of operations, excluding project specific costs, for the Volund field during the reporting period was below USD 2.50 per barrel.

Production from the Gaupe field during the reporting period has been in line with expectations. The field will be shut-in for approximately one month during the third quarter of 2013 for planned maintenance.

Development

Licence	Field	WI	PDO Approval	Estimated gross 2P reserves	First production expected	Gross plateau production rate expected
PL148	Brynhild	90%	November 2011	23 MMboe	Late 2013	12.0 Mboepd
PL340	Bøyla	15%	October 2012	22 MMboe	Late 2014	19.0 Mboepd
PL338	Edvard Grieg	50%	June 2012	186 MMboe	Late 2015	100.0 Mboepd

Brynhild

The Brynhild development is progressing according to schedule and budget and first oil is expected in the fourth quarter of 2013 with a gross plateau rate of 12,000 boepd. The first development well on Brynhild commenced drilling in June 2013 by the Maersk Guardian jack-up rig. The Brynhild subsea template and manifolds were successfully installed in April 2013 and the production and water injection pipelines have also been successfully installed during the reporting period. The Haewene Brim FPSO, which will receive the crude from Brynhild, arrived at the dry dock in Scotland in July 2013 for topside modification and life extension work as scheduled. The development involves the drilling of four wells tied back to the existing Shell operated Pierce field infrastructure in the United Kingdom sector of the North Sea.

Bøyla

The Bøyla field will be developed as a 28 km subsea tie-back to the Alvheim FPSO. The field will be developed with two production wells and one water injection well. Fabrication of the field's subsea structures has commenced.

Edvard Grieg

The development is progressing on schedule and on budget. Construction and engineering work on the jacket, topside and export pipelines is ongoing.

All the major contracts for the Edvard Grieg development have been awarded. Kværner has been awarded a contract covering engineering, procurement and construction of the jacket and the topsides for the platform and a contract has been awarded to Rowan Companies for a jack-up rig to drill the development wells. Saipem has been awarded the contract for marine installation. An appraisal well is planned to be drilled in the southeastern part of the Edvard Grieg reservoir in 2013 with potential to increase reserves and optimise the location of the Edvard Grieg development wells. During the reporting period a plan for installation and operation (PIO) has been submitted to the Ministry of Petroleum and Energy for the 43 km long Edvard Grieg oil pipeline and a PIO is also anticipated to be submitted for the 94 km long Edvard Grieg gas pipeline in August 2013. The pipelines will be jointly owned by the licence partners in Edvard Grieg PL338 and Ivar Aasen PL001B/PL028B/PL242 with Lundin Petroleum having an ownership of 30 percent in the oil pipeline and 20 percent in the gas pipeline. Statoil will be the operator of the pipelines. The oil pipeline will be tied-into the Grane oil pipeline and the gas pipeline will be tied-in to the Sage Beryl gas system in the United Kingdom. Installment of the pipelines will be carried out in the summer of 2014.

The Edvard Grieg development plan incorporates the provision for the coordinated development solution with the nearby Ivar Aasen field (formerly Draupne) located in PL001B and operated by Det norske oljeselskap ASA. The Ivar Aasen development plan was approved by the Norwegian authorities during the first quarter of 2013.

Appraisal

Johan Sverdrup

Lundin Petroleum discovered the Avaldsnes field in PL501 (WI 40%) in 2010. In 2011, Statoil made the Aldous Major South discovery on the neighbouring PL265 (WI 10%). Following appraisal drilling, it was determined that the discoveries were connected and in January 2012 the combined discovery was renamed Johan Sverdrup. An appraisal programme is ongoing to define the recoverable resource and assist with the development planning strategy.

A total of 18 wells have now been drilled on the Johan Sverdrup field and the appraisal campaign is now substantially complete. Statoil, the largest equity owner of the field, is anticipated to release updated resource estimates for the field towards the end of 2013.

All parties in PL501 and PL265 have agreed a timetable for the Johan Sverdrup field with development concept selection to be made by the fourth quarter of 2013, a plan of development is scheduled to be submitted by the fourth quarter of 2014 and first oil production is estimated to commence by the end of 2018.

During the reporting period five appraisal wells, two sidetracks and three production tests were completed and one additional exploration well was spudded.

In July 2013, the appraisal well 16/2-17S and the exploration sidetrack 16/2-17B drilled on the eastern and western side respectively of the boundary fault on PL265, were successfully completed. The appraisal well, which was drilled on the Fault Margin location, encountered an 82 metre gross column of oil bearing good quality Jurassic reservoir sequence and confirming the extension of good Jurassic reservoir close to the Fault Margin. The well was production tested from two zones and achieved a flow rate of 1,500 barrels of oil per day (bopd) from the lower sandstone layers with interbedded shales and 5,900 bopd from the upper zone with excellent quality Jurassic sandstones. The exploration sidetrack well 16/2-17B was drilled 800 metres to the west of the main fault and encountered tight basement with no presence of reservoir.

In June 2013, the appraisal well 16/2-21 drilled on Johan Sverdrup field on PL501 was successfully completed. The well encountered an excellent Jurassic gross reservoir sequence of 30 metres of which 12 metres were above the Oil Water Contact (OWC) with a high net-to-gross ratio. The OWC was encountered at 1,922 metres below Mean Sea Level (MSL).

In July 2013, the appraisal well 16/3-6, which is the tenth well drilled on Johan Sverdrup in PL501, was successfully drilled on the eastern flank of the Johan Sverdrup field. The well encountered excellent upper Jurassic Draupne sandstone with a gross reservoir section of 24 metres with 11.5 metres being above the OWC, which was encountered at 1,926 metres below MSL.

The exploration well 16/2-18S, targeting the Cliffhanger North prospect, was spudded in July 2013. The well is targeting new volume to the west of the boundary fault for Johan Sverdrup field on PL265. The well is expected to complete in August 2013.

The following table outlines the drilled, currently drilling and the remaining appraisal wells planned to be drilled on Johan Sverdrup in 2013. The partners in PL501 have agreed to add one additional appraisal well to the 2013 programme to be drilled on the southeastern flank of the Johan Sverdrup field, referred to as the G location in the table below.

2013 appraisal well programme on Johan Sverdrup

Licence	Operator	Lundin Petroleum WI	Well	Spud Date	Gross oil column	Result
PL501	Lundin Petroleum	40%	16/2-16aAT2	December 2012	30m	Successfully completed February 2013
PL501	Lundin Petroleum	40%	16/3-5	January 2013	30m	Successfully completed March 2013, Drill Stem Test (DST) completed
PL502	Statoil	10%	16/5-3	February 2013	13.5m	Successfully completed March 2013
PL265	Statoil	10%	16/2-17S	March 2013		Successfully completed June 2013, 2 DST completed
PL501	Lundin Petroleum	40%	16/2-21	May 2013		Successfully completed June 2013
PL501	Lundin Petroleum	40%	16/3-6	June 2013		Successfully completed July 2013
PL265	Statoil	10%	16/2-18S Cliffhanger, North	July 2013		Drilling ongoing
PL501	Lundin Petroleum	40%	E location (SW flank)	Q3 2013		
PL501	Lundin Petroleum	40%	G location (SE flank)	Q4 2013		

Exploration
Four exploration wells have been completed in Norway in 2013 and three high impact exploration wells are currently drilling offshore Norway. The Luno II well has resulted in a further exploration discovery in the Utsira High area.

2013 exploration well programme

Licence	Well	Spud Date	Target	WI	Operator	Result
Southern NCS						
PL453S	8/5-1	January 2013	Ogna	35%	Lundin Petroleum	Dry
PL495	7/4-3	April 2013	Carlsberg	60%	Lundin Petroleum	Dry
Utsira High						
PL338	16/1-17	February 2013	Jorvik	50%	Lundin Petroleum	Oil discovery – non-commercial
PL359	16/4-6S	April 2013	Luno II	40%	Lundin Petroleum	Oil discovery – gross contingent resources 25 – 120 MMboe
PL501	16/2-20	Q3 2013	Torvastad	40%	Lundin Petroleum	
PL544		July 2013	Biotitt	40%	Lundin Petroleum	Drilling ongoing
PL625		Q4 2013/ Q1 2014	Kopervik	40%	Lundin Petroleum	
Utgard High						
PL330		June 2013	Sverdrup	30%	RWE Dea	Drilling ongoing
Barents Sea						
PL492		July 2013	Gohta	40%	Lundin Petroleum	Drilling ongoing
PL659		Q4 2013	Langlitinden	20%	Det norske oljeselskap	

The completion of the well 16/4-6S targeting the Luno II prospect in PL359 (WI 40%) was announced in May 2013 as an oil discovery. The well was drilled on the southwestern flank of the Utsira High approximately 15 km south of the Edvard Grieg field. Lundin Petroleum estimates that the Luno II structure, which is believed to span across two separate reservoir segments, contains gross contingent resources of 25 – 120 MMboe as well as gross prospective resources of 10 – 40 MMboe for the Luno II North segment. The contingent resources relate to the southern segment of the Luno II structure and the prospective resources to the northern segment. Appraisal drilling of the Luno II discovery is planned to take place later this year or early in 2014 to further delineate the southern reservoir segment which at the high end of the resource range is likely to extend into PL410 (WI 70%) to the east of PL359. The lower end of the contingent resource range only reflects the northern part of the southern reservoir segment directly proven by the well.

The well has been production tested and flowed at over 2,000 bopd through a 48/64 inch choke with a gas to oil ratio of 1,100 scf/bbl. The well proved the presence of a Jurassic/Triassic reservoir with a gross oil column of 45 metres and proved an OWC at 1,950 metres below MSL. The oil is saturated and in contact with a gas cap at the top of the reservoir. The well also proved a sand sequence of 280 metres with fair reservoir quality. A comprehensive coring and logging programme has been carried out and pressure data indicates that the petroleum system in the Luno II discovery is different to that found at Edvard Grieg and Johan Sverdrup. The Luno II discovery is the fifth discovery Lundin Petroleum has made in the Utsira High area following discoveries on Edvard Grieg/Tellus, Apollo, Luno South and Johan Sverdrup.

