PremierOil

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22nd March 2007

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Securities and Exchange Commission
450 Fifth Street, N.W.
Washington DC 20549
UNITED STATES OF AMERICA

SUPPL

Dear Sirs

Premier Oil ~~plc~~ Group plc (f/k/a Premier Oil Group plc)
Rule 12g3-2(b) Exemption: File No. 82-34723

In accordance with Premier Oil plc's exemption from the disclosure requirements under Rule 12g3-2(b) of the Securities Exchange Act of 1934, please find enclosed the following press releases dated 22nd March 2007.

"Preliminary Results for the year ended 31 December 2006"

Yours faithfully

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FINANCIAL

Stephen Huddle
Company Secretary

Enc

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Press Release

Preliminary Results for the year ended 31 December 2006

Premier is a leading FTSE 250 independent exploration and production company with gas and oil interests in Asia, Middle East and Pakistan, the North Sea and West Africa. Our strategy is to add significant value through exploration and appraisal success, astute commercial deals and asset management.

Highlights

Operational

- Excellent exploration results in Indonesia and Vietnam with seven out of 11 successful wells;
- Good progress on development projects including gas sales agreements in Indonesia;
- Three successful acquisitions adding low cost barrels;
- Production maintained at 33kboepd;
- Reserves and contingent resources increased by 25 per cent to 289 mmboe;
- New acreage acquired in Indonesia, Norway, Congo, UK and Vietnam.

Financial

- Profit after tax and EPS up 75 per cent to US$67.6 million, 82.6 cents per share;
- Operating cash flow up 102 per cent to US$244.8 million (2005: US$121.2 million);
- Field operating costs stable at US$6.0 per barrel (2005: US$5.9 per barrel);
- Strong balance sheet with net cash of US$40.9 million (2005: net debt of US$26.2 million).

2007 Outlook

- Significant programme of high impact wells under way; up to 15 exploration wells planned;
- Key milestones on nine development projects during the year;
- Production expected above 35kboepd, on track to achieve 50kboepd in medium-term;
- New joint venture company in Middle East expected to build on opportunities in the region;
- Encountered hydrocarbons in Pakistan (Qadirpur deep) and Indonesia (Ibu Lembu), work ongoing.

"2006 was a year of very good progress for Premier with exploration success, development projects moving forward and good quality acquisitions at reasonable prices. All of these steps demonstrate successful execution of our stated strategy and are supported by improving financial results."

22 March 2007

Sir David John, Chairman

Simon Lockett, Chief Executive

ENQUIRIES

Premier Oil plc — **Tel: 020 7730 1111**
Simon Lockett
Tony Durrant

Pelham PR
James Henderson — **Tel: 020 7743 6673**
Gavin Davis — **Tel: 020 7743 6677**

Premier will be making a presentation to equity analysts at 10.00am. A live webcast of this presentation will be available via Premier's website at www.premier-oil.com.

CHAIRMAN'S STATEMENT

Premier's results for 2006 reflect on the impact of our quality producing assets at higher oil and gas prices. Our commercial and operating successes during the year have significantly added to this strong base.

Financial and operating performance

Continuing strength in oil and gas prices, especially in the first half of the year, supported sales revenues from continuing operations of US$358.8 million in 2006 (2005: US$359.4 million). Of particular note was the high gas demand in Pakistan which led to record gas production.

Profit after tax for the year was US$67.6 million (2005: US$38.6 million) reflecting higher realised oil and gas prices. Operating cash flow after tax and interest was US$244.8 million (2005: US$121.2 million) which fully funded our investments in exploration and development activities and our acquisition activity in the year. Net cash at 31 December 2006 was US$40.9 million (2005: net debt of US$26.2 million).

Average production for the year was stable at 33,000 barrels of oil equivalent per day (boepd) (2005: 33,300 boepd) and finished the year with a final production rate of 34,300 boepd through increased gas volumes in Pakistan. The Chinguetti field in Mauritania was successfully brought on-stream in February 2006 but subsequently produced below expectations as a result of reservoir complexities. Following a review and third party approaches, it has been decided to pursue sale discussions with a limited number of parties for our Mauritanian assets. Therefore the financial results of our activities in Mauritania are reported separately from all continuing operations in the attached financial statements.

Subsequent to year-end we exercised a pre-emptive right to acquire a further interest in the Scott field. On completion, this interest will add approximately 5,000 boepd to our current year production.

In addition to this increased interest in the Scott field, we are pleased to have completed two separate purchases of interests in North Sumatra Block A in Indonesia. Together, these take our equity in the block to 41.66 per cent. The block contains several undeveloped gas fields which will be developed to supply existing local fertiliser plants. A Memorandum of Understanding (MoU) for the sale of this gas has already been signed. There is much further prospectivity on the block and in North Sumatra generally.

Oil and gas proven and probable booked reserves amount to 165 million barrels of oil equivalent (mmboe), including 13 mmboe acquired with the Scott field interest subsequent to year-end (2005: 164 mmboe). Following our successful exploration activity during the year, and the completion of the two acquisitions in North Sumatra, total reserves and resources, which include discoveries not yet booked pending commercialisation, have increased to an estimated 289 mmboe (2005: 232 mmboe).

Our exploration programme in 2006 delivered seven successes out of 11 wells (including two sidetracks) at less than the planned spend of US$50 million. Of particular encouragement were the two discoveries in Vietnam, Dua and Blackbird. Our teams in Ho Chi Minh City and elsewhere are now moving rapidly into planning the development of these discoveries. The continuing success in Indonesia, where as operator we have drilled 13 out of 15 successful wells in the last seven years, is also pleasing and we are following up with an extensive programme of exploration, appraisal and development in 2007.

Beyond the significant current year plans, it is important to build a future programme of drilling opportunities. To this end, we have added good quality new acreage in Congo, UK, Vietnam and Indonesia and, in early 2007 received five new awards in the 2006 Norwegian APA round. During the year we qualified as an operator on the Norwegian Continental Shelf and the new awards include our first operated block.

We continue to focus on improving our consistent health, safety and environmental performance and yet again are pleased to state that we have beaten our own targets in this area.

Shareholder returns

During 2006 Premier shares increased in value by 52 per cent. Over the five years to 31 December 2006, Premier's share price has increased by 645 per cent. The company continues to be a top ten performer in the FTSE 250 over the same period. This exceptional performance has reinforced our policy to reward shareholders principally through share price growth and to utilise cash flow within the business.

The Board announced on 7 December 2006, that it had terminated all discussions regarding a possible offer for the company following the earlier receipt of a preliminary and conditional proposal. The Board remains extremely confident that the pursuit of the company's strategy of high impact exploration and its growing portfolio of development projects will continue to be of long-term benefit to shareholders.

Board changes
During the year we were pleased to announce the appointment of Professor David Roberts as a non-executive director. David has over 30 years experience in all aspects of exploration worldwide and will provide invaluable technical input at Board level.

Two non-executive directors, Azam Alizai and Ian Gray, retired after 10 years on the Board. We are enormously grateful for their contributions over a long period of time.

Outlook
It is pleasing to report early successes in delivering on the strategic targets set out by the Board in September 2005. In particular, with good progress on our development projects we feel increasingly confident that our production will exceed the medium-term target level of 50,000 boepd. In addition, the discoveries in Vietnam are early evidence that our exploration strategy - focusing our efforts on at least four high impact wells per year - is bearing fruit.

