19 March 2009

Hardy Oil and Gas plc

("Hardy" or "the Company" or “the Group”)

Preliminary Results

for the year ended 31 December 2008

Hardy Oil and Gas plc (LSE : HDY), the oil and gas exploration and production company with interests predominantly in India, today announces its Preliminary Results for the year ended 31 December 2008.

**All financial amounts in US dollars unless otherwise stated.*

Operational Highlights

2008

- Two gas discoveries (Dhirubhai 39 and 41) on the D3 exploration block
- Acquired additional 1,165 km^2 of 3D seismic data on the GS-01 block
- Added the onshore petroleum exploration licence AS-OON-2000/1 located in Assam (10% PI) in partnership with Reliance
- Farmed out 20% working interest in Oza to fund the field development programme
- Hardy’s net participating interest average daily production for FY 2008 was 458 stbd (FY 2007: 747 stbd)

2009 to date

- Commenced 3D seismic acquisition programme for D3 exploration block
- D3 appraisal programme submitted to DGH for review
- PY3-PD4 re-entry – the well was completed as a producer with a gas lift valve for future production once gas lift and compression facilities are installed
- Commenced 2D seismic acquisition programme for Assam exploration block

Financial Highlights

- Profit before taxation of $12.4 million* (2007: $10.6 million*)
- Cash flow from operations $1.6 million† (2007: $2.6 million†)
- Capital expenditure of $31.6 million (2007: $32.1 million)
- Cash and short term investments at 31 December 2008 of $30.1 million (2007: $31.9 million)

† Before charges in non-cash working capital
** Including gain from sale of investment*

Outlook

- *D3:* Drilling of third exploration well on the D3 block expected in H2 2009 and completion of 3D seismic acquisition programme on the D3 block in H1 2009
- *Technical review:* Publication of a third party technical review updating the Company's D9, D3 and Assam exploration block potential, is anticipated by the end of Q209
- D9: The joint venture budget has provided for the drilling of one well in the 2009 calendar year.

Commenting on the results, Mr E.P. Mortimer, Chairman of Hardy said:

"Commitment to our strategy of organic growth through exploration of our India assets produced encouraging results in 2008. The potential represented by our D3 discoveries is a major contributor to significantly de-risking Hardy's growth potential from its exploration blocks in the Krishna Godavari basin."

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CHAIRMAN AND CHIEF EXECUTIVE'S STATEMENT

Overview

The current economic downturn, and fall in oil prices, presents a challenging outlook for the upstream oil and gas industry. Despite these conditions we are pleased to recognise 2008 as another positive year for Hardy. We anticipate 2009 to be an important year for Hardy, with further drilling planned on our Krishna Godavari basin exploration blocks.

The Group achieved several major milestones through the year with positive exploration results, expansion of our board and the move of our share listing to the Main Market. Commitment to our strategy and stated goals of organic growth through exploration of our India assets, produced encouraging results in 2008. Of particular note are the Dhirubhai 39 and 41 gas discoveries on the Company's D3 block in the KG basin, and the recent submission of an appraisal programme for the D3 discoveries. The discoveries have reduced the overall geological risk of the block, and are an encouraging start to a six well exploration programme.

Key Financial Results

During 2008 the Company increased revenues due to higher oil prices (despite reduced production), derived positive cash flow from operations (before non-cash working capital changes), and realised a significant infusion of capital through liquidation of its investment in HOEC, resulting in another profitable year. The Company completed the year with cash and short term investments of approximately $30 million and no long term debt.

Revenue (after profit oil) for the year ended 31 December 2008 amounted to $17.3 million compared with $11.8 million for 2007. Sales oil of 179,524 stb was realised for the year ended 31 December 2008 (2007: 232,870 stb); the average price realised was $104.44 per stb (2007: $66.65 per stb).

The Company liquidated its entire holding in HOEC during 2008 and 2007, realising cash proceeds of $41.4 million and a pre-tax gain of $13.0 million and $10.2 million for 2008 and 2007 respectively.

Profit before taxation amounted to $12.4 million in 2008 compared to $10.6 million in 2007. The Company's fully diluted earnings per share amounted to $0.11 in 2008 (2007: $0.13).

Cash flow from operating activities (before changes in non-cash working capital) amounted to $1.6 million in 2008 compared to $2.6 million in 2007.

Total capital expenditure amounted to $31.6 million (2007: $32.1 million), principally on the drilling of four wells on the D3 and GS-01 blocks, the acquisition of 3D seismic data and partial drilling of a development well on the PY-3 field, which was completed in February 2009.

The Company has adequate resources to enable it to undertake its planned work programme over the next twelve months. The Company also has the ability to raise additional capital, if required, to fund its ongoing work programmes.

Operational Overview

We completed the majority of our planned programme for 2008. Our activity was focused on our exploration blocks in India with the drilling of four exploration wells and the acquisition of over 1,100 km^2 of additional 3D seismic on one of our exploration blocks in India.

India (Operated)

PY-3 - The field's production for 2008 was 0.93 MMstb of oil (2007: 1.51 MMstb). Hardy is the operator and holds an 18% participating interest. The daily net average production on a participating interest basis was 458 stbd (2007: 747 stbd). The fall in production is attributed to the suspension of well PD-3-RL (which was converted into a water injector), natural decline, and shut-in of the field for unplanned maintenance. The gross average daily production of the field for January and February of 2009 was 2,846 stbd and 2,797 stbd respectively. Hardy anticipates PY-3's gross daily production for 2009 to average 3,000 stbd.

The drilling of an additional lateral well, via the re-entry of the producing PY-3-PD4 well was completed in February 2009. With the assistance of nitrogen lift, the well flowed at 700 stbd of oil with 30% water-cut, however, the well was unable to be reactivated as a self flowing well. The well has been completed as a producer with a gas lift valve to allow for future production when gas lift compression facilities are installed on the FPU.

CY-OS/2 - The Company submitted a proposal to revise the appraisal programme, for the CY-OS/2 block's Ganesha gas discovery, to reduce three firm and two contingent wells to one firm and one contingent well. The revised work programme was approved by the CY-OS/2 Operating Committee and reviewed by the Management Committee in October 2008. The CY-OS/2 joint venture is working with the Ministry of Petroleum and Natural Gas of the

Government of India for an extension of the exploration licence to January 2012 to establish commerciality.

India – (Non-operated)

Results on our non-operated exploration assets have been encouraging as we continue to pursue our strategy of de-risking this portfolio.

KG Basin - The Company's two key exploration assets are located in the Krishna Godavari basin, a prolific proven hydrocarbon province, with world class discoveries since the introduction of India's New Exploration Licensing Policy. Subsequent substantial private sector capital investment in offshore field development and onshore infrastructure is facilitating further exploration and development. The Reliance operated D6 block is a current example with production expected to reach 80 MMcmd by 2010, effectively doubling India's domestic natural gas production capacity. Continued investment in the basin promises to unlock the substantial resource potential of this prolific basin.

D3 – Exploration drilling commenced on this block in 2008 and we were pleased to announce two successive gas discoveries on the block, with encouraging initial testing results including an observed flow rate of 38.1 MMscfd from the KDVD3-A1 well (Dhirubhai 39). An appraisal programme for the Dhirubhai 39 and 41 discoveries has been approved by the Operating Committee and is under consideration by the Directorate General of Hydrocarbons.

The operator recently commenced the final 3D seismic acquisition programme on the block. Upon completion the entire block will be covered by 3D seismic data. The block was acquired with 210 km^2 of which the first two well locations were selected. In 2007 the operator acquired 1,900 km^2 of 3D seismic.

D3 is an important block within Hardy's asset portfolio, representing a significant proportion of Hardy's overall resource potential. The drilling of the third well on the block is expected in the second half of 2009 with further drilling expected in 2010.

D9 – Due to the industry-wide shortage of drilling ships capable of operating in water depths greater than 2,000 m, delays have been experienced on the D9 exploration licence. An ultra deepwater drill ship, Deepwater Expedition, arrived in Indian waters in August 2008 and is currently operating on the adjacent D6 block. Reliance has issued an authority for expenditure and the joint venture has provided for the drilling of one well in the 2009 calendar year. Timing will continue to be dependent on Reliance's scheduled operations and commitments.