The Carlsberg well 7/4-3 drilled on PL495 in the southern North Sea was completed in May 2013 as a dry hole. The well targeted an Upper Triassic reservoir and an Upper Cretaceous reservoir with the reservoir being absent in the former target and water wet in the latter target.

Licence awards and relinquishments
Lundin Petroleum was awarded one licence in the Barents Sea in the 22nd Norwegian licensing round as announced by the Ministry of Petroleum and Energy in June 2013. Lundin Petroleum has increased its working interest (WI) in PL505/505BS from 30 percent to 40 percent and its working interest in PL570 from 30 percent to 50 percent during the reporting period.

During the reporting period, PL576 and PL440S were relinquished.

CONTINENTAL EUROPE

Production

Production in Mboepd	Lundin Petroleum Working Interest (WI)	**1 Jan 2013-30 Jun 2013 6 months**	**1 Apr 2013-30 Jun 2013 3 months**	1 Jan 2012-30 Jun 2012 6 months	1 Apr 2012-30 Jun 2012 3 months	1 Jan 2012-31 Dec 2012 12 months
France						
- Paris Basin	100% [1]	2.4	2.4	2.3	2.3	2.3
- Aquitaine Basin	50%	0.4	0.4	0.6	0.6	0.5
Netherlands	Various	2.1	2.0	1.9	1.9	1.9
		4.9	**4.8**	4.8	4.8	4.7

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

France
Production from France during the reporting period has been stable with good production from the Grandville field in the Paris Basin which continues to ramp up production from increased water injection capacity and a higher well stock, offset by a production underperformance from certain Aquitaine Basin fields related to various, non-reservoir related, mechanical failures.

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

Lundin Petroleum is participating in two exploration wells onshore Netherlands in 2013.

SOUTH EAST ASIA

Malaysia
Lundin Petroleum's planned 2013 exploration wells in Malaysia have been delayed to 2014 to align the rig schedule with the development drilling campaign on the Bertam field, where it is anticipated that development drilling will commence in the first half of 2014.

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

Lundin Petroleum continues to evaluate the potential for commercialisation of the Berangan, Tarap, Cempulut and Titik Terang gas discoveries in Block SB303, most likely through a cluster development. Seismic processing of the 500 km^2 Emerald 3D survey on SB307 is substantially complete and prospect maturation and high grading is well advanced. An additional 500 km^2 3D seismic acquisition referenced as the Francis 3D, on SB307/308 was completed at the end of the July 2013 and processing of the seismic is scheduled to be completed in the first half of 2014.

The drilling of one exploration well on SB307/308 will commence in early 2014.

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

A field development plan for the Bertam field on Block PM307 (WI 75%) has been submitted to Petronas and development approval is expected to be received in the second half of 2013. The Bertam field contains gross 2P reserves of 17 MMboe and is scheduled to commence first oil in 2015 with a gross plateau rate of 15,000 bopd. A 3D seismic acquisition programme over the northern part of Block PM307 and the southern part of Block PM319 (WI 85%) was completed during the reporting period and processing of the seismic is ongoing. The Tembakau gas discovery made in 2012, with gross best estimate contingent resources of 306 bcf will be appraised as part of the next offshore Peninsular Malaysia drilling campaign to commence in 2014.

Block PM308A (WI 35%) contains the Janglau and Rhu oil discoveries. A further exploration well targeting the Ara prospect on Block PM308A was completed in the first quarter 2013 as an oil discovery. The discovery is currently considered to be non-commercial however further studies are to be carried out to calibrate the Ara-1 and Janglau discoveries to the 3D seismic shot over the area in an effort to improve the imaging of the sand thickness and distribution to ascertain whether further appraisal drilling is warranted. The Ara-1 well was drilled to a total depth of 4,030 metres below MSL and encountered nine thin oil bearing sands in a high pressure intra-rift section extending over a vertical interval of 800 metres.

The offshore Peninsular Malaysia exploration and appraisal drilling programme in 2014 will likely involve the drilling of two exploration wells. An appraisal well will also be drilled on Tembakau.

Indonesia
Lundin Petroleum's assets in Indonesia are located in the Natuna Sea and offshore northeastern Indonesia and onshore South Sumatra. The Indonesian assets consist of approximately 24,750 km^2 of exploration acreage and one producing field onshore Sumatra.

Production

Production in Mboepd	Lundin Petroleum Working Interest (WI)	**1 Jan 2013- 30 Jun 2013 6 months**	**1 Apr 2013- 30 Jun 2013 3 months**	1 Jan 2012- 30 Jun 2012 6 months	1 Apr 2012- 30 Jun 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Singa	25.9%	1.6	1.6	0.9	0.6	1.0

The production for the reporting period increased compared to the same period last year following wellhead repairs on the Singa field.

Exploration

Baronang/Cakalang

Exploration drilling on the Baronang Block (WI 90%) is planned to commence in the fourth quarter of 2013 with a well and a sidetrack targeting the Balqis and Boni prospects. A rig has been identified for the purpose of drilling the well and the sidetrack.

Gurita

Following the completion of the interpretation of the 3D seismic acquisition of 950 km^2 acquired in 2012, the Gloria A prospect has been identified as the targeted prospect for the 2013 exploration well on the Gurita Block (WI 90%). The Gloria A prospect is a fault-dip closure on the south flank of the Jemaja High, with stacked closures at multiple levels for Oligocene aged fluvial and alluvial sands which have been proven in many wells in the Natuna Basin. The Gloria A prospect is scheduled to be drilled in 2013 immediately following the completion of the drilling of the Balqis and Boni prospects on the Baronang Production Sharing Contract (PSC).

South Sokang

A 3D seismic acquisition programme of 1,000 km^2 has been completed on the South Sokang Block (WI 60%) during the reporting period. The seismic processing and interpretation is schedule to be completed in the first half of 2014.

Cendrawasih

In July 2013, Lundin Petroleum announced that it has signed a new PSC with SKKMigas whereby Lundin Petroleum is swapping its Sareba Block with a new Block called the Cendrawasih VII Block (WI 100%) offshore northeastern Indonesia.

Licence farm-out

During the reporting period, Lundin Petroleum signed an agreement with Nido Petroleum Limited (Nido) whereby Nido is acquiring a 10 percent interest in the Baronang, Cakalang and Gurita PSCs in return for paying their pro-rata share of back costs and a disproportional share of the exploration costs associated with the drilling of the Baronang and Gurita wells. Nido also has an option to increase its participating interest in all three PSCs with up to an additional 10 percent on the same terms. The option expires once the drilling campaign commences. The farm-out agreement with Nido is subject to governmental and regulatory approvals.

OTHER AREAS

Russia

Production

Production in Mboepd	Lundin Petroleum Working Interest (WI)	**1 Jan 2013- 30 Jun 2013 6 months**	**1 Apr 2013- 30 Jun 2013 3 months**	1 Jan 2012- 30 Jun 2012 6 months	1 Apr 2012- 30 Jun 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Onshore Komi Republic	50%	2.4	2.4	2.8	2.8	2.7

Lagansky Block

In the Lagansky Block (WI 70%) in the northern Caspian a major oil discovery, Morskaya, was made in 2008. The discovery is deemed to be strategic by the Russian Government, due to its offshore location, under the Foreign Strategic Investment Law (FSIL). As a result a 50 percent ownership by a state owned company is required prior to appraisal and development. Discussions continue with third parties to meet the requirements of the FSIL.

FINANCIAL REVIEW

Result

The net result for the six month period ended 30 June 2013 amounted to MUSD 48.2 (MUSD 111.7). The net result attributable to shareholders of the Parent Company for the reporting period amounted to MUSD 50.9 (MUSD 113.8) representing earnings per share of USD 0.16 (USD 0.37).

Earnings before interest, tax, depletion and amortisation (EBITDA) for the reporting period amounted to MUSD 520.2 (MUSD 580.6) representing EBITDA per share of USD 1.68 (USD 1.87). Operating cash flow for the reporting period amounted to MUSD 502.9 (MUSD 375.6) representing operating cash flow per share of USD 1.62 (USD 1.21).

Changes in the Group

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

Revenue

Revenue for the reporting period amounted to MUSD 627.8 (MUSD 685.6) and is comprised of net sales of oil and gas, change in under/over lift position and other revenue as detailed in Note 1. From 1 January 2013, the change in under/over lift position is reported in revenue as stated in the Accounting Policies section below. The comparatives have also been restated for this change.

FINANCIAL REPORT FOR THE SIX MONTHS ENDED 30 JUNE 2013

Net sales of oil and gas for the reporting period amounted to MUSD 603.2 (MUSD 674.3). The average price achieved by Lundin Petroleum for a barrel of oil equivalent amounted to USD 97.23 (USD 102.50) and is detailed in the following table. The average Dated Brent price for the reporting period amounted to USD 107.50 (USD 113.61) per barrel. The Alvheim and Volund field crude cargoes sold during the reporting period, which represented 70 percent (70 percent) of the total volumes sold, averaged over USD 3.00 per barrel over Dated Brent for the pricing period for each lifting.

