LUNDIN PETROLEUM – PRESS RELEASE

Lundin Petroleum AB (publ)
Hovslagargatan 5
SE-111 48 Stockholm
Tel: +46-8-440 54 50, Fax: +46-8-440 54 59, E-mail: info@lundin.ch
Visit our website: www.lundin-petroleum.com

Company registration number 556610-8055

NASDAQ OMX Stockholm : LUPE
Toronto Stock Exchange (TSX): LUP

Stockholm 31 October 2012

REPORT FOR THE NINE MONTHS ENDED 30 SEPTEMBER 2012

HIGHLIGHTS

Nine months ended 30 September 2012 (30 September 2011)

- Production of 35.6 Mboepd (32.8 Mboepd)
- Net result of MUSD 156.6 (MUSD 169.3)
- EBITDA of MUSD 854.3 (MUSD 767.3)
- Operating cash flow of MUSD 594.0 (MUSD 586.8)
- New USD 2.5 billion seven year secured revolving borrowing base facility signed on 25 June 2012
- Edvard Grieg field PDO approved
- Pre-Unit agreement signed for the Johan Sverdrup field
- Extensive appraisal drilling on the Johan Sverdrup field

Third quarter ended 30 September 2012 (30 September 2011)

- Production of 36.6 Mboepd (33.9 Mboepd)
- Net result of MUSD 44.9 (MUSD 38.9)
- EBITDA of MUSD 273.6 (MUSD 262.0)
- Operating cashflow of MUSD 218.4 (MUSD 196.5)
- Geitungen oil discovery of between an estimated 140 and 270 MMboe gross recoverable resources located north of the Johan Sverdrup field within PL265
- Berangan-1 gas discovery on Block SB303, offshore Sabah, Malaysia
- Bøyla field PDO approved in October 2012

	1 Jan 2012- 30 Sep 2012 9 months	**1 Jul 2012- 30 Sep 2012 3 months**	1 Jan 2011- 30 Sep 2011 9 months	1 Jul 2011- 30 Sep 2011 3 months	1 Jan 2011- 31 Dec 2011 12 months
Production in Mboepd	35.6	36.6	32.8	33.9	33.3
Operating income in MUSD	1,002.5	322.5	946.5	327.5	1,269.5
Net result in MUSD	156.6	44.9	169.3	38.9	155.2
Net result attributable to shareholders of the Parent Company in MUSD	159.7	45.9	172.6	39.5	160.1
Earnings/share in USD[1]	0.51	0.15	0.56	0.13	0.51
Diluted earnings/share in USD[1]	0.51	0.15	0.56	0.13	0.51
EBITDA in MUSD	854.3	273.6	767.3	262.0	1,012.1
Operating cash flow in MUSD	594.0	218.4	586.8	196.5	676.2

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

Lundin Petroleum is a Swedish independent oil and gas exploration and production company with a well balanced portfolio of world-class assets primarily located in Europe and South East Asia. The Company is listed at the NASDAQ OMX, Stockholm (ticker "LUPE") and at the Toronto Stock Exchange (TSX) (Ticker "LUP"). Lundin Petroleum has proven and probable reserves of 211 million barrels of oil equivalent (MMboe).

Dear fellow shareholders,

I am pleased that our Company has once again delivered excellent financial results and outperformed market expectations. This performance has been driven by a combination of record quarterly production and low operating costs. The result is a strong cash generative business highlighted by our operating cash flow of USD 594.0 million and EBITDA of USD 854.3 million for the nine month period ended 30 September 2012 (reporting period).

Our financial performance will further improve in forthcoming years driven by our exciting pipeline of development projects which will deliver increased production. The Edvard Grieg, Brynhild and Bøyla Norwegian developments, all of which are now in the execution or construction phase, are expected to result in our production doubling to over 70,000 barrels of oil equivalent per day (boepd) following first oil from Edvard Grieg in late 2015. Whilst the exact scope of the Johan Sverdrup development in Norway has still to be determined, I am confident that the expected size of this project will contribute to our production doubling again to over 150,000 boepd following first oil in late 2018. Simplistically, I believe that Lundin Petroleum can quadruple its production over the next seven to eight years from current levels and can achieve this without shareholder dilution and is not dependent upon any further development projects or exploration success.

However, we still view ourselves very much as an exploration focused company. Our exploration team has been the most successful explorer in Norway in recent years with post tax finding costs at well below USD 1 per barrel, with a portfolio of over 50 exploration licences which we believe has excellent prospectivity and with secured rig capacity to meet our drilling requirements over the next three years. Similarly our exploration strategy in South East Asia has started to deliver positive results and I expect that next year the Bertam field will be declared commercial. We are committed to spending about USD 500 million per year on our exploration programme for the foreseeable future and expect this to create further shareholder value.

Financial Performance
Our financial performance in the first nine months of 2012 continued the positive trend from previous quarters. The financial performance was driven by Norwegian production and resulted in an after tax profit of USD 156.6 million for the reporting period.

Production
Production for the first nine months of 2012 was 35,600 boepd and again exceeded our forecasts. Production from the Alvheim and Volund fields was the major contributor to the strong performance with uptime on the Alvheim FPSO and Volund reservoir performance again outperforming. I believe this strong performance will continue into 2013 with new multilateral development wells on both Alvheim and Volund expected to have a positive impact on production.

As a result of the strong production we have revised our 2012 production forecast from the previous range of 33,000 boepd to 37,000 boepd to a range between 34,000 boepd to 37,000 boepd. We will provide our 2013 production guidance in January 2013.

Development
I am extremely pleased that, despite the manpower and cost pressures being experienced within our industry, our three ongoing development projects in Norway are all progressing well.

The Brynhild and Edvard Grieg operated projects are well into the execution phase. The Brynhild field, which is a subsea tieback to Shell's Pierce FPSO facilities in the United Kingdom, will come on production in late 2013 and we expect to commence the drilling of the four development wells in the second quarter of next year. The Edvard Grieg project team has awarded the major topside and jacket contracts as well as drilling and installation contracts and construction has already commenced on the jacket. Our project team is staffed by professionals with many years experience of executing construction projects in Norway who I am confident can deliver this major new facility. Edvard Grieg is a world class project containing 186 MMboe of reserves, will produce at 100,000 boepd and cost approximately USD 4 billion in development capital. I am pleased that both OMV and Statoil will become Edvard Grieg partners following recently announced asset transactions and encouraged that the OMV deal values Edvard Grieg at over USD 8.5 per barrel providing tangible evidence of the value of our Norwegian resource base.

We are making good progress with the plans for development of the Bertam field, offshore Malaysia, where conceptual studies are ongoing and where we hope to make a fast track development decision next year.

Appraisal
Both ourselves and Statoil continue to be busy with the appraisal of the Johan Sverdrup discovery. Eight wells have now been drilled on Johan Sverdrup structure which all provide valuable information in respect of the size of the resource and to assist with development planning. Lundin Petroleum as operator of PL501 has completed three appraisal wells this year and we will drill two further wells before the end of the year. Statoil will also complete two further appraisal wells before the end of the year, the first of which is currently underway.

The results of the 2012 appraisal drilling programme will be used to update recoverable resources for Johan Sverdrup which we expect will be announced in the first quarter of 2013.

We now expect that at least four further appraisal wells will be drilled in 2013, two in PL501 and two in PL265.

Statoil, as ‘working operator’ of Johan Sverdrup, are coordinating work in relation to the development plan and we still expect a decision on conceptual development by the end of 2013 and a development plan submission by the end of 2014.

Exploration

As I highlighted in my shareholders letter last quarter, our exploration activity has increased over the last quarter and we will remain very busy for the rest of this year and throughout 2013. We plan to drill 33 exploration and appraisal wells over this period with an exploration budget in 2013 likely to exceed USD 500 million. Our focus will remain in Norway and South East Asia where we are currently most active. In recent months various stakeholders have commented to me that Lundin Petroleum is no longer an exploration company with our increased focus on production and development activities. This is not true and I continue to believe that a proactive exploration strategy is the best way for Lundin Petroleum to continue to deliver increased value to our shareholders.

The highlight of the last quarter was the Geitungen discovery in PL265. It now appears that this discovery, estimated to contain about 200 MMboe mid case, is actually a northern extension of the Johan Sverdrup discovery. We are likely to drill the Torvestad prospect in PL501 in 2013 which has the potential to be a northerly extension of Geitungen and Johan Sverdrup. We do believe that there will be further discoveries in the Greater Luno or southern Utsira High Area and will be drilling exploration wells in 2012/2013 in PL359 (Luno II), PL625 (Kopervik), PL544 (Biotitt), PL338 (Jorvik) and PL410. We are the largest equity owner in most of these licences and therefore have arguably the most leverage to further exploration success in this area.

We also continue to be very active in the Barents Sea. Prior to Statoil’s recent Skrugard and Havis discoveries in the Barents Sea, we had pursued a strategy to build up a material licence position in the Barents Sea based upon a theory that the area had oil potential. We today have a substantial acreage position and the area has become much more in focus from the industry since Statoil’s discoveries. This will continue with strong industry interest for Barents Sea acreage in the ongoing APA and upcoming 22nd Norwegian licensing round. In the third quarter, the Salina exploration well was a gas discovery which has the potential to become larger. The understanding of oil versus gas source rocks and hydrocarbon migration is technically challenging, but despite these results, we continue to believe in the oil potential of the Barents Sea. I also believe that there will be significant amounts of gas discovered in the Barents Sea and therefore it is only a matter of time before a gas export solution for the area is developed. We are currently drilling the Juksa/Snurrevad exploration well in the Barents Sea and will drill at least one further well in the area next year.

The final part of our exploration strategy in Norway is to try and unearth a new core exploration area. The Albert well in the northern North Sea towards the Møre Basin was an uncommercial oil discovery. We will continue to not only explore this area but drill in other new interesting areas. For example, we will drill an exploration well in 2013 on a large prospect in PL330 located in the northern Norwegian Sea, an area which has been relatively underexplored to date. In addition, 2013 will also include two exploration wells in the southern North Sea on the Ogna and Carlsberg prospects.

Finally, we have been busy securing rig capacity for our exploration drilling activities. I am very pleased that in what is a tight Norwegian rig market we have secured the Island Innovator, a new build semi-submersible rig, for two years from 2013 and an extension of our existing Bredford Dolphin contract. We now have the rig capacity to execute our Norwegian exploration programmes into 2015.