GS-01 – Results on the GS-01 block were disappointing for 2008 with two wells (M1 and S1 being plugged and abandoned. However, the GS-01 Management Committee reviewed and adopted an appraisal programme for the GS01-B1 gas and condensate discovery (Dhirubhai - 33). With an effective term through to May 2010, the appraisal area comprises 5,890 km^2. The GS-01 joint venture will be making a decision on further appraisal drilling, after completion of a planned geological and geophysical review, in a few months time.

Assam – Early in 2008, the company was issued (jointly with Reliance) the onshore petroleum exploration licence AS-ONN-2000/1 in Assam. We are delighted with the Company's continued partnership with Reliance. This is the fourth block that Hardy holds in partnership with Reliance and the Company's only onshore asset in India. A 2D seismic acquisition programme commenced prior to the end of 2008 and is expected to be complete in the first half of 2009.

Upon reflection of the developments on our non-operated blocks, the Company has commissioned Gaffney, Cline & Associates Ltd to complete a technical review of our KG basin exploration blocks D3 and D9 and the recently added Assam block.

Nigeria

Oza - In April 2008, the Company entered into an agreement to farm-out a 20 per cent interest in the Oza block to a local Nigerian company, which has agreed to assume Hardy's financial obligations in the funding of the Oza field initial development programme. The Company retains a 20% working interest in the block.

Atala – Securing the necessary drilling equipment for the planned re-entry and testing of Atala-1 continues to be challenging. We will continue to work closely with the operator to source the necessary equipment.

Corporate

On 20 February 2008, the Company's shares began trading on the London Stock Exchange's market for listed securities ('Main Market'). The decision to admit Hardy's shares to the Main Market was taken to increase the Company's profile and liquidity of its Ordinary Shares while increasing access to capital to fund its future exploration and development expenditures.

With our commitment to continually enhance our corporate governance practices, on 24 October 2008, the Company was pleased to appoint Mr Ian Bruce FCA as an independent non-executive director. His strong financial background and extensive industry experience are a valuable and timely addition to our Board as we experience a challenging economic environment.

We also made a number of changes to the composition of the Board committees. Mr Pradip Shah has been appointed to chair the remuneration committee; and Mr Ian Bruce has been appointed to the audit committee; and Mr Mortimer and Mr Karra are no longer members of the audit and remuneration committee respectively.

2009 Programme

In 2009, the Company will continue to focus on organic growth as our primary strategy to create shareholder value. The majority of our activity will be focused on enhancing development plans for 2010 and non-operated exploration and we are looking forward to an active 2009 with the following plan of work:

Block	Activity	Timing 2009
D3	Complete acquisition of 1,150 km^2 of 3D seismic	1st Quarter
	Drilling of third exploration well	2nd Half
D9	Drilling of one exploration well	During the year
GS-01	Contingent appraisal well for Dhuribhai 33 gas discovery	TBD
Assam	Complete acquisition of 450 lkm of 2D seismic	2nd Quarter
CY-OS/2	Finalisation of extension for appraisal of Ganesha gas discovery	3rd Quarter
PY-3	Production / Geoscience and Engineering studies	Ongoing
Oza	Commencement of field tie-in	3rd Quarter
Atala	Re-entry and testing of Atala-1	TBD

The Company has commissioned a third party technical report for our KG basin blocks (D9 and D3) and the recently added Assam block. The report is expected to be completed by the end of the second quarter of 2009.

Current Trading and Outlook

The global economic downturn and lower oil prices preset adverse conditions for the industry, and Hardy, in the coming year. We are able to defer non-committed capital projects to 2010 and are implementing measures with a focus on cash conservation through 2009 whilst maintaining high impact activities. Our conservative strategy will focus capital expenditure on high impact operations, such as exploration drilling on our two KG basin assets D3 and D9.

In 2009 the KG basin will mark a significant step forward in reducing India's dependence on foreign energy supply to meet the needs of its growing economy. With approximately 40 MMscmd, from the Reliance operated D6 block off the east coast of India, expected in the second quarter and ramping up to 80 MMscmd by 2010 effectively doubling the country's domestic gas production capacity.

The appraisal programme for the Company's D3 block, also in the KG basin, has been submitted to the joint venture Management Committee for consideration.

With the main D6 gas field producing, we anticipate the operator's focus, and more importantly the ultra-deepwater drill ship "Deepwater Expedition", to become available to commence exploration drilling on several other, Reliance operated, deep water blocks in the KG basin. We will be watching with great anticipation the commencement of the first exploration well on the Company's D9 block where we carry significant resource potential.

With the KG basin activity in mind, we have commissioned a technical review, by Gaffney, Cline & Associates Ltd, for our D3, D9 and Assam exploration blocks, and we look forward to publishing the results by the end of the second quarter of 2009.

The Board looks to the balance of 2009 with a renewed focus on activities that have the potential to significantly de-risk our exploration portfolio in the KG basin in India. We are confident that cash conservation and disciplined investment will see our company through this challenging economic environment. We are optimistic of the potential of the Company's asset portfolio and anticipate that exploration drilling will be the catalyst for a step change in shareholder value through 2010. The Company is well positioned to see itself through the key exploration activities.

FINANCIAL REVIEW

During 2008, the Company has increased revenues, derived positive cash flow from operations (before changes in non cash working capital) and realised a significant infusion of capital through liquidation of its investment in HOEC. The Company completed the year with cash and short term investments of approximately $30 million and no long term debt.

Key Performance Indicators

	Year ended 31 December	
	2008	**2007**
Production (barrels of oil per day – net entitlement basis)	397	573
Average realised price per barrel - $	104.44	66.65
Average cost per barrel - $	54.91	21.19
Revenue (thousands of $)	17,306	11,830
Net profit (thousands of $)	7,472	8,316
Cash flow from operations* (thousands of $)	1,568	2,588
Diluted earnings per share - $	0.11	0.13
Wells drilled	4	2

*Before change in non-cash working capital

Operating Results

(Thousands of dollars, unless otherwise indicated)	**Year ended 31 December**	
	2008	**2007**
Production (barrels of oil per day)		
Gross field	2,542	4,150
Participating interest	458	747
Net entitlement interest	397	573
Sales (barrels of oil per day)		
Gross field	2,725	3,547
Participating interest	491	638
Average realised price per barrel - $	104.44	66.65

Production, Sales and Revenue

The Company operates the PY-3 field in the Cauvery Basin with an 18 per cent participating interest. Actual gross field production for the year ended 31 December 2008 amounted to 2,542 stbd compared with 4,150 stbd for 2007. The decrease in production is due to the conversion of PY3-3 as a water injection well together with the shutdown of the field for 42 days due to equipment failure and renewal of a jumper hose.

Hardy's net entitlement interest in production is after the Government of India's share of profit oil of $ 2.3 million (2007 - $ 4.3 million).

Revenue from oil sales (after profit oil) increased from $11.3 million in 2007 to $ 16.4 million in 2008. The average price realised per barrel increased significantly from $66.65 during 2007 to $104.44 per barrel. Average daily sales amounted to 491 barrels of oil per day compared with 638 barrels of oil per day reflecting lower production volumes, offset by partial liquidation of inventory at year end. Other revenue increased from $0.6 million to $0.8 million reflecting additional overhead recovery.

Cost of Sales

Cost of sales for 2007 increased from $5.8 million in 2007 to $9.2 million in 2008. This reflects the full year impact of higher costs of operating the PY-3 field. The contract for the floating processing and storage systems was renegotiated effective July 2007, resulting in a substantial increase in day rates. The contract expires in July 2009 with renewal expected to result in a substantial reduction in day rates in the future.

Gross Profit

Gross profit increased from $6.1 million in 2007 to $8.1 million in 2008. The increase arises principally from higher revenues as a result of higher average crude price in 2008 offset by a substantial increase in operating cost of running the PY-3 field.

Administrative Expenses

Administrative expenses increased from $6.9 million in 2007 to $9.7 million in 2008. The increase principally results from exchange losses on cash, short term investments and site restoration deposits of $2.4 million, and cost of the move of the listing of the Company's shares to the Main Market of the London Stock Exchange.