2007 promises to be another exciting year for Premier as we continue to pursue our strategy. We have already acquired interests in existing fields such as North Sumatra Block A in Indonesia, and the Scott field in the UK. Our drilling campaign for the year is under way with early success in Pakistan and Indonesia and with current activity in Guinea Bissau, India and the UK. Additional wells will follow later in the year in Pakistan, Indonesia and Gabon. We will be returning for a further programme in Vietnam during 2008. I am confident that we will achieve further significant milestones during the year in our development projects in Norway, Indonesia, Pakistan and Vietnam.

The strength of our performance has generated an excellent set of financial results and maintained our solid balance sheet position. We will maintain this disciplined approach as we enter a period of significant growth.

Sir David John KCMG
Chairman

FINANCIAL REVIEW

Economic environment

2006 saw further strength in oil and gas commodity prices reaching a peak early in the second half of the year. The Brent oil price, which began the year at US$58.9 per barrel (bbl), averaged US$65.4/bbl reaching a peak of US$78.6/bbl during August. Gas prices worldwide were also boosted according to the degree of linkage with crude pricing. The early part of 2007 has seen some weakness in spot pricing with a relatively warm start to the year. Forward prices have remained above US$60/bbl.

Strong commodity prices and increased industry activity levels have continued to put pressure on both operating and development costs. Rig rates and other drilling service costs remain at historically high levels and shortages of key vessels and equipment are contributing to project delays. The industry is responding to cost and availability issues by seeking out new engineering and commercial approaches to optimise use of available resources.

Income statement

Production levels in 2006, on a working interest basis, averaged 33,000 boepd compared to 33,300 boepd in 2005. In 2006 this included an average of 2,400 boepd from the Chinguetti field in Mauritania. On an entitlement basis, which allows for additional government take under the terms of our Production Sharing Contracts (PSC), production was 28,900 boepd (2005: 28,700 boepd). Realised oil prices averaged US$64.90/bbl compared with US$48.38 in the previous year.

Gas production averaged 127 million standard cubic feet per day (mmscfd) (22,000 boepd) during the year or approximately 67 per cent of total production. Average gas prices for the group were US$5.11 per thousand standard cubic feet (mscf) (2005: US$3.82/mscf). Gas prices in Singapore, which are linked to High Sulphur Fuel Oil (HSFO), have moved broadly in line with crude pricing, averaging US$9.43/mscf (2005: US$7.90/mscf) during the year.

Total sales revenue from all operations was 12 per cent higher than 2005 at US$402.2 million (2005: US$359.4 million) as a result of the higher average commodity prices. Excluding revenues of US$43.4 million from the Chinguetti field, sales revenue for continuing operations was US$358.8 million.

Cost of sales decreased to US$126.6 million compared to US$176.5 million in 2005. The year-end inventory position moved from a stock overlift to an underlift position, driven by the timing of liftings around each year-end, and resulting in a credit to cost of sales of US$22.3 million (2005: charge of US$25.9 million). After excluding this stock effect, underlying unit operating costs were stable at US$6.0 per barrel of oil equivalent (boe) (2005: US5.9/boe) despite the general rise in the cost environment faced by the industry in fuel, material and wage costs. Underlying unit amortisation amounted to US$6.3 per boe (2005: US$5.5/boe).

The cost of sales and operating cost figures exclude those relating to Mauritania, which are separately reported in the balance sheet and income statement as assets held for sale. The results of the Mauritanian operation include a one-off adjustment for a bonus of US$9.2 million paid to the Mauritanian authorities on renegotiation of the PSC documentation and a loss on reclassification as assets held for sales of US$8.1 million..

Administrative costs fell by US$3.0 million to US$16.6 million. This includes a charge of US$5.7 million in respect of current year and future provisions for long-term incentive plans.

Operating profits were US$178.5 million, a 41 per cent increase from the prior year. Finance charges net of interest income totalled US$5.7 million (2005: US$1.1 million). Pre-tax profits were 37 per cent higher at US$172.8 million (2005: US$125.8 million). The taxation charge totalled US$86.7 million (2005: US$86.3 million) despite higher profits benefiting from the favourable resolution of certain outstanding prior year provisions. Basic earnings per share from continuing operations amounted to 105.3 cents, an increase of 119 per cent on the previous year.

Cash flow

Cash flow from operating activities, including the assets held for sale, amounted to US$244.8 million, up from US$121.2 million in 2005. These cash flows include payments of US$31.9 million received from the joint venture in Pakistan (2005: US$47.1 million).

Capital expenditure and pre-licence exploration expenditure in the period was US$175.7 million (2005: US$144.4 million). This spend includes the US$17 million cost of our first acquisition in North Sumatra Block A (an equity interest of 16.67 per cent) which was completed in March 2006. Exploration spending was US$46.9 million in line with our stated target.

Net cash inflow, before movements related to financing, amounted to US$69.1 million (2005: US$23.2 million outflow).

Net cash position

Net cash at 31 December 2006 amounted to US$40.9 million against a net debt position of US$26.2 million at the previous year-end. This comprised cash balances and short-term investments. As a result of this strong cash position, the US$275 million credit facility was undrawn at year-end. Together with its strong cash flow from producing assets, the company is in an excellent position to fund an increased exploration and development programme over the next few years.

Hedging and risk management

The Board's policy remains to lock in oil and gas price floors at a level which protects the cash flow of the company and the business plan. Such floors are purchased for cash or by selling puts at a ceiling price where market conditions are considered favourable. All transactions are matched as closely as possible with expected cash flows to the company; no speculative transactions are undertaken.

Hedges utilising collars were previously entered into for the period 1 January 2006 to 31 December 2010 covering nine million barrels of oil (mmbbls). The average floor price was US$37.42/bbl with a ceiling price of US$100/bbl. In addition, 384,000 metric tonnes of HSFO, representing the equivalent of around a third.of Indonesian gas production for the period 1 January 2006 to 31 December 2009 were covered at a floor price of US$200 per metric tonne and a ceiling price of US$480 per metric tonne.

During the course of 2006 the volume, pricing and maturity of these transactions was kept under review and changes made where market conditions were favourable. As at 31 December 2006, hedges covered 7.2 million barrels of liquids for the period to 31 December 2010 at an average floor price of US$38.55/bbl and a ceiling price of US$100/bbl. A further 1.2 million barrels are covered for the period 1 January 2011 to 31 December 2012 at a floor of US$41/bbl and a cap of US$100/bbl. On the gas side, 612,000 metric tonnes (mt) of HSFO are hedged for the period 1 January 2007 to 30 June 2012 at a floor level of US$245/mt and ceiling price of US$500/mt. Under International Financial Reporting Standards (IFRS) IAS 39, these hedges are required to be marked to market at the balance sheet date. The aggregate valuation is a US$0.3 million liability (2005: US$1.6 million asset) generating at US$1.9 million charge in the 2006 income statement.

Since the group now reports in US dollars, exchange rate exposures relate only to sterling receipts and expenditures, which are hedged in dollar terms on a short-term basis. The group recorded a gain of US$0.1 million on such hedging at year-end.

Cash balances are invested in short-term bank deposits, managed liquidity funds and commercial paper subject to Board approved limits. The group undertakes an insurance programme to reduce the potential impact of the physical risks associated with its exploration and production activities. In addition, business interruption cover is purchased for a proportion of the cash flow from producing fields.

Production and reserves

2006 has seen key milestones in a number of our development projects and initial success in our high impact exploration programme. These are material steps forward in achieving our medium-term production target of 50,000 boepd and in growing our portfolio of four regional businesses.

