LEED
PETROLEUM PLC

Registered number 06034226

Leed Petroleum PLC annual report and accounts 2010

Leed Petroleum PLC is an oil and natural gas exploration, development and production company focused on the US Gulf of Mexico.

The Company has interests in 17 US Federal Outer Continental Shelf blocks and one onshore field, with its headquarters in Lafayette, Louisiana.

Highlights

Operational

- Recommenced drilling programme in February 2010 encountering 65 feet of net pay sand in the Ship Shoal 201 A-6 well Independent reservoir auditing firm attributed initial net 1P reserves of 1 1 MMBOE and net 2P reserves of 1 3 MMBOE (84% natural gas) to the reservoir Following completion of facilities during calendar Q2 2010, daily production for the Company more than doubled from previous level as a result of adding the A-6 well
- Proved developed producing reserves at year end were 70% higher than at mid-year and 25% higher year-on-year
- Higher-capacity natural gas compressor installed at Eugene Island 184 platform
- Installed gas lift supply line in Main Pass 64 oil field during August 2009, approximately doubling well production capability
- East Cameron 317 field returned to production during December 2009 after being shut in for approximately 15 months following Hurricane Ike in 2008
- For the twelve months ended 30 June 2010, net oil, natural gas and natural gas liquids production sold was lower in comparison to the twelve month period ended 30 June 2009 (447 MBOE versus 738 MBOE respectively) However, a significant upward trend in oil, natural gas and natural gas liquids production began during May 2010 with the commencement of production from the Ship Shoal 201 A-6 well Recent production rates for that well include a curtailed rate of approximately 1,148 gross (920 net) BOEPD for the month of October 2010

Financial

- Raised £20 0 million (£19 3 million net after expenses) from the issuance of 400 million Ordinary Shares at 5 pence Cash on hand of $10 8 million at 30 June 2010
- Amended bank credit facility and deleveraged the balance sheet by reducing outstanding bank debt to $26 5 million at period end
- Revenue of $23 3 million earned in the twelve months ended 30 June 2010

Post period update

- Sidetracked the Main Pass 64 #1 well which was drilled to a total measured depth of 8,086 feet on 19 September 2010 Leed owns a 25% working interest and a 19 18% net revenue interest in the well which encountered 71 net feet of true vertical thickness pay The well was placed on production during November 2010
- During November 2010, the borrowing base on the Company's revolver facility was re-determined at $23 0 million, a reduction of $2 0 million which is payable on or before 31 March 2011 In addition, the Company reached an agreement with its bank, UniCredit Bank AG, whereby the bank agreed to waive certain conditions of default concerning the Company's credit facility that were expected to occur at the 31 December 2010 measurement date in return for an additional principal payment of $10 0 million on or before 31 March 2011 and a 1% increase in the credit facility interest rate effective 15 December 2010
- Leed is now exploring additional alternatives to re-finance the Company These alternatives include, but are not limited to, selling all or part of the Company's oil and natural gas assets in order to pay off some or all of its bank debt by 31 March 2011, merging with another company, re-financing with another bank or another potential transaction

Chairman's statement

Leed successfully drilled the Ship Shoal 201 A-6 well in the second half of the financial year, providing improved cash flow, enhancing shareholder value and diversifying sources of production.

Robert Adair Non-executive Chairman

Leed Petroleum PLC is pleased to report progress in developing its resources and reserves in the shallow offshore waters of the Gulf of Mexico

After beginning the period with our drilling programme suspended due to low commodity prices, conditions improved and in November 2009 the Company was able to raise net proceeds of £19 3 million through the placing of 400 million Ordinary Shares to institutional and other shareholders to recommence our drilling campaign I am grateful for the continuing support of our shareholders

We began applying funds from the share placing in January 2010 with the acquisition of an existing platform at Ship Shoal Block 202 In early February we successfully drilled the Ship Shoal A-6 well from that platform and placed the well on production in early May 2010, more than doubling the Group's production rate at that time Our success at Ship Shoal demonstrates that our strategy is still relevant, repeatable and scalable

In April 2010, Leed was awarded Grand Isle Block 96 at the federal lease sale We believe that Grand Isle 96 will complement our leasehold position and upside reserve potential in the Grand Isle area Most of the Group's oil and natural gas reserves are undrilled as reported in Leed's recent reserve auditor's report, which indicates 78 % of our proved and probable (2P) reserves remain undeveloped at the end of this financial year

Like many other Gulf of Mexico companies, our planned activities were severely impacted as a result of the BP Macondo well blow-out whilst drilling and other activities were suspended as the US Department of the Interior reorganised and began promulgating new rules Energy is the lifeblood of the industrialised world, but it comes with certain risks Leed identifies and manages risk by employing hard working seasoned professionals who pay attention to detail, do things right, and follow strict standards and procedures to produce the Group's oil and natural gas reserves After period end, we began moving forward with the development of our property portfolio taking advantage of improved oil prices by participating in the drilling of a non-operated oil well at Main Pass 64

"Your Board is exploring a broad range of strategic alternatives."

LEFT
Ship Shoal 202
Platform A

Leed had a very challenging year financially, with EBITDAX ("earnings before interest, taxes, depreciation, depletion, amortisation, exploration costs and impairments") for the year falling to a negative $1 0 million from a positive $23 9 million in the prior year An after tax loss of $18 1 million was incurred on revenue of $23 2 million for this financial year This was after an impairment of $23 5 million lowered the carrying value of its East Cameron 317/318 filed (a non-operated, non-core asset) during the restated 2009 financial year and de-recognising $7 2 million of deferred tax assets at financial year end 2010 Revenues and cash flows began to improve towards the end of the financial year as a result of new production from the Ship Shoal A-6 well

As a result of adverse well performance and production delays, most notably the delay in recompleting the Eugene Island A-8 well to the more prolific T-1 sand reservoir, we have agreed to reduce our bank debt by $12 0 million on or before 31 March 2011 With that in mind, your Board of Directors is considering a broad range of strategic alternatives including, but not limited to, divesting some or all of the Company's oil and natural gas assets, securing a new bank credit facility and/or other potential transactions, such as a merger with another company

In choosing a strategic option, the Board will carefully consider whether the Company has adequate financial resources to continue to develop its resource base

After two years as a Non-executive Director, Stephen Fleming announced he will stand down from the Board at the Annual General Meeting ("AGM") in December 2010 and Anthony Stalker will be nominated in his stead as a Non-executive Director and representative of our largest shareholder, ADM Galleus Fund Limited through their wholly owned subsidiary Asia Special Situations GJP1 We thank Stephen for his service and wish him all the best

I thank management, staff and Directors for their hard work and efforts in what has been a challenging year for the Company and for the industry in the Gulf of Mexico After the strategic options available to the Company are analysed, the Board will decide on the path forward to maximize shareholder value We thank all of our shareholders and employees for their support

Robert FM Adair

Robert Adair
Non-executive Chairman
25 November 2010

Oil and natural gas reserves

RIGHT

Directors' meeting at
corporate headquarters
June 2010

Leed owns a diversified portfolio of assets ranging from high impact exploratory prospects to lower risk undeveloped proved reserves

Proved and probable reserves (also referred to as "2P reserves") are the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible The figures are estimated on the basis that there should be a 90% probability that the actual quantity of recoverable reserves will be more than the amount estimated as proven and there should be a 50% probability that the actual quantity of recoverable reserves will be more than the amount estimated as proved and probable Leed's proved and probable reserves are evaluated by independent petroleum engineers

At 1 July 2010, the Group's proved and probable reserves comprised the following

	Oil (mbbl)	Natural gas (mmcf)	Natural gas liquids (mgal)	Total (mboe)	% of total (mboe)
Proved reserves					
Developed producing	620	6,187	3,136	1,726	8%
Non-producing	822	6,041	5,227	1,953	9%
Undeveloped	2,053	33,595	6,826	7,815	38%
	3,495	**45,823**	**15,189**	**11,494**	**55%**
Probable reserves					
Developed	327	3,729	1,152	976	5%
Undeveloped	1,963	36,897	3,753	8,202	41%
	2,290	**40,626**	**4,906**	**9,178**	**45%**
2P reserves	**5,785**	**86,449**	**20,095**	**20,672**	**100%**

A substantial amount of Leed's oil and natural gas reserves are currently categorised as undeveloped. There can be no assurance that Leed will be able to fund the future capital required to fully develop its portfolio of undeveloped oil and natural gas reserves. In addition, the economics of developing such reserves are very sensitive to commodity prices As such, future adverse movements in commodity prices could in turn have an adverse impact on the economics of developing Leeds undeveloped oil and natural gas reserves.

Chief Executive and operational report

Acquisition of an existing platform in January 2010 enabled our Company to place the newly drilled Ship Shoal 201 A-6 well online only 94 days after spud date.

Howard Wilson Chief Executive Officer

The Company has continued to make progress in implementing its strategy of developing a diverse portfolio across the Gulf of Mexico region

Asset base

With the spudding of the Ship Shoal A-6 well in February 2010, the Company recommenced development activity on its portfolio of seventeen offshore properties in the US waters of the Gulf of Mexico and one onshore Louisiana property Numerous high quality projects with excellent potential have been identified and planned, which have the capacity to increase proved developed producing reserves and thereby our cash flows All of the Company's offshore properties are located in shallow waters of the Outer Continental Shelf of the Gulf of Mexico

The operational focus for the Group has been to maximise production from its producing fields and, following the side-by-side equity fund raising and credit facility amendment during late 2009, the Group successfully drilled the Ship Shoal 201 A-6 well Leed's technical staff approach evaluation of each field from different but complementary professional perspectives that allow a full understanding of each project

Production

For the year ended 30 June 2010 the Company's total net production averaged 1,224 BOEPD (37% crude oil, 56% natural gas and 7% natural gas liquids), as compared to 2,022 BOEPD (43% crude oil, 49% natural gas and 8% natural gas liquids), in the prior year The Company experienced several well performance issues during the 2010 financial year, as monthly production rates ranged from a high of 1,943 BOEPD in July 2009, declined to a low of 610 BOEPD in April 2010, and rebounded to 1,862 BOEPD during June 2010 as a result of placing the Ship Shoal 201 A-6 well into production

"Leed's third year of being listed on AIM includes operational success at Ship Shoal."

Chief Executive and operational report continued

As demonstrated with our recent success at Ship Shoal, we believe our strategy remains relevant, repeatable and scalable.

LEFT
Ship Shoal 202 Platform A

Reserves
Leed's resumption in drilling has resulted in proven developed producing reserves that have increased period-to-period As of 1 July 2010, the Group had net proved producing reserves of 1,726 MBOE an increase of 25%, as compared to 1,386 MBOE a year earlier The Company has an independent oil and natural gas reserves assessment prepared at least annually

Ship Shoal
Leed's success in developing its Ship Shoal 201 licence, where it is the operator and holds a 100% working interest, was one of the most significant events during the past year Leed is also the operator of two adjacent blocks (Ship Shoal 197 and Ship Shoal 202), where it holds a 75% working interest

Following the Group's equity fundraising in late November 2009, Leed acquired an existing platform on Ship Shoal 202 during January 2010 and successfully drilled the Ship Shoal 201 A-6 well during February 2010 The Ship Shoal opportunity developed a downthrown fault closure with oil and natural gas reserves in a Pleistocene sand stone After reaching a measured depth of 13,341 feet, the Company logged 65 feet of net pay sand in one reservoir and flow tested the Ship Shoal 201 A-6 well

LEFT

Top view of the Eugene Island wellheads

at an initial rate of 10 4 MMCFPD and 423 BOPD (approximately 2,156 gross BOEPD equating to 1,729 net BOEPD) Following refurbishment and completion of the facilities, the well was placed online on 6 May 2010, a mere 94 days after the well had been spudded, demonstrating the advantage of operating in the Gulf of Mexico where there is a wealth of existing infrastructure to support new production

Commencement of production from this well more than doubled the entire Company's production at the time During the month of October 2010, production from the Ship Shoal 201 A-6 well was curtailed and averaged approximately 1,148 BOEPD gross (920 BOEPD net) We believe this is a clear demonstration that Leed's approach is relevant, repeatable and scalable to other projects in the Leed portfolio

Eugene Island
Leed's Eugene Island field is located approximately 50 miles south of Morgan City, Louisiana in approximately 80 feet of water The property comprises three licences Eugene Island 172, 183 and 184 Leed operates the property and owns an average working interest of 75% across the three licences

The field was originally discovered by a major oil company in 1955 with the original wells drilled adjacent to the salt dome which straddles blocks 172 and 184 Several low risk development and exploration opportunities have been identified and these comprise the upside potential of these under exploited assets The Company's A-6, A-7 and A-8 wells at Eugene Island during 2007 and 2008 further confirmed the region's geology and allowed further refinement of our understanding of the potential

The much anticipated recompletion of the A-8 well from the Mid-Tex sand reservoir to the more prolific T-1 sand reservoir has yet to occur Production from the A-8 well continued to decline during the past year, but has yet to decline to rate that would justify approval from the BOEMRE ("Bureau of Ocean Energy Management, Regulation and Enforcement") to recomplete the well into the T-1 reservoir It is possible that the reservoir will not deplete to a level sufficient to obtain regulatory approval of the well recompletion for some time

Chief Executive and operational report continued

Our goal is to be in the position to self-fund our future exploration and development.

ABOVE
Sunrise at the heliport

Eugene Island continued
Assuming there are no regulatory road blocks during financial year 2011 and adequate financial resources, the Company is considering an alternative plan of drilling a sidetrack well into the T-1 sand in lieu of waiting for the A-8 well to deplete its current producing zone. Leed looks forward to the possibility of exploiting and unlocking the cash flow from the T-1 sand at Eugene Island which is estimated to contain 2,892 net mboe of proved developed reserves.

During 2010, the Company installed additional natural gas compression to enhance long-term field deliverability.

At period end, the A-6 and A-7 wells were not producing due to sand control issues. The Group is currently evaluating the best approach to economically attempt to place these wells back on production. During October 2010, production from the Eugene Island field averaged approximately 441 BOEPD gross (266 BOEPD net).

Main Pass
Main Pass 64/65 field is a non-operated property located in federal waters approximately 18 miles east of Venice, Louisiana in about 30 feet of water. Leed holds a working interest averaging approximately 25% across the Main Pass

SUMMARY OF CHIEF EXECUTIVE AND OPERATIONAL REPORT

- The Company has a number of high quality prospects in the Gulf of Mexico that have yet to be fully exploited
- During the second half of the year, the Company aggressively addressed its challenges and, near year end, significantly increased production
- At period end, 2P reserves were adjusted to 20 7 mboe

64/65 field, which was discovered in 1982 and consists of two licences all of Main Pass block 64 and the federal water portion of Main Pass block 65 The field sits atop a large deep seated structural high which sets up a combination of four-way and stratigraphic closures which trap both oil and natural gas Natural gas produced in the field is utilised for operations and to gas lift oil, the only product being sold

Main Pass 64/65 oil production comes predominately from two sands, the 6,900-foot and 7,300-foot sands The majority of the field's historical production and remaining proved oil reserves are contained in the 7,300-foot sand which is subject to a successful waterflood pressure maintenance program utilising a "dump flood" in which water is crossflowed directly from a shallower higher pressure water sand to the oil bearing 7,300-foot sand

In addition to the producing reservoirs, exploration and exploitation potential exists in the intermediate and deep intervals Wells in the non-operated Main Pass 64/65 field were restored to full production capability during the past financial year by installing a gas lift supply line from an offset operator's field However, production was hampered whilst the owner of the third party oil sales line serving the field made repairs to its line At year end the field was shut in However, during August 2010 the operator of the field began barging oil prior to the recommencement of pipeline service, which occurred during early November 2010 During October 2010 oil production from the Main Pass 64/65 field averaged approximately 824 BOEPD gross (158 BOEPD net)

After year end, the operator of the field sidetracked the Main Pass 64 #1 well, reaching a total measured depth of 8,086 feet on 19 September 2010 Leed owns a 25% working interest and a 19 18% net revenue interest in the well which encountered approximately 71 feet of true vertical thickness pay The well was placed on production during November 2010

In addition to its interests in Main Pass 64 field, Leed was awarded Main Pass block 115 in MMS lease sale 205 in 2007 The block is located approximately 83 miles southeast of New Orleans, Louisiana in 50 feet of water The Company has identified several exploratory opportunities on the licence and owns 100% working interest in the property subject to Byron Energy Pty Ltd's right to acquire up to 25% of Leed's working interest in the block

Chief Executive and operational report continued

The Ship Shoal 201 A-6 well encountered hydrocarbon bearing sands covering 65 feet of total net pay.

East Cameron
The non-operated East Cameron 317/318 field is located offshore approximately 112 miles south of Cameron, Louisiana in about 224 feet of water Both licences produce from Upper and Lower Pleistocene progradational deltaic sandstones Leed owns a 25% working interest in the East Cameron 317/318 field

The field returned to production during December 2009 after being shut in for approximately 15 months following Hurricane Ike in 2008 The field has since flowed natural gas at a steady rate, including approximately 2 0 gross (0 4 net) MMCFPD during October 2010

Grand Isle
Grand Isle 95, 96 and 100 sit in approximately 200 feet of water about 100 miles south of New Orleans, Louisiana and form part of a large field discovered by a major oil company in 1974 Leed is operator and holds a 100% working interest subject to a working interest election of up to 25% by Byron Energy Pty, Ltd The Grand Isle 95 field is located on the upthrown side of a large regional fault which trends northeast to southwest with hydrocarbons trapped in several sand intervals It is believed that salt migration was responsible for creating the fault system, setting up the structural trap which crests in the northwestern corner of Grand Isle 95 Sediments dip to the southeast, with hydrocarbon accumulations generally trending northeast to southwest and are comprised of a complex series of enechelon bar sands Hydrocarbons are trapped either stratigraphically or by fault bound structural closures or a combination thereof Producing horizons provide strong analogies for Leed's exploration prospects in Grand Isle blocks 95 and 96

Leed acquired its Grand Isle licences over blocks 95 and 100 in May 2006 (expires May 2011) and block 96 in April 2010 (expires April 2015) Assuming the Company is successful in funding this project during early 2011 and natural gas prices are at sufficient levels to justify the investment, Leed plans to drill a well on Grand Isle 95 prior to its expiration date

Together the Grand Isle block 95 and 96 licences provide Leed with a material working interest in a range of prospects from pure exploration resources to a proved reserve development opportunity Should Leed's drilling campaign prove successful, the Company would need to install a platform and facilities on its leasehold

South Marsh Island
South Marsh Island consists of two licences, South Marsh Island 8 and Eugene Island 133, both of which are located in approximately 60 feet of water about 90 miles south-southeast of Lafayette, Louisiana South Marsh Island 8 was initially developed by a major oil and natural gas company and was acquired by Leed in August 2008 Leed is operator and holds a 100% working interest subject to a working interest election of up to 25% by Byron Energy Pty, Ltd in South Marsh Island 8 and a 75% working interest in Eugene Island 133

The Company has identified numerous opportunities in the field with 3-D seismic, subsurface well control, and by matching historical production data The opportunities lie on the southeast flank of a large salt dome The field has produced from numerous sands at depths ranging from 10,000 feet to 15,000 feet

Oil and natural gas were trapped in structural closures bound on the west by salt, the north and south by radial faults, and the east by structural dip The opportunities consist of proved undeveloped, probable undeveloped, and possible undeveloped locations targeting numerous pay sands

LEFT
Newly drilled
Ship Shoal 201
A-6 well

The proved undeveloped locations are well defined and updip to previously producing wells The probable undeveloped locations are predominately in undrilled fault blocks adjacent to production and updip to wells which logged oil and or natural gas The numerous prospects at South Marsh Island will enable Leed to drill wells with multiple objectives Should Leed's drilling campaign prove successful, the Company will have to install a platform and facilities on its lease

Sorrento
Leed's only onshore property is located in a field created by a salt dome structure in Ascension Parish, Louisiana approximately 50 miles northwest of New Orleans Leed is the operator and holds a 100% working interest It contains both proved reserves and exploratory prospects as confirmed by the Company's reserves auditor The field was discovered by a major oil company in 1929 and Leed holds a 100% working interest in its acreage which is located on the eastern and northern flanks of the Sorrento salt dome Proved reserves are located in the Lower Miocene Marg A Sand and Planulina Sands The trapping mechanisms are both structural and stratigraphic Leed's acreage is located at the eastern edge of the productive Oligocene Marg Vag trend, which the Company believes has additional untapped exploration potential

As of the date of this report, the Sorrento field, comprised of one legacy well and a saltwater disposal well, was shut in

West Cameron
West Cameron block 106 is a promising exploration prospect located in approximately 30 feet of water offshore Louisiana and is owned 100% by the Company, subject to Byron Energy Pty Ltd's right to acquire up to 25% of Leed's working interest in the block There are no proved or probable reserves associated with the prospect The licence drew multiple bids at the federal auction in which Leed acquired the prospect

Outlook
During the second half of the financial year the Company significantly increased production We are excited about progressing forward with development of Leed's resource base Our staff have worked diligently to prepare a high quality line up of projects that provide the capacity for strong growth in reserves and production once we have overcome the financial hurdles and other hurdles that we currently face

Howard Wilson

Howard Wilson
Chief Executive Officer
25 November 2010

Financial review

Lower production was a significant contributing factor leading to a loss of $18.1 million for the Company, but the trend improved towards the end of the year with cash flow from the newly drilled Ship Shoal 201 A-6 well.

James Slatten Chief Operating Officer

The Company's period under review is the financial year ended 30 June 2010 The financial year ended 30 June 2009, which has been restated for a non-cash property impairment (refer to Note 30 "Restatement of prior period" within the current year financial statements), is also presented to aid with comparison.

Consolidated statement of income

The 2010 financial year presented many challenges, both operationally and financially The Company incurred a loss of $18 1 million during the 2010 financial year, as compared to a restated loss of $18 5 million for the prior year

Revenues declined 31% to $23 2 million, principally as a result of adverse well performance issues and pipeline shut ins that resulted in an overall drop in production of 40% (447 MBOE for the 2010 financial year, as compared to 738 MBOE for the prior year) The Group's daily production rate during the 2010 financial year began at 1,943 BOEPD in July 2009 and declined to 610 BOEPD in April 2010 before rebounding to 1,862 BOEPD in June 2010 after the Ship Shoal 201 A-6 well was placed online in May 2010 Oil and natural gas commodity price movements included a 26% increase in average oil prices ($73 92 per bbl in the 2010 financial year, as compared to $58 88 per bbl in the prior year) and a decrease in average natural gas prices of 18% ($4 64 per MCF in the 2010 financial year, as compared to $5 67 per MCF in the prior year) Gas processing fees were $2 7 million for the 2010 financial year, an increase of $2 2 million over the prior year, due to a favourable ownership adjustment regarding the Group's interest in the N Terrebonne gas processing plant and Tebone gas fractionation plant, which is based on the percentage of natural gas production from our Eugene Island field, as compared to total overall natural gas production processed by the plants

Production costs per BOE increased to $16 87 per BOE in the 2010 financial year, as compared to $7 44 per BOE for the prior year The increase per BOE was a reflection of lower production rates coupled with higher production costs A majority of the higher production costs were applicable to Eugene Island, where the A-6 and A-7 wells were shut in at period end due to sand control issues

"Leed is seeking a broad range of strategic alternatives to move the Company forward."