Operating Loss

The Company is reporting an operating loss of $1.7 million in 2008 compared with $0.8 million in 2007.

Gain on Sale of Investment

In December 2007 and during 2008, the Company sold 3,010,000 and 8,086,156 shares for net cash consideration of $12.5 million and $28.9 million respectively. As a result, the Company recorded a pre-tax gain on sale of its investment in HOEC of $13.0 million in 2008 and $10.2 million in 2007.

Interest and investment Income

Investment and other income in 2008 amounted to $1.3 million compared with $1.4 million in 2007.

Finance Costs

Finance costs principally include the cost of providing bank guarantees to the Government of India required in accordance with the provisions of Production Sharing Contracts and are based on the agreed annual work programme on blocks in India.

Profit before taxation

Profit before taxation increased from $12.4 million in 2008 compared with $10.6 million in 2007.

Taxation

Current taxes amounted to $1.6 million reflecting the liability for Minimum Alternate Tax in India of $0.8 million, and current taxes on short term capital gains on the sale of HOEC shares of $0.8 million on the shares that were purchased under the rights issue in January 2008 that were disposed in May and August 2008.

Most of the provision for taxation is with respect to deferred income taxes since the Company's capital expenditure programme is sufficient to shield the Company from a large portion of current tax liabilities.

Tax rate, as a percentage of pre-tax income amounted to 40.2 per cent in 2008 compared to 21.8 per cent in 2007. This increase is mainly on account of short term capital gains tax of $0.8 million paid on sale of HOEC shares in 2008 as well as the impact of Minimum Alternate Tax in India. In 2007, the tax provision was reduced as a result of the benefit arising from carry forward capital losses of earlier years against capital gain on sale of HOEC shares.

Net Profit

As a result, net profit declined from $8.3 million in 2007 to $7.5 million in 2008.

Cash Flow from Operating Activities

The Company's cash flow from operating activities, before changes in non-cash working capital, amounted to $1.6 million in 2008. This compares with $2.6 million for 2007. The decline principally results from higher operating costs and general and administrative costs in 2008 compared to 2007.

Capital Expenditure

Capital expenditure amounted to $31.6 million during 2008, compared to $32.1 million incurred during 2007. Capital expenditure amounting to $14.1 million was incurred on the GS-01 block with the drilling of two exploration wells and the acquisition of 1,166 km^2 of 3D seismic data. Approximately $7.6 million was incurred in the drilling of two successful exploration wells on the D3 block in the Krishna Godavari basin. As part of the Ganesha appraisal programme, the Company incurred $1.8 million on the CY-OS/2 block, on a number of geological and geophysical studies including reprocessing of the 3D seismic data covering the block to improve subsurface understanding. Minimal expenditure was incurred on the D-9 block and $0.6 million was spent on the Oza operations in Nigeria.

Investment in HOEC

In early January 2008, HOEC completed a rights offering with Hardy participating in the rights offering to the extent of its pro rata share of 8.5 per cent investing an additional $13.2 million.

During 2007, the Company made a strategic decision to liquidate its investment in HOEC. As a result, during December 2007 and during 2008, the Company sold 3,010,000 and 8,086,156 shares for net cash consideration of $12.5 million and $28.9 million respectively. Aggregate proceeds of $41.4 million were received in 2008.

Site Restoration Deposits

These represent deposits for site restoration for the PY-3 field. At 31 December 2008, the Company had invested $3.2 million in site restoration deposits.

Finance Costs

Finance costs essentially represent the cost of bank guarantees provided to the Government of India in connection with annual work programmes in India.

Cash and Short Term Investments

The Company's cash and short term investments declined from $31.2 million at the end of 2007 to $30.1 million at the end of 2008. The Company's capital expenditures were principally funded by proceeds from the liquidation of HOEC holdings during 2008.

During 2008, the Company commenced investing its surplus funds in HSBC Sterling and US Dollar Liquidity Funds that invest in a diversified portfolio of money market instruments that seek to provide security of capital, a competitive return and same day liquidity. At 31 December 2008, the Company had invested £2,881,445 and $17,795,890 in Sterling and US Dollar Liquidity Funds with an average underlying maturity of 21 and 20 days respectively.

Summary Balance Sheet

Hardy has continued to grow during 2008. Its non-current assets have increased from $121.4 million at the end of 2007 to $135.8 million at the end of 2008. This results largely from the capital expenditure programme on exploration, principally on the drilling of wells and seismic acquisition on GS-01 and D3 blocks.

Current assets represent the Group's cash and short term investments, trade and other receivables and inventory. At the end of 2008, of the $38.0 million of current assets, $30.1 million are represented by cash and short term investments.

Current liabilities are principally trade and other accounts payable. The level of current liabilities is $13.8 million at the end of 2008 compared with $9.9 million in 2007 reflecting the impact of the re-entry operations on the PD-4 well in the PY-3 field that were in progress.

The Company issued minimal equity during 2008 of $0.3 million upon exercise of stock options. Consequently, the Company's net assets remained at approximately the same level in 2008 as in 2007 of $144 million.

Liquidity and Capital Resources

Hardy has been funding its cash requirements from internally generated cash flows and equity capital, principally from institutional investors, in each of the years 2005, 2006 and 2007. The Company continues to be an emerging company with limited cash flows and significant exploration assets, and as a result has been principally relying upon equity capital markets to build and grow its asset base.

At 31 December 2008, the Company had cash resources of approximately $30.1 million that were available to meet future capital expenditures and to fund operating deficiencies. The Company does not have any long term debt.

The Company's present 2009 planned work programme includes drilling of a well on block D-9, one well on block D3, the acquisition of seismic on block D3 and Assam and ongoing planning and studies on remaining blocks in India and the tie-in of Oza to bring it into production.

The Company has adequate resources to enable it to undertake its planned work programme over the next twelve months. The Company also has the ability to raise additional capital, if required, to fund its ongoing work programmes.

Dividends

The Company has limited internally generated cash flows and has a planned capital expenditure programme. In the circumstances, the Board of Directors has chosen to reinvest cash flows and does not recommend the payment of a dividend in the foreseeable future.

REVIEW OF OPERATIONS

The Company's operations in India are conducted through its wholly owned subsidiary Hardy Exploration & Production (India) Inc. (HEPI). The Company's operations in Nigeria are conducted through its wholly owned subsidiary Hardy Oil Nigeria Limited (HON).

2008 Performance

Hardy had an excellent start to 2008 with two gas discoveries on our D3 block in the KG basin and had an active operations programme planned for the remainder of the year.

At the beginning of 2008 the Company planned to drill four exploration wells, one to three appraisal wells, acquire 2,100 km^2 of 3D seismic data and acquire 500 lkm of 2D seismic in India. During 2008, the Company had participated in the drilling of four exploration wells (KGV-D3-A1 and B1, GS01-S1 and M1), commenced the drilling of a development well (PY-3-D4-RL) and acquired over 1,100 km^2 of 3D seismic data over the GS-01 exploration blocks.

In Nigeria the Company planned to conduct a work-over of one well and start installation of a pipeline. The Company now plans to initiate the installation of the pipeline in the second half of 2009.

The table below provides a brief comparison of our stated operational objectives for 2008 and our subsequent accomplishments through the year;

Block	Projection	Execution
D3	Drill two wells, processing and interpretation of acquired 1,200 km^2 3D seismic data	Drilled two exploration wells. 3D seismic programme commenced Q109
D3	Submission of appraisal programme for Dhirubhai 39 and 41 discoveries	Appraisal programme was submitted in February 2009 to DGH for review
D9	Commencement of exploration drilling programme	Drilling deferred to 2009 due to rig shortage
GS-01	Drilling of three exploration wells Acquire 1,000 km^2 of 3D Seismic	Drilled two exploration wells Acquired 1,165 km^2 of 3D Seismic data
PY-3	No operations planned	Commenced re-entry of PD-4
CY-OS/2	Commencement of appraisal drilling to assess Ganesha discovery	Revised appraisal programme and applied for an extension
Assam	Acquisition of 350 lkm of 2D seismic data	2D seismic acquisition programme of 450lkm commenced in January 2009
Oza	Commence field development operations	Long lead items ordered. Commencement of field operations expected in Q3 2009
Atala	No operations planned	Community consultation initiated

Competent Person's Report Update

The Company recently commissioned Gaffney, Cline & Associates Ltd (GCA) to prepare an independent technical review report on the Company's D9, D3, and Assam exploration blocks. We expect this report to be completed in the second quarter of 2009.