Working interest production for 2006 averaged 33,000 boepd. Comparable production from 2005 was 33,300 boepd. Production comprised 33 per cent liquids and 67 per cent gas, with Pakistan and Indonesia each accounting for around 37 per cent and 35 per cent of the total respectively, the UK 21 per cent and West Africa the remainder. On an entitlement basis, group production for the year was 28,900 boepd (2005:.28,700 boepd).

	Working interest		Entitlement	
Production (boepd)	**2006**	**2005**	**2006**	**2005**
North Sea	6,850	9,750	6,850	9,750
Middle East-Pakistan	12,150	11,500	12,150	11,500
Asia	11,550	12,050	7,800	7,450
West Africa	2,450	-	2,100	-
Total	**33,000**	**33,300**	**28,900**	**28,700**

As at 31 December 2006 proven and probable reserves, on a working interest basis, based on Premier and operator estimates, were 152 mmboe. On a pro forma basis the Scott field acquisition would increase reserve estimates to 165 mmboe.

	Reserves (mmboe)	**Reserves and contingent resources (mmboe)**
Start of 2006	164	232
Production	(12)	(12)
Net additions and revisions	-	69
End of 2006	**152**	**289**
Scott acquisition*	13	13
Pro forma total	165	302

* Expected to be completed in the first half of 2007.

At year-end, pro forma reserves comprised 18 per cent liquids and 82 per cent gas, and the equivalent volume on an entitlement basis amounted to 146 mmboe (2005: 146 mmboe).

Reserve revisions represent the write-down of 5 mmboe from the Chinguetti field in Mauritania, offset by an increase in booked reserves from the Anoa field following strong offtake volumes by the buyers under the existing Gas Sales Agreement (GSA). Discoveries made in the year in Vietnam have not been recorded in booked reserves, pending completion of ongoing appraisal and commercialisation work. These volumes, together with others in the process of being commercialised (including unsold gas in Indonesia and other discoveries which have not yet received development sanction elsewhere) give increased total reserves and contingent resources of 289 mmboe (2005: 232 mmboe).

Exploration and appraisal

Premier's achievement in growing its exploration portfolio in recent years yielded a series of exploration successes in 2006 and the opening up of significant follow-on opportunities. The company has also continued to seek and sign-up new prospective areas in its North Sea, West Africa and Asian business units.

In 2006 Premier drilled 11 exploration and appraisal wells with a success rate of over 60 per cent. In Vietnam we drilled three wells resulting in a successful appraisal well and two new exploration discoveries. In our Indonesian Natuna A Block we made three discoveries. Five of these six wells were Premier-operated, and Premier's E&A success rate has continued to exceed 50 per cent since 2000. In Indonesia we have now drilled 13 out of 15 successful operated exploration wells since 2000. In Vietnam the Blackbird oil discoveries are the first in the vicinity, and open up substantial future opportunities across two large tranches of mostly unexplored acreage in Vietnam (Block 12 and Block 7&8/97) and another large tranche in Indonesia (the Tuna Block), awarded early in 2007.

These successes in Asia have confirmed the validity of our strategy of extending the knowledge we have gained over many years from our interests in the Indonesian Natuna Sea area into the neighbouring Vietnamese waters. In adding acreage around the world during 2006 - in Vietnam, in Indonesia, in Congo and in Norway we have been mindful of staying within our areas of competency.

Premier planned to spend no more than US$50 million on seismic and drilling in 2006. In order to ensure a broad exposure to high reward prospects and, at the same time, keep its cost exposure down, we undertook several farmouts reducing our equity in projects in return for funding current exploration on favourable terms. These projects include farmouts for the 2006 wells in Vietnam Block 12E and W, and for the 2007 wells in Guinea Bissau, the UKCS Peveril well and the Philippines Ragay Gulf SC-43 licence.

2007 sees a very active exploration programme, with Espinafre-1 and Eirozes-1 being drilled offshore Guinea Bissau, Peveril-1 in the UKCS, Masimpur-3 targeting a large structure in NE India, several exploration wells in Indonesia, a deep-water well in Indus offshore Pakistan, a well on our Themis Block in Gabon, and programmes unfolding in Vietnam for 3D acquisition and more wells drilling in late 2007 and through 2008. The 2007 programme will include up to 15 wells at an estimated pre-tax cost of US$100 million (post-tax and recoveries: US$70 million).

ASIA

Indonesia

Premier's core asset in Indonesia is its interest in the West Natuna Gas project, which supplies gas under a long-term gas sales contract to Singapore. This is held through equity interests in Natuna Sea Block A and the Kakap Production Sharing Contracts (PSCs).

In 2006, Premier-operated Block A sold an overall average of 130 billion British thermal units per day (BBtud) (gross) with a further 66 BBtud (gross) average sold from the non-operated Kakap fields under the same agreement. Oil production from Anoa averaged 2,581 barrels of oil per day (bopd) gross (2005: 3,023 bopd) with the reduction due to natural depletion of the oil reservoirs. Oil production from Kakap averaged 6,998 bopd gross (2005: 7,263 bopd).

Overall, net production from Indonesia amounted to 11,550 boepd (2005: 12,050 boepd) with Anoa and Kakap contributing 7,890 boepd and 3,660 boepd respectively.

Premier's commitment to health, safety and environmental performance was demonstrated with the award of OHSAS 18001 and retention of the ISO 14001 certification and Indonesia's 'PROPER Blue' rating.

The West Lobe Wellhead platform was installed in April 2006 with hook up taking place in May 2006. The Seadrill-5 jack-up drilling rig arrived on location at the platform in August 2006 to drill four gas production wells into the West Lobe of the Anoa field. All wells achieved their objectives with first gas flowing from the platform in December 2006. During the drilling campaign an opportunity was taken to appraise an un-drilled potential oil reservoir in the central area of the Anoa field. The well successfully encountered and evaluated a 67ft oil column before being sidetracked to the planned gas development location for the well. Planning is now under way for the development of the oil discovery with a well expected to be drilled in the first half of 2007 which is expected to add initially up to 2,000 bopd (gross) to Anoa production.

Negotiations for further gas sales from Block A continue with prospective buyers in the region and we are targeting sales of gas from 2010 to the Singapore petrochemical sector. Discussions have also been held with PLN, the Indonesian national power company, to sell gas domestically to Batam. We expect to move to definitive gas sales agreements on these projects during the second half of 2007.

The 2006 Indonesia exploration drilling campaign resulted in a 100 per cent success rate with a gas discovery in Macan Tutul-1 and the discovery and testing of oil and condensate rich gas at Lembu Peteng-1. Lembu Peteng forms part of a trend of structures that stretches east to the existing Lembu-1 discovery, dating from 1984. Further exploration and appraisal wells on the trend are planned for 2007 to establish the significance and development potential of this area as part of the drive to ensure maximum value is extracted from the Natuna Block A asset. Technical studies were also carried out across other areas on Block A to identify additional potential drilling targets for the 2007 drilling campaign. A number of prospects have been highlighted for further assessment with the final programme dependent on ongoing work and results of the early wells.

During the year, Premier acquired a 16.67 per cent stake in the North Sumatra Block A PSC. Initially Premier partnered with Japex and Medco holding equal interests. After year-end Premier increased its stake in the PSC to 41.67 per cent by jointly purchasing the ConocoPhillips share of the PSC with Medco. The acquisition cost for the two transactions was US$53 million.