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 2013- 30 Jun 2013 6 months**	**1 Apr 2013- 30 Jun 2013 3 months**	1 Jan 2012- 30 Jun 2012 6 months	1 Apr 2012- 30 Jun 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Crude oil sales					
Norway					
- Quantity in Mboe	3,941.5	1,826.7	4,209.0	2,160.2	8,270.1
- Average price per boe	*110.81*	*105.56*	*116.56*	*110.40*	*115.29*
France					
- Quantity in Mboe	433.5	220.4	492.2	212.8	1,041.1
- Average price per boe	*104.87*	*101.34*	*111.04*	*99.94*	*110.44*
Netherlands					
- Quantity in Mboe	1.2	0.6	1.2	0.6	1.7
- Average price per boe	*97.07*	*89.54*	*100.65*	*93.76*	*100.09*
Russia					
- Quantity in Mboe	438.3	222.6	509.8	244.5	981.6
- Average price per boe	*76.92*	*73.98*	*77.15*	*76.51*	*77.23*
Tunisia					
- Quantity in Mboe	–	–	227.5	29.1	227.5
- Average price per boe	–	–	*108.09*	*82.97*	*108.14*
Total crude oil sales					
- Quantity in Mboe	**4,814.5**	**2,270.3**	5,439.7	2,647.2	10,522.0
- Average price per boe	***107.18***	***102.06***	*112.01*	*106.12*	*110.90*
Gas and NGL sales					
Norway					
- Quantity in Mboe	761.8	371.2	618.3	349.6	1,513.9
- Average price per boe	*72.55*	*67.79*	*62.18*	*62.94*	*64.18*
Netherlands					
- Quantity in Mboe	363.9	168.0	358.1	172.8	704.2
- Average price per boe	*64.25*	*63.13*	*59.17*	*57.88*	*60.18*
Indonesia					
- Quantity in Mboe	263.9	132.1	162.2	64.4	338.1
- Average price per boe	*32.32*	*32.74*	*32.83*	*33.35*	*32.43*
Total gas and NGL sales					
- Quantity in Mboe	**1,389.6**	**671.3**	1,138.6	586.8	2,556.2
- Average price per boe	***62.74***	***59.73***	*57.05*	*58.21*	*59.69*
Total sales					
- Quantity in Mboe	**6,204.1**	**2,941.6**	6,578.3	3,234.0	13,078.2
- Average price per boe	***97.23***	***92.40***	*102.50*	*97.43*	*100.89*

The oil produced in Russia is sold on either the Russian domestic market or exported into the international market. 46 percent (44 percent) of Russian sales for the reporting period were on the international market at an average price of USD 106.47 per barrel (USD 109.84 per barrel) with the remaining 54 percent (56 percent) of Russian sales being sold on the domestic market at an average price of USD 54.91 per barrel (USD 51.04 per barrel).

Hydrocarbon sales 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 credit of MUSD 16.0 (MUSD 5.5) to the income statement and primarily related to Norway where sales volumes were lower than production volumes for the reporting period.

Other revenue amounted to MUSD 8.6 (MUSD 5.8) for the reporting period and included the quality differential compensation received from the Vilje field owners to the Alvheim and Volund field owners in Norway, 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 94.2 (MUSD 106.0) and are detailed in the table below. The comparatives have been restated for the reclassification of the change in under/over lift from production costs to revenue.

Production costs	**1 Jan 2013- 30 Jun 2013 6 months**	**1 Apr 2013- 30 Jun 2013 3 months**	1 Jan 2012- 30 Jun 2012 6 months	1 Apr 2012- 30 Jun 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Cost of operations					
– In MUSD	58.6	32.0	50.5	25.3	105.6
– In USD per boe	*9.19*	*10.11*	*7.91*	*7.84*	*8.09*
Tariff and transportation expenses					
– In MUSD	13.3	6.8	13.6	6.8	29.7
– In USD per boe	*2.09*	*2.17*	*2.14*	*2.10*	*2.27*
Royalty and direct production taxes					
– In MUSD	23.2	11.3	27.1	14.5	51.3
– In USD per boe	*3.64*	*3.57*	*4.24*	*4.50*	*3.93*
Change in inventory position					
– In MUSD	-2.3	-1.3	13.7	2.0	14.8
– In USD per boe	*-0.37*	*-0.46*	*2.14*	*0.63*	*1.13*
Other					
– In MUSD	1.4	1.4	1.1	0.7	1.8
– In USD per boe	*0.22*	*0.45*	*0.18*	*0.19*	*0.14*
Total production costs					
– In MUSD	**94.2**	**50.2**	106.0	49.3	203.2
– In USD per boe	***14.77***	***15.84***	*16.61*	*15.26*	*15.56*

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 58.6 (MUSD 50.5) and includes costs associated with well intervention work on the Alvheim and Volund fields, Norway and well intervention work and maintenance projects in the Paris Basin fields, France. During the second quarter of 2013, well intervention work was performed on the two water disposal wells shared by the Alvheim and Volund fields at a cost of MUSD 4.8 and radial drilling was performed on the Villeperdue field, Paris Basin at a cost of MUSD 1.6. In addition, MUSD 1.3 was incurred on the Alvheim field KB4 well tie-in in the first quarter of 2013 and MUSD 1.2 was incurred in the second quarter on preparatory works for the Kneler well workovers on the Alvheim field scheduled for the second half of 2013. Also included are cost of operations of MUSD 5.8 (MUSD 2.4) associated with the Gaupe field, Norway, which came onstream on 31 March 2012. In the comparative reporting period, there are cost of operations of MUSD 7.7 associated with the Oudna field, Tunisia, which ceased production at the end of the first quarter of 2013.

The cost of operations per barrel for the reporting period was USD 9.19 (USD 7.91) per barrel and USD 10.11 (USD 7.84) per barrel for the second quarter 2013. The cost of operations per barrel are higher than for the comparative periods for 2012 due mainly to the well intervention work in Norway and France in 2013. The cost of operations for the second quarter of 2013 of USD 10.11 per barrel is higher than that reported for the first quarter of 2013 of USD 8.28 per barrel due to the higher level of well intervention activity during the second quarter.

Incorporating the planned workovers of the Kneler wells on the Alvheim field, the average cost of operations per barrel forecast for the full year 2013 is USD 11.00 per barrel. The increase compared to the guidance given in the first quarter report is mainly due to an extended workscope for the Alvheim field workovers. Excluding operational projects, the 2013 average cost of operations would be less than USD 8.75 per barrel.

Royalty and direct production taxes amounted to MUSD 23.2 (MUSD 27.1) and includes Russian Mineral Resource Extraction Tax (MRET) and Russian Export Duties. The rate of MRET is levied on the volume of Russian production and varies in relation to the international market price of Urals blend and the Rouble exchange rate. MRET averaged USD 23.08 (USD 23.14) per barrel of Russian production for the reporting period. The rate of export duty on Russian oil is revised monthly by the Russian Federation and is dependent on the average price obtained for Urals Blend for the preceding one month period. The export duty is levied on the volume of oil exported from Russia and averaged USD 55.64 (USD 60.82) per exported barrel for the reporting period.

Change in inventory position amounted to a net credit of MUSD 2.3 in the reporting period compared to a net MUSD 13.7 charge in the comparative period. There were liftings of inventory from the Ikdam FPSO on the Oudna field, Tunisia, in the comparative period resulting in a MUSD 14.6 charge for the six month period ended 30 June 2012.

Depletion and decommissioning costs
Depletion charges amounted to MUSD 85.6 (MUSD 87.7) and are detailed in Note 3. Norway contributed 74 percent of the total depletion charge for the reporting period at an average rate of USD 13.27 per barrel. The depletion charge for the reporting period is in line with Capital Market Day guidance.

Exploration costs
Exploration costs expensed in the income statement for the reporting period amounted to MUSD 134.3 (MUSD 22.9) 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 there is uncertainty regarding their recoverability.

During the second quarter of 2013, MUSD 62.3 was expensed and mainly related to the cost of the Carlsberg well along with associated licence costs on PL495, Norway and the cost associated with unsuccessful licence applications in the Norwegian 22nd licensing round.

During the first quarter of 2013, the cost of the Ogna well along with associated licence costs on PL453S, Norway and the Jorvik well on PL338, Norway were expensed for amounts of MUSD 43.8 and MUSD 24.2 respectively.

Impairment costs
The carrying values of oil and gas properties are continuously assessed to ensure recoverability. The carrying values of the gas discoveries on PL438 Skalle, PL533 Salina and PL088 Peik in Norway were concluded to be no longer supportable, particularly in view of the recently announced Norwegian tax changes, and were fully expensed in the second quarter of 2013 for an amount of MUSD 81.7 (MUSD -). The non-cash impairment charge of MUSD 81.7 is before tax and there is an associated deferred tax credit of MUSD 51.4 reflected in the income statement.

General, administrative and depreciation expenses
The general, administrative and depreciation expenses for the reporting period amounted to MUSD 15.4 (MUSD 0.6) which included non-cash credits of MUSD 3.2 (MUSD 11.5) in relation to the Group's Long-term Incentive Plan (LTIP) scheme.

The provision for the LTIP is calculated based on Lundin Petroleum's share price at the balance sheet date using the Black and Scholes method and is applied to the portion of the outstanding LTIP awards which are recognised at the balance sheet date. Any change in the value of the awards due to a change in the share price impacts all awards recognised at the balance sheet date including those of previous periods with the change in the provision being reflected in the income statement. The Lundin Petroleum share price decreased by 11 percent to SEK 133.00 per share during the reporting period compared to a 24 percent decrease from SEK 169.20 per share during the first six months ended 30 June 2012. Lundin Petroleum has mitigated the cash exposure of the LTIP by purchasing its own shares. For more detail refer to the remuneration section below.

Fixed asset depreciation charges for the reporting period amounted to MUSD 2.1 (MUSD 1.6).

Financial income
Financial income for the reporting period amounted to MUSD 1.8 (MUSD 7.6) and is detailed in Note 4.

Financial expenses
Financial expenses for the reporting period amounted to MUSD 36.8 (MUSD 28.0) and are detailed in Note 5.

Interest expenses for the reporting period amounted to MUSD 2.7 (MUSD 3.2). An additional amount of interest of MUSD 6.0 (MUSD 0.8) associated with the funding of the Norwegian development projects was capitalised in the reporting period.