We continue our exploration programme in South East Asia. In the last quarter we had another gas discovery in east Malaysia and will drill two further exploration wells offshore peninsular Malaysia before the end of the year. Exploration drilling will continue in Malaysia in 2013 and we will also commence our offshore exploration drilling in Indonesia with at least two wells.

Oil Market and Lundin Petroleum

There are some early signs of recovery in the world economy but still a lot of uncertainty remains. I hope that the worst of the Euro crisis is behind us and that the availability of cheap gas in the United States will act as a catalyst for industrial growth in the region. In the short term further falls in the Chinese economy growth rate with reductions in capital spending pose the largest threat to commodity prices. In the medium term there is no question that with the growth in shale oil production in North America coupled with improved energy efficiency and substitution from oil to gas we will see North America moving towards hydrocarbon self-sufficiency. Nevertheless the increase in demand from the developing world coupled with reductions in conventional oil supply will ensure continued strong oil prices.

We continue to communicate with our major shareholders particularly in Sweden regarding recent media allegations regarding our historical operations in Sudan and Ethiopia. We have now been contacted by the Swedish prosecutor in respect of his investigation and reiterate our previous statements that we will assist with this process.

Together with Lundin Petroleum's management, we continue to emphasise within our organisation the importance of our Corporate Social Responsibility, Health, Safety and Environmental management framework. This is good business and going forward we will be making an increased effort in communicating to stakeholders not only about our policies and management system but also about how they are put in practice.

Yours Sincerely,

C. Ashley Heppenstall
President and CEO

Stockholm, 31 October 2012

OPERATIONAL REVIEW

Production
Production for the nine month period ended 30 September 2012 (reporting period) amounted to 35.6 thousand barrels of oil equivalents per day (Mboepd) and was comprised as follows:

Production in Mboepd	**1 Jan 2012- 30 Sep 2012 9 months**	**1 Jul 2012- 30 Sep 2012 3 months**	1 Jan 2011- 30 Sep 2011 9 months	1 Jul 2011- 30 Sep 2011 3 months	1 Jan 2011- 31 Dec 2011 12 months
Crude oil					
Norway	23.4	23.4	20.7	21.7	21.1
France	2.9	2.8	3.1	3.1	3.1
Russia	2.7	2.7	3.2	3.1	3.1
Tunisia	0.1	0.0	0.8	0.7	0.7
Total crude oil production	**29.1**	**28.9**	27.8	28.6	28.0
Gas					
Norway	3.8	5.0	2.0	2.0	2.1
Netherlands	1.9	1.9	2.0	1.9	2.0
Indonesia	0.8	0.8	1.0	1.4	1.2
Total gas production	**6.5**	**7.7**	5.0	5.3	5.3
Total production					
Quantity in Mboe	**9,749.6**	**3,364.5**	8,963.3	3,117.5	12,151.5
Quantity in Mboepd	**35.6**	**36.6**	32.8	33.9	33.3

EUROPE

Norway

Production

in Mboepd	Lundin Petroleum Working Interest (WI)	**1 Jan 2012- 30 Sep 2012 9 months**	**1 Jul 2012- 30 Sep 2012 3 months**
Alvheim	15%	11.9	11.4
Volund	35%	13.3	13.4
Gaupe	40%	2.0	3.6
		27.2	**28.4**

Production from the Alvheim field during the reporting period remains ahead of forecast due to the excellent uptime performance of the FPSO at over 95 percent and the cancellation of the anticipated second quarter shut down of the SAGE system. An Alvheim development well was drilled during the first half of 2012 and has been tied in and put on production in October 2012. During the third quarter of 2012 cost of operations for the Alvheim field were impacted by planned well intervention work. The cost of operations, excluding the well intervention work, remains at below USD 5 per barrel for the reporting period.

Volund field production continued to exceed forecasts due to better than expected reservoir performance and the FPSO uptime. An additional Volund development well is currently being drilled and is expected to come on production in the first quarter of 2013. The cost of operations for the Volund field for the reporting period is below USD 2 per barrel.

First production from the Gaupe field in PL292 was achieved on 31 March 2012. Production from the Gaupe field has been below forecast since the commencement of production. Technical analysis indicates that the two production wells are connected to lower hydrocarbon volumes than was forecast prior to production startup which will negatively impact Gaupe reserves.

Development

In January 2012, a plan of development was submitted for the Edvard Grieg field (formerly named Luno) (WI 50%) to the Norwegian Ministry of Petroleum and Energy. The development plan incorporates the provision for the coordinated development solution of the Edvard Grieg field with the nearby Ivar Aasen field (formerly Draupne) located in PL001B and operated by Det norske oljeselskap ASA. The Norwegian Parliament approved the Edvard Grieg plan of development in June 2012.

The Edvard Grieg field is estimated to contain 186 million barrels of oil equivalents (MMboe) of gross reserves with first production expected in late 2015 and forecast gross peak production of approximately 100.0 Mboepd. The gross capital cost of the Edvard Grieg field development is estimated at USD 4 billion to include platform, pipelines and 15 wells. Contracts have been awarded to Kværner covering engineering, procurement and construction of the jacket and the topsides for the platform and to Rowan Companies for a jack up rig to drill the development wells. Saipem has been awarded the contract for marine installation. The development is progressing well and construction work on the jacket has commenced.

A plan of development of the Brynhild field in PL148 (WI 70%) was approved by the Norwegian Ministry of Petroleum and Energy in November 2011. The Brynhild field contains gross reserves of 20 MMboe and is expected to produce at an estimated gross plateau production rate of 12.0 Mboepd with first oil forecast in late 2013. 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. The development is now well advanced in respect of engineering and construction work and the Maersk Guardian jack-up rig will commence development drilling in the first half of 2013. In March 2012, Lundin Petroleum announced that it had entered into an agreement with Talisman Energy to acquire an additional 30 percent interest in PL148 containing the Brynhild field, offshore Norway.

A plan of development for the Bøyla field in PL340 (WI 15%) was approved in October 2012. The Bøyla field contains gross reserves of 21 MMboe and will be developed as a subsea tieback to the Alvheim FPSO. First oil from the Bøyla field is expected in 2014 at a gross plateau production rate of 19.0 Mboepd.

Appraisal

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.

In January 2012, a third appraisal well, 16/5-2S, located on PL501 was completed. The objective of the well was to delineate the southern flank of the Johan Sverdrup, PL501 discovery. The well, despite encountering good Jurassic sandstone reservoir, was deep to prognosis and as a result the reservoir was below the oil water contact. In May 2012, a further appraisal well, 16/2-11, was completed on PL501 which encountered a 54 metre gross oil column in Upper and Middle Jurassic sandstone reservoir in an oil-down-to situation. The reservoir was encountered at depth prognosis. A sidetrack of the well was successfully completed confirming similar excellent reservoir thickness and quality.

In the third quarter of 2012, the drilling of the appraisal well 16/2-13S on the north eastern part of the Johan Sverdrup discovery and a side-track well 16/2-13A were successfully completed. The results from the wells were excellent in respect of reservoir quality and thickness, validating the field geological model and confirming a deeper oil water contact at this location.

Well 16/2-13S encountered a 25 metre gross oil column in Upper and Middle Jurassic sandstone reservoir in an oil-down-to situation. The side-track well 16/2-13A encountered a gross reservoir column of approximately 22 metres, of which 12 metres were above the oil water contact. The top of the reservoir was 4 metres shallower than the prognosis. The oil water contact was established at approximately 1,925 metres below Mean Sea Level which is approximately 3 metres deeper than observed in earlier PL501 wells.

Lundin Petroleum will drill a further two appraisal wells in 2012 in PL501 of which one well will be in the northern Johan Sverdrup area. The appraisal well 16/2-16 will be drilled 3.7 km to the northwest of the 16/2-13 well. The second well, 16/3-5, will be drilled in the south eastern part of Johan Sverdrup in PL501.

In September 2012, Statoil commenced the first of its two appraisal wells to be drilled on PL265 in the fourth quarter of 2012. Well 16/2-14 will appraise the crestal part of the Johan Sverdrup discovery in PL265. The main objective is to determine the thickness and quality of Jurassic age sandstone reservoir on a structural high between the Johan Sverdrup appraisal wells 16/2-8 and 16/2-10 in PL265. Well 16/2-15 will be drilled back to back with this well. It is likely that at least two further appraisal wells will be drilled in both PL501 and PL265 in 2013.

Lundin Petroleum, as operator of PL501, has signed a Pre-Unit agreement with the partners within PL501 and PL265 for the joint field development of the Johan Sverdrup field. Statoil has been elected as working operator for the pre-unit phase. 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 to be submitted by the fourth quarter of 2014 and first oil production by the end of 2018.

Exploration
Lundin Petroleum has continued with its exploration drilling programme in Norway with a key focus on the southern Utsira High and Barents Sea areas.

In August 2012, the exploration well 16/2-12 targeting the Geitungen structure in PL265 (WI 10%) was successfully completed as an oil discovery. The well, which was located to the north of the Johan Sverdrup discovery and to the south of 16/2-9S Aldous Major North discovery, has proved a gross oil column of 35 metres in high quality sandstone of Jurassic age. Oil was also proven in the basement rock. Data acquisition in the well, including coring, wireline logging and fluid sampling, indicates that the Geitungen structure is in communication with the Johan Sverdrup discovery made by Lundin Norway in 2010. Preliminary calculations of the size of the Geitungen discovery are between 140 and 270 million barrels of gross recoverable oil.

In October 2012, Lundin Petroleum announced the results of the Albert well in PL519 (WI 40%). The main objective of well 6201/11-3 was to test Cretaceous and Triassic age sandstones of a multiple target structure. The well encountered oil in thin Cretaceous reservoir sequence at the predicted level for the primary target. The thin thickness and uncertain distribution of the reservoir do not give a basis for resource estimation at this stage and as such the discovery is currently deemed uncommercial. Further potential exists within the Albert structure if thicker Cretaceous reservoir section in this large structure can be identified. The Triassic secondary reservoir was tight without movable hydrocarbons. A minor column of movable hydrocarbons were also encountered in a Palaeocene secondary target. Further exploration activity is planned in this area in late 2013 or early 2014 with the drilling of the Storm prospect in PL555 where Lundin Petroleum holds a 60 percent interest and is operator.