The acreage contains undeveloped discoveries on the Alur Siwah, Alur Rambong, and July Rayeu fields, with certified reserves of over 650 billion cubic feet (bcf) of gas. There is substantial upside from around 20 identified exploration prospects with total prognosed unrisked potential reserves of 1.5 trillion cubic feet (tcf) gross, Enhanced Oil Recovery (EOR) opportunities through redevelopment of old abandoned oil fields, as well as from the possible development of the giant Kuala Langsa gas field. Subject to completing a Gas Sales Agreement, first gas is expected to commence in early 2010, supplying feed gas to two fertiliser plants in North Sumatra.

In December, Premier was awarded an interest in the Buton PSC in South Eastern Sulawesi. The Buton PSC covers 3,396km^2 and lies on the south-eastern side of Buton Island, Sulawesi, Indonesia. It is an underexplored block in an onshore frontier area. Oil seeps are prolific over the island and volumes of expelled oil are sufficient to underpin the commercial asphalt mining operations that have been ongoing on the island since colonial times. The acreage has potential for multiple targets on structures that are known to exist from satellite image analysis. Our initial work programme will focus on identifying prospects to support a high impact drilling opportunity in 2009. Premier is partnered by Japex and Kufpec in this PSC, and holds a 30 per cent non-operated interest.

Vietnam

Premier Oil drilled three successful exploration wells as operator and acquired over 1,500km of 2D marine seismic data on Block 12. The first discovery, Dua-4X, drilled in the north of the Dua field, confirmed the extent of an oil accumulation first discovered in 1974 with the Dua-1X well. Dua-4X was then sidetracked to delineate the northern half of the Dua field. The rig was then moved to drill the Dua-5X well which intersected oil in multiple reservoirs in the southern part of the Dua field, two reservoir zones were tested and flowed at a combined rate of 6,947 boepd. Dua-5X was then suspended as a potential producer.

The second exploration structure to be drilled was 20km to the southwest at Blackbird, where well 12E-CS-1X discovered oil in multiple reservoir zones, two of which were tested at a combined rate of 6,569 boepd. This well was sidetracked to delineate the extent of the hydrocarbon bearing reservoir. Following this exploration success, Premier has commenced appraisal and development studies for each of the Blackbird and Dua discoveries. Oil in place across the two discoveries is currently estimated to be in the range of 180 to 620 mmbbls, of which approximately 80 mmbbls represents most likely recoverable volumes. With first oil currently scheduled for 2010, Premier has commenced pre-development studies for both fields and a programme of 3D seismic acquisition will commence in early April 2007 to clarify the volumetric uncertainty on the Blackbird field. The Dua field is already covered by 3D seismic data acquired in 2005. The 3D area will be extended beyond the Blackbird field to define other prospects ahead of the next phase of exploration drilling likely to be in 2008. Premier holds a 37.5 per cent exploration working interest in Block 12, with partners Santos (37.5 per cent) and Delek (25 per cent).

In December, Premier exercised an option to acquire from VAMEX a 45 per cent working interest in, and operatorship of, Block 7&8/97. Block 7&8/97 is located immediately to the southeast of Block 12 in the Nam Con Son Basin. Interpretation of 2D marine seismic data from Block 7&8/97 has demonstrated the existence of the same play elements which create petroleum prospectivity in Block 12 and the potential for numerous large structures suitable for high impact well locations.

India

Drilling commenced on the high impact Masimpur prospect in Assam on 21 January 2007. Work is under way to prepare for drilling of two follow-up wells to Masimpur on the large Hailakandi and Kanchampur gas prospects and road and site construction has begun at Hailakandi following environmental approvals. Premier is operator of the Cachar Block and holds a 14.5 per cent working interest.

All outstanding issues have been resolved between the partners regarding the development of the Ratna oil fields, offshore Mumbai and documentation leading to the formal signature of the PSC is being progressed through the ministries concerned. Premier holds a 10 per cent (carried) working interest in the Ratna fields, estimated to contain around 80 mmbbls.

Philippines

During 2006 Premier operated the SC43 licence in the Ragay Gulf of SE Luzon province with a 42.5 per cent working interest. During 2006 Premier carried out seismic reprocessing, geological studies and preparatory work for a well on the Monte Cristo prospect. Geological work led to the identification of a new prospective trend in the Panaon Limestone formation and marine seismic acquisition is planned in 2007 to pursue this promising lead. Subsequent to year-end, Premier has farmed out 21.5 per cent of its 42.5 per cent interest to Pearl Energy and PNOC in exchange for a carry in the forthcoming well now expected in the first half of 2008.

MIDDLE EAST PAKISTAN

Pakistan

The record production level achieved in 2005 was exceeded during 2006. Production net to Premier in 2006 was 12,150 boepd, an increase of 6 per cent over 2005 (11,500 boepd). The increase in production was mainly due to higher sales from Zamzama field, on exceptionally high gas demand.

Qadirpur produced an average of 3,866 boepd, for Premier's net interest of 4.75 per cent (2005: 3,807 boepd). The project to enhance Qadirpur plant capacity from 500 mmscfd to 600 mmscfd was ongoing through 2006 and first gas from that increased capacity is expected by end of December 2007. A Term Sheet has been signed with the gas buyer, Sui Northern Gas Pipelines Limited, to increase the Annual Contract Quantity (ACQ) from the existing 450 mmscfd to 550 mmscfd. Qadirpur Deep-1 well has been drilled to a depth of 4,681 metres. The well encountered hydrocarbons in several zones and was suspended when higher than anticipated temperatures were encountered. Specialist equipment has now been ordered and testing on the well will be resumed later in 2007.

On Kadanwari, the K-15 well was tied back to the processing plant. The additional production from it compensated for the natural decline of the field and also provided some production redundancy. The field produced an average of 1,200 boepd during 2006 (2005: 1,228 boepd) for Premier's interest of 15.79 per cent. To exploit additional reserves in Kadanwari, two wells (K-16 and 18) are planned to be drilled in the first half of 2007.

Zamzama produced an average of 4,140 boepd, net to Premier, during 2006 from its 9.375 per cent interest. This was some 13 per cent higher than the previous year (2005: 3,677 boepd). Work continued in 2006 on the Zamzama Phase 2 development – to make available gross 150 mmscfd high calorific value sale gas in the third quarter of 2007.

The production level in the Bhit field from Premier's 6 per cent working interest was 2,944 boepd in 2006 (2005: 2,788 boepd). A supplemental GSA to increase the Bhit ACQ from 270 mmscfd to 300 mmscfd has been signed by the gas buyer Sui Southern Gas Company Limited (SSGCL) and by joint venture partners. The Bhit plant capacity is being enhanced to 315 mmscfd to allow accelerated Bhit field production and production of Badhra reserves starting by the end of the fourth quarter of 2007.

In Zarghun South, negotiations on the GSA were successfully concluded with the gas buyer, SSGCL, for the sale of 22 mmscfd gas from the field. The field development has commenced and first gas is planned for the first quarter of 2009. Premier's interest of 3.75 per cent is carried by the operator (other than for government commitments) during the development and production phases of the field.

Egypt

In Egypt, the Al Amir-2 well was drilled to appraise the 2005 Al Amir discovery on the onshore North West Gemsa Concession in Egypt. The discovery well, Al Amir-1, had flowed oil at over 750 bopd from the South Gharib Formation. The Al Amir-2 well confirmed oil at the same reservoir level. However, on test, the well flowed water and oil at sub-commercial rates and was plugged and abandoned. The Al-Fagr wildcat well was plugged and abandoned after MDT tests were run. Although shows were recorded while drilling and logs displayed possible hydrocarbon saturations in the target section, no hydrocarbons were recovered on test. Subsequent to year-end, Premier has exercised an option with the operator, Vegas, to reduce its interest to 10 per cent in the block which entitles Premier to a partial refund of past costs. Premier continues to participate in exploration licensing rounds and farm-in discussions with a view to building on its position in Egypt.