For the periods presented, administrative expenses include:

Administrative expenses	2010 $000	Restated 2009 $000
Employee benefits expense excluding share-based payments	**4,522**	5,906
Share-based payments	**2,272**	1,156
Professional fees and outside consultants	**1,366**	459
Delay rentals for evaluation assets	**539**	339
Insurance, including that related to oil and natural gas properties	**6,121**	3,657
Other and miscellaneous	**390**	635
	15,210	12,152

Depletion (per BOE of proved/probable reserves produced) was $24 89 per BOE for the 2010 financial year, as compared to $27 61 per BOE for the prior year The depletion rate per BOE was reflective of the level of oil and natural gas reserves and the mix of production from each producing field during each financial year

Administrative costs were $15 2 million in the 2010 financial year, as compared to $12 2 million for the prior year The year-on-year increase of $3 0 million included increased insurance costs of $2 5 million, which was a result of industry-wide insurance premium increases experienced by most oil and gas companies operating in the Gulf of Mexico during the past year The number of employees and Directors receiving wages or fees averaged 29 for the periods ended 30 June 2010 and 2009 No management bonuses were accrued for or paid during either financial year

The Group adjusts the fair value movements of its derivatives through other gains and losses at the end of each financial period Changes in the fair value of the Group's derivatives outstanding at each financial period end resulted in an unrealised loss of $1 0 million for the 2010 financial year and a gain of $6 5 million for the prior year Realised gains and losses on oil and natural gas commodity contracts that closed in the current year were also included in other gains and losses and included a gain of $1 7 million in each of the 2010 and 2009 financial years

During the year, the Group carried out a thorough review of its impairment testing procedures and concluded that the single cash generating unit that previous reviews had been based on was inappropriate to the current business structure Cash generating units are now based on individual fields in distinct geographical locations with proved and probable reserves, unless cash flows are directly linked to another field As a result of this more detailed and rigorous assessment of impairment, an impairment was identified with respect to the East Cameron 317/318 field (a non-core and non-operated property for which the Group has a 25% working interest) which was offline from August 2008 until December 2008 due to third party pipeline damage from Hurricane Ike Upon further analysis, it was determined that this field was impaired at 30 June 2009 due to low natural gas prices coupled with negative volumetric reserve adjustments As a result, the Group recorded before tax non-cash impairment expense of $23 5 million for the 2009 financial year Accordingly, the Group's financial statements for the 2009 financial year have been restated to reflect the aforementioned adjustment

As noted in the Report of the Directors, EBITDAX for the 2010 financial year included a loss of $1 0 million, as compared to income of $23 9 million for the prior year The variance between years was principally due to a combined $17 9 million decrease in revenues and other gains and losses, coupled with a $6 2 million decrease in the amount of depreciation, depletion and amortisation added back as an adjustment to EBITDAX for the 2010 financial year, as compared to the prior year

Statement of financial position

In the year ended 30 June 2010, carrying value of the Group's property plant and equipment increased by a net of $3 4 million to $127 0 million During the year, the Company recorded gross asset additions of $15 7 million (including $13 1 million to drill and complete the Ship Shoal 201 A-6 well)

In the current year, the Group also expended $0 7 million towards exploration and evaluation assets, including a 100% working interest in Grand Isle 96 for $0 4 million at the federal lease sale Grand Isle 96 is adjacent to Grand Isle 95, where the Company holds a 100% working interest subject to an election of up to a 25% working interest by Byron Energy Pty, Ltd

Financial review continued

Cash flows and funding
During November 2009, the Company completed an additional equity fund raising pursuant to which it issued 400 million Ordinary Shares (5p) at 5 pence each to raise net proceeds of $31 6 million The Group used the net equity proceeds primarily to re-commence its drilling programme and to reduce its credit facility

Also during November 2009, the Group entered into an amended and restated credit facility with its bank, which was further modified during November 2010 and is more fully described in Note 15 "Borrowings" of the financial statements within this annual report At 30 June 2010, the amended and restated credit facility comprised two tranches a revolver loan ($25 0 million principal balance) and a term loan ($1 5 million principal balance) The effect of the November 2010 modification to the Group's credit facility resulted in the following

- the Group will be required to make a principal payment of $12 0 million on or before 31 March 2011,
- the interest rate on the revolver and term tranches of the credit facility will increase by 1% effective 15 December 2010 As a result, the interest rate will be at three month LIBOR plus 7 25% for the revolver facility and three month LIBOR plus 8 0% for the term facility as of that date, and

LEFT
Separator facility at Ship Shoal 202 Platform A

Summary of the Financial review

- EBITDAX was a negative $1 0 million for the 2010 financial year, as compared to a positive $23 9 million for the 2009 financial year
- The Company undertook an additional equity fundraising for 400 million Ordinary Shares (5p) at 5 pence per share and deleveraged its financial structure by paying down debt during the financial year from $40 8 million to $26 5 million at period end.
- The Company has agreed to further reduce its bank debt by $12 0 million on or before 31 March 2011

ABOVE
Eugene Island facility

- the maximum credit facility will be set at $30 0 million as of 15 December 2010 and will be reduced by $6 0 million in a semi-annual basis thereafter

As of the date of this report the Group is exploring several alternatives including divesting some or all of its oil and natural gas assets in order to raise $12 0 million or more to pay off some or all of its bank borrowings prior to 31 March 2011 Additional alternatives under consideration include, but are not limited to, securing a new bank credit facility and/or other potential transactions such as a merger with another company

Going concern
The Directors have prepared cash flow forecasts (including selected sensitivities) for the Company covering a twelve month period from the authorisation of these financial statements. The cash flow forecasts reflect the Company's plan for the coming year, including expected net proceeds from divestitures, projected production rates, commodity prices, capital expenditure levels, principal payments, interest rates and expected compliance with loan covenants. Based on these assumptions, which the Board believes are reasonable, these cash flow forecasts show that the Group should have sufficient liquidity to continue as a going concern. Nevertheless, possible adverse future events or circumstances are beyond the control of the Company and seriously influence doubt on the Company's ability to continue as a going concern Moreover, the regulatory environment in the Gulf of Mexico post the BP oil spill at Macondo is in flux and some regulatory changes under consideration in the US Congress could imperil the Company's business model Clearly, it is impossible to predict the regulatory changes that may come about on account of governmental initiatives

Future growth of the Group during the next twelve months and beyond is heavily dependent upon the Group's ability to raise enough capital to continue the development of its undeveloped oil and natural gas reserve portfolio, which represents approximately 78% of its oil and natural gas reserves calculated on a BOE basis at 1 July 2010 The cash flow forecasts assume the Group will be successful in raising sufficient capital to further develop these oil and natural gas reserves

After carefully considering the aforementioned factors, cash flow forecasts and material uncertainties set forth within Note 2 20 "Significant accounting policies – going concern" within the financial statements for the 2010 financial year, the Directors' assessment is that Leed is a going concern Clearly, we will face challenges in the period ahead.

James Slatten

James Slatten
Chief Operating Officer
25 November 2010

Corporate governance and Directors' remuneration report

Corporate governance

As an AIM quoted company Leed Petroleum PLC is not required to comply with the UK Corporate Governance Code (the "Corporate Governance Code") (formerly referred to as the Combined Code on Corporate Governance prior to 1 July 2010) However, the Directors support high standards of corporate governance and confirm that, where practicable, having regard to the Company's current stage of development, the Company complies with the main principles of the Corporate Governance Code The Company has adopted and operates a share dealing code for Directors and senior employees

The Directors are accountable to shareholders for the creation and delivery of strong sustainable financial performance and creation of long-term shareholder value To achieve this, the Board directs and monitors the Group's affairs, assesses risk, sets strategic objectives whilst attempting to ensure that all necessary resources are in place to achieve the business objectives, and reviews management's performance An element of risk is central to the activities of oil and natural gas exploration and development and it is the Directors' objective to be aware of the risks, to evaluate them and to mitigate them where possible to insure against them where appropriate and cost-effective and to manage any residual risk within the financial constraints under which the Company operates

Directors

The Board comprises a Chairman, two Executive Directors and four Non-executive Directors Biographies of the Directors are presented on pages 18 and 19 Robert Alcock is a Senior Non-executive Director as defined by the Corporate Governance Code A summary of attendance by Director follows

Attendance record at Board meetings	Director status	Year ended 30 June 2010 Attended	Year ended 30 June 2010 Eligible	Year ended 30 June 2009 Attended	Year ended 30 June 2009 Eligible
Robert Adair	Chairman	10	10	5	6
Robert Alcock	Non-executive	10	10	6	6
Stephen Fleming	Non-executive	10	10	3	3
Ian Shaun Gibbs	Non-executive	10	10	5	6
Peter Hirsch	Non-executive	10	10	6	6
James Slatten	Executive	10	10	6	6
Howard Wilson	Executive	10	10	6	6

Audit and Remuneration Committees

The Board has established an Audit Committee and a Remuneration Committee with formally delegated duties and responsibilities Robert Alcock and Peter Hirsch are members of the Audit Committee Robert Adair, Stephen Fleming and Peter Hirsch are members of the Remuneration Committee

The Audit Committee is chaired by Robert Alcock and the Remuneration Committee is chaired by Robert Adair

All members of the Audit Committee are independent of management, attendance at Committee meetings is at the invitation of the Chairman of the Audit Committee and the external auditors are invited to attend The external auditors have the right at all times for direct access to the Chairman of the Committee and to meet with the Committee without management present The Committee meets at least twice a year and has responsibility for, amongst other things, reviewing the nature and scope of work for auditing the accounts and reviewing the half year and annual financial statements before their submission to the Directors The Committee is provided terms of reference from the external auditors and focuses particularly on compliance with accounting standards and financial reporting It is also responsible for ensuring that an effective system of internal controls is maintained

The Audit Committee also advises the Board on appointment of external auditors and approves the fees to be paid to the external auditors The ultimate responsibility for reviewing and approving the annual accounts and interim statements remains with the Board The Board also has the overall responsibility for the Group's system of internal controls, including reviewing the effectiveness thereof Such system is designed to manage rather than eliminate the risk of failure to achieve business objectives and can only provide reasonable, not absolute, assurance against material misstatement of the accounts

The Remuneration Committee meets at least twice a year and has responsibility for making recommendations to the Board on the compensation of senior executives and determining, within agreed terms of reference, the specific remuneration packages for each of the Executive Directors It also oversees the incentive share plan and sets performance conditions in respect of such arrangements The Committee periodically engages the services of external consultants which are independent of the Company to assist them in their duties and did so during the 2010 financial year

Compliance with the Corporate Governance Code

The Corporate Governance Code states that the Board of Directors of a UK public company should include a balance of Executive and Non-executive Directors Smaller UK public companies (being those that are below the FTSE 350 throughout the year immediately prior to the reporting year) should have at least two independent Non-executive Directors The Company has four independent Non-executive Directors Robert Adair, Robert Alcock, Peter Hirsch and Ian Shaun Gibbs Notwithstanding all Non-executive Directors' eligibility to participate in the Company's incentive share plan and purchase stock in the Company, as at the date of this report the Board considers the four Non-executive Directors to be independent Stephen Fleming is not an independent Non-executive Director due to his past business relationships with IB Daiwa Corporation and Asia Debt Management Galleus Fund Limited The Corporate Governance Code further provides that a majority of Non-executive Directors should be independent of management and free from any business or other relationship which could materially interfere with the exercise of their independent judgement

The Directors are satisfied that the Company continues to comply with the requirements of the Corporate Governance Code so far as possible having regard to the size and current state of development of the Company

All Directors have access to the advice of the Group Chairman who is responsible to the Board for ensuring that Board procedures are followed and that applicable rules and regulations are complied with In addition, the Chairman ensures that Directors receive an appropriate induction to the Group and that the Board has access to appropriate knowledge development as required If necessary, the Chairman will arrange for seminars to be held on specific topics for the Board, as done in 2010 regarding "Changes to the UK Combined Code of Corporate Governance"

The Board has procedures in place which are intended to ensure that if any Director has, or is perceived to have, a conflict of interest in relation to his Directorship of the Group, or any transaction involving Leed, he will abstain from voting on that matter or counting towards a quorum at a Board meeting in relation to that matter

Relationship with former Parent Company and successor

Prior to 1 February 2010, IB Daiwa Corporation ("IBD") through its wholly owned subsidiary, Asia Special Situations GJP1 Limited ("ASSGJP1"), held 28 65% of the issued share capital of Leed, which gave IBD significant influence over the Company's management and affairs For example, IBD could block any shareholder action that must be passed by a special resolution requiring a 75% shareholder vote Effective 1 February 2010, IBD transferred all of its ownership in ASSGJP1 to ADM Galleus Fund Limited ("ADM") in settlement of certain claims, liabilities and obligations At 30 June 2010, ADM through its wholly owned subsidiary, ASSGJP1, owns 28 65% of the currently issued share capital (193,695,929 total shares) of Leed Petroleum PLC Stephen Fleming, a Non-executive Director of the Company, served as an executive director of IBD until 26 February 2010 and is a former employee of ADM

Investor relations

Communications with shareholders are given a high priority The Company keeps its institutional shareholders up to date with its business objectives and obtains their views on the Company by means of investor presentations Additionally, the Company is ready to respond appropriately to particular issues or questions that may be raised by investors through the contact email address, info@leedpetroleum com, displayed in the investor centre section of the Company's website, www leedpetroleum com

The Company s website is regularly updated and contains a wide range of information about the Company including the AIM Admission Document, circulars sent to shareholders, share capital information, Company announcements and the annual report and financial statements

Directors' remuneration

Details of the emoluments for each Director for the periods are presented below There were no bonuses paid or accrued for during financial year 2010 and financial year 2009

Director	Year ended 30 June 2010 $000	Year ended 30 June 2009 $000
Robert Adair	**110**	113
Robert Alcock	**39**	39
Stephen Fleming	**19**	12
Ian Shaun Gibbs	**19**	18
Peter Hirsch	**28**	29
Seiki Takahashi	**—**	7
James Slatten	**422**	397
Howard Wilson	**526**	485
Total	**1,163**	1,100

The terms of the Directors' shareholdings and awards granted under the incentive share plan (stock appreciation rights and restricted stock units) are discussed in the Report of the Directors, included with the accounts, and at Note 21 "Employees, Director and auditor remuneration" of the accounts During the periods presented, the Directors did not sell any shares of the Company nor exercise any rights to Company stock

Board of Directors

Robert F M. Adair
Non-executive Chairman (aged 54)
After graduating in geology from Oxford University, Mr Adair qualified as a Chartered Accountant and then had several years' corporate finance experience Mr Adair is executive chairman of Melrose Resources plc, a UK listed oil and gas group which he founded in 1992 He is also executive chairman of Terrace Hill Group plc, a property development and investment group listed on AIM He is also Non-executive Chairman of AIM-listed Plexus Holdings PLC, a company producing innovative wellheads for the oil industry

Howard H Wilson Jr.
President and Chief Executive (aged 52)
Mr Wilson has over 29 years experience in oil and gas exploration and production Mr Wilson has served as President and CEO of Leed Petroleum LLC since November 2005 Immediately prior to joining the Company Mr Wilson was Vice President of Engineering and Operations of Darcy Exploration, Inc from January 2000 through to October 2002 when Darcy Exploration, Inc was purchased by Novus Petroleum, Ltd He then served as Vice President of Engineering and Operations of Novus Louisiana, LLC until October 2005 Mr Wilson was also Vice President of Operations of Petsec Energy, Inc , a position he held from 1993 to 2000 Between 1981 and 1993 Mr Wilson held various technical and managerial positions with Placid Oil Company and Nerco Oil and Gas, Inc involving onshore and offshore oil and natural gas fields in Louisiana, Mississippi and Texas Mr Wilson holds a Bachelor of Science degree in Petroleum Engineering from the Louisiana Polytechnic Institute, USA

Robert H. Alcock
Senior Non-executive Director (aged 69)
Mr Alcock commenced his career as a financial analyst with Ford of Europe from where he joined Gulf Oil Company in London, initially dealing with their exploration and production activities in the Middle East and Africa He later moved to senior financial positions with Gulf Oil Company and eventually became Head of Strategic Planning for refining and marketing in Europe Following his time at Gulf Oil Company, Mr Alcock joined Black and Decker Inc as chief financial officer based in Maryland, USA He left Black and Decker Inc to become chief financial officer at RJR Nabisco UK Formerly the Non-executive Chairman of Anglo and Overseas Investment Trust and the Chairman of Next Group Pensions Trustees Ltd, Mr Alcock is currently senior Non-executive Director at Huntsworth Plc and a Non-executive Director of Connaught Group Plc Mr Alcock is a fellow of the Institute of Chartered Accountants of England and Wales

Ian S. Gibbs
Non-executive Director (aged 44)
Mr Gibbs is a founding partner and principal in Bromius Capital, a natural resources focused investment and advisory firm based in Singapore During Mr Gibbs' investment banking career he has worked on a wide range of transactions covering both equity and debt capital markets, M&A, debt restructuring and principal investment Prior to founding Bromius, Mr Gibbs was responsible for the SE Asian operations of a leading Asian independent merchant bank, which included a team that was directly responsible for a number of high profile and successful natural resources transactions across the region, with a particular focus on upstream oil and gas Mr Gibbs is a member of the Institute of Chartered Accountants of England and Wales and has an MA in Economics from the University of Cambridge, England

James E. Slatten III

Chief Operating Officer (aged 52)

Mr Slatten has over 27 years of commercial, financial and legal experience in the oil and natural gas industry He has served as an Executive Director of Leed Petroleum LLC since November 2005 Immediately prior to joining Leed, Mr Slatten was Vice President of Land and Legal at Darcy Exploration Inc (later Novus Louisiana LLC) from March 2000 to November 2005 He served in a similar capacity at Petsec Energy, Inc between 1998 and 2001 Mr Slatten was a member of the Gordon, Arata law firm from 1985 to 1998, where he focused on energy and financing transactions, and he clerked for the United States District Court in New Orleans in 1983 to 1984 Mr Slatten holds a Bachelor of Arts degree in Political Science and Economics from the University of Louisiana and post-graduate degrees in business management and law from Tulane University

Stephen Fleming

Non-executive Director (aged 39)

Mr Fleming is a Senior Analyst at ADM Capital a $1 8 billion private equity and special situations fund management company based in Hong Kong. Mr Fleming joined ADM Capital in 2005, and has twelve years of investment experience, having worked at Robertson Stephens as a senior equity research analyst, and at MRET, where he managed a portfolio of investments in venture-stage energy technology companies and clean energy projects Mr Fleming served as an Executive Director at the IB Daiwa Corporation until 26 February 2010, and was appointed to the Board on 29 December 2008 Mr Fleming holds a BA degree in Government and East Asian Studies from Harvard College and a Master of Business Administration degree from Harvard Business School

Peter D. Hirsch

Non-executive Director (aged 59)

Mr Hirsch is Managing Director of Hirsch Technical Ltd a London based management consultancy specialising in business development and transformation During his 25 year international career in oil and natural gas exploration with Shell, Chevron and others, he was responsible for several new oil field discoveries, a positive outcome from a complex North Sea equity re-determination and a number of technical innovations Following an assignment as internal Change Management consultant with the company's UK operating company, in which his team reduced OPEX by several million dollars while improving service quality, he founded Hirsch Technical in 1998 to support clients in a wide variety of management consulting projects, mainly in the oil and engineering sectors Mr Hirsch has an MA in Natural Science from University of Cambridge, England, an MSc and DIC from Imperial College, University of London and a Diploma in Management Studies from Birkbeck College, London University

Leed Petroleum PLC (Registered number 06034226)
financial statements for the year ended 30 June 2010

Report of the Directors
for the year ended 30 June 2010

The Directors of Leed Petroleum PLC ("Leed", "the Company" or "Parent Company") present to shareholders this report and the audited consolidated financial statements as of and for the year ended 30 June 2010 The year ended 30 June 2009 is also presented for comparative purposes The Company is listed on AIM part of the London Stock Exchange ("AIM") and trades under the symbol LDP

Principal activity
The principal activity of the Company and its subsidiaries (together, the "Group" or "Leed") is exploring, developing, producing and operating oil and natural gas properties from onshore and offshore locations within the Gulf Coast region of the United States As of 30 June 2010, the Group has working interests in seventeen offshore blocks (including eight producing and nine non-producing) and one onshore field The Group also holds a small interest in a gas processing plant and a fractionation plant located onshore in Louisiana In the current period, the Group acquired one new offshore block from the Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE") Leed believes the interests it owns in its non-producing assets have significant potential for future production

Business review
The financial year ended 30 June 2010 presented many challenging issues, both operational and financial

Operational review
Production performance was hampered throughout the year ended 30 June 2010, primarily at the Eugene Island field, where the Eugene Island 183 A-8 well continued to decline at a steady rate, but not in sufficient quantity to obtain regulatory approval for the recompletion into the more prolific T-1 sand Two other wells in the field, the Eugene Island 183 A-6 and Eugene Island 183 A-7, each experienced significant downtime due principally to sand control issues and were not producing at period end The Company s Main Pass 64/65 field also experienced significant downtime during the year ended 30 June 2010 due to ongoing pipeline repair issues and was shut in at period end The East Cameron 317/318 field came back online during December 2009 after being offline for fifteen months while hurricane damage to the third party pipeline serving the field was repaired During May 2010, the Group commenced production from the Ship Shoal 201 A-6 well (drilled during the first calendar quarter of 2010) at an average rate of approximately 1,295 net BOEPD, which was the primary contributor to the higher BOEPD rate for May 2010 and June 2010

During the year ended 30 June 2010, the average net BOE produced per day reached a high of 1,943 net BOEPD during July 2009 and dipped to a low of 610 net BOEPD in April 2010, before rebounding to 1,862 net BOEPD at the end of June 2010

Financial review
The Group recorded a loss after taxation of $18 1 million for the period ended 30 June 2010, as compared to a restated loss of $18 5 million for the prior year Components of the $18 1 million loss for the period ended 30 June 2010 comprised the following

Revenues: Revenues were $23 2 million for the period ended 30 June 2010, a decrease of 31% as compared to the prior year Oil, natural gas, and natural gas liquids production for the period ended 30 June 2010 was 447 MBOE, a decrease of 40% (49% crude oil production decrease and 39% natural gas production decrease), as compared to 738 MBOE for the prior year Average crude oil prices were 26% higher ($73 92 per bbl for 2010 as compared to $58 88 per bbl for 2009), while average natural gas prices for 2010 were 18% lower than 2009 ($4 64 per mcf during the year ended 30 June 2010, as compared to $5 67 per mcf during the year ended 30 June 2009) Gas plant processing fees included a year-on-year increase of $2 2 million, as the Group's ownership interest in the N Terrebonne gas processing plant and Tebone gas fractionation plant increased from 0 6% to 2 5% as a result of a favourable ownership adjustment which was based on the percentage of natural gas production from our Eugene Island field, as compared to total overall natural gas production processed by the plants