In October 2012, Lundin Petroleum announced that exploration well 7220/10-1 in PL533 (WI 20%) had discovered gas condensate in the Salina structure located on the west flank of the Loppa High in the Barents Sea. The well has proved two gas columns in sandstone of Cretaceous and Jurassic age. Data acquisition in the well, including coring, wireline logging and fluid sampling, has proven good reservoir quality in the sandstone. Preliminary calculations, made by the Norwegian Petroleum Directorate, give a range of gross discovered volume in the Salina structure of between 5 and 7 billion standard cubic metres (29 to 41 MMboe) of recoverable gas/condensate. Further upside exists in fault compartments associated with the Salina structure.

Lundin Petroleum commenced drilling its second 2012 exploration well in the Barents Sea in October 2012. Well 7120/6-3 S is located in PL490 (WI 50%) in the Barents Sea and is targeted at the Snurrevad-Juksa prospect. The well is located 10 km to the north west of the Snøhvit field. The main objective of the well is to prove the presence of hydrocarbons in lower Cretaceous/upper Jurassic reservoirs.

Lundin Petroleum announced in July 2012 that it had entered into farm-out agreements to reduce its holdings in a number of licences. Spring Energy Norway AS has acquired a 10 percent interest in PL490, with Lundin Petroleum retaining 50 percent and Norwegian Energy Company ASA will acquire a 10 percent interest in PL492, with Lundin Petroleum retaining 40 percent; both licences are located in the Barents Sea. Explora Petroleum AS has acquired a 30 percent interest in PL544 and Lundin Petroleum retains 40 percent; the licence is located in the North Sea. The Norwegian authorities have approved the farm-out agreements on PL490 and PL544 whilst the farm-out agreement for PL492 is expected to be approved in the fourth quarter of 2012.

Lundin Petroleum’s exploration programme in Norway from now to the end of 2013 is likely to consist of 11 exploration wells with a continued focus on the Utsira High area with six exploration wells and the Barents Sea with two exploration wells. In addition, one exploration well is likely to be drilled on PL330 (WI 30%) to the south of the Lofoten area in the Norwegian Sea and 2 exploration wells are likely to be drilled in the southern North Sea.

France

Production

in Mboepd	Lundin Petroleum Working Interest (WI)	**1 Jan 2012- 30 Sep 2012 9 months**	**1 Jul 2012- 30 Sep 2012 3 months**
Paris Basin	100%	2.4	2.3
Aquitaine Basin	50%	0.5	0.5
		2.9	**2.8**

The redevelopment of the Grandville field in the Paris Basin is substantially complete following the drilling of the development wells to be brought onstream in the fourth quarter of 2012.

Well operations are ongoing in the first of two exploration wells to be drilled in the Paris Basin during the second half of 2012. The well has reached the targeted depth and is an oil discovery.

The Netherlands

The net gas production to Lundin Petroleum from the Netherlands averaged 1.9 Mboepd for the reporting period. Development drilling on existing production assets is ongoing to optimize field recovery. The Vinkega-2 exploration well in the Gorredijk concession (WI 7.75%) was a gas discovery in the third quarter of 2012 and is currently planned to commence production in the first quarter of 2013.

Ireland

Following the completion of seismic studies on the Slyne Basin licence 04/06 (WI 50%) discussions regarding future work programme are being considered by the licence partners.

SOUTH EAST ASIA

Indonesia

Lematang (South Sumatra)

The net production to Lundin Petroleum from the Singa gas field (WI 25.9%) during the reporting period amounted to 0.8 Mboepd. Production in the reporting period has been negatively affected by well maintenance work which was completed in September 2012.

Baronang/Cakalang (Natuna Sea)

Exploration drilling on the Baronang Block (WI 100%) is expected to commence in 2013.

South Sokang (Natuna Sea)

A 3D seismic acquisition programme is planned to be completed in 2013 on South Sokang (WI 60%)

Gurita (Natuna Sea)

A 3D seismic acquisition programme of 950 km² has been completed in 2012 on the Gurita Block (WI 100%) and an exploration well is expected to be drilled in 2013.

Malaysia

East Malaysia, offshore Sabah

Lundin Petroleum holds two licences offshore Sabah in east Malaysia. SB303 (WI 75%) contains the Tarap, Cempulut and Titik Terang gas discoveries with an estimated gross contingent resource of more than 250 billion cubic feet (bcf). Further evaluation of the potential for commercialisation of these gas discoveries most likely through a cluster development. In September 2012, the Berangan-1 exploration well in SB303 was successfully completed as a gas discovery. The well penetrated a gross gas column of over 165 metres in the target mid-Miocene aged sands 10 km to the southeast of the Tarap gas discovery made by Lundin Petroleum in 2011, and 15 km to the south of the Cempulut gas discovery also made in 2011. Further work will follow to estimate recoverable resource ranges. It is likely that the Berangan discovery will be included in any cluster development of the other SB303 gas discoveries.

In July 2012 he Tiga Papan 5 well in SB307/308 (WI 42.5%) targeting mid-Miocene aged sands of the Tiga Papan Unit was plugged and abandoned as a dry hole.

Offshore Peninsular Malaysia

Lundin Petroleum holds 3 licences offshore Peninsular Malaysia. In June 2011, Lundin Petroleum acquired a 75 percent working interest in Block PM307. A 2,100 km² 3D seismic acquisition programme was completed in 2011. In January 2012, the Bertam-2 appraisal well was successfully completed proving the continuity and quality of the K10 oil reservoir sandstone. Conceptual development studies are currently ongoing in relation to a potential development of the Bertam field and a decision will most likely be taken in 2013. In the fourth quarter of 2012, a well will be drilled on Block PM307 targeting the Tembakau prospect.

Block PM308A (WI 35%) contains the Janglau and Rhu oil discoveries. A further exploration well will be drilled in PM308A in the fourth quarter 2012 on the Ara prospect which will target the Oligocene intra-rift sands discovered with last year's Janglau exploration well. An acquisition of 1,450 km² of new 3D seismic in PM308A was completed during the reporting period.

In Block PM308B (WI 75%) the Merawan Batu-1 exploration well was completed in October 2012 and plugged and abandoned as a dry hole.

RUSSIA

The net production to Lundin Petroleum from Russia for the reporting period was 2.7 Mboepd. In the Lagansky Block (WI 70%) in the northern Caspian a major oil discovery was made on the Morskaya field in 2008. The discovery is deemed to be strategic, due to its offshore location, by the Russian Government under the Foreign Strategic Investment Law. As a result a 50 percent ownership by a state owned company is required prior to appraisal and development.

AFRICA

Tunisia

The production from the Oudna field (WI 40%) for the first quarter of 2012 was 0.4 Mboepd. Following storm damage to a flowline in March 2012, the Oudna field was shut-in. An assessment of repair solutions to the flowline was carried out and it was determined to be uneconomic to repair. During the third quarter of 2012, the Ikdam FPSO was disconnected from the field and work commenced to plug and abandon the two wells. Lundin Petroleum has increased its ownership in the Ikdam FPSO to 100 percent and will now seek new opportunities for the vessel.

Congo (Brazzaville)
With the relinquishment of its interest in the Block Marine XI license (WI 18.75%) in June 2012 and the expiry of the Block Marine XIV license (WI 21.55%) in October 2012, Lundin Petroleum has exited Congo (Brazzaville). Lundin Petroleum has no carrying value associated with these Blocks.

FINANCIAL REVIEW

Result
The net result for the nine month period ended 30 September 2012 (reporting period) amounted to MUSD 156.6 (MUSD 169.3). The net result attributable to shareholders of the Parent Company for the reporting period amounted to MUSD 159.7 (MUSD 172.6) representing earnings per share on a fully diluted basis of USD 0.51 (USD 0.56).

Earnings before interest, tax, depletion and amortisation (EBITDA) for the reporting period amounted to MUSD 854.3 (MUSD 767.3) representing EBITDA per share on a fully diluted basis of USD 2.75 (USD 2.47). Operating cash flow for the reporting period amounted to MUSD 594.0 (MUSD 586.8) representing operating cash flow per share on a fully diluted basis of USD 1.91 (USD 1.89).

Changes in the Group
On 27 August 2012, Lundin Petroleum acquired a further 60 percent equity in Ikdam Production SA, a company which owns the Ikdam FPSO, bringing its total ownersip to 100 percent. The financial results of Ikdam Production SA are fully consolidated in the Group's financial statements from the end of August 2012.

Operating income
Net sales of oil and gas for the reporting period amounted to MUSD 982.2 (MUSD 938.9) and are detailed in Note 1. For the reporting period, sales volumes were 5.0 percent higher and the achieved oil price was 0.4 percent lower resulting in 4.6 percent higher oil and gas revenues than for the comparative period. The average price achieved by Lundin Petroleum for a barrel of oil equivalent amounted to USD 101.21 (USD 101.63) and is detailed in the following table. The average Dated Brent price for the reporting period amounted to USD 112.21 (USD 111.89) per barrel. The premium over Dated Brent on the Alvheim and Volund field crude cargoes sold during the reporting period averaged USD 3.66 (USD 3.82) per barrel.