Our new business efforts continue to be focussed on building existing relationships in the region. In January we signed an MoU with Emirates International Investment Corporation (EIIC), an Abu Dhabi investment company, with a view to acquiring new interests in Abu Dhabi and elsewhere in the region.

NORTH SEA

In the North Sea, Premier is continuing to pursue the established strategy of seeking out high impact exploration while maximising the value from its existing producing assets.

UK

Production in the UK in 2006 amounted to 6,850 boepd (2005: 9,750 boepd) representing 21 per cent of the group total (29 per cent in 2005). This represents a decrease of some 30 per cent on last year's level due to a combination of natural decline and specific operational problems.

The Wytch Farm oil field contributed 3,205 boepd net production to Premier, down 20 per cent on last year. In 2006, the production performance was severely impacted by a number of serious well failures. In January, the F05 well, producing 3,000 bopd gross, failed and required a workover. The well was brought back onstream in March. The M07 well was completed and brought on production in February but was suspended due to a suspected collapsed hole. The subsequent intervention was unsuccessful and the well was redrilled and production re-established in June. Year-end production recovered to 27,000 boepd gross (3,300 boepd net). BP, the operator, is planning to complete two new wells and four workovers during 2007, together with various plant upgrades and a new office facility.

Net production from Kyle was 1,962 boepd, down 46 per cent on last year. Gas production remained below the annual target for most of the year however this was compensated by higher oil production that enabled Kyle to deliver in line with the annual composite production budget. The re-perforation of the Kyle-15 well was delayed until October and when completed produced disappointing results. The K16 well that was scheduled to be drilled in 2006 has been rescheduled to 2008. The gas lift project that was originally planned to commence in 2006 has now slipped and is expected to be completed in May 2007. Concurrently facility upgrades are being undertaken on the Petrojarl Banff host processing facility.

In the Fife area, Premier's net production amounted to 1,156 bopd from the Fife, Fergus, Flora and Angus fields. The Angus field was suspended in September after an intervention failed and remains suspended subject to the joint venture determining the forward strategy for this asset. The Fife FPSO fixed contract term ends in December 2007 with discussions currently under way with Bluewater to exercise the contract extension option.

Scott and Telford accounted for the remainder of net UK production. In December, the company received notification of Hess' intention to sell its 20.05 per cent equity interest in the Scott field to Nexen Petroleum UK. Premier has since advised Hess that it is pre-empting the proposed transaction. Upon completion of the relevant Sale and Purchase Agreement Premier's working interest will become 21.83 per cent effective 1 January 2007, representing an average 2007 entitlement of 5,000 bopd at expected production rates.

Detailed evaluation of the UK exploration portfolio continued throughout 2006 working on developing the prospects to drillable candidates for 2007 and 2008, specifically in Blocks 23/22b (P1181) and 21/7b (P1177) in the Central North Sea. Further geological and geophysical work integrated with a comprehensive commercial evaluation on the Southern North Sea portfolio of Blocks 44/21c, 44/26b (P1184), Blocks 42/10, 42/15 (P1229) and Blocks 43/22b, 43/23, 43/27b, 43/28, and 43/29 (P1235) resulted in Premier having fulfilled the work obligations for these licences, relinquishing them in December as no commercial viable hydrocarbon prospects were identified. Integration of the results from the 21/6a-7 well on the Palomino prospect in licence P1048, which was plugged and abandoned dry in January 2006, are being integrated into the adjacent licence P1177 evaluation to assess the remaining prospectivity.

Premier's 100 per cent equity in the Fife area Blocks 39/1c and 39/2c was successfully farmed down to a 30 per cent equity level carried through the forecast costs of the Peveril prospect well, due to spud in March 2007 to test the Jurassic Fulmar sands in a similar setting to the Angus field. Significant follow on potential is provided by Blocks 39/1b & 39/7 (P1152) where additional prospects have been identified on the reprocessed 3D seismic.

Two licence applications were made by Premier in the UK 24th Licensing round covering Blocks 15/24a, 15/25f, 15/29e and 15/23c. As of the 31 December no licence round announcement had been made by the DTI. Subsequently, in February it was announced that Premier had been awarded a split portion of the 15/24a application area excluding the Bowmore accumulation. This offer is currently being evaluated for response to the DTI.

Norway

The five licences awarded to Premier in the APA 2005 licence round are being progressed through the work programmes tendered to reach critical decision points: drill or drop for three of the licences by the end of 2007; acceleration of a possible well on one licence and development approval for the Frøy potential redevelopment. These licences offer a spectrum of redevelopment, appraisal and exploration opportunities which have the potential for both early production and high impact exploration. The five APA 2005 licences consist of Blocks 35/12 and 36/10 licence PL378; Blocks 16/1 and 16/4 licence PL359, Blocks 34/2 and 34/5 licence PL374(s), Blocks 34/5 and 34/5 licence PL375, and Blocks 25/3, 25/5, and 25/6 PL364 Frøy.

The Frøy field was abandoned in 2001 by a previous operator in a much lower oil price environment and due to the imminent abandonment of the nearby Frigg field to which it was tied back. The Frøy field is the subject of extensive redevelopment studies with plans to seek early development approvals.

Premier was very active in the APA 2006 licensing round submitting applications for five potential licences. The licence round announcement in January 2007 confirmed that we had been successful in securing five new licences, including two licences in the very competitive Bream discovery area. The licence interests obtained in the APA 2006 round are as follows:

Block no. (or part block no.)	Working interest	Operator
17/8,9,11,12 & 18/7,10 (Bream appraisal)	20	British Gas
7/12, 18/10, 18/11, 8/3 & 9/1 (Bream exploration)	40	Premier Oil
31/3, 32/1, 36/10	40	Revus
35/9 (part)	25	Nexen
35/8, 35/9	15	Nexen

The Bream appraisal area contains the Bream discovery which is to be appraised by a well with a declaration of development by the end of 2008. Contingent upon a successful appraisal of the Bream structure, the partnership group will drill a further exploration well to target additional resources identified in this highly prospective area.

Premier successfully qualified as an operator in Norway in 2006 and the award as operator for the Bream exploration acreage reflects Premiers commitment to develop a business in Norway. The licence has a five-year first term duration requiring 3D seismic acquisition and a firm well.

Blocks 31/3, 32/1, and 36/10 are adjacent to the PL378 licence and help in the development of a core area around the Tampen Spur for Premier. The remaining two licence awards are adjacent to the Gjøa field which is currently being developed and offer some interesting stratigraphic potential.

WEST AFRICA

Mauritania

The Chinguetti oil field came on production in Woodside operated PSC B on 24 February 2006 at an initial rate of 70,000 bopd (5,600 bopd net to Premier). The field is located in 800 metres of water some 90km west of the capital Nouakchott.

The initial development of six production wells and three water injectors did not perform to initial expectations in 2006. This is the result of more than expected reservoir compartmentalisation due to reservoir geometry and complex structure. Production at the end of 2006 was in the region of 22,000 bopd (1,780 bopd net Premier). Remedial action to increase production commenced in late December 2006 with drilling of the Chinguetti-18 well. This well encountered 35 metres of net oil pay, close to expectations, and was being completed at the end of the reported period. Additional development drilling is planned in the third and fourth quarter of 2007, with up to six wells being considered, which would extend the drilling campaign in to 2008.