Report of the Directors continued
for the year ended 30 June 2010

Business review continued
Financial review continued
Cost of sales The Group's cost of sales was $22 2 million for the period ended 30 June 2010, a decrease of $2 2 million as compared to the prior year The year-on-year decrease was principally due to a $6 2 million reduction in depletion costs, which were partially offset by $4 0 million of higher production costs, which include both lease operating costs and gas plant processing costs Lease operating costs were $2 0 million higher for the year ended 30 June 2010 as compared to the prior year, primarily as a result of higher work over costs associated with adverse well performance issues at the Eugene Island field Gas plant processing costs also included a year-on-year increase of $2 0 million, primarily due from the Group's aforementioned annual ownership adjustment in the N Terrebonne gas processing plant and fractionation plant that was effective 1 January 2010

Administrative expenses The Group's administrative costs were $15 2 million for the period ended 30 June 2010, an increase of $3 0 million over the prior year Insurance expenses, which are included within administrative costs, were $6 1 million, an increase of $2 5 million over the prior year

Other losses and gains The Group's other gains and losses were comprised of net gains of $0 8 million for the year ended 30 June 2010, as compared to a net gain of $8 1 million that was principally the result of commodity hedging activity during the prior year During the year ended 30 June 2010, forward commodity prices were substantially higher as compared to the prior year, which in turn resulted in lower unrealised gains pertaining to the fair value of its commodity hedges at period end

Non-cash impairment of oil and natural gas properties The Group did not have any non-cash impairment expense or recovery during the period ended 30 June 2010, as compared to a restated non-cash impairment expense of $25 1 million during the period ended 30 June 2009, which included a non-cash impairment of $23 5 million pertaining to its East Cameron 317/318 field (a non-core and non-operated property for which the Group has a 25% working interest) The East Cameron 317/318 field non-cash impairment was the result of a change in application of accounting policy pertaining to identified cash generating units for impairment testing purposes that was instituted for the period ended 30 June 2010 The Group now tests each field for impairment as an individual cash generating unit, as compared to grouping all fields as a single cash generating unit in prior periods, since such an application provides more relevant information Changing application of this policy required the financial statements for the period ended and as of 30 June 2009 to be restated See Note 30 "Restatement of prior period" within the Group's financial statements included in this report

Loss on sale of assets The Group did not record any gains or losses from the sale of assets during the period ended 30 June 2010 During the prior year, the Group recorded a loss on the sale of assets of $2 5 million pertaining to sale of a 25% working interest in the Group's Eugene Island field

Finance income and finance costs The Group's net finance income and finance costs for the period ended 30 June 2010 of $3 6 million were broadly flat, as compared to $3 8 million for the prior year

During November 2009, the Company issued 400,000,000 new Ordinary Shares at 5 pence par value to raise a net amount of $31 6 million, which was inter-conditional on amending its credit facility After the share placement, the Group paid down its credit facility from $41 0 million to $35 0 million The Group made additional principal payments during the remainder of the year ended 30 June 2010 of $8 5 million, resulting in an overall principal balance of $26 5 million at period end pertaining to its bank credit facility On 30 June 2010, the Group's bank granted a waiver of certain defaults and the interest rate applicable to its credit facility increased 2% effective 15 June 2010 During November 2010, the Company reached an agreement with the Group's bank whereby the Company would make and additional principal payment of $12 0 million on or before 31 March 2011 and the interest rate on its credit facility would increase by 1% effective 15 December 2010 in return for waiving certain conditions of default that may exist at the 31 December 2010 measurement date

Key performance indicators
Leed focuses on four key performance indicators

(1) Growth of hydrocarbon reserves,

(2) Production of oil and natural gas reserves,

(3) Cash flows and earnings growth, and

(4) Material adverse health, safety and environmental events

Oil and natural gas reserves
The Group's oil, natural gas and natural gas liquids reserves, as quantified by an independent reserves auditor, are recapped below

	Independent Reserve Report Date	
2P reserves (mmboe)	1 July 2010	1 July 2009
Proved	**11 5**	11 2
Probable	**9 2**	10 3
	20 7	21 5

Key performance indicators continued

Proved reserves were relatively flat between the above referenced independent reserve reports A recap of the Group's 2P reserves at 1 July 2010 follows

A substantial amount of the Group's oil and natural gas reserves are currently categorised as undeveloped There can be no assurance that the Group will be able to fund the future capital required to fully develop its portfolio of undeveloped oil and natural gas reserves In addition, the economics of developing such reserves are very sensitive to commodity prices As such, future adverse movements in commodity prices could in turn have an adverse impact on the economics of developing the Group's undeveloped oil and natural gas reserves

Oil, natural gas and natural gas liquids production

Details of the Group's net oil and natural gas volumes produced and sold are as follows

Production	Year ended 30 June 2010	Restated Year ended 30 June 2009
Oil (thousands of barrels)	**163**	319
Natural gas (mmcf)	**1,495**	2,171
Natural gas liquids (thousands of gallons)	**1,432**	2,393
Total MBOE	**447**	738

Financial year-on-year production volumes were lower due to the natural production declines of existing wells, sand control issues at the Eugene Island field and the postponement of the Group's drilling program in calendar year 2009 due to the global financial crisis that began in late 2008 During the first half of 2010, the Group re-commenced its drilling programme by drilling the Ship Shoal 201 A-6 well, which began producing during May 2010 at a rate of approximately 1,295 net BOEPD, effectively reversing the trend of declining production experienced in prior months

Cash flows and earnings

The Group measures its cash flow and earnings growth by utilising the metric earnings before interest, taxes, depreciation, depletion, amortisation, exploration costs and impairments ("EBITDAX") EBITDAX for the years ended 30 June 2010 and 2009, respectively, was comprised of the following items

EBITDAX	2010 $000	Restated 2009 $000
Loss before taxation	**(16,914)**	(26,048)
Add back		
Depreciation, depletion and amortisation	**12,294**	18,498
Impairment expense	**—**	25,145
Unsuccessful exploration costs	**11**	16
Net financing and expense, including accretion of decommissioning costs	**3,574**	3,849
Loss on sale of oil and natural gas assets	**—**	2,472
	(1,035)	23,932

During the years ended 30 June 2010 and 2009, the Group's loss before taxation was $16 9 million, a $9 1 million decrease, as compared to a loss of $26 0 million for the prior year (see "Business review") The decrease of $6 2 million in depreciation, depletion and amortisation for the year ended 30 June 2010 over the prior year was principally due to lower year-on-year oil and natural gas production During the year ended 30 June 2010, the Group had no non-cash impairment expense or recovery, as compared to a restated non-cash impairment expense of $25 1 million for the prior year Net financing expense was relatively flat year-on-year The Group did not sell any oil and natural gas assets during the period ended 30 June 2010, while it incurred a $2 5 million loss on the sale of oil and natural gas assets of $2 5 million during the prior year

Health, safety and environmental

During the years ended 30 June 2010 and 2009, the Group did not experience any material adverse health, safety or environmental events

Report of the Directors continued
for the year ended 30 June 2010

Substantial interests
The following shareholders have reported to the Company that they own more than 3% of the issued Ordinary Shares of 5 pence each in the share capital of the Company as at 30 June 2010

Shareholder	Percentage of issued share capital
Asia Special Situations GJP1 Limited	28 65%
Standard Life Investments Ltd	8 51%
Allianz Global Investors Global Equity Business Unit	8 02%
Scottish Widows Investment Partnership Ltd	7 79%
AXA Framlington UK Select Ops	5 03%
F&C Management Ltd	4 36%
GK GOH Holdings	3 46%

Principal risks and uncertainties facing the Group
Going concern
During the past financial year, the Group's financial performance was affected by adverse production performance issues In the Eugene Island field, the Eugene Island 183 A-8 well continued to decline at a steady rate, but not in sufficient quantity to obtain regulatory approval for the recompletion into the more prolific T-1 sand Two other wells in the field, the Eugene Island 183 A-6 and Eugene Island 183 A-7, each failed to produce at anticipated production levels, principally due to sand control issues, and were not producing at period end The Group's Main Pass 64/65 field also experienced significant downtime during the year ended 30 June 2010 due to ongoing pipeline repair issues and was shut in at period end The aforementioned items were the primary contributors to a 31% decrease in year-on-year revenues, resulting in a $1 0 million negative EBITDAX for the 2010 financial year, as compared to positive $23 9 million EBITDAX for the 2009 financial year

The Group's banking facility is subject to financial covenants and other conditions which the Group monitors regularly These covenants and conditions are sensitive to changes in EBITDAX, interest rates, commodity prices, production levels, net assets and estimated oil and natural gas reserves The Group's ability to comply with such covenants and conditions in future periods is a key element in the ability of the Company to continue as a going concern During June 2010, the Group disclosed certain defaults on the credit facility to its bank, UniCredit Bank AG, that were projected to exist at the 30 June 2010 review date The defaults related to EBITDAX ratios pertaining to the period ended 30 June 2010 that were projected to be deficient at period end, principally due to oil and natural gas production performance issues incurred during the aforementioned twelve month period that negatively affected EBITDAX. Following discussions with UniCredit Bank AG, the Group agreed to an interest rate increase of 2% on its credit facility effective 15 June 2010 in exchange for waiving the projected defaults to ensure the Group would be in full compliance with the terms and conditions of its banking facilities at 30 June 2010 During November 2010, the Group reached an agreement with the Group's bank whereby the Group would make an additional principal payment of $12 0 million on or before 31 March 2011 and the interest rate on its credit facility would increase by 1% effective 15 December 2010 in return for waiving certain conditions of default that may exist at the 31 December 2010 measurement date The Group is uncertain of the bank's stance post 31 March 2011 and this could therefore represent a significant risk to the Group

As of the date of this report the Group is exploring several alternatives including divesting some or all of its oil and natural gas assets in order to raise $12 0 million or more in order to pay off some or all of its bank borrowings prior to 31 March 2011 Additional alternatives under consideration include, but are not limited to, securing a new bank credit facility and/or other potential transactions, such as a merger with another company In anticipation of executing one or a combination of the aforementioned alternatives during the 2011 financial year and the accompanying measurement uncertainty thereof, the Company wrote off its net deferred tax balances of $7 2 million during the period ended 30 June 2010

The Directors have prepared cash flow forecasts (including selected sensitivities) for the Company covering a twelve month period from the authorisation of these financial statements The cash flow forecasts reflect the Company's plan for the coming year, including expected net proceeds from divestitures, projected production rates, commodity prices, capital expenditure levels, principal payments, interest rates and expected compliance with loan covenants Based on these assumptions, which the Board believes are reasonable, these cash flow forecasts show that the Group should have sufficient liquidity to continue as a going concern Nevertheless, possible adverse future events or circumstances are beyond the control of the Company and could seriously influence the Company's ability to continue as a going concern Moreover, the regulatory environment in the Gulf of Mexico post the BP oil spill at Macondo is in flux and some regulatory changes under consideration in the US Congress could imperil the Company's business model Clearly, it is impossible to predict the regulatory changes that may come about on account of governmental initiatives

Principal risks and uncertainties facing the Group continued

Going concern continued

Future growth of the Group during the next twelve months and beyond is heavily dependent upon the Group's ability to raise enough capital to continue the development of its undeveloped oil and natural gas reserve portfolio, which represents approximately 78% of its oil and natural gas reserves calculated on a barrels oil equivalent ("BOE") basis at 1 July 2010 The cash flow forecasts assume the Group will be successful in raising sufficient capital to further develop these oil and natural gas reserves

The Directors' assessment of the Group's ability to continue as a going concern involves making a judgement about inherently uncertain future outcomes of events and conditions based upon available information at the time of assessment Subsequent events and additional information may result in outcomes that are inconsistent with judgements that were reasonable at the time they were made The Directors have concluded that the combination of these circumstances represents a material uncertainty that casts significant doubt upon the Group's ability to continue as a going concern and that, therefore, the Group may be unable to realise its assets and discharge its liabilities in the normal course of business Nevertheless, after making enquiries and considering the uncertainties described above, the Directors have a reasonable expectation that the Group has adequate resources to continue in operational existence for the foreseeable future For these reasons, they continue to adopt the going concern basis of accounting in preparing the annual financial statements

Commodity price risks

The Group derives substantially all of its income from the sale of oil, natural gas and natural gas liquids Commodity prices are highly volatile and the Group's income will drop significantly with a material decline in the prices of crude oil, natural gas and/or natural gas liquids The Group has derivative commodity contracts in place to offset to a small degree commodity price declines and the Group could defer capital expenditures if the pricing environment becomes unfavourable However, without a viable drilling programme, the Group will come under financial pressure to reduce its debt and, in such an environment, growth would be difficult to achieve

Technical performance

Finding, developing and producing oil and natural gas is a highly technical endeavour Large sums of capital expenditures must be spent to search for and produce hydrocarbons Drilling disappointments can occur and engineering challenges can result in incurring higher than expected costs Oil and natural gas reserve estimates can misstate the quantity of hydrocarbons in place, resulting in reserve revisions The Group's drilling and production projects are evaluated on rigorous technical standards using state-of-the-art technology and the Group regularly accesses leading industry service providers to advise it on technical issues relating to its operations Estimated oil and natural gas reserves are reviewed and updated twice annually and are audited by an independent reserve auditor at least once each year Such reserve reports are also utilised as a basis to periodically determine the Group's available borrowing base under the terms of its bank credit facility and for impairment testing purposes Due to numerous assumptions, including commodity prices, volumetric decline curves, operating costs, capital expenditures and other factors, actual results could vary materially from estimates contained within the reserve report prepared by the independent reserve auditor

Infrastructure limitations

A well developed oil and natural gas production and transportation infrastructure exists in the onshore and offshore Gulf Coast region of the United States Nevertheless, the Group is dependent on production, transportation and refining facilities owned by third parties to bring its oil, natural gas and natural gas liquid production to market The Group manages these risks through contractual relationships with third parties and to some extent certain risks of loss of access to transportation facilities are mitigated by open access laws Disruption of third party transportation service can arise from a variety of circumstances including weather damage, accidents and obsolescence In the financial year under review, the Company did experience a disruption in its East Cameron field as the sales pipeline owned by a third party was damaged and went out of service following a hurricane during 2008 and did not come back online until December 2009 In addition, the Main Pass field was shut in at period end due to repairs to its third party sales pipeline, which did not come back online until October 2010

Asset concentration risk

The Eugene Island and Ship Shoal assets are the Group's core producing assets and hence its core cash flow source The Group plans to diversify its production base through a combination of future acquisitions and drilling on its assets over time in other areas in future periods In the near future, however, asset concentration risk may increase if the Group drills additional wells in the proximity of its existing infrastructure in order to expedite production and near-term cash flows

Capital development risk

Continued development of the Group's portfolio of oil and natural gas properties with proved and probable reserves will require substantial future outlays of capital If the Group is unable to finance its share of such expenditures from existing cash flows and/or capital resources, the Group will have to raise capital from other sources such as additional debt financing, placement of additional Ordinary Shares in an equity offering, selling all or partial property interests or a combination thereof There can be no assurance that the Group would be able to obtain such financing. In addition, there can be no assurance that existing partners in the Group's projects will be able to carry their pro-rata share of future capital costs, which could in turn lead to delays and other adverse financial issues Further, the Group does not control the timing or scope of future capital projects on the Main Pass 64/65 and East Cameron 317/318 fields, where it holds a minority non-operated 25% working interest

Report of the Directors continued
for the year ended 30 June 2010

Principal risks and uncertainties facing the Group continued

Exposure to casualties and other events

Substantially all of the Group's oil and natural gas assets are located in the shallow waters of the US Gulf of Mexico, where they may be subjected to blow-outs, hurricanes, unstable sea floor conditions, fire and explosion, collision with moving vessels, pipeline and facility outages, terrorist attacks and other casualties Following the blow-out of an exploratory well drilled by BP offshore in the deep water of the Gulf of Mexico in April 2010, BOEMRE issued a six month drilling moratorium in offshore waters in excess of 500 feet BOEMRE in effect cancelled all existing drilling permits regardless of water depth by requiring all permits to include additional information and plans covering safety and environmental concerns As such, the deep water drilling moratorium resulted in a de facto moratorium in shallow federal waters, where the Group has all of its offshore projects Due to the current uncertainty surrounding the issuance of drilling permits, there can be no assurance as to the timing and scope of future drilling operations on the Group's offshore projects Other potential future changes in the political and regulatory environment could also adversely impact the Group's performance

The Group carries insurance on its assets that, when balanced against the cost, it believes is prudent and within industry norms, but this insurance does not protect the Group from all casualty risks By monitoring regulatory and political developments and participating in industry trade groups and forums, the Group reviews legal and regulatory matters that affect its business and revises its operating plans in order to remain in compliance with existing regulations

Changing regulatory environment

The majority of the Group's asset base is located within federal waters offshore in the Gulf of Mexico and is subject to the jurisdiction of BOEMRE, a federal agency within the US Department of the Interior Pursuant to the Oil Pollution Act of 1990, as amended, the US Department of the Interior sets rules for demonstrating financial responsibility in the event of an oil spill The Company currently satisfies its financial responsibility requirement through the use of insurance Should the US Department of the Interior require higher levels of financial responsibility or should the Company be unable to acquire insurance to satisfy such requirements, the Company would likely experience adverse effects

The Company utilises over the counter derivative commodity contracts (see Note 16 "Financial Instruments" in the consolidated financial statements) to hedge against changes in oil and natural gas commodity prices and may be subject to new regulations to be promulgated by the US Commodity Futures Trading Commission under the Dodd–Frank Wall Street Reform and Consumer Protection Act enacted during July 2010, which may in turn adversely affect the Group's commodity price hedging programme and bank credit facility

Surety bonding

BOEMRE regulations require surety bonding for operators in the Gulf of Mexico and for future decommissioning obligations There is a risk the Group may not be able to obtain sufficient bonding and may have to collateralise obligations with cash If the Group was unable to provide such bonds, it would not be able to proceed with its operating plans

Personnel constraints

The market for organisational talent in the US oil and natural gas industry is extremely competitive Since the Group employs only 22 full time employees (at 30 June 2010), the Group would suffer materially if it lost the services of any of its key personnel The Group strives to retain its most precious resource – its people – by offering its employees a pleasant and challenging work environment, significant opportunities for growth and contribution, competitive salaries, and long-term incentive compensation tied to share performance

The Group has contractual relationships with over 500 suppliers and vendors who provide necessary services to the Group's business The market for these services is very competitive and operational inefficiencies can arise because service provider personnel lack deep experience In addition to quality concerns, costs can escalate The Group is selective about whom it hires to provide services and constant monitoring and evaluation of third party services will continue to be a priority

Health, safety and the environment

Health, safety and the environment continues to be a top concern for the Group Exploration and production of oil and natural gas in the Gulf of Mexico presents many health, safety and environmental challenges As a result of the BP Macondo oil spill during April 2010 in the deep water of Gulf of Mexico, BOEMRE regulations covering health, safety and the environment have become more stringent and continue to evolve The Group has policies and procedures in place to protect people and property from harm in areas in which it operates and this will continue to be a management focus area The Group's policy with regards to the environment is to ensure that the Company understands and effectively manages the actual and potential environmental impact of its activities The Group's operations are conducted such that the Company seeks to comply with all legal requirements relating to health, safety and the environment in all areas where the Company carries out its business Over the past year, the Group had no material health, safety or environmental incidents and did not incur any fines or penalties for violating any BOEMRE regulations

Other matters

Financial instruments

The Group's financial instruments include cash balances, trade receivables and payables, bank debt and commodity contracts on oil and natural gas swaps and puts, and interest rate swaps Financial risk management is more fully discussed in Note 4 "Financial risk management" of the financial statements

Employees

Employees' performance is aligned to Group goals through an annual performance review process that is carried out with all employees and through an incentive bonus programme administered by the Board that is tied in part to the Group's performance No performance bonuses were paid to executives or management during the financial year ended 30 June 2010

Dividends

The Company does not have plans to pay dividends at this time

Third party indemnity provisions for Directors

During the year and continuing to date the Company has maintained third party indemnity insurance for its Directors and Officers

Donations

The Company encourages and supports its management and employees in supporting and giving of their time to local charitable and other non-profit organisations The Group made charitable contributions of $6,000 in the year ended 30 June 2010 and $2,000 in the year ended 30 June 2009

Supplier payment policy

It is the Group's payment policy to pay its suppliers in conformance with industry norms Trade payables are paid in a timely manner within contractual terms, which is generally 30 to 45 days from the date an invoice is received

Events since date of statement of financial position

Details of significant post statement of financial position events are set out in Note 31 "Post-statement of financial position events" in the consolidated financial statements

Directors

The Directors of the Company are set out below

Director	Title	Director since	Term expires at Annual General Meeting in
Robert Adair	Non-executive Chairman	July 2007	2012
Robert Alcock	Non-executive Director	July 2007	2012
Stephen Fleming	Non-executive Director	October 2008	2011
Ian Shaun Gibbs	Non-executive Director	December 2006	2011
Peter Hirsch	Non-executive Director	July 2007	2012
James Slatten	Chief Operating Officer and Executive Director	December 2006	2010
Howard Wilson	President, Chief Executive and Executive Director	December 2006	2010

At 30 June 2010 the interest of the Directors in Company shares was

Director holdings	Ordinary Shares of 5 pence	Stock Appreciation Rights ("SARs") vested and unvested	Restricted Stock Units ("RSUs") vested and unvested
Robert Adair	6,127,660	2,510,208	1,255,104
Robert Alcock	503,191	627,552	—
Stephen Fleming	—	—	—
Ian Shaun Gibbs	706,383	627,552	—
Peter Hirsch	130,638	627,552	—
James Slatten	5,296,600	1,255,104	—
Howard Wilson	5,296,600	1,255,104	—

Additional information regarding director compensation is contained in Note 21 "Employees, Directors and auditor remuneration" of the consolidated financial statements within this report

Report of the Directors continued
for the year ended 30 June 2010

Statement of Directors' responsibilities for the financial statements
The Directors are responsible for preparing the annual report and the financial statements in accordance with applicable laws and regulations

Company law requires the Directors to prepare financial statements for each financial year Under that law the Directors have elected to prepare the financial statements in accordance with International Financial Reporting Standards ("IFRS") as adopted by the European Union The financial statements are required by law to give a true and fair view of the state of affairs of the Company and the Group, and of the profit or loss of the Group for that period In preparing these financial statements, the Directors are required to

- select suitable accounting policies and then apply them consistently,
- make judgements and estimates that are reasonable and prudent,
- state whether the financial statements comply with IFRS as adopted by the European Union, and
- prepare the financial statements on the going concern basis unless it is inappropriate to presume that the Group will continue in business (Note 2 20 "Significant accounting policies – going concern")

The Directors are responsible for keeping adequate accounting records which disclose with reasonable accuracy at any time the financial position of the Company and the Group and enable them to ensure that the financial statements comply with the Companies Act 2006 They are also responsible for safeguarding the assets of the Company and the Group and hence for taking reasonable steps for the prevention and detection of fraud and other irregularities

The Directors are responsible for the maintenance and integrity of the corporate and financial information on Leed's website Legislation in the United Kingdom governing the preparation and dissemination of the financial statements and other information included in annual reports may differ from legislation in other jurisdictions

Disclosure of information to auditor
At the date of making this report each of the Company's Directors, who are identified above in this report, confirm the following