Sales of oil and gas for the reporting period were comprised as follows:

Sales Average price per boe expressed in USD	**1 Jan 2012- 30 Sep 2012 9 months**	**1 Jul 2012- 30 Sep 2012 3 months**	1 Jan 2011- 30 Sep 2011 9 months	1 Jul 2011- 30 Sep 2011 3 months	1 Jan 2011- 31 Dec 2011 12 months
Crude oil sales					
Norway					
- Quantity in Mboe	6,210.7	2,001.7	5,810.3	2,062.9	7,896.0
- Average price per boe	115.60	113.57	116.11	117.63	115.38
France					
- Quantity in Mboe	703.2	211.0	872.2	295.4	1,155.5
- Average price per boe	111.22	111.62	110.56	112.59	110.59
Netherlands					
- Quantity in Mboe	1.2	–	1.6	0.6	2.2
- Average price per boe	100.65	–	106.89	88.81	103.87
Russia					
- Quantity in Mboe	756.2	246.4	867.2	290.2	1,138.4
- Average price per boe	76.70	75.75	69.69	70.07	69.85
Tunisia					
- Quantity in Mboe	227.5	–	198.2	–	198.2
- Average price per boe	108.09	–	125.12	–	125.12
Total crude oil sales					
- Quantity in Mboe	**7,898.8**	**2,459.1**	7,749.5	2,649.1	10,390.3
- Average price per boe	**111.27**	**109.62**	110.52	111.85	110.25
Gas and NGL sales					
Norway					
- Quantity in Mboe	1,046.4	428.1	679.2	237.8	947.2
- Average price per boe	61.42	60.34	61.22	59.43	61.14
Netherlands					
- Quantity in Mboe	534.8	176.7	538.7	171.4	722.8
- Average price per boe	59.32	59.61	59.43	61.86	60.61
Indonesia					
- Quantity in Mboe	224.7	62.5	270.7	111.8	387.7
- Average price per boe	32.79	32.66	32.52	32.26	32.83
Total gas and NGL sales					
- Quantity in Mboe	**1,805.9**	**667.3**	1,488.6	521.0	2,057.7
- Average price per boe	**57.24**	**57.55**	55.36	54.39	54.50
Total sales					
- Quantity in Mboe	**9,704.7**	**3,126.4**	9,238.1	3,170.1	12,448.0
- Average price per boe	**101.21**	**98.51**	101.63	102.41	101.04

Sales quantities in a period can differ from production quantities as a result of permanent and timing differences. Timing differences can arise due to inventory, storage and pipeline balances effects. Permanent differences arise as a result of paying royalties in kind as well as the effects from production sharing agreements.

The oil produced in Russia is sold on either the Russian domestic market or exported into the international market. 45 percent (36 percent) of Russian sales for the reporting period were on the international market at an average price of USD 109.97 per barrel (USD 110.28 per barrel) with the remaining 55 percent (64 percent) of Russian sales being sold on the domestic market at an average price of USD 49.78 per barrel (USD 46.56 per barrel).

Other operating income amounted to MUSD 20.3 (MUSD 7.6) for the reporting period and includes MUSD 11.0 (MUSD -) relating to a pre-tax settlement of an equity redetermination that was agreed between the parties in blocks K4a, K4b/K5a and K5b, offshore Netherlands and MUSD 4.7 (MUSD 3.5) of income relating to a quality differential compensation payable from the Vilje field owners to the Alvheim and Volund field owners in Norway. The quality compensation adjustment in Norway arises as all three fields produce to the Alvheim

FPSO vessel and the oil is commingled to produce an Alvheim crude blend which is then sold. Also included in other operating income is 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 124.2 (MUSD 146.2) and are detailed in Note 2. The production costs in the reporting period includes a MUSD 13.9 credit for inventory movements compared to a MUSD 13.1 charge in the comparative period as explained below. The production and depletion costs per barrel of oil equivalent produced are detailed in the table below.

Production costs and depletion in USD per boe	**1 Jan 2012- 30 Sep 2012 9 months**	**1 Jul 2012- 30 Sep 2012 3 months**	1 Jan 2011- 30 Sep 2011 9 months	1 Jul 2011- 30 Sep 2011 3 months	1 Jan 2011- 31 Dec 2011 12 months
Cost of operations	7.83	7.69	8.27	8.20	8.43
Tariff and transportation expenses	2.15	2.19	1.97	1.67	1.88
Royalty and direct taxes	4.00	3.55	4.41	4.53	4.31
Changes in inventory/lifting position	-1.43	-6.55	1.47	0.89	1.08
Other	0.18	0.18	0.19	0.18	0.18
Total production costs	**12.73**	**7.06**	16.31	15.47	15.88
Depletion*	14.14	14.92	13.54	13.71	13.59
Total cost per boe	**26.87**	**21.98**	29.85	29.18	29.47

* excludes decommissioning costs

The total costs of operations for the reporting period was MUSD 76.4 compared to MUSD 74.1 for the comparative period and includes cost of operations associated with the Gaupe field, Norway which came onstream on 31 March 2012. The cost of operations for the Oudna field, Tunisia was MUSD 8.5 for the reporting period compared to 12.6 MUSD for the comparative period following the shut-in of production in March 2012. The cost of operations per barrel for the reporting period was 5 percent lower than the comparative period due mainly to the production being 9 percent higher.

The cost of operations per barrel for the third quarter of 2012 amounted to USD 7.69 per barrel and was significantly lower than forecast despite planned well intervention work which was carried out on the Alvheim field, Norway. Other maintenance activity due to be carried out in the third quarter of 2012 was rephased. The cost of operations per barrel is now forecast to increase in the fourth quarter of 2012 due to rephased Paris Basin, France operations and completion of the intervention work on the Alvheim field. For 2012, the average cost of operations per barrel for the year is forecast at USD 8.25 per barrel compared to the prior guidance of USD 8.60 per barrel.

The tariff and transportation expenses for the reporting period amounted to MUSD 21.0 compared to MUSD 17.6 for the comparative period. Included in the reporting period are costs associated with the Gaupe field.

Royalty and direct taxes 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 23.16 (USD 21.34) 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 57.07 (USD 57.78) per barrel for the reporting period.

There are both permanent and timing differences that result in sales volumes not being equal to production volumes during a period. Changes to the hydrocarbon inventory and under or overlift positions result from these timing differences and an amount of MUSD 13.9 was credited to the income statement for the reporting period compared to a MUSD 13.1 charge for the comparative period. There was a net underlift movement of MUSD 17.7 on the Alvheim/Volund fields, Norway, where crude sales volumes during the reporting period were lower than production volumes compared to a MUSD 14.0 net overlift position for the comparative period. The Gaupe field was also underlifted during the reporting period resulting in a MUSD 9.8 (MUSD -) credit to production costs. The Gaupe field hydrocarbons are processed across the non-operated Armada host platform and there is an allocation agreement whereby new fields compensate existing fields through volume for production deferred by the new production stream. The resultant underlift position is repaid by the existing fields in future periods. There was also a lifting in January 2012 of inventory from the Ikdam FPSO on the Oudna field, Tunisia, resulting in a MUSD 14.6 charge to production costs in the reporting period.

Depletion and decommissioning costs
Depletion costs amounted to MUSD 137.9 (MUSD 121.4) and are detailed in Note 3. Norway contributed 83 percent of the total depletion charge for the reporting period at an average rate of USD 15.43 per barrel.

The increase in depletion costs over the comparative period is mainly as a result of the production start-up from the Gaupe field, Norway.

Decommissioning costs charged to the income statement in the reporting period amounted to MUSD 3.5 (MUSD -) and represent the costs of disconnecting the FPSO from the Oudna field, Tunisia, in excess of the site restoration provision for the work. The cost for decommissioning of the Oudna field wells, which will be performed in the fourth quarter of 2012, has been provided for in the balance sheet.

Exploration costs
Exploration costs for the reporting period amounted to MUSD 33.6 (MUSD 80.2) and are detailed in Note 4. 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.

In July 2012, the Tiga Papan 5 well in SB307/308, offshore Sabah, east Malaysia was plugged and abandoned as a dry hole. The cost of the well and associated licence costs amounting to MUSD 9.2 were expensed.

During the first half of 2012, costs associated with the Clapton well on PL440S, Norway and the Rangkas Block, Indonesia were expensed.

General, administrative and depreciation expenses
The general, administrative and depreciation expenses for the reporting period amounted to MUSD 26.4 (MUSD 35.1) of which MUSD 11.1 (MUSD 18.1) related to non-cash charges 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. The value of the awards, calculated using the Black and Scholes method, is applied to the vested portion of the outstanding LTIP awards including that of previous periods with the change in the provision being reflected in the income statement. The Lundin Petroleum share price decreased in the first half of 2012 and the reversal of part of the provision reported at 31 December 2011 resulted in a credit to the income statement in the reporting period up to 30 June 2012. The share price increased by approximately 24 percent as at 30 September 2012 compared to 30 June 2012, which resulted in an increase in the provision for LTIP at the balance sheet date and a corresponding charge to the income statement for the third quarter 2012. Lundin Petroleum has mitigated the exposure of the LTIP by purchasing its own shares. For more detail refer to the remuneration section below.

Depreciation charges for the reporting period amounted to MUSD 2.3 (MUSD 2.0).

Financial income
Financial income for the reporting period amounted to MUSD 16.8 (MUSD 39.2) and is detailed in Note 6.

Interest income for the reporting period amounted to MUSD 2.5 (MUSD 3.3). The interest income in the comparative period includes an amount of MUSD 1.5 earned on a loan to Etrion Corporation. The Etrion loan was repaid during the second quarter of 2011.

Net foreign exchange gains for the reporting period amounted to MUSD 0.7 (MUSD 2.7). The US Dollar weakened against the Euro and the Norwegian Kroner during the third quarter of 2012 resulting in a net loss of MUSD 8.1 reversing the exchange gain movements on the intercompany loans and working capital balances reported for the period up to 30 June 2012. This loss was partially offset by an exchange gain of MUSD 2.9 (MUSD -) on settled foreign exchange hedges in the third quarter of 2012.

A gain on consolidation of a subsidiary of MUSD 13.4 (MUSD -) is reported in the third quarter of 2012 and relates to the accounting for the full consolidation of Ikdam Production SA (IPSA) following the acquisition of the outstanding 60 percent of the shares of the company at the end of August 2012. Lundin Petroleum already held 40 percent of the shares in IPSA which was acquired as part the Coparex acquisition in 2002. At the time of the Coparex acquisition, no value was assigned to the shares of IPSA and a provision was made against a loan to IPSA from the Group. Following the acquisition of the remaining 60 percent equity, a step-up in the carrying value of the existing 40 percent interest based on the fair value of the assets and liabilities of the company at the end of August 2012 was recorded and the provision made against the original loan was released.

An amount of MUSD 30.0 relating to the gain on sale of Africa Oil Corporation shares is included in financial income for the comparative period.

Financial expenses
Financial expenses for the reporting period amounted to MUSD 38.1 (MUSD 16.2) and are detailed in Note 7.

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 3.8 (MUSD 3.4) has been charged to the income statement for the reporting period.

The amortisation of the deferred financing fees for the reporting period amounted to MUSD 4.6 (MUSD 1.7) and relates to the expensing of the fees incurred in establishing the previous loan facility over the period of usage of that facility. Lundin Petroleum arranged a new USD 2.5 billion financing facility which was signed on the 25 June 2012 and the fees associated with this facility are being amortised on a going forward basis.