KRISHNA GODAVARI BASIN – Eastern India

Block KG-DWN-2003/1 (D3): Exploration

(Hardy 10% interest)

Operations

The highlight of Hardy's exploration programme in 2008 was the two gas discoveries in the D3 block (Dhirubhai 39 and 41). The primary results are listed below:

KGV-D3-A1: On 13 February 2008, the Company announced the first discovery on this licence (Dhirubhai 39). The well was drilled to a depth of 1,937 m MDRT and encountered natural gas between 1,513 m and 1,597 m MDRT with a gross sand thickness of 84 m. One interval was selected for cased hole DST covering 1,565 m to 1,585 m MDRT and produced natural gas at a rate of 38.1 MMscfd through a 120/64 " choke.

KGV-D3-B1: On 1 April 2008, the Company announced a second discovery on the D3 block (Dhirubhai 41). The well encountered good quality reservoirs in the Pleistocene and Pliocene formations. MDT tests were conducted over several intervals (1,814 m to 2,101 m MDRT and 2,119 m to 2,463 m MDRT) and confirmed the presence of hydrocarbons.

The evaluation and incorporation of the data recovered from the D3 discoveries noted above is ongoing. The acquisition of a further 1,150 km^2 of 3D seismic data has commenced and is expected to be complete in the first half of 2009. The drilling of the third well on the block is expected in the second half of 2009.

Appraisal: On 9 February 2009, the D3 joint venture Operating Committee reviewed and approved an appraisal programme for the evaluation of the Dhirubhai 39 and 41 gas discoveries. The proposed appraisal area comprises 750 km^2 covering a large portion of the northwest corner of the block. The appraisal programme provides for the initial undertaking of various geological, geophysical and development concept studies, following which, two appraisal wells could be drilled prior to February 2011. The proposed appraisal programme has been submitted to DGH for consideration.

Background

In August 2005, Reliance and HEPI were awarded, under NELP V, a second licence in the deepwater Krishna Godavari Basin. The D3 licence encompasses an area of 3,288 km^2, in water depths of 400 m to 2,100 m, and is located approximately 45 km from the east coast. Reliance is the operator.

The licence had approximately 210 km^2 of existing 3D seismic data, which has been reprocessed. The A-1 and B-1 locations were identified after this data was interpreted and mapped. Under Phase – I of exploration programme, 1,930 km^2 of 3D data was acquired in the year 2007. Presently, depth migration and inversion processing is being carried out on this data at GXT ION.

The various play types envisaged in this block are:

- High amplitude geobody with prominent direct hydrocarbon indicators within the Pleistocene / Pliocene stratigraphic sequence.
- High amplitude deep water channel complex with well preserved channel geometry within Middle Miocene/ Upper Miocene sequence
- Roll over anticline within Lower Miocene / Middle Miocene sequence with concentration of high amplitude channel like depositional features at the crest.
- High amplitude channel like features truncated by unconformity which provides the top and lateral seal
- Deep water fan lobe on roll over anticline within Pleistocene sequence.

KRISHNA GODAVARI BASIN – Eastern India

Block KG-DWN-2001/1 (D9): Exploration

(Hardy 10% interest)

Operations

The ultra-deep-water drilling rig, “Deepwater Expedition”, which is capable of drilling in waters in excess of 3,000 m, arrived in Indian waters in August 2007 and is currently operating in the KG basin. The Company has received an AFE for the drilling of an exploration well which prescribes the use of the “Deepwater Expedition” drilling rig (currently operating on the adjacent D6 block). The joint venture recently approved a budget for the fiscal year ended 31 March 2010, which provides for the drilling of one exploration well in the 2009 calendar year. The timing of commencement of drilling will remain dependent on the drilling schedule of the operator, Reliance.

Hardy has completed a review of the geological and geophysical data and interpretation completed to date and has subsequently commissioned an independent technical update of this block which is expected to be completed in the second quarter of 2009.

Background

The licence encompasses 11,605 km^2 in the Bay of Bengal where water depths vary from 2,300 m to 3,100 m.

The joint venture has acquired over 4,188 km^2 of 3D seismic including infill, and subsequently leads at Upper Miocene, Middle Miocene, Oligocene and Cretaceous have been identified. These leads are aerially large structural closures located toward the relatively shallower-water north-western corner of the concession, for which GIIP of many TCF has been computed by the operator. A fourth lead is a Pleistocene channel in the south eastern part of the block which is in ultra deep water with a prognosticated GIIP of a similar order of magnitude to the other leads.

Initial exploration will be focused upon amplitude anomalies within structural closure in the Miocene and Pliocene. There are many seismic anomalies within the block and, given its proximity to D6, exploration potential of this large block is regarded with considerable optimism.

GUJARAT-SAURASHTRA BASIN – Western India

Block GS-OSN-2000/1 (GS-01): Exploration

(Hardy 10% interest)

Operations

In 2008 the GS-01 joint venture drilled two exploration wells on the block and acquired additional 3D seismic.

On 26 August 2008, the Company announced that the exploratory well GS01-S1 was drilled to a total depth of 3,985 m TVDRT on the western shelf edge of the block to explore the Miocene carbonate build-up, Miocene and Oligocene reefal carbonates. While there was porosity development in the reefal carbonates, no hydrocarbons were found. The well has been plugged and abandoned.

On 3 October 2008 the Company announced that the exploratory well GS01-M1 was drilled to a total depth of 4,326 m TVDRT to explore the Oligocene and Eocene carbonate targets. Porosity development was observed in the Oligocene target but no proper seal was present. Gas shows with heavier end hydrocarbons were recorded while drilling the mid-Eocene target zone over a 20 m interval. However, the middle Eocene carbonates could not be drilled in its entirety due to BOP pressure limitations of the rig. Well logs showed reservoir development but the MDT tests were inconclusive and a conventional DST was not conducted. The well was plugged and abandoned.

Operator acquired 1,166 km^2 of 3D seismic data including in fill in the north western part of the block and subsequent interpretation led to the drilling of M1 well.

The GS-01 Management Committee reviewed and adopted an appraisal programme and budget for the GS01-B1 gas and condensate discovery (Dhirubhai - 33). With an effective term through to May 2010, the appraisal area comprises 5,890 km^2. The GS-01 joint venture will be making a decision on further appraisal drilling, after completion of a planned geological and geophysical review, in a few months time.

Background

The GS-01 exploration licence is located in the Gujarat-Saurashtra offshore basin off the west coast of India, NW of prolific Bombay High oil field. The original licence encompassed 8,841 km^2 (5,890 km^2 post relinquishment) and water depths vary between 80 m and 150 m. The joint venture has previously acquired 1,216 km^2 of 3D seismic.

As announced on 15 May 2007, the Dhirubhai – 33 discovery (GS01-B1) flow-tested at a rate of 18.6 MMscfd gas with 415 stbd of condensate through a 56/64” choke at flowing tubing head pressure of 1,346 psi.

ASSAM ARAKAN BASIN – North Eastern India

Block AS-ONN-2000/1: Exploration

(Hardy 10% interest)

Operations KG-V-D9

On 2 April 2008, Hardy announced the award of a 10% interest in the exploration licence AS-ONN-2000/1. This is the Group's first onshore block and fourth licence in partnership with Reliance. This block was offered in NELP II but commencement of operations had been delayed due to the outstanding grant of an onshore petroleum exploration licence from the appropriate state agencies.

The acquisition of 450 lkm of 2D data commenced in December 2008 and is scheduled to be completed by the second quarter of 2009. The joint venture is expected to complete the reprocessing of the existing 124 lkm 2D seismic data in 2009. Upon completion of the reprocessing and acquisition of 2D data, the phase I minimum work programme commitment for the block will be achieved.