- so far as each Director is aware, there is no relevant information needed by the Group's auditor in connection with preparing their report of which the Group's auditor is unaware, and
- each Director has taken all the steps that he ought to have taken as a Director in order to make himself aware of any relevant information needed by the Group's auditor in connection with preparing their report and to establish that the Group's auditor is aware of that information

Auditor
Grant Thornton UK LLP ("Grant Thornton") serves as the Company's and Group's auditor and has expressed a willingness to continue in office In accordance with Section 489(4) of the Companies Act 2006, a resolution to reappoint Grant Thornton as auditor of the Group may be proposed at the Annual General Meeting to be held on 20 December 2010

Approval
The report of the Directors was authorised and approved by the Board and signed on 25 November 2010 on its behalf by

James Slatten

James Slatten
Chief Operating Officer

Report of the independent auditor
to the members of Leed Petroleum PLC (Registered number 06034226)

We have audited the financial statements of Leed Petroleum PLC for the year ended 30 June 2010 which comprise the consolidated statement of comprehensive income, the Group and Parent Company statements of changes in equity, the Group and Parent Company statements of financial position, the Group and Parent Company statement of cash flows and the related notes The financial reporting framework that has been applied in their preparation is applicable law and IFRS as adopted by the European Union and, as regards the Parent Company financial statements, as applied in accordance with the provisions of the Companies Act 2006

This report is made solely to the Company's members, as a body, in accordance with Chapter 3 of Part 16 of the Companies Act 2006 Our audit work has been undertaken so that we might state to the Company s members those matters we are required to state to them in an auditor's report and for no other purpose To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the Company and the Company's members as a body, for our audit work, for this report, or for the opinions we have formed

Respective responsibilities of Directors and auditors
As explained more fully in the Statement of Directors' responsibilities for the financial statements, set out on page 28, the Directors are responsible for the preparation of the financial statements and for being satisfied that they give a true and fair view Our responsibility is to audit the financial statements in accordance with applicable law and International Standards on Auditing (UK and Ireland) Those standards require us to comply with the Auditing Practices Board's ("APB's") Ethical Standards for Auditors

Scope of the audit of the financial statements
The APB's website at www frc org uk/apb/scope/UKNP provides a description of the scope of an audit of financial statements

Opinion on financial statements
In our opinion

- the financial statements give a true and fair view of the state of the Group's and of the Parent Company's affairs as at 30 June 2010 and of the Group's loss for the year then ended,
- the Group financial statements have been properly prepared in accordance with IFRS as adopted by the European Union,
- the Parent Company financial statements have been properly prepared in accordance with IFRS as adopted by the European Union and as applied in accordance with the provisions of the Companies Act 2006, and
- the financial statements have been prepared in accordance with the requirements of the Companies Act 2006

Emphasis of matter – going concern
In forming our opinion, which is not qualified in this respect, we have considered the adequacy of the disclosure made in Note 2 20 "Significant accounting policies – going concern" to the financial statements concerning the Company's ability to continue as a going concern

As explained in Note 2 20, the Directors are seeking to raise additional finance to repay certain borrowings, provide working capital and progress the development of the Group's oil and natural gas assets These conditions, along with other matters explained in Note 2 20 to the financial statements, indicate the existence of a material uncertainty which may cast significant doubt on the Company's ability to continue as a going concern The financial statements do not include the adjustments that would result if the Company was unable to continue as a going concern

Separate opinion in relation to IFRS
As explained in Note 2 1 "Significant accounting policies – basis of preparation" to the Group financial statements, the Group, in addition to complying with its legal obligation to comply with IFRS as adopted by the European Union, has also complied with IFRS as issued by the International Accounting Standards Board (IASB)

In our opinion the Group financial statements comply with IFRS as issued by the IASB

Report of the independent auditor continued
to the members of Leed Petroleum PLC (Registered number 06034226)

Opinion on other matter prescribed by the Companies Act 2006
In our opinion the information given in the Report of the Directors for the financial year for which the financial statements are prepared is consistent with the financial statements

Matters on which we are required to report by exception
We have nothing to report in respect of the following matters where the Companies Act 2006 requires us to report to you if, in our opinion

- adequate accounting records have not been kept by the Parent Company, or returns adequate for our audit have not been received from branches not visited by us, or
- the Parent Company financial statements are not in agreement with the accounting records and returns, or
- certain disclosures of Directors' remuneration specified by law are not made, or
- we have not received all the information and explanations we require for our audit

Grant Thornton UK LLP.

John Corbishley
Senior Statutory Auditor
for and on behalf of Grant Thornton UK LLP
Statutory Auditor, Chartered Accountants
Milton Keynes
25 November 2010

Consolidated statement of comprehensive income
for the year ended 30 June 2010

Group	Note	2010 $000	Restated 2009 $000
Continuing operations			
Revenue	8	**23,228**	33,823
Cost of sales			
Production costs	8	**(10,006)**	(5,982)
Depletion costs	12	**(12,188)**	(18,368)
Gross profit		**1,034**	9,473
Administrative expenses	8	**(15,210)**	(12,152)
Operating loss		**(14,176)**	(2,679)
Other gains	8, 16	**835**	8,097
Impairment expense	5, 8, 11, 12, 30	—	(25,145)
Loss on sale of assets	26	—	(2,472)
Finance income	6	**71**	130
Finance costs	7	**(3,644)**	(3,979)
Loss before taxation		**(16,914)**	(26,048)
Taxation	2 2, 9, 18, 30	**(1,147)**	7,510
Loss for the period from continuing operations and attributable to equity owners		**(18,061)**	(18,538)
Other comprehensive loss			
Unrealised foreign currency loss, net of tax		**(61)**	—
Total comprehensive loss for period, net of tax attributable to equity owners		**(18,122)**	(18,538)
Loss per share (cents)			
Basic	28	**(3 5)**	(6 7)
Diluted	28	**(3 5)**	(6 7)

Leed Petroleum PLC (Company number 06034226)

Statements of changes in equity
for the year ended 30 June 2010

Group	Share capital $000	Share premium $000	Translation reserve $000	Retained earnings $000	Total $000
Total owners' equity at 30 June 2008	24,750	97,237	—	(15,370)	106,617
Transactions with owners					
– Share capital issued by Company	2,428	26,705	—	—	29,133
– Share issue costs	—	(1,061)	—	—	(1,061)
– Share-based payments	—	—	—	2,627	2,627
Total transactions with owners	2,428	25,644	—	2,627	30,699
Other comprehensive loss					
– Loss for the year as originally reported	—	—	—	(3,523)	(3,523)
– Loss for the year attributable to restatement	—	—	—	(15,015)	(15,015)
Total comprehensive loss for the year (restated)	—	—	—	(18,538)	(18,538)
Total owners' equity at 30 June 2009 (restated)	27,178	122,881	—	(31,281)	118,778
Transactions with owners					
– Share capital issued by Company	33,157	—	—	—	33,157
– Share issue costs	—	—	—	(1,542)	(1,542)
– Share-based payments	—	—	—	2,272	2,272
Total transactions with owners	33,157	—	—	730	33,887
Comprehensive loss					
– Loss for the year	—	—	—	(18,061)	(18,061)
– Translation reserve	—	—	(61)	—	(61)
Total comprehensive loss for the year	—	—	(61)	(18,061)	(18,122)
Total owners' equity at 30 June 2010	**60,335**	**122,881**	**(61)**	**(48,612)**	**134,543**

Statements of changes in equity
for the year ended 30 June 2010

Company	Share capital $000	Share premium $000	Translation reserve $000	Other reserve $000	Retained earnings $000	Total $000
Total owners equity at 30 June 2008	24,750	97,237	23	2,731	(2,899)	121,842
Transactions with owners						
– Share capital issued	2,428	26,705	—	—	—	29,133
– Share issue costs	—	(1,061)	—	—	—	(1,061)
– Expiration of equity instrument issued with loan	—	—	—	(560)	—	(560)
– Share-based costs	—	—	—	2,627	—	2,627
Total transactions with owners	2,428	25,644	—	2,067	—	30,139
Other comprehensive loss						
– Translation reserve	—	—	(23)	—	—	(23)
– Loss for the year	—	—	—	—	(2,294)	(2,294)
Total comprehensive loss for the year	—	—	(23)	—	(2,294)	(2,317)
Total owners' equity at 30 June 2009	27,178	122,881	—	4,798	(5,193)	149,664
Transactions with owners						
– Share capital issued	33,157	—	—	—	—	33,157
– Share issue costs	—	—	—	—	(1,542)	(1,542)
– Share-based payments	—	—	—	2,272	—	2,272
– Options terminated during year	—	—	—	(652)	652	—
Total transactions with owners	33,157	—	—	1,620	(890)	33,887
Other comprehensive loss						
– Translation reserve	—	—	(61)	—	—	(61)
– Loss for the year	—	—	—	—	(2,163)	(2,163)
Total comprehensive loss for the year	—	—	(61)	—	(2,163)	(2,224)
Total owners' equity at 30 June 2010	**60,335**	**122,881**	**(61)**	**6,418**	**(8,246)**	**181,327**

Statements of financial position
as at 30 June 2010

		Group			Company		
	Note	2010 $000	Restated 2009 $000	2008 $000	2010 $000	2009 $000	2008 $000
Assets							
Non-current assets							
Investments in subsidiaries	23	—	—	—	**181,033**	148,802	119,842
Goodwill	10	**29,005**	29,005	29,005	—	—	—
Intangible exploration and evaluation assets	11	**2,956**	2,228	5,284	—	—	—
Notes receivable	13	—	—	—	**1,000**	1,000	1,000
Derivative financial instruments	16	**516**	529	—	—	—	—
Deferred tax	2 2, 18, 30	—	1,147	377	—	—	377
Property, plant and equipment	12, 30	**127,030**	123,657	138,563	—	—	—
		159,507	156,566	173,229	**182,033**	149,802	121,219
Current assets							
Trade and other receivables	13	**5,662**	10,718	10,068	**24**	12	170
Derivative financial instruments	16	**1,019**	2,314	—	—	—	—
Cash and cash equivalents	20	**10,812**	4,482	10,317	**255**	269	856
		17,493	17,514	20,385	**279**	281	1,026
Liabilities							
Current liabilities							
Trade and other payables	14	**8,615**	4,421	15,263	**985**	419	403
Other finance obligations	15	**4**	3,264	5	—	—	—
Derivative financial instruments	16	**837**	310	2,849	—	—	—
Current portion of borrowings	15	**1,500**	—	—	—	—	—
		10,956	7,995	18,117	**985**	419	403
Net current assets (liabilities)		**6,537**	9,519	2,268	**(706)**	(138)	623
Non-current liabilities							
Borrowings	15	**25,000**	40,815	52,531	—	—	—
Derivative financial instruments	16	**22**	904	2,980	—	—	—
Decommissioning obligation	17	**6,479**	5,588	6,629	—	—	—
Deferred tax	2 2, 18, 30	—	—	6,740	—	—	—
		31,501	47,307	68,880	—	—	—
Net assets		**134,543**	118,778	106,617	**181,327**	149,664	121,842
Owners' equity							
Ordinary Share Capital	19	**60,335**	27,178	24,750	**60,335**	27,178	24,750
Share premium		**122,881**	122,881	97,237	**122,881**	122,881	97,237
Translation reserve		**(61)**	—	—	**(61)**	—	23
Other reserve		—	—	—	**6,418**	4,798	2,731
Retained earnings		**(48,612)**	(31,281)	(15,370)	**(8,246)**	(5,193)	(2,899)
Total owners' equity		**134,543**	118,778	106,617	**181,327**	149,664	121,842

The financial statements on pages 31 to 66 were authorised and approved by the Board of Directors and were signed on 25 November 2010 on its behalf by

James Slatten

James Slatten
Executive Director
Company number 06034226

Statements of cash flow
for the year ended 30 June 2010

		Group		Company	
	Note	2010 $000	2009 $000	2010 $000	2009 $000
Net cash flows from operating activities	20	**9,366**	17,915	**(393)**	(531)
Cash flows from investing activities					
Capital contribution to subsidiary	23	—	—	**(31,115)**	(28,162)
Purchase of derivative contracts, net of expired positions		**(16)**	(1,035)	—	—
Proceeds from sale of assets		—	15,852	—	—
Purchase of intangible assets		**(728)**	(758)	—	—
Purchase of property, plant and equipment		**(13,113)**	(53,699)	—	—
Interest received (paid)		**71**	130	**(53)**	66
Net cash used in investing activities		**(13,786)**	(39,510)	**(31,168)**	(28,096)
Cash flows from financing activities					
Net proceeds from issue of Ordinary Shares	19	**31,615**	28,072	**31,615**	28,072
Interest and other financing costs paid		**(3,037)**	(3,570)	—	—
Proceeds from other financing obligations		—	4,657	—	—
Principal payments of other financing obligations		**(3,260)**	(1,399)	—	—
Borrowings raised		—	13,000	—	—
Borrowings repaid	15	**(14,500)**	(25,000)	—	—
Net cash from financing activities		**10,818**	15,760	**31,615**	28,072
Net increase (decrease) in cash and cash equivalents		**6,398**	(5,835)	**54**	(555)
Exchange differences in cash and cash equivalents		**(68)**	—	**(68)**	(32)
Cash and cash equivalents at beginning of period		**4,482**	10,317	**269**	856
Cash and cash equivalents at end of period	20	**10,812**	4,482	**255**	269

Notes to the financial statements
for the year ended 30 June 2010

1. General information
Leed Petroleum PLC (LDP LN) is a publicly listed company registered in the United Kingdom The address of its registered office is 110 Cannon Street, London, EC4N 6AR

The Leed Petroleum PLC Group (collectively, "Leed" or the "Group") comprises one operating segment which acquires, explores, develops, produces and operates oil and natural gas properties offshore and onshore of the Gulf Coast region of the United States At 30 June 2010, Leed owned mineral interests in 17 blocks located in federal waters offshore of the Louisiana coastline, one onshore field in Louisiana and a small interest in a gas processing plant and a fractionation plant located onshore in Louisiana

The Company's functional currency is the Pound Sterling. As substantially all of the Group's activity and financial transactions occur in the United States, US Dollars is used as a presentation currency for both the Group and the Parent Company At 30 June 2010 and 2009, the exchange rate of the US Dollar to the Pound Sterling was $0 6635 and $0 6053, respectively Foreign operations are consolidated in accordance with the policies set out in Note 2 11 "Significant accounting policies – foreign currencies" below

2. Significant accounting policies
2.1 Basis of preparation
The Group and Parent Company financial statements have been prepared in accordance with EU adopted IFRS, and International Financial Reporting Interpretations Committee ("IFRIC") interpretations All accounting standards and interpretations issued by the International Accounting Standards Board and the IFRIC effective for the periods covered by these financial statements have been applied

The financial statements for the period ended and as at 30 June 2009 have been restated to reflect the change in the application of an accounting policy related to identification of cash generating units for impairment testing purposes The financial statements as at and for the period ended 30 June 30 2008 were not affected by this restatement In accordance with IAS 1 "Presentation of financial statements", the statement of financial position as at 30 June 2008 is included herein for comparative purposes only (Note 30 "Restatement of prior period")

The Group reports its proportional interests in joint oil and natural gas exploration, development, and production activities A summary of the significant Group accounting policies adopted in the preparation of the financial statements is set out below These policies have been consistently applied to all the periods presented, unless otherwise stated

The preparation of financial statements in conformity with IFRS requires the use of estimates and assumptions and for management to exercise its judgement in the process of applying the Group's accounting policies Critical judgements and key estimates and assumptions are disclosed in Note 3 "Critical accounting judgements and key sources of estimation uncertainty" below The following new standards and amendments to standards are applicable for the financial year commencing 1 July 2009

IAS 1 "Presentation of Financial Statements"
The Group applies revised IAS 1 "Presentation of Financial Statements", which became effective for the Group as of 1 July 2009 As a result, the Group presents in the statement of changes in equity all owner changes in equity, whereas all non-owner changes in equity are presented in the consolidated statement of comprehensive income This presentation has been applied within these financial statements In accordance with IAS 1, the Group has elected to present the combined consolidated statement of income and the statement of comprehensive income Comparative information has been re-presented so that it also is in conformity with the revised standard Since the change in accounting policy only impacts presentation aspects, there is no impact on earnings per share

IFRS 8 "Operating Segments"
IFRS 8 "Operating Segments" replaces IAS 14 "Segment Reporting" The chief operating decision maker has been identified as the Group's Board of Directors The Board of Directors reviews the Group's internal reporting in order to assess performance and allocate resources The information provided to the chief operating decision maker is measured in a manner which is consistent with the financial statements and management has determined the Group has one operating segment, the "exploration and production" segment, based on these reports and other factors The Group's exploration and production segment consists of the acquisition, exploration, development, production and operation of oil and natural gas properties in the Gulf Coast region of the United States and comprises multiple cash generating units ("CGUs") The Group's CGUs within its exploration and production segment are generally classified at the field level, which is based on the physical location of the asset and the independence of cash inflows from other assets within the segment The exploration and production segment derives all of its revenues from external customers (Note 5 "Operating segments")

The adoption of IFRS 8 did not result in changes to the statement of financial position at 30 June 2008 Accordingly, the statement of financial position at 30 June 2008 has not been included in these financial statements

IAS 23 "Borrowing Costs"
The Group early adopted IAS 23 "Borrowing Costs" for the financial year beginning 1 July 2008, which is mandatory for financial years beginning on or after 1 January 2009 In accordance with IAS 23, the Group capitalises borrowing costs that are directly attributable to the acquisition, construction or production of a qualifying asset as part of the cost of that asset (Note 2 16 "Significant accounting policies – borrowing and other finance costs")

2. Significant accounting policies continued
2.1 Basis of preparation continued
Other new accounting standards and interpretations
The Company has reviewed additional new standards and interpretations currently in issue but not effective as of 30 June 2010 and determined that none of these new standards and interpretations will have significant impact on reported results Those new standards and interpretations include IFRS 9 "Financial instruments", IFRS 24 (revised 2009) "related party disclosures", and "Group cash-settled share-based payment transactions – amendment to IFRS 2"

2.2 Basis of consolidation
The consolidated financial statements incorporate the results, assets, liabilities and cash flows of the Company and each of its subsidiaries for the years ended 30 June 2010 and 2009, respectively

Subsidiaries are entities controlled by Leed Petroleum PLC Control is deemed to exist when Leed Petroleum PLC has the power, directly or indirectly, to govern the financial and operating policies of an entity so as to obtain benefits from its activities The results of subsidiaries are included in the consolidated financial statements from the date control commences until the date that control ceases

Where necessary, adjustments are made to the financial statements of subsidiaries to bring the accounting policies used in line with those used by Leed Petroleum PLC

Unless there is an indication of impairment, intra group balances and transactions are eliminated on consolidation

2.3 Business combinations
Merger accounting involving entities under common control is outside the scope of IFRS 3 "Business combinations" In applying IAS 8 "Accounting Policies, Changes in Accounting Estimates and Errors," to determine an appropriate accounting policy, the Group follows UK GAAP for business combinations The purchase method is applied to other combinations under the scope of IFRS 3 None of the aforementioned items are relevant to these financial statements

2 4 Goodwill
Goodwill on acquisition of subsidiaries represents the excess of the cost of an acquisition over the fair value of the Group's share of the identifiable net assets of the acquired subsidiary Goodwill is not amortised, but tested at least annually for impairment, and carried at cost less accumulated impairment losses (Note 2 17 "Significant accounting policies – impairment of property, plant and equipment and intangible assets")

2 5 Oil and natural gas assets
The Group follows the successful efforts method of accounting for its oil and natural gas properties The Group's interests in oil and natural gas exploration and production joint ventures are proportionately consolidated

Exploration and evaluation ("E&E") assets
E&E assets comprise the cost of rights to extract minerals ("leases") for fields with no known proven oil and/or natural gas reserves and are held at cost unless impaired Each E&E asset is reviewed on an annual basis to confirm that drilling activity is planned and that it is not impaired Geological and geophysical costs pertaining to E&E assets are expensed as incurred Other direct costs related to the pursuit of an E&E asset are capitalised If, through geological and geophysical studies, proven commercial reserves are discovered, the cost of the E&E asset is transferred to property, plant and equipment Otherwise, such costs are expensed in the period it is ascertained that there are no commercial reserves Initial terms for offshore leases in the federal waters of the Gulf of Mexico are five years, but are indefinite if there is production occurring in commercial quantities Initial terms for leases onshore usually range from three to five years and, in some cases, include optional lease extensions from one to five years Onshore leases or unitised portions of onshore leases also continue indefinitely with production in commercial quantities Other direct costs related to the pursuit of a potential lease are capitalised as part of the cost of the E&E asset Once it is decided a lease will not or cannot be obtained, such pursuit costs are expensed

The costs that are directly associated with an exploration well are capitalised as an intangible asset until the drilling of the well is complete and the results have been evaluated These costs include the use of materials and fuel, directly related employee remuneration, rig costs and payments made to contractors As discussed above and in Note 2 16 "Significant accounting policies – borrowing and other finance costs", as of 1 July 2008 the Group commenced the capitalisation of borrowing costs related to its construction and drilling projects If it is found that hydrocarbons are not present, the exploration expenditure is written off If hydrocarbons are discovered and are likely to be capable of commercial development, subject to further appraisal activity, which may include the drilling of further wells (exploration or exploratory type test wells), the costs continue to be carried as an asset All such carried costs are subject to technical, commercial and management review at least once a year to confirm the continued intent to develop or otherwise extract value from the well If it is found that value can no longer be extracted, the costs are written off When proved reserves of oil and natural gas are determined and development is sanctioned, the relevant expenditure is transferred to property, plant and equipment

Development expenditures
Expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells, including unsuccessful development or delineation wells, is capitalised within property, plant and equipment With the early adoption of IAS 23 "Borrowing Costs (revised 2007)" as of July 2008, borrowing costs attributable to development expenditure are included with the amount capitalised

Notes to the financial statements continued
for the year ended 30 June 2010

2. Significant accounting policies continued

2 6 Amortisation and depletion of tangible oil/gas assets

The Group depletes the costs of its oil and natural gas assets on a field by field basis using the unit of production method Assets arising from the recording of a decommissioning obligation are amortised as described in Note 2 9 "Significant accounting policies – decommissioning obligation"

2.7 Property, plant and equipment – other non-oil/gas assets

Property, plant and equipment are stated at cost less accumulated depreciation and any impairment losses Cost comprises the purchase price of property, plant and equipment together with any directly attributable costs Subsequent costs are included in an asset's carrying value or recognised as a separate asset, when it is probable that future economic benefits associated with the item will flow to the Group and the cost of the item can be measured reliably All other costs are charged to profit and loss when incurred

Depreciation commences when an asset is available for use and is charged so as to write off the depreciable amount of assets other than land to their residual values, over their estimated useful lives, using a method that reflects the pattern in which the assets' future economic benefits are expected to be consumed by the Group

Depreciation is charged in equal annual instalments as follows

Leasehold improvements	over the term of the lease
Office equipment	3–5 years
Fixtures and fittings	Up to 7 years

Methods of depreciation, residual values and useful lives are reviewed and adjusted, if appropriate, at each statement of financial position date Assets held under finance leases are depreciated over the shorter of their expected useful lives or the term of the relevant lease, when there is no reasonable certainty that title will be obtained at the end of the lease term The gain or loss arising from the disposal or retirement of an item of property, plant and equipment is determined as the difference between the net disposal proceeds and the carrying amount of the item, and is included in profit and loss

2 8 Taxation

The tax expense represents the sum of tax currently payable and deferred tax

Current tax

Tax currently payable is based on taxable profit for the year and is calculated using tax rates enacted or substantively enacted at the statement of financial position date Taxable profit differs from accounting profit either because items are taxable or deductible in periods different to those in which they are recognised in the accounts or because they are never taxable or deductible

Deferred tax

Deferred tax on temporary differences at the statement of financial position date between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes is accounted for using the balance sheet liability method, which assumes that such amounts will be expended or recovered in future periods (Note 18 "Deferred tax")

Using the balance sheet liability method, deferred tax liabilities are recognised in full for all taxable temporary differences, and deferred tax assets are recognised to the extent that it is probable that taxable profits will be available against which deductible temporary differences can be utilised Deferred tax assets for share-based payments are re-calculated at each statement of financial position date based on the closing price of the Company's share price However, if the deferred tax asset or liability arises from the initial recognition of goodwill or the initial recognition of an asset or liability in a transaction other than a business combination that at the time of the transaction affects neither accounting nor taxable profit, it is not recognised.