Loan facility commitment fees for the reporting period amounted to MUSD 5.6 (MUSD 0.8). The increase over the comparative period relates to the commitment fees on the undrawn portion of the larger USD 2.5 billion financing facility entered into in June 2012.

Lundin Petroleum owns 50 million shares in ShaMaran Petroleum which were acquired in 2009 in a non-cash transaction. The investment was booked at the fair value of the shares at the date of acquisition and under accounting rules, subsequent movements in the fair value of the shares were being recognised in other comprehensive income. In January 2012, ShaMaran Petroleum announced that it had relinquished its working interests in its operated Production Sharing Contract licences and, as such, it was considered that there had been a permanent diminution in the fair value of the shares of ShaMaran Petroleum held by Lundin Petroleum. As a result of the permanent diminution in the fair value of the shares, the cumulative loss recognised in other comprehensive income of MUSD 18.6 was reclassified from equity and recognised in the income statement in the first quarter of 2012. The subsequent gain on the shares since the impairment has been recognised in other comprehensive income.

Tax
The tax charge for the reporting period amounted to MUSD 499.0 (MUSD 417.3) and is detailed in Note 8.

The current tax charge for the reporting period amounted to MUSD 284.4 (MUSD 213.5) of which MUSD 262.6 (MUSD 185.7) relates to Norway. The Norwegian current tax charge for the reporting period is calculated using the actual results achieved and the development and exploration expenditure incurred during the reporting period.

The deferred tax charge for the reporting period amounted to MUSD 214.7 (MUSD 203.7) and arises primarily where there is a difference in depreciation for tax and accounting purposes. MUSD 211.0 (MUSD 194.0) of the deferred tax charge is attributable to Norway.

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 76 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 overall effective rate of tax is driven by Norway where the tax rate is 78 percent reduced by the effect of uplift on development expenditure for tax purposes. The effective rate is increased due to a number of non-tax adjusted items in the reporting period including the impairment of the ShaMaran shares, the Malaysian expensed exploration costs and certain general and administrative costs, as well as a lower tax credit on the exploration costs relating to the Rangkas Block, Indonesia. There is no tax expense associated with the financial income booked on full consolidation of Ikdam Production SA.

Non-controlling interest
The net result attributable to non-controlling interest for the reporting period amounted to MUSD -3.1 (MUSD -3.4) 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 2,825.7 (MUSD 2,329.3) and are detailed in Note 9.

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

Development expenditure in MUSD	**1 Jan 2012- 30 Sep 2012 9 months**	**1 Jul 2012- 30 Sep 2012 3 months**	1 Jan 2011- 30 Sep 2011 9 months	1 Jul 2011- 30 Sep 2011 3 months	1 Jan 2011- 31 Dec 2011 12 months
Norway	235.9	101.2	156.0	63.9	186.8
France	26.3	5.7	20.7	11.3	30.9
Netherlands	6.8	2.0	2.4	1.2	4.1
Indonesia	0.0	0.0	4.1	0.0	6.4
Russia	5.7	1.7	3.5	0.8	4.2
	274.7	**110.6**	186.7	77.2	232.4

During the reporting period, an amount of MUSD 235.9 of development expenditure was incurred in Norway, primarily on the Brynhild and Edvard Grieg field developments. In the comparative period, MUSD 156.0 was spent on the development of the Gaupe and Alvheim fields. In the reporting period, MUSD 26.3 was incurred in France primarily on the Grandville field redevelopment.

Exploration and appraisal expenditure in MUSD	**1 Jan 2012-30 Sep 2012 9 months**	**1 Jul 2012-30 Sep 2012 3 months**	1 Jan 2011-30 Sep 2011 9 months	1 Jul 2011-30 Sep 2011 3 months	1 Jan 2011-31 Dec 2011 12 months
Norway	210.2	99.1	237.0	84.7	288.6
France	4.1	3.1	1.0	0.5	1.7
Indonesia	13.4	6.7	12.0	5.6	16.4
Russia	1.8	-1.2	6.9	2.4	10.0
Malaysia	60.3	48.7	60.3	33.9	98.7
Congo (Brazzaville)	1.8	0.4	7.6	4.9	19.0
Other	2.5	1.6	2.4	1.8	3.1
	294.1	**158.4**	327.0	133.8	437.5

During the reporting period, exploration and appraisal expenditure of MUSD 210.2 was incurred in Norway mainly on the appraisal drilling of the Johan Sverdrup field and exploration drilling of the Clapton prospect on PL440S, the Albert prospect on PL519 and the Salinas prospect on PL533. In the comparative period, MUSD 237.0 was spent in Norway on the Johan Sverdrup field appraisal drilling and four exploration wells. MUSD 60.3 (MUSD 60.3) was spent in Malaysia on drilling the Tiga Papan 5, Berangan-1 and Merawan Batu-1 exploration wells. Three exploration wells were also drilled in Malaysia in the comparative period.

Tangible fixed assets amounted to MUSD 44.5 (MUSD 16.1) and represent office fixed assets and real estate, as well as the addition of the Ikdam FPSO which has been consolidated for the first time in August 2012.

Financial assets amounted to MUSD 95.6 (MUSD 46.6) and are detailed in Note 10. Other shares and participations amounted to MUSD 22.6 (MUSD 17.8) and predominantly relate to the shares held in ShaMaran Petroleum which are reported at market value.

Capitalised financing fees amounted to MUSD 48.9 (MUSD 2.5) and relate to the new seven year USD 2.5 billion financing facility entered into in June 2012. The capitalised fees are being amortised over the expected life of the financing facility. The comparative amount relates to the balance of the capitalised financing fees for the previous financing facility which were fully expensed during the reporting period.

Current assets
Receivables and inventories amounted to MUSD 266.4 (MUSD 224.4) and are detailed in Note 11.

Inventories amounted to MUSD 19.4 (MUSD 31.6) and include both hydrocarbon inventories and well supplies. The reduction compared to 31 December 2011 is due to the lifting of the Oudna field, Tunisia hydrocarbon inventory during the reporting period.

Other assets amounted to MUSD 53.6 (MUSD 21.2) and include an amount of MUSD 47.4 (MUSD 11.2) for a carried interest in PL148 Brynhild, Norway, under the terms of a sale agreement with the seller of the interest, Talisman Energy. The amount will be transferred to oil and gas properties on completion of the deal.

Cash and cash equivalents amounted to MUSD 156.9 (MUSD 73.6). Cash balances are held to meet operational and investment requirements and include MUSD 57.0 for a Norwegian tax instalment due on 1 October 2012.

Non-current liabilities
The non-current part of provisions amounted to MUSD 1,272.7 (MUSD 988.0) and is detailed in Note 12.

The provision for site restoration amounted to MUSD 141.5 (MUSD 119.3) and relates to future decommissioning obligation liabilities. The increase compared to 31 December 2011 mainly results from a reduction in the discount factor used to calculate the present value of the decommissioning liabilities.

The provision for deferred taxes amounted to MUSD 1,058.1 (MUSD 803.5) and is arising on the excess of book value over the tax value of oil and gas properties. Deferred tax assets are netted off against deferred tax liabilities where they relate to the same jurisdiction.

The non-current portion of the provision for Lundin Petroleum's LTIP scheme amounted to MUSD 68.2 (MUSD 58.1).

Bank loans amounted to MUSD 321.3 (MUSD 207.0) and relates to the outstanding loan under the Group's USD 2.5 billion revolving borrowing base facility.

Other non-current liabilities amounted to MUSD 22.1 (MUSD 21.8) and mainly arises 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
Other current liabilities amounted to MUSD 481.4 (MUSD 390.6) and are detailed in Note 13.

Tax liabilities amounted to MUSD 231.2 (MUSD 240.1) of which MUSD 220.9 (MUSD 223.0) relates to Norway.

Joint venture creditors amounted to MUSD 188.4 (MUSD 88.4) and relates to the high level of development and drilling activity in Norway and Malaysia during the third quarter of 2012.

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 -58.3 (MSEK -96.5) for the reporting period.

The operating income includes service income received from Group companies. The result includes general and administrative expenses of MSEK 77.5 (MSEK 112.0) and interest expense of MSEK 25.8 (MSEK 18.3). The general and administrative expenses in the reporting period is impacted by the increase in the provision for the Group's LTIP as a result of a higher Lundin Petroleum share price at the balance sheet date. The comparative period includes financial income of MSEK 4.5 for supporting certain financial obligations for ShaMaran Petroleum.

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 0.3 (MUSD 0.5) from ShaMaran Petroleum for the provision of office and other services and MUSD – (MUSD 0.7) for supporting certain financial obligations.

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

LIQUIDITY

Lundin Petroleum had a secured revolving borrowing base facility of MUSD 850 with a seven year term expiring in 2014. On 25 June 2012, Lundin Petroleum entered into a new seven year senior secured revolving borrowing base facility of USD 2.5 billion. The facility is with a group of 25 banks including many of the banks providing the USD 850 million facility. 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 the bank accounts of the pledged companies.

The new facility has been completed to provide funding for Lundin Petroleum's ongoing exploration expenditure and development costs, particularly in Norway.

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 amounting to MUSD 61.4. In addition, bank guarantees have been issued to cover work commitments in Indonesia amounting to MUSD 2.4.

During the second quarter of 2012, Lundin Petroleum purchased 485,647 of its own shares at an average share price of SEK 128 per share.

SUBSEQUENT EVENTS

In October 2012, Lundin Petroleum completed the drilling of the Merawan Batu-1 well on Block PM308B, Malaysia. The well was unsuccessful and the associated costs will be expensed in the fourth quarter of 2012.

The results of two further exploration wells drilled during the third quarter were announced during October 2012. In PL533, Barents Sea Norway, where Lundin Petroleum holds a 20 percent working interest, there was a gas/condensate discovery of 29 to 41 MMboe gross recoverable resources. The cost associated with the well will remain capitalised whilst Lundin Petroleum further evaluates the results of the well and assesses the commerciality of the discovery.

In PL519, Norway, the exploration well targeting the Albert prospect encountered oil but in non-commercial quantities. The costs associated with the well will be expensed in the fourth quarter of 2012.

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.

Under the authorisation of the Board granted at the AGM held on 10 May 2012, Lundin Petroleum purchased 485,647 of its own shares during the second quarter of 2012. As at 30 September 2012, Lundin Petroleum held 7,368,285 of its own shares.