Background

The AS-ONN-2000/1 exploration licence is located in the north eastern state of Assam, India and north of Brahmaputra River. The exploration licence covers an area of 5,754 km^2 and falls within the districts of Darrang and Sonitpur. The block is in phase I of the three-phase exploration licence. Phase I (three years) will expire in the month of January 2011.

The topography of the area is primarily a plain of low relief and there is a reasonably established road network across the block. A national highway runs parallel to the river Brahmaputra and passes through the block. Different play types expected are, Anticlinal structures within Paleocene – Eocene and Gondwana, Fault closures, Pinchout/wedgeout, Fractured/weathered basement.

CAUVERY BASIN – South Eastern India
Block CY-OS 90/1 (PY-3): Producing Oil Field
(Hardy 18% interest – Operator)

Production

Actual gross field production for the year ended 31 December 2008 was 2,550 stbd (2007: 4,150 stbd). The production facilities' uptime performance was 88.2 per cent (2007: 96.8 per cent). The decrease in production is due to the conversion of well PY3-3RL into a water injection well as the well ceased to produce due to water loading. In addition, work over on well PD-4 commenced on 15 October 2008 to drill a lateral well from the existing surface location.

Production for January and February was 2,846 stbd and 2,787 stbd respectively. We anticipate that the PY-3 field will average gross daily production of 3,000 stbd for 2009. Currently the field is producing at a gross rate of 3,200 stbd.

For the year ended 31 December 2008, the average water injection rate was 7,139 bwpd (2007: 5,800 bwpd) which, at current production levels, is sufficient to maintain voidage replacement. Voidage replacement is important for maintaining pressure levels in the field that should ultimately enhance overall recovery of oil from the field. Injection facilities' uptime performance was 84.5 per cent (2007: 86.8 per cent).

The PY-3 field was shutdown twice in 2008. The first shutdown occurred between the 3rd to 12th of February 2008, due to Normor Buoy inspection and the renewal of jumper hose as per ABS requirements. The field was again shutdown from 26 November to 29 December 2008, due to the FSO loading hose, mooring hawser & back-up rope failure during tropical cyclone Nisha.

Operations

The PY3-3RL well was converted to a water injector on 23 July 2008. The current injection rate of the well is 11,350 bwpd.

As announced on 17 February 2009, the Company completed the re-entry and drilling of the PY3-PD4RL well. The PD4 vertical well was re-entered and side-tracked from 2,916 m MD (2,890 m TVDSS) and drilled down to 4,375 m MD (3,525 m TVDSS). The lateral (PR4-RL) well was drilled to increase the field production and the reservoir was expected to be encountered at 3,440m TVDSS; however the reservoir came 25 m down from the prognosis at 3,465 m TVDSS due to thickening of the overlying shale coupled with anomalous velocity variation, which is a common problem in the field. The well drilled a gross reservoir pack of 173 m MD (60 m TVD) within the reservoir section.

With the assistance of nitrogen lift, the well flowed at 700 stbd of oil with 30% water-cut, however, the well was unable to be reactivated as a self flowing well. The well has been completed as a producer with a gas lift valve to allow for future production when gas lift compression facilities are installed on the FPU.

Further drilling on PY-3 will be determined after remapping of the field has been completed incorporating the results of the PD4-RL well.

Background

The PY-3 field is located off the East Coast of India 80 km south of Pondicherry in water depths of between 40 m and 400 m. The Cauvery basin developed in the late Jurassic/early Cretaceous period and straddles the present-day East Coast of India.

The licence, which covers 81 km^2, produces oil of high quality light crude (49° API). The field was developed using floating production facilities and subsea wellheads, a first for an offshore field in India.

The facility at PY-3 consists of the floating production unit, 'Tahara', and a 65,000 DWT tanker, 'Endeavor', which acts as a floating storage and offloading unit. There are four sub-sea wells tied back to Tahara. Tahara has a three-stage crude oil separation system, with the first two stages being three-phase separators and the third stage a two-phase separator. Actual liquid processing capacity on Tahara is 20,000 stbd with 17 MMscfd of gas handling capacity.

The field currently produces associated gas in the range of 3.5 MMscfd. This produced gas is used as fuel gas with excess gas being flared. The stabilised crude oil is pumped from Tahara to Endeavor for storage and offloading to shuttle tankers. Crude oil from the PY-3 field is sold to CPCL at its refinery in Nagapattinam, approximately 70 km south of the PY-3 field.

CAUVERY BASIN – South Eastern India
Block CY-OS/2: Exploration
(Hardy 75% interest – Operator)

Operations

As part of the Ganesha appraisal programme, a number of geological and geophysical studies have been undertaken, including reprocessing of the 3D seismic data covering the block to improve subsurface understanding.

The resulting reprocessing and interpretation assessment has led the Operating Committee to recommend a revision of the appraisal programme from three firm and two contingent wells to one firm well and one contingent well. The amended programme has been approved by the joint venture and reviewed by the Management Committee. The joint venture has applied for the extension of the appraisal period to January 2012. The approval is awaited from the Government of India to establish the commerciality of the non-associated gas discovery.

The joint venture has applied to the Ministry of Petroleum and Natural Gas of the Government of India to establish commerciality of the Ganesha gas discovery during an appraisal period to January 2012 as per the PSC. On 20 February 2009 HEPI received a communication from DGH to establish commerciality within 15 days or relinquish the block. We believe that this action was taken by DGH on the assumption that the Ganesha discovery was an oil discovery. As Ganesha is a non-associated gas discovery, the CY-OS/2 PSC provides for an appraisal programme to establish commerciality to January 2012. The Company is working with the Ministry and DGH to finalise the extension period.

The Company is actively considering farming out a significant portion of its participating interest in the licence.

Background

The CY-OS/2 block is located in the northern part of the Cauvery Basin immediately offshore from Pondicherry and covers approximately 859 km^2. HEPI is the operator of this block.

The CY-OS/2 licence comprises two retained areas. The northern area includes the Ganesha (Fan A -1) discovery. The southern area lies immediately adjacent to the HEPI-operated PY-3 field. Another commercial gas field (PY-1) lies within the southern part of the acreage. The PY-1 field is owned by Hindustan Oil Exploration Company Limited and is expected to begin production in 2009.

Ganesha gas discovery (Fan A-1 well): On 8 January 2007 the Company announced that the Fan A-1 well had discovered hydrocarbons. On 10 August 2007, the Company announced that it would proceed with an appraisal programme to delineate the Cretaceous Fan A -1 gas discovery to establish the potential commerciality of the discovery.

NIGER DELTA BASIN – Nigeria

Block Oza (OML 11): Development

(Hardy 20% interest)

Operations

In 2008, the Oza joint venture continued to work jointly with Shell Petroleum Development Company (SPDC) towards implementing a solution on meeting applicable statutory Federal Government norms on cessation of gas flaring, which is likely to come into force in 2010.

In February 2008, Hardy Oil Nigeria Limited farmed out 20 percent of its participating interest in Oza Field to another Nigerian oil company, which has agreed to assume the responsibility of financing the first phase of the Oza Field development. The assignment was duly approved by Nigerian Federal Government on 1 August 2008.

During the year, line pipe has been acquired and has arrived in Nigeria in February 2009. Front end engineering study (FEED) and pipeline route survey commenced and final reports will be available in the first quarter of 2009. It is anticipated that pipeline construction and installation will commence in the third quarter of 2009. The Operator also successfully concluded discussions with the Oza community which culminated in the execution of an MOU.

Millenium Oil and Gas Limited, the operator for Oza field, with inputs from HON, continued efforts to obtain additional data in the field and to conclude agreements for crude handling and purchase of Oza 3D seismic with Shell Petroleum Development Company (SPDC).

Background

The Oza Field is located on-land in the north-western part of OML 11, near Port Harcourt and covers an area of 20 km^2.