Net foreign exchange losses for the reporting period amounted to MUSD 16.1 (MUSD -5.9 gain). During the reporting period there was an exchange loss of MUSD 20.8 (MUSD -5.9 gain) on the non-USD denominated intercompany loans and working capital balances and this loss was partly offset by a realised exchange gain of MUSD 4.7 (MUSD -0.1 loss) on settled foreign exchange hedges. Of the MUSD 16.1 net foreign exchange loss reported in the first six months of 2013, a net foreign exchange loss of MUSD 15.7 was reported in the second quarter of 2013. The net foreign exchange loss during the second quarter of 2013 was mainly from the impact of a five percent weakening of the NOK against the Euro over the second quarter of 2013 on a NOK intercompany loan receivable by a subsidiary using a functional currency of the Euro.

A provision for the costs of site restoration is recorded in the balance sheet at the discounted value of the estimated future cost. The effect of the discount is unwound each year and charged to the income statement. An amount of MUSD 3.1 (MUSD 2.5) has been charged to the income statement in the reporting period.

The amortisation of the deferred financing fees amounted to MUSD 4.4 (MUSD 2.5) for the reporting period and relates to the expensing of the fees incurred in establishing the USD 2.5 billion financing loan facility, which was signed on 25 June 2012, over the period of usage of the facility. The charge for the comparative period relates to the previous loan facility.

Loan facility commitment fees for the reporting period amounted to MUSD 9.6 (MUSD 0.7). The increase over the comparative period relates to the commitment fees on the undrawn portion of the USD 2.5 billion financing facility.

Tax
The tax charge for the reporting period amounted to MUSD 133.4 (MUSD 336.3) and is detailed in Note 6.

The current tax charge for the reporting period amounted to MUSD 30.7 (MUSD 204.0) of which MUSD 22.6 (MUSD 192.8) relates to Norway. The current tax charge for the reporting period for Norway is lower than the comparative period primarily as a result of higher development and exploration expenditure spent in the first six months of 2013 compared to the first six months of 2012 as shown in the Non-current assets section below.

The deferred tax charge for the reporting period amounted to MUSD 102.7 (MUSD 132.3) and arises primarily where there is a difference in depletion for tax and accounting purposes. In Norway, there is a deferred tax charge for the reporting period of MUSD 98.2 (MUSD 128.7). In the second quarter of 2013, there was a deferred tax credit of MUSD 51.4 to the income statement relating to the Norwegian impairments.

The Group operates in various countries and fiscal regimes where corporate income tax rates are different from the regulations in Sweden. Corporate income tax rates for the Group vary between 20 percent and 78 percent. The effective tax rate for the Group for the reporting period amounted to 73 percent. This effective rate is calculated from the face of the income statement and does not reflect the effective rate of tax paid within each country of operation. The high overall effective rate of tax is driven by Norway where the tax rate is 78 percent and the fact that part of the impairment during the second quarter was not tax deductible.

Non-controlling interest

The net result attributable to non-controlling interest for the reporting period amounted to MUSD -2.7 (MUSD -2.1) and relates 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 3,069.5 (MUSD 2,864.4) and are detailed in Note 7.

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

Development expenditure in MUSD	**1 Jan 2013- 30 Jun 2013 6 months**	**1 Apr 2013- 30 Jun 2013 3 months**	1 Jan 2012- 30 Jun 2012 6 months	1 Apr 2012- 30 Jun 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Norway	378.2	199.5	134.7	87.7	369.0
France	3.3	1.3	20.6	10.0	29.2
Netherlands	1.9	1.0	4.8	3.2	8.5
Indonesia	-1.0	-1.0	–	–	-0.4
Russia	0.8	0.4	4.0	2.8	7.5
	383.2	**201.2**	164.1	103.7	413.8

An amount of MUSD 378.2 (MUSD 134.7) of development expenditure was incurred in Norway during the reporting period, of which MUSD 350.1 (MUSD 97.8) was invested in the Brynhild and Edvard Grieg field developments. In the comparative period, MUSD 20.6 was spent in France, mainly on the Grandville field redevelopment.

Exploration and appraisal expenditure in MUSD	**1 Jan 2013- 30 Jun 2013 6 months**	**1 Apr 2013- 30 Jun 2013 3 months**	1 Jan 2012- 30 Jun 2012 6 months	1 Apr 2012- 30 Jun 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Norway	238.8	114.0	111.1	63.8	323.2
France	1.1	0.5	1.0	0.6	9.8
Indonesia	8.5	6.7	6.7	5.5	16.4
Russia	2.1	1.0	3.0	1.5	3.6
Malaysia	25.9	8.4	11.6	8.1	100.5
Other	0.2	0.1	2.3	1.0	3.8
	276.6	**130.7**	135.7	80.5	457.3

Exploration and appraisal expenditure of MUSD 238.8 was incurred in Norway during the reporting period, mainly on the appraisal drilling of the Johan Sverdrup field and exploration drilling of the Ogna, Jorvik and Carlsberg prospects. In the comparative period, MUSD 111.1 was spent in Norway mainly on Johan Sverdrup field appraisal drilling and two exploration wells.

During the reporting period MUSD 25.9 (MUSD 11.6) was spent in Malaysia on the Ara well on Block PM308A which was drilling over the year end and the completion of a seismic acquisition programme over Blocks PM307 and PM319. An additional seismic acquisition programme on Block SB307/308 was ongoing at the end of June 2013.

Other tangible fixed assets amounted to MUSD 55.8 (MUSD 49.4) and includes an amount of MUSD 37.1 (MUSD 32.5) relating to the Ikdam FPSO vessel and MUSD 18.7 (MUSD 16.9) relating to real estate and office fixed assets.

Financial assets amounted to MUSD 43.3 (MUSD 44.1) and are detailed in Note 8. Other shares and participations amounted to MUSD 17.6 (MUSD 20.0) and mainly relates to the shares held in ShaMaran Petroleum which are reported at market value with any change in value being recorded in other comprehensive income.

Deferred tax assets amounted to MUSD 14.6 (MUSD 13.3) and is mainly relating to the part of the tax loss carry forwards in the Netherlands that are expected to be utilised.

Current assets
Receivables and inventories amounted to MUSD 221.1 (MUSD 238.4) and are detailed in Note 9.

Inventories amounted to MUSD 22.2 (MUSD 18.7) and include both hydrocarbon inventories and well supplies. The underlift position amounted to MUSD 39.2 (MUSD 26.4) of which MUSD 36.2 (MUSD 24.6) relates to production from the Norwegian fields. Derivative instruments amounted to MUSD 0.3 (MUSD 9.1) and relates to the mark-to-market on outstanding interest rate and foreign currency hedge contracts, see Derivative financial instruments section below. Prepaid expenses and accrued income amounted to MUSD 27.4 (MUSD 32.9) and includes prepaid operational and insurance expenditure.

Cash and cash equivalents amounted to MUSD 86.5 (MUSD 97.4). Cash balances are held to meet operational and investment requirements.

Non-current liabilities
Provisions amounted to MUSD 1,212.2 (MUSD 1,204.6) and are detailed in Note 10.

The provision for site restoration amounted to MUSD 197.5 (MUSD 190.5) and relates to future decommissioning obligations. The provision has increased during the second quarter of 2013 following the inclusion of the Brynhild field development. The subsurface template and manifold and pipelines were installed during the second quarter of 2013. The provision for deferred taxes amounted to MUSD 976.1 (MUSD 942.2) of which MUSD 834.2 (MUSD 802.8) relates 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. Included in non-current liabilities is the non-current portion of the provision for Lundin Petroleum's LTIP scheme which amounted to MUSD 30.8 (MUSD 67.1). Lundin Petroleum's LTIP scheme is outlined in this report under the Remuneration section. The phantom option plan vests in May 2014 at which time 50 percent of the vested amount will become payable and this amount due is included in provisions in current liabilities. The non-current portion of the provision includes the 50 percent of the vested amount which is payable in May 2015.

Financial liabilities amounted to MUSD 644.7 (MUSD 384.2).

Bank loans amounted to MUSD 685.0 (MUSD 432.0) and relates to the outstanding loan under the Group's USD 2.5 billion revolving borrowing base facility. Capitalised financing fees amounted to MUSD 40.3 (MUSD 47.8) relating to the establishment costs of the USD 2.5 billion financing facility are being amortised over the expected life of the financing facility.

Other non-current liabilities amounted to MUSD 23.8 (MUSD 22.6) and mainly arise from the full consolidation of a subsidiary in which the non-controlling interest entity has made funding advances in relation to LLC PetroResurs, Russia.

Current liabilities
Current liabilities amounted to MUSD 355.0 (MUSD 423.4) and are detailed in Note 12.

During the second quarter of 2013, Lundin Petroleum entered into a new sales agreement for crude oil production from the Alvheim and Volund fields whereby Lundin Petroleum will receive cash payment based upon forecast production rather than crude oil lifted. As Lundin Petroleum only records sales at the time that a cargo of crude oil is lifted and risk passes to the purchaser, there will be an amount payable or receivable between Lundin Petroleum and the purchaser reflecting the difference between forecast production and actual liftings. As at 30 June 2013, an amount of MUSD 29.7 (MUSD -) was included as deferred revenue within other current liabilities reflecting this difference. Tax liabilities amounted to MUSD 28.8 (MUSD 170.0) of which MUSD 21.0 (MUSD 163.6) relates to Norway. Norwegian tax instalments in relation to the taxable year 2012 were paid in the first half of 2013. Joint venture creditors amounted to MUSD 230.3 (MUSD 213.9) and relates to the high level of development and drilling activity in Norway and Malaysia.

Short term provisions amounted to MUSD 33.1 (MUSD 8.8) and relates to the current portion of the provision for Lundin Petroleum's LTIP scheme. The current portion of the provision as at 30 June 2013 includes the 50 percent of the vested amount of the phantom option plan which is payable in May 2014.

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 -29.4 (MSEK 9.7) for the reporting period.