The performance of the initial development wells has an impact on the expected reserves of the field, with the operator's proven and probable reserves being reduced from the pre-development expectation of 123 million barrels of oil (mmbo) to 62 mmbo. Further revisions are expected as a result of a 3D high-resolution and 3D seismic survey that is to commence in the first half of 2007 over the field. Premier expects that, as a result, the 2P reserves will be revised upwards in the course of the year. The reserves are also expected to increase with further phases of development drilling, if commercially viable.

In 2006, the Mauritanian government challenged certain amendments (avenants) to Woodside operated concessions, including those in which Premier has an interest (PSCs A and B). This resulted in the joint ventures signing revised PSCs with the Mauritanian government in June 2006, under which the fiscal provisions in the contracts were altered to reflect the higher oil prices prevailing at that time at a net cost to Premier of US$9.2 million.

One exploration well was drilled in Premier's Mauritanian acreage, Colin-1 in PSC A. The well encountered good quality sand reservoirs but was dry. A second well, Kibaro-1, which had been planned to test a Cretaceous objective in PSC A, was deferred to 2008 due to rig scheduling necessitated to drill the Chinguetti-18 well.

In December following a number of approaches, the Board determined that our interests in Mauritania were unlikely to generate high impact exploration opportunities which are our key targets in the region. Accordingly we have decided to conduct an auction with a view to the sale of the asset. The results of the Mauritanian operation have, therefore, been classified separately in the financial statements under 'assets held for sale'.

Guinea Bissau
During 2006 processing of the 2005 3D seismic data over the Eirozes prospect, and re-processing of the existing 3D seismic over the Espinafre prospect, were completed. The two data sets were interpreted to mature the Espinafre and Eirozes prospects for drilling.

The Global Santa Fe jack-up rig 'Baltic' was contracted for a two well programme commencing in the first quarter of 2007, and the rig was under tow to our acreage at the end of the reported period. The Espinafre-1 well was spudded in February.

Success on either of these two wells will lead to a significant increase in value and enhance the prospectivity of a number of lookalike prospects on the block.

Gabon
In 2006 both existing 2D and 3D seismic data on the Sterling Energy operated Themis Permit were re-processed. The results of the interpretation of this reprocessed data have been incorporated into a block-wide understanding of the prospectivity to mature a prospect for drilling. Premier, as drilling operator for the joint venture, has contracted the Global Santa Fe 'Adriatic 6', to drill this exploration well, which will take place during the third quarter of 2007.

Data interpretation and studies on the Dussafu Permit have been carried out during 2006 leading to development of a leads and prospects portfolio. This will be used to find potential targets for drilling in the fourth quarter of 2007 or the first quarter of 2008.

Congo
During 2006, Premier was awarded a 58.5 per cent operated working interest in Block IX, with its joint venture partners Ophir Energy Company Limited and the Congo national oil company, SNPC. The Production Sharing Contract was ratified by the Congolese Parliament on 5 October 2006. The block contains several prospects with high impact exploration potential. Technical evaluation is ongoing with the expectation that the first well on the block could commence in 2008.

SADR
The company's exploration assets in the Saharawi Arab Democratic Republic (SADR) remain under force majeure, awaiting resolution of sovereignty under a United Nations mandated process.

CONSOLIDATED INCOME STATEMENT

	2006 $ million	2005 $ million
Continuing operations:		
Sales revenues	**358.8**	359.4
Cost of sales	**(126.6)**	(176.5)
Exploration expense	**(15.3)**	(20.6)
Pre-licence exploration costs	**(21.8)**	(15.8)
General and administration costs	**(16.6)**	(19.6)
Operating profit	**178.5**	126.9
Interest revenue and finance gains	**2.0**	5.9
Finance costs and other finance expenses	**(7.7)**	(7.0)
Profit before tax	**172.8**	125.8
Tax	**(86.7)**	(86.3)
Profit for the year from continuing operations	**86.1**	39.5
Discontinued operations		
Loss for the year from assets held for sale	**(18.5)**	(0.9)
Profit for the year	**67.6**	38.6
Earnings per share (cent):		
From continuing operations		
Basic	**105.3**	48.1
Diluted	**104.1**	47.7
From continuing and discontinued operations		
Basic	**82.6**	47.0
Diluted	**81.7**	46.6

STATEMENT OF TOTAL RECOGNISED INCOME AND EXPENSES

	2006 $ million	2005 $ million
Currency translation differences	**0.3**	-
Pension costs – actuarial gains/(losses)	**1.4**	(2.2)
Net gains/(losses) recognised directly in equity	**1.7**	(2.2)
Profit for the year	**67.6**	38.6
Total recognised income	**69.3**	36.4

RECONCILIATION TO NET ASSETS

	2006 $ million	2005 $ million
Net assets at 1 January	**376.1**	354.1
Total recognised income	**69.3**	36.4
Adjustments relating to past restructuring	-	3.1
Purchase of shares for ESOP Trust	-	(8.5)
Provision for share-based payments	**3.0**	2.9
Issue of ordinary shares	**0.7**	1.3
Repurchase of ordinary share capital	-	(13.2)
Net assets at the year-end	**449.1**	376.1

CONSOLIDATED BALANCE SHEET

	2006 **$ million**	2005 $ million
Non-current assets:		
Intangible exploration and evaluation assets	**114.7**	67.4
Property, plant and equipment	**502.6**	576.6
Investments in associates	**-**	1.1
Deferred tax asset	**-**	0.8
	617.3	645.9
Current assets:		
Inventories	**14.8**	13.3
Trade and other receivables	**174.4**	144.7
Cash and cash equivalents	**40.9**	38.8
Assets held for sale	**90.4**	-
	320.5	196.8
Total assets	**937.8**	842.7
Current liabilities:		
Trade and other payables	**(169.6)**	(113.7)
Current tax payable	**(52.4)**	(38.8)
Liabilities directly associated with assets held for sale	**(14.2)**	-
	(236.2)	(152.5)
Non-current liabilities:		
Long-term debt	**-**	(63.6)
Deferred tax liabilities	**(194.1)**	(198.3)
Long-term provisions	**(49.6)**	(41.0)
Long-term employee benefit plan deficits	**(8.8)**	(11.2)
	(252.5)	(314.1)
Total liabilities	**(488.7)**	(466.6)
Net assets	**449.1**	376.1
Equity and reserves:		
Share capital	**73.3**	73.2
Share premium account	**8.6**	8.0
Revenue reserves	**365.6**	293.6
Capital redemption reserve	**1.7**	1.7
Translation reserves	**(0.1)**	(0.4)
	449.1	376.1

The financial statements were approved by the Board of Directors and authorised for issue on 21 March 2007.

CONSOLIDATED CASH FLOW STATEMENT

	2006 $ million	2005 $ million
Net cash from operating activities	**244.8**	121.2
Investing activities:		
Capital expenditure	**(156.5)**	(132.6)
Pre-licence exploration costs	**(21.8)**	(15.8)
Proceeds from disposal of intangible exploration and evaluation assets	**2.6**	4.0
Net cash used in investing activities	**(175.7)**	(144.4)
Financing activities:		
Issue of ordinary shares	**0.7**	1.1
Repurchase of ordinary shares	**-**	(21.0)
Repayment of long-term financing	**(65.0)**	-
Loan drawdowns	**-**	25.0
Arrangement fee for the loan facility	**-**	(1.4)
Interest paid	**(2.7)**	(3.5)
Net cash (used) in/from financing activities	**(67.0)**	0.2
Currency translation differences relating to cash and cash equivalents	**-**	2.2
Net increase/(decrease) in cash and cash equivalents	**2.1**	(20.8)
Cash and cash equivalents at the beginning of the year	**38.8**	59.6
Cash and cash equivalents at the end of the year	**40.9**	38.8

Notes to the accounts

1 Geographical segments

The group's operations are located in the North Sea, Asia, Middle East-Pakistan and West Africa. These geographical segments are the basis on which the group reports its primary segmental information (the only basis on which it can report such information). Sales revenue represents amounts invoiced, exclusive of sales-related taxes, for the group's share of oil and gas sales.