The Oza field is subject to a farm-out agreement between NNPC, SPDC, Elf Petroleum Nigeria Limited and AGIP as farmor and Milennium as farmee. The terms of this agreement are for an initial five year period from 27 April 2004 subject to an extension of the Oza Farm-out Agreement if approved by the Nigerian Department of Petroleum Resources (DPR).

The field has cumulatively produced approximately 1.0 MMstb from four open zones of three wells targeting three reservoirs, M5.0, L9.0 and M2.1, with the principal reservoir being M5.0. At present, Oza has three suspended wells in the field. In November 2007 the Oza joint venture successfully executed a flow test of the Oza 4 well. The flow rates averaged approximately 600 stbd of oil with a GOR of 5,466 scf/stb.

NIGER DELTA BASIN – Nigeria
Block Atala (OML 46): Development
(Hardy 20% interest)

Operations

The Atala joint venture submitted the Atala Field Development Report to the Federal Government for its review and approval. The development focuses on initially developing the oil reserves whilst exploring viable options to monetise the field's substantial natural gas potential. The Operator has been in discussions with other companies in the area to jointly evolve an approach for gas development.

The joint venture continued efforts to lease a suitable swamp barge for Atala-1 well re-entry. Preparatory work at the field location was undertaken including the completion of hydrographic survey in and around the field, tendering for dredging of well locations and engagement with the local communities for execution of MOU. The Federal government has approved the planned re-entry programme including the environmental impact assessment report. Commencement of operations will be subject to securing an appropriate swamp-barge drilling rig.

Background

Atala is located within OML 46 which is situated within a mangrove swamp on the Dodo River, a coastal area of NW Bayelsa State. The concession area is 34 km^2. The Atala field was discovered in 1982 with the drilling of the Atala-1 well to a total depth of 4,058 m. Hydrocarbons were encountered and the well was cased but not tested or completed.

The Atala field is subject to a farm-out agreement between NNPC, SPDC, Elf Petroleum Nigeria Limited and Nigerian AGIP Oil Company Limited as farmor and Bayelsa as farmee. The terms of this agreement are for an initial five-year period from 27 April 2004, subject to an extension of the term of the Atala Farm-out Agreement if approved by the Nigerian Department of Petroleum Resources.

HARDY OIL AND GAS plc

Consolidated Income Statement

For the year ended 31 December 2008

	Notes	2008 US$	2007 US$
Revenue	2	17,306,042	11,829,554
Cost of sales			
Production costs		(7,523,972)	(4,216,138)
Depletion		(1,521,919)	(1,344,101)
Decommissioning charge		(151,174)	(217,397)
Gross profit		8,108,977	6,051,918
Administrative expenses		(9,847,526)	(6,865,187)
Operating loss		(1,738,549)	(813,269)
Gain on sale of investment		12,953,064	10,243,729
Interest and investment income		1,320,189	1,381,121
Finance costs		(91,204)	(180,400)
Profit before taxation		12,443,500	10,631,181
Tax on profit		(4,971,144)	(2,315,203)
Profit attributable to the equity shareholders of the parent company		7,472,356	8,315,978
Earnings per share			
Basic	4	0.12	0.14
Diluted	4	0.11	0.13

HARDY OIL AND GAS plc

Consolidated Statement of Changes in Equity

For the year ended 31 December 2008

	Notes	2008 US$	2007 US$
Beginning of year		143,995,825	91,401,836
Profit for the year		7,472,356	8,315,978
Available for sale investments:			
Unrealised valuation gain		-	3,514,603
Transferred to profit on sale from other reserves		(12,354,477)	-
Deferred tax on valuation gain released on sale of investment		3,441,945	-
Deferred tax liability on unrealised valuation gain		-	(966,780)
Total recognised (losses) / gains		(1,440,176)	10,863,801
New shares issued		250,944	40,168,691
Share based payments		1,425,280	1,561,497
End of year		144,231,873	143,995,825

HARDY OIL AND GAS plc

Consolidated Balance Sheet

As at 31 December 2008

	Notes	2008 US$	2007 US$
Assets			
Non-current assets			
Intangible assets – exploration		124,013,261	99,284,534
Intangible assets - others		111,640	246,572
Property, plant and equipment		8,477,099	3,375,463
Investments		-	15,092,311
Site restoration deposit		3,211,830	3,369,820
		135,813,830	121,368,700
Current assets			
Inventory		3,736,437	2,703,915
Trade and other receivables		4,087,719	14,525,440
Short term investments		22,010,291	-
Cash and cash equivalents		8,139,314	31,157,048
		37,973,761	48,386,403
Total assets		173,787,591	169,755,103
Liabilities			
Current liabilities			
Trade and other payables		(13,758,099)	(9,857,909)
Non-current liabilities			
Provision for decommissioning		(4,500,000)	(4,500,000)
Provision for deferred tax		(11,297,619)	(11,401,369)
		(15,797,619)	(15,901,369)
Total liabilities		(29,555,718)	(25,759,278)
Net assets		**144,231,873**	**143,995,825**
Equity			
Called-up share capital	6	623,210	622,625
Share premium		93,351,938	93,101,579
Shares to be issued		3,926,870	2,501,590
Other reserves		-	8,912,532
Retained earnings		46,329,855	38,857,499
Total equity attributable to equity holders of the parent		**144,231,873**	**143,995,825**

HARDY OIL AND GAS plc

Consolidated Statement of Cash flows

For the year ended 31 December 2008

	Notes	2008 US$	2007 US$
Operating activities			
Cash flow from operating activities	3	2,065,776	(1,844,914)
Taxation paid		(1,373,117)	63,235
Net cash from (used in) operating activities		692,659	(1,781,679)
Investing activities			
Expenditure on intangible assets -exploration		(24,728,727)	(32,068,253)
Expenditure of property, plant and equipment		(6,802,348)	5,856
Purchase of intangible assets - others		(3,841)	(147,297)
Purchase of other fixed assets		(117,097)	(38,753)
Purchase of investment		(13,184,387)	-
Sale of investment		41,378,216	-
Site restoration deposit		157,990	(585,160)
Short term investment		(22,010,291)	-
Net cash (used in) investing activities		(25,310,485)	(32,833,607)
Financing activities			
Interest and investment income		1,520,555	1,293,104
Finance costs		(91,204)	(180,400)
Issue of shares		170,741	40,168,691
Net cash from financing activities		1,600,092	41,281,395
Net (decrease) increase in cash and cash equivalents		**(23,017,734)**	**6,666,109**
Cash and cash equivalents at the beginning of the year		31,157,048	24,490,939
Cash and cash equivalents at the end of the year		**8,139,314**	**31,157,048**

1. Accounting Policies

The following accounting policies have been applied in preparation of consolidated financial statements of Hardy Oil and Gas plc ("Hardy" or the "Group").

a) Basis of preparation

Hardy prepares its financial statements on a historical cost basis except as otherwise stated. Investment in a publicly traded company is restated at fair value.

b) Going concern

The Group has a history of profitable operations and has successfully raised financing in the past to provide funding for its ongoing exploration and development programs and to augment its working capital. Having regard to the Group's existing working capital position and its ability to raise potential financing, if required, the Directors are of the opinion that the Group has adequate resources to enable it to undertake its planned work programme of exploration, appraisal and development activities over the next twelve months.

c) Accounting standards

Hardy prepares its financial statements in accordance with applicable International Financial Reporting Standards (IFRS) and interpretations issued by the International Accounting Standards Board as adopted by the European Union.

As at the date of approval of these financial statements, the following standards and interpretations were in issue but not yet effective:

IFRS 3	(revised) *Consolidated financial statements*
IFRS 8	*Operating segments*
IFRIC 13	*Customer loyalty programmes*
IFRIC 15	*Agreements for the construction of real estate*
IFRIC 16	*Hedges of a net investment in a foreign operation*
IFRIC 17	*Distribution of non-cash assets to owners*
IFRIC 18	*Transfer of assets from customers*
IAS 1	(revised) *Presentation of financial statements*
IAS 23	(revised) *Borrowing costs*
IAS 27	(revised) *Consolidated and separate financial statements*

The Directors do not anticipate that the adoption of these standards and interpretations in future reporting periods will have a material impact on the Group's results.

d) Basis of consolidation

The consolidated financial statements include the results of Hardy Oil and Gas plc and its subsidiary undertakings. The consolidated income statement and consolidated cash flow statements include the results and cash flows of subsidiary undertakings up to the date of disposal.