The result includes general and administrative expenses of MSEK 30.9 (MSEK -4.9 credit), guarantee fees of MSEK 1.5 (MSEK –) and interest income from a group company of MSEK 0.1 (MSEK 17.1 interest expense). The general and administrative expenses in the comparative period were impacted by the variation in the Group's LTIP and the negative cost was a result of a decrease in the Lundin Petroleum share price during the first six months of 2012.

Pledged assets of MSEK 12,284.3 (MSEK 11,911.6) relate to the accounting value of the pledge of the shares in respect of the new financing facility entered into by its fully-owned subsidiary Lundin Petroleum BV. See also the Liquidity section below.

RELATED PARTY TRANSACTIONS
During the reporting period, the Group has entered into transactions with related parties on a commercial basis as described below.

The Group received MUSD 0.2 (MUSD 0.2) from ShaMaran Petroleum for the provision of office and other services.

The Group paid MUSD 0.1 (MUSD 0.6) to other related parties in respect of aviation services received.

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, particularly in Norway. The USD 2.5 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 at an oil price and economic assumptions agreed with the banking syndicate providing the facility. The facility is secured by a pledge over the shares of certain Group companies and a charge over some of the bank accounts of the pledged companies. The pledged amount at 30 June 2013 is MUSD 1,830.6 (MUSD 1,831.3) and represents the accounting value of net assets of the Group companies whose shares are pledged.

Lundin Petroleum has, through its subsidiary Lundin Malaysia BV, entered into five Production Sharing Contracts (PSC) with Petroliam Nasional Berhad, the oil and gas company of the Government of Malaysia (Petronas), in respect of the six operated Blocks in Malaysia. Bank guarantees have been issued in support of the work commitments in relation to these PSCs and the outstanding amount of the bank guarantees at 30 June 2013 was MUSD 27.8. In addition, bank guarantees have been issued to cover work commitments in Indonesia amounting to MUSD 0.9 and in Tunisia for MUSD 1.5 relating to tax disputes.

SUBSEQUENT EVENTS

In July 2013, Lundin Petroleum announced that it has signed a new PSC with SKKMigas whereby Lundin Petroleum is swapping its Sareba Block with a new Block called the Cendrawasih VII Block (WI 100%) offshore northeastern Indonesia.

SHARE DATA

Lundin Petroleum AB's issued share capital amounted to SEK 3,179,106 represented by 317,910,580 shares with a quota value of SEK 0.01 each.

As at 30 June 2013, Lundin Petroleum held 8,254,970 of its own shares. In July 2013, a further 85,280 shares were purchased bringing the total number of own shares held to 8,340,250.

REMUNERATION

Lundin Petroleum's principles for remuneration and details of the Unit Bonus and Phantom Option Plans are provided in the Company's 2012 Annual Report.

Unit Bonus Plan

The number of units relating to the 2011, 2012 and 2013 Unit Bonus Plans outstanding as at 30 June 2013 were 124,492, 239,294 and 419,790 respectively.

Phantom Option Plan

The LTIP for Executive Management includes 5,500,928 phantom options with an exercise price of SEK 52.91. The phantom options will vest in May 2014 being the fifth anniversary of the date of grant.

Lundin Petroleum holds 8,340,250 of its own shares which mitigates against the exposure of the LTIP. The Lundin Petroleum share price at 30 June 2013 was SEK 133.00. The provision for the Phantom Option Plan amounted to MUSD 59.2 including social charges as at 30 June 2013 and the market value of the shares held at 30 June 2013 was MUSD 163.6. The gain in the value of the own shares held cannot be offset against the cost for the LTIP in the financial statements in accordance with accounting rules.

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 2013, Lundin Petroleum has applied the following new accounting standards: IFRS 13 Fair value measurement, revised IAS 1 Presentation of financial statements and amendment to IFRS 7 Financial instruments. 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 2012 except for the classification of the change in under/over lift position as mentioned below.

With effect from 1 January 2013, the change in under/over lift position is reported in revenue and not as previously reported in production costs as detailed in Note 1. The comparative amounts have been restated. Under or overlifted positions of hydrocarbons are valued at market prices prevailing at the balance sheet date. An underlift of production from a field is included in the current receivables and valued at the balance sheet date spot price or prevailing contract price and an overlift of production from a field is included in the current liabilities and valued at the balance sheet date spot price or prevailing contract price. A change in the under/over lift position is reflected in the income statement as revenue such that revenue reflects the Group's working interest share of production (entitlement method).

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 and consequently the Parent Company's financial information is reported in SEK and not in 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 2012 Annual Report.

Derivative financial instruments

During the second quarter of 2012, the Group entered into currency hedging contracts to meet part of the 2013 NOK operational requirements as summarised in the table below.

Buy	Sell	Average contractual exchange rate	Settlement period
MNOK 670.7	MUSD 110.4	NOK 6.07: USD 1	2 Jan 2013 – 20 Dec 2013

During the first quarter of 2013, the Group entered into currency hedging contracts as summarised in the table below.

Buy	Sell	Average contractual exchange rate	Settlement period
MNOK 505.9	MUSD 86.0	NOK 5.88: USD 1	19 Apr 2013 – 20 Dec 2013
MNOK 616.9	MUSD 103.9	NOK 5.94: USD 1	21 Jan 2014 – 19 Dec 2014
MNOK 139.9	MUSD 23.4	NOK 5.99: USD 1	21 Jan 2015 – 21 Dec 2015

During the second quarter of 2013, the Group entered into currency hedging contracts as summarised in the table below.

Buy	Sell	Average contractual exchange rate	Settlement period
MNOK 361.0	MUSD 59.7	NOK 6.04: USD 1	19 Jul 2013 – 19 Dec 2013
MNOK 526.4	MUSD 86.9	NOK 6.06: USD 1	21 Jan 2014 – 28 Dec 2014
MNOK 103.8	MUSD 17.0	NOK 6.11: USD 1	21 Jan 2015 – 21 Dec 2015

In the first quarter of 2013, the Group also 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.

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. At 30 June 2013, a current asset amounting to MUSD 0.3 (MUSD 9.1) and a non-current asset of MUSD 0.5 (MUSD –) has been recognised representing the fair value of the outstanding interest rate hedging contracts. The comparative period short term current asset related to currency hedge contracts. In addition, a current liability of MUSD 5.4 (MUSD –) and a non-current liability of MUSD 3.2 (MUSD –) has been recognised representing the fair value of the outstanding currency hedges.

EXCHANGE RATES

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

	30 Jun 2013		30 Jun 2012		31 Dec 2012	
	Average	Period end	Average	Period end	Average	Period end
1 USD equals NOK	5.7271	6.0279	5.8394	5.9833	5.8148	5.5639
1 USD equals Euro	0.7613	0.7645	0.7711	0.7943	0.7778	0.7579
1 USD equals Rouble	31.0355	32.7561	30.6125	32.8594	31.0546	30.5665
1 USD equals SEK	6.4940	6.7105	6.8489	6.9681	6.7725	6.5045

CONSOLIDATED INCOME STATEMENT IN SUMMARY

Expressed in MUSD	Note	**1 Jan 2013-30 Jun 2013 6 months**	**1 Apr 2013-30 Jun 2013 3 months**	1 Jan 2012-30 Jun 2012 6 months	1 Apr 2012-30 Jun 2012 3 months	1 Jan 2012-31 Dec 2012 12 months
Revenue [1]	1	**627.8**	**300.2**	685.6	321.0	1,375.8
Cost of sales						
Production costs [1]	2	-94.2	-50.2	-106.0	-49.3	-203.2
Depletion and decommissioning costs		-85.6	-42.6	-87.7	-46.3	-191.4
Exploration costs		-134.3	-62.3	-22.9	-14.0	-168.4
Impairment costs of oil and gas properties		-81.7	-81.7	–	–	-237.5
Gross profit	3	**232.0**	**63.4**	469.0	211.4	575.3
General, administration and depreciation expenses		-15.4	-7.1	-0.6	-1.1	-31.8
Operating profit		**216.6**	**56.3**	468.4	210.3	543.5
Result from financial investments						
Financial income	4	1.8	0.9	7.6	7.0	27.3
Financial expenses	5	-36.8	-26.3	-28.0	-0.7	-48.5
		-35.0	**-25.4**	-20.4	6.3	-21.2
Profit before tax		**181.6**	**30.9**	448.0	216.6	522.3
Income tax expense	6	-133.4	-29.7	-336.3	-152.1	-418.4
Net result		**48.2**	**1.2**	111.7	64.5	103.9
Net result attributable to the shareholders of the Parent Company		50.9	2.7	113.8	65.0	108.2
Net result attributable to non-controlling interest		-2.7	-1.5	-2.1	-0.5	-4.3
Net result		**48.2**	**1.2**	111.7	64.5	103.9
Earnings per share – USD [2]		0.16	0.01	0.37	0.21	0.35

[1] The comparatives have been restated for the reclassification of the change in under/over lift from production cost to revenue from 1 January 2013.
[2] Based on net result attributable to shareholders of the Parent Company.