Deferred taxation is measured at the tax rates that are expected to apply when the asset is realised or the liability settled based on tax rates and laws enacted or substantively enacted at the statement of financial position date No provision is made for deferred tax on the unremitted earnings of foreign subsidiaries because such remittances are not probable as the Group's policy is to reinvest profits to fund growth in the US Deferred tax assets and liabilities are offset only when there is a legally enforceable right to set off current tax amounts and when they relate to the same tax authority and the Group intends to settle its current tax amounts on a net basis Current and deferred tax are recognised in profit and loss except when they relate to items recognised directly in equity, when they are similarly taken to equity

2.9 Decommissioning obligation

The Group recognises the present value of decommissioning obligations in the financial statements in the period in which the obligation arises Upon initial recognition of the liability, an asset retirement cost is capitalised by increasing the carrying amount of the long lived asset by the same amount as the liability In periods subsequent to initial measurement, the capitalised asset retirement cost is allocated to depreciation/ amortisation expense using the straight line basis over the asset's useful life Changes in the liability for decommissions are recognised for the passage of time by charges to accretion expense and classified as finance costs in profit and loss Annually, the Group reassesses the liability in accordance with IFRIC 1 "Changes in Existing Decommissioning, Restoration and Similar Liabilities", the cost of the applicable asset to which the liability relates is offset by the amount of the adjustment to the liability If the obligation is ultimately settled for other than the carrying amount, then a gain or loss is recognised upon settlement

2. Significant accounting policies continued

2.10 Revenue

Revenue is measured at the fair value of the consideration received or receivable and represents the amounts receivable for goods provided in the normal course of business, net of all related discounts and sales tax Revenue from the Group's crude oil, natural gas and natural gas liquids production is recognised on the date sold, which coincides with physical delivery The Group follows the net method of accounting for royalties, the royalty owner's share of sales or production does not appear in profit loss Gas processing fees are recognised on the date the physical gas processing occurs

2 11 Foreign currencies

Transactions in foreign currencies are translated at the exchange rate ruling at the date of each transaction Foreign currency monetary assets and liabilities are retranslated using the exchange rates at the statement of financial position date Gains and losses arising from changes in exchange rates after the date of the transaction are recognised in profit and loss Non-monetary assets and liabilities that are measured in terms of historical cost in a foreign currency are translated at the exchange rate at the date of the original transaction

In the Group and Company financial statements, the net assets of the Company are translated into its presentation currency at the rate of exchange at the statement of financial position date Income and expense items are translated at the date of the transaction The resulting exchange differences are recognised in equity and included in translation reserve

2.12 Finance leases

Leases are classified as finance leases where the terms of the lease transfer substantially all the risks and rewards of ownership to the Group All other leases are classified as operating leases

Property, plant and equipment held under finance leases are recognised as assets in the statement of financial position at their fair values or, if lower, at the present value of the minimum lease payments, both determined at the inception of the lease The corresponding obligation is recorded as amounts payable under finance leases The interest element of leasing payments represents a constant proportion of the capital balance outstanding and is charged to profit and loss over the period of the lease

2.13 Operating leases

The costs of all operating leases are charged against operating profit on a straight line basis at existing rental levels Incentives to sign operating leases are recognised in profit and loss in equal instalments over the term of the lease

2.14 Financial instruments

The Group classifies its financial instrument assets, or their component parts, on initial recognition into two categories a financial asset at fair value through profit or loss, or loans and receivables Financial instrument liabilities are classified as either a financial liability at fair value through profit or loss, or as another financial liability Financial assets and financial liabilities are recognised on the Group's statement of financial position when the Group becomes party to the contractual provisions of the instrument The particular recognition and measurement methods adopted for trade and other receivables, bank and cash, trade and other payables, borrowings and derivatives are disclosed below

Cash and cash equivalents

Cash and cash equivalents include cash in hand and cash at bank, these financial instruments are classified with loans and receivables

Trade and other receivables

Trade and other receivables are measured initially at fair value and subsequently at amortised cost using the effective interest rate method These financial instruments are categorised with loans and receivables The receivables do not carry interest, the carrying value of the receivables, as presented, is reduced by appropriate allowances for estimated irrecoverable amounts A provision for impairment of trade receivables is established when there is evidence that the Group will not be able to collect all amounts due according to the original terms of these receivables The amount of the provision is the difference between the carrying value and the present value of estimated future cash flows, discounted using the effective interest rate method Impairment losses are recognised in profit and loss

Trade and other payables

Trade and other payables are measured initially at fair value and subsequently at amortised cost using the effective interest rate method These financial instruments are categorised with other financial liabilities

Borrowings and other finance obligations

Borrowings and other finance obligations are recognised initially at the fair value of proceeds received, net of transaction costs Subsequent measurement is at amortised cost using the effective interest rate method (Borrowing and other finance costs are discussed at Note 2 16 "Significant accounting policies – borrowing and other financing costs" on page 40) These financial instruments are categorised with other financial liabilities

Borrowings and other finance obligations are classified as current liabilities unless the Group has an unconditional right to defer settlement of the liability for at least twelve months after the statement of financial position date

Notes to the financial statements continued
for the year ended 30 June 2010

2. Significant accounting policies continued
2.14 Financial instruments continued
Derivative contracts
The Company's derivative contracts consist of commodity contracts and interest rate swaps, which are carried at fair value Changes in the fair value of such contracts are recognised in profit and loss as they arise The Company has elected to not to qualify for hedge accounting treatment

Equity instruments
An equity instrument is any contract that evidences a residual interest in the assets of the Group after deducting all its liabilities Equity instruments issued by the Company are recorded at the amount of proceeds received, net of direct issue costs

Fair value determination
The Group establishes fair value by utilising valuation techniques, including the use of information from recent arm's length market transactions between knowledgeable willing parties, if available, reference to the current fair value of similar instruments, and discounted cash flow analysis The valuation technique used incorporates factors that market participants would consider in setting a price and is consistent with accepted economic methodologies for pricing financial instruments

Embedded derivative
The fair value of an option granted to a provider of finance has been determined based on the difference between the rate of (higher) interest charged by the bank on those loans with and without the option attached The additional interest that would have been charged is charged to finance cost in profit and loss, with the offset being a credit to equity

2 15 Dividends
Final dividends are recognised as a liability in the period in which they are approved by the Company's shareholders Interim dividends are recognised when they are paid

2 16 Borrowing and other finance costs
Borrowing and finance charges, including any premiums payable on settlement or redemption and direct issue costs, are generally recognised in profit and loss as incurred Commencing 1 July 2008 with the early adoption of IAS 23 (revised 2007), borrowing costs incurred during the construction period and attributable to constructed assets are capitalised as a part of the asset The transitional provisions of IAS 23 (revised 2007) allow capitalisation of interest only on projects that commenced in the period the standard is adopted The Company early adopted IAS 23 and capitalised $21,000 and $119,000 for the periods ended 30 June 2010 and 2009, respectively The average borrowing rate was 4 6% for the period ended 30 June 2010 and 4 9% for the period ended 30 June 2009

2.17 Impairment of property, plant and equipment and intangible assets
At each statement of financial position date, the Group assesses whether there is any indication that its property, plant and equipment and intangible assets have been impaired

Exploration and evaluation assets
Impairment testing for the Group's E&E assets are conducted on an asset-by-asset level on an annual basis or when circumstances arise which indicate that the carrying value of an E&E asset may be impaired E&E assets are also tested for impairment when reclassified to property, plant and equipment If any such indication exists, the recoverable amount of the asset is estimated in order to determine the extent of the impairment, if any

Field cash generating units
Development costs pertaining to the Group's oil and natural gas assets classified as property, plant and equipment are grouped by individual CGUs ("Field CGUs") for impairment testing purposes At 30 June 2010, each Field CGU was comprised of a grouping of wells within a distinct geographical location which contain proven and probable oil and natural gas reserves, but no interconnected cash inflows with other fields In the prior annual report for the year ended 30 June 2009, the Group classified all of its oil and natural gas wells with proven and probable reserves as one operating segment and one CGU The change in application of the policy year-on-year was a result of re-examining the assets within the Group's exploration and production operating segment and determining that components (multiple CGUs) with separately identifiable cash inflows existed Since the change in application of policy provides more relevant information which is also reliable, the change was adopted (Note 30 "Restatement of prior period")

The recoverable amount of a Field CGU is the higher of its fair value less costs to sell or its value in use The value in use is the present value of the future cash flows expected to be derived from the Field CGU This present value is discounted using a pre-tax rate that reflects current market assessments of the time value of money and of the risks specific to the asset, for which future cash flow estimates have not been adjusted If the recoverable amount of the Field CGU is less than its carrying amount, the carrying amount of the Field CGU is reduced to its recoverable amount and an impairment loss is recognised If an impairment loss subsequently reverses because of changing circumstances, the carrying amount of the Field CGU is increased to the revised estimate of its recoverable amount, but limited to the carrying amount that would have been determined had no impairment loss been recognised in prior years A reversal of an impairment loss is recognised in profit and loss

2. Significant accounting policies continued

2.17 Impairment of property, plant and equipment and intangible assets continued

Goodwill

Goodwill is tested for impairment at the operating segment level at least annually and whenever there is an indication the asset may be impaired Impairment losses on goodwill are not subsequently reversed in accordance with IFRS

2 18 Share-based payments

The Group has issued Stock Appreciation Rights ("SARs") and Restricted Stock Units ("RSUs") of the Company's stock as additional compensation to its Directors, executives, management and other employees with the offset being a share-based cost credit to equity The Company has the choice of settling these amounts with cash or by issuing stock The share-based payments are accounted for as equity settled share-based payments as it is expected the amounts will be settled by the issuance of Company stock Equity settled share-based payments are measured at fair value at the date of grant as determined by an independent appraiser with assumptions that the Directors consider as reasonable The fair value is expensed on a straight line basis over the vesting period, which is based on the Group's estimate of shares that will eventually vest and adjusted for the effect of non-market based vesting conditions

2.19 Reserves of equity

The Group and Company's reserves of equity include a translation reserve The translation reserve is the offsetting account for the adjustment of the Company's accounts from its functional currency (the Pound Sterling) to the presentation currency (the US Dollar) In addition to the foregoing, the Company's reserves of equity also include an other reserve The other reserve is the offsetting account for share-based payments

2.20 Going concern

The Group's business activities, together with factors likely to affect its future developments, performance and financial position are set out in the Chairman's statement on page 2 and the Report of the Director's on page 21 Financial risks to the Company are set out in Note 4 "Financial Risk Management"

During the past financial year, the Group's financial performance was affected by adverse production performance issues In the Eugene Island field, the Eugene Island 183 A-8 well continued to decline at a steady rate, but not in sufficient quantity to obtain regulatory approval for the recompletion into the more prolific T-1 sand Two other wells in the field, the Eugene Island 183 A-6 and Eugene Island 183 A-7, each failed to produce at anticipated production levels, principally due to sand control issues, and were not producing at period end The Group's Main Pass 64/65 field also experienced significant downtime during the year ended 30 June 2010 due to ongoing pipeline repair issues and was shut in at period end The aforementioned items were the primary contributors to a 31% decrease in year-on-year revenues, resulting in a $1 0 million negative earnings before interest, taxes, depreciation, depletion, amortisation, exploration costs and impairments ("EBITDAX") for the 2010 financial year, as compared to positive $23 9 million EBITDAX for the 2009 financial year

The Group's banking facility is subject to financial covenants and other conditions which the Group monitors regularly These covenants and conditions are sensitive to changes in EBITDAX, interest rates, commodity prices, production levels, net assets and estimated oil and natural gas reserves The Group's ability to comply with such covenants and conditions in future periods is a key element in the ability of the Group to continue as a going concern During June 2010, the Group disclosed certain defaults on the credit facility to its bank, UniCredit Bank AG, that were projected to exist at the 30 June 2010 review date The defaults related to EBITDAX ratios pertaining to the period ended 30 June 2010 that were projected to be deficient at period end, principally due to oil and natural gas production performance issues incurred during the aforementioned twelve month period that negatively affected EBITDAX Following discussions with UniCredit Bank AG, the Group agreed to an interest rate increase of 2% on its credit facility effective 15 June 2010 in exchange for waiving the projected defaults to ensure the Group would be in full compliance with the terms and conditions of its banking facilities at 30 June 2010 Since the default provisions are reviewed every six months and are based on actual results from the prior twelve month period, the Group expects to seek a similar waiver at the next measurement date, which is 31 December 2010 During November 2010, the Group reached an agreement with the Group's bank whereby the Group would make an additional principal payment of $12 0 million on or before 31 March 2011 and the interest rate on its credit facility would increase by 1% effective 15 December 2010 in return for waiving certain conditions of default that may exist at the 31 December 2010 measurement date

As of the date of this report the Group is exploring several alternatives including divesting some or all of its oil and natural gas assets in order to raise $12 0 million or more in order to pay off some or all of its bank borrowings prior to 31 March 2011 Additional alternatives under consideration include, but are not limited to, securing a new bank credit facility and/or other potential transactions, such as a merger with another company In anticipation of executing one or a combination of the aforementioned alternatives during the 2011 financial year and the accompanying measurement uncertainty thereof, the Company wrote off its period end net deferred tax balances of $7 2 million for the period ended 30 June 2010 (Note 18 "Deferred tax") The Group is uncertain of the bank's stance post 31 March 2011 and this could therefore represent a significant risk to the Group

Notes to the financial statements continued

for the year ended 30 June 2010

2. Significant accounting policies continued

2 20 Going concern continued

The Directors have prepared cash flow forecasts (including selected sensitivities) for the Company covering a twelve month period from the authorisation of these financial statements The cash flow forecasts reflect the Company's plan for the coming year, including expected net proceeds from divestitures, projected production rates, commodity prices, capital expenditure levels, principal payments, interest rates and expected compliance with loan covenants Based on these assumptions, which the Board believes are reasonable, these cash flow forecasts show that the Group should have sufficient liquidity to continue as a going concern Nevertheless, possible adverse future events or circumstances are beyond the control of the Company and could seriously influence the Company's ability to continue as a going concern Moreover, the regulatory environment in the Gulf of Mexico post the BP oil spill at Macondo is in flux and some regulatory changes under consideration in the US Congress could imperil the Company's business model Clearly, it is impossible to predict the regulatory changes that may come about on account of governmental initiatives

Future growth of the Group during the next twelve months and beyond is heavily dependent upon the Group's ability to raise enough capital to continue the development of its undeveloped oil and natural gas reserve portfolio, which represents approximately 78% of its oil and natural gas reserves calculated on a barrels of oil equivalent ("BOE") basis at 1 July 2010 The cash flow forecasts assume the Group will be successful in raising sufficient capital to further develop these oil and natural gas reserves

The Directors' assessment of the Group's ability to continue as a going concern involves making a judgement about inherently uncertain future outcomes of events and conditions based upon available information at the time of assessment Subsequent events and additional information may result in outcomes that are inconsistent with judgements that were reasonable at the time they were made The Directors have concluded that the combination of these circumstances represents a material uncertainty that casts significant doubt upon the Group's ability to continue as a going concern and that, therefore, the Group may be unable to realise its assets and discharge its liabilities in the normal course of business Nevertheless, after making enquiries and considering the uncertainties described above, the Directors have a reasonable expectation that the Group has adequate resources to continue in operational existence for the foreseeable future For these reasons, they continue to adopt the going concern basis of accounting in preparing the annual financial statements

3. Critical accounting judgements and key sources of estimation uncertainty

Key assumptions concerning the future and other key sources of estimation uncertainty that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities are as follows

3 1 Estimated oil and natural gas reserves

At least annually the Group obtains an independent audit of its oil and natural gas reserves The total amount of oil and natural gas reserves is a critical estimate for the purpose of determining the carrying value of oil and natural gas assets, the depletion rate utilising the unit of production method, estimated future production rates, net present value of future cash flows utilised for impairment testing purposes and credit available under the Company s bank credit facility Due to numerous assumptions, including commodity prices, volumetric decline curves, operating costs capital expenditures and other factors, actual results could vary materially from estimates contained within the reserve report prepared by the independent reserve auditor

3.2 Fair value of oil and natural gas derivatives

The Group obtains valuations of its oil and natural gas commodity contracts from the counterparties to the contracts The Group then reviews those valuations for reasonableness using published market information for similar contracts and the expertise of an independent consultant The value of the derivatives is a critical estimate in determining the financial position of the Group (Note 16 "Financial instruments")

3.3 Intangible assets acquired in a business combination

Intangible assets acquired in a business combination, including leases and exploration assets, are recognised when they are identifiable or arise from contractual or other legal rights and their fair value can be reliably measured Fair value is estimated using risk adjusted future cash flows Significant assumptions are made in estimating future cash flows about future events, including future market conditions and future growth rates Changes in these assumptions could affect fair values

3.4 Decommissioning obligation

Provisions for asset retirement obligations are recognised when management is satisfied that an outflow of economic benefits is probable and a reliable estimate can be made of the obligation and when a present obligation exists The Group obtains an independent fair market valuation of the obligation at the time an affected asset is placed in service The carrying amount of the asset that has such a retirement obligation and the liability related to the future obligation to decommission the asset, and the resulting expense from the amortisation of the added cost of the asset and accretion of the liability are significant estimates in the Group's accounts

3. Critical accounting judgements and key sources of estimation uncertainty continued

3.5 Treatment of overriding royalty interests (ORRIs)

Overriding royalty interests ("ORRIs") may be granted to third parties An ORRI is an immovable property right (akin to a real right in a common law jurisdiction) As an immovable property right, an ORRI has the same legal standing as does a working interest in a mineral lease or an interest in land

Scouting Agreement with Byron Energy Pty, Ltd ("Byron")

In December 2005, the Group granted Byron a contractual right to receive ORRIs of 2% in certain properties in exchange for scouting services Under terms of the agreement (the "scouting agreement"), Byron was to be granted a 2% ORRI relative to the Group's ownership interest at the time when the Group acquired its working interests in each relevant property under terms of the scouting agreement Byron had earned the right to receive these ORRIs by virtue of the scouting services which they had performed The Group considers that Byron holds a 2% ORRI interest in the property, with the remaining 98% share, less other royalty interests, representing the asset of the Group The scouting agreement provides that Byron will receive each ORRI prior to the commencement of production Once these properties reach production, any cash received by the Group in relation to Byron's ORRIs will not be regarded as revenue, as the Group reports only its proportional interests in its oil and natural gas exploration, development, and production activities The Group would recognise a financial liability for any funds received on behalf of Byron, and that liability would then be extinguished on a short-term basis by remitting the funds to Byron Payments which may be made in the future in respect of future production would not be considered to be a financial liability Under further terms of the scouting agreement, the Group also granted a written option to Byron which gives Byron the option to purchase up to 25% of the Group's working interest in certain fields The exercise of this option would involve Byron paying a pro-rata exercise price equivalent to the Group's original purchase price plus all subsequent costs incurred with respect to the property, together with the relinquishment of the 2% ORRI to the Group The exercise date commences upon notice from the Group that it is preparing to spud a well and expires on the earlier of 30 business days or the day before the expected spud date The option represents a financial liability In the opinion of the Directors, the fair value of this financial liability is not significant to the financial statements (Note 26 "Related party transactions")

4. Financial risk management

The Group's business activities expose it to a variety of financial risks that include oil and natural gas price risk, liquidity risk, interest rate risk, credit risk and currency risk

4.1 Liquidity risk

Liquidity risk is the risk arising from the Group not being able to meet its obligations The Group manages its liquidity needs by monitoring scheduled debt servicing payments for its borrowings as well as forecast cash flows and inflows due in day-to-day business The Group's objective is to maintain cash and cash equivalents to meet its liquidity requirements for a minimum of 30 days

The Group finances its operations through a combination of bank borrowings, finance leases and cash generated from operations Besides operations, the Group's principal source of funding is bank borrowings secured by property assets Liquidity is maintained through committed bank credit facilities (Note 15 "Borrowings")

The Group currently satisfies its financial responsibility requirements under the Oil Pollution Act of 1990, as amended, through the use of insurance As a result of the BP oil spill at its Macondo prospect in the deep water of the Gulf of Mexico, legislative initiatives are currently under consideration that may increase the level of responsibility the Group would be required to demonstrate If such legislative initiatives are enacted, the Company would likely experience adverse effects

There is a risk the Group may not be able to obtain future surety bonding as required by the Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE") for Gulf of Mexico operators and lessees (related to future decommissioning obligations) In the event the Company's operating subsidiary does not qualify for future surety bonding, it may have to post cash collateral before obtaining BOEMRE approval of future operations

There is a risk that the Group may be called upon by the surety provider which has issued surety bonds related to expected future decommissioning activities to the US Department of the Interior to collateralise previously issued surety bonds pursuant to the agreement of indemnity between the parties

Notes to the financial statements continued
for the year ended 30 June 2010

4 Financial risk management continued
4 1 Liquidity risk continued
A summary of the Group's maturities for its liabilities (excluding derivative financial instruments, decommissioning obligations and deferred taxes) follows

	Group			
Maturities	Current within six months $000	Current six to twelve months $000	Non current one to five years $000	Non-current over five years $000
30 June 2010				
Borrowings	**500**	**1,000**	**25,000**	—
Trade and other payables	**8,615**	—	—	—
Other finance obligations	**4**	—	—	—
	9,119	**1,000**	**25,000**	—
30 June 2009				
Borrowings	—	—	40,815	—
Trade and other payables	4,421	—	—	—
Other finance obligations	2,614	650	—	—
	7,035	650	40,815	—

4.2 Price risk
Volatility of oil and natural gas prices can have considerable impact on the Group's results To mitigate such risks, the Group regularly enters into oil and natural gas commodity derivative contracts Currently, the Group has a number of such contracts in place as a part of the credit facility with its primary banker (Note 16 "Financial instruments")

4.3 Credit risk
Currently, the Company receives payment from five entities for most of its revenue The revenue is derived from the Company's pro-rata share of the production of oil, natural gas, and natural gas liquids from its producing properties and from gas plant processing fees pertaining to a gas plant where the Company holds a minority interest The Gulf Coast area of the United States has an extensive, well maintained infrastructure and market for producers with many potential buyers (Note 13 "Trade and other receivables")