REMUNERATION
Lundin Petroleum's principles for remuneration are provided in the Company's 2011 Annual Report.

Unit Bonus Plan
In 2008, Lundin Petroleum implemented a LTIP scheme consisting of a Unit Bonus Plan which provides for an annual grant of units that will lead to a cash payment at vesting. The LTIP has a three year duration whereby the initial grant of units vests equally in three tranches: one third after one year; one third after two years; and the final third after three years. The cash payment is conditional upon the holder of the units remaining an employee of the Group at the time of payment. The share price for determining the cash payment at the end of each vesting period will be the five trading day average closing Lundin Petroleum share price prior to and following the actual vesting date.

An LTIP that follows the same principles as the 2008 LTIP has been implemented annually for employees other than Executive Management.

The number of units relating to the 2010, 2011 and 2012 Unit Bonus Plans outstanding as at 30 September 2012 were 210,094, 251,559 and 361,158 respectively.

Phantom Option Plan
At the AGM on 13 May 2009, the shareholders of Lundin Petroleum approved the implementation of an LTIP for Executive Management (being the President and Chief Executive Officer, the Chief Operating Officer, the Chief Financial Officer and the Senior Vice President Operations) consisting of a grant of phantom options exercisable after five years from the date of grant. The exercise of these options entitles the recipient to receive a cash payment based on the appreciation of the market value of the Lundin Petroleum share. Payment of the award under these phantom options will occur in two equal installments: (i) first on the date immediately following the fifth anniversary of the date of grant and (ii) second on the date which is one year following the date of the first payment.

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. The recipients will be entitled to receive a cash payment equal to the average closing price of the Company's shares during the fifth year following grant, less the exercise price, multiplied by the number of phantom options. The participants of the phantom option plan are not entitled to receive new awards under the Unit Bonus Plan whilst the phantom options are still outstanding.

Lundin Petroleum purchased 6,882,638 of its own shares up to 31 December 2010 at an average cost of SEK 46.51 per share to mitigate against the exposure of the LTIP. The Lundin Petroleum share price at 30 September 2012 was SEK 160.10. The provision for LTIP amounted to MUSD 61.4 as at 30 September 2012 and the market value of these shares held at 30 September 2012 was MUSD 168.6. The gain in the value of the own shares held cannot be offset against the cost for the LTIP 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 (1995:1554). The accounting policies adopted are consistent with those followed in the preparation of the Group's annual financial statements for the year ended 31 December 2011.

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 (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 2011 Annual Report.

Derivative financial instruments

During the second quarter of 2012, the Group entered into currency hedging contracts fixing the rate of exchange from USD into NOK to meet NOK operational and tax requirements as summarised in the table below. Under IAS 39, subject to hedge effectiveness testing, these hedges are treated as effective and changes to the fair value are reflected in other comprehensive income. At 30 September 2012, a current asset has been recognised amounting to MUSD 13.0 (MUSD -) representing the short-term portion of the fair value of the outstanding currency hedging contracts. In addition, a financial asset has been recognised at 30 September 2012 amounting to MUSD 0.9 (MUSD -) representing the long-term portion of the fair value of the outstanding currency hedging contracts.

Buy	Sell	Average contractual exchange rate	Settlement period
MNOK 1,580.7	MUSD 261.6	NOK 6.04: 1 USD	1 Jun 2012 – 20 Dec 2012
MNOK 670.7	MUSD 110.4	NOK 6.07: 1 USD	2 Jan 2013 – 20 Dec 2013

EXCHANGE RATES

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

	30 Sep 2012		30 Sep 2011		31 Dec 2011	
	Average	Period end	Average	Period end	Average	Period end
1 USD equals NOK	5.8613	5.6995	5.5498	5.8417	5.5998	5.9927
1 USD equals Euro	0.7802	0.7734	0.7111	0.7406	0.7185	0.7729
1 USD equals Rouble	31.0502	31.0441	28.7857	32.1040	29.3738	32.2784
1 USD equals SEK	6.8146	6.5350	6.4047	6.8563	6.4867	6.8877

CONSOLIDATED INCOME STATEMENT

Expressed in TUSD	Note	**1 Jan 2012-30 Sep 2012 9 months**	**1 Jul 2012-30 Sep 2012 3 months**	1 Jan 2011-30 Sep 2011 9 months	1 Jul 2011-30 Sep 2011 3 months	1 Jan 2011-31 Dec 2011 12 months
Operating income						
Net sales of oil and gas	1	982,232	307,975	938,881	324,637	1,257,691
Other operating income		20,310	14,489	7,631	2,907	11,824
		1,002,542	**322,464**	946,512	327,544	1,269,515
Cost of sales						
Production costs	2	-124,231	-23,741	-146,169	-48,247	-193,104
Depletion and decommissioning costs	3	-141,393	-53,738	-121,381	-42,747	-165,138
Exploration costs	4	-33,560	-10,617	-80,227	-64,041	-140,027
Gross profit		**703,358**	**234,368**	598,735	172,509	771,246
General, administration and depreciation expenses		-26,386	-25,838	-35,119	-17,976	-67,022
Operating profit	5	**676,972**	**208,530**	563,616	154,533	704,224
Result from financial investments						
Financial income	6	16,755	9,125	39,150	4,105	46,455
Financial expenses	7	-38,094	-10,030	-16,232	7,984	-21,022
		-21,339	**-905**	22,918	12,089	25,433
Profit before tax		**655,633**	**207,625**	586,534	166,622	729,657
Income tax expense	8	-499,040	-162,744	-417,255	-127,687	-574,413
Net result		**156,593**	**44,881**	169,279	38,935	155,244
Net result attributable to the shareholders of the Parent Company:		159,706	45,887	172,637	39,489	160,137
Net result attributable to non-controlling interest:		-3,113	-1,006	-3,358	-554	-4,893
Net result		**156,593**	**44,881**	169,279	38,935	155,244
Earnings per share – USD[1]		0.51	0.15	0.56	0.13	0.51
Diluted earnings per share – USD[1]		0.51	0.15	0.56	0.13	0.51

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

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

Expressed in TUSD	**1 Jan 2012- 30 Sep 2012 9 months**	**1 Jul 2012- 30 Sep 2012 3 months**	1 Jan 2011- 30 Sep 2011 9 months	1 Jul 2011- 30 Sep 2011 3 months	1 Jan 2011- 31 Dec 2011 12 months
Net result	**156,593**	**44,881**	169,279	38,935	155,244
Other comprehensive income					
Exchange differences foreign operations	36,179	45,335	-12,332	-86,788	-37,525
Cash flow hedges	14,001	11,340	5,263	1,628	6,971
Available-for-sale financial assets	19,037	13,540	-48,627	-17,569	-50,210
Income tax relating to other comprehensive income	-3,500	-2,835	-1,316	-407	-1,743
Other comprehensive income, net of tax	65,717	67,380	-57,012	-103,136	-82,507
Total comprehensive income	**222,310**	**112,261**	112,267	-64,201	72,737
Total comprehensive income attributable to:					
Shareholders of the Parent Company	223,595	110,686	118,198	-56,457	80,466
Non-controlling interest	-1,285	1,575	-5,931	-7,744	-7,729
	222,310	**112,261**	112,267	-64,201	72,737

CONSOLIDATED BALANCE SHEET

Expressed in TUSD	Note	**30 September 2012**	31 December 2011
ASSETS			
Non-current assets			
Oil and gas properties	9	2,825,662	2,329,270
Other tangible assets		44,546	16,084
Financial assets	10	95,573	46,586
Total non-current assets		**2,965,781**	2,391,940
Current assets			
Receivables and inventories	11	266,435	224,407
Cash and cash equivalents		156,918	73,597
Total current assets		**423,353**	298,004
TOTAL ASSETS		**3,389,134**	2,689,944
EQUITY AND LIABILITIES			
Equity			
Shareholders´ equity		1,215,767	1,000,882
Non-controlling interest		68,116	69,424
Total equity		**1,283,883**	1,070,306
Non-current liabilities			
Provisions	12	1,272,730	987,993
Bank loans		321,310	207,000
Other non-current liabilities		22,077	21,830
Total non-current liabilities		**1,616,117**	1,216,823
Current liabilities			
Other current liabilities	13	481,411	390,600
Provisions	12	7,723	12,215
Total current liabilities		**489,134**	402,815
TOTAL EQUITY AND LIABILITIES		**3,389,134**	2,689,944

CONSOLIDATED STATEMENT OF CASH FLOW

Expressed in TUSD	Note	**1 Jan 2012- 30 Sep 2012 9 months**	**1 Jul 2012- 30 Sep 2012 3 months**	1 Jan 2011- 30 Sep 2011 9 months	1 Jul 2011- 30 Sep 2011 3 months	1 Jan 2011- 31 Dec 2011 12 months
Cash flow from operations						
Net result		156,593	44,881	169,279	38,935	155,244
Adjustments for non-cash related items	14	706,324	255,936	623,200	238,855	915,174
Interest received		1,255	527	1,416	326	1,457
Interest paid		-5,619	-2,369	-3,932	454	-1,597
Income taxes paid		-307,247	-206,441	-64,323	-19,655	-183,870
Changes in working capital		69,911	190,894	37,485	-55,635	10,528
Total cash flow from operations		**621,217**	**283,428**	763,125	203,280	896,936
Cash flow from investments						
Investment in oil and gas properties		-567,174	-268,197	-513,727	-210,979	-670,032
Investment in office equipment and other assets		-4,796	-3,380	-3,113	-1,042	-3,786
Investment in subsidiaries		-11,000	-11,000	–	–	–
Change in other financial fixed assets		–	–	-10,260	724	1,908
Proceeds from sale of other shares and participations		–	–	53,938	–	53,938
Decommissioning costs paid		-8,734	-6,245	–	–	–
Other payments		-2,886	-2,841	-875	36	-1,168
Total cash flow from investments		**-594,590**	**-291,663**	-474,037	-211,261	-619,140
Cash flow from financing						
Changes in long-term liabilities		114,557	121,573	-238,622	66,091	-252,238
Financing fees paid		-48,780	-48,271	–	–	–
Purchase of own shares		-8,710	–	–	–	–
Dividend to non-controlling interest paid		-23	–	-212	–	-212
Total cash flow from financing		**57,044**	**73,302**	-238,834	66,091	-252,450
Change in cash and cash equivalents		83,671	65,067	50,254	58,110	25,346
Cash and cash equivalents at the beginning of the period		73,597	90,641	48,703	38,127	48,703
Cash acquired on consolidation of subsidiary		815	815	–	–	–
Currency exchange difference in cash and cash equivalents		-1,165	395	-882	1,838	-452
Cash and cash equivalents at the end of the period		**156,918**	**156,918**	98,075	98,075	73,597