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME IN SUMMARY

Expressed in MUSD	**1 Jan 2013-30 Jun 2013 6 months**	**1 Apr 2013-30 Jun 2013 3 months**	1 Jan 2012-30 Jun 2012 6 months	1 Apr 2012-30 Jun 2012 3 months	1 Jan 2012-31 Dec 2012 12 months
Net result	**48.2**	**1.2**	111.7	64.5	103.9
Other comprehensive income					
Items that may be subsequently reclassified to profit or loss:					
Exchange differences foreign operations	-57.4	-13.1	-9.2	-61.9	61.6
Cash flow hedges	-17.0	-8.2	2.7	2.5	9.2
Available-for-sale financial assets	-2.3	0.7	5.5	-3.9	16.1
Income tax relating to other comprehensive income	4.3	2.0	-0.7	-0.7	-2.3
Other comprehensive income, net of tax	-72.4	-18.6	-1.7	-63.9	84.6
Total comprehensive income	**-24.2**	**-17.4**	110.0	0.6	188.5
Total comprehensive income attributable to:					
Shareholders of the Parent Company	-18.2	-13.7	112.9	6.4	190.2
Non-controlling interest	-6.0	-3.7	-2.9	-5.8	-1.7
	-24.2	**-17.4**	110.0	0.6	188.5

CONSOLIDATED BALANCE SHEET IN SUMMARY

Expressed in MUSD	Note	**30 June 2013**	31 December 2012
ASSETS			
Non-current assets			
Oil and gas properties	7	3,069.5	2,864.4
Other tangible fixed assets		55.8	49.4
Financial assets	8	43.3	44.1
Total non-current assets		**3,168.6**	2,957.9
Current assets			
Receivables and inventories	9	221.1	238.4
Cash and cash equivalents		86.5	97.4
Total current assets		**307.6**	335.8
TOTAL ASSETS		**3,476.2**	3,293.7
EQUITY AND LIABILITIES			
Equity			
Shareholders´ equity		1,145.8	1,182.4
Non-controlling interest		61.6	67.7
Total equity		**1,207.4**	1,250.1
Non-current liabilities			
Provisions	10	1,212.2	1,204.6
Financial liabilities	11	644.7	384.2
Other non-current liabilities		23.8	22.6
Total non-current liabilities		**1,880.7**	1,611.4
Current liabilities			
Current liabilities	12	355.0	423.4
Provisions	10	33.1	8.8
Total current liabilities		**388.1**	432.2
TOTAL EQUITY AND LIABILITIES		**3,476.2**	3,293.7

CONSOLIDATED STATEMENT OF CASH FLOW IN SUMMARY

Expressed in MUSD	Note	**1 Jan 2013- 30 Jun 2013 6 months**	**1 Apr 2013- 30 Jun 2013 3 months**	1 Jan 2012- 30 Jun 2012 6 months	1 Apr 2012- 30 Jun 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Cash flow from operations						
Net result		48.2	1.2	111.7	64.5	103.9
Adjustments for non-cash related items	14	467.4	238.0	450.4	198.5	1,056.9
Gain on sale of asset		–	–	–	–	-1.1
Interest received		0.6	0.4	0.7	0.6	3.5
Interest paid		-8.0	-4.4	-3.3	-1.7	-8.9
Income taxes paid		-165.4	-105.4	-253.4	-166.6	-428.8
Changes in working capital		75.9	34.8	31.7	78.7	93.5
Total cash flow from operations		**418.7**	**164.6**	337.8	174.0	819.0
Cash flow from investments						
Investment in oil and gas properties		-659.4	-331.7	-299.0	-183.4	-919.4
Investment in office equipment and other assets		-9.3	-6.5	-1.4	-0.4	-9.7
Investment in subsidiaries		–	–	–	–	-10.2
Decommissioning costs paid		-0.9	-0.8	–	–	-18.6
Other payments		-0.2	–	-2.5	-2.2	-3.2
Total cash flow from investments		**-669.8**	**-339.0**	-302.9	-186.0	-961.1
Cash flow from financing						
Changes in long-term liabilities		254.1	150.4	-7.0	-26.5	225.7
Financing fees paid		–	–	-0.5	-0.5	-49.2
Purchase of own shares		-18.4	-18.4	-8.7	-8.7	-8.7
Distributions		-0.1	-0.1	–	–	–
Total cash flow from financing		**235.6**	**131.9**	-16.3	-35.7	167.8
Change in cash and cash equivalents		-15.5	-42.5	18.6	-47.7	25.7
Cash and cash equivalents at the beginning of the period		97.4	125.1	73.6	137.6	73.6
Currency exchange difference in cash and cash equivalents		4.6	3.9	-1.6	0.7	-1.9
Cash and cash equivalents at the end of the period		**86.5**	**86.5**	90.6	90.6	97.4

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY IN SUMMARY

Expressed in MUSD	Share capital	Additional paid-in-capital/ Other reserves	Retained earnings	Net result	Non-controlling interest	Total equity
Balance at 1 January 2012	**0.5**	**337.8**	**502.5**	**160.1**	**69.4**	**1,070.3**
Transfer of prior year net result	–	–	160.1	-160.1	–	–
Total comprehensive income	**–**	**-0.9**	**–**	**113.8**	**-2.9**	**110.0**
Transactions with owners						
Purchase of own shares	–	-8.7	–	–	–	-8.7
Balance at 30 June 2012	**0.5**	**328.2**	**662.6**	**113.8**	**66.5**	**1,171.6**
Total comprehensive income	**–**	**82.9**	**–**	**-5.6**	**1.2**	**78.5**
Balance at 31 December 2012	**0.5**	**411.1**	**662.6**	**108.2**	**67.7**	**1,250.1**
Transfer of prior year net result	–	–	108.2	-108.2	–	–
Total comprehensive income	**–**	**-69.1**	**–**	**50.9**	**-6.0**	**-24.2**
Transactions with owners						
Distributions	–	–	–	–	-0.1	-0.1
Purchase of own shares	–	-18.4	–	–	–	-18.4
Total transaction with owners	**–**	**-18.4**	**–**	**–**	**-0.1**	**-18.5**
Balance at 30 June 2013	**0.5**	**323.6**	**770.8**	**50.9**	**61.6**	**1,207.4**

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Revenue MUSD	**1 Jan 2013- 30 Jun 2013 6 months**	**1 Apr 2013- 30 Jun 2013 3 months**	1 Jan 2012- 30 Jun 2012 6 months	1 Apr 2012- 30 Jun 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Crude oil	516.0	231.7	609.3	280.9	1,169.0
Condensate	1.4	0.3	0.5	0.1	3.3
Gas	85.8	39.8	64.5	34.1	147.2
Net sales of oil and gas	**603.2**	**271.8**	674.3	315.1	1,319.5
Change in under/over lift position	16.0	24.6	5.5	3.1	30.7
Other revenue	8.6	3.8	5.8	2.8	25.6
Revenue	**627.8**	**300.2**	685.6	321.0	1,375.8

The reclassification of the change in under/over lift from production costs to revenue is effective from 1 January 2013 and the comparatives have been restated.

Note 2. Production costs, MUSD	**1 Jan 2013- 30 Jun 2013 6 months**	**1 Apr 2013- 30 Jun 2013 3 months**	1 Jan 2012- 30 Jun 2012 6 months	1 Apr 2012- 30 Jun 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Cost of operations	58.6	32.0	50.5	25.3	105.6
Tariff and transportation expenses	13.3	6.8	13.6	6.8	29.7
Direct production taxes	23.2	11.3	27.1	14.5	51.3
Change in inventory position	-2.3	-1.3	13.7	2.0	14.8
Other	1.4	1.4	1.1	0.7	1.8
	94.2	**50.2**	106.0	49.3	203.2

The reclassification of the change in under/over lift from production costs to revenue is effective from 1 January 2013 and the comparatives have been restated.

Note 3. Segment information, MUSD	**1 Jan 2013- 30 Jun 2013 6 months**	**1 Apr 2013- 30 Jun 2013 3 months**	1 Jan 2012- 30 Jun 2012 6 months	1 Apr 2012- 30 Jun 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Norway					
Crude oil	436.7	192.8	490.6	238.5	953.4
Condensate	0.8	–	–	–	2.3
Gas	54.5	25.2	38.4	21.9	94.9
Net sales of oil and gas	**492.0**	**218.0**	529.0	260.4	1,050.6
Change in under/over lift position	14.2	23.5	6.7	3.1	31.4
Other revenue	2.9	1.3	3.1	1.5	6.5
Revenue	**509.1**	**242.8**	538.8	265.0	1,088.5
Production costs	-38.4	-21.1	-27.3	-14.9	-65.5
Depletion and decommissioning costs	-63.2	-31.6	-71.9	-38.9	-154.1
Exploration costs	-133.4	-62.0	-13.0	-12.4	-103.1
Impairment costs of oil and gas properties	-81.7	-81.7	–	–	-205.8
Gross profit	**192.4**	**46.4**	426.6	198.8	560.0

Note 3. Segment information cont., MUSD	**1 Jan 2013- 30 Jun 2013 6 months**	**1 Apr 2013- 30 Jun 2013 3 months**	1 Jan 2012- 30 Jun 2012 6 months	1 Apr 2012- 30 Jun 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
France					
Crude oil	45.5	22.4	54.7	21.3	115.0
Net sales of oil and gas	45.5	22.4	54.7	21.3	115.0
Change in under/over lift position	-0.2	0.1	-0.1	0.7	–
Other revenue	1.1	0.6	0.7	0.3	2.6
Revenue	**46.4**	**23.1**	55.3	22.3	117.6
Production costs	-17.2	-9.6	-12.5	-4.6	-29.9
Depletion and decommissioning costs	-6.0	-3.0	-5.9	-2.9	-11.7
Exploration costs	-0.1	-0.1	-0.3	-0.3	-5.0
Gross profit	**23.1**	**10.4**	36.6	14.5	71.0
Netherlands					
Crude oil	0.1	–	0.1	–	0.2
Condensate	0.6	0.3	0.5	0.1	1.0
Gas	22.8	10.3	20.8	10.1	41.4
Net sales of oil and gas	**23.5**	**10.6**	21.4	10.2	42.6
Change in under/over lift position	2.0	1.0	-0.4	-0.3	-0.7
Other revenue	0.9	0.4	0.6	0.3	12.2
Revenue	**26.4**	**12.0**	21.6	10.2	54.1
Production costs	-6.4	-3.4	-5.8	-3.0	-12.4
Depletion and decommissioning costs	-8.0	-3.8	-5.4	-2.6	-10.4
Exploration costs	–	–	-0.5	-0.5	-0.6
Gross profit	**12.0**	**4.8**	9.9	4.1	30.7
Indonesia					
Gas	8.5	4.3	5.3	2.1	10.9
Net sales of oil and gas	**8.5**	**4.3**	5.3	2.1	10.9
Change in under/over lift position	–	–	-0.7	-0.4	–
Revenue	**8.5**	**4.3**	4.6	1.7	10.9
Production costs	-2.3	-1.2	-2.9	-1.6	-5.5
Depletion and decommissioning costs	-5.8	-2.9	-2.3	-0.8	-5.6
Exploration costs	-0.2	-0.1	-7.0	-0.2	-7.4
Gross profit	**0.2**	**0.1**	-7.6	-0.9	-7.6
Russia					
Crude oil	33.7	16.5	39.3	18.7	75.8
Net sales of oil and gas	**33.7**	**16.5**	39.3	18.7	75.8
Revenue	**33.7**	**16.5**	39.3	18.7	75.8
Production costs	-29.9	-14.9	-34.7	-18.5	-65.2
Depletion and decommissioning costs	-2.6	-1.3	-2.2	-1.1	-4.3
Impairment costs of oil and gas properties	–	–	–	–	-31.7
Gross profit	**1.2**	**0.3**	2.4	-0.9	-25.4