	2006 **$ million**	2005 $ million
Continuing operations		
Revenue:		
North Sea	**119.3**	169.6
Asia	**149.9**	121.5
Middle East-Pakistan	**89.6**	68.3
Total group sales revenue	**358.8**	359.4
Interest revenue	**2.0**	1.0
	360.8	360.4
Discontinued operations:		
Revenue:		
West Africa	**43.4**	-
Total group revenue	**404.2**	360.4
Results		
Continuing operations		
Group operating profit/(loss):		
North Sea	**54.3**	32.2
Asia	**91.4**	66.2
Middle East-Pakistan	**50.2**	41.9
West Africa	**(1.6)**	(4.8)
Other	**(15.8)**	(8.6)
Group operating profit	**178.5**	126.9
Interest revenue and finance gains	**2.0**	5.9
Finance costs and other finance expenses	**(7.7)**	(7.0)
Profit before tax	**172.8**	125.8
Tax	**(86.7)**	(86.3)
Profit after tax	**86.1**	39.5
Discontinued operations:		
Loss for the year from discontinued operations	**(18.5)**	(0.9)
Profit for the year	**67.6**	38.6
Balance sheet		
Segment assets:		
North Sea	**261.5**	268.9
Asia	**454.4**	350.6
Middle East-Pakistan	**114.1**	95.7
West Africa	**107.2**	123.1
Unallocated	**0.5**	3.3
Investment in associates:		
West Africa	**0.1**	1.1
Total assets	**937.8**	842.7
Liabilities:		
North Sea	**(178.7)**	(154.5)
Asia	**(206.8)**	(160.3)
Middle East-Pakistan	**(28.4)**	(30.8)
West Africa	**(21.5)**	(16.9)
Unallocated	**(53.3)**	(104.1)
Total liabilities	**(488.7)**	(466.6)

1 Geographical segments *continued*

	2006 $ million	2005 $ million
Other information		
Capital additions:		
North Sea	**46.7**	14.5
Asia	**90.8**	37.9
Middle East-Pakistan	**22.9**	13.3
West Africa	**26.0**	65.8
Total capital additions	**186.4**	131.5
Depreciation and amortisation		
Continuing operations:		
North Sea	**36.4**	36.5
Asia	**25.1**	22.3
Middle East-Pakistan	**9.8**	9.2
Discontinued operations:		
West Africa	**24.6**	-
Total depreciation and amortisation	**95.9**	68.0

2 Cost of sales

	2006 $ million	2005 $ million
Operating costs	**44.7**	100.7
Royalties	**10.6**	7.8
Amortisation and depreciation of property, plant and equipment:		
Oil and gas properties	**70.0**	66.6
Other	**1.3**	1.4
	126.6	176.5

3 Intangible exploration and evaluation (E&E) assets

	Oil and gas properties				
	North Sea $ million	**Asia $ million**	**Middle East-Pakistan $ million**	**West Africa $ million**	**Total $ million**
Cost:					
At 1 January 2005	0.2	17.6	9.0	14.6	41.4
Additions during the year	1.6	24.5	8.3	16.6	51.0
Disposals	-	(3.4)	(1.0)	-	(4.4)
Exploration expenditure written off	-	(12.5)	(3.1)	(5.0)	(20.6)
At 1 January 2006	**1.8**	**26.2**	**13.2**	**26.2**	**67.4**
Additions during the year	11.5	65.3	4.3	11.5	92.6
Disposals	-	(6.9)	-	-	(6.9)
Transfer to tangible fixed assets	(0.4)	-	-	-	(0.4)
Exploration expenditure written off	(2.2)	(0.1)	(11.2)	(8.3)	(21.8)
Reclassified as held for sale	-	-	-	(16.2)	(16.2)
At 31 December 2006	**10.7**	**84.5**	**6.3**	**13.2**	**114.7**

4 Property, plant and equipment

	Oil and gas properties				Other fixed assets	Total
	North Sea	Asia	Middle East - Pakistan	West Africa		
	$ million	$ million	$ million	$ million	$ million	$ million
Cost:						
At 1 January 2005	229.3	301.9	110.3	33.3	19.0	693.8
Exchange movements	-	-	-	-	(2.0)	(2.0)
Additions during the year	12.3	13.4	5.0	49.2	0.6	80.5
Disposals	(1.0)	-	-	-	-	(1.0)
Disposal of fully written down assets	-	-	-	-	(12.2)	(12.2)
At 1 January 2006	**240.6**	**315.3**	**115.3**	**82.5**	**5.4**	**759.1**
Exchange movements	-	-	-	-	0.2	0.2
Additions during the year	34.5	25.0	18.6	14.5	1.2	93.8
Transfer from intangible fixed assets	0.4	-	-	-	-	0.4
Reclassified as held for sale	-	-	-	(97.0)	-	(97.0)
At 31 December 2006	**275.5**	**340.3**	**133.9**	-	**6.8**	**756.5**
Amortisation and depreciation:						
At 1 January 2005	39.3	24.8	48.1	-	16.4	128.6
Exchange movements	-	-	-	-	(1.7)	(1.7)
Charge for the year	35.1	22.3	9.2	-	1.4	68.0
Disposals	(0.2)	-	-	-	-	(0.2)
Disposal of fully written down assets	-	-	-	-	(12.2)	(12.2)
At 1 January 2006	**74.2**	**47.1**	**57.3**	-	**3.9**	**182.5**
Exchange movements	-	-	-	-	0.1	0.1
Charge for the year	35.3	24.9	9.8	24.6	1.3	95.9
On assets reclassified as held for sale	-	-	-	(24.6)	-	(24.6)
At 31 December 2006	**109.5**	**72.0**	**67.1**	-	**5.3**	**253.9**
Net book value:						
At 31 December 2005	166.4	268.2	58.0	82.5	1.5	576.6
At 31 December 2006	**166.0**	**268.3**	**66.8**	-	**1.5**	**502.6**

5 Notes to the cash flow statement

	2006 $ million	2005 $ million
Profit before tax for the year	**172.8**	125.8
Adjustments for:		
Depreciation, depletion and amortisation	**95.9**	68.0
Exploration expense	**15.3**	20.6
Pre-licence exploration costs	**21.8**	15.8
Net operating charge for long-term employee benefit plans less contributions	**(1.9)**	(1.5)
Share-based payment provision	**3.0**	2.9
Release of warranty provision	**(2.5)**	-
Discontinued operations	**(1.3)**	(1.2)
Operating cash flows before movements in working capital	**303.1**	230.4
Increase in inventories	**(1.5)**	(1.0)
Increase in receivables	**(32.4)**	(29.3)
Increase in payables	**84.1**	5.4
Cash generated by operations	**353.3**	205.5
Income taxes paid	**(116.2)**	(86.4)
Interest payable and other finance expense	**7.7**	2.1
Net cash from operating activities	**244.8**	121.2

5. Notes to the cash flow statement *continued*

Analysis of changes in net cash/(debt)

a) Reconciliation of net cash flow to movement in net cash/(debt):	**2006 $ million**	2005 $ million
Movement in cash and cash equivalents	**2.1**	(20.8)
Proceeds from long-term loans	**-**	(25.0)
Repayment of long-term loans	**65.0**	-
Increase/(decrease) in net cash in the period	**67.1**	(45.8)
Opening net (debt)/cash	**(26.2)**	19.6
Closing net cash/(debt)	**40.9**	(26.2)

b) Analysis of net cash/(debt):	**2006 $ million**	2005 $ million
Cash and cash equivalents	**40.9**	38.8
Long-term debt	**-**	(65.0)
Total net cash/(debt)	**40.9**	(26.2)

6 Basis of preparation

The above financial information does not represent statutory accounts within the meaning of Section 240 of the Companies Act 1985. A copy of the statutory accounts for 2005 has been delivered to the Registrar of Companies and those for 2006 will be delivered following the Company's Annual General Meeting. The auditors' report on those accounts was unqualified and did not contain statements under Section 237(2) or (3) of the Act.