4.4 Currency risk
The Company is exposed to currency risk with the Pound Sterling relative to maintaining the Company's United Kingdom domicile That cost is a minimal portion of the Company's overall operations and as such it is not material Accordingly, the Group does not hedge this risk

4.5 Interest rate risk
The Company is exposed to a cash flow interest rate risk on bank borrowings, which are arranged at floating rates As part of the credit facility with its primary banker, the Group uses interest rate swaps to hedge a portion of its exposure to interest rate fluctuations (Note 16 "Financial instruments")

4.6 Capital maintenance
The Board of Directors' policy with regards to capital maintenance includes an objective to maintain a strong capital base consisting of appropriate borrowings that comply with its credit facility in order to maintain investor and creditor confidence and sustain future development of the business The Group endeavours to maintain a capital structure that will maximise shareholder value while employing only a level of debt that the Board of Directors considers prudent for an oil and natural gas company of the Group's size and on terms that the Board of Directors believes to be reasonable after taking into account the Group's capital needs and considering other alternatives The Board of Directors directs and monitors the allocation of cash resources against projects to maximise the return on asset value within the Group Day-to-day working capital requirements and medium-term funding requirements are managed through use of internally generated funds and the Group's bank facility Periodically, the Board of Directors will consider raising additional equity when the Group has access to opportunities, which in the opinion of the Board of Directors will increase shareholder value if acted upon The Board of Directors also determines the timing and level of dividends to Ordinary Shareholders with the objective of maximising shareholder value

4 7 Treasury management
Daily reports are generated showing the volumes of oil and natural gas produced This information, combined with published market prices, becomes the basis for estimating the revenues included in a monthly cash flow report circulated for use by management and the Board Additionally, a schedule of the expected receipts and disbursements by category expected in the next eight to twelve weeks is maintained for managing cash flows The Group also prepares a formal budget for adoption by the Board on an annual basis

As a part of the credit facility with its principal bank (Note 15 "Borrowings"), the Group has an independent audit of its oil and natural gas reserves done on a periodic basis (at least annually) This audit provides an unbiased third party estimate of the expected future cash flows from the proved, probable and possible reserves, using certain expected future commodity prices, oil and natural gas production rates and other related cost assumptions

4. Financial risk management continued

4.8 Fair value estimation

The fair values of cash and cash equivalents, receivables, payables and borrowings with a maturity of less than one year are assumed to approximate their book values The fair value of forward contracts (oil and natural gas hedges and interest rate swaps) has been determined based on market forward rates at the statement of financial position date (Note 16 "Financial instruments") The Group's borrowings due in more than one year bear interest at prevailing market rates and their fair values are assumed to approximate their book values

5. Operating segments

The chief operating decision maker has been identified as the Group's Board of Directors The Board of Directors reviews the Group's internal reporting in order to assess performance and allocate resources The information provided to the chief operating decision maker is measured in a manner which is consistent with the financial statements and management has determined the Group has one operating segment (exploration and production) based on these reports and other factors The exploration and production segment consists of the acquisition, exploration, development, production and operation of oil and natural gas properties in the Gulf Coast region of the United States The exploration and production segment derives all of its revenues from external customers External customers exceeding 10% of total revenues during the period ended 30 June 2010 included two oil purchasers ($11 5 million), two gas purchasers ($6 9 million) and the operator of the natural gas liquids processing plant ($2 7 million)

Results of operations by segment

	Note	Exploration and production $000	Consolidated total $000
Year ended 30 June 2010			
Revenues	8	**23,228**	**23,228**
Operating expenses	8	**(10,006)**	**(10,006)**
Depreciation and amortisation		**(12,188)**	**(12,188)**
Operating profit		**1,034**	**1,034**
Administrative expenses	8		**(15,210)**
Other losses and gains	8		**835**
Finance income	6		**71**
Finance costs	7		**(3,644)**
Loss before taxation			**(16,914)**
Restated year ended 30 June 2009			
Revenues	8	33,823	33,823
Operating expenses	8	(5,982)	(5,982)
Depreciation and amortisation		(18,368)	(18,368)
Operating profit		9,473	9,473
Administrative expenses	8		(12,152)
Other losses and gains	8		8,097
Impairment expense	11, 12, 30	(25,145)	(25,145)
Finance income	6		130
Finance costs	7		(3,979)
Loss on sale of assets		(2,472)	(2,472)
Loss before taxation			(26,048)

Total assets by segment

	30 June 2010 $000	Restated 30 June 2009 $000
Exploration and production	**158,877**	154,678
Unallocated assets	**18,123**	19,402
	177,000	174,080

Notes to the financial statements continued
for the year ended 30 June 2010

6 Finance income
The Company's interest income on bank and other deposits during the years ended 30 June 2010 and 2009, respectively, were as follows

Finance income

	Group 2010 $000	Group 2009 $000
Interest income on bank and other deposits	**71**	130

7. Finance costs
The Company's finance costs during the years ended 30 June 2010 and 2009, respectively, were as follows

Finance costs

	Group 2010 $000	Group 2009 $000
Interest payable on borrowings and other finance obligations	**1,920**	2,454
Other financing costs, including charges on undrawn credit facilities	**1,537**	1,342
Interest relative to equity instrument issued with loan	**—**	—
Unwinding of decommissioning provision	**208**	302
Foreign exchange losses	**—**	—
	3,665	4,098
Less finance costs capitalised in property, plant and equipment	**(21)**	(119)
	3,644	3,979

8. Loss for the period
Selected items comprising the loss for the periods ended 30 June 2010 and 2009, respectively, along with selected metrics, are as follows

Selected items comprising loss

	Group 2010 Metric	Group 2010 $000	Group Restated 2009 Metric	Group Restated 2009 $000
Included in revenue				
– Crude oil (bbl)	**$73 92/bbl**	**12,068**	$58 88/bbl	18,798
– Natural gas (mcf)	**$4 64/mcf**	**6,946**	$5 67/mcf	12,303
– Natural gas liquids (ngl)	**$1 06/ngl**	**1,524**	$0 92/ngl	2,204
– Gas plant processing fees		**2,690**		518
		23,228		33,823
Included in cost of sales				
– Lease operating costs	**$8 65/boe**	**3,864**	$5 30/boe	3,909
– Expensed workovers and repairs	**$8 22/boe**	**3,669**	$2 14/boe	1,580
– Gas plant processing costs		**2,473**		493
– Depletion costs (Note 12)	**$24 89/boe**	**12,188**	$27 61/boe	18,368
		22,194		24,350

8. Loss for the period continued

	Group 2010 $000	Restated 2009 $000
Included in administrative expenses		
– Depreciation and amortisation of other fixed assets (Note 12)	**106**	128
– Employee benefits expense (Note 21)	**6,794**	7,062
– Professional fees and outside consultants	**1,366**	459
– Delay rentals for evaluation assets	**539**	339
– Insurance, including that related to oil and natural gas properties	**6,121**	3,657
– Office rent	**243**	238
– Other	**41**	269
	15,210	12,152
Included in other gains and losses		
– Unrealised income (loss) from fair valuations (Note 16)	**(969)**	6,424
– Realised income from derivative transactions	**1,700**	1,673
– Gain on sale of pipe inventory	**104**	—
	835	8,097
Included in impairment expense		
– East Cameron 317/318 field	**—**	23,461
– Intangible exploration and evaluation assets	**—**	1,684
	—	25,145

Professional fees were substantially higher for the year ended 30 June 2010, as compared to the prior year, due to additional contract engineering costs incurred throughout the year and higher costs pertaining to technical advisory services associated with the Company's continued listing on AIM following its successful equity raising and the amendment of its credit facility during November 2009

9. Taxation

A summary of taxation charges, and components thereof, incurred during the years ended 30 June 2010 and 2009, respectively, are set out in the tables below based on a tax rate of 36% pertaining to the US subsidiaries

Taxation for period

	Group 2010 $000	Restated 2009 $000
Deferred tax (Note 18)		
– Continuing operations	**6,083**	7,510
– Reversal of net deferred taxes	**(7,230)**	—
	(1,147)	7,510

Taxation components

	Group 2010 $000	Restated 2009 $000
Loss on ordinary activities before tax		
– Continuing operations	**(16,945)**	(26,048)
Tax effects		
(Loss) income on ordinary activities multiplied by rate of corporation tax (28%) in the UK	**(4,745)**	(7,293)
Disallowed portion of UK tax provision asset (Note 18)	**4,745**	7,293
Effect of different tax rates of overseas subsidiaries	**6,083**	7,510
Reversal of net deferred taxes	**(7,230)**	—
Total tax	**(1,147)**	7,510

Notes to the financial statements continued
for the year ended 30 June 2010

10. Goodwill
Goodwill of $29 0 million arose from the acquisition of Leed Petroleum LLC (formerly Darcy Energy, Ltd) by Darcy Energy Holdings, LLC on 8 December 2005 and has been allocated to the Group's exploration and production segment, which comprises all of the Group's CGUs The key assumptions utilised in the annual goodwill impairment test at 30 June 2010 included a weighted average cost of capital rate of 11 64% used to discount to future net cash flows covering the life expectancy of the proved and probable reserves of assets comprising the exploration and production segment Commodity prices used in the impairment test were the average 1 July 2010 NYMEX light sweet crude oil strip (starting at $72 95 per bbl on 1 July 2010, rising to $89 00 per bbl on 1 December 2018 and held constant thereafter) and the average Henry Hub natural gas price strip (starting at $4 72 per mmbtu on 1 July 2010, rising to $8 25 per mmbtu on 1 January 2021 and held constant thereafter) Additional assumptions included expected future production volumes, capital costs, fixed operating costs and variable operating costs The resulting total net cash flows were then further reduced by a total of 15% for unexpected additional down time Based on the impairment test conducted at 30 June 2010 utilising the aforementioned components, goodwill was not impaired at 30 June 2010

The goodwill testing at 30 June 2010 indicated sensitivities primarily to the pricing of oil and natural gas, which historically have been very volatile A sensitivity to the test indicated that there would be an impairment of goodwill of approximately $9 4 million if commodity prices fell 35% (average of $49 65 per bbl and $4 00 per mmbtu) over the life expectancy of the cash flows

The majority of the Group's proved and probable reserves (78% calculated on a BOE basis per the 1 July 2010 reserve report) are currently undeveloped and will require substantial future capital expenditures to develop. The reserves utilised for goodwill impairment testing Field CGU impairment testing and calculating depletion expense assume the Group will be able to fund the future development costs necessary fully develop such non-producing reserves

11. Intangible exploration and evaluation assets
A summary of the Group's intangible exploration and evaluation assets follows

Reconciliation of intangible exploration and evaluation assets

	Group $000
At 30 June 2008	5,284
Additions	758
Transfers to property, plant and equipment	(2,114)
Unsuccessful acquisition costs	(16)
Impairment	(1,684)
At 30 June 2009	2,228
Additions	739
Unsuccessful acquisition costs	(11)
At 30 June 2010	**2,956**

The impairment of $1 7 million during the year ended 30 June 2009 relates to the abandonment of undeveloped properties Delay rentals for evaluation properties were $539,000 and $339,000 for the years ended 30 June 2010 and 2009, respectively Delay rental expense, unsuccessful acquisition costs and impairment are included with administrative expenses in profit and loss

12. Property, plant and equipment

A summary of the Group's property plant and equipment follows

	Group			
	Oil and natural gas assets $000	Leasehold improvements $000	Other fixed assets $000	Total $000
Cost				
At 30 June 2008	149,830	63	462	150,355
Additions and adjustments				
- separately acquired	45,815	61	54	45,930
- adjustment to asset retirement obligation	(1,797)	—	—	(1,797)
- transfers from evaluation	2,114	—	—	2,114
Disposals				
- cost of assets sold	(20,019)	—	—	(20,019)
At 30 June 2009	175,943	124	516	176,583
Additions and adjustments				
- separately acquired	16,313	—	7	16,320
- adjustment to asset retirement obligation	483	—	—	483
Disposals				
- cost of pipe inventory disposed of	(1,136)	—	—	(1,136)
At 30 June 2010	**191,603**	**124**	**523**	**192,250**
Accumulated depreciation				
At 30 June 2008	11,492	32	268	11,792
- Charge for the year	18,368	37	91	18,496
- Impairment allowance (restated)	23,461	—	—	23,461
- Disposals	(823)	—	—	(823)
At 30 June 2009 (restated)	52,498	69	359	52,926
- Charge for the year	12,188	43	63	12,294
At 30 June 2010	**64,686**	**112**	**422**	**65,220**
Net book amount				
At 30 June 2008	138,338	31	194	138,563
At 30 June 2009 (restated)	123,445	55	157	123,657
At 30 June 2010	**126,917**	**12**	**101**	**127,030**

The depreciation charge for oil and natural gas assets is disclosed separately within profit and loss The oil and natural gas assets are mortgaged as security for the Group's bank credit facility (Note 15 "Borrowings") Included within other fixed assets is equipment acquired under financing leases with a carrying value of $4,000 and $6,000 at 30 June 2010 and 2009, respectively

Non-cash impairment of non-core property

Due to a change in the application of accounting policy which resulted from a more detailed and rigorous examination of assets within the Group's single operating segment, a determination was made that multiple CGUs exist When the carrying value of assets was reviewed on a multi-CGU basis as compared to the single CGU approach previously utilised, a non-cash impairment was identified with respect to the East Cameron 317/318 field (a non-core and non-operated property for which the Group has a 25% working interest, which was offline from August 2008 until December 2009 due to third party pipeline damage from Hurricane Ike) Upon further analysis, it was determined that this field was initially impaired at 30 June 2009 ($23 5 million before tax non-cash impairment expense based on a calculated net present value of future net cash flows discounted at a weighted average cost of capital rate of 11 19% at that date), due primarily to falling natural gas prices Natural gas prices utilised for the 1 July 2010 reserve report improved slightly as compared to the 1 July 2009 reserve report, and the Group's weighted average cost of capital rose to 11 64% as a result of the equity raise and debt re-financing accomplished during the 2010 financial year The net impact of the two aforementioned factors resulted in no additional impairment expense or recovery for the period ended 30 June 2010 No amounts relating to any components of the property, plant and equipment balances as of 30 June 2008 were affected by this restatement Accordingly, the Company has restated the affected amounts within the financial statements as appropriate for the period ended and as of 30 June 2009 as per IAS 8 "Accounting policies, changes in accounting estimates and errors" (Note 30 "Restatement of prior period")

Notes to the financial statements continued
for the year ended 30 June 2010

12. Property, plant and equipment continued

Possible sale of oil and natural gas property assets during financial year 2011

Due to changes in circumstances since the end of the 2010 financial year, the Group is exploring a strategic alternative that includes divesting some or all of its oil and natural gas assets The primary purpose of such a transaction would be to provide funds necessary to reduce the Group's borrowings by at least $12 0 million on or before 31 March 2011, when a $12 0 million principal payment is due on the Company's credit facility Should the Company consummate such a transaction, there can be no assurance that the net proceeds will exceed the Company's carrying value of such assets (Note 31 "Post-statement of financial position events – revision to the credit facility with UniCredit Bank AG")

13. Trade and other receivables

The Directors consider that the carrying amount of trade and other receivables approximates their fair value

	Group		Company	
	2010 $000	2009 $000	2010 $000	2009 $000
Trade receivables	**4,176**	4,721	**—**	—
Joint interest billings receivable	**186**	142	**—**	—
Notes receivable from subsidiary undertakings	**—**	—	**1,000**	1,000
Other receivables	**434**	171	**14**	7
Prepayments	**866**	5,684	**10**	5
	5,662	10,718	**1,024**	1,012
Short-term trade and other receivables	**5,662**	10,718	**24**	12
Long-term notes receivable	**—**	—	**1,000**	1,000

Trade receivables, joint interest receivables, other receivables and prepayments represent the primary exposure to credit risk. As discussed in Note 4 3 "Financial risk management – credit risk", credit risk is concentrated particularly to five customers within the trade receivables category in the above table As is the industry practice, the sale of oil, natural gas and natural gas liquids is remitted by purchasers on a monthly basis The Company's pro-rata share of gas plant processing fees is also remitted on a monthly basis At each statement of financial position date presented there are no material amounts that are past due

At 30 June 2010, a receivable for gas production pertaining to the Group's 25% working interest share of natural gas production from its East Cameron 317/318 field covering the production periods of December 2009 to June 2010 in the amount of $340,000 was included within trade receivables Of that amount $262,000 represented the Group's share of December 2009 through April 2010 natural gas production revenues and was delinquent Effective May 2010, the operator dedicated the proceeds from its 75% working interest share of natural gas production from the East Cameron 317/318 field towards payment of the outstanding amount owed to the Group The Group received payments during July and August 2010 that covered the delinquent amount Accordingly, the Group did not provide a bad debt allowance for this receivable at 30 June 2010

At 30 June 2010, 2009 and 2008, respectively, the Company had an outstanding note receivable from its US operating subsidiary with an outstanding principal balance of $1 0 million that is due in 2015 As it bears interest at floating rates, which represent prevailing market rates, the Directors consider the carrying amount of the note approximates its fair value at each statement of financial position date

14. Trade and other payables

The Directors consider that the carrying amount of trade and other payables approximates to their fair value and is generally payable within 30 to 45 days of the relevant period end

	Group		Company	
	2010 $000	2009 $000	2010 $000	2009 $000
Trade payables	**8,531**	4,351	**254**	141
Amounts owed to Group undertakings	**—**	—	**731**	278
Accruals and deferred income	**84**	70	**—**	—
	8,615	4,421	**985**	419

15. Borrowings

A summary of the borrowings at 30 June 2010 and 2009, respectively, follows

	Group		Company	
	2010 $000	2009 $000	2010 $000	2009 $000
Current				
Other finance obligations	**4**	3,264	—	—
Bank loans	**1,500**	—	—	—
	1,504	3,264	—	—
Non-current				
Bank loans	**25,000**	40,815	—	—

At 30 June 2010, the Group did not have any of its insurance policies financed During the year ended 30 June 2009, the Group financed renewals of its insurance policies with a finance company ("other finance obligations") In total $4 6 million was financed, after a 30% down payment, in three contracts The balance for each was due in nine monthly, fixed instalments The interest rates for the three contracts ranged from 3 8% to 5 5%

Bank loans are denominated in US Dollars and bear interest based on LIBOR The credit facility is secured by a mortgage on the Group's oil and natural gas properties, a security interest in the proceeds from the sale of hydrocarbons as they are produced, a guaranty by the Company and by a security interest in the shareholding of the Company's subsidiaries, Leed Petroleum Inc and Leed Petroleum LLC (the Group's operating subsidiary) (Note 23 "Investments in subsidiaries")

As the Group's bank borrowings bear interest at floating rates, which represent prevailing market rates, the Directors consider the carrying amount of these borrowings approximates their fair value

The weighted average interest rates on the Group's borrowings at 30 June 2010 and 2009, respectively, follow

Weighted average interest rates

	Group		Company	
	2010 %	2009 %	2010 %	2009 %
Bank borrowings – floating rates	**4 5**	5 6	—	—
Finance leases – fixed rates	**4 7**	3 8–5 5	—	—

For the year ended 30 June 2010, the median bank floating rate was 0 59% and ranged from 0 38% to 1 28% Assuming a movement of 45 basis points to the ending balances to the bank at 30 June 2010, such movement would increase or decrease post-tax net income by $763,000 for the year For the year ended 30 June 2009, the median bank floating rate was 2 75% and ranged from 1 10% to 4 40% Assuming a movement of 165 basis points to the ending balances to the bank at 30 June 2009, such movement would increase or decrease post-tax net income by $433,000 for the year

Maturity of bank loans

The maturity profile of the Group's non-current bank loans at 30 June 2010 and 2009, respectively, follows

	Group		Company	
	2010 $000	2009 $000	2010 $000	2009 $000
Between one and two years	**1,500**	—	—	—
Between two and five years	**25,000**	40,815	—	—
More than five years	—	—	—	—
	26,500	40,815	—	—

Notes to the financial statements continued
for the year ended 30 June 2010

15. Borrowings continued

Amended credit facility

During the year ended 30 June 2010, the Group placed 400,000,000 new Ordinary Shares of 5 pence par value at 5 pence to raise £20 million before expenses (the "Fundraising"), which was inter-conditional with amending its existing credit facility (the "Amended Facility") between Leed Petroleum LLC (a wholly owned subsidiary of the Company) and UniCredit Bank AG The Group expensed fees of $0 5 million in conjunction with the amendment Primary terms of the amended facility as of 30 June 2010 are as follows

- the facility consists of two tranches ranked pari passu the available revolving facility and the available term facility,
- the available revolving facility is subject to a semi-annual borrowing base redetermination set at the discretion of UniCredit Bank AG The amount of the borrowing base is calculated by UniCredit Bank AG based upon their valuation of projected cash flows stemming from the Group's oil and natural gas reserves and their own internal criteria The available revolving facility is the lesser of
  - the aggregate of available revolving commitments,
  - the predetermined maximum revolving facility, or
  - the borrowing base amount, less

  an amount equal to one-third of the aggregate amount outstanding under the term facility The maximum revolving facility of $48 0 million on 15 June 2010 will be reduced by $6 0 million on a semi-annually basis thereafter until the amended facility expires on 15 June 2014 The initial available revolving facility at the time of amendment in November 2009 was $30 0 million with interest at three month LIBOR plus a margin of up to a maximum of 4 25% On 15 June 2010, the available facility was reduced to $25 0 million per the redetermination terms contained within the amended facility with interest at three month LIBOR plus a margin of up to a maximum of 6 25%,
- the initial available term facility at the time of amendment in November 2009 was $11 0 million The Group made principal payments of $9 5 million during the 2010 financial year, resulting in a principal balance of $1 5 million at 30 June 2010 The term facility has the following repayment and interest schedule aggregate principal repayments of $0 5 million during the second half of calendar year 2010 with interest at three month LIBOR plus 4 75% prior to 15 June 2010 and three month LIBOR plus 6 75% thereafter through 15 December 2010, and aggregate principal repayments of $1 0 million during the calendar year 2011 with interest at three month LIBOR plus 7 0%, and
- the existing security for the amended facility includes a mortgage on the Group's oil and natural gas properties, a pledge of the proceeds from the sale of oil and natural gas from the Group's properties, the Group's bank account funds, the Group's subsidiary stock and guarantees from its affiliated companies The amended facility contains customary covenants including financial ratios calculated semi-annually and covenants that restrict the payment of cash dividends, share repurchases, borrowings other than from the facilities, sales or transfers of assets other than permitted, loans to others, merger activity, and liens on collateral other than permitted without the prior consent of the lender

Prior to 30 June 2010, the Group requested a waiver from UniCredit Bank AG for certain defaults which management expected to exist at 30 June 2010 In exchange for granting the waiver request, the Group agreed to a 2% margin increase on its credit facility effective 15 June 2010 In addition, on 30 June 2010, the Group made a principal payment of $3 0 million, reducing the overall principal balance of its credit facility to $26 5 million ($1 5 million for the term and $25 0 million for the revolver) as of that date During November 2010, the Group reached an agreement with the Group's bank whereby the Group would make additional principal payment of $12 0 million on or before 31 March 2011 and the interest rate on its credit facility would increase by 1% effective 15 December 2010 in return for waiving certain conditions of default that may exist at the 31 December 2010 measurement date (Note 31 "Post-statement of financial statement events – revision of credit facility with UniCredit Bank AG")