Note 3. Segment information cont., MUSD	**1 Jan 2013- 30 Jun 2013 6 months**	**1 Apr 2013- 30 Jun 2013 3 months**	1 Jan 2012- 30 Jun 2012 6 months	1 Apr 2012- 30 Jun 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Other					
Crude oil [1]	–	–	24.6	2.4	24.6
Net sales of oil and gas	–	–	24.6	2.4	24.6
Other revenue	3.7	1.5	1.4	0.7	4.3
Revenue	**3.7**	**1.5**	26.0	3.1	28.9
Production costs	–	–	-22.8	-6.7	-24.7
Depletion and decommissioning costs	–	–	–	–	-5.3
Exploration costs [2]	-0.6	-0.1	-2.1	-0.6	-52.3
Gross profit	**3.1**	**1.4**	1.1	-4.2	-53.4

[1] Net sales of crude oil related to Tunisia in the comparative period and in 2012.
[2] Exploration costs in 2012 related mainly to Malaysia and amounted to MUSD 46.7. An amount of MUSD 0.5 (MUSD 0.1) has been expensed in the reporting period relating to Malaysia.

Total					
Crude oil	516.0	231.7	609.3	280.9	1,169.0
Condensate	1.4	0.3	0.5	0.1	3.3
Gas	85.8	39.8	64.5	34.1	147.2
Net sales of oil and gas	**603.2**	**271.8**	674.3	315.1	1,319.5
Change in under/over lift position	16.0	24.6	5.5	3.1	30.7
Other revenue	8.6	3.8	5.8	2.8	25.6
Revenue	**627.8**	**300.2**	685.6	321.0	1,375.8
Production costs	-94.2	-50.2	-106.0	-49.3	-203.2
Depletion and decommissioning costs	-85.6	-42.6	-87.7	-46.3	-191.4
Exploration costs	-134.3	-62.3	-22.9	-14.0	-168.4
Impairment costs of oil and gas properties	-81.7	-81.7	–	–	-237.5
Gross profit	**232.0**	**63.4**	469.0	211.4	575.3

Note 4. Financial income, MUSD	**1 Jan 2013- 30 Jun 2013 6 months**	**1 Apr 2013- 30 Jun 2013 3 months**	1 Jan 2012- 30 Jun 2012 6 months	1 Apr 2012- 30 Jun 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Interest income	1.3	0.7	1.6	1.0	5.1
Foreign currency exchange gain, net	–	–	5.9	5.9	6.2
Guarantee fees	0.2	0.2	–	–	0.2
Gain on consolidation of subsidiary	–	–	–	–	13.4
Other	0.3	–	0.2	0.1	2.4
	1.8	**0.9**	7.6	7.0	27.3

Note 5. Financial expenses, MUSD	**1 Jan 2013- 30 Jun 2013 6 months**	**1 Apr 2013- 30 Jun 2013 3 months**	1 Jan 2012- 30 Jun 2012 6 months	1 Apr 2012- 30 Jun 2012 3 months	1 Jan 2012- 31 Dec 2012 12 months
Interest expense	2.7	1.4	3.2	1.8	6.8
Foreign currency exchange loss, net	16.1	15.7	–	-4.1	–
Result on interest rate hedge settlement	0.5	0.5	0.2	–	0.2
Unwinding of site restoration discount	3.1	1.5	2.5	1.3	5.1
Amortisation of deferred financing fees	4.4	2.2	2.5	1.3	6.6
Loan facility commitment fees	9.6	4.7	0.7	0.3	10.3
Impairment of other shares	–	–	18.6	–	18.6
Other	0.4	0.3	0.3	0.1	0.9
	36.8	**26.3**	28.0	0.7	48.5

Note 6. Income tax expense, MUSD	**1 Jan 2013-30 Jun 2013 6 months**	**1 Apr 2013-30 Jun 2013 3 months**	1 Jan 2012-30 Jun 2012 6 months	1 Apr 2012-30 Jun 2012 3 months	1 Jan 2012-31 Dec 2012 12 months
Current tax	30.7	7.2	204.0	62.7	341.3
Deferred tax	102.7	22.5	132.3	89.4	77.1
	133.4	**29.7**	336.3	152.1	418.4

Note 7. Oil and gas properties, MUSD	**30 Jun 2013**	31 Dec 2012
Norway	1,901.4	1,702.3
France	213.8	216.8
Netherlands	59.3	65.8
Indonesia	98.4	96.9
Russia	587.8	599.2
Malaysia	208.8	183.4
	3,069.5	2,864.4

Note 8. Financial assets, MUSD	**30 Jun 2013**	31 Dec 2012
Other shares and participations	17.6	20.0
Bonds	9.4	9.5
Deferred tax	14.6	13.3
Derivative instruments	0.5	–
Other	1.2	1.3
	43.3	44.1

Note 9. Receivables and inventories, MUSD	**30 Jun 2013**	31 Dec 2012
Inventories	22.2	18.7
Trade receivables	105.4	125.9
Underlift	39.2	26.4
Corporate tax	3.4	4.0
Joint venture debtors	18.4	11.5
Derivative instruments	0.3	9.1
Prepaid expenses and accrued income	27.4	32.9
Other	4.8	9.9
	221.1	238.4

Note 10. Provisions, MUSD	**30 Jun 2013**	31 Dec 2012
Non-current:		
Site restoration	197.5	190.5
Deferred tax	976.1	942.2
Long-term incentive plan	30.8	67.1
Derivative instruments	3.2	–
Pension	1.5	1.5
Other	3.1	3.3
	1,212.2	1,204.6
Current:		
Long-term incentive plan	33.1	8.8
	33.1	8.8
	1,245.3	1,213.4

Note 11. Financial liabilities,

MUSD	**30 Jun 2013**	31 Dec 2012
Bank loans	685.0	432.0
Capitalised financing fees	-40.3	-47.8
	644.7	384.2

Note 12. Current liabilities,

MUSD	**30 Jun 2013**	31 Dec 2012
Trade payables	16.1	15.7
Deferred revenue	30.1	1.6
Overlift	–	0.5
Tax liabilities	28.8	170.0
Accrued expenses	32.9	8.3
Joint venture creditors	230.3	213.9
Derivative instruments	5.4	–
Other	11.4	13.4
	355.0	423.4

Note 13. Financial instruments,

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

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

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

30 June 2013 MUSD	Level 1	Level 2	Level 3
Assets			
Available for sale financial assets			
- Other shares and participations	17.2	–	0.4
- Bonds	9.4	–	–
- Derivative instruments – non-current	–	0.5	–
- Derivative instruments - current	–	0.3	–
	26.6	**0.8**	**0.4**
Liabilities			
- Derivative instruments – non-current	–	3.2	–
- Derivative instruments – current	–	5.4	–
	–	**8.6**	**–**

31 December 2012 MUSD	Level 1	Level 2	Level 3
Assets			
Available for sale financial assets			
- Other shares and participations	19.6	–	0.4
- Bonds	9.5	–	–
- Derivative instruments – non-current	–	–	–
- Derivative instruments - current	–	9.1	–
	29.1	**9.1**	**0.4**
Liabilities			
- Derivative instruments – non-current	–	–	–
- Derivative instruments – current	–	–	–
	–	–	–

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

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

Fair value of the following financial assets and liabilities is estimated to equal the carrying value.
- Trade receivables
- Joint venture debtors
- Cash and cash equivalents
- Trade payables
- Joint venture creditors
- Bank loans
- Other non-current liabilities

The USD 2.5 billion financing facility, entered into on 25 June 2012 is a revolving borrowing base facility secured against certain cash flows generated by the Group. The amount available under the facility is recalculated every six months based upon the calculated cash flow generated by certain producing fields 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, no repayments of the current outstanding bank loan balance falls due within five years.