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

Expressed in TUSD	Share capital	Additional paid-in-capital/Other reserves	Retained earnings	Net result	Non-controlling interest	Total equity
Balance at 1 January 2011	**463**	**417,430**	**-9,352**	**511,875**	**77,365**	**997,781**
Transfer of prior year net result	–	–	511,875	-511,875	–	–
Total comprehensive income	**–**	**-54,439**	–	**172,637**	**-5,931**	**112,267**
Transactions with owners						
Distributions	–	–	–	–	-212	-212
Total transactions with owners	**–**	**–**	**–**	**–**	**-212**	**-212**
Balance at 30 September 2011	**463**	**362,991**	**502,523**	**172,637**	**71,222**	**1,109,836**
Total comprehensive income	**–**	**-25,232**		**-12,500**	**-1,798**	**-39,530**
Balance at 31 December 2011	**463**	**337,759**	**502,523**	**160,137**	**69,424**	**1,070,306**
Transfer of prior year net result	–	–	160,137	-160,137	–	–
Total comprehensive income	**–**	**63,889**	**–**	**159,706**	**-1,285**	**222,310**
Transactions with owners						
Distributions	–	–	–	–	-23	-23
Purchase of own shares	–	-8,710	–	–	–	-8,710
Total transactions with owners	–	**-8,710**	–	–	**-23**	**-8,733**
Balance at 30 September 2012	**463**	**392,938**	**662,660**	**159,706**	**68,116**	**1,283,883**

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Net sales of oil and gas, TUSD	**1 Jan 2012- 30 Sep 2012 9 months**	**1 Jul 2012- 30 Sep 2012 3 months**	1 Jan 2011- 30 Sep 2011 9 months	1 Jul 2011- 30 Sep 2011 3 months	1 Jan 2011- 31 Dec 2011 12 months
Net sales of:					
Crude oil					
Norway	717,947	227,340	674,641	242,652	911,072
France	78,211	23,553	96,430	33,256	127,789
Netherlands	117	–	174	59	231
Russia	58,000	18,667	60,437	20,333	79,515
Tunisia	24,597	12	24,795	–	24,795
	878,872	**269,572**	856,477	296,300	1,143,402
Condensate					
Netherlands	730	273	971	363	1,314
	730	**273**	971	363	1,314
Gas					
Norway	64,272	25,827	41,580	14,130	57,909
Netherlands	30,992	10,262	31,048	10,239	42,496
Indonesia	7,367	2,041	8,805	3,605	12,570
	102,630	**38,130**	81,433	27,974	112,975
	982,232	**307,975**	938,881	324,637	1,257,691

Note 2. Production costs, TUSD	**1 Jan 2012- 30 Sep 2012 9 months**	**1 Jul 2012- 30 Sep 2012 3 months**	1 Jan 2011- 30 Sep 2011 9 months	1 Jul 2011- 30 Sep 2011 3 months	1 Jan 2011- 31 Dec 2011 12 months
Cost of operations	76,368	25,858	74,138	25,559	102,476
Tariff and transportation expenses	21,003	7,359	17,635	5,220	22,863
Direct production taxes	39,013	11,949	39,547	14,119	52,390
Change in inventory/lifting position	-13,921	-22,041	13,146	2,780	13,129
Other	1,768	616	1,703	569	2,246
	124,231	**23,741**	146,169	48,247	193,104

Note 3. Depletion and decommissioning costs, TUSD	**1 Jan 2012- 30 Sep 2012 9 months**	**1 Jul 2012- 30 Sep 2012 3 months**	1 Jan 2011- 30 Sep 2011 9 months	1 Jul 2011- 30 Sep 2011 3 months	1 Jan 2011- 31 Dec 2011 12 months
Depletion costs					
Norway	114,515	42,643	95,389	33,761	130,011
France	8,714	2,819	9,118	3,126	12,174
Netherlands	7,938	2,609	8,954	2,767	11,939
Indonesia	3,387	1,066	4,318	1,896	6,250
Russia	3,297	1,059	3,602	1,197	4,764
	137,851	**50,196**	121,381	42,747	165,138
Decommissioning costs					
Tunisia	3,542	3,542	–	–	–
	3,542	**3,542**	–	–	–
	141,393	**53,738**	121,381	42,747	165,138

Note 4. Exploration costs, TUSD	**1 Jan 2012- 30 Sep 2012 9 months**	**1 Jul 2012- 30 Sep 2012 3 months**	1 Jan 2011- 30 Sep 2011 9 months	1 Jul 2011- 30 Sep 2011 3 months	1 Jan 2011- 31 Dec 2011 12 months
Norway	13,681	720	66,727	52,177	74,060
Indonesia	7,100	94	566	193	967
Malaysia	9,181	9,181	11,015	10,747	11,015
Congo (Brazzaville)	1,754	332	–	–	51,263
Other	1,844	290	1,919	924	2,722
	33,560	**10,617**	80,227	64,041	140,027

Note 5. Operating profit, TUSD	**1 Jan 2012- 30 Sep 2012 9 months**	**1 Jul 2012- 30 Sep 2012 3 months**	1 Jan 2011- 30 Sep 2011 9 months	1 Jul 2011- 30 Sep 2011 3 months	1 Jan 2011- 31 Dec 2011 12 months
Operating profit					
Norway	639,212	212,938	507,536	153,540	703,711
France	52,207	15,968	65,446	22,276	85,334
Netherlands	25,538	15,935	14,082	4,489	18,868
Indonesia	-7,488	51	435	495	168
Russia	4,773	2,721	6,524	1,712	7,715
Tunisia	-2,007	-4,360	13,673	-70	13,476
Malaysia	-10,801	-9,388	-11,010	-11,010	-11,010
Congo (Brazzaville)	-1,754	-332	-10	–	-51,273
Other	-22,708	-25,003	-33,060	-16,899	-62,765
	676,972	**208,530**	563,616	154,533	704,224

Note 6. Financial income, TUSD	**1 Jan 2012- 30 Sep 2012 9 months**	**1 Jul 2012- 30 Sep 2012 3 months**	1 Jan 2011- 30 Sep 2011 9 months	1 Jul 2011- 30 Sep 2011 3 months	1 Jan 2011- 31 Dec 2011 12 months
Interest income	2,505	940	3,323	736	4,138
Foreign currency exchange gain, net	681	-5,224	2,654	2,654	8,945
Insurance proceeds	–	–	1,734	8	1,734
Guarantee fees	–	–	704	215	998
Gain on sale of shares	–	–	29,974	–	29,974
Gain on consolidation of subsidiary	13,409	13,409	–	–	–
Other	160	–	761	492	666
	16,755	**9,125**	39,150	4,105	46,455

Note 7. Financial expenses, TUSD	**1 Jan 2012- 30 Sep 2012 9 months**	**1 Jul 2012- 30 Sep 2012 3 months**	1 Jan 2011- 30 Sep 2011 9 months	1 Jul 2011- 30 Sep 2011 3 months	1 Jan 2011- 31 Dec 2011 12 months
Loan interest expenses	4,790	1,604	4,297	1,457	5,390
Foreign currency exchange loss, net	–	–	–	-13,365	–
Result on interest rate hedge settlement	198	–	5,234	1,800	6,995
Unwinding of site restoration discount	3,762	1,266	3,403	1,144	4,494
Amortisation of deferred financing fees	4,584	2,072	1,722	520	2,181
Loan facility commitment fees	5,648	4,970	801	363	1,005
Impairment of other shares	18,631	–	–	–	–
Other	481	118	775	97	957
	38,094	**10,030**	16,232	-7,984	21,022

Note 8. Income taxes, TUSD	**1 Jan 2012- 30 Sep 2012 9 months**	**1 Jul 2012- 30 Sep 2012 3 months**	1 Jan 2011- 30 Sep 2011 9 months	1 Jul 2011- 30 Sep 2011 3 months	1 Jan 2011- 31 Dec 2011 12 months
Current tax	284,354	80,329	213,509	82,804	400,210
Deferred tax	214,686	82,415	203,746	44,883	174,203
	499,040	**162,744**	417,255	127,687	574,413

Note 9. Oil and gas properties, TUSD	**30 Sep 2012**	31 Dec 2011
Norway	1,677,514	1,269,746
France	195,988	172,467
Netherlands	46,365	43,739
Indonesia	95,682	93,610
Russia	625,282	615,015
Malaysia	179,978	129,830
Other	4,853	4,863
	2,825,662	2,329,270

Note 10. Financial assets, TUSD	**30 Sep 2012**	31 Dec 2011
Other shares and participations	22,562	17,775
Capitalised financing fees	48,896	2,506
Bonds	9,483	9,588
Derivative instruments	876	–
Deferred tax	12,380	15,345
Other	1,376	1,372
	95,573	46,586

Note 11. Receivables and inventories, TUSD	**30 Sep 2012**	31 Dec 2011
Inventories	19,435	31,589
Trade receivables	134,816	144,954
Underlift	22,418	1,851
Corporate tax	2,950	–
Joint venture debtors	13,339	20,252
Derivative instruments	12,959	–
Prepaid expenses and accrued income	6,918	4,522
Other	53,600	21,239
	266,435	224,407

Note 12. Provisions, TUSD	**30 Sep 2012**	31 Dec 2011
Non-current:		
Site restoration	141,453	119,341
Deferred tax	1,058,059	803,493
Long-term incentive plan	68,220	58,079
Pension	1,513	1,460
Other	3,485	5,620
	1,272,730	987,993
Current:		
Long-term incentive plan	7,723	12,215
	7,723	12,215
	1,280,453	1,000,208

Note 13. Other current liabilities, TUSD	**30 Sep 2012**	31 Dec 2011
Trade payables	23,309	16,546
Overlift	928	7,670
Tax liabilities	231,182	240,052
Accrued expenses and deferred income	25,949	16,227
Joint venture creditors	188,418	88,417
Derivative instruments	–	168
Other	11,625	21,520
	481,411	390,600