At 30 June 2009, the Group's bank credit facility was comprised of an $80 0 million facility that expired in $8 0 million increments semi-annually commencing December 2009 through December 2013 At 30 June 2009, there was $185,000 of unamortised arrangement fees netted to drawn amounts which were being amortised and reported with interest expense over the expected life of the loans The $185,000 of unamortised arrangement fees were expensed when the facility was amended during the year ended 30 June 2010, resulting in no such amounts outstanding at 30 June 2010 At 30 June 2009, the Group had borrowed $40 8 million of the $45 2 million available to be borrowed under the $80 0 million credit facility The summary of the Group's committed borrowing facilities are as follows

Maximum borrowing facility

	Group		Company	
	2010 $000	2009 $000	2010 $000	2009 $000
Expiring within one year	**12,000**	16,000	—	—
Expiring between one and two years	**12,000**	16,000	—	—
Expiring between two and five years	**24,000**	48,000	—	—
Expiring after five years	—	—	—	—
	48,000	80,000	—	—

15 Borrowings continued

Minimum payments for finance obligations

Minimum payments that are due under other finance obligations at 30 June 2010 and 2009, respectively, follow

	Group		Company	
	2010 $000	2009 $000	2010 $000	2009 $000
Within one year	4	3,217	—	—
Future finance charges on finance leases	—	47	—	—
Present value of finance lease liabilities	4	3,264	—	—

16 Financial instruments

A summary of financial assets and liabilities by category at 30 June 2010 and 2009, respectively, follows

Financial instruments

	Group		Company	
	2010 $000	2009 $000	2010 $000	2009 $000
Non-current assets				
Loans and receivables	—	—	1,000	1,000
Financial asset at fair value through profit or loss	516	529	—	—
	516	529	1,000	1,000
Current assets				
Loans and receivables	15,621	9,516	269	276
Financial asset at fair value through profit or loss	1,019	2,314	—	—
	16,640	11,830	269	276
Current liabilities				
Other financial liabilities	10,119	7,685	985	419
Financial liability at fair value through profit or loss	837	310	—	—
	10,956	7,995	985	419
Non-current liabilities				
Other financial liabilities	25,000	40,815	—	—
Financial liability at fair value through profit or loss	22	904	—	—
	25,022	41,719	—	—

Derivative financial instruments

The Group manages its financial risks with derivatives, including hedging for changes in future oil and natural gas prices The instruments purchased are denominated in US Dollars, the Group's functional currency

	Group		Company	
	2010 $000	2009 $000	2010 $000	2009 $000
Assets				
Forward commodity contracts	1,535	2,843	—	—
Derivative financial instruments assets	1,535	2,843	—	—
Current portion	1,019	2,314	—	—
Non-current portion	516	529	—	—
Liabilities				
Forward commodity contracts	(668)	(727)	—	—
Interest rate swaps	(191)	(487)	—	—
Derivative financial instruments liabilities	(859)	(1,214)	—	—
Current portion	(837)	(310)	—	—
Non-current portion	(22)	(904)	—	—

Notes to the financial statements continued
for the year ended 30 June 2010

16 Financial instruments continued
Other gains and losses
Gains and losses on derivative financial instruments that close in each period are realised gains and losses Changes in the movement of the fair value of derivative financial instruments that are still open at each statement of financial position date are unrealised gains and losses Both are included in profit and loss for each period and shown as other gains and losses (Note 8 "Loss for period") A recap of those gains and losses for each period is shown in the table below

	Group		Company	
	2010 $000	2009 $000	2010 $000	2009 $000
Commodity contracts realised gains	**2,010**	1,801	—	—
Commodity contracts unrealised (losses) gains	**(1,265)**	6,479	—	—
Interest rate swaps realised losses	**(310)**	(128)	—	—
Interest rate swaps unrealised gains (losses)	**296**	(55)	—	—
	731	8,097	—	—

Commodity contracts
As a part of its bank credit facility (Note 15 "Borrowings"), the Group entered into crude oil and natural gas commodity contracts, with staggered effective and termination dates to manage its price risk to oil and natural gas Such contracts were entered into only at the US subsidiary level A summary of the open contracts at 30 June 2010 and 2009, respectively, follows

Contract type	Volumes	Floor price	Valuation level	Time period
At 30 June 2010				
Natural gas swaps	202,197 mmbtu	$5 89 – $6 89	Level 2	July 2010 – January 2011
Natural gas puts	420,000 mmbtu	$5 94 - $6 13	Level 1	July 2010 – January 2011
Natural gas puts	283,114 mmbtu	$6 00	Level 2	March 2011 – March 2012
Natural gas puts	36,000 mmbtu	$5 00	Level 3	April 2012 – June 2012
Crude oil swaps	32,000 bbl	$55 30 - $56 85	Level 2	September 2010 – January 2011
Crude oil puts	40,000 bbl	$55 00	Level 2	July 2010 – November 2011
Crude oil puts	37,406 bbl	$75 00	Level 2	April 2011 – June 2012
30 June 2009				
Natural gas swaps	255,430 mmbtu	$5 89 – $7 72	Level 2	July 2009 – June 2010
Natural gas swaps	184,740 mmbtu	$6 15 – $7 16	Level 2	July 2010 – June 2011
Natural gas puts	940,000 mmbtu	$5 75 - $6 70	Level 1	July 2009 – June 2010
Natural gas puts	260,000 mmbtu	$5 75 - $6 50	Level 2	July 2010 – November 2010
Natural gas puts	80,000 mmbtu	$6 20 - $6 40	Level 1	December 2010 – January 2011
Crude oil swaps	12,000 bbl	$95 35	Level 2	July 2009 – June 2010
Crude oil puts	32,000 bbl	$55 30 - $56 85	Level 2	July 2010 – June 2011
Crude oil puts	32,000 bbl	$55 00	Level 2	July 2009 – June 2010
Crude oil puts	32,000 bbl	$55 00	Level 2	July 2010 – June 2011

Valuations levels in the above table are categorised as follows

Level 1 fair value based quoted prices for similar instruments,

Level 2 fair value based on directly observable market inputs other than Level 1 inputs, and

Level 3 estimate, inputs not based on observable market data

At 30 June 2009, there were no crude oil and natural gas commodity contracts classified as level 3 and there were no significant movements between level 1 and level 2 during the years ended 30 June 2010 and 2009, respectively For the year ended 30 June 2010, average end of month prices of NYMEX/Henry Hub futures for the open contract periods above ranged from $4 38 to $6 06 per mmbtu for natural gas and average end of month prices of NYMEX/WTI futures for the open contracts for crude oil ranged from $75 80 to $81 09 per barrel Considering the unrealised gain at 30 June 2010 and these movements to the volumes and fixed prices of the contracts then open, a post-tax increase of $2,539,000 or a post-tax increase of $1,699,000 could have resulted

For the year ended 30 June 2009, average end of month prices of NYMEX/Henry Hub futures for the open contract periods above ranged from $3 64 to $12 58 per mmbtu for natural gas and average end of month prices of NYMEX/WTI futures for the open contracts for crude oil ranged from $49 82 to $123 87 per barrel Considering the unrealised gain at 30 June 2009 and these movements to the volumes and fixed prices of the contracts then open, a post-tax increase of $479,000 or a post-tax decrease of $4,663,000 could have resulted

16. Financial instruments continued

Interest rate swaps

In December 2005, as a part of its bank credit facility (Note 15 "Borrowings"), the Group entered into interest rate swaps, with staggered effective and termination dates, to manage its exposure to interest rate movements on its bank borrowings Such contracts were entered into only at the US subsidiary level The swaps are compared to the variable six month British Banker Association rates for US Dollar denominated loans and close semi-annually At 30 June 2010 the remaining swaps, their effective dates, notional amounts and fixed rates are as follows

Effective date of interest rate swap	Fixed rate %	Notional amount $000
5 January 2010	6 1	3,910
6 July 2010	6 1	2,457
5 January 2011	5 4	1,018

For the year ended 30 June 2010, forward interest rates had a movement of 17 basis points over the effective dates of the contracts then open An increase or decrease of this amount in the forward interest rate at 30 June 2010 would have resulted in a post-tax change of $64,000 in net income For the year ended 30 June 2009, forward interest rates had a movement of 215 to 216 basis points over the effective dates of the contracts then open An increase or decrease of this amount in the forward interest rate at 30 June 2009 would have resulted in a post-tax increase of $49,000 or a post-tax decrease of $29,000

17. Decommissioning obligations

A summary of the Group's decommissioning obligations follows

	Group $000
30 June 2008	6,629
On acquisition	1,326
Charged to profit and loss (Note 7)	302
Revaluation	(1,797)
Disposals	(872)
30 June 2009	5,588
On acquisition	1,490
Charged to profit and loss (Note 7)	208
Revaluation	(807)
30 June 2010	**6,479**

The costs associated with decommissioning an asset are recorded as a liability and as a part of the cost of the asset when it is acquired The decommissioning costs are recorded at the present value of future obligations when initially incurred and then adjusted for inflation These estimates are reviewed regularly to consider material changes that may have occurred At 30 June 2010, a revaluation in accordance with IFRIC 1 "Changes in existing decommissioning, restoration and similar liabilities" was undertaken, resulting in a net decrease of $807,000 to the present value of the expected obligation The revaluation offset was to property, plant and equipment It is expected that the obligations, all on Gulf of Mexico oil and natural gas interests, will not be incurred before 15 to 25 years from 30 June 2010, and are thus presented as non-current Prior to the 30 June 2010 revaluation, the previous revaluation was undertaken at 30 June 2009 and resulted in a net decrease of $1,797,000 to the obligation

18. Deferred tax

As per Note 2 20 "Significant accounting policies – going concern", the Company reversed all deferred tax asset and liability balances at 30 June 2010 The movement on the net deferred taxes of both jurisdictions in which the Company operates is as per the following

Net deferred taxes

	Net US deferred tax $000	Net UK deferred tax $000	Total $000
30 June 2008	(6,740)	377	(6,363)
Profit and loss charge (restated)	7,887	(377)	7,510
30 June 2009	1,147	—	1,147
Profit and loss charge	6,083	—	6,083
Reversal of deferred tax balances	(7,230)	—	(7,230)
30 June 2010	—	—	—

Due to changes in UK tax legislation, it is expected that the Company will not be subject to UK taxes on future dividends it receives from its US subsidiary As such, the Company has no deferred tax assets or liabilities related to activities in the UK At 30 June 2010 net US deferred taxes of $7 2 million were unrecognised

Notes to the financial statements continued
for the year ended 30 June 2010

18 Deferred tax continued

The movements in US deferred tax assets and liabilities (prior to the offsetting of balances within the same jurisdiction as permitted by IAS 12 "Income taxes") during the period are shown below With the exception of share-based costs, they are calculated in full on temporary differences under the liability method using a tax rate of 36%, which is the effective tax rate applicable to the Group's operating entity in the US As the Company's stock price at 30 June 2010 was below the exercise price of the outstanding SARs awards, none of the current year share-based payments related to the SARs was recognised in the current year

Deferred tax assets (US)

	Group			
	Share-based costs $000	Tax losses $000	Other $000	Total $000
At 30 June 2008	351	26,506	3,768	30,625
Adjustment of accelerated capital allowances per actual tax filings	—	(17,287)	(1,073)	(18,360)
Charged to profit and loss (restated)	(346)	1,787	6,351	7,792
At 30 June 2009	5	11,006	9,046	20,057
Charged to profit and loss	818	10,679	2,645	14,142
Reversal of deferred tax asset balances	(823)	(21,685)	(11,691)	(34,199)
At 30 June 2010	—	—	—	—

Deferred tax liabilities (US)

	Group		
	Other $000	Accelerated capital allowances $000	Total $000
At 30 June 2008	—	37,366	37,366
Adjustment of tax losses and other temporary differences per actual tax filings	—	(18,360)	(18,360)
Charged to profit and loss	389	(485)	(96)
At 30 June 2009	389	18,521	18,910
Charged to profit and loss	(26)	8,085	8,059
Reversal of deferred tax liability balances	(363)	(26,606)	(26,969)
At 30 June 2010	—	—	—

19. Issued capital

A recap of issued capital follows

	Group and Company	
	30 June 2010 £000	30 June 2009 £000
Authorised		
301,000,000 Ordinary Shares of 5 pence each	**15,050**	15,050
	$000	$000
Issued and fully paid		
676,020,767 Ordinary Shares at 30 June 2010 and 276,020,767 Ordinary Shares at 30 June 2009	**60,335**	27,178

A recap of movement in issued shares follows

Issued shares	Group and Company
At 30 June 2008 Ordinary Shares (5 pence)	251,020,767
Additional shares issued (5 pence)	25,000,000
At 30 June 2009 Ordinary Shares (5 pence)	276,020,767
Additional shares issued (5 pence)	400,000,000
At 30 June 2010 Ordinary Shares (5 pence)	**676,020,767**

19. Issued capital continued

On 24 November 2009, the Company issued an additional 400,000,000 Ordinary Shares at 5 pence par value at 5 pence per share, resulting in net proceeds of $31 6 million The following Directors of the Company participated in the offering

Director	Ordinary Shares purchased in offering	Percent of offering
Robert Adair	4,000,000	1 00%
Howard Wilson	2,000,000	0 50%
James Slatten	2,000,000	0 50%
Robert Alcock	400,000	0 10%
Ian Shaun Gibbs	600,000	0 15%
Peter Hirsch	120,000	0 03%
	9,120,000	2 28%

In addition to the above, IB Daiwa Corporation ("IBD"), the Company's largest shareholder, participated in the offering by purchasing 89,080,545 Ordinary Shares, or 22 27% of the total offering, through one of its affiliates Also, certain members of the Group's management team purchased 2,920,000 Ordinary Shares, or 0 73% of the total offering (Note 26 "Related party transactions")

Options

During the year ended 30 June 2010, 1,147,288 options issued prior to 30 June 2009 expired unexercised, leaving no options outstanding at 30 June 2010 As a part of its agreement with its nominated adviser Matrix Corporate Capital LLP ("Matrix") for services rendered relative to the August 2007 public listing, Matrix received an option to acquire 1,147,288 Ordinary Shares at 47 pence At that time, an independent appraiser valued the option at $387,000, with assumptions that the Directors consider as reasonable The option expired unexercised in August 2009

A summary of movement in options to the Ordinary Shares of 5 pence follows

	Weighted average exercise price for the year ended 30 June 2010	Number of options for the year ended 30 June 2010	Weighted average exercise price for the year ended 30 June 2009	Number of options for the year ended 30 June 2009
Outstanding at beginning of the period	**47 0 pence**	**1,147,288**	27 0 pence	4,415,863
Expired during the period	**47 0 pence**	**1,147,288**	25 2 pence	(2,998,575)
Outstanding at end of the period	—	—	47 0 pence	1,147,288
Exercisable at the end of the period	—	—	47 0 pence	1,147,288

20 Cash flows from operating activities

Cash flows from continuing operations

A summary of the components of cash flows generated from continuing operations follows

	Group		Company	
	2010 $000	Restated 2009 $000	2010 $000	2009 $000
Loss before taxation	**(16,914)**	(26,048)	**(2,163)**	(1,917)
Adjustments for				
– Loss on sale off assets	—	2,488	—	—
– Impairment expense	—	25,145	—	—
– Depreciation, depletion and amortisation	**12,294**	18,498	—	—
– Finance income	**(71)**	(130)	**53**	(66)
– Finance expense	**3,644**	3,979	—	—
– Share-based costs	**2,272**	2,627	**1,156**	1,267
– Translation reserve	**7**	—	**7**	9
– Fair value changes in derivative contracts	**969**	(6,424)	—	—
Changes in working capital				
– Decrease/(increase) in trade and other receivables	**5,056**	(650)	**(13)**	160
– Increase/(decrease) in payables	**2,109**	(1,570)	**567**	16
Cash generated from continuing operations	**9,366**	17,915	**(393)**	(531)
Corporate taxation paid	—	—	—	—
Net cash from continuing operations	**9,366**	17,915	**(393)**	(531)

Notes to the financial statements continued
for the year ended 30 June 2010

20. Cash flows from operating activities continued

Cash and cash equivalents for the statement of cash flows

	Group		Company	
	2010 $000	2009 $000	2010 $000	2009 $000
Cash and cash equivalents	10,812	4,482	255	269

21 Employees, Directors and auditor remuneration

A summary of total employee and Director costs follows

Employee and Director costs

	Group		Company	
	2010 $000	2009 $000	2010 $000	2009 $000
Wages, salaries, fees and bonuses	3,756	3,703	215	219
Social security costs	178	244	—	22
Other pension costs	88	98	—	—
Other benefits	500	390	—	—
	4,522	4,435	215	241
Share-based payments	2,272	2,627	1,156	1,267
	6,794	7,062	1,371	1,508

The average number of personnel was as follows

	Group		Company	
	2010	2009	2010	2009
Average number of Directors and employees	29	29	5	5

Key management (part of employee and Director costs above)

The Company has two Executive and five Non-executive Directors In addition, the Company has a Chief Financial Officer ("CFO") who is not a Director These eight individuals are the key management of the Company (in accordance with IAS 24 "Related Party Disclosures") The Executive Directors and the CFO receive no remuneration or fees specific to their role as Directors and Officers of the Company, they are employees of the operating subsidiary

Key management costs

	Group		Company	
	2010 $000	2009 $000	2010 $000	2009 $000
Fees, salaries and bonuses	1,304	1,259	215	219
Social security costs	36	61	—	22
Other pension costs	20	19	—	—
Other benefits	126	42	—	—
	1,486	1,381	215	241
Share-based payments	1,703	1,850	1,156	1,267
	3,189	3,231	1,371	1,508

Other pension costs for key management are payments towards a money purchase scheme for the two (US) Executive Directors The Company does not have any defined benefit programmes for any of its Directors

21. Employees, Directors and auditor remuneration continued
Companies Act and AIM disclosures (part of employee and Directors cost)
Payments to Directors are recapped below

Director costs

	Group 2010 $000	Group 2009 $000	Company 2010 $000	Company 2009 $000
Fees, salaries and bonuses	**1,029**	1,100	**215**	219
Social security costs	**25**	52	**—**	22
Other pension costs	**20**	19	**—**	—
Other benefits	**90**	36	**—**	—
	1,164	1,207	**215**	241

Total compensation by Director during the year ended 30 June 2010

Director compensation paid	Robert Adair Non-executive Chairman $000	Howard Wilson President and CEO $000	James Slatten Chief Operating Officer $000	Robert Alcock Non executive Director $000	Ian Shaun Gibbs Non executive Director $000	Peter Hirsch Non-executive Director $000	Stephen Fleming Non executive Director $000	2010 Total $000
Wages, salaries, fees and bonuses	110	441	373	39	19	28	19	**1,029**
Social security costs	—	13	12	—	—	—	—	**25**
Other pension costs	—	10	10	—	—	—	—	**20**
Other benefits	—	62	27	—	—	—	—	**89**
	110	526	422	39	19	28	19	**1,163**

All outstanding SARS and RSUs applicable to Directors were issued during 2007 and were still outstanding and fully vested at 30 June 2010 Based on the closing share price of 3 45 pence at 30 June 2010, none of the outstanding SARs were in the money A summary of SARs and RSUs awards applicable to Directors follows

SARs – Directors

	Weighted average for the year ended 30 June 2010 pence	Number of shares to be issued in respect of exercise price for the year ended 30 June 2010	Weighted average for the year ended 30 June 2009 pence	Number of shares to be issued in respect of exercise price for the year ended 30 June 2009
Outstanding, beginning of period	**47 00**	**6,903,072**	47 00	6,903,072
Granted, forfeited, exercised, or expired during the period	**—**	**—**	—	—
Outstanding, end of period	**47 00**	**6,903,072**	47 00	6,903,072
Exercisable, end of period	**47 00**	**6,903,072**	47 00	4,602,043

The SARs referenced in the above table were issued on August 6, 2007 and contain vesting provisions of one-third per year and a ten year life The SARS were issued to the individual Directors as follows 2,510,208 SARs to Robert Adair, 1,255,104 SARs each to Howard Wilson and James Slatten, and 627,552 SARs each to Robert Alcock, Peter Hirsch and Ian Shaun Gibbs

RSUs – Directors

	Number of shares awarded year ended 30 June 2010	Number of shares awarded year ended 30 June 2009
Outstanding, beginning of period	**1,255,104**	1,255,104
Granted, forfeited, exercised, or expired during the period	**—**	—
Outstanding, end of period	**1,255,104**	1,255,104

All of the RSU awards in the above table apply to Robert Adair and were issued on August 6, 2007 (Note 27 "Share-based payments – Directors and employees")

Notes to the financial statements continued
for the year ended 30 June 2010

21. Employees, Directors and auditor remuneration continued

Highest paid Director

Payments to Howard Wilson (highest paid Director for the year ended 30 June 2010 and 2009), President, CEO and Executive Director, for the year ended 30 June 2010 and 2009, respectively, were as follows

	Group	
	2010 $000	2009 $000
Salary and bonus	**441**	485
Social security costs	**13**	15
Other pension costs	**10**	10
Other benefits	**62**	22
	526	532

Note 27 "Share-based payments – Directors and employees" provides details of the incentive schemes, during the period, there were no sales of shares under the incentive schemes

There were no other undertakings with the Directors

Auditor's remuneration

A summary of the remuneration paid to the Company's auditor follows

	Group		Company	
	2010 $000	2009 $000	2010 $000	2009 $000
Services by the Company's auditor				
Fees payable to the Company's auditor for the audit of the annual financial statements	**178**	133	**178**	133
Fees payable to the Company's auditor and its associates for other services				
– Audit of financial statements of Company's subsidiaries	**68**	—	—	—
– Interim review of Company accounts	**65**	65	**65**	65
– Other services including taxation	**16**	20	**16**	20
	149	85	**81**	85

22. Operating lease commitments

The Group has the following operating leases

Office lease

The Group leases space for administrative purposes under two agreements a one and a five year operating lease, comprising total monthly payments of $19,000 per month as of 30 June 2010 These leases were combined and renewed as one lease effective 30 September 2010 for a period of two years, with an optional three year extension at the aforementioned monthly rate The office lease is strictly for the use of improved realty on a stated payment, certain basis and contains no other contingent, purchase or renewal clauses

Compressor lease

The Group leases the compressor that is utilised on its Eugene Island field, where it is the operator and has a 75% working interest Gross rental payments for the compressor are $32,000 per month for a period of 60 months which commenced 17 November 2009, with an option to continue on a month-to-month basis at the end of the lease term

A summary of minimum lease payments under the aforementioned non-cancellable operating leases follows

	Group		Company	
	2010 $000	2009 $000	2010 $000	2009 $000
Operating lease commitments				
Within one year	**440**	233	—	—
After one year and less than five years	**910**	56	—	—
	1,350	289	—	—