The group conducts the majority of its exploration, development and production through unincorporated joint arrangements with other companies.

The consolidated financial statements reflect the group's share of production and costs attributable to its participating interests under the proportional consolidation method.

e) Revenue and other income

Revenue represents the sale value of the group's share of oil which excludes the profit oil sold and paid to the Government as a part of profit sharing in the year, tariff, and income from technical services to third parties if any. Revenues are recognised when crude oil has been lifted and title has been passed to the buyer or when services are rendered.

f) Oil and gas assets

i) Exploration and evaluation assets

Hardy follows the full cost method of accounting for its oil and gas assets. Under this method, all expenditures incurred in connection with and directly attributable to the acquisition, exploration and appraisal having regard to the requirements of IFRS 6 "Exploration for and Evaluation of Mineral Resources" are accumulated and capitalised in two geographical cost pools, which are not larger than a segment: India and Nigeria.

The capitalised exploration and evaluation costs are classified as Intangible assets – exploration which includes the license acquisition, exploration and appraisal costs relating either to unevaluated properties or properties awaiting further evaluation but do not include costs incurred prior to having obtained legal right to explore an area, which are expensed directly to the income statement as they are incurred.

Intangible exploration and evaluation cost relating to each license or block remain capitalised pending a determination of whether or not commercial reserves exists. Commercial reserves are defined as proven and probable on a net entitlement basis.

When a decision to develop these properties is taken or there is evidence of impairment, the costs are transferred to the cost pools within development/producing assets when the commercial reserves attributable to the underlying asset have been established.

ii) Oil and gas development and producing assets

Development and production assets are accumulated on a field by field basis. These comprise of the cost of developing commercial reserves discovered to put them on production and the exploration and evaluation costs transferred from intangible exploration and evaluation assets, as stated in policy above. In addition, interest payable and exchange differences incurred on borrowings directly attributable to development projects, if any, and assets in the production phase, as well as cost of recognising provision for future restoration and decommissioning, are capitalised.

iii) Decommissioning

At the end of the producing life of a field, costs are incurred in removing and decommissioning facilities, plugging and abandoning wells. Future decommissioning costs are estimated and stated at an amount representing the costs which would be incurred should decommissioning occur at the balance sheet date and the estimates are reassessed each year. The provision is assessed at prices ruling at the balance sheet date and, accordingly, it is not appropriate to discount this provision. The decommissioning asset is included within the property, plant and equipment with the cost of the related assets installed and is adjusted for any revision to the decommissioning costs and the provision thereof. The amortisation of the asset, calculated on a unit of production basis based on proved and probable reserves, is shown as "Decommissioning charge" in the income statement.

iv) Disposal of assets

Proceeds from any disposal of assets are credited against the specific capitalised costs included in the relevant cost pool and any loss or gain on disposal is recognised in the income statement. Gain or loss arising on disposal of a subsidiary is recorded in the income statement.

g) Depletion and impairment

i) Depletion

The net book values of the producing assets are depreciated on a field by field basis using the unit of production method, based on proved and probable reserves taking into consideration future development expenditures necessary to bring the reserves into production. Hardy periodically obtains an independent third party assessment of reserves which is used as a basis for computing depletion.

ii) Impairment

Exploration assets are reviewed regularly for indications of impairment, if any, where circumstances indicate that the carrying value might not be recoverable. In such circumstances, if the exploration asset has a corresponding development / producing cost pool, then the exploration costs are transferred to the cost pool and depleted on unit of production. In cases where no such development/producing cost pool exists, the impairment of exploration costs is recognised in the income statement. Impairment reviews on development / producing oil and gas assets for each field are carried out on each year by comparing the net book value of the cost pool with the associated discounted future cash flows. If there is any impairment in a field representing a material component of the cost pool, an impairment test is carried out for the cost pool as a whole. If the net book value of the cost pool is higher, then the difference is recognised in the income statement as impairment.

h) Property, plant and equipment

Property, plant and equipment other than oil and gas assets are measured at cost and depreciated over their expected useful economic lives as follows:

	Annual Rate (%)	Depreciation Method
Leasehold improvements	over lease period	Straight line
Furniture and fixtures	20%	Straight line
Information technology and computers	33%	Straight line
Other equipment	20%	Straight line

i) Intangible assets

Intangible assets other than oil and gas assets are measured at cost and depreciated over their expected useful economic lives as follows:

	Annual Rate (%)	Depreciation Method
Computer software	33 %	Straight line

j) Investments

Investments in publicly traded securities are treated as available for sale are recognised at fair values based upon the quoted market prices on the balance sheet date. Unrealised gains and losses are recognised under equity – other reserves. On disposal of an investment, the cumulative gain or loss is recognised in the income statement.

k) Short term investments

Short term investments are regarded as “financial assets at fair value through profit or loss” and are carried at fair value. In practice, the nature of these investments is such that the fair value equates to the value of initial outlay and therefore in normal circumstances no fair value gain or loss is recognised in the income statement.

l) Inventory

Inventory of crude oil is valued at the lower of average cost and market value. Average cost is determined based on actual production cost for the year. Inventories of drilling stores are recorded at cost including taxes duties and freight. Provision is made for obsolete or defective items where appropriate based on technical evaluation.

m) Financial instruments

Financial assets and financial liabilities are recognised at fair value in the group’s balance sheet based on the contractual provisions of the instrument.

Trade receivables do not carry any interest and are stated at their nominal value as reduced by necessary provisions for estimated irrecoverable amounts.

Trade payables are not interest bearing and are stated at their nominal value.

n) Equity

Equity instruments issued by Hardy and the group are recorded at net proceeds after direct issue costs.

o) Taxation

The tax expense represents the sum of current tax and deferred tax.

Current tax is based on the taxable profit of the year. Taxable profit differs from net profit as reported in the income statement as it excludes certain items of income or expenses that are taxable or deductible in years other than the current year, and it further excludes items that are never taxable or deductible. The current tax liability is calculated using the tax rates that have been enacted or subsequently enacted by the balance sheet date.

Deferred tax is the tax expected to be payable or recoverable on differences between the carrying amounts of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit, and is accounted for using the liability method.

Deferred income tax liabilities are recognised 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 income tax liabilities are recognised for all temporary differences except in respect of taxable temporary differences associated with investment in subsidiaries, associates and interest in joint ventures where the timing of the reversal of the temporary differences can be controlled and it is possible that the temporary differences will not reverse in the foreseeable future.

Deferred tax is recognised in respect of all temporary differences that have originated but not reversed at the balance sheet date, where transactions or events have occurred at that date that will result in an obligation to pay more or a right to pay less or to receive more tax.

Deferred tax assets and liabilities are measured on an undiscounted basis at the tax rates that are expected to apply in the periods in which temporary differences reverse, based on tax rates and laws enacted or substantively enacted at the balance sheet date.

p) Foreign currencies

Hardy maintains its accounts and the accounts of its subsidiary undertakings in US dollars. Foreign currency transactions are accounted for at the exchange rate prevailing on the date of the transaction. At the year end, all foreign currency assets are restated at the closing rate at the balance sheet date. Exchange difference arising out of actual payments / realisations and from the year end restatement are reflected in the income statement.

Rates of exchanges are as follows:

	31 December 2008	31 December 2007
£ to US$	1.4626	1.9828
US$ to Indian Rupees	48.52	39.420

q) Estimation uncertainty

(i) Decommissioning

The liability for decommissioning is based on estimates of the costs of decommissioning that will arise at some point in future. Significant changes in costs as a result of technical advancements can result in material change to this provision.