The financial information has been prepared in accordance with the recognition and measurement criteria of International Financial Reporting Standards (IFRS) and with IFRS adopted for use in the European Union. However, this announcement does not itself contain sufficient information to comply with IFRS. The announcement is prepared on the basis of accounting policies as stated in the 2005 financial statements. The company will publish full financial statements that comply with IFRS on 18 April 2007.

The financial information has been prepared under the historical cost basis except for the revaluation of financial instruments and certain properties at the transition date to IFRS. These financial statements are presented in US$ since that is the currency in which the majority of the group's transactions are denominated.

This preliminary announcement was approved by the Board on 21 March 2007.

7 Dividends

The directors do not propose any dividend.

8 Earnings per share

The calculation of basic earnings per share is based on the profit after tax and on the weighted average number of Ordinary Shares in issue during the year. The diluted earnings per share allows for the full exercise of outstanding share purchase options and adjusted earnings.

Basic and diluted earnings per share are calculated as follows:

	Profit after tax		**Weighted average number of shares**		**Earnings per share**	
	2006	2005	**2006**	2005	**2006**	2005
	$ million	$ million	**million**	million	**cents**	cents
From continuing operations:						
Basic	**86.1**	39.5	**81.8**	82.1	**105.3**	48.1
Outstanding share options	**-**	-	**0.9**	0.7	*****	*
Diluted	**86.1**	39.5	**82.7**	82.8	**104.1**	47.7
From continuing and discontinued operations:						
Basic	**67.6**	38.6	**81.8**	82.1	**82.6**	47.0
Outstanding share options	**-**	-	**0.9**	0.7	*****	*
Diluted	**67.6**	38.6	**82.7**	82.8	**81.7**	46.6

*The inclusion of the outstanding share options in the 2006 and 2005 calculations produce a diluted earnings per share. The outstanding share options number includes any expected additional share issues due to future share-based payments.

9 Share-based payments

The company currently operates an Asset and Equity plan to reward employees for improvement in the asset value of the business and the market value of the company over a three-year period. The plan has two bonus pools, an equity bonus pool and an asset bonus pool. The asset bonus pool is created by reference to the increase in the net asset value per share of the company over a three-year period and the equity bonus pool is created by reference to the increase in the equity market value per share of the company over a three-year period.

For the year-ended 31 December 2006, the total cost recognised by Premier for share-based payments is US$26.4m (2005: US$6.4m). Part of this cost is capitalised as projects and part charged to the income statement as exploration write off, operating costs, pre-licence expenditure or general and administration costs.

10 External Audit

This Preliminary Announcement is consistent with the audited financial statements of the group for the year-ended 31 December 2006.

11 A full set of financial statements will be posted to shareholders on 18 April 2007 and will be available at the company's head office, 23 Lower Belgrave Street, London SW1W 0NR, from that date.

12 The Annual General Meeting will be held at Clothworkers' Hall, Dunster Court, Mincing Lane, London, EC3R 7AH on Friday 18 May 2007 at 11.00am.

Oil and gas reserves (unaudited)
Group proved plus probable reserves

	Working interest basis									
	North Sea		Asia		Middle East-Pakistan		West Africa[2]	Total		
	Oil and NGLs	Gas	Oil and NGLs	Gas	Oil and NGLs	Gas	Oil and NGLs	Oil and NGLs	Gas	Oil, NGLs and gas
	mmbbls	bcf	mmbbls	bcf	mmbbls	bcf	mmbbls	mmbbls	bcf	mmboe
Group:										
At 1 January 2006	16.5	22	5.7	337	-	-	9.7	31.9	359	102.2
Revisions[1]	1.7	(7)	0.4	24	-	-	(5.0)	(2.9)	17	0.1
Acquisitions and divestments	-	-	-	-	-	-	-	-	-	-
Production	(2.3)	(1)	(0.7)	(18)	-	-	(0.9)	(3.9)	(19)	(7.6)
At 31 December 2006	**15.9**	**14**	**5.4**	**343**	-	-	**3.8**	**25.1**	**357**	**94.7**
Joint venture - group share:										
At 1 January 2006	-	-	-	-	1.6	389	-	1.6	389	61.3
Revisions[1]	-	-	-	-	-	4	-	-	4	0.5
Production	-	-	-	-	(0.1)	(28)	-	(0.1)	(28)	(4.4)
At 31 December 2006	-	-	-	-	**1.5**	**365**	-	**1.5**	**365**	**57.4**
Total group and group share of joint ventures:										
At 1 January 2006	16.5	22	5.7	337	1.6	389	9.7	33.5	748	163.5
Revisions[1]	1.7	(7)	0.4	24	-	4	(5.0)	(2.9)	21	0.6
Acquisitions and divestments	-	-	-	-	-	-	-	-	-	-
Production	(2.3)	(1)	(0.7)	(18)	(0.1)	(28)	(0.9)	(4.0)	(47)	(12.0)
At 31 December 2006	**15.9**	**14**	**5.4**	**343**	**1.5**	**365**	**3.8**	**26.6**	**722**	**152.1**
Total group and group share of joint ventures:										
Proved developed	8.1	10	1.5	145	1.2	214	1.5	12.3	369	74.9
Proved undeveloped	1.0	-	1.9	110	-	8	0.5	3.4	118	26.1
Probable developed	2.8	2	0.9	32	0.3	114	0.4	4.4	148	28.4
Probable undeveloped	4.0	2	1.1	56	-	29	1.4	6.5	87	22.7
At 31 December 2006	**15.9**	**14**	**5.4**	**343**	**1.5**	**365**	**3.8**	**26.6**	**722**	**152.1**

Notes:

1. Revisions include upgrades on Block A, Zarghun South, Scott and Telford fields, together with downgrades on Chinguetti and the Fife area fields.

2. The West Africa reserves relate entirely to a disposal group held for sale.

Proved and probable reserves are based on operator or third-party reports and are defined in accordance with the Statement of Recommended Practice (SORP) issued by the Oil Industry Accounting Committee (OIAC), dated July 2001.

The group provides for amortisation of costs relating to evaluated properties based on direct interests on an entitlement basis, which incorporates the terms of the Production Sharing Contracts in Indonesia and Mauritania. On an entitlement basis reserves decreased by 13.5 mmboe giving total entitlement reserves of 132.4 mmboe as at 31 December 2006 (2005: 145.9 mmboe). This was calculated in 2006 using an oil price assumption of US$50/bbl (2005: US$40/bbl).

END