Note 14. Adjustment for non-cash related items, TUSD	**1 Jan 2012-30 Sep 2012 9 months**	**1 Jul 2012-30 Sep 2012 3 months**	1 Jan 2011-30 Sep 2011 9 months	1 Jul 2011-30 Sep 2011 3 months	1 Jan 2011-31 Dec 2011 12 months
Exploration costs	33,560	10,617	80,227	64,041	140,027
Depletion, depreciation and amortisation	140,207	50,943	123,468	43,410	167,812
Current tax	284,354	80,329	213,509	82,804	400,210
Deferred tax	214,686	82,415	203,746	44,883	174,203
Gain on sale of shares	–	–	-29,974	–	-29,974
Impairment of other shares	18,631	–	–	–	–
Long-term incentive plan	14,198	27,886	28,264	16,934	63,443
Other	688	3,746	3,960	-13,217	-547
	706,324	**255,936**	623,200	238,855	915,174

PARENT COMPANY INCOME STATEMENT IN SUMMARY

Expressed in TSEK	**1 Jan 2012- 30 Sep 2012 9 months**	**1 Jul 2012- 30 Sep 2012 3 months**	1 Jan 2011- 30 Sep 2011 9 months	1 Jul 2011- 30 Sep 2011 3 months	1 Jan 2011- 31 Dec 2011 12 months
Operating income					
Other operating income	44,042	22,732	29,045	15,912	42,644
Gross profit	**44,042**	**22,732**	29,045	15,912	42,644
General and administration expenses	-77,528	-82,420	-111,951	-59,093	-206,108
Operating loss	**-33,486**	**-59,688**	-82,906	-43,181	-163,464
Result from financial investments					
Financial income	951	348	4,683	1,798	6,560
Financial expenses	-25,753	-8,655	-18,314	-6,483	-25,495
	-24,802	**-8,307**	-13,631	-4,685	-18,935
Profit before tax	**-58,288**	**-67,995**	-96,537	-47,866	-182,399
Income tax expense	–	–	–	–	–
Net result	**-58,288**	**-67,995**	-96,537	-47,866	-182,399

PARENT COMPANY COMPREHENSIVE INCOME STATEMENT IN SUMMARY

Expressed in TSEK	**1 Jan 2012- 30 Sep 2012 9 months**	**1 Jul 2012- 30 Sep 2012 3 months**	1 Jan 2011- 30 Sep 2011 9 months	1 Jul 2011- 30 Sep 2011 3 months	1 Jan 2011- 31 Dec 2011 12 months
Net result	-58,288	-67,995	-96,537	-47,866	-182,399
Other comprehensive income	–	–	–	–	–
Total comprehensive income	**-58,288**	**-67,995**	-96,537	-47,866	-182,399
Total comprehensive income attributable to:					
Shareholders of the Parent Company	-58,288	-67,995	-96,537	-47,866	-182,399
	-58,288	**-67,995**	-96,537	-47,866	-182,399

PARENT COMPANY BALANCE SHEET IN SUMMARY

Expressed in TSEK	**30 September 2012**	31 December 2011
ASSETS		
Non-current assets		
Shares in subsidiaries	7,871,947	7,871,947
Total non-current assets	**7,871,947**	7,871,947
Current assets		
Receivables	17,673	8,954
Cash and cash equivalents	6,985	3,849
Total current assets	**24,658**	12,803
TOTAL ASSETS	**7,896,605**	7,884,750
SHAREHOLDERS´EQUITY AND LIABILITIES		
Shareholders´ equity including net result for the period	7,049,264	7,169,977
Non-current liabilities		
Provisions	36,403	36,403
Payables to Group companies	806,219	673,988
Total non-current liabilities	**842,622**	710,391
Current liabilities		
Current liabilities	4,719	4,382
Total current liabilities	**4,719**	4,382
TOTAL EQUITY AND LIABILITIES	**7,896,605**	7,884,750

PARENT COMPANY CASH FLOW STATEMENT IN SUMMARY

Expressed in TSEK	**1 Jan 2012-30 Sep 2012 9 months**	**1 Jul 2012-30 Sep 2012 3 months**	1 Jan 2011-30 Sep 2011 9 months	1 Jul 2011-30 Sep 2011 3 months	1 Jan 2011-31 Dec 2011 12 months
Cash flow from operations					
Net result	-58,288	-67,995	-96,537	-47,866	-182,399
Adjustment for non-cash related items	85,542	86,145	-5,019	-6,271	207,811
Changes in working capital	-8,361	-4,146	5,301	18,636	-12,492
Total cash flow from operations	**18,893**	**14,004**	-96,255	-35,501	12,920
Cash flow from investments	–	–	–	–	–
Cash flow from financing					
Change in long-term liabilities	-15,579	-22,057	90,371	33,078	-15,702
Total cash flow from financing	**-15,579**	**-22,057**	90,371	33,078	-15,702
Change in cash and cash equivalents	3,314	-8,053	-5,884	-2,423	-2,782
Cash and cash equivalents at the beginning of the period	3,849	15,192	6,735	3,302	6,735
Currency exchange difference in cash and cash equivalents	-178	-154	43	15	-104
Cash and cash equivalents at the end of the period	**6,985**	**6,985**	894	894	3,849

PARENT COMPANY STATEMENT OF CHANGES IN EQUITY

	Restricted equity		Unrestricted equity			
Expressed in TSEK	Share capital	Statutory reserve	Other reserves	Retained earnings	Net result	Total equity
Balance at 1 January 2011	**3,179**	**861,306**	**2,551,805**	**–**	**3,936,086**	**7,352,376**
Transfer of prior year net result	–	–	–	3,936,086	-3,936,086	–
Total comprehensive income	**–**	**–**	**–**	**–**	**-96,537**	**-96,537**
Balance at 30 September 2011	**3,179**	**861,306**	**2,551,805**	**3,936,086**	**-96,537**	**7,255,839**
Total comprehensive income	**–**	**–**	**–**	**–**	**-85,862**	**-85,862**
Balance at 31 December 2011	**3,179**	**861,306**	**2,551,805**	**3,936,086**	**-182,399**	**7,169,977**
Transfer of prior year net result	–	–	–	-182,399	182,399	–
Total comprehensive income	**–**	**–**	**–**	**–**	**-58,288**	**-58,288**
Transactions with owners						
Purchase of own shares	–	–	-62,425	–	–	-62,425
Total transactions with owners	**–**	**–**	**-62,425**	**–**	**–**	**-62,425**
Balance at 30 September 2012	**3,179**	**861,306**	**2,489,380**	**3,753,687**	**-58,288**	**7,049,264**

KEY FINANCIAL DATA

Financial data (TUSD)	**1 Jan 2012-30 Sep 2012 9 months**	**1 Jul 2012-30 Sep 2012 3 months**	1 Jan 2011-30 Sep 2011 9 months	1 Jul 2011-30 Sep 2011 3 months	1 Jan 2011-31 Dec 2011 12 months
Operating income	1,002,542	322,464	946,512	327,544	1,269,515
EBITDA	854,282	273,632	767,311	261,984	1,012,063
Net result	156,593	44,881	169,279	38,935	155,244
Operating cash flow	593,957	218,394	586,834	196,493	676,201
Data per share (USD)					
Shareholders' equity per share	3.91	3.91	3.34	3.34	3.22
Operating cash flow per share	1.91	0.70	1.89	0.63	2.17
Cash flow from operations per share	2.00	0.91	2.45	0.65	2.88
Earnings per share	0.51	0.15	0.56	0.13	0.51
Earnings per share fully diluted	0.51	0.15	0.56	0.13	0.51
EBITDA per share fully diluted	2.75	0.88	2.47	0.84	3.25
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	310,542,295	310,542,295	311,027,942	311,027,942	311,027,942
Weighted average number of shares for the period	310,735,227	310,441,462	311,027,942	311,027,942	311,027,942
Weighted average number of shares for the period (fully diluted)	310,735,227	310,441,462	311,027,942	311,027,942	311,027,942
Share price					
Quoted price at period end (SEK)	160.10	160.10	117.60	117.60	169.20
Quoted price at period end (CDN)	23.50	23.50	17.00	17.00	24.54
Key ratios					
Return on equity (%)	13	4	16	4	15
Return on capital employed (%)	45	15	41	10	53
Net debt/equity ratio (%)	15	15	14	14	15
Equity ratio (%)	38	38	42	42	40
Share of risk capital (%)	69	69	73	73	69
Interest coverage ratio	132	134	62	47	59
Operating cash flow/interest ratio	119	136	62	60	55
Yield	–	–	–	–	–

KEY RATIO DEFINITIONS

Shareholders' equity per share: Shareholders' equity divided by the number of shares in circulation at period end.

Operating cash flow per share: Operating income less production costs and less current taxes divided by the weighted average number of shares for the period.

Cash flow from operations per share: Cash flow from operations in accordance with the consolidated statement of cash flow divided by the weighted average number of shares for the period.

Earnings per share: Net result attributable to shareholders of the Parent Company divided by the weighted average number of shares for the period.

Earnings per share fully diluted: Net result attributable to shareholders of the Parent Company divided by the weighted average number of shares for the period after considering the dilution effect of outstanding warrants.

EBITDA per share fully diluted: EBITDA divided by the weighted average number of shares for the period after considering the dilution effect of outstanding warrants. EBITDA is defined as operating profit before depletion of oil and gas properties, exploration costs, impairment costs, depreciation of other assets and gain on sale of assets.

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: Operating income less production costs and less current taxes divided by the interest charge for the period.

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

Stockholm, 31 October 2012

C. Ashley Heppenstall
President and CEO

Financial information

The Company will publish the following reports:

- The year end report (January – December 2012) will be published on 6 February 2013
- The three month report (January – March 2013) will be published on 7 May 2013.
- The six month report (January – June 2013) will be published on 7 August 2013.
- The nine month report (January – September 2013) will be published on 6 November 2013.

The AGM will be held on 8 May 2013 in Stockholm, Sweden.

For further information, please contact:

Teitur Poulsen
VP Corporate Planning & Investor Relations
Tel: + 41 22 595 10 00

Maria Hamilton
Head of Corporate Communications
Tel: +46 8 440 54 50
Tel: +41 79 63 53 641

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 2011, 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 and Resources" 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.