(ii) Depletion

Depletion calculations are based on the best estimate of commercial reserves existing as at the balance sheet date. The determination of commercial reserves is based on assumptions which include those relating to the future price of crude oil, capital expenditure plans and the cost of production. Any changes in these assumptions could result in a material change in the depletion charge or the carrying value of associated assets.

r) Leasing commitments

Rental charges or charter hire charges payable under operating leases are charged to the income statement as part of production cost over the lease term.

s) Share based payments

Hardy issues share options to directors and employees, which are measured at fair value at the date of grant. The fair value of the equity settled options determined at the grant date is expensed on a straight line basis over the vesting period based on the actual number of shares vested in the accounting period. In performing the valuation of these options, only conditions other than the market conditions are taken into account. Fair value is derived by use of the binomial model. The expected life used in the model is based on management estimates and considers non-transferability, exercise restrictions and behavioural considerations.

2. Revenue and other income

	2008 US$		2007 US$	
	India	UK	India	UK
Oil sales	18,748,999	-	15,531,311	-
Profit oil to government	(2,311,862)	-	(4,268,322)	-
Other income	-	868,905	-	566,565
	16,437,137	868,905	11,262,989	566,565

The directors do not consider there to be more than one class of business or geographic segment for the purposes of reporting. The Group is engaged in one business activity, the production of and exploration for oil and gas. The revenue, segment result and assets of the geographic segments, other than India, are nil or less than 10% of the total for all segments. Other income relates to technical services to third parties, overhead recovery from joint venture operations and miscellaneous receipts if any. Revenue arises from the sale of oil produced from the contract area CY-OS-90/1-India and the revenue by destination is not materially different from the revenue by origin.

In the contract area CY-OS-90/1, an un-recovered development cost of US$ 2,868,277 is carried as at 31 December 2008. As a consequence, no profit oil is payable to Government of India until such cost is fully recovered from future revenue from this contract area.

3. Reconciliation of operating profit to operating cash flows

	2008 US$	2007 US$
Operating loss	(1,738,549)	(813,269)
Depletion and depreciation	1,805,408	1,622,030
Decommissioning charge	151,174	217,397
Share based payments charges	1,429,736	1,561,497
	1,647,769	2,587,655
(Increase)/decrease in inventory	(1,032,522)	25,849
(Increase)/ decrease in trade and other receivables	(2,676,392)	2,720,211
Increase /(decrease) in trade and other payables	4,126,921	(7,178,629)
Net cash inflow/(outflow) from operating activities	2,065,776	(1,844,914)

The decrease in trade and other receivables reported above for 2007 for the Group excludes an amount of US$ 12,502,931 due from the sale of investment in Hindustan Oil Exploration Company ('HOEC") during the year 2007.

4. Earnings per share

Earnings per share are calculated on a profit of US$ 7,472,356 for the year 2008 (2007: US$ 8,315,978) on a weighted average of 62,287,526 ordinary shares for the year 2008 (2007: 60,117,416).

The diluted earnings per share are calculated on a profit of US$ 7,472,356 for the year 2008 (2007: US$ 8,315,978) on a weighted average of 66,994,627 ordinary shares for the year (2007: 64,469,515). The weighted average shares are calculated after giving impact to dilutive potential ordinary shares of 4,302,101 relating to share options after excluding 405,000 options wherein the strike price exceeds the average market price of the shares of the company for 2008 (2007: 4,352,099).

5. Members of the Group

The group comprises the parent company – Hardy Oil and Gas plc – and the following subsidiary companies, all of which are wholly owned:

- Hardy Exploration & Production (India) incorporated under the Laws of State of Delaware, United States of America.

- Hardy Oil (Africa) Limited registered under the laws of the Isle of Man.

- Hardy Oil Nigeria Limited, owned by Hardy Oil (Africa) Limited, registered under the laws of Nigeria.

All members of the group are engaged in the business of exploration and production of oil and gas and all are included in the consolidation.

6. Share Capital

	Number $0.01 Ordinary Shares "000"	US$
Authorised ordinary shares		
At 1 January 2007	200,000	2,000,000
At 1 January 2008	200,000	2,000,000
At 31 December 2008	200,000	2,000,000
Allotted, issued and fully paid ordinary shares		
At 1 January 2007	57,252,994	572,530
Share options exercised during the year	45,001	450
Shares issued during the year	4,964,540	49,645
At 1 January 2008	62,262,535	622,625
Share options exercised during the year	38,330	383
Shares issued during the year	20,182	202
At 31 December 2008	62,321,047	623,210

Ordinary shares issued are with equal voting and other rights with no guarantee on dividend or other payments.

DEFINITIONS & GLOSSARY OF TERMS:

AFE	authority for expenditure
AIM	the market of that name operated by the London Stock Exchange
Assam block	licence AS-ONN-2000/1
Bayelsa	Bayelsa Oil Company Limited
Board	the Board of Directors of Hardy Oil and Gas plc
the Company	Hardy Oil and Gas plc
CPCL	Chennai Petroleum Company Limited, formerly known as Madras Refinery Limited
D3	licence KG-DWN-2003/1 awarded in NELP V
D9	licence KG-DWN-2001/1 awarded in NELP III
Deepwater Expedition	Operated by Transocean Inc the Deepwater Expedition is a self-propelled dynamically positioned drillship capable of drilling in water depths up to 10,000 feet
DGH	Directorate General of Hydrocarbons
Dhirubhai 33	gas discovery on GS-01-B1 well
Dhirubhai 39	gas discovery on KGV-D3-A1 well
Dhirubhai 41	gas discovery on KGV-D3-B1 well
DPR	Nigerian Department of petroleum Resources
Emerald	Emerald Energy Resources Limited
FCA	Financial Chartered Accountant
FDP	field development plan
FEED	front end engineering study
FSO	floating Storage and offloading vessel
GAIL	Gas Authority of India Limited
Ganesha	gas discovery on Fan-A1 well located in CY-OS/2
GCA	Gaffney, Cline & Associates Ltd.
Group	the Company and its subsidiaries
GS-01	licence GS-OSN-2000/1 awarded under NELP II
GXT ION	GX Technology Corporation
H2	second half of the year
Hardy	Hardy Oil and Gas plc
HEPI	Hardy Exploration & Production (India) Inc.
HOEC	Hindustan Oil Exploration Company Limited
HON	Hardy Oil Nigeria Limited
IFRS	International Financial Reporting Standards
IPO	initial public offering
KG basin	Krishna Godavari sedimentary basin comprising an area on the southeast India continental shelf
London Stock Exchange	London Stock Exchange plc
Main Market	Official List of the London Stock Exchange's market for listed securities
Management Committee	as per India PSC's the management committee comprises representatives of each participating

	interest holder, DGH and the Ministry of Petroleum and Natural Gas of India
Millenium	Millenium Oil and Gas Company Limited
MOU	memorandum of understanding
NELP	New Exploration Licensing Policy of the Ministry of Petroleum and Natural Gas of India
Operating Committee	as per India PSC's operating committee's comprise representatives of the various participating interest holders in the licence
OML	Oil mining licence
Ordinary Shares	the ordinary share of US$ 0.01 each in the capital of the Company
PSC	production sharing contract
PY-3	licence CY-OS-90/1
Reliance	Reliance Industries Limited
SPDC	Shell Petroleum Development Company of Nigeria
UK	United Kingdom

Glossary of terms:

$	United States dollars
2D/3D	two dimensional/three dimensional
2P	proven plus probable
API°	American Petroleum Institute gravity
AVO	amplitude variations with offset
BOP	blow-out preventer
bwpd	barrels of water per day
Contingent Resources	those quantities of petroleum estimates, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to on or more contingencies
Prospective Resources	Prospective Resources are those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from undiscovered accumulations.
DST	drill stem test
DWT	dead weight tonne
FDP	field development plan
GIIP	gas initially in place
GOR	gas to oil ratio
km	kilometre
km^2	kilometre squared
lkm	line kilometre
m	metre
MDRT	measured depth from the rotary table

MDT	modular formation dynamics tester
MMscfd	million standard cubic feet per day
MMscmd	million standard cubic metres per day
MMstbd	million stock tank barrels per day
PSDM	pre-stack depth migration
psi	pounds per square week
scf	standard cubic feet
scfd	standard cubic feet per day
SPM	single point mooring
stb	stock tank barrel
stbd	stock tank barrel per day
TCF	trillion cubic feet
TVD	total vertical depth
TVDRT	total vertical depth from rotary table