23. Investments in subsidiaries

Leed Petroleum PLC, the Parent Company, owns 100% of the issued Ordinary Share Capital in Leed Petroleum Inc (US holding incorporated in Delaware), who in turn, owns 100% of the issued Ordinary Share Capital in Leed Petroleum LLC (limited liability company incorporated in Delaware acting as the operating entity of the Group) A summary of Leed Petroleum PLC's investments in its subsidiaries follows

Investment in subsidiaries – cost and net book amount

	Company $000
At 30 June 2008	119,842
Capital contribution	28,162
Expired Company equity instrument issued with subsidiary loan (Note 19)	(560)
Share-based payment of Company stock by subsidiary (Note 27)	1,358
At 30 June 2009	148,802
Capital contribution	31,115
Share-based costs	1,116
At 30 June 2010	**181,033**

The shareholdings of Leed Petroleum Inc and Leed Petroleum LLC are pledged as security for borrowings undertaken by Leed Petroleum LLC (Note 15 "Borrowings")

24 Capital commitments

	Group		Company	
	2010 $000	2009 $000	2010 $000	2009 $000
Contracts placed for future capital expenditure not provided in the financial statements	**1,358**	4,112	—	—

At 30 June 2010, the Group had capital commitments covering the sidetrack of a well in the Main Pass 64/65 field, where the Group has a non-operated 25% working interest At 30 June 2009, the Group had capital commitments to establish reserves in connection with potential bonding obligations to secure decommissioning work relating to certain of its offshore properties

25. Contingent liabilities

The Group has contingent liabilities in respect of legal claims arising in the ordinary course of business It is not anticipated that any material liabilities will arise from the contingent liabilities

The Group has recorded its estimated proportionate share of asset retirement liabilities in all of its oil and natural gas properties (Note 17 "Decommissioning obligations") The Group is jointly and severally liable with its respective co-lessees for decommissioning obligations associated with each mineral lease (Note 26 "Related party transactions")

26. Related party transactions

Identity of related parties

The Group has a related party relationship with its subsidiaries, its Directors, IBD, Asia Debt Management Galleus Fund Limited ("ADM"), Asia Special Situations GJP1 Limited ("ASSGJP1") and Byron

Byron scouting agreement

In December 2005, in connection with the acquisition of the shares of Leed Petroleum LLC ("LP LLC") (formerly Darcy Energy, Ltd), IBD agreed that LP LLC enter into a "scouting agreement" with Byron for an initial term of three years (Note 3 5 "Critical accounting judgements and key sources of estimation uncertainty – treatment of overriding royalty interests") Under this exclusive scouting agreement, Byron was to use its best efforts to introduce oil and natural gas producing property acquisition opportunities to LP LLC In return, Byron earned the right at its election to receive either a proportional 2% ORRI or to up to 25% of LP LLC's working interest in any properties acquired by LP LLC pursuant to the agreement If Byron elects a working interest pursuant to the agreement terms, Byron must pay LP LLC pro-rata up to 25% of LP LLC's net investment in the property (out of pocket costs less any revenues) During the year ended 30 June 2009, the Group recorded a loss on sale of assets of $2,472,000 pertaining to Byron's election to participate in the Eugene Island field with a 25% working interest Subsequent to its election to participate in the Eugene Island field, Byron sold a 7 25% working interest to Leni Gas & Oil PLC, leaving Byron with a 17 75% working interest in the Eugene Island field At 30 June 2010, approximately 5 2% of Byron's outstanding shares were owned by certain Directors of the Company and 0 4% of Byron's outstanding shares were owned by other professional employees of the Group Prior to the Company's initial public offering in 2007, IBD had an ownership interest of approximately 10% in Byron However, IBD sold its investment in Byron to parties unrelated to the Company during the calendar year 2008 Although the Byron scouting agreement expired in December 2008, both parties retain rights to acquire the respective interests in any Offshore Continental Shelf ("OCS") blocks contiguous to those covered by the agreement

Notes to the financial statements continued
for the year ended 30 June 2010

26. Related party transactions continued

Byron scouting agreement continued

The status of the Company's properties subject to the scouting agreement as of 30 June 2010 follows

Property	Development status	Byron election status
Eugene Island 133	Non-producing	Elected to take 25% working interest with no ORRI
Eugene Island 172, 183 and 184	Producing	Elected to take 25% working interest with no ORRI
Grand Isle 95 and 100	Non-producing	Election pending
Main Pass 115	Non-producing	Election pending
Ship Shoal 197	Non-producing	Elected to take 25% working interest with no ORRI
Ship Shoal 201	Producing	Elected to take 2% proportional ORRI
Ship Shoal 202	Non-producing	Elected to take 25% working interest with no ORRI, not a working interest owner in the platform utilised to produce oil and natural gas from Ship Shoal 201 A-6 well
South Marsh Island 8	Non-producing	Election pending
West Cameron 106	Non-producing	Election pending

Byron consultancy agreement

On 8 June 2006, LP LLC entered into a consultancy agreement with Byron covering East Cameron 317, East Cameron 318, Main Pass 64, Main Pass 65 and Main Pass 57 (the "Main Pass and East Cameron leases"), all of which are federal oil and natural gas leases located offshore in the Gulf of Mexico Under terms of the agreement, Byron agreed to provide geological and geophysical services pertaining to the Main Pass and East Cameron leases for the same consideration set forth in the scouting agreement Prior to the consultancy agreement, LP LLC had acquired a 25% working interest the Main Pass and East Cameron leases (excluding Main Pass 57) that was not subject to the consultancy agreement Either party may terminate the consultancy agreement at any time with a 30 day written termination notice At 30 June 2010, no additional working interest acquisitions involving the Main Pass and East Cameron leases had been completed to that date by LP LLC and the consultancy agreement was still in effect However, on 8 September 2010 the Group elected to terminate this agreement effective 8 October 2010 As per the termination clause within the consultancy agreement, the rights and obligations arising prior to termination inure

Summary of related party transactions with Byron

A summary of transactions with Byron during the year ended 30 June 2010 and 2009, respectively, follows

	2010 $000	2009 $000
Pro-rata share of oil and natural gas revenues paid to Byron during year	**5,501**	7,940
Pro-rata share of joint venture costs billed to Byron during year	**2,202**	14,139
Joint interest receivable from Byron at period end	**132**	142
Accrued oil and natural gas revenues payable to Byron at period-end	**419**	1,426

The Group estimates Byron's share of costs to decommission the Eugene Island field at the end of its economic life, based on its 17 75% working interest share at 30 June 2010, to be approximately $0 3 million on an undiscounted basis ($0 2 million discounted) before taking into account any estimated salvage values Byron's pro-rata share of the Eugene Island field decommissioning costs represents an unsecured obligation

IB Daiwa Corporation

Following the public listing of the Company in August 2007, the ownership interest of the Company's former ultimate parent, IBD, fell to approximately 42% IBD transferred its Leed Petroleum PLC shares to its wholly owned subsidiary, ASSGJP1, in June 2008 ASSGJP1's ownership was further reduced to approximately 38% following a second equity fund raising in August 2008 ASSGJP1's shareholding was further reduced to approximately 29% following the November 2009 equity offering During February 2010, IBD transferred all of its ownership of ASSGJP1 to ADM in exchange for cancellation of debt owed by IBD to ADM At 30 June 2010, ADM, through its wholly owned subsidiary ASSGJP1, owns 193,695,929 Ordinary Shares of the Company (Note 19 "Issued capital") Stephen Fleming, a Non-executive Director of the Company, served as an executive director of IBD until 28 February 2010 and is a former employee of ADM

Other related party transactions

Key management and Director compensation is disclosed in Note 21 "Employees, Directors and auditor remuneration" Related party participation in the Company's offering covering the issuance of 400,000,000 Ordinary Shares on 24 November 2010 is disclosed in Note 19 "Issued capital"

27. Share-based payments - Directors and employees

The Company operates one share-based cost scheme, the 2007 Omnibus Incentive Plan Under the plan, the Company has granted SARs and RSUs

SARs

Awards entitle grantees to receive the appreciation (based on the fair value of the stock) of the number of shares in respect of the SAR granted over the exercise price The exercise price is normally (but not less than) the closing price of the Company's stock on the date of the award The SARS have a ten year life, one-third (1/3) vest to the holder at each anniversary date of the grant over three years from the award date, the SARs are subject to forfeiture during the vesting period if the Grantee's service with the Group terminates, vested but unexercised awards normally expire when the Grantee's service with the Group terminates The SARs are expected to be settled with stock, although the Company has the right to settle them in cash or a combination of cash and stock During the year ended 30 June 2010, the Company awarded 100,000 SARS to one individual employee A binomial tree model was used to value the granted award at $11,000 Principal inputs for the current year award used in the model were a risk free interest rate of 3 71%, expected volatility of 73%, and, as in prior years, a 0% expected dividend yield Additional assumptions included an exercise factor of 2 25 and no turnover rate The Group will have an obligation to the Grantee for any gain above the 5 pence nominal value on each share issued to satisfy the obligation, in addition to any related payroll tax expense A recap of the SAR awards follows

	Weighted average for the year ended 30 June 2010 pence	Number of shares to be issued in respect of exercise price for the year ended 30 June 2010	Weighted average for the year ended 30 June 2009 pence	Number of shares to be issued in respect of exercise price for the year ended 30 June 2009
Outstanding, beginning of period	**43 56**	**11,794,461**	47 00	10,668,383
Granted during the period	**10 50**	**100,000**	23 85	1,753,630
Forfeited during the period	**44.86**	**(1,536,108)**	47 00	(418,368)
Expired during the period	—	—	47 00	(209,184)
Outstanding, end of period	**42 64**	**10,358,353**	43 56	11,794,461
Exercisable, end of period	**44 81**	**6,309,123**	47 00	3,346,944

On 1 July 2010, the Company awarded 23,242,272 replacement SARs to certain executive officers and employees of the Company (Note 31 "Post-statement of financial position events")

RSUs

Awards are performance based and entitle grantees to receive Company shares or cash equalling the fair value of the shares on the date of vesting, at the Company's option Awards are valued at the fair value of the Company's stock on the date granted, unless market conditions are a part of the performance or vesting condition The August 2007 market condition award (see table below) was valued using a statistical probability model Principal inputs in that model were a 12% expected return on equity, an expected volatility of 57% (as discussed above) and a 98 73% standard deviation over the three year period that vesting is considered The resulting probabilities for meeting the 8% and 20% per year compounding growth were applied to the 47 pence market price of the stock at the August 2007 grant date, resulting in a valuation of $280,000 A description of the RSU awards and their value at dates of grant follows

Date of grant	Number of shares	Performance condition	Award value at date of grant	Vesting
March 2009	443,136	Non-market condition service requirement	$95,000	50% at two years of service, 50% at three years
August 2007	627,552	Market condition percentage growth in Company share price from 47 00 pence	$280,000	50% at three years if 8% per year compound increase, 50% at three years if 20% per year compound increase
August 2007	627,552	Non-market condition percentage growth in after-tax value per fully diluted share of Company's proved and probable oil and natural gas reserves	$602,000	50% at three years if 8% per year compound increase, 50% at three years if 20% per year compound increase

RSU awards

	Number of shares awarded year ended 30 June 2010	Number of shares awarded year ended 30 June 2009
Outstanding, beginning of period	**1,698,240**	1,255,104
Granted during the period	—	443,136
Outstanding, end of period	**1,698,240**	1,698,240

Notes to the financial statements continued
for the year ended 30 June 2010

28 Loss per Ordinary Share
A recap of loss per Ordinary Share and weighted average shares outstanding for the years ended 30 June 2010 and 2009, respectively, follows

	30 June 2010	30 June 2009
Loss attributable to Ordinary Shareholders	**($18,061,000)**	($18,538,000)
Weighted average shares outstanding		
Weighted average number of shares at end of the period	**516,020,767**	273,623,507
Effect of share options in issue	**—**	2,023,249
Weighted average number of shares at end of the period for diluted loss per share	**516,020,767**	275,646,756

29. Capital management policies and procedures
The Board of Directors' capital management goals and objectives are to ensure the Group's ability to continue as a going concern and to provide an adequate return to shareholders by managing the Group's productive assets and further developing its asset portfolio

The Board of Directors directs and monitors the allocation of cash resources against projects to maximise the return on asset value within the Group Day-to-day working capital requirements and medium-term funding requirements are managed through use of internally generated funds and the Group's bank facility The Group also manages the effect of commodity price volatility through the purchase of oil and natural gas commodity derivative contracts covering a portion of its expected future production of crude oil and natural gas The Group manages the capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying assets In order to maintain or adjust the capital structure, the Group may pay dividends to shareholders, return capital to shareholders, buy back shares, issue new shares, sell assets or reduce its borrowings, all of which may be subject to approvals from the Group's shareholders or bank

Capital components
Capital pertaining to the Group for the reporting periods under review is summarised as follows

	30 June 2010 $000	Restated 30 June 2009 $000
Total equity	**134,543**	118,778
Borrowings	**26,500**	40,815
Derivative financial instruments (net)	**(676)**	(1,629)
Cash and cash equivalents	**(10,812)**	(4,482)
	149,555	153,482

The Group strives to meet the covenants under its credit facility with UniCredit Bank AG, including certain covenants pertaining to (1) the ratio of total Group equity to Group equity plus Group debt, (2) total Group debt compared to the total estimated net present value of its reserve portfolio, (3) total Group debt compared to multiple of the total Group EBITDAX less certain adjustments, and (4) total Group EBITDAX less certain adjustments compared to Group interest expense At 30 June 2010, the Group obtained a waiver for the aforementioned items (3) and (4) from UniCredit Bank AG During November 2010, the Company reached an agreement with the Group's bank whereby the Company would make an additional principal payment of $12 0 million on or before 31 March 2011 and the interest rate on its credit facility would increase by 1% effective 15 December 2010 in return for waiving certain conditions of default that may exist at the 31 December 2010 measurement date (Note 31 "Post statement of financial position events – revision to credit facility with UniCredit Bank AG")

30. Restatement of prior period
At year end, the Group carried out a rigorous and detailed review of the assets within its single operating segment and determined that separately identifiable independent sources of cash inflows existed within that segment Accordingly, the Group adopted a change in application of accounting policy since the change would provide more relevant information In the prior annual report for the year ended 30 June 2009, the Group classified all of its oil and natural gas fields with proved and probable reserves as one CGU Field CGUs are now based on individual fields in distinct geographical locations with proved and probable reserves, unless cash flows are directly linked to another field Based on this new application of accounting policy, the Group performed impairment tests for each Field CGU for the periods ended 30 June 2010 and 2009, respectively The weighted average cost of capital of 11 64%, and 11 19% was applied to the annual impairment test covering each Field CGU for periods ended 30 June 2010 and 2009, respectively

As a result of change in application of accounting policy, an impairment was identified with respect to the East Cameron 317/318 field (a non-core and non-operated property for which the Group has a 25% working interest), which was offline from August 2008 until December 2009 due to third party pipeline damage from Hurricane Ike

30. Restatement of prior period continued

Upon further analysis, it was determined that this field was initially impaired at 30 June 2009 ($23 5 million before tax non-cash impairment expense based on a calculated net present value of future net cash flows discounted at a weighted average cost of capital rate of 11 19% at that date) due primarily to low natural gas prices Natural gas prices utilised for the 1 July 2010 reserve report improved slightly as compared to the 1 July 2009 reserve report and the Group's weighted average cost of capital rose to 11 64% as a result of the equity raise and debt re-financing accomplished during the 2010 financial year The net impact of the two aforementioned factors resulted in no additional impairment expense or recovery for the period ended 30 June 2010 Accordingly, the Company has restated the affected amounts within the financial statements for the period ended and as of 30 June 2009 as appropriate per IAS 8 "Accounting policies, changes in accounting estimates and errors"

A summary of the effect of the East Cameron 317/318 field impairment on the period ended 30 June 2010 is summarised in the table below

	Group		
	As previously stated 2009 $000	As restated 2009 $000	Effect of restatement 2009 $000
Effect on the statement of financial position			
Property, plant and equipment	147,118	123,657	(23,461)
Deferred tax	(7,299)	1,147	8,446
Net decrease in net assets			(15,015)
Retained deficit	16,266	31,281	15,015
Net decrease in owners' equity			15,015
Effect on the statement of consolidated income			
Increase in impairment expense	1,684	25,145	23,461
Increase Group loss before taxation	2,587	26,048	23,461
Increase in taxation	(936)	7,510	8,446
Increase in Group loss for the period from continuing operations and attributable to equity owners	3,523	18,538	15,015
Effect on the loss per share			
Increase in basic loss per share (cents)	1 3	6 7	5 4
Increase in diluted loss per share (cents)	1 3	6 7	5 4

There was no cash flow impact as a result of the restatement applicable to the period ended 30 June 2009

No line items within the statements of financial position at 30 June 2008 for the Group or Company, both of which are included herein for comparative purposes in accordance with IAS 1 "Presentation of financial statements", were affected by the above referenced restatement

31. Post-statement of financial position events

Replacement SARs

On 1 July 2010, the Company awarded 23,242,272 replacement SARs to certain executive officers and employees of the Company The replacement SARs vest one-third per year beginning two years from the date of grant, have an exercise price of 5 pence and a term of ten years The replacement SARs issued on 1 July 2010 replace 5,200,708 SARs that were outstanding at 30 June 2010 pertaining to the same certain executive officers and employees

Resumption of oil production at Main Pass 64/65

The Main Pass 64/65 field was completely shut in commencing 25 May 2010 for repairs to the third party oil sales pipeline serving the field During August 2010, Medco Energi, the operator, began barging oil to maintain crude oil sales from the field while the pipeline was being repaired Normal service by the third party pipeline operator resumed during October 2010

Main Pass 64 #1 Sidetrack

On 23 August 2010, drilling operations commenced on the Main Pass 64 #1 Sidetrack The Company holds a 25% non-operated working interest and a 19 18% net revenue interest in the well. On 19 September 2010, the Main Pass 64 #1 Sidetrack reached a total measured depth of approximately 8,086 feet and encountered approximately 71 feet of true vertical thickness pay covering three sands, including 48 feet of true vertical thickness pay in the primary targeted zone The well is expected to cost at least $5 4 million ($1 4 million net to the Group) and was placed on production during November 2010

Notes to the financial statements continued
for the year ended 30 June 2010

31. Post-statement of financial position events continued

Revision to credit facility with UniCredit Bank AG

During November 2010, the Group reached an agreement with UniCredit Bank AG, whereby the bank agreed to waive certain conditions of default concerning the Group's credit facility that were expected to occur at the 31 December 2010 measurement date in return for the following

- the Group will make a principal payment of $12 0 million on the revolver facility on or before 31 March 2011,
- the interest rate on the revolver and term tranches of the credit facility will increase by 1% effective 15 December 2010 As a result, the interest rate will be at 3 month LIBOR plus 7 25% for the revolver facility and 3 month LIBOR plus 8 0% for the term facility as of that date,
- the maximum credit facility will be set at $30 0 million as of 15 December 2010 and will be reduced by $6 0 million in a semi-annual basis thereafter; and
- the schedule principal payments of the term facility were unaffected (Note 15 "Borrowings")

As of the date of this report the Group is exploring several alternatives including divesting some or all of its oil and natural gas assets in order to raise $12 0 million or more in order to pay off some or all of its bank borrowings on or before 31 March 2011 Should the Group divest some or all of its oil and natural gas assets, there can be no assurance that the sales price will exceed the Group's carrying value of such assets Additional alternatives under consideration include, but are not limited to, securing a new bank credit facility and/or other potential transactions, such as a merger with another company

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Glossary

The following technical terms apply throughout this document, unless the context requires otherwise:

"1P"
Proved reserves

"2P"
the combined total of proved and probable reserves

"bbl"
barrel(s)

"bcf"
billion cubic feet of gas

"bcfe"
billion cubic feet equivalent, determined using the ratio of six mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids

"boe"
barrels oil equivalent, determined using the ratio of one bbl of crude oil, condensate or natural gas liquids to six mcf of natural gas

"boepd"
barrels oil equivalent produced per day

"BOEMRE"
the Bureau of Ocean Energy Management, Regulation and Enforcement is a bureau in the US Department of the Interior and the federal agency that manages the US's oil, natural gas and other mineral resources on the Outer Continental Shelf and conducts federal lease sales

"bopd"
barrels of oil produced per day

"delay rental"
a provision in an oil-and-gas lease that provides the lessee the right to maintain the lease from period to period during the primary term by way of paying delay rentals instead of starting drilling operations

"held by production"
when an acquirer holds the lease indefinitely, as long as production is maintained in paying quantities The leaseholder will have a set period in which to start producing (called the "primary term," which is generally five years for OCS leases in the shallow shelf water and one or more years for onshore leases), however, the lease generally expires after the primary term once production, and operations to obtain or restore production, have ceased for 180 days for OCS leases and a shorter period, generally 90 days, for onshore leases In the event of a lapsing lease, the leaseholder will generally be required to decommission existing equipment and return the leased area to a state agreed with the lessor

"hydrocarbons"
crude oil, natural gas and liquid natural gas in the form first produced from below the surface of the earth

"mboe"
thousand barrels oil equivalent, determined using the ratio of one bbl of crude oil, condensate or natural gas liquids to six mcf of natural gas

"mcf"
thousand cubic feet

"mgal"
thousand gallons of natural gas liquids

"mmcf"
million cubic feet

"mmbo"
million barrels of oil

"mmboe"
million barrels oil equivalent, determined using the ratio of one bbl of crude oil, condensate or natural gas liquids to six mcf of natural gas

"mmbtu"
million British thermal units

Glossary continued

"mmcfd"
million cubic feet of gas produced per day

"ngl"
natural gas liquids

"OCS"
Outer Continental Shelf

"operator"
the entity with the right and obligation to operate the lease or leases, when there is only one working interest owner, these rights and obligations arise by virtue of being the sole working interest owner; when there are multiple working interest owners, these rights and obligations arise under a contract called an operating agreement executed by the working interest owners of the lease or leases

"platform"
a structure attached to the seabed and rising above sea level onto which facilities and equipment necessary to produce hydrocarbons in an offshore environment are located

"proved (or proven) reserves"
estimated volumes of crude oil, condensate, natural gas and natural gas liquids which, based upon geologic and engineering data, are reasonably certain to be commercially recovered from known reservoirs under existing economic and political/regulatory conditions and using conventional or existing equipment and operating methods

"probable reserves"
are those reserves which geologic and engineering data demonstrate with a degree of certainty sufficient to indicate they are more likely to be recovered than not

"shut in"
a well that is closed down temporarily for repair, building up of reservoir pressure, lack of market, lack of an available pipeline outlet, or for some other reason

"spudded"
a well is "spudded" when a drill bit is first turned and the earth's surface is broken

"sidetrack"
to abandon a lower portion of a wellbore hole and divert the drill path in a new direction using the upper portion of the bore hole, this may be done to save drilling costs (the costs of drilling the upper portion of the bore hole) when targeting a new bottom hole location or to bypass mechanical impairments or equipment obstacles in the original bore hole

"ST"
abbreviation of sidetrack relating to a well number

"working interest" or "WI"
the lease interest which gives the owner the right to drill, produce and conduct operations (subject to contractual rights with other joint working interest owners pursuant to operating agreements) on a property and share in production

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