Note 14. Adjustment for non-cash related items, MUSD	**1 Jan 2013-30 Jun 2013 6 months**	**1 Apr 2013-30 Jun 2013 3 months**	1 Jan 2012-30 Jun 2012 6 months	1 Apr 2012-30 Jun 2012 3 months	1 Jan 2012-31 Dec 2012 12 months
Exploration costs	134.3	62.3	22.9	14.1	168.5
Depletion, depreciation and amortisation	87.6	43.7	89.3	47.1	189.3
Current tax	30.7	7.2	204.0	62.7	341.3
Deferred tax	102.7	22.5	132.3	89.4	77.1
Impairment of oil and gas properties	81.7	81.7	–	–	237.5
Impairment of other shares	–	–	18.6	–	18.6
Long-term incentive plan	0.4	-1.5	-13.7	-3.6	13.0
Other	30.0	22.1	-3.1	-11.1	11.6
	467.4	**238.0**	450.4	198.5	1,056.9

PARENT COMPANY INCOME STATEMENT IN SUMMARY

Expressed in MSEK	**1 Jan 2013-30 Jun 2013 6 months**	**1 Apr 2013-30 Jun 2013 3 months**	1 Jan 2012-30 Jun 2012 6 months	1 Apr 2012-30 Jun 2012 3 months	1 Jan 2012-31 Dec 2012 12 months
Revenue	**-0.1**	**–**	21.3	12.0	71.0
General and administration expenses	-30.9	-18.7	4.9	-1.0	-84.6
Operating profit	**-31.0**	**-18.7**	26.2	11.0	-13.6
Result from financial investments					
Financial income	1.7	0.8	0.6	0.6	807.1
Financial expenses	-0.1	–	-17.1	-8.4	-31.3
	1.6	**0.8**	-16.5	-7.8	775.8
Profit before tax	**-29.4**	**-17.9**	9.7	3.2	762.2
Income tax expense	–	–	–	–	–
Net result	**-29.4**	**-17.9**	9.7	3.2	762.2

PARENT COMPANY COMPREHENSIVE INCOME STATEMENT IN SUMMARY

Expressed in MSEK	**1 Jan 2013-30 Jun 2013 6 months**	**1 Apr 2013-30 Jun 2013 3 months**	1 Jan 2012-30 Jun 2012 6 months	1 Apr 2012-30 Jun 2012 3 months	1 Jan 2012-31 Dec 2012 12 months
Net result	**-29.4**	**-17.9**	9.7	3.2	762.2
Other comprehensive income	**–**	**–**	–	–	–
Total comprehensive income	**-29.4**	**-17.9**	9.7	3.2	762.2
Total comprehensive income attributable to:					
Shareholders of the Parent Company	-29.4	-17.9	9.7	3.2	762.2
	-29.4	**-17.9**	9.7	3.2	762.2

PARENT COMPANY BALANCE SHEET IN SUMMARY

Expressed in MSEK	**30 June 2013**	31 December 2012
ASSETS		
Non-current assets		
Shares in subsidiaries	7,871.8	7,871.8
Receivables from group companies	–	21.4
Total non-current assets	**7,871.8**	7,893.2
Current assets		
Receivables	14.7	20.7
Cash and cash equivalents	4.4	1.1
Total current assets	**19.1**	21.8
TOTAL ASSETS	**7,890.9**	7,915.0
SHAREHOLDERS´EQUITY AND LIABILITIES		
Shareholders´ equity including net result for the period	7,719.9	7,869.8
Non-current liabilities		
Provisions	36.4	36.4
Payables to group companies	121.8	–
Total non-current liabilities	**158.2**	36.4
Current liabilities		
Current liabilities	12.8	8.8
Total current liabilities	**12.8**	8.8
TOTAL EQUITY AND LIABILITIES	**7,890.9**	7,915.0
Pledged assets	12,284.3	11,911.6

PARENT COMPANY CASH FLOW STATEMENT IN SUMMARY

Expressed in MSEK	**1 Jan 2013-30 Jun 2013 6 months**	**1 Apr 2013-30 Jun 2013 3 months**	1 Jan 2012-30 Jun 2012 6 months	1 Apr 2012-30 Jun 2012 3 months	1 Jan 2012-31 Dec 2012 12 months
Cash flow from operations					
Net result	-29.4	-17.9	9.7	3.2	762.2
Adjustment for non-cash related items	–	0.3	-0.6	-0.7	-725.2
Changes in working capital	10.2	4.5	-4.2	-2.0	-6.4
Total cash flow from operations	**-19.2**	**-13.1**	4.9	0.5	30.6
Cash flow from investments					
Change in long-term receivables	–	-5.7	–	–	–
Change in long-term financial fixed assets	–	–	–	–	0.1
Total Cash flow from investments	**–**	**-5.7**	–	–	0.1
Cash flow from financing					
Change in long-term liabilities	143.1	143.1	68.9	76.5	29.1
Purchase of own shares	-120.5	-120.5	-62.4	-62.4	-62.4
Total cash flow from financing	22.6	22.6	6.5	14.1	-33.3
Change in cash and cash equivalents	3.4	3.8	11.4	14.6	-2.6
Cash and cash equivalents at the beginning of the period	1.1	0.7	3.8	0.6	3.8
Currency exchange difference in cash and cash equivalents	-0.1	-0.1	–	–	-0.1
Cash and cash equivalents at the end of the period	**4.4**	**4.4**	15.2	15.2	1.1

PARENT COMPANY STATEMENT OF CHANGES IN EQUITY IN SUMMARY

	Restricted equity		Unrestricted equity			
Expressed in MSEK	Share capital	Statutory reserve	Other reserves	Retained earnings	Net result	Total equity
Balance at 1 January 2012	**3.2**	**861.3**	**2,551.8**	**3,936.1**	**-182.4**	**7,170.0**
Transfer of prior year net result	–	–	–	-182.4	182.4	–
Total comprehensive income	**–**	**–**	**–**	**–**	**9.7**	**9.7**
Transactions with owners						
Purchase of own shares	–	–	-62.4	–	–	-62.4
Total transactions with owners	**–**	**–**	**-62.4**	**–**	**–**	**-62.4**
Balance at 30 June 2012	**3.2**	**861.3**	**2,489.4**	**3,753.7**	**9.7**	**7,117.3**
Total comprehensive income	**–**	**–**	**–**	**–**	**752.5**	**752.5**
Balance at 31 December 2012	**3.2**	**861.3**	**2,489.4**	**3,753.7**	**762.2**	**7,869.8**
Transfer of prior year net result	–	–	–	762.2	-762.2	–
Total comprehensive income	**–**	**–**	**–**	**–**	**-29.4**	**-29.4**
Transactions with owners						
Purchase of own shares	–	–	-120.5	–	–	-120.5
Total transactions with owners	**–**	**–**	**-120.5**	**–**	**–**	**-120.5**
Balance at 30 June 2013	**3.2**	**861.3**	**2,368.9**	**4,515.9**	**-29.4**	**7,719.9**

KEY FINANCIAL DATA

Financial data (MUSD)	**1 Jan 2013-30 Jun 2013 6 months**	**1 Apr 2013-30 Jun 2013 3 months**	1 Jan 2012-30 Jun 2012 6 months	1 Apr 2012-30 Jun 2012 3 months	1 Jan 2012-31 Dec 2012 12 months
Revenue [1]	627.8	300.2	685.6	321.0	1,375.8
EBITDA	520.2	244.0	580.6	271.4	1,144.1
Net result	48.2	1.2	111.7	64.5	103.9
Operating cash flow	502.9	242.9	375.6	209.0	831.4
Data per share (USD)					
Shareholders' equity per share	3.70	3.70	3.56	3.56	3.81
Operating cash flow per share	1.62	0.78	1.21	0.67	2.68
Cash flow from operations per share	1.35	0.53	1.09	0.56	2.64
Earnings per share	0.16	–	0.37	0.21	0.35
Earnings per share fully diluted	0.16	–	0.37	0.21	0.35
EBITDA per share	1.68	0.79	1.87	0.88	3.68
Dividend per share	–	–	–	–	–
Number of shares issued at period end	317,910,580	317,910,580	317,910,580	317,910,580	317,910,580
Number of shares in circulation at period end	309,655,610	309,655,610	310,542,295	310,542,295	310,542,295
Weighted average number of shares for the period	310,059,705	309,901,766	310,735,227	310,638,361	310,735,227
Share price					
Quoted price at period end (SEK)	133.00	133.00	128.90	128.90	149.50
Quoted price at period end (CAD)	20.54	20.54	19.05	19.05	22.87
Key ratios					
Return on equity (%)	4	–	10	6	9
Return on capital employed (%)	11	3	33	15	35
Net debt/equity ratio (%)	54	54	12	12	30
Equity ratio (%)	35	35	40	40	38
Share of risk capital (%)	62	62	71	71	66
Interest coverage ratio	63	26	132	114	75
Operating cash flow/interest ratio	159	128	111	115	119
Yield	–	–	–	–	–

[1] The comparatives have been restated for the reclassification of the change in under/over lift from production cost to revenue from 1 January 2013.

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: Net interest bearing liabilities divided by shareholders' equity.

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

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

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

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

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

BOARD ASSURANCE

The Board of Directors and the President and CEO certify that the half-yearly financial report gives a fair view of the performance of the business, position and profit or loss of the Company and the Group, and describes the principal risks and uncertainties that the Company and the companies in the Group face.

Stockholm, 7 August 2013

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

We have reviewed this report for the period 1 January 2013 to 30 June 2013 for Lundin Petroleum AB (publ). The board of directors and the President and CEO are responsible for the preparation and presentation of this interim report in accordance with IAS 34 and the Swedish Annual Accounts Act. Our responsibility is to express a conclusion on this interim report based on our review.

We conducted our review in accordance with the Swedish Standard on Review Engagements SÖG 2410, Review of Interim Report Performed by the Independent Auditor of the Entity. A review consists of making inquiries, primarily of persons responsible for financial and accounting matters, and applying analytical and other review procedures. A review is substantially less in scope than an audit conducted in accordance with International Standards on Auditing, ISA, and other generally accepted auditing standards in Sweden. The procedures performed in a review do not enable us to obtain assurance that we would become aware of all significant matters that might be identified in an audit. Accordingly, we do not express an audit opinion.

Based on our review, nothing has come to our attention that causes us to believe that the interim report is not prepared, in all material respects, in accordance with IAS 34 and the Swedish Annual Accounts Act, regarding the Group, and with the Swedish Annual Accounts Act, regarding the Parent Company.

Stockholm, 7 August 2013

PricewaterhouseCoopers AB

Klas Brand
Authorised Public Accountant
Lead Auditor

Johan Malmqvist
Authorised Public Accountant

FINANCIAL INFORMATION

The Company will publish the following reports:

- The nine month report (January – September 2013) will be published on 6 November 2013.
- The year end report (January – December 2013) will be published on 5 February 2014.
- The three month report (January – March 2014) will be published on 7 May 2014.

The AGM will be held on 8 May 2014 in Stockholm, Sweden.

For further information, please contact:

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DISCLOSURE
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 2012, 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.

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.

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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